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**Technical Assistance for Improvement of
Performance-Based Tariff Regulation of EMRA for
Turkish Energy Markets through Introducing
an Enhanced Monitoring System**

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**Task-1: Improvement of Performance- based Tariff Setting
for Transmission and Distribution System Operations
at Turkish Electricity and Natural Gas Markets**

Activity 1.1 – Full DRAFT Report



REPUBLIC OF TURKEY
MINISTRY OF ENERGY AND
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Central Finance And Contracts Unit

CFCU Contract Manager : Duygu Sarıkan

Address : T.C. Hazine ve Maliye Bakanlığı Kampüsü E Blok İnönü Bulvarı No:36
06510 Emek / ANKARA

Telephone : +90 312 295 49 00

Fax : +90 312 286 70 72

e-mail : duygu.sarikan@cfcu.gov.tr

Beneficiary : **Republic of Turkey Energy Market Regulatory Authority**

Address : İşçi Blokları Mahallesi Muhsin Yazıcıoğlu Caddesi
No:51/C 06530 Yüzüncüyıl Çankaya / ANKARA

Telephone : +90 312 201 40 00 - 201 40 01 - 201 40 02

Fax : +90 312 201 40 50

Consultant : Hulla & Co Human Dynamics KG

Project Director : Mr. Valter Anacleto

Address : Lothringer Strasse 16, A-1030 Wien, Austria

Telephone : +43 1 402 50 20 133

Fax : +43 1 402 50 20 20

e-mail : valter.anacleto@humandynamics.org

Project Team Leader : Dr. Wietze Lise

Address (Project Office) : Mustafa Kemal Mahallesi, 2138 Sokak No 5/10, 06520, Çankaya,
Ankara, Türkiye

Telephone/Fax : +90 312 219 4108

e-mail : lise.tariffproject@gmail.com

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Abbreviations

€/EUR	European Euros
£/POUND	British Pound Sterling (in 2019 1 Euro costs 0.88 POUND)
₺/TL	Turkish Liras (in 2019 1 Euro costs 6.3477 TL)
\$/USD	United States Dollars (in 2019 1 Euro costs 1.12 USD)
A	Ampere
AAHEDC	Assistance for Areas with High Electricity Distribution Costs
ACER	Agency for the Cooperation of Energy Regulators
ACM	Authority for Consumers & Markets (in the Netherlands)
AEEGSI	Italian Regulatory Authority for Electricity Gas and Water
AID	Average Interruption Duration
AIP	Annual Iteration Process (in the UK)
AIT	Average Interruption Time
AR	Allowed Revenue
ARegV	Incentive Regulation Ordinance (in Germany)
ARERA	Autorità di Regolazione per Energia Reti e Ambiente (Italian regulator)
ASIDI	Average System Interruption Duration Index
ASIFI	Average System Interruption Frequency Index
ATEM	Minimum Concession Area (in Italy)
BC	Baltic Cable
BMU	Balancing Mechanism Units
BNetzA	Bundesnetzagentur (German regulator)
BOTAS	Turkish Gas Transmission Co.
BSUoS	Balancing Use of System (in UK)
CAA	Cost Allocation Assessment
CAE	Power purchase agreements (in Portugal)
CAIDI	Customer Average Interruption Duration Index
CAM	Capacity Allocations Methodologies
CAPEX	Capital Expenditures
CAPM	Capital Asset Pricing Model
CBA	Cost Benefit Analysis
CBb	Dutch Trade and Industry Appeals Tribunal
CCCM	Common Connections Charging Methodology
CCGT	Combined Cycle Gas Turbine
CDCM	Common Distribution Charging Methodology
CEER	Council of European Energy Regulators
CEI	Electrotechnical Italian Committee
CEMI	Customers experiencing multiple interruptions
CENS	Cost of Energy not Supplied
CEO	Corporate Executive Officer
CHP	Combined Heat and Power
CIR	Regulatory invested capital (in Italy)



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CMEC	Maintenance of the contractual balance (in Portugal)
CML	Customer Minutes Lost
CNG	Compressed Natural Gas
CNMC	Comisión Nacional de los Mercados y la Competencia, Spanish Competition Authority
CoF	Consequence of Failure
COLS	Corrected Ordinary Least Squares
CoS	Continuity of Supply
CPI	Consumer price index
CRP	Country Risk Premium
CSEA	Fund for energy and environmental services (in Italy)
Ct/€c	Cent (100 th of a Euro)
CTAIDI	Customer Total Average Interruption Duration Index
CTR	Italian Transmission Tariff
CUSC	Connection and Use of System Code
CWD	Capacity Weighted Distance
D/E	Debt/Equity
DADSEC	Day Ahead Daily System Entry Capacity
DEP	Depreciation
DEA	Data Envelopment Analysis
DISEC	Daily Interruptible System Entry Capacity
DNO	Distribution Network Operators
DP	Delivery Points (in Italy)
DSO	Distribution System Operator
DUoS	Distribution use-of-system
EBT	Electronic Bulletin Board
EDCM	EHV Distribution Charging Methodology
EEI	Environmental Emissions Incentive
EHV	Extra High Voltage
EI	Energy Markets Inspectorate (in Sweden)
EML	Electricity Market Law
EMRA	Energy Market Regulatory Authority
END	Energy not distributed due to interruptions
ENS	Energy Not Supplied
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Natural Gas
ENW	Energy Not Withdrawn
EnWG	Energy Industry Law (in Germany)
EPIAS	Energy Market Operations Co.
ERSE	National Regulatory Authority in Portugal
EU	European Union
EV	Electric Vehicle
FDH	Free Disposable Hull
GAV	Gross Asset Value



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GDN	Gas Distribution Network (in the UK)
GIS	Geographic Information System
GrDF	Distribution de gaz naturel en France, French Gas Distribution Co.
GTNC	BOTAS Network Code
GTS	Natural Gas Transmission Services (in the Netherlands)
GTUoS	Generator Transmission Use of System
GSE	Electricity Service Operator (in Italy)
HH	Household or half-hour
HR	Human resources
HV	High Voltage
IFRS	International Financial Reporting Standards
IGT	Independent Gas Transporter (in the UK)
IQI	Information Quality Incentive
ISEE	Yearly income (in Italy)
IT	Individual Threshold
KET	Small size network addendums
km	kilo meter
kV	kilo Volt
kVA	kilo Volt Ampere
kVARh	kilo Volt Amperes Reactive hours
kWh	kilo Watt hour
LDD	Losses and Diverse Discrepancies
LDR	Losses discretionary reward (in the UK)
LNG	Liquified Natural Gas
LP	Low Pressure
LPM	Line pack Performance Measure
LR	Loss Rate
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MENR	Ministry of Energy and Natural Resources
MLE	Maximum Likelihood Estimation
MOLS	Modified ordinary least squares
MPE	Ministry of Petroleum and Energy
MRP	Market Risk Premium
MV	Medium Voltage
MVA	Mega Volt Ampere
MVARh	Mega Volt Ampere Ractive hour
MW	Mega Watt
MWh	Mega Watt hour
MO	Market Operations
MOD	Incremental changes to base revenue (in the UK)
MP	Market Premium or Medium Pressure
MSEC	Monthly System Entry Capacity



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NAV	Net Asset Value
NCC	National Commission for Energy Control and Prices (in Lithuania)
NGESO	National Grid Electricity System Operator
NGET	National Grid Electricity Transmission plc (UK)
NGGT	National Grid Natural Gas Transmission Plc (UK)
NGML	Natural Gas Market Law
NHH	Non-half hour
NIA	Network Innovation Allowance
NIC	Network Innovation Competition
NRA	National Regulatory Authority
NGTR	Natural Gas Tariff Regulation
NTS	National Grid Natural Gas Transportation Services
NVE	Norwegian regulator
OCM	Operating Capital Maintenance (in Sweden)
ODI	Output Delivery Incentive
Offer	Office of electricity Regulation (in the UK)
Ofgas	Office of Gas Supply (in the UK)
Ofgem	Office of Gas and Electricity Markets (in the UK)
OFTO	Offshore Transmission Operator
OIZ	Organised Industrial Zone
OLS	Ordinary Least Square
OPEX	Operational Expenditures
OT	Operational Technology
OUG	Own Use of Gas
PCFM	Price Control Financial Model
PdR	Final delivery points (in Italy)
PNS	Power Not Supplied
PL	Power losses
POD	Point of Delivery (in Italy)
PoF	Probability of Failure
PPF	Pension Protection Fund
PPI	Producer price index
PPM	Price Performance Measure
PPRC	Principles and Procedures for Determining the Revenue Caps
QF	Quality Factor
R&D	Research and Development
RAB	Regulatory Asset Base
RAV	Regulatory Asset Value
REN	Transmission Network Operator (in Portugal)
REPEX	Replacement Expenditure (in the UK)
RES	Renewable Energy Source
RFR	real Risk-Free Rate
RIIO	Revenue = Incentive + Innovation + Output (in the UK)



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RoC	Rate of Change (in Poland)
RoE	Return on Equity
RoI	Return on Investment
RoR	Rate of Return
RoRE	Return on Regulatory Equity
RPM	Reference Price Methodologies
RRM	Revenue Requirement Model
RTDG	Natural Gas Distribution and metering services (in Italy)
RTN	National Transmission Network of Electrical Energy (in Portugal)
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAP	System Average Price
SARI	Average time to restore the supply after an interruption
Scm	Standard cubic meter
SCT	Special Consumption Tax
SEN	Portuguese National Electric System
SFA	Stochastic frontier analysis
SHET	Scottish Hydro Electric Transmission plc (UK)
SIP	Second Implementation Period
SME	Small and Medium Enterprise
SO	System Operator
SoLR	Supplier of Last Resort
SpLV	Special Low Voltage
SPT	Scottish Power Transmission Limited (UK)
STMD	More detailed project plan (in Italy)
STMG	Possible connection solution (in Italy)
StLV	Standard Low Voltage
SSM	Site-Specific Maintenance
SvK	Svenska Kraftnät
T&D	Transmission and Distribution
TAP	Trans Adriatic Pipeline
TAR NC	Tariff Network Code
TC	Regulated Grids (in Norway)
TCD	Combined average availability rate (in Portugal)
TEC	Transmission Entry Capacity
TEDAS	Turkish Electricity Distribution Co.
TEIAS	Turkish Electricity Transmission Co.
TEPE	Turkish Entry Postalised Exit
TFR fund	Trattamento di fine rapporto, severance pay (in Italy)
TIE	Equivalent duration of interruptions
TIEPI	Average duration of interruptions
TIM	TOTEX Incentive Mechanism (in UK)
TLM	Transmission Loss Multiplier



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TMR	Total Market Return
TNS	Transmission Network Service (UK)
TNUoS	Transmission Network Use of Service
TO	Transmission Operator
TOTEX	Total Expenditures (the sum of OPEX and CAPEX)
ToU	Time of Use
TPA	Third-party access
TRC	Transmission Running Cost
TSO	Transmission System Operator
TWh	Tera Watt hour
TYNDP	Ten Year Network Development Plan
UAG	Unaccounted for Gas
UK	United Kingdom
UR	Northern Ireland Authority for Utility Regulation
URT	Use of the Transmission Grid (in Portugal)
VAT	Value Added Tax
VoLL	Value of Lost Load
WACC	Weighted Average Cost of Capital
WDDSEC	Within Day Daily System Entry Capacity
WHD	Warm Home Discount (in the UK)
YEKDEM	Renewable Energy Support Mechanism (FIT)

Executive summary

The initial unbundling of the sector took place in 1994, when TEK was separated into two state-owned companies: Turkish Electricity Generation and Transmission Company (“**TEAS**”) responsible for generation and transmission activities and Turkish Electricity Distribution Company (“**TEDAS**”) responsible for distribution and retail sale activities.

The Electricity Market Law (“**EML**”) No 4628,¹ which was enacted by the Turkish Parliament on 20 February 2001, was the first appropriate step in order to determine the legal and institutional framework of the sector. The goal of Law No 4628 is to liberalise the electricity market in Turkey establishing a financially strong, stable, transparent, and competitive electricity market. By this new law, Turkey also created an autonomous Energy Market Regulatory Authority (“**EMRA**”), governed by its independent board initiating a major electricity market reform program. The reform program entails privatisation, liberalisation as well as a radical restructuring of the whole electricity industry.

Further unbundling of the sector took place in compliance with EML, which TEAS was separated into three state-owned companies: Turkish Electricity Transmission Company (“**TEIAS**”) responsible for transmission activities and Electricity Generation Company (“**EUAS**”) responsible for generation activities, and Turkish Electricity Trading and Contracting Company (“**TETAS**”) which has a mandate to deal with purchasing the electricity from the producers and the sale of this electricity to the Distribution Companies.

In 2013, the new EML No 6446 was enacted which repealed the EML No 4628. The new EML, was the second appropriate step in order to determine the legal and institutional framework, as well as the further development of the sector.

Electricity Distribution

Although the general approach to determine tariffs in Electricity Distribution sector show similarities in most of the countries in Europe, the detailed methodology, parameters and incentives might differ.

There is considerable variation in the number, size and structure of Electricity Distribution System Operators (DSO) throughout Europe as well as the methodology they use to determine allowed revenues.

In many European countries, the revenue cap is used as revenue requirement model. Each country decides for itself on the type and structure of its regulatory system. International benchmarks show that there is a tendency to switch to incentive-based mechanisms recently.

Turkey situation

Like most of the EU countries, revenue cap model is implemented in Turkey to determine allowed revenues and Electricity Distribution tariffs. National tariff together with price equalization methodology is somewhat unique process due to very high loss rates in few DSOs. On the other hand, although there was a small amount of incentive-based revenue cap, whole scheme was not able to define real DSO performance. System is based on what was spent in fiscal terms rather than necessity. This was the natural outcome of data inconsistencies, lack of operational data, unreliability of network assets such as lack of GIS data and unable to measure system quality indices (i.e. SAIDI, SAIFI) correctly. Outsourcing through own companies or third parties was also polluting photo year benchmarking process among DSOs. OPEX budgets were not related to actual assets including number of customers although almost all cost items in the general ledgers are related with those assets.

OPEX is set by EMRA on an ex-ante basis for each year of the implementation period. Being a part of the revenue cap, it is up to DSOs how to spend it and all savings from OPEX stays with DSO. Besides, there are five CAPEX categories that are network investments, network operation system investments, meter investments, environment, safety and other investments for legal liabilities and other expenditures having the characteristics of CAPEX. Since there is a separation between OPEX and CAPEX budgets, current tariff methodology does not give a chance for DSOs to choose the optimal solution, either by OPEX or CAPEX budget.

¹ Law No 4628 was published in the Official Gazette No 24335 dated 3 March 2001 (repeated edition).

RAB consists of unamortized network assets, expropriation costs, buildings, vehicles which were constructed or acquired by DSOs and approved by EMRA as CAPEX at the end of each year. Amortization period has been set as ten years. Third party assets are not included in the RAB, however, operating costs related to specific ones are included in overall operating costs since 2013 after the new Law No: 6446. Closing RAB is carried over to the following year by CPI.

In Turkey, due to lack of long-term funds for CAPEX with fixed rates in TL currency, it is becoming common practice to borrow in foreign currencies. This adds further complexity in the DSO business for financial sustainability.

In Turkey, one-time connection charges are applied as is common in other EU countries. However, deep or shallow connection charges differ with EU practices. In some countries, connection charges do not include network reinforcement costs (shallow pricing), while in others new customers also shares the burden of these costs.

In Turkey, DEA is used for the calculation of the efficiency factor, which is in theory, in line with the international practices. DEA analysis of EMRA depends on the previous OPEX expenditures (as input) of the DSOs and their network assets (as outputs). However, there are data problems with the inputs and outputs used in the model.

Due to the high loss rates of Turkey compared to EU countries, there is a specific regulation for loss reduction “Regulation on Measures for the Reduction of Losses in the Distribution System” in the country.

Network tariffs are determined by customer types and voltage levels in Turkey. Industry customers who chooses to have a set capacity, pays a fee per MW capacity per month and a lower distribution fee per kWh consumption is applied.

In Turkey, reactive fee is applied on a monthly measurement for customers above 9kW installed capacity, except for households. In general, Turkey and EU are compatible for reactive power measurements and charging, however, reactive power increases technical losses. Monthly charges do not incentivize/penalize the customers and DSOs reduce reactive power optimally.

In Turkey, last resort tariffs are differentiated for small (vulnerable) and large customers. In addition, lower energy prices for specified customer groups (martyr and veteran families) exists. The vulnerability of the consumers should be defined by the income levels, the share of energy expenditure of disposable income, the energy efficiency of homes, critical dependence on electrical equipment for health reasons, age or other criteria.

Situation in three EU countries

Germany started with an incentive-based mechanism in 2009 where DSOs have to lower their cost within the regulatory period to reach their profit targets. Regulatory period is set for five-years. Revenue cap is set for each calendar year of the regulatory period, based on an efficiency benchmark. TOTEX approach (with CAPEX subtraction) was used until the end of second regulatory period. Regulator approved revenues ex-ante and network operator-controlled costs autonomously within regulatory period.

New assets (capitalized since 01/01/2006) are valued at historical costs. Old assets (capitalised before 01/01/2006) are valued at replacement costs if they are financed by equity (indexed historical cost, maximum equity ratio of 40%) and at historical costs if they are financed by debt capital (debt ratio at least 60% of all old assets).

The regulatory authority sets the costs of capital, whereas the cost of debt is defined by law. For the 3rd implementation period. Cost of debt is treated as pass-through and therefore allows for natural hedge against changes in interest rate environment.

Quality regulation started to be implemented in 2012 and it is valid just for DSOs on LV and MV with more than 30,000 customers. If DSO performs above-average quality than an amount is added to their cap, while DSOs performing with comparatively poor quality-levels have amounts deducted (bonus/penalty system). Overall performance of the DSO is measured by SAIDI on LV.

Efficiency benchmarking is carried out on the basis of the cost examination (TOTEX) and structural data validation before the start of each new regulatory period. Efficiency benchmarking is a comparative method and the results for the individual DSOs have a

mutual influence on each other. A DSO that provides the same scope of services but has higher costs than another DSO (100% efficiency) will have an efficiency score lower than 100%. The efficiency scores are then applied to the controllable costs (total costs - permanently non-controllable costs - CAPEX subtraction). Moreover, both DEA and SFA methods are used to determine efficiency scores. Input parameter is generally controllable TOTEX and output parameters are area supplied, customers connected and environmental parameters.

Only technical losses are considered. Any method to derive the amount of losses is allowed and this can include estimation, free valuation, and calculation. However, there are discussions about taking reverse flow of electricity into account when calculating losses. DSO is responsible from network losses and it is paid through network tariffs.

Network charges are calculated by the network operators and they are based on the allowed revenue caps set by the regulatory authorities. The permissible revenue caps result from the costs of operation, maintenance and expansion of the network, plus regulatory profits as defined in previous sections. Network costs are allocated to the users taking into account each user's contribution to the annual simultaneous peak load.

Power prices are among the highest in Europe. Although wholesale electricity prices on average have been in decline in recent years, surcharges, taxes, and grid fees raise the bill for Germany's private households and small businesses.

Italy:

The model currently used in Italy for tariff regulation is **hybrid**. The hybrid system provides for the recognition in the tariff of sums to cover operating costs incurred by the operator (OPEX) and a fair return on the capital invested (CAPEX). The recognition of operating costs (OPEX) is established through the price-cap mechanism: this procedure allows to retain part of the recoveries of efficiency in excess of what is defined ex-ante through a profit-sharing mechanism that allows to distribute correctly profits between businesses and consumers.

Fixed assets are included in the regulatory asset base (RAB), with a one-year lag if investment costs are efficiently incurred and are consistent with system security, follow cost-effective criteria and, with regard to transmission, are included in the ten-year transmission development plans approved by the relevant authorities.

The rate of **return on invested capital** is calculated in the same way for the gas and electrical infrastructural services and it is periodically reviewed. WACC is set for the period 2016-2021.

Since the entry into force of the Bersani decree, ARERA has instituted a progressive regulation for the quality of the distribution, transmission and electrical measurement service with the aim of gradually orienting the company to a more general public interest, thereby preventing the effects of the original tariff methodology. of the price cap.

Productivity targets (X-factors) are differentiated by activity (transmission, distribution and metering) and are basically used as a tool to redistribute to network users the efficiency gains of the previous regulatory periods, which were temporarily retained by network operators under the profit-sharing mechanism. On the basis of this mechanism, at the end of the regulatory period, in order to set tariffs for the following period, efficiency gains are symmetrically shared between network operators and network users.

There are some mechanisms for network losses in order to improve the service in the next years. Losses could depend on not only of the distribution network but also where it is located, for instance the territory. Losses are paid by network tariffs and DSOs have to buy losses from the power exchange or through bilateral contracts.

The **mandatory tariff** for the distribution service covers the costs for the transport of electricity on the distribution networks and for the metering service.

With regard to the electricity bill, a distinction is needed among the users served with greater protection as compared to the users who have freely chosen for the free market. The users served with greater protection are the ones who have not changed their

supplier or supply contract and who therefore take advantage of the conditions and prices of electricity calculated and updated by ARERA every three months.

UK:

RIIO (Revenue = Incentives + Innovation + Outputs) model is used for network regulation companies in UK. The regulatory period consists of 4+4 years (2015-2023). RIIO regime is unique in the sense that:

- Outputs, to which the revenue allowances are linked, are defined on a long-term basis.
- Rather than all CAPEX going into the RAB, and all OPEX being funded in that same year, a fixed proportion of total expenditure is funded that year (fast money), with the remainder being funded through the RAB.
- Rewards and penalties related to cost savings and output delivery is triggered during the regulatory period, whereas in most of the other methods they are calculated only at the regulatory review.
- DSOs submit long-term business plans that extend beyond the current regulatory period.

Reliability and availability, service for connections, social obligations, customer service, environment and safety are six main outputs in the RIIO model. RIIO is a performance-based framework to set the price controls. The model considers the future national targets and consists of incentives for satisfaction of customers, compliance with health and safety standards, contribution to environmental targets and services provided to poor and vulnerable consumers. Success of the model will be clearer after the first 4+4-year implementation period.

RIIO uses a variation of the RAB approach and is hybrid between RAB and Net Present Value approaches. As explained in previous sections, for Base Revenue calculations a portion of allowed TOTEX is directly added to the Base Revenue (Fast Money) and the company collects this much amount of revenue during the next allowed revenue year. The remainder of allowed TOTEX is named Slow Money and it is added to the opening RAV, where RAV is based on the initial market value of the regulated asset base at privatisation, plus all subsequent additions. RAV is gradually reflected in Base Revenue over multiple decades, reflecting the average lifetime of network assets. Amounts are deducted annually from opening RAV (this is depreciation). The depreciation value is then added to Base Revenue in the next Allowed Revenue year. The average of opening and closing RAV for the year also earns a return (at WACC).

Like other countries WACC is used to calculate allowed return. In estimating the cost of equity parameter within the WACC, Ofgem primarily relied on the CAPM but “sense checked” the result with other methods, e.g. dividend growth model and market to asset ratios. Cost of debt is based on a long-term trailing average of forward interest rates, and the revenues allowed under the price control is adjusted each year for changes in this trailing. Allowed cost of equity is determined as 6.4% for Western Power Distribution and 6% for other DSOs.

The DSOs are incentivised to outperform their TOTEX allowances. DSOs that submit better forecasts of the costs they expect to incur during the price control receive a higher TOTEX efficiency incentive rate, meaning they get to keep more of any underspend.

Total expenditure benchmarking is used for efficiency and positive cost savings, measured as the difference between realized and planned costs is an indicator of efficiency in general. There are three main ways to make sure that DSOs are cost efficient.

Ofgem introduced a losses incentive mechanism as part of the Electricity Distribution price control, in order to encourage distribution network areas to manage an efficient level of losses on their network. A losses reduction mechanism consisting of four components, which are license obligation, loss reduction expenditure in the business plans, annual reporting and discretionary reward (LDR), was introduced.

DSOs largely recover costs through a simple tariff which includes a standing charge per day and a unit charge per kWh. The standing charge is relatively small, and the majority of domestic distribution revenue is recovered through the unit charge. Distribution charges account for around 15% - 20% of a domestic consumer’s total bill. Retailers do not have an obligation to pass the structure of the distribution tariff on to their consumers.

Recommendations for Turkey

When the tariff methodologies are assessed, it is concluded that the revenue cap model with performance and quality indicators and efficiency parameters is suitable for Turkey to achieve good EU practices.

It is advisable to be inspired by certain RIIO approaches and use the fourth implementation as a transition period to create a sustainable, quality driven and customer centric Electricity Distribution sector. Therefore, it is recommended that the TOTEX approach should be applied in at least certain areas such as IT, vehicles, buildings and network rehabilitation/replacements. Application of this approach in some fields might be a solution for a rational decision-making process between CAPEX and OPEX to increase cost efficiency in the overall DSO quality performance. Also, it should be DSO's decision whether to operate the grid by either CAPEX or OPEX. Technological developments also close the gap between OPEX and CAPEX in some areas such as: data management, smart remote meter installations versus -labor intensive- manual meter reading.

CAPEX budgets are approved by EMRA at the beginning of the tariff period. As capacity increase CAPEX is driven by external parameters, it is recommended that this budget should not be limited, as treated like non-controllable cost items (i.e. legal and environment investments, expropriation costs, etc.).

Also, regardless of the revenue requirement model, DSOs should prepare well-justified Business Plans before the implementation periods, as a good EU practice. In these plans, DSOs should explain their previous activities and related costs, achievements (outputs) of the activity, forecasts for the activity and cost projection, uncertainties and risks for activities, financing expectations for following period (equity/debt ratios), impact on customer bills, etc.

For a sustainable and economically viable distribution sector, regulation should drive the stakeholders (DSOs) to an equilibrium level between profitability and being utility. Therefore, RIIO model in UK could be a role model in many aspects by introducing TOTEX and output-based approach together with encouraging innovations.

To incentivize DSOs to utilize aged network infrastructure (over 30-year age) longer rather than replacement, additional RAB calculations might be considered. Certain percentage of replacement value of over 30-year assets could be added to the initial 2021 RAB (the fourth implementation period's first year).

It is recommended to define an updating mechanism for WACC values. This will make the future WACC foreseeable for DSOs and remove the uncertainty for investments. For example, based on the long-term financial parameters, which are used to calculate the WACC, the WACC may be calculated annually and if there is a need for reduction/increase (change above a threshold value), it can be updated automatically.

To improve overall quality of supply, monitoring SAIDI/SAIFI at MV grid should also be the focus. Together with ASIDI and ASIFI, improvement scheme for the worst served customers should also be implemented as the existing compensation method.

With the increased reliability of data collected by EMRA, it is recommended to use two-stage efficiency analysis. (1) A DEA model can be used where loss-free OPEX is input and composite variable scores for number of customers (both consumers and distributed generators), line lengths and number of transformers, and age index (share of network assets older than 30 years old) as outputs. (2) The environmental factors, such as the area of the region, forestry area and urbanization rate can be incorporated as Z-scores to reflect the geographical differences between DSOs, by utilizing a regression model which adjusts the efficiencies calculated in (1).

To eliminate high loss rate effect on the tariff, loss-free OPEX should be considered to compare DSO expenditures. As EMRA already exempted those three high loss DSOs from several performance obligations through a special decree², there could be two separate DSO performance methodology: one focusing loss reduction, one focusing output (performance). Once realized losses in those

²

Regulation on Distribution System Loss Reduction.

three high loss regions are reduced to 8% level (current applied benchmark), the separation may be removed. Additionally, for the following implementation period, EMRA may ask high-loss DSOs to provide their 5-year, 10-year loss reduction targets and roadmap to secure equal or lower than 8% aggregated loss ratio.

Similar to UK, according to value of lost energy calculations (VoLL) EMRA may provide additional bonus to those DSOs with highest VoLL figures who reduce their loss ratios. Same loss reduction in Boğaziçi region and Vangölü have quite different impact on Nation's economy. Therefore, not only loss reduction ratio, actual loss energy amount needs to be included in the process.

Network loss could be considered as DSO's carbon footprint. Environmental responsibilities for DSOs (reduction of CO₂ emissions and reduced usage of SF₆) exist in European Countries. Reduction of losses corresponds less natural gas import and less thermal generation. To help this EMRA may allow DSOs to invest in renewable energy to generate electricity up to their losses and add this additional CAPEX into their RAB or meter readings of such plants calculated by average monthly day-ahead prices added to their revenue ceilings in two quarters after.

Although the methods used in Turkey for electricity distribution network tariffs are compatible with EU countries, to manage congestions and balance the usage of distribution network, peak load charges may be applied to small and large industrial customers.

Currently there is no ToU for network tariffs in Turkey, but it will increase network optimization if implemented. Distribution fee component of the end user tariff could have ToU consideration. Also, depending on roll out of high speed EV charging infrastructure, a stand-alone charging tariff is recommended.

Another issue related with retail end user tariffs is dollarization of the feed-in tariffs (YEKDEM). Exchange rate volatility increases pricing risks in the retail sector. As an alternative approach, EMRA could announce YEKDEM tariff in TL at the beginning of each quarter and this may be taken as fixed through the period. This way eligibility usage will increase after lowering the price risks.

Legal implications

In terms of regulations, in Turkey, performance indicators are defined by separate EMRA Board Decisions and there is no single regulation that contains these rules together. First recommendation could be to cover all performance indicator bonuses (and penalties) in a single communique.

Due to EU regulations and practises, regulated customer category should be narrowed and phased out to increase market openness, evolving of the retail market and competitiveness in the retail market. Only social tariff and last resort tariffs should remain regulated in Turkey too. Since the EU legislation obliges to define the 'vulnerable consumer' concept, this should be in place in the energy legislation of Turkey also. Directive 2019/944 Article 58 states that "*Member States should take the necessary measures to protect vulnerable and energy poor customers in the context of the internal market for electricity.*"

Summary of overall assessments and recommendations on Electricity Distribution is given in the following Table.

Table 0.1 – Overall Assessments and Recommendations on Electricity Distribution Tariffs

	Recommendation	Comments	Regulatory changes
Incentive-based model	None	Current revenue cap model is appropriate for Turkey	None

	Recommendation	Comments	Regulatory changes
TOTEX	TOTEX approach could be applied in certain areas such as IT/OT, vehicles, buildings and network rehabilitation/replacements.	This approach in some fields might be a solution for rational decision-making process between CAPEX and OPEX to increase cost efficiency in overall DSO quality performance. It should be DSO's decision whether to operate grid by CAPEX or OPEX.	Electricity Market Tariffs Regulation Communique on Regulation of Distribution System Revenue
CAPEX	It might be considered to reclassify capacity increase network investments as uncontrollable items like environment and legal investments.	Turkey is in line with the EU practice: Investment plans are prepared by DSOs and approved by regulators.	Procedures and Principles on Electricity Market Distribution System Investments
Business plans	Business Plan requirement should be defined (see Annex 9 for a possible template).	There is currently no business plan liability and no standard template in Turkey, whereas it can be found in the UK for instance.	Electricity Market Tariffs Regulation Communique on Regulation of Distribution System Revenue
Cost accounting	Costs related to below activities should be separately hold in DSO accounting: ○ Meter operations (meter reading, (dis)connect, meter replacement) ○ Non-technical loss operations, ○ Street Lighting operations, ○ Network operations,	There is no account unbundling for Distribution activities in Turkey.	Electricity Market Tariffs Regulation Communique on Regulation of Distribution System Revenue
Regulatory period	5-year tariff period is compatible with the EU practices.	Longer periods are better to reduce the risk of regulation for the DSOs, while it increases uncertainty and revising ability to adapt new conditions for the regulator. Shorter periods reduce the effects of efficiency gains for the DSOs.	None
Regulatory Asset Base	Assets are recommended to be transferred to DSOs.	Even though Electricity Distribution assets are not owned by DSOs: Natural Gas Distribution network belong to private DSOs. Transmission assets belong to the public TSO (TEIAS).	<i>Decree Law on Public Economic Enterprises</i> (dated 08/06/1984, numbered 233), Annex A <i>Law on Privatization Implementations</i> , Article 15 <i>Electricity Market Law</i> Article 9/6
Dynamic WACC	Dynamic WACC which is updated by financial parameters might be implemented to secure long-term financial sustainability (see Annex 8)	The static WACC approach in Turkey may not be flexible enough to respond to changing financial economic conditions	Electricity Market Tariffs Regulation Communique on Regulation of Distribution System Revenue



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	Recommendation	Comments	Regulatory changes
Depreciation	Depreciation period should be extended in general. For IT/OT investments depreciation periods could be set shorter.	Depending on Nation's financial environment, WACC and RAB considerations, depreciation of such long-life network assets could be extended to reduce CAPEX portion of end-user distribution fee and allow more needed CAPEX for those new items as well as capacity increase and refurbishment investments.	EMRA Board Decision for the relevant tariff period
Connection fees	Each DSO might prepare their own connection fee methodology and submit to EMRA for approval. Connection fees should include network reinforcement costs (and not the same for all new customers). Connection fees should include the related OPEX costs.	Every customer should bear the cost of its own connection fees, both CAPEX and OPEX of the connection, minimizing socialization.	Electricity Market Law, Article 17/6/a (indicating connection charges do not include network investments)
Supply Continuity Indicators (Clustering Regions)	Clustering DSO regions for KPIs. Implementing VOLL based performance indicators in addition to SAIDI, SAIFI for industrial/commercial regions (see Annex 5.6).	In order to improve the overall performance, 21 regions could be grouped into categories (i.e. high loss, high consumption, other) to differentiate KPI target setting methodology accordingly.	Regulation on the Service Quality of Electricity Distribution and Retail Sales
Supply Continuity Indicators	SAIDI and SAIFI only for MV in the 4 th implementation period. LV is included for the 5 th implementation period (see Annex 5.6).	Network faults affecting the most customers are arising from MV network. LV faults are more local and affects less customers. Therefore, firstly MV faults should be targeted to reduce. Number of customers fed from each transformer and connectivity of each meter and related distribution transformer or MV feeder correctly by DSOs should be recorded and confirmed by DSO's GIS data.	None
Force Majeure Methodology	An exceptional events definition should be defined, like UK case. Action plans to reduce the affects of worst days may be submitted to EMRA.	There is currently no force majeure methodology in Turkey	None



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	Recommendation	Comments	Regulatory changes
Street Lighting	Application of street lighting performance criteria, based on the criticality of the failure (such as number of lamps and HSE cases)	The time limit for repair regarding street lighting might be extended. Instead of using a case by case penalty, there should be defined a performance indicator for street lighting. Based on the target performance, DSO revenue cap should be decreased. Alignment is needed between cost-benefit quality indices of street lighting and penalty calculations.	Electricity Market Law, Article 16/8
Commercial Quality	A methodology for customer satisfaction surveys should be prepared and defined as an indicator for commercial quality. Customer satisfaction should be measured by proper independent surveys instead of the number of letters arriving to EMRA. Bonus and penalty ratios could be defined for the revenue cap.	Client satisfaction surveys are tools used by Energy sales providers to better redesign the service. In contexts where the market is liberalized, network operators use complaints as an indirect indicator of satisfaction. It is understood that being the operators certified according to ISO 9001, the choice of the most suitable indicators to measure customer satisfaction is left to the choice of the individual company.	Regulation on the Service Quality of Electricity Distribution and Retail Sales Consumer Services Regulation
Efficiency Methods	In the DEA regional factors correction may be utilized.	This would follow the example of Norway.	None
Efficiency versus Quality Factor	Relation between the average quality factor (QF) and average efficiency factor may be established. DSOs that do not satisfy a pre-determined level of quality, may not be accounted for in the efficiency analysis	For example, expenditure for network maintenance causes a DSO to lose in X factor calculation while it gains from the QF factor. While another DSO do not spend for maintenance and gains from X factor while losing from the QF factor. Second DSO, should not benefit more from the first DSO to incentivize QF.	Regulation on the Service Quality of Electricity Distribution and Retail Sales Consumer Services Regulation
Losses	None	DSOs are responsible for losses in Turkey which is in line with EU	None
Losses (Cost-Benefit Analysis)	Annual action plans and related CAPEX requirements are recommended to be used for ex-post evaluation. If the stated targets are not achieved, some portion of the used CAPEX may not be accepted in RAB calculations. In this way, relation between cost and benefit may be established more effectively.	Current loss target mechanism may be continued as is.	None
Losses – Environmental Liability	EMRA might allow DSOs to invest in renewable energy to decrease technical losses with network operation and reduce total cost of electricity purchased by generation.	Loss reduction is the main environmental target for the DSOs, since the lost energy increases energy generation.	None

	Recommendation	Comments	Regulatory changes
Network Tariffs	Capacity or Peak-load charges should be introduced for small and large industrial customers.	Capacity charges would be two segments: ○ Subscribed capacity, ○ Peak used capacity,	Electricity Market Tariffs Regulation Communique on Regulation of Distribution System Revenue
Network Tariffs (Time of Use)	Distribution fee component of the end user tariff could have time of use (ToU) consideration. Depending on roll out of high speed EV charging infrastructure, a stand-alone charging tariff is recommended.	If the difference of electricity prices between peak and off-peak hours do not represent network congestions, ToU for network tariffs may be used to balance the system.	None
Reactive Power Fees	It is recommended that reactive power shall be measured and charged hourly to reduce technical losses.	However, due to likely measurement problems, during the 4 th implementation period, TEIAS would continue reactive metering with monthly readings. In the 5 th implementation period once DSOs improved reactive compensation, TEIAS could start measuring and charging reactive power hourly.	None
Retail Tariffs (Incumbent Retailer)	Regulated tariff segment together with the low-consumption last resort customers may be reduced to serve only as a social tariff.	None	None
Retail Tariffs (Social Tariff)	Within the regulated National tariff, (1) A sub tariff group may be introduced as social tariff or (2) Coverage of the last resort tariff may be reduced to target only vulnerable customers or (3) Vulnerable customers may be supported by other social institutions.	None	Directive 2019/944 Article 58: "Member States should take the necessary measures to protect vulnerable and energy poor customers in the context of the internal market for electricity."
Renewable feed-in tariffs	YEKDEM tariff could be announced in TL at the beginning of each quarter and this may be taken as fixed throughout the period. Adjustments may be done in the next quarter.	This way eligibility usage will increase by lowering the price risks. However, financing of RES investments will become more difficult as TL-based loans will be needed, which currently have a short tenure.	Regulations related to YEKDEM Law #5346.

Electricity Transmission

There is considerable variation in the number, size and structure of Electricity TSOs including network length and ownership of the transmission network in EU as well as the methodology they used to determine allowed revenues. The most EU countries only

have a single TSO, as in Turkey.

In many European countries and Turkey, the revenue cap is used as revenue requirement model. Each country decides for itself on the type and structure of its regulatory system. International benchmarks show that there is a tendency to switch to incentive-based mechanisms recently.

In incentive-based mechanisms, companies aim to reach the targets defined by the regulatory authorities, and they will retain a profit. By setting targets, consumers benefit from increased efficiency and quality, whereas the companies can increase profits by achieving these targets.

Electricity Transmission tariffs are used to recover the costs of providing Electricity Transmission services. There are many different systems of Electricity Transmission pricing and associated tariff structures in EU.

The main characteristics of Transmission Tariffs in European Countries and Turkey are namely the share of Generation and Load network charges in %, seasonal and locational differentiation, whether the costs of losses and system services are included in their transmission tariffs.

Turkey situation

In Turkey, transmission activity is regulated, monitored, and audited by Energy Market Regulatory Authority, EMRA according to EML No 6446. EMRA's objective is to establish a financially viable, stable and transparent energy market, which functions as per the provisions of private law and within a competitive environment to ensure the independent regulation and supervision of the market in order to provide sufficient electricity, natural gas, petroleum and LPG of good quality to consumers, at low cost, in a reliable and environment friendly manner.

Turkey is 3rd country in Europe in terms of network length, after France and Italy. Turkish Electricity Transmission Corporation, TEIAS is a single publicly owned TSO in Turkey. TEIAS is responsible for the expansion, renovation, operation and maintenance of Turkish Power System, Capacity Allocation of Cross-border Lines, operation of the Congestion Management, Electricity Balancing and Ancillary Services Markets. TEIAS also undertakes the mission of providing the quality, uninterrupted, secure, and economic Electricity Transmission through a strong transmission system. TEIAS exhibits a vision of a reliable company by making the Turkish Electricity Transmission system stronger, contributing to a competitive and transparent energy market, and improving its interconnections with neighbouring electricity systems.

The revenue cap methodology has been applied by EMRA as revenue requirement model for TEIAS to OPEX and rate of return to CAPEX for a 3-year regulatory period.

RAB consists of unamortized network assets, expropriation costs, buildings, vehicles which were constructed or acquired by TSO and approved by EMRA as CAPEX at the end of each year. Depreciation period has been set as 15 years for the old assets constructed or acquired before EMRA implementation periods and 30 years for new assets.

Pre-tax corrected real WACC is used in Turkey. Time adjustment conversion is used for final real WACC. For conversion of WACC from nominal to real, expected inflation rate (by the Central Bank) is used. WACC is applied as 12.47% for fifth implementation period of TEIAS.

The RAB value is linked with depreciation and straight-line depreciation is applied by EMRA, like other regulators of EU Member countries. The depreciation of capital is linear.

EMRA has not introduced performance indicators for TEIAS yet. Moreover, although efficiency is written in the secondary regulation as an item of tariff structure, an efficiency benchmarking method for the TSO has not yet defined by EMRA.

First connection charges are characterized as "Super-Shallow" types in and Turkey.

In Turkey, the costs of losses and system services are included in TSO tariffs and they are charged by TEIAS. TEIAS considers locational price signal for their transmission tariff methodology. TEIAS charges 50% generator and 50% demand consumers for the provision of transmission network services.

Transmission charges have capacity and energy components. The capacity related component of the tariff is applied for each unit produced or consumed and this part of the tariff varies locational. Energy related component of the tariff is unique for all regions and it is applied for each unit produced or consumed. System Operation charges is also included transmission charges having just an energy component. This part of the tariff is applied for each unit produced or consumed. System operation tariff is unique for all regions.

Situation in three EU countries

Germany: BNetzA is responsible for regulating all TSOs in Germany. There are four German TSOs; 50Hertz, Amprion, TenneT and Trans-netBW. They are responsible for the secure and reliable operation of the network as well as for the transmission of the electricity. TSOs are also responsible to hold reserve to restore the stability of the networks in the event of an actual failure in the transmission system.

As part of its monitoring role, BNetzA provides quarterly updates on the progress in planning and construction that has occurred for individual projects in the transmission system, as well as transmission links to offshore wind farms during the previous three months.

BNetzA's revenue model is based on the incentive regulation and cost approval (TOTEX) for electricity transmission. The revenue caps for network operators are set for a five-year regulatory period.

In Germany, RAB consists of fixed assets, working capital, and assets under construction. New assets are valued at historical costs. Old assets are valued at replacement costs if they are financed by equity and at historical costs if they are financed by debt capital.

Straight line depreciation is used in Germany. Depreciations depend on asset type. Individual lifetime of each asset is considered for depreciation period. Regulatory authority determines the asset life for different asset groups.

WACC is not used in the regulation of German electricity TSOs. Regulatory authority sets the costs of capital, whereas the cost of debt is defined by law. The equity return is determined as 6.91% (pre-tax) for the new assets. Cost of debt is treated as pass-through and therefore allows for natural hedge against changes in interest rate environment.

Overall performance of the TSOs are measured by SAIFI on HV and EHV. Reward - penalty schemes to optimise continuity of supply levels have been introduced. However, a reward or a penalty is not applied to the TSOs, because there is no reliable data available concerning continuity level on high voltage level and extra high voltage level.

BNetzA carries out its efficiency benchmarking based on TOTEX and structural data validation before the start of each new regulatory period for TSOs. The efficiency scores for the network operators are determined by applying the DEA and SFA methods to the defined parameter groups. Since the efficiency benchmarking is a comparative method, the results for the individual network operators have a mutual influence on each other.

First connection charges are characterized as "Shallow" / "Super-Shallow" types in Germany.

The costs of losses and system services are included in TSO tariffs and they are charged by TSOs, who do not consider locational and seasonal price signal for their transmission tariff methodology. German TSOs charge 100% demand consumers for the provision of transmission network services.

Norway: The Norwegian Energy Regulatory Authority, NVE is the national regulator for the Norwegian electricity and downstream gas market.

Statnett SF is licensed as the Norwegian TSO. Statnett SF is a public enterprise, owned by the Norwegian state subordinate to the Ministry of Petroleum and Energy (MPE). Statnett SF also always provides frequency regulation to ensure momentary balance system.

NVE controls and audits Statnett's activities. NVE and Statnett have review meetings biannually. The meetings revolve around the license for system operation, system operation regulations, revenue cap regulations and license for foreign trade.

The Norwegian regulatory model is an ex-ante revenue cap model. The regulator uses the model to decide the total level of allowed revenues for the TSO, taking into account that the TSO should be able to obtain a reasonable rate of return on invested capital, given effective operation, utilization and development of the network. The level of the regulatory rate of return is decided by a weighted average cost of capital model.

Depreciation of capital is linear. TSO decides the economic life of components based on their own experience, and then calculate the depreciation according to the expected technical lifetime of the specific grid component.

Overall performance of the TSOs are measured by SAIDI, SAIFI, CAIDI, CTAIDI, CAIFI, interrupted power per incident and ENS for all voltage level. The Norwegian financial incentive-based regulation on CENS gives network companies, TSO level, economic motivation to ensure an optimal resource allocation when all minimum requirements are complied with. The objective is to achieve the most optimal level of continuity of supply for the society.

The revenue cap for Statnett is based on a yardstick model, as for any other network company. 40 % of the costs included in the revenue cap are based on the Statnett's actual costs based on book values, while 60 % is based on a norm. The cost norm is a result of benchmarking analyses. The benchmarking of Statnett's transmission grid is based on the results of the international studies on the TSOs. Statnett also owns part of the regional grid, which is benchmarked by DEA, comparing Statnett's data to data for the other regional grid companies. The results from each analysis are weighed together to calculate the cost norm. The weights attached to the results are calculated as the respective shares of the total cost base. The cost norm is then found by multiplying the weighted result with the total cost base.

First connection charges are characterized as "Shallow" type in Norway.

The costs of losses and system services are included in TSO tariffs and they are charged by TSO. Statnett SF considers locational price signal, but not consider seasonal price signal for their transmission tariff methodology. Statnett SF charges mainly demand consumers for the provision of transmission network services.

UK: Ofgem sets price controls – a ceiling on the amount companies can earn from charges to use the transmission networks. RIIO is Ofgem's performance-based framework to set the price controls.

There are 3 licensed Transmission Operators (TOs) and 12 Offshore Transmission Operators (OFTOs) in UK. These operators can develop, operate, and maintain the high-voltage system within their own geographical transmission areas, and own OFTO assets.

The three TOs are: National Grid Electricity Transmission plc (NGET) for England and Wales, Scottish Power Transmission Limited (SPT) for Southern Scotland and Scottish Hydro Electric Transmission plc (SHET) for Northern Scotland and Scottish Islands Groups.

NGET owns and operates the England and Wales electricity transmission network and operates the Scottish transmission network. NGET is also responsible for balancing the system and managing generation output to make sure it matches demand throughout the day, and that voltage and frequency are kept within acceptable limits.

The current network price controls for electricity transmission (RIIO-T1) run from 2013-2021, 4+4 regulatory period. For each year of the price control, Ofgem sets network company cost baselines for each network company, which is their allowed TOTEX. There are mechanisms to adjust revenues year-on-year depending on TOs' performance against pre-set targets. There are outputs

associated with baseline revenues that TOs must deliver either on an annual or eight-year basis.

WACC is used to calculate allowed return in UK. Cost of debt is based on a long-term trailing average of forward interest rates, and the revenues allowed under the price control is adjusted each year for changes in this trailing. Allowed cost of equity and Vanilla WACC are determined as 7% and 3.95% respectively for NGET (TO) in 2019.

At present linear depreciation is used. The depreciation rate is expected to reflect the average expected economic life of the asset base.

Tariff mechanism provides an opportunity for TOs to specify their forecasted efficiency savings over the RIIO T1 period. The efficiency initiatives included here should be explained within the associated commentaries. Assumed efficiency savings should only be recorded where they cannot be allocated to specific schemes with reasonable levels of accuracy. TSOs should use best endeavours to allocate efficiencies to individual schemes and include these savings to their forecasts provided in a table. Reconciliation can also be extended to mechanism-level efficiencies.

First connection charges are characterized as “Shallow” type in UK.

The costs of system services are included in TSO tariffs and they are charged by TSO. However, 45% of the transmission losses are *deducted* from the metered volumes of generators, and the remaining 55% of the losses are *added* to the metered volumes of demand users. TOs in UK consider locational price signal, but not consider seasonal price signal for their transmission tariff methodology. TOs charge mainly demand consumers for the provision of transmission network services.

Recommendations for Turkey

To have a sustainable and economically viable transmission system, regulation should drive TEIAS to an equilibrium level between profitability and being a utility. Therefore, RIIO model in UK could be a role model in many aspects by introducing TOTEX and output-based approach together with encouraging innovations. It is advisable to be inspired by certain RIIO approaches and use sixth implementation period as a transition period to create a sustainable, quality driven and customer centred Electricity Transmission sector.

Due to the volatile financial environment compared with EU countries, long-term financial sustainability and foreign currency-based financing, Dynamic WACC which is updated by financial parameters is recommended to be implemented to secure long-term financial sustainability.

The RAB value is linked with depreciation and straight-line depreciation is applied by EMRA, like other regulators of EU Member countries. However, each regulator uses different depreciation values, with the majority using the historical values in different variations. The lifetime of the typical network asset ranges from 30 to 50 years and the majority of the Regulators use the individual depreciation ratio for each type of asset. 30 years depreciation is used by EMRA. This is reasonable from a financial point of

view for TEIAS. However, depreciation ratio is different than lifetime of assets which is not in compliance with EU Countries. It is recommended to use individual lifetimes of assets for depreciation.

To improve overall quality of supply in Turkish transmission networks, monitoring most common ENS (energy not supplied) and AIT (average interruption time) grid should be introduced by EMRA for TEIAS. On the other hand, to increase renewables energy connection capacity in Turkey, setting and monitoring a target ratio for connection of renewables should be the focus in 6th implementation period.

It is recommended that efficiency factor for TEIAS should be defined. As a first stage, the controllable cost is reduced year by year by an efficiency target. It is also recommended that cost efficiency of the transmission system shall be assessed by international benchmarking or referring to a reference network

The costs for losses are passed on to consumers, giving system operators no incentive to reduce network losses. Proper measures should be introduced to incentivise TEIAS to reduce losses in their grids or at least maintain them at low levels if they are already efficient.

Legal implications

Legal basis of the Transmission Tariff is as follows:

- Regulation on Electricity Market Tariffs,
- Regulation on Connection and Use of System in Electricity Market,
- Communiqué regarding Regulation of Transmission System Revenue.
- Transmission System Usage and System Operating Tariff Calculation and Application Method Statement

The tariff related legislation prepared by EMRA can be considered as aligned with the EU case in general. Some issues like the transparency obligations of both the TSO and the NRA require amendments to the secondary legislation, such as methodology for congestion management, failure index, etc.

The Communiqué regarding Regulation of Transmission System Revenue refers to the concept of the “efficiency”, but there is no clear indication of the requirement for the involvement of efficiency targets in the transmission tariff. Clear definitions for efficiency related concepts should be included in the secondary legislation for transmission.

A specific methodology (as EMRA Board Decision) for the determination of “efficiency parameter” needs to be developed and published. This methodology should define the maximum level of revenue adjustment out of efficiency parameter. Such methodology may also detail certain incentives and indicators of the success and select targets for the TEIAS for a certain tariff period.

Performance indicators and reward - penalty schemes to optimise continuity of supply levels have also been introduced for TEIAS in secondary legislation. Summary of overall assessments and recommendations on Electricity Transmission is given in the following Table.

Table 0.2 – Overall Assessments and Recommendations on Electricity Transmission Tariffs

	Recommendation	Comments	Regulatory changes
Revenue Requirement Model	Revenue cap model with performance and quality indicators and efficiency parameter is suitable for Turkey.	Consumers benefit from increased efficiency and quality to increase TEIAS’ profits by achieving these targets and good EU practices.	Electricity Market Tariffs Regulation Communique on Regulation of Transmission System Revenue
TOTEX	TOTEX approach is recommended to be experienced in certain areas such as IT, vehicles, buildings and network rehabilitation/replacements	Enabling investment to maintain the existing network and accommodate a new network infrastructure, and to create a sustainable, quality driven and customer centric Electricity Transmission system.	Electricity Market Tariffs Regulation Communique on Regulation of Transmission System Revenue
Regulatory Period	5-year tariff period is recommended to be continued which is in line with EU practices.	Fixed medium periods or longer periods with parameter updates may be applicable.	Communique on Regulation of Transmission System Revenue



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	Recommendation	Comments	Regulatory changes
Regulatory Asset Base	There is no need for any change.	Depreciation period has been set as 15 years for the old assets constructed or acquired before EMRA' implementation periods.	None
CAPEX	There is no need for any change.	Methodology is compatible with EU	None
Rate of Return	Dynamic WACC which is updated by financial parameters shall be implemented to secure long-term financial sustainability.	Volatile financial environment compared with EU countries. Long-term financial sustainability. Long-term foreign currency-based financing. Dynamic WACC methodology is suitable, for TEIAS.	Electricity Market Tariffs Regulation Communique on Regulation of Transmission System Revenue
Depreciation	It is recommended to use individual lifetime of assets for depreciation	30 years depreciation of assets are currently considered, rather than individual lifetime which is common the EU. As a second stage, EU- harmonized lifetimes for assets may be considered.	Communique on Regulation of Transmission System Revenue
Performance Indicators	It is recommended to set quality indicators for measuring continuity of supply and targets. To implement rewards and /or penalties in 6 th implementation period to reach EU environmental targets.	To improve overall quality of supply in transmission networks, monitoring most common indicators such as ENS and AIT should be the focus. TEIAS should be subject to a quality regulation with a simple penalty system.	Communique on Regulation of Transmission System Revenue
Efficiency	It is recommended to define an efficiency factor for TEIAS. It is also recommended to assess cost efficiency of TEIAS via EU international benchmarking.	As a first stage, the controllable cost is reduced year by year by an efficiency target.	Communique on Regulation of Transmission System Revenue
Losses	It is recommended to introduce proper measures to incentivize TEIAS to reduce losses in grid or at least maintain them at low levels.	Reducing losses, or at least maintaining them at a low level, plays an important role financially, environmentally and technically. Reducing power losses helps with Turkey's energy efficiency objectives.	Communique on Regulation of Transmission System Revenue
Losses	It is recommended to introduce environmental responsibilities to TEIAS.	It is necessary to protect the environment in line with the EU.	None
System Services	There is no need for any change	Methodology is compatible with EU	None



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	Recommendation	Comments	Regulatory changes
Connection Fees	Firstly, Shallow for the transition period and then Deep First Connection charges methodology are recommended.	Methodology is compatible with EU. For example, due to geography difficulty of Sweden, which is similar to Turkey, deep first connection charges methodology is preferred.	Electricity Market Tariffs Regulation Communique on Regulation of Transmission System Revenue
Sharing of Transmission Network Charges	It is recommended to re-evaluate sharing of use of system charges for 6 th implementation period.	None	None
Energy and Power Components	There is no need any change for Methodology	Methodology is compatible with EU	None
Network Tariff; Locational differentiation	There is no need any change for Methodology	Methodology is compatible with the ENTSO-E recommendation, However, Locational differentiation studies might be improved and reperformed at least for each regulatory implementation period.	None
Network Tariff; Seasonal differentiation	Seasonal differentiation price signal methodology is recommended.	Methodology is compatible with the EU. However, it is necessary to consider seasonal differentiation to increase efficiency.	Electricity Market Tariffs Regulation Communique on Regulation of Transmission System Revenue
Network Tariff; Utilization Time	It is recommended to consider utilization time for transmission charges paid by network.	According to current tariff structure, energy (MWh) component has a revenue driver due to the utilization of transmission system implicitly, but, power component has not.	Electricity Market Tariffs Regulation Communique on Regulation of Transmission System Revenue
Network Tariff; Non-TSO Cost	There is no need any change for transmission charges paid by network.	None	None
Network Tariff; Netting	There is no need any change for transmission charges paid by network.	When there is a situation of connected generation and load at the same connection point to the grid, those cases can be treated differently in transmission tariff settlement.	None
Network Tariff; Reactive Tariffs	It is recommended to apply hourly reactive tariffs to both transmission and distribution customers. Reactive tariffs at transmission level should stay as monthly billing in 4 th implementation period and changed into hourly in 5 th implementation period of DSOs.	Reactive compensation should be applied more to end user side rather than supply side to reduce losses and the reactive energy impact on the grid.	Electricity Market Tariffs Regulation Communique on Regulation of Transmission System Revenue

	Recommendation	Comments	Regulatory changes
Reactive Power Control	It is recommended to incentivize reactive power control ancillary services.	None	Communique on Regulation of Transmission System Revenue Electricity Market Ancillary Services Regulation

Natural Gas Distribution

The ownership of the gas DSOs is variable in the EU, both privately and public owned even the lasting of the concession period is variable from a few years, up to 50 years. This shows a significant variation in the number, size and structure of Natural Gas Distribution System Operators (DSO) throughout Europe as well as the methodology they used to determine allowed revenues. Natural Gas Distribution is initiated by TSOs or the major state-owned utilities in the majority of the EU countries and likewise in Turkey.

Unlike to Turkey, in all major European gas markets distribution and retail activities are unbundled. EU countries' regulatory bodies use different overall approaches to setting allowed revenues in Natural Gas Distribution segment such as revenue cap, price cap, cost-plus, and rate of return, hybrid and other approaches that might not fit into former examples. The revenue cap model is the most common model used and it is followed by the hybrid model. Regardless of the overall approach, EU countries are using incentive-based schemes to calculate the required revenue for DSOs.

Beside the different revenue requirement models, regulatory bodies employ different methodologies for assessing the cost of services for DSOs. Building blocks (CAPEX and OPEX) approach is the most common one, whereas some countries employ a TOTEX approach.

Turkey situation

In Turkey, the regulatory body is the Energy Market Regulatory Authority (EMRA) and is responsible for calculating all aspects of tariffs in Natural Gas Distribution segment. At present, there are 72 DSOs, where all are regulated and audited by EMRA. The number of residential subscribers reached 15.75 million as of December 2019 and the number of eligible consumers in distribution zones reached 614,900 in Turkey.

In contrary to most EU countries, the price cap model is implemented in Turkey since 1st January 2012 for the gas DSOs (the ones that completed 8 year-period following the first tender), as stated in the Natural Gas Market Distribution and Customer Services Regulation. CAPEX and OPEX model are in use in terms of allowed revenue. Projected OPEX for each year of the tariff implementation period is calculated from historical costs and adjusted through benchmarking with other distribution companies. Base OPEX is composed of fixed and variable costs. The variable part is adjusted based on the projected expansion. If the company is an inefficient one in the DEA analysis, the sum of fixed and adjusted variable OPEX is discounted with the efficiency factor of the relevant company.

CAPEX calculations also have a performance cut or bonus depending on the actualizations of the company compared to sector average. CAPEX analysis is based on acceptance limit method (some relatively low amount types are analysed differently). Previously, each type of asset was assigned a higher limit of acceptance (derived from sectoral averages using statistical methods) and if for this single type a company exceeded this limit, limit would be applied, and if below the limit, it is accepted as the actual value. Regulatory period is 5 years (which can be changed by the EMRA's Board) and depreciation period is 22 years.

In Turkey, currently quality factor is not implemented in distribution tariffs. Distribution sector is very young in Turkey, so EMRA has focused on the expansion of network so far. However, it is thought that the sector is mature enough to apply quality factor.

Situation in three EU countries

In Germany, there are 728 gas DSOs registered with private and local public ownership and almost all DSOs (693) has customers

fewer than 100,000. Network charge calculations are based on Gas Network Charges Ordinance (GasNEV) which is binding for all DSOs and revenue cap for each operator is calculated based on the Incentive Regulation Ordinance (AregV).

The revenue cap is composed of the permanently non-controllable costs, temporarily non-controllable costs, controllable costs (applying a distribution factor for reducing inefficiencies), a possible efficiency bonus, general inflation relative to the base year and a general sectoral productivity factor, a CAPEX in period top-up to take account of the cost of capital for investments after the base year and volatile costs. The difference between the allowed revenue and the development of actual volumes over the year is entered into a regulatory account.

Revenues are decoupled from costs, where more efficient companies are granted higher returns as they can keep the profits until the end of the regulatory period when getting more efficient and less efficient companies receive lower returns. The regulator seeks to incentivize network operators to identify further cost savings and increase profits. Customers also benefit from this efficiency increase. Revenue cap is set for each calendar year of the regulatory period (or “revenue path”) which is based on an efficiency benchmark. Revenue cap avoids giving network operators an incentive to increase sales.

In Italy, Natural Gas Distribution sector is highly fragmented, where the top six DSOs (Italgas, 2i Rete Gas, Hera, A2A, Iren, Toscana Energia) represent nearly 70% of the existing 22 million delivery points, while the remaining 30% is split among more than 200 players.

The current tariff calculation model is based on parametric remuneration of OPEX / central assets and allowed return for local distribution and metering assets (RAB). The tariff structure defines a mandatory tariff, applied to end customers, and a reference tariff, which imposes the revenue admitted for each DSO to cover the recognized cost (tariff decoupling).

The level of allowed revenue for each company depends on the reference tariff, divided into a series of tariff components allocated to cover specific cost aggregates (for example Costs of capital of location, centralized capital costs, operating costs, etc.), and from the number of redelivery points served. The reference tariff is divided into distribution service and measurement service.

In the UK, there are eight Natural Gas Distribution networks (GDNs), each of which covers a separate geographical region. These eight networks are owned and managed by Cadent Gas Ltd, Northern Gas Networks Limited Wales & West Utilities Limited and SGN. In addition, there are 16 independent gas transporters (IGT) and 6 site specific pipeline operators covering a number of relatively small networks.

Gas distribution companies are regulated by Ofgem and Ofgem initiated the RIIO program on 1 April 2013 and has been publishing reports on RIIO Natural Gas Distribution, which review the progress made by the relevant DSOs and provide information on how the DSOs are performing against their obligations and incentives.

TOTEX is the sum of the projected OPEX, CAPEX incurred in that year and the replacement expenditure (REPEX) in Natural Gas Distribution. In distribution, it consists of all the expenditures relating to DSOs’ regulated activities with some exceptions. The TOTEX approach to setting price controls aims to incentivize companies to deliver outputs at the lowest total cost, without preferring cost savings derived from OPEX or CAPEX solutions. The RIIO-GD1 price control sets out the outputs that the eight Natural Gas Distribution network companies need to deliver for their consumers and the associated revenues they are allowed to collect for the eight-year period from 1 April 2013 until 31 March 2021.

Under RIIO, additions to the asset base do not reflect actual CAPEX only; instead they reflect a proportion (the capitalisation rate) of the TOTEX of the company, referred to as ‘slow money’. The capitalisation rate reflects expectations of the future OPEX-CAPEX split and determines the proportion of TOTEX added to RAV in base. This may change over time as the balance of operating and asset-based activities changes. It is set at the outset generally based on the historical and forecast split of CAPEX/OPEX. The residual TOTEX is referred to as ‘fast money’ and is recovered in the year in which it is incurred.

Recommendations for Turkey

It is thought that it is time to change the structure of distribution tariffs namely, to use pure revenue cap as the distribution tariff

which is used in the electricity sector. With a large amount of RAB, revenue cap method will decrease the risk of the financial sustainability of the distribution companies. The bigger portion of the required revenue is CAPEX, the amount of fixed cost is high, whereas natural gas consumption is fluctuating a lot. To decrease that risk, it is recommended that EMRA revises the methodology in the following tariff period, using incentives for DSOs.

Even though the TOTEX approach is not suitable for the current situation, it is proposed that the TOTEX approach may be used in the future when network expansion reaches a saturation phase and allocate total allowed revenue into two parts as CAPEX and OPEX.

In around the year 2030, TOTEX can be a practical alternative approach for Turkish natural gas distribution tariffs. In that phase of the sector with more maturity, TOTEX approach will incentivize companies to spend wisely in a way that they will allocate allowed revenue between network investment and operation expenditure without focusing to maximize tariff by inflating inefficient investments. In addition to that, the right allocation between OPEX and CAPEX will provide sustainable revenue inflow. TOTEX approach will also eliminate the risk of low level of RAB for some companies with a low opportunity to expand the network. Thus, some portion of OPEX will be accepted as CAPEX and the companies will have a chance to get return. Currently, in tariff methodology of EMRA there are some regulations to eliminate the risk of low return by calculating return from OPEX. TOTEX approach will be much fairer to increase return portion of the required return.

EMRA currently take historic operation expenditure and network investment costs and analyze them by benchmarking with historic values of the company itself and unit costs of other companies in the same period. This approach can be used also in TOTEX approach at the time EMRA starts practicing it. EMRA can determine accepted operation expenditure and investment costs in a similar way, then calculate total of those two components and allocate that total accepted costs between OPEX and CAPEX based on predetermined shares for each of them. OPEX and CAPEX share can be determined as the fixed single ratios for the whole sector or can be determined different ratios for different categories of companies.

In addition to switching to revenue cap and continuing existing building blocks methodology, another important issue is the integration of quality factor into the tariff structure. The Quality Factor has not been applied yet, although it is defined in the tariff regulations. The Quality Factor can be implemented as a component of the price cap model by establishing common service quality standards.

In Turkey, WACC is calculated by the regulator EMRA based on the various economic parameters. An increase in the overall rate of return in Turkey is expected to strengthen the sustainability of the DSOs and sustain further financial steps such as IPOs.

Expanding the depreciation term may reduce cash flows in the short term but would offer a more financially sustainable revenue structure in the mid and long term. The longevity of finance is another factor in the determination of depreciation period because distribution companies need loan to finance network investments.

Quality factor is currently not implemented in Natural Gas Distribution tariffs. Distribution sector is in its early stages in Turkey, so EMRA has focused on the expansion of network so far. However, it is thought that the sector is mature enough to apply quality factor.

Legal implications

Turkish gas legislation is quite aligned with EU regulations, however, since gas distribution and retail activities are not unbundled in Turkey, to increase competitiveness at downstream activities, unbundling related legislation amendments might be considered.

As recommended above, gas distribution sector in Turkey seems mature enough for bonus & penalty tariff structure. Therefore, performance parameters might be included to new tariff period. These elements should be added to legislation.

Summary of overall assessments and recommendations on Natural Gas Distribution is given in the following Table.

Table 0.3 – Overall Assessments and Recommendations on Natural Gas Distribution tariffs

	Recommendation	Comments	Regulatory changes
Revenue Requirement Model	It is recommended to use revenue cap methodology instead of price cap in the upcoming implementation periods due to saturation of the natural gas connections. Even though the TOTEX approach is not suitable for the current situation, it is proposed that the TOTEX approach may be used in the future when network expansion reaches a saturation phase. The Quality Factor can be implemented as a component of the price cap model by establishing common service quality standards.	In this way, EMRA can be more flexible in allowing errors in the demand forecast, there will be less requirements for tariff revisions, and there can be more focus on methodology development, instead of having a high workload for frequent tariff calculations.	The current 5120/1 methodology implies an implicit profit opportunity for DSOs.
Rate of Return	WACC can be set to be 10% minimum as in the storage tariffs and can be adjusted according to changes in country risk and other relevant components of WACC. In pre-determined conditions, non-controllable OPEX method can be used for ensuring financial sustainability of DSOs. For example, losses due to unexpected interest rate increases, non-controllable OPEX can be added to revenues to compensate DSOs, instead of revising WACC.	In Turkey, WACC is calculated by EMRA based on various economic parameters. An increase in the overall rate of return in Turkey is expected to strengthen the sustainability of the DSOs and sustain further financial steps such as IPOs.	None
Depreciation	In Turkey loan payment period is lower compared to European countries, so lower depreciation period is needed. Therefore, it is suggested that continuing with the current depreciation term of 22 years. In case individual DSOs require shorter terms for financeability reasons, EMRA can decide individually. TOTEX approach in the future can compensate some of the disadvantageous aspects of shorter terms.	The depreciation term in Turkey is 22 years, while the EU countries mostly set depreciation terms longer, even up to 50 years. Expanding the depreciation term may reduce cash flows in the short term but would offer a more financially sustainable revenue structure in the mid and long term. The longevity of finance is another factor in the determination of depreciation period because distribution companies need loan to finance network investments.	None



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	Recommendation	Comments	Regulatory changes
Connection Fee	The connection fee model applied in Turkey may be diversified by considering below parameters as a premium of the fixed one-time fee: ○ Subscriber status ○ Delivery pressure ○ Capacity booking ○ Load factor	The connection fees collected by the DSOs do not generate revenue for the DSOs as the connection fee revenues are extracted from the value of realized investments during RAB calculations. The connection fees only support the cash balance of the companies.	None
Quality Factor Performance Indicators	It is recommended to use quality factor in the next tariff implementation period namely, to use the performance indicators as used in the UK. With the application of the quality factor, the level of service quality can be increased in the sector.	In Turkey, currently quality factor is not implemented in Natural Gas Distribution tariffs. Distribution sector is in its early stages in Turkey, so far EMRA has focused on the expansion of network. However, it is thought that the sector is mature enough to start the application of a quality factor.	None
Efficiency	EMRA has already applied efficiency factor to the tariff, but so far only used efficiency scores resulted from DEA analysis. It is suggested to use alternative methods like SFA and use a combination of the results of those methods. It will eliminate the shortcoming of one method.	Indicators used in efficiency analysis in the Natural Gas Distribution sector are mostly set by taking the general characteristics of each country or region into account. In Turkey efficiency indicators are network length, number of city gate stations build in tariff period, consumption and number of consumers. Those parameters mostly effect the level of OPEX, so they are right choice for that purpose.	None



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	Recommendation	Comments	Regulatory changes
Losses	For promoting precautions to reduce shrinkage, the shrinkage rate would be set as one of the performance indicators for the DSOs. EMRA should deal with shrinkage issue as a matter of empirical evidence. If it is proven that a major issue of shrinkage is existing in the network, which is not expected in a near future EMRA can transfer its knowledge from Electricity Distribution to Natural Gas Distribution. In the case of Electricity Distribution, main reference for target levels is past actualizations by the DSO itself. In the case of natural gas, EMRA can choose an engineering model in the future, to set maximum allowable cost of shrinkage for each DSO	The DSOs in Turkey are responsible for the technical losses, leakages, and shrinkage, unlike the practices in most of the EU countries. Some EU countries reflect the cost of shrinkage and losses to the consumers. However, the shrinkage volumes in Turkey are at reasonable levels at the moment due to concrete network construction quality and the relatively new grid. But in the mid and long term, the shrinkage volumes are expected to exceed reasonable levels due to the nature of Natural Gas Distribution activity. By taking this fact into account, the shrinkage losses shall be implemented into the tariff methodology as a partial cost for maintaining sustainability.	None
Social Tariff Determinations for Consumers	No change recommended for Turkey.	Most of the EU countries and Turkey apply different pricing mechanisms for each consumer segment based on the fixed and variables costs. Social tariffs are implemented in Europe in different ways. In some countries, this consumer group is protected by providing tax exemptions, discounts in invoices, and in others by direct support.	None
Tariffs for Distribution Region Expansions and CNG / LNG Applications	External sources to fund line extensions can be widened. Before extending the license region by adding a new district, a demand collection process (which may include some monetary contribution from demandants) can be carried out to make investment plans more realistic. Spending of DSOs to encourage fuel switching in both unserved and underserved areas can be included in tariffs upon pre-approval of EMRA. This can help increasing utilization of the network.	Currently, municipalities waive infrastructure fees for the benefit of the prospected customers in the region.	Differentiated tariffs for existing and new customers to reflect costs to those causing them can be fairer in tariff design. However, this can require a revision of the law.

	Recommendation	Comments	Regulatory changes
Reliability of Demand Forecasting for the Industrial Consumers in Distribution Regions	For having a more precise demand forecast in Turkey, the forecast of the DSOs based on the below variables may be considered as the main component of the estimates, conducted by EMRA. ○ Annual grid expansion expansions ○ Gas consumption profiles of the industrial facilities ○ Seasonal effects on consumptions	Consumption forecast for residential consumers is made more predictable than estimations for industry and power plants. For industrial consumers, considering the 5-year tariff period, it is difficult to make a predictable consumption estimate. Therefore, reducing the share of industry and power plant's consumption in the revenue requirements may lower the deviations in the revenue realizations of DSOs. Since the industrial consumers, which has regular consumption, has a high network usage rate and a low load, the revenue requirement allocated to this group may be lower than the revenue requirement of the residential segment, which has seasonal and variable consumption pattern. As a result of this improvement, the impact of the forecasting deviations may be reduced.	None
Last resort tariff practices in Natural Gas Distribution	Allowing DSOs to benefit from a reasonable margin from the compulsory last-resort sales may improve the sustainability of the companies.	By considering the market structure and development pattern of Turkey, DSOs may be allowed to make intraday, day-ahead, and futures transactions for securing their last-resort demand, when the liquidity of the market is increased to a certain level by progressing towards a liberalized market structure.	None

Natural Gas Transmission

Regarding the gas transmission systems, the most widely established structure seen in the EU and the rest of the world is that there is a single TSO operating the transmission grid and the TSO is a state-owned company. The USA and Germany may be considered as rare examples for multi TSO structure. Noting that the gas TSOs have kind of monopoly status, the absence of competition may result in low efficiency performance in terms of costs and the quality of the gas transmission services. On the other side, adoption of certain quality of service and cost efficiency indicators and benchmarking with the other country TSOs is very complicated task since the structure of the networks are very different. Such cost benchmarking studies of the other networks (electricity transmission and distribution and gas distribution where benchmarking is more prevalent) suggests that there are very large divergences between the most and least efficient businesses.

There can be seen many requirements in the related legislation in both Turkey and the EU referring to the efficient operation of the gas transmission systems. Although the existing EU legislation requires the NRAs and gas TSOs apply similar framework, still there may be seen very limited provisions defining specific efficiency incentives to be commonly applied by all TSOs. As of today, there are very limited country examples where certain efficiency performance evaluations are clearly defined in the legislation. The NRAs are in a position to develop their own methodologies to incentivise the gas TSOs for the efficient operation of the gas

transmission networks.

Turkey situation

The gas transmission infrastructure has been spread throughout the country exceeding 17,000 km in total pipeline length. The Natural Gas Market Law (the NGML) and the secondary legislation allows for licensing of gas transmission networks other than the existing national gas transmission grid owned and operated by the single state owned BOTAS.

The regulatory authority EMRA is responsible for the preparation of tariff legislation and approving the proposed tariffs by the operators. EMRA published the first Natural Gas Tariff Regulation in 2002. The methodologies for preparing the tariffs have been published through EMRA Board Decisions.

The Tariff for the gas transmission is referred as “Transmission and Shipping Control Tariff” in the secondary legislation. The Transmission System Operating Regulation specifies the Entry/Exit model for gas transmission activities and so does the Tariff Regulation.

The related legislative documents in effect are:

- Natural Gas Tariff Regulation dated 13/10/2016.
- Principles and Procedures for Determining the Revenue Caps to be Taken as Basis to the Tariffs of Natural Gas Transmission License Holding Companies.

Revenue Cap model is adopted for gas transmission. So far, the evaluation of the “Efficiency Parameter” in the Revenue Cap model has not been practised by EMRA.

Situation in three EU countries

The Revenue Cap model is the most widely adopted application in the EU and the majority of the NRAs (19 out of 27) apply Efficiency Parameter for OPEX. TOTEX approach is very limited yet as seen only in three countries, Germany, the UK and the Netherlands.

In terms of applying efficiency measures in the Tariffs, there are limited applications which may be considered as well developed. The cases for Germany, Italy and the UK are the best illustrative examples.

In **Germany**, an incentive-based regulatory regime was introduced in 2009 to replace cost-plus regulation. Under this regime, the revenue that network operators are allowed to earn within a certain regulatory period is determined using a mathematical formula and fixed for the period.

In the gas market, there are 16 Transmission System Operators whose activities are regulated by the regulatory authority BNetzA. ‘BNetzA’ applies the same reference price methodology (‘RPM’), a postage stamp methodology, jointly for all transmission system operators.

The revenue caps for network operators are set for a five-year regulatory period. Each cap is composed of the permanently non-controllable costs, temporarily non-controllable costs, controllable costs (applying a distribution factor for reducing inefficiencies), and volatile costs. The difference between the allowed revenue and the development of actual volumes over the year is entered into a regulatory account.

The starting point for setting the revenue caps and, in turn, the network charges is based on each network operator’s actual costs. Prior to the start of a regulatory period, the regulatory authorities determine the base level used to set the revenue cap. This is done by means of a cost examination carried out in accordance with the provisions of the network charges ordinances. All network operators – regardless of their size – are subject to these cost examinations.

The BNetzA carries out its efficiency benchmarking on the basis of TOTEX and structural data validation before the start of each new regulatory period for gas and electricity network operators separately. The efficiency benchmarking involves assessing the operator's individual costs against the services they provide and determining each operator's cost efficiency compared to the other operators.

The efficiency level is applied to the generally controllable costs to create a block of efficient and a block of inefficient controllable costs. The operator is required to gradually reduce only the inefficient controllable costs over the course of a regulatory period.

The efficiency factor is TSO-specific, and each TSO must eliminate any inefficiencies compared to the industry benchmark within a regulatory period. Germany also applies an efficiency factor, currently set at 0.49% per year. A network operator's efficiency is not determined solely on the basis of the absolute level of the operator's costs. Rather, the costs recognized as necessary for network operation are assessed in relation to the operator's supply obligations. The efficiency benchmarking determines each operator's relative cost efficiency compared to other operators, taking into account the individual supply tasks.

In *Italy*, ARERA establishes the methodology and sets allowed/target revenues in terms of gas transmission tariff. There are 9 licensed TSOs in the country, however, the most significant TSO is Snam Rete Gas S.p.a. who owns more than 95% of the entire gas transmission network.

The applied tariff regulation is: "Cost plus for capital expenditure with a price cap for operating expenditure".

At the beginning of each regulatory period, allowed OPEX are aligned to actual OPEX expenditure, net of:

- A profit-sharing mechanism, if efficiency targets have been met; and
- loss sharing mechanism, if efficiency targets have not been met.

For determining and setting capital expenditures, ex ante business case analysis is required as part of the process of developing a National Development Plan.

The method for updating the price cap tariffs is applied only to revenues related to operating costs, which is updated for inflation and reduced by an annual recovery coefficient set at 2.4%. The revenue component relating to the return and amortization and depreciation is updated on the basis of an annual recalculation of net invested capital (RAB) and additional revenue from the higher rate of return for investments realized in previous regulatory periods.

Cost-plus approach is used for capital expenditures. An adjustment is not applicable.

Inclusion of efficiency or productivity improvements are applicable only for the OPEX (not for CAPEX) and the efficiency factors used in most recent regulatory period is 1.3% per year (being an average for the sector, as company-specific factors are set). The allowance covering operating costs is subject to annual updating.

In *the UK*, Ofgem has put into application the performance-based framework to set the price controls, the RIIO and the first regulatory period was set as 8 years (2013 – 2021). There is single TSO, *National Grid Gas Transmission Plc (NGGT)*, operating the gas transmission grid. The price control set by the Regulatory Authority Ofgem for the National Grid Natural Gas Transportation Services (NTS) is divided into TO and SO controls.

Each year, transmission and distribution network owners report to Ofgem on their performance against the RIIO price control. Ofgem publishes annual reports and interactive charts and data on their performance as part of its market monitoring.

Under a Revenue cap regulatory regime, Ofgem uses an overall TOTEX approach to determine allowed revenues. However, benchmarking and bottom-up assessments are also used to assess the robustness of the National Grid Gas plc - NGGT's business plans. Uncontrollable expenses are fully passed through such as license fees, business rates, security costs (for 'critical'

infrastructure).

National Grid has been given commercial incentives to operate the gas NTS in an economic and efficient manner, as they are required to do under the terms of their license as the System Operator. To achieve this, Ofgem works to develop incentive schemes that provide National Grid with an appropriate balance of risk and reward. Cash out arrangements and the System Operator incentive schemes form part of Ofgem's overall work to regulate the NTS monopolies and to work towards maintaining market efficiency.

The annual net additions to RAV are calculated as a percentage of TOTEX. TOTEX consists of all the expenditure relating to a licensee's regulated activities with certain exceptions.

Additions to the RAV are calculated as a set percentage of TOTEX. TOTEX is dealt with as follows:

- An agreed percentage of TOTEX will be funded as slow money (i.e. as an addition to RAV)
- The remainder will be funded as fast money (i.e. which is spent and funded in the year of expenditure)

For both CAPEX and OPEX allowances, efficiency or productivity improvements are included in evaluation. There is no single "efficiency/productivity factor" but many factors are embedded in cost allowances.

Ofgem collects data from NGGT and monitors NGGT's performance against the outputs required to deliver, to calculate any rewards or penalties associated with incentive mechanisms, and to determine adjustments to allowances determined within period, i.e. costs determined through uncertainty mechanisms. The data provided in accordance with the "Regulatory Instructions and Guidance" documents (the RIGs) of Ofgem provides a database of NGGT's performance which Ofgem draws on to set cost proposals at subsequent review periods. The framework also allows Ofgem to collect data on provisional TOTEX expenditure for use in the annual iteration process and the calculation of the incremental change to base revenue .

System Operator Incentive arrangements encourage National Grid to minimize the overall cost of system operation to consumers, to consider environmental impacts and to support the efficient operation of the wholesale gas market. The incentives defined for NTS are as follows:

- NTS Shrinkage
- Residual Balancing
- Day Ahead Demand Forecasting
- Greenhouse Gas Emissions
- Maintenance
- Demand Forecasting
- Entry capacity and Exit Capacity Constraint Management
- Customer and Stakeholder Satisfaction

Recommendations for Turkey

Currently applied the Revenue Cap Regulation for gas transmission tariff is generally adopted as the convenient regulation for incentive/efficiency basis tariff applications. Bottom up assessment for OPEX, as applied by EMRA, is the most widely followed method by the regulators in the EU and cost benchmarking has limited adoption. Considering the complexity and potential objections, the TOTEX approach together with benchmarking application would not be a preferable option. Considering the single TSO in Turkey, benchmarking with the past performance would be considered where applicable.

Although the use of “efficiency parameter” in gas transmission tariff has been referred in the related secondary legislation, as of date the concept has not been enforced yet. A specific methodology (as EMRA Board Decision) for the determination of “efficiency parameter” can be developed and published. This methodology should define the maximum level of revenue adjustment out of efficiency parameter. Such methodology may also detail certain incentives and indicators of the success and select targets for the Transporter for a certain tariff period. The application is usually referred as “Rewards and Penalties” which increases or decreases the realized revenues of the TSO in accordance with a transparent performance regime where the quality and performance targets are set. The application in the UK (System Operator Incentives) would be considered as good reference to follow. Such a regime would also be formulated as “Rewards Only” as a percentage of the OPEX which is considered to be at risk and linked with the success of the TSO.

Certain capacity products as applied in the EU (such as daily capacity bookings, interruptible capacity bookings) are not offered by BOTAS yet although the existing secondary legislation published by EMRA refers to usability of such products. EMRA may define certain incentives for the offering of such products by the TSO (as an example, a small percentage of the revenues of the TSO out of capacity can be linked with the offer of daily capacity products). The facilitation of gas trading can be included in the evaluation criteria of the efficiency of the TSO.

Legal implications

Regarding the alignment of the *acquis*, the tariff related legislation prepared by EMRA can be considered as aligned with the EU case in general. Some issues like the transparency obligations of both the TSO and the NRA require amendments to the secondary legislation, such as Natural Gas Tariff Regulation.

As already stated above, certain revisions are required in the BOTAS Network Code to offer new capacity products, as in the EU case.

The Natural Gas Tariff Regulation (NGTR) refers to the concept of the “efficiency target” for gas distribution and there is no clear indication of the requirement for the involvement of efficiency targets in the transmission tariff. Although the “Principles and Procedures for Determining the Revenue Caps to be taken as basis to the Tariffs of natural Gas Transmission License Holding Companies” sets out the use of “efficiency parameter” in gas transmission tariff, clear definitions for efficiency related concepts should be included in the NGTR separately for distribution and transmission.

A specific methodology (as EMRA Board Decision) for the determination of “efficiency parameter” needs to be developed and published. This methodology should define the maximum level of revenue adjustment out of efficiency parameter. Such methodology may also detail certain incentives and indicators of the success and select targets for the Transporter for a certain tariff period.

Summary of overall assessments and recommendations on Natural Gas Transmission is given in the following Table.

Table 0.4 – Overall Assessments and Recommendations on Natural Gas Transmission tariffs

	Recommendation	Comments	Regulatory changes
NRA's capability in setting tariffs	Stakeholder participation, more transparency procedures for auditing the TSOs Capability Sanction and inspective role	Generally, EMRA sets the gas tariffs in line with other EU countries. However, transparency needs to be increased	Including specific terms in the Principles and Procedures for Determining the Revenue Caps (the PPRC) for stakeholder involvement and transparency
Grid ownership	No Recommendation. Existing terms are proper	Single TSO in Turkey, even though legislation allows for a multi TSO structure	None



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	Recommendation	Comments	Regulatory changes
Tariff structure	Development of a methodology for the determination of efficiency parameter (X factor) and putting it into operation.	Revenue cap model including an efficiency parameter. However, a methodology for the determination of the efficiency parameter (X factor) is not in place yet.	EMRA to publish a specific methodology to define the efficiency factor and certain incentives related with operational efficiency
Rate of Return	Dynamic WACC to be updated by financial parameters, because it depends heavily on volatile economic conditions	Requirement to cope with the volatile economic conditions	Dynamic WACC to be referenced in the PPRC
Depreciation	Straight Line	No change needed	None
Depreciation Period	Apply similarly with the EU cases, namely from 22 years to variable per asset	Depends on the asset in the EU, pipelines 50-70 years, compressor stations 30-40 years, metering stations 30 years, SCADA 10-20 years	Assets and respective depreciation periods to be defined in the PPRC
Efficiency OPEX	Define certain incentives in applying rewards/penalties for both physical and commercial operations	An item as "Facilitation of gas trading by TSO" should be included in performance areas	EMRA to publish a specific methodology to define the efficiency factor and certain incentives related with operational efficiency
Performance Indicators	Fuel Gas, Unaccounted for Gas, Demand Forecasting, Vented Gas, Maintenance, Compressor Outages and Shortfalls	Complexity of the methodology for the supervision of the performance and required manpower	EMRA to publish a specific methodology to define the efficiency factor and certain incentives related with operational efficiency
Shrinkage (Fuel Gas + Unaccounted for Gas-UAG)	Unit cost of the Fuel Gas and the amount can be included in performance indicators when setting the methodology for the determination of X Factor. A benchmarking can be done by using the Daily Reference Gas Price in the Organized Wholesale Market and similar throughput conditions in past years. The cap for the UAG as specified in the GTNC may be revised as a lower figure.	UAG improvement for the Natural Gas Transmission grid involves both the TSO and DSO's, since the measurement stations at exit points are owned and operated by the DSOs.	-EMRA to publish a specific methodology to define the efficiency factor and certain incentives related with operational efficiency -Specific reporting requirement from the TSO for UAG periodically
Capacity/ Commodity Split	Adopt a similar approach as in the EU and set the capacity booking based revenue as at least 80% with a cost allocation methodology.	Concerns related with the likely impact of increased retail tariff for residential consumers.	Related terms in the PPRC to be revised
Tariff Period	No recommendation, keep existing	None	None

Introduction to the whole report

As part of the Tariff project's Task 1, "improvement of performance-based tariff setting for transmission and distribution system operations", one of the deliverables is to conduct a general assessment of what has been carried out in the various European Countries and in Turkey.

The main objective of this document is the elaboration of a comparative desktop analysis, so to assist to the Beneficiary to identify amendment options for secondary legislation.

The scope of this report consists of the following elements:

- A Chapter for the Electricity Distribution tariff model;
- A Chapter for the Electricity Transmission tariff model;
- A Chapter for the Natural Gas Distribution tariff model;
- A Chapter for the Natural Gas Transmission tariff model.

Within the individual sections, some practices, adopted by some selected European Countries, were examined in depth to realize a gap analysis with the practises adopted by the beneficiary country and to elaborate the needed recommendations.

1 Improvement of performance-based tariff setting: Electricity Distribution

1.1 Introduction to the Electricity Distribution Chapter

There is considerable variation in the number, size and structure of Electricity Distribution System Operators (DSO) throughout Europe as well as the methodology they use to determine allowed revenues. The following table shows summary information about DSOs in European countries, including number of DSOs, network length and ownership of the network companies.

Table 1.1 – Summary Table for DSOs³

Country	# of DSOs	Network length	Ownership
Austria	130	MV 69,000 km LV 173,400 km,	Private and Public
Bulgaria	3 regional	280 000 km national	Private and local public ownership
Czechia	4 regional, 247 local	241,223 km (2016, regional DSOs)	Private and local public ownership
Denmark	47 (2017 data)	165,000 km (2016)	Private and local public ownership
Estonia	34	65,700 km	State owned and private investors
Finland	77	400,000 km	State, local public and private ownership
France	~160	1,400,000 km	Mainly indirect public ownership
Germany	~850	1,800,000 km	Private and local public ownership
Greece	1	238,300 km	State ownership and private investors
Hungary	6	161,800 km	1 public, 5 private owners
Iceland	6	22,000 km	Private, public and local public ownership
Ireland	1	172,000 km	Semi-state
Italy	135 (2016 data)	167,528 km	Mainly private, public
Latvia	11	96,500 km	Public ownership
Lithuania	6	125,155 km	State owned, private investors
Luxembourg	5	10,819 km	Mainly direct and indirect public ownership
Netherlands	7	318,000 km	Local public ownership
Norway	128	102,500 km – HV 204,700 km – LV (≤ 1 kV)	Mainly municipality / local public ownership
Poland	182 local DSOs	815,000 km	Public, partly public and private
Portugal	1	82,558 km	Private ownership
Romania	51	325,532 km (+165,825 – final connections)	Mainly private investors, indirect public ownership
Turkey	21 DSOs plus 174 Organized Industrial Zones (OIZ)	1,164,170 km	30-year concession for DSOs, pre-determined period by EMRA for OIZs
United Kingdom (UK)	14	585,000 km overhead lines MV	Private ownership (14 DNOs are owned by 6 different groups). In addition, there are also several smaller networks owned and operated by Independent Network Operators.

In some of the countries such as Greece and Portugal there is country-wide monopoly, whereas in the others there are more than 100 DSOs owned by private companies.

Within the scope of this report, summary tables regarding operation of Electricity Distribution sector are provided for most of

³ Source: CEER, February 2019, Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks. Moreover, information gaps have been filled where possible by the HD Consortium, based on their experience.

the countries, whereas some countries such as Germany, Norway, Portugal, Italy and UK are analysed in more detail in terms of distribution revenue requirement and tariffs. The purpose will be to cover at least three third countries in detail, which do not have to be the same for each topic. Other countries will also be highlighted where relevant for Turkey.

This chapter is divided in 6 more sections. Section 1.2 deals with stakeholder responsibilities, which provides a short summary of the institutional set-up of DSOs in several selected countries. Section 1.3 presents the revenue requirement model and the incentive-based mechanisms across the EU. This is the most important tool for determining performance-based tariffs in the EU. Section 1.4 deals with the issue of service efficiency in DSOs, whereas the management of (mainly technical) losses is dealt with in Section 1.5. Concrete examples of tariff setting in several selected EU countries are given in Section 1.6. The final section, Section 1.7, concludes with an assessment and draws the main conclusions and recommendations for changes in the Turkish tariff setting system.

1.2 Stakeholder Responsibilities

Regulatory bodies' responsibilities and responsibility limits are generally similar in many EU Countries. However, their approach in determining tariffs and its developments sometimes can be very different. Regulatory bodies could regulate nearly all aspects of Electrical and Natural Gas Transmission, Distribution, and even other competencies (water and sewage management, waste management, energy efficiency, etc.). In the meanwhile, the level of regulation in some countries is mainly related to allowed revenue and consumer tariff calculations.

Most European regulators have mandated accounting separation of metering activities, whereas in some cases smart-metering costs are subject to specific treatment, whereas street lighting responsibilities are mainly the duty of the local authorities in EU countries.

As can be seen in Table 1.1, ownership of the DSOs is variable in the EU and both privately and publicly owned DSOs are in operation. Generally, as the distribution region gets larger, there is a tendency for private ownership, whereas for small regions, public municipalities are mainly responsible for Electricity Distribution.

Except for UK, the prevailing organization of metering activities in Europe is generally based on a monopoly of gas and electricity distributors, either formally established or *de-facto*. Most European regulators have mandated accounting separation of metering activities, whereas in some cases smart-metering costs are subject to specific treatment.⁴

Street lighting responsibilities are mainly the duty of the local authorities in EU countries.

In **Germany**, *Bundesnetzagentur* (Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway, *BNetzA*) is responsible for regulating all operators with more than 100,000 customers or whose network area covers more than one federal state. All other network operators are regulated by the regulatory authorities in the federal states, which can delegate their regulatory task to the *BNetzA*. Therefore, government has key role in determination of allowed revenues. One characteristic of the German energy network industry is the high number of distribution system operators. DSOs are primarily responsible for metering.

In **Italy**, the National Regulatory Commission (*ARERA – Autorità di Regolazione per Energia Reti e Ambiente*) regulates grid access, determine grid end-user tariffs, promote competition, quality and efficiency, etc.

Another public economic body is **CSEA** - Fund for energy and environmental services, controlled to ARERA and the Ministry of Economy and Finance, which operates in the electricity, gas and water sectors.

For the electrical distribution market, the Bersani decree provided for the release of only one distribution concession per municipal area and granted the companies in which local entities hold an interest to ask the former Enel monopolist for the sale of the branches of the company operating in the activities in the municipal area. This has given rise to a process of gradual rationalization

⁴ Study on tariff design for distribution systems, EU Directorate-General for Energy Directorate B - Internal Energy Market, p.105.

of the business, destined to continue in the years to come.

In particular, in the period 2000-2002, the reorganization process of the distribution activity was a particularly intense one, with the transfer by Enel to the company of participating in local entities of more than one and a half million end customers, located in 27 municipalities including Rome, Milan, Turin, Verona and Parma. In the subsequent two-year period 2003-2004, further operations were sold for the sale of Enel networks involving around 61 municipalities, including Brescia, for a total of approximately 140,000 users.

In the period 2000-2004, moreover, it was completely sold to Enel Distribution for the distribution of 13 municipalities, with a transfer of approximately 14,000 customers, and it is sold in 46 municipalities, with a transfer of approximately 2,000 customers. During 2005, however, Enel Distribution sold the business branch of the entire province of Trento to SET Distribution; this sale involved approximately 231,000 customers. The last major reorganization took place in 2006, when Enel Distribution sold the networks of 18 municipalities in Emilia to Hera Spa, for a total of approximately 80,000 customers.

In the following years, the reorganization process continued, albeit on a smaller scale. To date, despite the transfer process described above, Enel Distribution (E-DISTRIBUZIONE SPA) is still the main operator to date, with over 85% of the market share. The top **four operators**, including Enel, on the other hand, cover almost 95% of the distribution service.

As shown in the below table, the Italian Electricity Distribution market, representing the remaining 15%, is characterized by the high number of distribution operators with less than 25,000 withdrawal points

Table 1.2 – Number of DSOs versus POD number – as of 31/12/2018

Number of POD	Number of DSO
to 1,000	48
From 1,001 to 5,000	33
From 5,001 to 10,000	8
From 10,001 to 25,000	8

The Regulator believes that the aggregation between distribution companies is an objective to be pursued and, consequently, worthy of mechanisms that incentivize the process. In fact, the presence of numerous distributor operators, often less than 5,000 POD, does not represent an optimal situation both from the point of view of production efficiency, due to the efficiencies achievable through the economy of scale, both from the point of view of the simplicity and cost-effectiveness of the administrative action, also in view of the tenders for the renewal of the concessions: the development of the real conditions of competition during the tender, in fact, requires the consolidation of subjects capable of competition in the procedures for the issue of new concessions pursuant to article 9, paragraph 2 of Legislative Decree 16 March 1999, No. 79.⁵

At the moment, also with resolution 654/2015/R/EEL, the Authority has provided incentive mechanisms for the aggregations also for the fifth regulatory period, with the same resolution has referred the detailed description of these parameters to a subsequent provision.

The role of electrical distributors is the management of the assets related to energy distribution, including the meter, which represents the boundary between the responsibility of the distributor and the end user.

So, the DSO is the unique actor responsible for the metering process and monthly metering data per time band of Low Voltage customers (contractual power below 55kW) are sent to retailers for invoicing purposes.

In **UK** the regulator, Ofgem determines allowed revenue, while the DSO sets tariffs and connection charges, subject to Ofgem approving its charging methodology. The market liberalization of the electricity market in the UK started in 1990.⁶ DSOs have

5 Source: Documento Per La Consultazione 318/2019/R/EEL

6 See for instance: http://ceswp.uaic.ro/articles/CESWP2013_V2_ROT.pdf

legal obligations to provide and operate electricity meters installed prior to that date, which are subject to separate price control arrangements. Subsequently the metering responsibility is generally on the suppliers. The Government coordinates the Smart Meter deployment plan, which involves the installation of more than 26.3 million smart meters by the end of 2020.

There are 14 licensed distribution network operators (DNOs) in UK and each is responsible for a regional distribution services area. The 14 DNOs are owned by six different groups. In addition, there are also several smaller networks owned and operated by Independent Distribution Network Operators. These are located within the areas covered by the DNOs.

New connection services can be provided by the Electricity DNOs, Independent Distribution Network Operators and Independent Connection Providers.

General lighting responsibility is mainly at the local municipalities on behalf of road users and communities. However, if the fault is caused because of the grid, then the DSO is responsible for the repairs needed. The supply of public lighting is currently based on estimates of consumption (unmetered supply) rather than readings of actual consumptions. Consumption is estimated, based on either the number of streetlights, the wattage of each lamp and the expected number of working hours (or the operation of a nearby light sensitive switch).

In Portugal, distribution activity is mainly controlled by the National Regulatory Authority (ERSE) which establishes the methodology to be used for calculating tariffs and prices and the ways of regulating the allowed revenues. A Tariff Board was established from stakeholders including regulated companies, members of consumer associations and institution entities. The NRA receives the opinion of the Tariff Board before taking its own decision. DSOs had full responsibility for metering, and they own the meters.

The mission of ERSE is to regulate the electricity and natural gas sectors, being an effective tool for the efficient and sustainable operation of the respective markets while ensuring the protection of consumers and the environment, transparently and impartially. In the scope of this public service mission, ERSE is given a range of powers by law and its Statutes. These powers include, most notably: protecting consumers' rights and interests as regards prices, services and service quality; monitoring compliance with public service obligations and all other legal, regulatory and similar requirements; guaranteeing economic and financial balance to the activities of the regulated sectors exercised in the public interest companies within the framework of appropriate and efficient management; promoting competition in the energy markets between all their players.

In Turkey, distribution activity is regulated, monitored and audited by EMRA according to Electricity Market Law (EML).⁷ However same Law article 15 assigns Ministry of Energy and Natural Resources (MENR) as the main audit body. According to 30-year concession agreements TEDAS, as owner of the assets, has right to audit DSO assets. MENR seems to transfer some of her audit duties to TEDAS again based on the same Article 15. Consequently, DSOs are audited by the Ministry, TEDAS and EMRA separately.

EMRA determines DSO allowed revenues and set Nationwide distribution tariffs. Due to high losses in certain DSOs, it is unlikely to introduce regional tariffs prepared by each DSO for EMRA approval, like in the case of UK. Current allowed revenue setting process is mainly based on the past expenditures of DSOs together with incentives for certain subjects such as no accident involving death, call center performance or supply continuity improvements.

Unlike the EU countries, street lighting is in the responsibility of the DSOs.⁸ Therefore, operation and maintenance cost of the street lighting system is incurred by the DSOs and included in the OPEX. Also, the energy consumption for the street lighting is procured by the DSOs (together with the grid losses)⁹ and charged to MENR or Municipalities.

1.3 Revenue Requirement Model

In many European countries, the revenue cap is used as revenue requirement model. Each country decides for itself on the type and structure of its regulatory system. International benchmarks show that there is a tendency to switch to incentive-based

⁷ Law No.6446 Article 9/6

⁸ EML Article 9/11

⁹ EML Article 26/12

mechanisms recently.

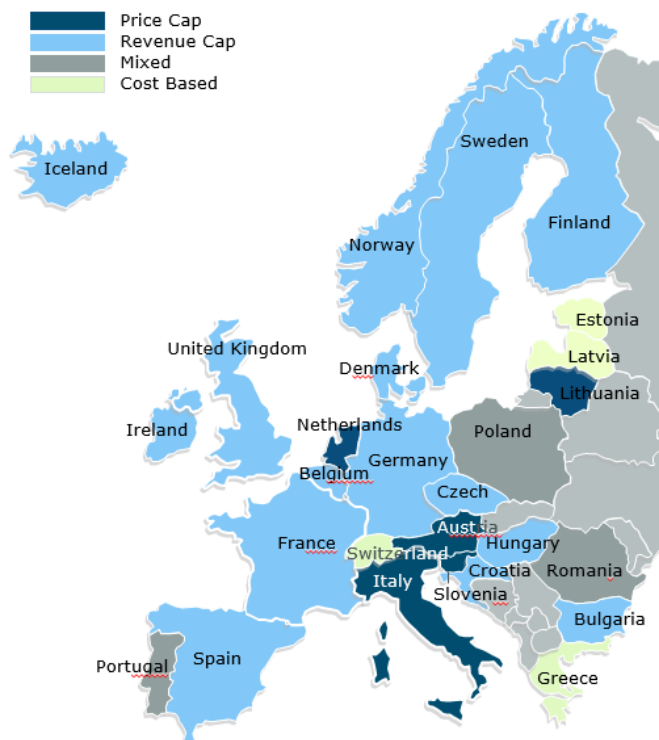


Figure 1.1 – Revenue Requirement Model

In incentive-based mechanisms, companies aim to reach the targets defined by the regulatory authorities, and they will retain a profit. By setting targets, consumers benefit from increased efficiency and quality, whereas the companies can increase profits by achieving these targets. Figure 1.1 and Table 1.1 show the revenue requirement models that are currently used in different countries.

Regulatory period also differs on a country basis. While the period is 8 years (mid-term evaluation is performed for the first 4 years) in UK, it is 4 years in Sweden and Spain and 5 years in Norway. In Sweden, Network Performance Assessment Model was used until 2012, but then they started using revenue cap, whereas in UK the output based RII model is currently implemented.

Main elements to determine revenue cap shows similarities in most of the countries. TOTEX is used in countries such as Germany, Austria, Iceland, the Netherlands and UK, whereas CAPEX and OPEX is assessed separately in other countries.

Table 1.3 – Tariff Methodology in European Countries¹⁰

Country	Tariff Methodology	Period	Main elements for Determining the Revenue Cap
Austria	Price Cap	2014-2018 (5 years)	Efficiency scores and general productivity offset, network price index and expansion factors
Bulgaria	Revenue cap	4 years	OPEX + CAPEX
Czechia	Revenue Cap	Originally set as 3-year (2016-2018), later it was prolonged until 2020	Allowed costs, allowed depreciation, RAB, WACC
Denmark	Revenue Cap	5 years, current period: 2018-2022	The reduction in the revenue cap is spread over permanent efficiency requirements arising from low financial efficiency, and single-year efficiency requirements imposed on the grid companies for not having satisfactory quality of supply.
Estonia	Cost plus	There is no period	Variable costs, operating costs, depreciation of RAB, justified return of RAB
Finland	Revenue Cap	2 regulatory periods (2016-2019 and 2020-2023) set	Efficiency, quality, security of supply, innovation and investment incentive, WACC return on RAB
France	Revenue Cap	4 years, current period: 2017-2021	Non-controllable and controllable costs, depreciation costs, taxes and fair margin
Germany	Revenue Cap	5 years, current period: 2019-2023	Non-controllable and controllable costs, TOTEX efficiency benchmark, efficiency bonus, general inflation and sectoral productivity factor, quality element, volatile costs
Greece	Cost Plus	1 year	OPEX (Non-controllable and controllable costs) depreciation, RAB (Assets and approved investment plans, working capital), WACC
Hungary	Revenue Cap	4 years, current period: 2017-2020	-
Iceland	Revenue Cap	5 years, current period 2016-2020	TOTEX; OPEX (CPI adjusted average 2010-2014+non-controllable OPEX from previous year) + CAPEX (previous year CPI adjusted book values) + other non-controllable cost (e.g. network losses). Efficiency factor = 0 for this period
Ireland	Revenue Cap	5 years, current period: 2016 - 2020	Revenue to cover the DSO's operational costs during that period, a return on the capital that the DSO has invested in the distribution system assets and revenue to cover depreciation of those assets
Italy	Price Cap and Cost of Service (TOTEX after 2020)	8 years (4+4)	In the first 4-year period service regulation has been applied in the second 4-year period (2020 – 2023) the TOTEX approach has been applied
Latvia	Cost Plus	Not exceeding five years	OPEX + CAPEX (Depreciation + return on capital)
Lithuania	Price Cap	5 years (2016-2020) and 5 years (for small DSOs, 2015-2019)	TOTEX, RAB, WACC, technical losses
Luxembourg	Revenue Cap	4-year period, current period 2017-2020	Remuneration on RAB; depreciation, controllable OPEX; non-controllable OPEX
Netherlands	Price Cap	3-5 years (currently 2017-2021)	TOTEX, CPI, yardstick, productivity change, WACC, RAB, quality incentive
Norway	Revenue Cap	Data is updated every year, important factors fixed for five years	Controllable and pass-through cost, TOTEX efficiency benchmark. Averagely efficient company receives RoR
Poland	Mixed (Revenue cap and quality regulation)	2016-2020	RoC (determined also by quality regulation factors) + OPEX, depreciation, property taxes (within justified operating costs and based on amount to be incurred), losses and pass-through costs
Portugal	Price-cap and rate of return (HV/MV) and TOTEX (LV)	3 years (current period 2018-2020)	Non-controllable and controllable costs, RAB, WACC, efficiency benchmark, inflation, incentives, general economic interest costs
Romania	Price cap / Cost+	5 years, current period: January 2014 – December 2018	Non-controllable and controllable OPEX, variable costs, RAB depreciation, rentability of RAB (RAB x WACC)
Sweden	Revenue cap	5 years	OPEX, RAB x WACC, quality
UK	RIO model	8 years (4+4) 1 April 2015 to 31 March 2023	TOTEX, incentives, innovation
Turkey	Revenue cap	5 years (current period 2016-2020), next period (2021-2025) ¹¹	OPEX and CAPEX

1.3.1 General Overview

1.3.0.1 Germany

In Germany, revenue requirement calculations started as a cost-plus regulation in 2005, however in 2009 it was replaced with an incentive-based mechanism where DSOs have to lower their cost within the regulatory period to reach their profit targets. Regulatory period is set for five-years. Revenue cap is set for each calendar year of the regulatory period, based on an efficiency benchmark. TOTEX approach (with CAPEX subtraction) was used until the end of second regulatory period. Regulator approved

¹⁰ Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03. Moreover, information gaps have been filled where possible by the HD Consortium, based on their experience.

¹¹ EMRA Board Decision dated 25/07/2019 and No.8750.

revenues ex-ante and network operator-controlled costs autonomously within regulatory period. The following Figure shows investment and expenditures between 2007-2015.

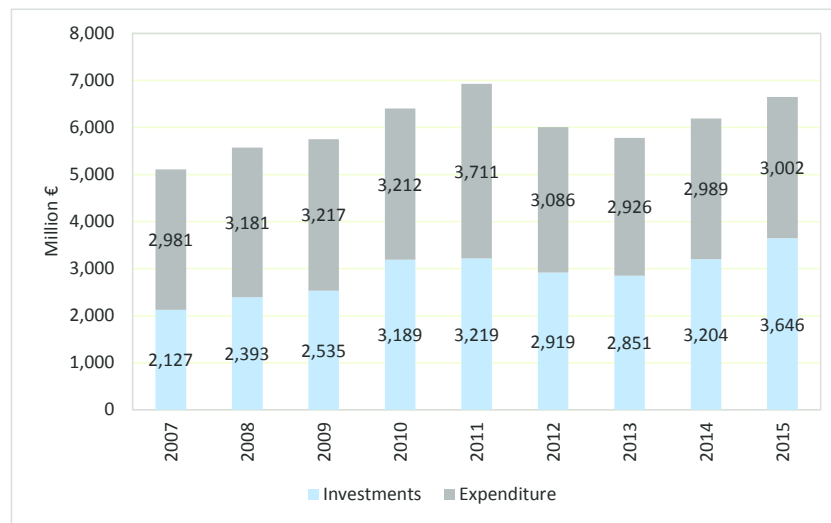


Figure 1.2 – Investment and Expenditure on DSO Network Infrastructure¹²

However, a new incentive-based mechanism with CAPEX true up¹³ within the period and efficiency bonus started to be applied in 2019 (3rd implementation period). The system was transferred from budgetary approach to CAPEX true up, which is based on actual investments and depreciation. Previously decreasing CAPEX were determined ex-ante, prior to the regulatory period and actual reduction of CAPEX was reflected in revenue cap. With the new CAPEX true up model for investments started to be used after the base year. There is no expansion factor and investment measure for DSOs. Figure 1.3 presents the key building blocks of the regulation needed for incentive-based mechanisms.

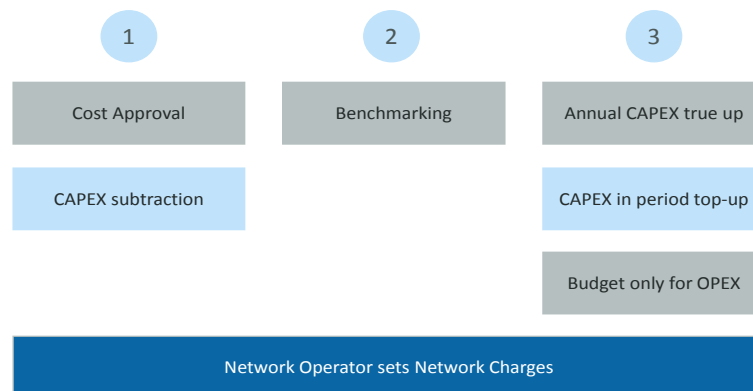


Figure 1.3 – Building Blocks of Incentive Regulation

Non-controllable costs are the costs that are not under the influence of the network operator such as special HR costs, legal payment obligations, curtailment, operating taxes etc. These costs are not subject to efficiency targets and intra-periodic adjustment (deviation from budgetary approach) is applied. On the other hand, controllable costs are subject to efficiency benchmarking and they are under the influence of the network operator. Base year is t-3.

Figure 1.4 presents the cost approval process using the TOTEX approach.¹⁴

¹² Source: Groebel A., (April 2018), BNetzA's role in energy infrastructure regulation and planning/permitting.

¹³ Hence, the planned amount of CAPEX will be trued up on a regular basis to reflect the CAPEX realizations.

¹⁴ German regulator does not use a WACC-approach. The regulator determines an allowed return on equity (RoE).

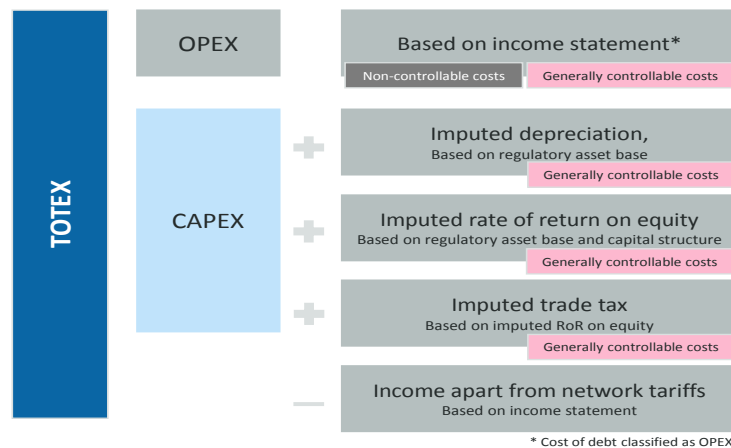


Figure 1.4 – Cost Approval - TOTEX^{15,16}

Figure 1.5 shows a general overview of revenue cap determination in the second and third regulatory periods.

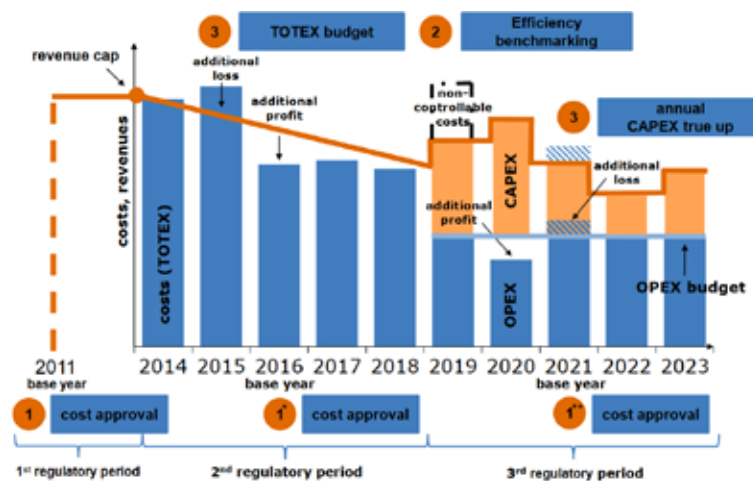


Figure 1.5 – Overview of the German Incentive Regulation¹⁷

The revenue cap is composed of:

- permanently non-controllable costs,
- temporarily non-controllable costs,
- controllable costs (applying an efficiency factor),
- a possible efficiency bonus (DSOs only),
- general inflation relative to the base year and a general sectoral productivity factor,
- a CAPEX in period top-up to take account of cost of capital for investments after the base year (DSOs only),
- quality element (electricity DSOs only),
- volatile costs.

In the 3rd implementation period, the methodology changed from budgetary approach to CAPEX true up which is based on actual

¹⁵ Source: Christine M., March 2018, Case study on the application of TOTEX benchmarking model in Germany.

¹⁶ In Germany, trade tax is different than corporate income tax. The trade tax rate is set by each municipality individually. The trade tax rate is applied similarly for all businesses within the same municipality. The German trade tax rate is currently set between 14% and 17%.

¹⁷ Source: Groebel A., (April 2018), BNetzA's role in energy infrastructure regulation and planning/permitting.

investments and depreciation. OPEX of base year 2016 are basis for allowed revenues from 2019 onwards. RAB is adjusted annually for investments (growth/replacement) and regulatory depreciation ('true up') and this leads to annual adaptation of capital costs. (e.g. allowed capital costs increase due to higher investments above depreciation.) Capital costs of base year 2016 for investments from 2007 to 2016 are kept constant in the 3rd regulatory period as interim solution due to change of regulatory system.

The revenue cap also takes account of the development of consumer prices in relation to the base year (CPI-X regime). General price increases lead to an increase in the revenue cap. Another component of the revenue caps is the general sectoral productivity factor, which is always applicable for one regulatory period. This factor is determined using scientific methods from the divergence between productivity gain in the network industry and productivity gain in the economy.

1.3.0.2 *Italy*⁸

The model currently used in Italy for tariff regulation is **hybrid**. The hybrid system provides for the recognition in the tariff of sums to cover operating costs incurred by the operator (OPEX) and a fair return on the capital invested (CAPEX). The recognition of operating costs (OPEX) is established through the price-cap mechanism: this procedure allows to retain part of the recoveries of efficiency in excess of what is defined ex-ante through a profit-sharing mechanism that allows to distribute correctly profits between businesses and consumers.

The costs incurred, however, for capital costs (CAPEX) are recognized by the regulator with a cost-based mechanism aimed at stimulating investments in energy distribution infrastructures.

Finally, the operator is granted the possibility of obtaining sums to cover costs and a regulated return on invested capital (revenue cap) calculated as the sum of three main components: return on invested capital, costs of using the invested capital and coverage of the operating costs incurred.

The aforementioned method, currently used by the Authority, however, presents problems related to the measurement of the manager's performance. In fact, the revenue cap mechanism does not consider the service delivery standards in terms of product quality and ends up recognizing in full the costs incurred by the manager in reference to the investments made, without therefore considering the effectiveness of the individual interventions.

With a view to making the incentives assigned by tariff regulation consistent with a greater selectivity in investments, the Authority, following the example of the best international regulatory practices (UK), provided, with resolution 654/2015/R/EEL, to define an activity plan, foreseeing specific phases of reconnaissance, consultation and creation of ad hoc working groups, for the updating of a new regulation approach based on the overall control of the expenditure and on the evaluation of the business plan proposed by the operators in relation to expected demand, system development needs and expected outputs (TOTEX).

Actually, in relation to the introduction of logics based on the recognition of total expenditure with mechanisms managed on medium-term planning, proposed since 2017, the Regulator intends to use a gradual approach, introducing, during the half-period 2020-2023, some preparatory tools typical of a regulatory system based on TOTEX logics and reserving the right to apply these logics in the last year of the regulatory period, for the purpose of determining the tariff logic costs starting from the next regulatory period (2024), providing to extend, with subsequent provision, the hiring also to larger Electricity Distribution operators.

As mentioned above, the current **hybrid system** provides that each DSO to obtain the **admitted revenues**, through a restriction on revenue regulated in a different way for operating (OPEX) and capital costs (CAPEX).

In fact, annually, ARERA publishes the components from which to calculate the guaranteed revenue.

The constraint on the revenues of DSOs is imposed through the **reference tariff** separately for the **distribution service** and the **measurement service**.

The **TV1 (dis) distribution service reference tariff** is composed of the components:

- a) p 1, c (dis), expressed in euro cents / delivery point, broken down by type of contract;
- b) p 3, c (dis), expressed in euro cents / kWh, broken down by type of contract.

The portions of the reference tariff TV1 (dis) to cover capital costs are determined on the basis of:

- a) the official balance sheet data of each company (individual regime), for companies serving at least 25,000 POD (withdrawal points);
- b) a parametric regime taking into account the gradual mechanism established by resolution 237/2018/R/EEL for companies serving less than 25,000 POD.

The **measurement service reference tariff** relating to the actual low voltage measurement points is called **T (MIS)** and is composed of the following components:

- a) T (ins), expressed in euros for effective measurement point, to cover the costs relating to the installation and maintenance of the measuring equipment installed in the actual low voltage measuring points;
- b) T (rav), expressed in euros per actual measuring point, to cover the costs relating to the management of data relating to actual low voltage measuring points;
- c) T (res), expressed in euros per actual measuring point, to cover the unamortised residual cost of electromechanical meters replaced with electronic meters.

Through the **equalization mechanism**, also adopted for the gas sector, the distributor balances the value actually gained from the distribution and measurement of electricity.

If the actual revenue exceeds the permitted revenue, the operator pays the difference to the Electric Equalization Fund, otherwise it is the cash that reimburses the operator

1.3.0.3 Norway

Revenue requirement model was updated several times in Norway. Rate of return regulation (1993-1996) was used in the first regulatory period and revenue cap was introduced for the second one (1997-2001). In 2001, an incentive mechanism for quality of service was introduced and third regulatory period was similar to the second in terms of methodology. In the fourth regulatory period, between 2007-2012, major changes were introduced to the model. CPI-X model was replaced with a hybrid model where each DSO's share of the revenue cap was decided by a combination of the DSO's own costs (cost plus) and a cost norm (yardstick competition). Finally, in the fifth regulatory period that started in 2013, main model framework from 2007 was maintained with some improvements. Disincentives for mergers and acquisitions were removed, and incentives for participation in research, development and pilot projects were strengthened. The number of outputs in Data Envelopment Analysis (DEA) were reduced and the method for adjusting for environment related Z-factors was revised.

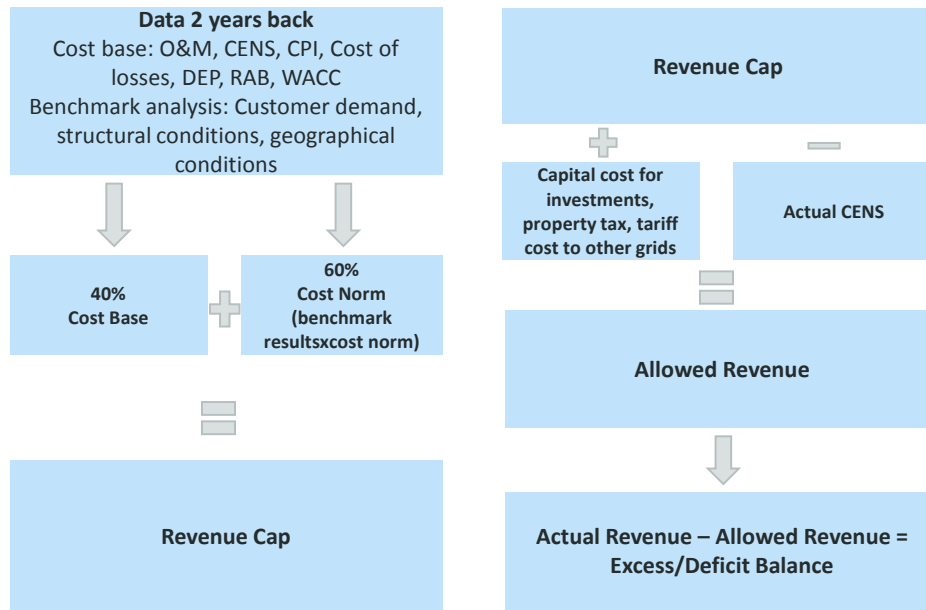


Figure 1.6 – Summary of Revenue Requirement Model¹⁹

At present, tariffs are set based on the allowed revenue as shown in the below formula.²⁰

$$AR_t = RC_t + PT_t + TC_t + R\&D_t - CENS_t + TL_t$$

revenue cap
pass-through costs related to property tax
tariff costs to other regulated networks
approved R&D costs
cost of energy not supplied
time lag component

The revenue cap (RC_t) component of the allowed revenue is set annually, based on a formula of 40 percent cost recovery (cost base) (C_t) and 60 percent cost norm (C_t^*) resulting from benchmarking models. There is a two-year lag in the cost data. That are the controllable operating costs, which are treated as other costs in the revenue cap, where 40% of all costs are passed through.

Figure 1.7 – Allowed Revenue Calculation

The next formula shows cost base calculation. To remove the time lag in the cost of capital recovery, the difference between actual cost of capital (depreciations and return on assets) in the revenue cap year and the cost base from two years back is included. CENS is a measure of the calculated value of lost load for the customers. It is an incentive for DSOs to maintain their assets properly and to ensure necessary investments in order to avoid power outages at a socioeconomic efficient level. In addition, environmental variables (Z-factors) were incorporated in the cost norm.

¹⁹ Source: NordReg, 2011, Economic regulation of electricity grids in Nordic countries.

²⁰ Source: www.nve.no

$$C_t = \underbrace{(OM_{t-2})}_{\text{Operation and Maintenance Cost}} + \underbrace{CENS_{t-2}}_{\text{Cost of energy not supplied}} \times \frac{CPI_t}{CPI_{t-2}} + \underbrace{PL_{t-2}}_{\text{Power loss}} \times \underbrace{P_t}_{\text{Weighted average electricity price}} + \underbrace{DEP_{t-2}}_{\text{Depreciation}} + \underbrace{RAB_{t-2}}_{\text{Book Value + \%1}} \times \underbrace{WACC_t}_{\text{Revised annually}}$$

Figure 1.8 – Cost Base Calculation²¹

The cost of power losses is calculated by multiplying actual losses (PL) with the reference price of power (P) from Nord Pool Spot. The purposes of capturing the cost of power losses are:

- Standardization of the price component over all DSOs implies that in the efficiency benchmarking companies are only compared by the quantity component, the actual power losses.
- It incentivizes DSOs to purchase the corresponding amounts of electricity as cost efficient as possible. If network operators are able to buy the corresponding amounts at prices lower than the reference price, they can keep the profit or make a loss if the purchase price is higher than the reference spot price.

In the benchmarking models, only the costs of network losses in the distribution grid are included. The calculated costs of network losses in regional grid are covered 100% and excluded from benchmarking, because the loss volume is not only dependent on the network company's decisions, but also influenced by external factors in the grid.

On the other hand, cost norm C_t^* of each network operator is a result of a Data Envelopment Analysis (DEA) benchmarking analysis, which will be explained in more detail in Section 1.4 (on Efficiency).

The controllable operation and maintenance costs mainly comprise of personnel and material costs related to own production of services and purchase of external services. Those are purchases of transmission and system services, purchases of goods and material, salaries and other personnel costs incl. pension costs, other operating costs, bad debts and internally priced services. A network company can charge a customer for costs related to existing network when the customer asks for quality or services that are usually not expected to be delivered as a network service. Revenues following these kinds of services can be kept out of actual revenues but are also subtracted from the cost base.

1.3.0.4 Portugal

In Portugal, price cap methodology applied to TOTEX was modified in 2012 and price cap started to be applied to OPEX and rate of return to CAPEX. On the other hand, price-cap methodology continued to be applied to TOTEX in the LV distribution activity in the regulatory period 2018-2020. Implementation period is 3 years.

The allowed revenues are calculated based on the information (both real audited and estimated data) sent annually by DSOs. This information includes:

- financial data,
- operating costs and depreciation,
- investments and subsidies
- technical data.

In addition to operating costs, controllable costs, non-controllable costs and investment costs, other costs that are not subject to efficiency such as concession rents and actuarial gains and losses are submitted.

21 Source: Schweinsberg A., Stronzik M., Wissner M., December 2011, Cost Benchmarking in Energy Regulation in European Countries.

As for CAPEX, in addition to the analysis of the investment values sent by the companies each year, the regulatory authority also takes into account the Development and Investment Plan prepared every two years by each sector's DSO. Moreover, there are also incentives for quality of service, losses reduction and for investments in smart grids.

1.3.0.5 UK

RIIO (Revenue = Incentives + Innovation + Outputs) model is used for network regulation companies in UK. The regulatory period consists of 8 years from 1 April 2015 to 31 March 2023. RIIO regime is different in that:

- Outputs, to which the revenue allowances are linked, are defined on a long-term basis.
- Rather than all CAPEX going into the RAB, and all OPEX being funded in that same year, a fixed proportion of total expenditure is funded that year (fast money), with the remainder being funded through the RAB (slow money).
- Rewards and penalties related to cost savings and output delivery is triggered during the regulatory period, whereas in most of the other methods they are calculated only at the regulatory review.
- DSOs submit long-term business plans that extend beyond the current regulatory period.

Each year the allowed revenue, that each DSO can collect from customers through electricity bills, is calculated by Ofgem. The main factors are the DSOs' TOTEX performances and incentive payments.

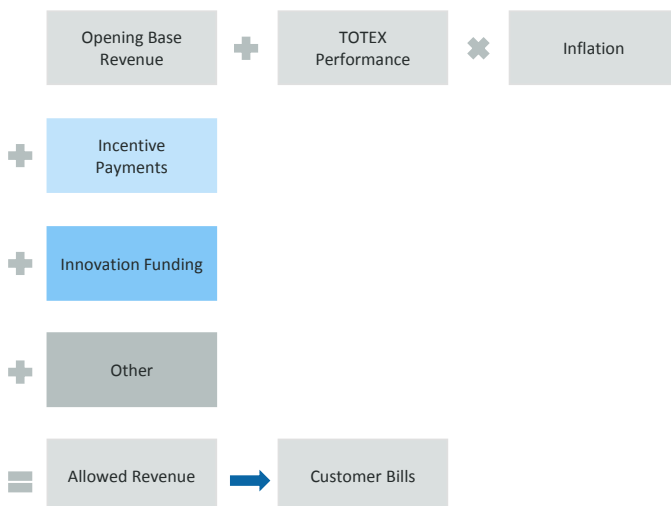


Figure 1.9 – Simplified Process for Calculating Allowed Revenue²²

TOTEX refers to the total controllable expenditure (this includes only the controllable costs; uncontrollable costs, such as business rates and licence fees, are excluded). TOTEX comprises of both capital expenditure (CAPEX) and operational expenditure (OPEX). DSOs are incentivised to deliver outputs based on whole-life costs, rather than being driven to prefer either CAPEX or OPEX solutions. DSOs in UK report their actual TOTEX annually, explaining their performance compared with their allowed TOTEX. They are also required to forecast their TOTEX performance to the end of the price control. Actual TOTEX and TOTEX incentive mechanism both affect the allowed revenue.

Innovation funding is provided to DSOs through an annual competition which provides funding to a small number of large-scale innovation projects. Its aim is to encourage DNOs to innovate in the design, build, development and operation of their networks.

The most significant cost categories are as follows:

- **Operational support:** the cost of supporting direct activity on the network, such as network design, project management, engineering management, clerical support, operational training, call centres and control centres.
- **Replacing and refurbishing equipment:** the cost of maintaining the existing network by replacing and refurbishing assets.
- **Network faults:** the cost of repairing faults on the network.

Replacing and refurbishing equipment, network capability and network faults are direct costs, whereas operational support and business support are indirect costs.

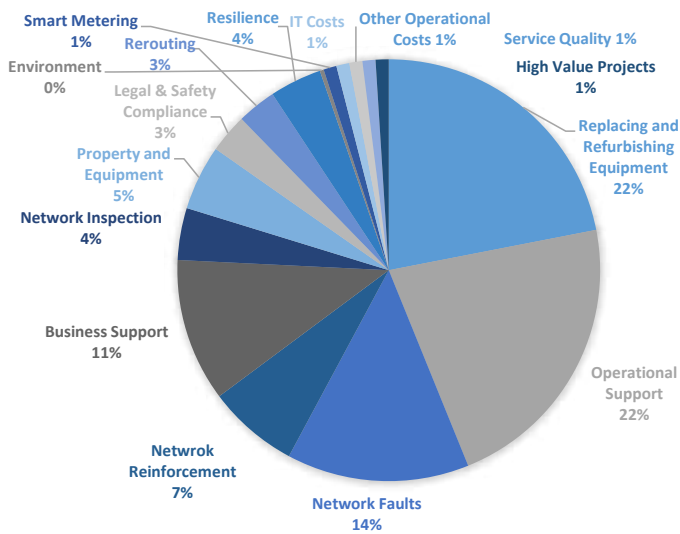


Figure 1.10 – Expenditures Realized in the first 3 years of Implementation Period

- **Business support:** the cost of running the DSO business, such as those associated with HR, finance and the CEO, and non-operational training.
- **Network reinforcement:** the cost of managing the load on the network, for example the installation of new assets to accommodate changes in the level and/or pattern of electricity demand and generation.
- **Other operational CAPEX costs.** This combines eight single cost categories; resilience (excluding tree cutting), legal and safety compliance, rerouting, IT, other operational costs, service quality, high value projects and environment.

In addition, Figure 1.11 describes determination of base revenue.

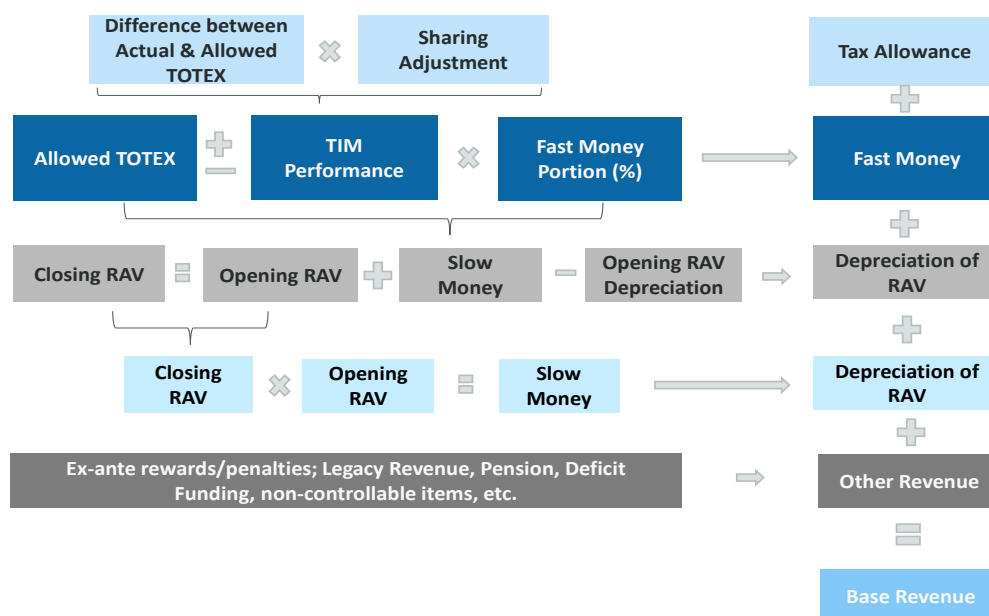


Figure 1.11 – Determination of Base Revenue²³

The difference between actual and allowed TOTEX is shared between the DSO (via modifying to Base Revenue) and customers and tax obligations. This process forms the TOTEX Incentive Mechanism (TIM). For Base Revenue calculations a portion of allowed TOTEX is directly added to the Base Revenue. This is known as Fast Money as the company is allowed to collect revenue equal to this value during the next Allowed Revenue year. The remainder of allowed TOTEX (Slow Money) is added to the opening Regulatory Asset Value (RAV). RAV is the long-term financial value of the capital employed in the regulated business. RAV is based on the initial market value of the regulated asset base at privatisation, plus all subsequent additions.

In UK, network reinforcement costs are treated as passthrough and corrected after the realizations. At the end of the tariff period underspent or overspent can be added or subtracted from the allowed revenue. If the load demand on the networks did not materialise, underspent amount is subtracted from the allowed revenue and if there was material overspend, allowances can be adjusted upwards to ensure appropriate investment by the DNOs to meet the demands on the network.

1.3.0.6 Turkey

Revenue cap methodology have been applied to OPEX and rate of return to CAPEX since 2006 in 5-year implementation periods. In 2006, 2010 and 2015 EMRA set revenue cap based on actual DSO operational expenditures in photo years of previous implementation period.

In the second and third implementation period OPEX budget is divided into two parts as controllable and uncontrollable. Controllable OPEX consists of 50% fixed, 50% variable linked to length of network lines, number of transformers, number of customers and distributed energy with corresponding coefficients although controllable OPEX varies average 80% by the asset increases and 20% by the corporate governance fixed costs.

So far, DSOs submitted their CAPEX plans with limited justifications plans which were almost inadequate to cover all capacity increase needs and network refurbishment as well as required technology investments. It is observed that DSOs are focusing on more CAPEX efficiency than the real network needs to improve overall performance. Revenue ceiling performance related part, although not significant, was working only upside.

1.3.1 Regulatory Asset Base (RAB)

The structure of individual components included in the RAB and their valuation differ significantly among EU Member States. The RAB can be comprised of several components such as fixed assets, working capital or construction in progress and the RAB value is usually linked with depreciation. Table 1.4 provides explanation of RAB components, valuation and RAB adjustment in most of the EU Member States.

Table 1.4 – Regulatory Asset Base²⁴

Country	Components of RAB	Regulatory asset value	RAB adjustments
Austria	Intangible and fixed assets, book values	Historic cost approach	Expansion factor for investments during a regulatory period leads to changes of the regulatory cost base
Bulgaria	Fixed assets, working capital, assets under construction	Historical costs	No adjustment, historical values
Czechia	Fixed assets, investments in progress, leased assets, no working capital	The RAB is based on re-evaluated values of assets that are recorded in the annual financial statements	The adjustment is similar to the net book value calculation (investment - depreciation), the formula for RAB adjustment is "investment - depreciation x k"; k is revaluation coefficient which is set annually and which is calculated as the result of dividing the planned value of the regulatory asset base in year "i-1" by the planned residual value of assets in year i-1; k = <0;1>
Denmark	Fixed assets, working capital and assets under construction	Historical costs included return on capital	Adjusted for non-controllable costs
Estonia	Fixed assets, working capital, leased assets	Historical costs	The fixed assets do not include: 1) long-term financial investments; 2) intangible assets, except for software licenses; 3) fixed assets acquired with grant aid (including targeted funding); 4) fixed assets acquired with funds obtained from connection fees; 5) fixed assets which the undertaking does not use for the purpose of providing network service.
Finland	Fixed assets, working capital, leased assets	Regulatory asset value is calculated from network replacement value by applying network component-specific average age and lifetime selection	Book values taken to RAB annually from balance sheet
France	Fixed assets	Net book value	Subsidies and grants are removed from the value of assets before entering the RAB
Germany	Fixed assets, working capital, assets under construction	Net substance preservation for business assets capitalised prior to 1st 2006, real capital preservation for business assets as from 1st 2006	The assets of the base year are used as RAB. No general adjustments after the base year
Greece	Fixed assets, working capital, assets under construction	Historical costs since 2009 (last revaluation in 2004)	No adjustment, historical values
Hungary	Fixed assets	Network assets: depreciated replacement value; Non-network assets: historical costs.	The assets of the base year are modified yearly with CPI and T-1 year's investments minus depreciation minus connection charges
Iceland	Fixed operating assets	Book value	CPI adjusted book values

²⁴ Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03. Moreover, information gaps have been filled where possible by the HD Consortium, based on their experience.



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Country	Components of RAB	Regulatory asset value	RAB adjustments
Ireland	Fixed assets, assets under construction	Replacement cost approach: Historic cost indexed to present value using inflation	Assets which have been added to the RAB, but have not been energised within 5 years (except in the case where the programme of work was scheduled to be longer than 5 years or where the SO can satisfactorily show that the delay is beyond its control) will be temporarily removed or “paused” from the RAB (with all return and depreciation paused) until the point at which the asset can be energised and utilised)
Italy	Historical revaluated cost	-	-
Latvia	Fixed assets, intangible investment, and does not include inventories and assets under construction.	Book value as per financial reports (taking into account asset revaluations carried out by the operator at replacement cost value)	The RAB is adjusted and set when the operator submits the tariff proposal; during the period the tariff is in force there is no RAB adjustment taking place.
Lithuania	Fixed assets	Values calculated using historical (for 5 small DSOs) as well as the historical and current (for the main network elements (lines, cables, transformers) assets which will be depreciated until 2020) cost – 1,059.04 million Euro (2018)	New investments and depreciation
Luxemburg	Fixed assets containing production costs, work in progress	For assets since 2010: historical costs Before: asset financed by own funds (max 50%); historical costs re-evaluated with published indexes Remaining part: historical costs	Adjustments not foreseen in the method; After activation, new assets also enter the RAB
Netherlands	Fixed assets and certain intangible assets (such as software) are included, no working capital	Indexed historical costs	Annual indexation (with CPI)
Norway	Book values from financial statement adjusted with 1% working capital premium, assets under construction and grants funded assets are excluded.	Book values from financial statements	BV + 1% working capital premium
Poland	Fixed assets, assets under construction, intangible assets	Re-evaluated assets	Annually
Portugal	Fixed assets deducted from third parties contributions	3,002 million € for 2016 (historical costs)	Each year the RAB allowed for year t is adjusted in order to consider new investments, write-offs and depreciation
Romania	Historical costs multiplied with index costs. Investments in new assets after the base year lead to an adjustment of the CAPEX	The assets of the base year used as initial RAB. For each year of the regulatory period, the RAB value increases with the investment in new assets and decreases with depreciation and the value of the asset that exits before complete depreciation. For RAB existing in 1 Jan. 2005 or the privatisation date, it was a fair value of the assets, updated with inflation. For the rest of the assets, based on historical costs updated with inflation.	RAB adjusted with CPI.
Turkey	Fixed assets, no working capital, no leased assets	Initial RAB was taken as “0” value at the beginning of 2006. Fixed asset, 5-year amortization in the first implementation period, 10-year amortization in the consequent periods.	RAB adjusted by CPI
UK	RIIO is used as a variation of RAB approach and hybrid between RAB and Net Present Value approaches, as explained in this section.		

In **Germany**, new assets (capitalized since 01/01/2006) are valued at historical costs. Old assets (capitalised before 01/01/2006) are valued at replacement costs if they are financed by equity (indexed historical cost, maximum equity ratio of 40%) and at historical costs if they are financed by debt capital (debt ratio at least 60% of all old assets).

Regulatory authority determines the asset life for different asset groups. E.g. MV network-underground cables (40–45 years), overhead lines (30–40 years), general fixed assets (buildings (50-70 years), furniture and fixtures (8-10 years), tools/devices (14-18 years), hardware – software (3-8 years), vehicles (5-8 years), etc.²⁵

In **Italy**, fixed assets are included in the regulatory asset base (RAB), with a one-year lag if investment costs are efficiently incurred and are consistent with system security, follow cost-effective criteria and, with regard to transmission, are included in the ten-year transmission development plans approved by the relevant authorities.

The RAB value is expressed at current cost and is based on depreciated historical costs inflated using a construction-specific index (*'Investimenti Fissi Lordi'*). In other words, capital costs are based on data from the accounting records of network operators. Assets under construction are also basically included in the RAB, with some exception for transmission. Depreciation is calculated under a straight-line method for all fixed assets in use included in the RAB.

The regulatory invested capital (CIR), made up of net fixed assets and net working capital, net of the “electrical pension fund” and TFR fund, constitutes the Regulated Asset Base (RAB) and are divided into capital relating to the distribution and capital service relating to the measurement service.

The value of the net fixed assets (land, high voltage lines, HV / MV transformation stations, MV and LV distribution networks entered into operation) is obtained by applying the criterion of the revalued historical cost.

For the purpose of revaluing investments, an investment deflator is applied annually, so as to accommodate them in RAB at their value at constant prices (i.e. considering the effect of inflation).

This setting responds to the choice of applying a real WACC for the purpose of calculating the tariff, which ensures a return on investment that is neutral to the trend in the general price level.

The application of the deflator is therefore consistent with a purely financial logic, which proposes the evaluation in real terms of the capital invested.

In calculating the recognized invested capital, the deflator serves to reflect the value of the infrastructures dedicated to transmission and distribution; the application of the variation of the deflator, even if negative, serves to keep the real value of the capital invested in the activity unchanged.

In **Norway** RAB consists of fixed assets such as central, regional and distribution networks, sites, buildings, customer-specific equipment, means of transport, fixtures, tools and computer equipment, and other fixed assets used in the network business. Leased assets are not included in the RAB. However, they are included in the operating costs. Assets that are financed by third parties as investment contributions are not included in the RAB, however, operating costs related to these are not excluded from the overall operating costs. To reflect the working capital, 1% of the total book value is added to the RAB. The RAB is then multiplied with the WACC to calculate a reasonable return on the regulatory asset base.

Asset additions in the last and current year (year t and $t-1$) are not included in the RAB as a result of the time-lag in the cost base. However, the companies can calculate the revenue from investments into their allowed revenue the year they are commissioned. This implies that investments are also included in the companies' tariff base as of the commissioning year.

In **Portugal** all the investments paid by DSO are included in the RAB and therefore accepted in the allowed revenues. Book value of assets is considered in the asset base. Costs with metering devices are not accepted in RAB.

In **UK** RIIO is a variation of the RAB approach and is hybrid between RAB and Net Present Value approaches. As explained in previous sections, for Base Revenue calculations a portion of allowed TOTEX is directly added to the Base Revenue (Fast Money) and the company collects this much amount of revenue during the next allowed revenue year. The remainder of allowed TOTEX is named Slow Money and it is added to the opening RAV, where RAV is based on the initial market value of the regulated asset base at privatisation, plus all subsequent additions. RAV is gradually reflected in Base Revenue over multiple decades, reflecting the average lifetime of network assets. Amounts are deducted annually from opening RAV (this is depreciation). The depreciation value is then added to Base Revenue in the next Allowed Revenue year. The average of opening and closing RAV for the year also earns a return (at WACC).

In **Turkey**, in contrary to almost all EU countries, assets do not belong to the DSOs. Whole system is 30-year concession. Apart from privatizations in 2013 and KCETAS, ADM and AKEDAS DSOs concessions started earlier. Initial RAB was taken as “zero” value. DSOs privatized in the first implementation period (BASKENT, SEDAS and MEDAS) had enjoyed receiving partial acquisition costs within their revenue cap. This process was ended in the second implementation period.

1.3.2 Rate of Return

Rate of return for countries is defined in the following table. In most of the countries WACC is used, where the value of WACC changes between 5% and 10%. Countries such as Germany and Spain do not use WACC in the regulation of electricity DSOs.

Table 1.5 – Rate of Return in European Countries²⁶

Country	Type of WACC	Determination of the rate of return on equity	Rate of return on equity before taxes	Use of rate of return
Austria	Nominal WACC pre-taxes	$Re = (\text{nominal risk-free rate} + \text{levered Beta} \times \text{MRP}) / (1 - \text{tax rate})$	8.97% (nominal pre-tax, set in 2013)	WACC nominal pre-taxes * RAB (book values)
Belgium	No use of WACC	Sum of a nominal risk-free rate and a risk premium (market risk premium multiplied with a risk factor) multiplied with (1+illiquidity premium) multiplied with a corporate tax factor	5.76%	Granted for existing assets to a maximum of 33% of the imputed business assets. Any available equity capital in the capital structure in excess of this will be subject to another equity interest rate
Czechia	Nominal, pre-tax WACC	Sum of nominal risk-free rate and a risk premium (market risk premium multiplied by beta factor)	10.28%	The whole RAB is multiplied by the WACC. When setting the nominal pre-tax WACC the D/E ratio of 45.75/54.25 was used.
Denmark	Nominal WACC pre-tax	Sum of a nominal risk-free rate and a risk premium (market risk premium multiplied with a beta risk factor)	5.63	A risk-free interest rate calculated as an average of the last three months available daily observations of ten-year zero-coupon rates for Danish government bonds.
Estonia	Pre-tax WACC nominal	1) Germany 10 years average bonds yield 2) Estonian risk premium 3) McKinsey market risk premium 4) Beta	5.59%	4,50%
Finland	Nominal, pre-tax	Risk-free rate + beta*Market risk premium + Premium for lack of liquidity (+ additional risk premium for natural gas TSO and DSOs)	8.65%	Reasonable return is calculated by multiplying the adjusted capital invested in network operations by the reasonable rate of return. Therefore, company receives reasonable return on adjusted equity and interest-bearing debt invested in network operations.

26 Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03. Moreover, information gaps have been filled where possible by the HD Consortium, based on their experience.

Country	Type of WACC	Determination of the rate of return on equity	Rate of return on equity before taxes	Use of rate of return
Germany	No use of WACC	Sum of a nominal risk-free rate and a risk premium (market risk premium multiplied with a beta risk factor) multiplied with a corporate tax factor	6.91%	Granted for existing assets to a maximum of 40% of the imputed necessary business assets. Any available equity capital in the capital structure in excess of this will be subject to another equity interest rate
Greece	Nominal, pre-tax	WACC: a) CAPM & additional country risk premium for cost of equity; and b) cost of debt based on operators' proposal and actual figures of base year	8.20%	WACC is applied on the value of Regulatory Asset Base (RAB) for each year of the Regulatory Period
Hungary	Real, pre-tax	Sum of the real risk-free rate and risk premium (equity beta multiplied by market risk premium)	6.20%	Has a 49% weight in WACC.
Iceland	Pre-tax WACC	$Re = (rf + (rm - rf) \times \beta + \text{specific risk}) / (1 - t)$ Sum of real risk-free rate and a risk premium (market risk premium multiplied with a beta risk factor) plus a specific risk premium multiplied with a corporate tax factor	10.7%	The Pre-Tax WACC is the rate of return, it is granted for operating necessary business assets.
Ireland	Baseline WACC plus an aiming up allowance	The CAPM methodology is used to calculate the cost of equity using the formula: $ke = rf + \beta \times (rm - rf)$ where: ke is the expected rate of return for the risky asset; rf is the rate of return on a 'risk-free' asset (the "risk-free rate" or "RFR"); β is the 'beta' factor, which is correlation of the return on the risk asset with the expected returns on a diversified portfolio of all investable assets; and rm is the expected rate of return on a market value-weighted portfolio of all assets (the 'market portfolio'). The term $rm - rf$ in the CAPM is referred to as the market risk premium ("MRP").	Cost of equity (pre-tax) – high 7.99% Low 5.62% Point Estimate 6.63 %	The Regulatory Asset Base (RAB) is the base to which the rate-of-return is applied when determining the return on capital
Italy	Real, pre-tax	-	5.6%	-
Latvia	Post-tax, nominal	Return on equity: Sum of a nominal risk-free rate, market risk premium multiplied with a beta risk factor, and a sector risk premium.	6.67% (post-tax) 7.85% (pre-tax)	WACC is applied to the value of RAB to calculate the return on capital, which is a part of capital costs in tariff.
Lithuania	Nominal, pre-tax	Return on investment is determined as weighted average cost of capital, calculated according to the formula: $WACC = Rd \times WD + Re \times 11 - m \times WE$	4.88%	WACC is used to calculate return on investment. WACC is a multiplied with whole RAB
Luxemburg	Nominal pre-tax WACC	Sum of cost of debt and cost of equity.	6.12%	Granted for self-financed assets in the RAB and for work in progress according with respect to the dispositions of E16/12/ILR and E16/13/ILR

Country	Type of WACC	Determination of the rate of return on equity	Rate of return on equity before taxes	Use of rate of return
Netherlands	Real, pre-tax	Equity risk premium is based on data in individual Eurozone countries over the period 1900-2015 (Dimson, Marsh & Staunton database). An average of both the geometric and arithmetic average is taken.	6.7%	Real WACC is currently based on a 50% debt and 50% equity capital structure. Real WACC is multiplied with the indexed RAB.
Norway	Nominal, pre-tax	CAPM	12 %	WACC is multiplied with RAB
Poland	Pre-tax nominal	(Risk-free rate + β_{equity} * equity risk premium) / (1 - corporate tax rate)	7.84%	In allowed revenue they include: RoC = WACC * RAB
Portugal	Nominal, pre-tax	CAPM	8.5%	WACC is currently based on 55% debt and 45% equity applied to RAB
Romania	Real, pre-tax	Sum of risk-free rate and a market risk premium multiplied with beta	7.17%	Granted for initial RAB (privatization value), existing assets and new assets. RRR is multiplied with whole RAB. Debt and equity percentages are 40/60%.
UK	Real, post-tax	CAPM	6.4% for Western Power DSO, 6% for other DSOs	Based on cost of debt and cost of equity
Turkey	Real, pre-tax	CAPM (Weighted Average Cost of Capital)	13.61%	Based on 50% debt, 50% equity. WACC rate is applied on the half of the sum of each year's initial and end RABs

In **Germany** the regulatory authority sets the costs of capital, whereas the cost of debt is defined by law. For the 3rd implementation period, in line with the related regulation in force, the allowed rate of return on equity needed for new installations may not exceed the average current yield²⁷ for the last 10 full calendar years on fixed interest securities of domestic issuers, plus an appropriate mark up to cover entrepreneurial risk specific to network operation. The equity return is determined as 6.91% (pre-tax) for the new assets²⁸. Cost of debt is treated as pass-through and therefore allows for natural hedge against changes in interest rate environment.

In **Italy** the rate of **return on invested capital** is calculated in the same way for the gas and electrical infrastructural services and it is periodically reviewed—according to the methodology defined in decision 583/2015 updated with decisions 654/2015/R/eel, 575/2017/R/gas, 653/2017/R/gas, 639/2018/R/com, 114/2019/R/gas, 419/2019/R/gas, 474/2019/R/gas e 570/2019/R/gas, as a WACC for the period 2016-2021.

The Regulator uses the following formula to evaluate the rate of return, and with specific resolution it publishes the values of the return for each period:

$$W_{pre-tax,p,s}^{real} = Ke_{p,s}^{real} \cdot \frac{(1 - g_{p,s})}{(1 - T_p)} + Kd_p^{real} \cdot \frac{g_{p,s} \cdot (1 - tc_p)}{(1 - T_p)} + F_{p,s}$$

- is the real rate of return on equity for the infrastructure service;
- is the cost of the debt in real terms recognized for the infrastructure services of the electricity and gas sectors, calculated

27 Source: yield in detail - public debt securities, corporate bonds (excluding non-profit institutions at banks [MFIs]), mortgage bonds). These yields are published by the German Central Bank (Deutsche Bundesbank) and as arithmetic means for the last ten completed calendar years.

28 Source: Groebel A., (April 2018), BNetzA's role in energy infrastructure regulation and planning/permitting.

according to the following formula;

- T_p is the theoretical rate of incidence of taxes on the operating result for infrastructure services in the electricity and gas sectors;
- tc_p is the tax rate for the calculation of the tax shield of financial charges;
- $g_{p,s}$ is the gearing level for the infrastructure service;
- $F_{p,s}$ is the corrective factor that allows the coverage of taxes on nominal profits.
- The equity value is expressed by the following formula

$$Ke_{p,s}^{real} = \max\left(\frac{RF_p^{nominal} - isrp_p}{1 + isrp_p}; 0,005\right) + \beta_s^{asset} \cdot \left[1 + (1 - tc_p) \cdot \frac{g_{p,s}}{1 - g_{p,s}}\right] \cdot \left(TMR - \max\left(\frac{RF_p^{nominal} - isrp_p}{1 + isrp_p}; 0,005\right)\right) + CRP_p$$

- is the level of inflation incorporated in the nominal rate of return;
- isrp is the level of inflation incorporated in the nominal rate of return
- are risk-free activities
- TMR is the total market return, which for the 2016-2021 PWACC takes on a value of 6.0%;
- CRPp is the level of the country risk premium.

The WACC values for infrastructure services in the electricity and gas sectors, deriving from the application of the previous formulas issued are shown in the following table.

Table 1.6 – Rate of return values for Italy

Service	Year	2016	2017	2018	2019	2020	2021
Electrical	Trasmission	5.3	5.3	5.3	5.6	5.6	5.6
	Distribution and measurement	5.6	5.6	5.6	5.9	5.9	5.9
GAS	Trasmission	5.4	5.4	5.4	5.7	5.7	5.7
	Distribution	6.1	6.1	6.1	6.3	6.3	6.3
	Measurment	6.6	6.6	6.6	6.8	6.8	6.8

The rate of return on invested capital is calculated and periodically reviewed—according to the methodology defined in decision 583/2015, as a WACC. The cost of equity is determined on the basis of the CAPM and reflects the systematic risk that is typical of each regulated activity. The systematic risk is assessed for each activity by estimating the value of the beta parameter used in the context of CAPM. The beta parameter is set at the beginning of the regulatory period.

Under the new calculation method, the WACC has been set at 5.6% for the first three years (2016-2018), down from the 6.4% for the 2014-2015 period. This decrease was mainly due to the reduction in interest rates.

In **Norway**, the level of the regulatory rate of return is decided by a weighted average cost of capital model as shown in the below formula:

$$WACC_{pre-tax} = (1 - G) \times [(R_f + Infl + \beta \times MP) / (1 - t)] + G \times (Swap + P_d)$$

Variables	Yıl	Rate
G : 0.6 - Gearing (Debt share of total capital)	2018	6.10%
R _f : %2,5 - Real risk free rate for equity	2017	6.12%
Infl: Moving average of 4 years inflation, observations from previous year and the current year, and expected inflation for the next two years	2016	6.32%
	2015	6.32%
	2014	6.61%
β _E : 0,875 - Equity beta	2013	6.90%
MP : %5 - Market Premium	2012	4.20%
Swap : Nominal rate for debt: Annual average of 5-years swap rate	2011	5.31%
	2010	5.62%
P _d : Debt premium: Annual average of credit spread for 5-year bonds for the power sector, minimum rating BBB+	2009	6.19%
	2008	7.44%
t : %25 - Tax rate	2007	7.83%

Figure 1.12 – Determination of WACC in Norway

Pre-tax nominal WACC is used in **Portugal**. CAPM is used to set the cost of equity and a default spread model, where a spread (debt premium) is added to the risk-free rate is used for cost of debt. In order to deal with uncertainty and financial volatility environment, rate of return is updated ex-post each year. WACC is indexed to the Portuguese 10-year bond benchmark and depends on its evolution with a cap and floor. The floor and cap limits within the annual RoR can evolve over the 2018-2020 period were determined as 4.75% and 9.75% respectively²⁹.

For electricity DSO, RoE parameters are as follows:

- Risk free rate (nominal): 1%
- Tax rate: 31.5%
- Equity risk premium: 7.66%
- Equity beta: 0.63
- Cost of equity (before taxes): 8.5%

Like other countries WACC is used to calculate allowed return in **UK**. In estimating the cost of equity parameter within the WACC, Ofgem primarily relied on the CAPM but “sense checked” the result with other methods, e.g. dividend growth model and market to asset ratios. Cost of debt is based on a long-term trailing average of forward interest rates, and the revenues allowed under the price control is adjusted each year for changes in this trailing. Allowed cost of equity is determined as 6.4% for Western Power Distribution and 6% for other DSOs.

Pre-tax corrected real WACC (corrected real reasonable return on investment) is used in **Turkey**. Time adjustment conversion is used for final real WACC³⁰. For conversion of WACC from nominal to real³¹, expected inflation rate (by the Central Bank) is used. However as in the recent years inflation rate was quite unstable, thus real RoI rates did not meet the expectations.

29 Source: <https://www.edp.com/en/news/2017/12/17/erse-announces-electricity-tariffs-2018-and-parameters-2018-2020>

30 EMRA communiqué dated 19th December 2015. Article 16, Paragraph 7.

31 EMRA communiqué dated 19th December 2015. Article 16, Paragraph 6.

1.3.3 Depreciation

Table consists of information about depreciation methods applied and the ratios.

Table 1.7 – Depreciation³²

Country	Depreciation Method	Depreciation Ratio	Consideration
Austria	Straight line	Depending on asset type: lines 2-3%, transformers 4-5%, substations 4%	Depreciation of new investments during the regulatory period is a pass through. Depreciation of the base year is adjusted with an individual productivity offset
Czechia	Straight line	Buildings 2%, Overhead lines and Cables 2.5%, Transformers EHV 4% Transformers MV, LV 3.3% Metering devices 6.6%	100% of the depreciation is used to determine the allowed revenue.
Denmark	Straight line	Depending on asset type	-
Estonia	Regulatory capital expenditure method	Depending on asset type. For new assets (after year 2003) 2.86%-3.33 from investment cost and for old assets (before year 2003) 7.14% from residual value.	Present regulation started at 2003 legal framework
Finland	Straight line	2.5%	Depreciation level based on average adjusted straight line based on the selected component lifetimes. Imputed straight-line depreciations are always allowed in full as far as the component is in actual use.
France	Straight line	Depending on asset type. Ratio between 2% and 4% for network assets (lines, pipes etc.)	Integrated directly and with 100% (except assets that were funded through subsidies or grants)
Germany	Straight line	Depending on asset type. Ratio between 1.5% and 4% e.g. lines & cables: ~2%, stations: ~4%	Part of the examined controllable costs
Greece	Straight line	Most assets are depreciated over a period of 25-50 years.	Depreciation ratio depends on asset type and it is integrated directly into the revenues
Hungary	Straight line	Depending on asset type. Ratio between 2.5 and 7% e.g. lines & cables: ~2.5%, stations: ~3.33%	Based on expected useful lifetime
Iceland	Straight line	Depending on asset type. Ratio between 2 and 20% e.g. DSO lines & cables: ~3%-4%	The regulator regularly inspects the RAB and the depreciations
Ireland	Straight line	Depends on asset category	Part of the examined controllable costs
Italy	Straight line	Based on economic technical life criteria is used. Depending on asset type e.g network assets 35 years for cables, 30 years for network stations, 30 years for transformers, 15-20 years for metering devices, 5 years for intangible assets and control devices.	Depreciation of the tangible and intangible assets based on re-evaluated values are allowed into the regulation.
Latvia	Straight line	Depending on asset type. Ratio between 1% and 20%, gas pipelines 1.7-2.5%, electricity lines 2-5%, electricity transformation substations 2.5-12.5%	Depreciation is a part of capital costs in the tariff

³² Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03. Moreover, information gaps have been filled where possible by the HD Consortium, based on their experience.

Country	Depreciation Method	Depreciation Ratio	Consideration
Lithuania	Straight line	4-70 years	Depreciation ratio depends on asset type. All depreciation of regulated assets is integrated into revenues.
Luxemburg	Straight line	Depending on the asset type. Useful lifetime 25-50 years for technical assets and constructions, and 3-20 years for IT related fixed assets	Depreciation is fully included in the allowed revenues
Netherlands	Straight line	Most assets are depreciated over a period of 35 – 55 years	Depreciation is part of the total costs, which are subject to an x-factor over the course of the regulatory period.
Norway	Linear depreciations from financial statements	Depending on asset type, must be approved by accountant	Part of examined controllable costs. The companies decide the economic life of components based on their own experience, and then calculate the depreciation according to the expected technical lifetime of the specific grid component.
Poland	Straight line	For transformers and substations economic useful life is 30-40 years. For new investments an average depreciation value of all investments (e.g. transformers, substations, IT systems, meters) equalled 4% is allowed	A component of allowed revenue
Portugal	Straight line	Depending on asset type. 5-40 years	Part of CAPEX
Romania	Straight line	Depending on asset type. Ratio between 2% and 16.6% e.g. lines & cables: 2.5-10% stations: 2%	Part of revenue requirement Depreciation is included directly and 100% in revenue, before the linearization
UK	Straight line	Amounts are deducted annually from opening RAV	the depreciation rate is expected to reflect the average expected economic life of the asset base. However, it is being discussed to accelerate depreciation and decrease economic life of assets from 40 to 20 years
Turkey	Straight Line	Regardless of economic life of assets, everything is depreciated in 10 years. IT, most part of operational technology (OT) assets have around 5-year economic life. Rapid changes in technology requires frequent replacement of those assets and with 10-year depreciation, replacement is automatically considered as OPEX. At the same time classic network components have 25-40-year economic life.	Corporate tax effect on regulatory depreciation and tax depreciation is added separately to revenue cap

Straight line depreciation is used in **Germany**. Depreciations depend on asset type. For instance, the ratio is between 12% for lines & cables and 4% for stations.

In **Italy**, straight-line depreciation based on economic technical life criteria is used. Net book values change due to new investments and depreciation. Depreciation for typical network assets are: 35 years for cables, 30 years for network stations, 30 years for transformers, 15-20 years for metering devices, 5 years for intangible assets and control devices. Depreciation of the tangible and intangible assets based on re-evaluated values are allowed into the regulation.

In **Norway**, depreciation of capital is linear. The companies decide the economic life of components based on their own experience, and then calculate the depreciation according to the expected technical lifetime of the specific grid component.

In **Portugal**, straight line depreciation is used. Economic life changes between 5-40 years depending on the asset.

Under the RIIO model in **UK**, the depreciation rate is expected to reflect the average expected economic life of the asset base. Amounts are deducted annually from opening RAV. The depreciation value is then added to base revenue in the next allowed

revenue year. At present linear depreciation is used, however it is being discussed to accelerate depreciation and decrease economic life of assets from 40 to 20 years.

In **Turkey**, straight line depreciation is utilized in Turkey like other EU Member countries. Regardless of economic life of assets, everything is depreciated in 10 years. IT, most part of operational technology (OT) assets have around 5-year economic life. Rapid changes in technology requires frequent replacement of those assets and with 10-year depreciation, replacement is automatically considered as OPEX. At the same time classic network components have 25-40-year economic life.

1.3.4 Connection Fees

Connection fees may be applied as 'deep' costs or 'shallow' costs. Shallow connection fees are based on costs for connecting a customer to the distribution network not including reinforcement of the core grid. While deep connection costs also include grid reinforcement costs.

Germany: The connection charge is meant to cover the cost of the facilities that are specifically set up to serve the customer and the connection to his housing. In addition, the consumer is obliged to pay a contribution towards the cost of the reinforcement of networks and shared resources. Connection charge is deep. The DSO prepares an estimate based on its cost, but the customer is free to procure the necessary works from a different provider. For consumers and generators alike, the DSO may refuse connection only if it is impossible or if it would entail an unreasonable cost.

Italy: ARERA has provided a specific resolution on the network connection service, providing for **the connection rates** to the distribution and transmission networks in the event of interconnection power lower than 10 MVA to the distributor network and in the event of interconnection power equal to or greater than 10 MVA to the transmission network.

The technical conditions for connecting end customers are defined:

- a) by the network code, in the case of connections to the national transmission network;
- b) by resolution ARG/let/33/08 in the case of connections to distribution networks with a voltage level greater than 1 kV;
- c) by the CEI 0-21 standard in the case of connections to distribution networks with a voltage level not exceeding 1 kV.

ARERA defines the content of the request for connection to the network and on the standards for providing the service in terms of connection time.

The **connection service** resolution refers to the following types:

- a) ordinary permanent connections;
- b) particular permanent connections;
- c) temporary connections.

Otherwise, the Regulator sets the following costs:

- a fixed contribution to cover administrative costs of € 25.81, to be applied to domestic customers only after 2023.
- contributions for the creation of ordinary permanent medium voltage (MV) connections
 - a) By distance between the pick-up point and the reference booth (distance altitude)
 - fixed fee: € 469.32

- additional quota to be applied for every 100 meters or fraction greater than 50 meters exceeding the distance of 1000 meters from the reference booth: € 46.94
- b) For each kW of power made available (power share) [€/ W] 56.04
 - Unit amount of fixed-rate contributions for the **transition from low to medium voltage (MV)** € 442.05
 - Connections that do not require the construction of a medium / low voltage MV/LV transformer substation, **with power up to 40 kW** and a maximum distance of 20 meters from the permanent distribution network systems existing near the place for which the connection is requested:

Table 1.8 – Connection fee details for Italy

A		B	C	
Amount for connection		Supplement for connection operation outside the working timetable	Plurality of requests	
	Cost [€]	Cost [€]	Number of requests	Reduction Coefficient [€]
Without crossing the road	150.09	18.68	1	0
			From 2 to 4	40
With crossing the road	250.14		From 5 to 9	50
			Up to 9	55

Contributions for power supplies by local generation plant

- Fee for each kW of power made available [€/kW] 69.93
- Fixed fee € 482.30
- Contributions for other specific services
 - a) Contribution for deactivations and activations as a result of arrears, reconnection and posting of seasonal recurring utilities € 25.10
 - 1. Contribution for requests to move the measurement groups within a radius of 10 meters from the previous location € 202.21
 - b) Contribution for requests to verify the correct functioning of the measurement group € 46.49
 - c) Contribution for requests for checking the supply voltage € 139.47
 - d) Advance on contributions for connections assessed on estimate value € 100.00

Norway^{33,34}: Network companies require a connection charge to cover the costs of connecting new customers to the network or costs of reinforcing the network for existing customers. Connection charges are shallow because it is generally not allowed to set connection charges for investments in the meshed network.

The connection charge is a one-time payment, and the grid company must present an estimate of what the charge will be in advance. The customer must pay the connection charge to be connected to the grid.

Portugal: The connection of a facility to the electricity network causes costs that depend on the type of facility to be connected (voltage level, technical requirements), the network itself (aerial, underground, meshed, radial), the distance, route, etc. Connection charges are deep for consumers and generators. Connection costs are calculated case by case and paid by the generators for the

33 Source: <https://www.nve.no/energy-market-and-regulation/network-regulation/network-connection/>

34 Source: NVE, 08/2018, The Norwegian power system. Grid connection and licensing.

generation side. As for large consumers ($S \geq 2\text{MVA}$), connection costs are computed case by case and distributed between the DSO and the consumers on an agreement basis. To determine the connection cost for generators and large consumers, DSO makes an estimate, but the client can ask the regulator to set the price in case he does not agree with the DSO's estimate. As for small consumers ($S < 2\text{MVA}$), part of the cost is supported by the consumer and the other by the DSO taking into account the length of the connection, the demanded power and the use of the connection (exclusive and/or shared).

The table shows network access tariffs in 2016 and 2017. SplV is the Special Low Voltage and StLV is the Standard Low Voltage. Capacity, active and reactive energy charges are applied to all customer types, however reactive energy charge is not applied to StLV networks.

Table 1.9 – 2017 Network Access Tariffs³⁵

	2016 Tariffs (average prices) (€/kWh)	2017 Tariffs (average prices) (€/kWh)	Change (%)
Access to HV Networks	0.03103	0.03249	4.7
Access to MV Networks	0.05348v	0.05597	4.7
Access to SplV Networks	0.09125	0.0955	4.7
Access to StLV Networks	0.12255	0.12826	4.7

UK³⁶ has a single charge to connect the distribution grid. If additional investment is required in the network, new customer pays some of the cost, with the rest being socialized. Each DSO prepares a charging methodology based on a set of principles and an associated charging statement. Ofgem approves the methodology but not the individual charges. The connection charge consists of three components:

- Cost of the connection assets that will be used solely to connect new customer,
- A proportion of the cost of network reinforcement where it is required. The proportion is calculated based on the share of new capacity created that will be used by the connecting customer.
- A rebate to the DNO or a previously connected customer under the Electricity (Connection Charges) Regulations 2002. This rebate will apply where the new connection uses network assets that were installed and paid for by a previous connection.

Most of the new connections do not require network reinforcement, for example, between 2011-2014, 95% of the connections do not trigger network reinforcement. Power increase of households or small business customers do not trigger network reinforcement costs.

Customers connecting generation equipment to the network will also have to pay for reinforcement in excess of £200/kW.³⁷ This is known as the high-cost project threshold. Its application makes sure that other network users are not unduly affected by the additional costs caused by the complexity of some connections.

In UK, companies may develop and operate small, local electricity networks and compete to connect new customers to the networks. By this way, customers are expected to connect to the network get fairer prices and better service. The small, local networks are owned and operated by Independent Distribution Network Operators. The Electricity DNOs, Independent Distribution Network Operators and Independent Connection Providers can all provide connection services. If the DSO makes the connection job, there is a 4% regulated margin on contestable connection services.

35 Source: ERSE, July 2018, Annual Report on the Electricity and Natural Gas Markets 2017.

36 Source: Ofgem, A guide to Electricity Distribution connections policy

37 The average exchange rate in 2019 between Euros and POUND is 0.88 POUND per EUR.

Turkey: Connection fees are determined by EMRA with an update every year. Connection fees are based on real CAPEX unit prices.

1.3.5 Performance Indicators^{38 39}

Quality indicators in European countries for long and short interruptions are as follows:

Table 1.10 – Indicators for Long and Short Interruptions

Country	Long Interruption-Index	Long Interruption-Weighting	Short Interruption-Index
Austria	SAIDI, SAIFI, ASIDI, ASIFI, CAIDI, (CML, ENS).	Weighted by both the transformer stations affected and by the number of customers.	MAIFI
Belgium	SAIDI, AIT	SAIDI used for LV/MV and weighted by the number of customers. AIT used for HV/EHV and weighted by the power affected	-
Bulgaria	SAIDI, SAIFI	By the number of customers.	-
Czechia	SAIFI, SAIDI, CAIDI	By the number of customers.	No specific indicator. Distribution system operators monitor them at the chosen points according the technical report CENELEC TR 50555.
Denmark	SAIDI, SAIFI	It is weighted by type of interruption, kilometres of electricity network and by the number of customers	-
Estonia	SAIFI, CAIDI, total annual interruption time for each customer	By the number of customers.	-
Finland	DSOs: 1-70 kV: T-SAIDI and T-SAIFI, < 1 kV: amount of interruptions; and 110 kV: amount and duration of interruptions (in total).	By the annual energy consumption.	In MV amount of short interruptions (high speed automatic reclosing and delayed automatic reclosing) which are proportional to the annual amount of energy
France	AIT, SAIFI and ENS for transmission network, as defined SAIFI, SAIDI and “Percentage of customers with insufficient quality of supply” for distribution network. There are several versions of each of these indicators, depending on the type of disconnection (planned/unplanned), the voltage level, and the cause (exceptional event included or not).	Depends on the indicator. For continuity indicators such as SAIDI, it is weighted by the number of delivery points affected (for HV and EHV) and by the number of customers (for LV).	MAIFI and percentage of customers with “insufficient quality of supply

³⁸ Source: 6TH CEER BENCHMARKING REPORT ON THE QUALITY OF ELECTRICITY AND GAS SUPPLY, 2016.

³⁹ Energy Quality of Supply Work Stream (EQS WS), CEER Benchmarking Report 6.1 on the Continuity of Electricity and Gas Supply, Data update 2015/2016.



This project is funded by the European Union



Country	Long Interruption-Index	Long Interruption-Weighting	Short Interruption-Index
Germany	SAIDI (LV), ASIDI (MV), SAIFI.	LV: Number of customers. MV: rated apparent power of the affected power.	-
Greece	SAIDI, SAIFI.	By the number of customers.	-
Hungary	Distribution level: the indicators used in IEEE Std. 1366-2003: SAIDI, SAIFI, CAIDI for both planned and unplanned interruptions.	By the number of customers.	Indicators used in IEEE Std. 1366-2003: MAIFI (for MV networks).
Ireland	Customer minutes lost, customer interruptions	For distribution, the customer interruptions and CMLs are reported on an average customer basis.	-
Italy	Distribution: SAIDI, SAIFI, number of customers affected by interruptions longer than 8 hours.	For distribution: by the number of users affected	MAIFI, separately for short and transient interruptions.
Latvia	SAIDI, SAIFI, CAIDI, ENS.	By the number of customers	MAIFI
Lithuania	SAIDI, SAIFI.	By the number of customers. ENS, AIT – interrupted power.	MAIFI
Luxemburg	SAIDI, SAIFI.	By the number of customers.	-
Netherlands	SAIDI, SAIFI and CAIDI.	By the number of customers.	-
Norway	With reference to end-users (all voltage levels): SAIDI, SAIFI, CAIDI, CTAIDI, CAIFI, interrupted power per incident and energy not supplied (ENS). With reference to reporting points (i.e. distribution transformer or a customer connected above 1 kV): number and durations.	By the number of customers. By the amount of ENS and by the amount of interrupted power.	With reference to end-users (all voltage levels): SAIDI, SAIFI, CAIDI, CTAIDI, CAIFI, interrupted power per incident and ENS. With reference to reporting points (i.e. distribution transformer or a customer connected above 1 kV): number and durations
Poland	SAIDI, SAIFI.	By the number of customers.	Distribution level according to the IEEE Std. 1366-2003: MAIFI.
Portugal	SAIFI HV, SAIDI HV, END MV, AIT MV (TIEPI), SAIFI MV, SAIFI LV, SAIDI MV, SAIDI LV	SAIFI and SAIDI: weighted by delivered points (transmission, HV and MV) and by the number of customers (LV); TIE (Distribution – TIEPI) and END (distribution): weighted by installed power; ENS (transmission): estimated; TIE (transmission): energy not supplied and energy supplied.	MAIFI (EHV, HV and MV).
Romania	SAIFI, SAIDI; ENS and AIT at 110 kV level.	By the number of customers. At 110 kV (max distribution level) and TSO (220-750 kV), ENS and AIT are used; at 110 kV SAIFI and SAIDI are also used.	-
Slovenia	SAIDI, SAIFI, CAIDI, CAIFI	By the number of customers.	MAIFI & MAIFI-E
Spain	In distribution TIEPI, NIEPI, 80% of TIEPI and 80% of NIEPI at zonal level or individual level.	By the power affected.	-

Country	Long Interruption-Index	Long Interruption-Weighting	Short Interruption-Index
Sweden	Since data on customer level is available regarding interruptions, NIS-tagged information, transferred energy, max effect and transferred energy of the overlying transformer, a large range of customer level and system level indicators can be calculated such as active power not supplied in kW, energy not supplied, ASIDI, ASIFI, SAIDI, SAIFI, customer experiencing multiple interruptions (CEMI), confidence interval reflecting best and worst served customers at arbitrary level, number of customer experiencing different yearly aggregated duration of interruption etc.	By the number of customers.	MAIFI-E.
Switzerland	SAIDI, SAIFI.	By the number of customers.	-
Turkey	SAIDI, SAIFI	By the number of affected customers.	N/A
UK	The 2 main indicators are Customer Interruptions and Customer Minutes Lost. Ofgem also collects information on the number of transmission incidents and the level of energy not supplied for each incident	By the number of customers.	-

As seen in the table, SAIDI and SAIFI are the most common used indicators for technical quality. Planned and unplanned SAIDI and SAIFI are shown in the figures between the years 2002 and 2016 and the values are provided as Annex to this document. The values of unplanned electricity SAIDI and SAIFI seem to be stable or improving over time. In 2016, unplanned SAIDI including exceptional events had a range between 9 and 371 minutes per customer while unplanned SAIDI without exceptional events was between 9 and 290 minutes per customer.

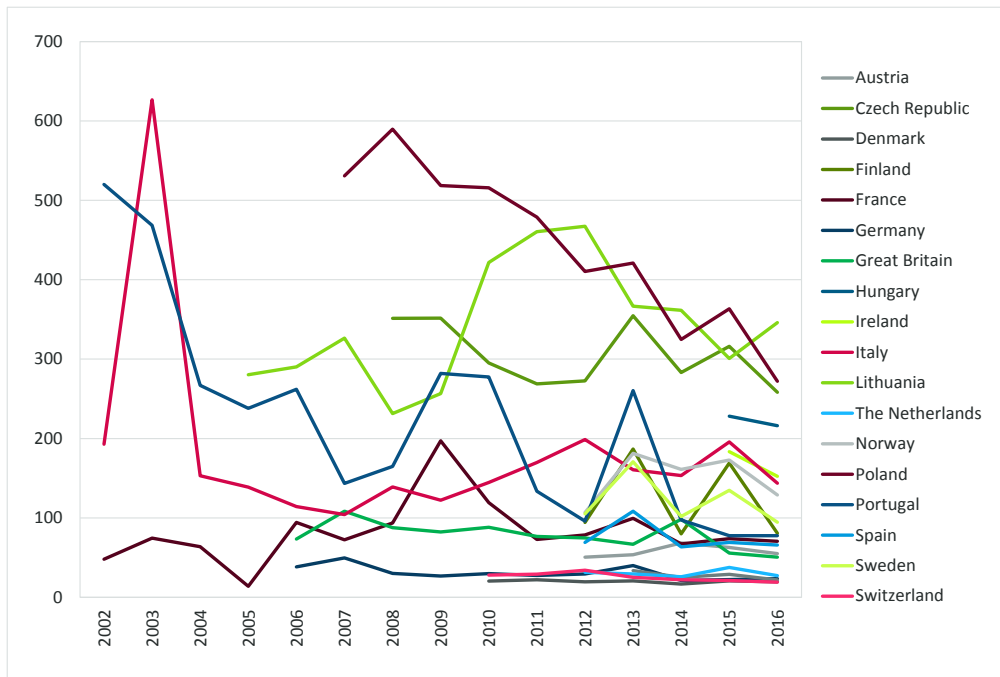


Figure 1.13 – Electricity: planned and unplanned SAIDI, including exceptional events (minutes per customer)⁴⁰

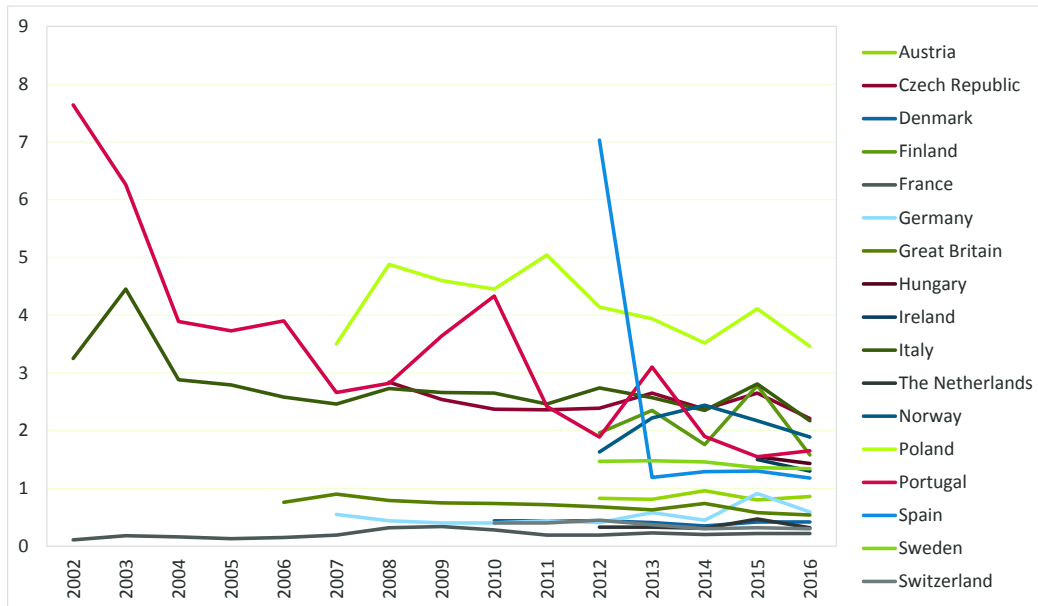


Figure 1.14 – Electricity: planned and unplanned SAIFI, including exceptional events⁴¹

Germany: In Germany, quality regulation started to be implemented in 2012 and it is valid just for DSOs on LV and MV with more than 30,000 customers. If DSO performs above-average quality than an amount is added to their cap, while DSOs performing with comparatively poor quality-levels have amounts deducted (bonus/penalty system). Overall performance of the DSO is measured by SAIDI on LV and DSO is benchmarked against an individual reference level SAIDI_i*.

$$\text{Reward/Penalty} = (\text{SAIDI}_i^* - \text{SAIDI}_i) \times \text{Customers}_i \times \text{Price of Quality}$$

For MV ASIDI is used. Structural differences such as peak load and geographical area are taken into account in when calculating the reference value.

The cap and floor for rewards and penalties is set to a fixed percentage of allowed revenues. Thus, the continuity scheme is explicitly linked with the general revenue-cap formula and the amount of rewards and penalties are funded by redistribution of the revenues. In Germany, each network operator is benchmarked against an individual reference level (SAIDI_i*). Structural differences in overall reliability are considered when calculating the reference value.

Continuity level and the continuity reference level are calculated as a mean of continuity indicators for the past 3 years to control for stochastic influences in network reliability. The price of quality is estimated by using a macroeconomic approach which is used to estimate the value of lost load (VoLL). Improving or worsening quality is an optimization decision taken by the network operator.

In Germany, the cost for performing voltage quality measurements upon receiving a complaint of the voltage quality is born by DSO.

Italy: Since the entry into force of the Bersani decree, ARERA has instituted a progressive regulation for the quality of the distribution, transmission and electrical measurement service with the aim of gradually orienting the company to a more general public interest, thereby preventing the effects of the original tariff methodology. of the price cap.

The tools adopted for this regulation were mainly the introduction of:

- service obligations;
- individual (or specific) standards to guarantee a minimum quality for each individual customer;
- automatic compensation for non-compliance with individual standards for reasons that are not beyond the control of the enterprise;
- general (or zonal) standards to guarantee a minimum quality to all customers;
- comparative publication of the yardstick competition quality levels;
- incentive / penalty mechanism systems related to quality and revenues (possibly quality / prices).

By summarizing the aspects relating to the performance of the service, it can be grouped into three macro categories as shown in the following diagram. Each of these categories is connected to the adoption of tools that encourage the improvement of the quality of the service.

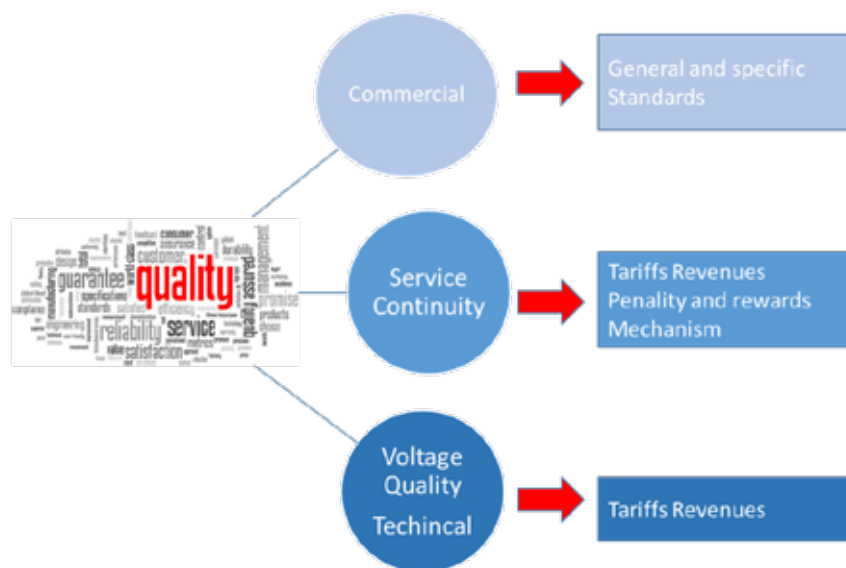


Figure 1.15 – Service performance in Italy

Generally, in Italy, the service continuity (service obligations) is described by the indicators SAIDI, SAIFI, number of customers affected by interruptions longer than 8 hours. They are the main quality indicators for long interruptions and MAIFI is used for short and transient interruptions.

The incentive mechanisms (reward/penalty) regulation for continuity of supply was introduced in **Italy** for electrical distribution in 2000 and is regularly updated every 4 years.

In the beginning, only SAIDI was considered since the 2008, then the regulation based on SAIDI was complemented by rewards and penalties for SAIFI+MAIFI as well.

A survey for estimating customer interruption costs was carried out in 2003 and the results have been embedded for valuating both rewards and penalties.

At distribution level, continuity targets are set at “district level” starting from the actual level reached in the previous regulatory period (for each district separately and targeting a nation-wide reference level to be reached in 3 regulatory periods (4-years each) for SAIDI and in 4 regulatory periods for SAIDI+MAIFI.

Planned interruptions and interruptions attributable to exceptional events are excluded from reward/penalty regulation.

DSOs have to make an advance notice to the customers involved of 3 working days since 1 January 2016 (previously it was 2 working days) in case of long interruption.

In addition, notice reduced to 24 hours in case of interventions after faults or during emergencies.

Nation-wide reference targets are differentiated only according to territorial density (i.e. nation-wide reference targets are the same for all districts having the same territorial density of which 3 levels are defined: urban, suburban, and rural areas).

Penalties are used to reduce distribution tariff, whilst rewards imply a limited increase in distribution tariff. There is a cap for rewards and floor for penalties in order to reduce risk.

A similar reward/penalty mechanism is applied to the TSO at system level for interruption generated in the transmission grid. Transmission quality has also been regulated with rewards and penalties since 2008.

Furthermore, a “mitigation” mechanism economically incentivizes DSOs to provide help to the TSO (when interruptions occur in the Transmission grid) through MV reconfiguration in order to back-feed interrupted customers via a non-standard network scheme until the supply is restored in the transmission system.

Norway: Technical Quality: Since 1995, network companies have been obliged to report interruptions above 1 kV to NVE. From 2014, interruptions on all voltage levels have been reported. The regulatory authority, NVE considers the continuity of the electrical supply to be good. However, the continuity of supply is highly influenced by conditions in the surroundings, such as wind, snow, ice, thunderstorms, vegetation, birds/animals, etc. NVE does not exclude any exceptional events from the interruption data. Planned interruptions are called notified interruptions. An interruption is considered notified if customers are informed a reasonable amount of time prior to the interruption and the information has been provided in an appropriate manner. Unplanned interruptions are called non-notified interruptions. An interruption is considered non-notified if it does not fulfil the requirements for a notified interruption. The interruption must be notified minimum 24 hours prior to the interruption, but as a main rule 2 business days prior to the interruption.

In 2018, the delivery reliability was 99.983%. That is, 0.017% of the electrical energy did not reach the end user due to faults or disconnections. This is average for the years reporting has taken place. On average, each power customer experienced 2.3 power outages with duration over 3 minutes. The average power customer was without supply 2 hours and 46 minutes. 38% of power customers experienced no interruptions.

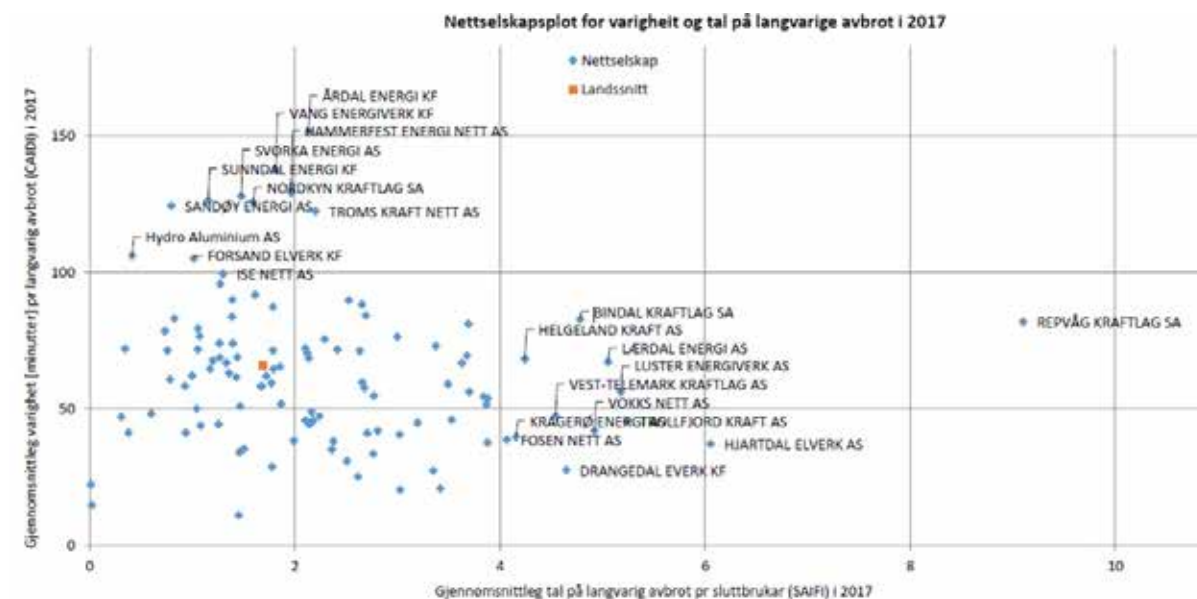


Figure 1.16 – CAIDI and SAIFI for DSOs in Norway⁴²

The Norwegian quality of supply regulation includes minimum requirements for **voltage quality**, including voltage frequency, supply voltage variations, rapid voltage changes, short and long-term flickering, voltage unbalance and harmonic voltages including total harmonic distortion. If considered necessary, NVE may set minimum requirements for other voltage disturbances, such as voltage dips, voltage swells, transient overvoltage, inter-harmonic voltage and main signalling voltage. Network companies have been required to continuously register dips, swells and rapid voltage changes in their own characteristic high and medium voltage network since 2006. In addition, from 2014, they have been obliged to register THD and flickering. From 2014, network companies have also been obliged to report the abovementioned voltage quality parameters (except rapid voltage changes) to NVE.

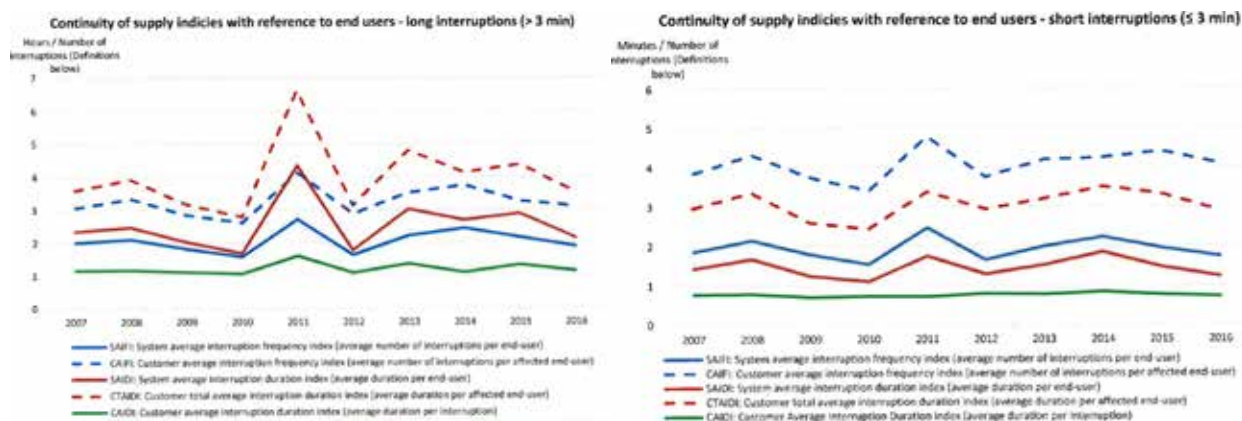


Figure 1.17 – Continuity of Supply Indices (Long and Short Interruptions)⁴³

The Norwegian financial incentive-based regulation on CENS gives the network companies (TSO and DSO level) economic motivation to ensure an optimal resource allocation when all minimum requirements are complied with. The objective is to achieve the most optimal level of continuity of supply for the society as a whole. The customers' costs related to interruptions are detected through nationwide surveys and will vary between different customer groups, when the interruptions occur etc. The costs related to investments to reduce the extent of interruptions will on the other hand depend significantly on the location of the customers' connection to the power system, including network topology, geography, climate etc. From the NRA's point of view, it is important that decisions influencing the continuity of supply are also based on cost-benefit analyses. Thus, the costs related to decreasing the extent of interruptions must be lower than the future decrease in customers' interruption costs due to the investment. Incentives

42 Source: <https://beta.nve.no/reguleringsmyndigheten/nettjenester/leveringskvalitet/leveringspalitelighet/avbruddsstatistikk/>

43 Source: NVE, 2018, National Report 2017. http://publikasjoner.nve.no/rapport/2018/rapport2018_74.pdf

to optimize the continuity of supply levels, should take into account all cost elements. Consequently, for some customers this may imply reduced, increased or maintained CoS levels. No minimum requirements and no caps or floor are addressed in the schemes. For both TSOs and DSOs, the indicators used include interrupted power at a specific reference time, duration, time of occurrence (during the day, during the week, calendar month), whether the interruption was notified in advance or not.

Commercial Quality: If there are customer complaints regarding power quality, network companies have to make the necessary investigations to verify compliance with the related regulations. If the complaint concerns voltage quality, on-site measurements must be made according to relevant IEC-standards. If the measurements prove non-compliance to limits set according to regulations, the network companies must identify the reason for this and who is responsible for the violation. Network companies cannot charge the customer for these investigations, if the complaint is legitimate. Network companies are obliged to give information on given data for the quality of supply in their network within one month, upon request by current or potential customers. This data includes, amongst other things, results from registration of interruption data, analyses of operational disturbances and specific conditions in the network that could have an influence on the quality of supply for the customer.

Commercial quality indicators measured in Norway are listed as follows⁴⁴:

- Time for response to customer claim for network connection
- Time for cost estimation for simple works
- Time for connecting new customers to the network
- Time for disconnection upon customer's request
- Time for a switching of supplier
- Response time to customer complaints
- Response time to customer enquiries
- Response time to customer voltage and/or current complaints
- Response time to customer interruption complaints
- Call Centers service level
- Waiting time in case of personal visit at client centers

Time for giving information in advance of a planned interruption

Portugal: Technical Quality: In Portugal the incentive for the DSO intends to improve the continuity of supply of the MV customers. This incentive consists of 2 components with different objectives, where the first objective is to improve the overall continuity of supply and the second is to improve the continuity of supply of the worst-served 5% of customers. Dead bands are used to avoid the activation of the incentives when small performance improvement or deterioration is experienced.

The parameters of the incentive scheme are defined for each regulatory period (every 3 years), while the values of the incentives (rewards or penalties) are calculated on an annual basis.

Table 1.11 – Continuity of Supply Indicators in Mainland Portugal, 2018⁴⁵

Voltage Level	Indicator	Interruptions		
		Planned	Unplanned	
			Operator Responsibility	Exceptional Events
HV Distribution	SAIDI	0	44.40	1542.40
	SAIFI	0	0.19	0.08
	MAIFI	0	1.37	0.18
MV Distribution	SAIDI	0.05	84.95	146.05
	SAIFI	0	1.77	0.46
	MAIFI	0	11.57	0.79
	TIEPI	0.08	57.51	80.32
LV Distribution	SAIDI	0.23	80.98	119.65
	SAIFI	0	1.55	0.35

The performance assessment of the distribution network in terms of continuity of supply consists of long interruptions (longer than 3 minutes) and short interruptions (between 1 second and 3 minutes).

In Portugal, the cost for performing **voltage quality** measurements upon receiving a complaint of the voltage quality is born by DSO only if the quality does not conform to national legislation or EN 50160. The customer pays if the quality voltage level meets the standard, or when it is not justified.

Portugal defined 2 incentive schemes (for the TSO and DSO responsible for HV and MV) based on rewards and penalties. Dead bands are used to avoid the activation of the incentives when small performance improvement or deterioration is experienced. The incentive for the TSO has the objective of increasing the availability of network equipment, where the relevant indicator corresponds to the combined average availability rate (TCD), expressed in (%), which results from the weight of the average availability rate of line circuits and power transformers. The incentive for the DSO intends to improve the continuity of supply of the MV customers. This incentive consists of 2 components with different objectives: (1) to improve the overall continuity of supply; and (2) to improve the continuity of supply of the worst-served 5% of customers. The parameters of the 2 incentive schemes (TSO and DSO) are defined for each regulatory period (every 3 years), while the values of the incentives (rewards or penalties) are calculated on an annual basis.

Commercial quality indicators measured in Portugal are listed as follow⁴⁶:

- Time for response to customer claim for network connection
- Time for connecting new customers to the network
- Punctuality of appointments with customers
- Response time to customer complaints
- Response time to customer enquiries
- Percentage of customers with a waiting time below the limit in call centers
- Percentage of customers attended within the waiting time limit in customer centers
- Percentage of customers' requests answered within the time limit

⁴⁵ Source: ERSE, July 2018, Annual Report on the Electricity and Gas Markets 2017.

⁴⁶ Source: CEER, 2016, 6TH CEER Benchmarking Report on the Quality of Electricity and Gas Supply – 2016.

- Average response time to customer complaints and/or requests
- Time until the start of restoration of supply following failure of fuse of DSO
- Time for restoration of power supply following disconnection due to non-payment
- Percentage of meter readings made within less than a certain amount of time after the last one

UK: The DSOs are incentivised to outperform their TOTEX allowances in UK. DSOs that submit better forecasts of the costs they expect to incur during the price control receive a higher TOTEX efficiency incentive rate, meaning they get to keep more of any underspend.

Several incentives within the RIIO-ED1 framework, both financial and reputational (such as public reporting on delivery), encourage strong performance against the output categories. Recently DSOs performed strongly against four of the six categories: reliability and availability, customer satisfaction, social obligations, and safety, however there is still need for improvement in the connections and environmental outputs.

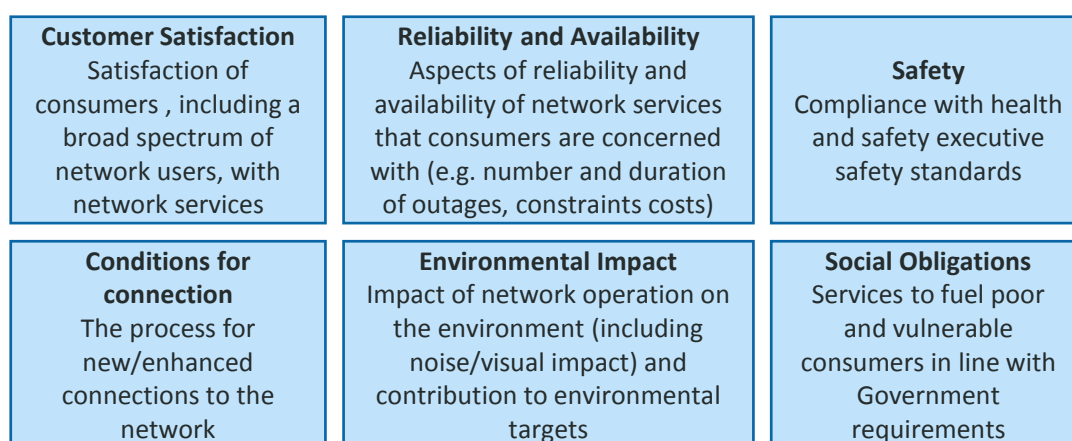


Figure 1.18 – Outputs for DSOs

Across all incentives, DSOs have earned £200m in incentive payments in 2017-18.

Reliability and availability output performance has been predominantly driven by the Interruptions Incentive Scheme. The scheme incentivizes DSOs to reduce the number and duration of interruptions experienced by their customers. Under the Interruptions Incentive Scheme, an interruption is defined as a loss of supply lasting three minutes or longer. In 2017-18 each customer was off supply for around 36 minutes over the course of the year. Based on performance in 2017-18 against the targets, DSOs will earn £138.0m under the Interruptions Incentive Scheme.

Connections: DSOs are incentivized to connect customers in an efficient and timely manner through the Time to Connect and Time to Quote incentive. This incentive resulted in a total payment of £12.8m across all 14 DSOs in 2017-18.

Social Obligations and Customer Service: There are three individual mechanisms including a customer satisfaction survey, the complaints metric, and the stakeholder engagement and consumer vulnerability incentive within the scope of social obligations and customer service. All DSOs met or outperformed their targets in 2017-18.

Environment: Reputational incentives were put in place to encourage DSOs to manage their overall impact on the environment, including reducing their Business Carbon Footprints, SF6 emissions and oil leakage from fluid-filled cables.

Safety: All DSOs continue to be compliant with the standards set by the Health and Safety Executive and are striving to reduce their

accident rates.

Customer Service: It has continued to improve in 2017-18 with all DSOs exceeding the target scores for customer satisfaction and customer complaints, resulting in an industry reward of £49.2m.

Table 1.12 – DSO Incentive & Rewards in 2017-18 (£m)⁴⁷

DSO	Interruptions Incentive Scheme	Time to Connect Incentive	Broad Measure of Customer Service	Total Incentive Payments
ENWL	10.9	1.3	1.7	13.9
NPgN	9.8	0.0	2.6	12.4
NPgY	15.1	0.1	2.9	18.1
WMID	19.9	1.8	6.1	27.7
EMID	15.9	1.8	6.2	23.9
SWALES	2.8	0.8	3.1	6.7
SWEST	-0.4	1.3	4.3	5.3
LPN	14.8	0.9	3.7	19.4
SPN	9.8	1.0	3.5	14.2
EPN	17.6	0.5	5.0	23.1
SPD	9.9	0.7	3.2	13.8
SPMW	5.1	0.7	3.3	9.1
SSEH	2.1	0.9	2.1	5.1
SSES	4.8	0.9	1.7	7.4
Total	138.0	12.8	49.2	200.0

Each DSO has separate targets for customer interruptions and customer minutes lost (CML). The targets were calculated by benchmarking across the DSOs and looking at their historical performance. Targets for the implementation period (2015-16) were set using data up to 2012-13 and then applying improvement factors based on industry-wide historical improvements.

In the UK, general (street) lighting responsibility is in municipalities and the faults are aimed to be repaired within 2 weeks, if there is no emergency. If the general lighting fault is because of the grid (such as underground cables, low voltage, etc.), distribution company is responsible for the repair.⁴⁸ Specific Unmetered Guaranteed Standards of Performance for street lighting is:⁴⁹

- Emergency fault repairs -> within 2 hours
 - Danger to the public or property arising from the Electricity Distribution network
- High Priority Fault Repair - Traffic Light Controlled -> 2 days
 - Major road junction or an area of public order concerns, and traffic lights are affected.
- High Priority Fault Repair – non-Traffic Light Controlled -> 2 working days
 - Major road junction or an area of public order concerns, and traffic lights are not affected
- Multiple unit fault repair -> 20 working days
 - Fault on service to more than one unit
- Single unit fault repair -> 25 working days
 - Fault on service to one unit

The **Czechia** relies on a combination of rewards and penalties for continuity regulation for distribution companies on the basis of SAIDI and SAIFI (only events which can be influenced by the DSOs, i.e. those under standard weather conditions and planned

⁴⁷ Source: Ofgem, RIIO ED1, Annual Report, 2015-16.

⁴⁸ Source: <https://www.suffolk.gov.uk/roads-and-transport/street-lighting-traffic-signals-and-pedestrian-crossings/street-lighting/report-a-faulty-street-light/#tab2>

⁴⁹ <https://www.ukpowernetworks.co.uk/internet/en/street-map/>

interruptions). An analysis of the dependency between costs and quality was made and the company specific target value of SAIFI, SAIDI for given price control period is set on the basis of this analysis. Furthermore, the scheme involves a dead band which is set as a percentage from the required value of the indicator and a 2-year moving average, whereby the goal is to eliminate year to year fluctuations. In this sense, the incentive formula uses a linear dependence between quality and reward/penalty with the dead band and the maximum reward/penalty limit, whereby the target which was set in advance is compared with average value of actual performance indicators in the past 2 years. Target values are updated at the beginning of the regulatory period, but the comparison happens on an annual basis. The financial result is set to +/- 2% of DSO's profit for each indicator and the maximal value of the reward or penalty is set as a percentage of the requested value of the indicator. The incentive scheme is funded by customers of DSOs which are entitled to incentives.

Denmark uses a regime which exclusively focuses on penalties for DSOs. An individual threshold (IT) value for each network company is calculated on an annual basis. If the interruption frequency or duration is higher than the IT, the company gets a penalty. The penalty is calculated as the minimum of the 2 values – 10% of the excess of the IT or 1% of the susceptible costs. The company can get a penalty for both frequency and duration. The maximum penalty is 2% of the susceptible costs, whereby there are caps of 1% for both frequency and duration to prevent too high penalties.

France uses a combination of rewards and penalties for distribution continuity regulation. SAIDI is used at distribution level. No cost estimation surveys or estimations of optimal levels were carried out for the development of the continuity scheme. The expected level of continuity is estimated in line with the investment program of the distribution companies and past values of indicators considered in the incentive scheme. No difference is made between rural and urban areas. Incentive scheme require a minimum improvement of continuity for distribution companies. For distribution companies, the expected level of continuity (i.e. the level that corresponds to no penalty and no reward) is set at 68 minutes for 2014, 67 minutes for 2015, 66 minutes for 2016 and 65 minutes for 2017. No tolerance/dead band is implemented. The incentive rate for TSO and DSOs is calculated according to formulas 1 and 2 respectively.

$$(1) \quad I_N = -10,4 \times AIT_{ref} \times \ln \left(\frac{AIT_N}{AIT_{ref}} \right) + 72 \times (SAIFI + MAIFI)_{ref} \times \ln \left(\frac{(SAIFI + MAIFI)_N}{(SAIFI + MAIFI)_{ref}} \right)$$

$$(2) \quad I_N = -4,3 \times (SAIDI_{N_{ref}} - 34) \times \ln \left(\frac{SAIDI_N - 34}{SAIDI_{N_{ref}} - 34} \right)$$

Where:

- I_N is the incentive of the year N (reward if positive; penalty if negative);
- $SAIDI_N$ is the system average interruption duration index for the year N (including interruptions for works);
- And $SAIDI_{N_{ref}}$ is the reference system average interruption duration index for the year N set at 68 minutes for 2014, 67 minutes for 2015, 66 minutes for 2016 and 65 minutes for 2017.

Moreover, the incentive of €4.3M/min for DSOs corresponds to a value of loss load of about €6/kWh. For DSOs, the cap for both penalties and rewards is set at €54.2M.

Incentive (reward/penalty) regulation for continuity of supply was introduced in **Italy** on distribution level in 2000 and is regularly updated every 4 years. In the beginning, only SAIDI was considered but since 2008, regulation based on SAIDI was complemented by rewards and penalties for SAIFI+MAIFI as well. Transmission quality has also been regulated with rewards and penalties since 2008. A survey for estimating customer interruption costs was carried out in 2003 and the results have been embedded for valuating both rewards and penalties. At distribution level, continuity targets are set at “district level” starting from the actual level reached in the previous regulatory period (for each district separately and targeting a nation-wide reference level to be reached in 3 regulatory periods (4-years each) for SAIDI and in 4 regulatory periods for SAIDI+MAIFI. Nation-wide reference targets are differentiated only according to territorial density (i.e. nation-wide reference targets are the same for all districts having the same territorial density of which 3 levels are defined: urban, suburban, and rural areas). Planned interruptions and interruptions attributable to exceptional

events are excluded from reward/penalty regulation. This also applies to interruptions generated in transmission grid which are excluded from interruptions considered for DSO reward/penalty mechanism. Penalties are used to reduce distribution tariff, whilst rewards imply a limited increase in distribution tariff. There is a cap for rewards and floor for penalties in order to reduce risk. A similar reward/penalty mechanism is applied to the TSO at system level for interruption generated in the transmission grid. Furthermore, a “mitigation” mechanism economically incentivizes DSOs to provide help to the TSO (when interruptions occur in the Transmission grid) through MV reconfiguration in order to back-feed interrupted customers via a non-standard network scheme until the supply is restored in the transmission system.

Spain applies a scheme that uses incentives for DSOs. The continuity indicators which are used for DSOs include TIEPI and NIEPI which are similar to ASIDI and ASIFI. For DSOs, the incentive is calculated separately for different areas. The scheme is based on target values, which are considering the average between specific DSO data indexes in each area in the previous 3 years, and national average data indexes in that area. The incentive scheme does neither involve a dead band nor a minimum improvement of the continuity level. Although the time scale is yearly, it considers previous quality values for establishing future targets. The incentives (rewards, penalties, others) are not proportional to the difference between the actual performance level and the standard (or target). The quality incentives vary between -3% and 3% of the distribution company’s total remuneration.

Sweden uses a combination of rewards and penalties for the DSO. SAIDI, SAIFI, CEMI are used as indicators. The NRA conducted a cost estimation survey to set an incentive rate for the continuity of supply (CoS) indicators. By setting an incentive rate based on data from customer surveys (“bottom up”), the quality regulation aims to give incentives for a socioeconomic level of CoS. An explicit Q-element is calculated using the mentioned CoS-indicators, whereby the target for DSOs is set using a benchmarking method where DSOs with similar customer density are exposed to a similar target. The target is not an “optimal” level but the mean value of the relevant CoS indicators, i.e. it is calculated based on the mean value of all DSO CoS-indicators (per customer group) as a function of customer density. That target is predefined during the regulatory period and has to be reached within 4 years. Afterwards it is updated for the next period. The scheme does not involve the use of a dead band. Incentives are calculated as follows:

$$(1) \quad Q_{ISO} = (ENS_{Target} - ENS_{result}) \times \cos t \quad (2) \quad Q_{DSO} = (SAIDI_{Target} - SAIDI_{result}) / 60 \times P_{mean} \times \cos t$$

For both TSOs and DSOs, the scheme is linked to the overall revenue-cap model while quality incentives are capped with 5% of total (capped) revenues. The scheme is funded only by costumers of areas/companies which are entitled to incentive.

Turkey uses the below quality indicators for the third implementation period⁵⁰:

- Installation and the integration of the Supply Continuity Recording System,
 - 20 points if the installation is completed, 0 otherwise.
- Improvement on the supply continuity,
 - 10 points max for SAIDI improvements based on the improvements compared to the average of the previous three years,
 - 10 points max for SAIFI improvements based on the improvements compared to the average of the previous three years,
- Increase in customer satisfaction,
 - 20 points max, based on the number of customer applications to EMRA for each DSO.
- Technical quality compliance,
 - 10 points for the installation of technical quality measurement devices at the points where EMRA required and submitting the measurement results to EMRA timely and complete, 0 points otherwise.
- Investment realization,
 - 30 points if the investment realization ration is above 90%, 0 points otherwise.

For each tariff year (2018, 2019 and 2020), 3.5% of the collected points is added to the revenue cap. In other words, DSOs can increase their revenue cap by 3.5% with these performance indicators and there is no penalty for not achieving the targets.

Besides, another performance indicator is defined by EMRA⁵¹ indicating that if there is no fatal work accident in the DSOs (together

50 Procedures and Principles of Quality Factor Application, EMRA Board Decision dated 21/12/2017 and No.7531.

51 EMRA Board Decision dated 30/12/2015

with their subcontractors), their revenue cap will be increased by 0.5% starting from 2018.

In addition to above performance indicators, Call Center performance indicators are defined by EMRA⁵² as the accessibility level (for number of calls $\geq 95\%$ or number of time intervals $\geq 99\%$), service level ($\geq 80\%$), response rate ($\geq 95\%$). With the EMRA Board Decision dated 05/04/2017 and No.7012-1, call center performance indicators are accepted as general quality indicator starting from 01/01/2017. The weights of the performance indicators are determined as 20% for accessibility level, 40% for service level and 40% for response rate. Points for each item is defined between 0 and 1. Therefore, with the call center performance, DSOs can increase their revenue cap by 1%.

Besides, there is compensation for the worst served customers. Compensation amount is:

Comp. for Interruption Time = $24 \text{ TL} + (\text{TKSURE} - \text{ESURE}) \times 2 \times \text{Distribution Fee} \times \text{Hourly Average Usage}$

Comp. for Interruption Count = $(\text{TKSAYI} - \text{ESAYI}) \times (\text{TKSURE} / \text{TKSAYI}) \times 2 \times \text{Distribution Fee} \times \text{Hourly Average Usage}$

where,

TKSAYI : total number of interruptions of a customer

TKSURE : total duration of interruptions of a customer

ESAYI : Limit for the total interruption count for compensation

ESURE : Limit for the total interruption duration for compensation

Table 1.13 – Compensation Limit Values for Power Outages in Turkey

Limit Value	Interruption Type	Urban Customers		Rural Customers	
		LV	MV	LV	MV
ESURE (hour)	Without Notification	48	24	72	36
ESAYI (count)		56	56	72	72
ESURE (hour)	With Notification (prior to 48 hours)	24	16	32	24
ESAYI (count)		6	4	8	6

Total compensation payable to the customers are limited to the 1% of the revenue cap of the relevant year.⁵³

In addition to this compensation, for each interruption longer than 12 hours, long-duration interruption compensation is paid to the customers. The amount is 50 TL for households and 100 TL for other customers.⁵⁴ Monthly total compensation is limited to the 1% of the revenue cap of that year.

In some countries such as Norway, Portugal and Turkey, quality of supply regulation includes minimum requirements for voltage quality too. In a few countries, DSO has an obligation to inform end-users about past or expected future voltage quality levels. Upon receipt of a customer complaint regarding the voltage quality at the customer's connection point, DSO (in several countries including Turkey) is obliged to perform measurements to verify the levels of all relevant voltage quality parameters. In case smart meters are rolled-out, voltage quality is monitored easily. In Turkey, nominal voltage levels and voltage fluctuation limits are also

52 Procedures and Principles of Call Center Quality Standards for DSOs and IRCs, EMRA Board Decision dated 29.09.2016 and No.6507-6

53 Regulation on the Service Quality of Electricity Distribution and Retail Sales, Article 16/9

54 The average exchange rate between Euros and TL in 2019 is 6.3477 TL per EUR.

defined for different levels and DSOs are required to install power analysers when required by the customer and correct the issue.

Commercial Performance: In Turkey, commercial performance indicators are defined in Table 6 of the Regulation on the Service Quality of Electricity Distribution and Retail Sales. Standard due dates to response customer requirements and the penalty amounts are defined in the table. This is a negative side table and there is no bonus. This is because the bonus comes from the customer satisfaction points which is mentioned above in the Procedures and Principles of Quality Factor Application.

Commercial quality indicators such as time for response to customer claim for network connection, time for connecting new customers to the network, response time to customer complaints and enquiries, % of customers with a waiting time below the limit in call centers are used nearly in all of the countries. In Turkey, commercial quality indicators are limited compared to other countries. DSOs have to reply customer within certain time after customer's applications. They have to give notice in mass media and own web page for planned maintenance and power interruptions and they shall also monthly announce their commercial quality performances in their web site. Otherwise penalty is applied.

1.4 Efficiency

Germany: Efficiency benchmarking is carried out on the basis of the cost examination (TOTEX) and structural data validation before the start of each new regulatory period. Efficiency benchmarking is a comparative method and the results for the individual DSOs have a mutual influence on each other. A DSO that provides the same scope of services but has higher costs than another DSO (100% efficiency) will have an efficiency score lower than 100%. The efficiency scores are then applied to the controllable costs (total costs - permanently non-controllable costs - CAPEX subtraction).

DSO's individual costs are assessed against the services they provide, and cost efficiency is compared with the other DSOs. Both cost parameters and output parameters such as the number of connection points, peak load, the amount of energy delivered or injected, and transformer and compressor station data are taken into account as well as regional characteristics.

Data envelopment analysis (DEA) and stochastic frontier analysis (SFA) methods are used to determine efficiency scores. Input parameter is generally controllable TOTEX and output parameters are area supplied, customers connected and environmental parameters.

The reason of using both DEA and SFA is to determine more than one efficiency score for each network operator. The network operators' costs are also adjusted to consider different lifetime structures of networks. The DEA and SFA methods are then applied to determine further efficiency scores using these standardized costs. Each network operator is then given the highest of the four efficiency scores calculated.

If the efficiency score calculated for a network operator using the two methods is lower than 60%, the score is raised to 60% as the set minimum efficiency level. A maximum efficiency level of 100% is also set. The results are also examined to identify any network operators that appear as "outliers" and whose efficiency scores clearly dominate the efficiency scores of other network operators. These network operators are no longer taken into account in the benchmarking and are given a fixed score of 100%, without having any further influence on the efficiency scores of the other network operators. The most efficient DSOs are eligible for a bonus added to the revenue cap on the basis of a super-efficiency analysis; this bonus is limited to a maximum value of 5%. This gives operators an incentive beyond the end of a regulatory period to improve efficiency in the long term even if they have already achieved an efficiency score of 100%.

Italy: In Italy, productivity targets (X-factors) are differentiated by activity (transmission, distribution and metering) and are basically used as a tool to redistribute to network users the efficiency gains of the previous regulatory periods, which were temporarily retained by network operators under the profit-sharing mechanism. On the basis of this mechanism, at the end of the regulatory period, in order to set tariffs for the following period, efficiency gains are symmetrically shared between network operators and network users.

The initial level of recognized OPEX is being updated each year based on inflation and a rate of reduction (the so-called X-factor) equal to 1.9% for distribution and 1% for metering. The X-factor in the regulatory period 2012-2015 was 2.8% for distribution and

7.1% for metering.⁵⁵

Norway: NVE implements two different efficiency assessment models for determining the revenue caps for DSOs in the local and regional distribution grids. The procedures are the same in both models, however the inputs differ.

- DEA: Compares efficiency solving specific tasks
- Z-factor correction: Adjusts DEA scores from first stage for differences in environmental factors. Efficiency may increase or decrease dependent on target units Z-factors (see Annex 5.7.4)
- Calibration: Addition to cost norm such that total industry cost base equals cost norm. This ensures that averagely efficient companies receive a return equal to the NVE-interest.

Table 1.14 – Differences between local and regional distribution

	Local Distribution		Regional Distribution	
	Input	Outputs	Input	Outputs
Stage 1 (DEA)	1) TOTEX=OPEX+ Depreciations+Return on BV+cost of network losses+ CENS	1)# of customers 2)Length of HV network (km) 3)# of substations	1) TOTEX=OPEX+ Depreciations+ Return on BV + CENS	1) OH lines, weighted value 2) Ground cables, weighted value 3) Sea cables, weighted value 4) Substations, weighted value
Stage 2 (Z factor correction)	Z factors		Z factors	
	Mountain environments		Forest environments	
	Coastal environments			
	Cold environments			
	City (share of grid laid as underground cables)			
	Forest environments (share of OH lines in coniferous forest)			

TOTEX is used as input in a single input cost-minimizing DEA assuming constant returns to scale. Also, the weighted values used as outputs in the regional distribution grid captures a lot of the differences between companies. This is one of the important reasons why there are more variables in the second stage analysis of the local distribution compared to the regional distribution.

Portugal: The definition of efficiency targets, with the objective of reducing controllable costs, is based on international and national benchmarking studies through the application of parametric and non-parametric methods. The methodologies used are Corrected Ordinary Least Squares (COLS) and Stochastic Frontier Analysis (SFA) in the parametric models and the Data Envelopment Analysis (DEA) methodology in the non-parametric models.

In 2017, targets applied to regulated activities have allowed for a consistent reduction in costs in Electricity Distribution segment. Being the third and final year of application of the efficiency targets defined for the 2015-2017 regulatory period, in which the cost bases were revised downwards in 2015, operating costs recovered through network tariffs have decreased.

For mainland Portugal, for the regulatory period between 2015-2017, cost drivers in HV/MV are distributed energy and network length (km); in LV, cost drivers are distributed energy and number of customers. The efficiency factor was 2.5% plus inflation⁵⁶. This efficiency factor is the same for 2018.

The cost drivers in the distribution activity in both autonomous regions are distributed power and the number of customers. In the trading activity, the cost driver is the number of customers. In the autonomous region of the Azores, the efficiency targets applied

⁵⁵ Source: <https://www.enel.com/media/press/d/2016/01/preliminary-assessment-of-effect-on-enel-group-of-new-2016-2023-regulatory-period-for-distribution-in-italy>

⁵⁶ Source: Annual Report on the Electricity and Natural Gas Markets in 2017, ERSE.

to each of the activities vary between 2% for distribution and 3.5% for trading. In the autonomous region of Madeira, the efficiency targets are 4% and 3.5% for distribution and trading, respectively. In general, the annual efficiency factors applied to OPEX varied between 2% and 7% per company, in distribution; and 2% for all suppliers of last resort.

UK⁵⁷: Total expenditure benchmarking is used for efficiency and positive cost savings, measured as the difference between realized and planned costs is an indicator of efficiency in general. There are three main ways to make sure that DSOs are cost efficient.

- The opportunity to be fast-tracked: If DSO submits a realistic and well-justified business plan that clearly provides sufficiently high quality and good value overall, Ofgem considers it for fast-tracking. This means they accept the business plan as submitted and conclude the company's price control review early.
- Ofgem's assessment of efficient costs in the slow-track DSOs' business plan. For more information, please see Annex 5.2.8.
- Information quality incentive (IQI): used to encourage slow-track DSOs to create business plans that reflect best available information about future efficient expenditure requirements. The elements of IQI are:
 - o DSOs receive a financial reward or penalty depending on their forecast relative to Ofgem's assessment of efficient expenditure.
 - o DSOs that submit better forecasts (e.g. closer to Ofgem's view of efficient cost) receive a higher efficiency incentive rate (sharing factor). This reduces the risk of companies gaming the price control settlement by inflating their forecasts and then significantly underspending.
 - o Allowed expenditure is based 75% on Ofgem benchmark view and 25% on the DNOs forecasts (called interpolation).

Any company that is fast-tracked receive an upfront financial reward of 2.5% in lieu of the IQI reward, and a 70% efficiency incentive rate.

Efficiency Incentive Rate (TIM-TOTEX Incentive Mechanism): The efficiency incentive rate is used to calculate the revenue adjustment the DSO receives as a result of over-spend or under-spend versus its allowed expenditure. It is symmetric and fixed for the duration of the price control period. The higher the efficiency incentive rate, the more of any over-spend is borne by the company and the more of any under-spend is retained by them. For instance, if a DSO's efficiency incentive rate is 60%, its investors will earn £60 profit (before tax) for each £100 that the company saves during the price control period and bear £60 of each additional £100 the company spends. The remainder will be passed on to consumers through lower or higher network charges.

In the first three years of RIIO-ED1, the DSOs have spent £10.2bn managing their networks, where the amount was 6% less than the allowances. Any underspend against allowed expenditure is shared between the DSO and its customers (reflected in customer bills), through TIM.

On the other hand, financial performance of the DSOs is measured with Return on Regulatory Equity (RoRE). The forecast eight-year RoRE for each of the DSO groups ranges from 6.51% to 11.63% and the forecast eight-year average RoRE across the industry is 9.15%.

TOTEX underspend is driven by two main CAPEX cost categories that are replacement and refurbishment of assets, and network reinforcement. On the other hand, there are two main areas with relatively high levels of overspend: network faults, and operational support costs.

In **Austria**, an overall budget based on TOTEX is audited based on last available cost data since the beginning of a regulatory period. This budget is adjusted via a network price index (consisting of a consumer price index and a wage index), a general productivity offset (1.25%) and an individual efficiency factor annually. Individual efficiency factors are calculated using modified ordinary least squares (MOLS) and two different data envelopment analysis (DEA) models based on a predefined base year before regulation period starts. Using TOTEX as the input and overhead line lengths, underground cable lengths, area (LV), peak load, meters and installed capacity as the outputs, efficiency scores are calculated as follows:

$$0.45 * \text{MOLS} + 0.15 * \text{DEA I} + 0.4 * \text{DEA II}$$

Table 1.15 – Austria Efficiency Analysis

	MOLS		DEA I		DEA II	
Input	TOTEX	Standardize TOTEX	TOTEX	Standardize TOTEX	TOTEX	Standardize TOTEX
Outputs	Peak Load (MV) Peak Load (LV) Weighted Line Length (HV, MV, LV)	Peak Load (MV) Peak Load (LV) Weighted Line Length (HV, MV, LV)	Peak Load (MV) Peak Load (LV) Weighted Line Length (HV, MV, LV)	Peak Load (MV) Peak Load (LV) Weighted Line Length (HV, MV, LV)	Peak Load (MV) Peak Load (LV) Line Length (HV) Line Length (MV) Line Length (LV)	Peak Load (MV) Peak Load (LV) Line Length (HV) Line Length (MV) Line Length (LV)
Average Efficiency Score	89.44%	88.85%	85.80%	90.28%	89.26%	82.48%
Minimum Efficiency Score	69.03%	74.23%	62.83%	70.14%	63.07%	54.05%
Number of Efficient DSOs	6	9	6	9	13	10

In **Finland**, efficiency frontier, based on the Stochastic Non-Smooth Envelopment of Data (StoNED) is used to benchmark the DSOs. In the model, output variables are: distributed energy, number of customers, total length of the electricity network, regulatory outage costs (i.e. VOLL) and operating environment variable (ratio of connections/customers). Input variables are the OPEX and the replacement value of the network.

In **Holland**, efficiency factor is based on annual change in revenues of DSO's. The calculation methodology is as follows: first base year revenues are calculated using the realized costs and static efficiency measures. Then, using parameters that forecast future cost trends, the income level in 2021 is predicted. Annual revenues are calculated based on CPI, quality factor and efficiency and are increased gradually from the base year value to 2021 level. Therefore, the efficiency factor becomes equal to price difference rather than efficiency targets. This methodology is illustrated the below graph.

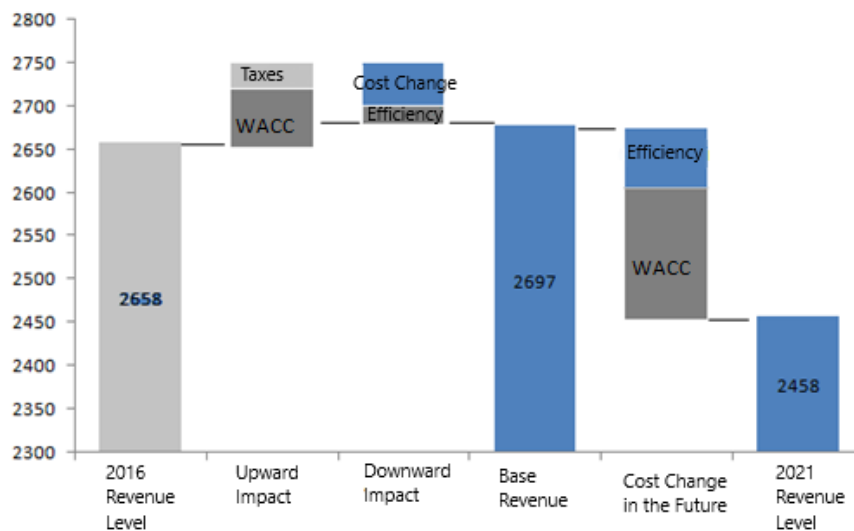


Figure 1.19 – Efficiency calculation in Holland

In **Turkey**, DEA is used to compare the DSOs and determine their efficiency parameters.⁵⁸ The target efficiency levels of the DSOs are to be achieved within 5 to 10 years. In the DEA model, previous realized OPEX of the DSOs (excluding non-controllable costs), line

length, transformer count and capacity, distributed energy, peak load, area, customer number, etc. may be used. As environmental factors, customer density, household consumption ratio, socioeconomic development index, loss ratio, etc. may be used. Efficiency parameters for the 3rd Tariff Period is shown in Table 1.16. As seen in the table, for Dicle, Aras and Vangölü DSOs, no efficiency parameter is determined. It is because of the high loss rates in these regions. For the high-loss DSOs, efficiency parameters are not applied until 31/12/2020. After this date, an efficiency parameter will be applied with a value of 50%.⁵⁹

Table 1.16 – Efficiency Parameters for DSOs in 3rd Tariff Implementation Period

DSO	2016	2017	2018	2019	2020	3 rd Tariff Period
	(%)	(%)	(%)	(%)	(%)	Efficiency Parameter (%)
ADM	0.00	0.00	0.00	0.00	0.00	0
Başkent	1.28	1.28	1.28	1.28	1.28	6.24
Sedaş	0.54	0.54	0.54	0.54	0.54	2.67
Kayseri ve C.	2.34	2.34	2.34	2.34	2.34	11.17
Meram	0.79	0.79	0.79	0.79	0.79	3.89
Osmangazi	0.00	0.00	0.00	0.00	0.00	0
Çamlıbel	0.00	0.00	0.00	0.00	0.00	0
Uludağ	0.43	0.43	0.43	0.43	0.43	2.13
Çoruh	0.00	0.00	0.00	0.00	0.00	0
Yeşilirmak	0.53	0.53	0.53	0.53	0.53	2.62
Akedaş	0.02	0.02	0.02	0.02	0.02	0.1
Fırat	0.00	0.00	0.00	0.00	0.00	0
Trakya	0.00	0.00	0.00	0.00	0.00	0
Akdeniz	1.61	1.61	1.61	1.61	1.61	7.79
Boğaziçi	0.00	0.00	0.00	0.00	0.00	0
GDZ	0.00	0.00	0.00	0.00	0.00	0
Dicle	-	-	-	-	-	-
Aras	-	-	-	-	-	-
Vangölü	-	-	-	-	-	-
Ayedaş	0.00	0.00	0.00	0.00	0.00	0
Toroslar	0.61	0.61	0.61	0.61	0.61	3.01

1.5 Losses⁶⁰

According to the regulatory framework established in European countries, different approaches have been employed in terms of procurement of (technical distribution) losses. In most countries, DSOs are responsible, but in some cases, it is the duty of suppliers. In case the system operator is responsible for the procurement, they can procure the energy on power exchanges from the day-ahead market or via longer contracts, bilaterally and by auctions/tenders where generators or traders submit their price offers. Average costs of losses are approved by the national regulatory authorities and used in the tariff calculation. In this case, losses are treated like any other induced or occurred imbalance. This option is used in 22 European countries, namely Austria, Belgium, Croatia, Cyprus, Czechia, Denmark, Estonia, France, Finland, Germany, Hungary, Iceland, Italy, Latvia, Lithuania, Malta, the Netherlands, Norway, Poland, Romania, Slovenia and Sweden.

If the supplier is responsible for the procurement, electricity to cover power losses is physically bought and injected into the system by suppliers. Estimated losses are then priced at the same level as the wholesale market price to supply the consumption. Losses

⁵⁹ Regulation on Measures for the Reduction of Losses in the Distribution System, Article 7.

⁶⁰ Source: CEER Report on Power Losses, Ref: C17-EQS-80-03, 18-October-2017.

are treated as imbalance. In this case, the difference between estimated losses and effective losses on the network is priced at the cost of providing the balancing energy on the balancing market. This option is used in only a few European countries, namely UK, Ireland, Portugal and Spain. A mixture of both systems is used in some countries such as Greece.

In **Germany** and **Norway**, cost of losses is paid via network tariffs, whereas in Portugal and UK, there are no tariffs for losses. In some countries such as Austria, Hungary and Latvia, there is a dedicated tariff for losses.

The following figure shows losses in distribution as share of total energy injected, these losses are highest in Romania, followed by Portugal in 2015, both around 8-9%, whereas they are the lowest in Iceland with 1%:

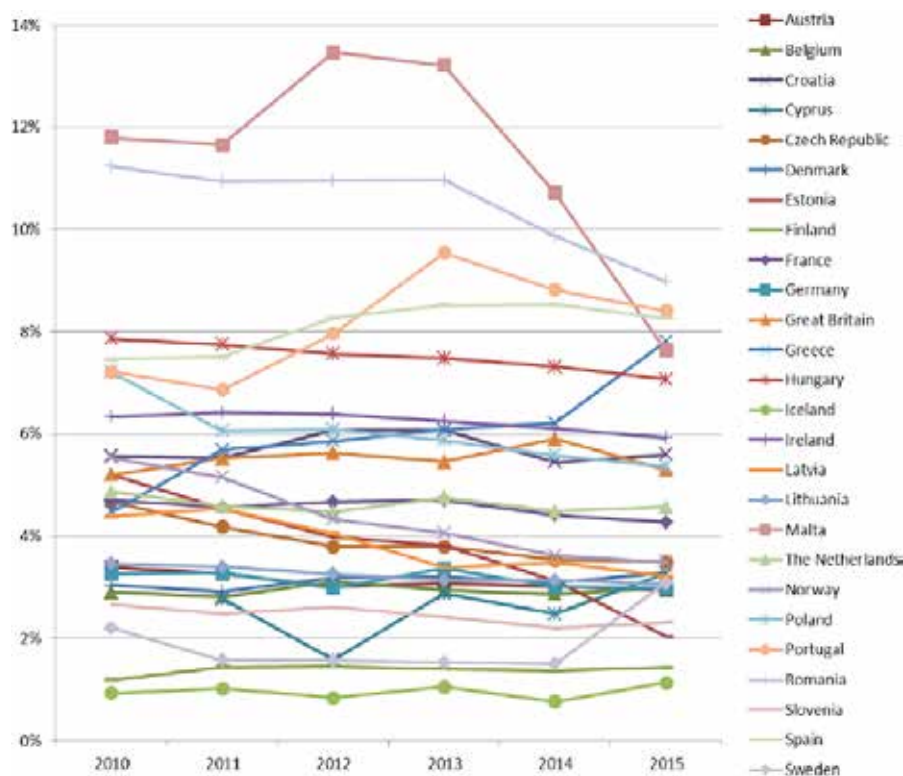


Figure 1.20 – Losses in distribution as percentage of total injected energy⁶¹

In **Germany**, only technical losses are considered. Any method to derive the amount of losses is allowed and this can include estimation, free valuation, and calculation. However, there are discussions about taking reverse flow of electricity into account when calculating losses. DSO is responsible from network losses and it is paid through network tariffs.

In **Norway**, network losses are measured as the difference between metered input and metered output (MWh). The costs related to the network losses are included in the cost base. It incentivizes DSOs to purchase the corresponding amounts of electricity as cost efficient as possible. If network operators are able to buy the corresponding amounts at prices lower than the reference price, they can keep the profit. To calculate the costs, NVE uses yearly reference prices of power. The prices are calculated based on volume weighted monthly area spot prices. The monthly area spot prices are collected from Nord Pool Spot AS and the weight is based on monthly national consumption volumes collected from statistics published by NVE. A mark-up of around 1.1 €/MWh is added to each calculated average volume weighted area spot price.

In **Italy**, there are some mechanism for network losses in order to improve the service in the next years. Losses are regulated by the article 24 of TIV “*Testo Integrato sulla Vendita*” where subsidies (PAU – *Prezzo Acquirente Unico*) to DSOs are determined by the difference between real and standard losses.

Losses could depend on not only of the distribution network but also where it is located, for instance the territory. Losses are paid by network tariffs and DSOs have to buy losses from the power exchange or through bilateral contracts.

The Regulator sets the conventional percentage factors of loss of electricity on the networks (called **standard loss factors**) and, in particular, defines:

- the standard loss factors applied to the electricity introduced and withdrawn on the networks with third party connection obligations;
- the standard loss factors for the determination of the fees for the Electricity Transmission service taken from the distributing companies from the national transmission grid and for the withdrawal of reactive energy;

Thanks to the significant growth of distributed generation, on one hand, it brings production closer to consumption sites, with a consequent decrease in electricity losses on the networks and, on the other hand, due to the growing penetration of renewable sources and the location of some renewable sources in areas with limited consumption, a possible increase in grid losses and a change in the management and operation of the grids themselves, it was necessary to change the approach to be adopted in defining the conventional input side loss factors to be used for equalization purposes.

So, with resolution 377/15 following a study supported by the Polytechnic of Milan, ARERA defined the current conventional loss factors.

Table 1.17 – Conventional loss factors in Italy

Voltage	A	B	C
	POD [%]	Interconnection points [%]	Inlet points [%]
380 V	0.7		
220V	1.1		
Measurement in correspondence of a transformer 380/220 V		0.8	
Measurement in correspondence of a transformer 220/MV		1.1	
- Other		0.9	
- ≤150V	1.8		
Measurement in correspondence of a transformer EHV/HV		1.1	
- Other		1.5	
- MV	3.8		2.3
Measurement in correspondence of a transformer HV/MV		2.3	
Measurement in correspondence of a transformer MV/LV		3.5	
- Other		2.9	
- LV	10.4		5.2
Measurement in correspondence of a transformer MV/LV		5.2	
Other		6.5	

In **UK**, Ofgem introduced a losses incentive mechanism as part of the Electricity Distribution price control, in order to encourage distribution network areas to manage an efficient level of losses on their network. A losses reduction mechanism consisting of four components, which are license obligation, loss reduction expenditure in the business plans, annual reporting and discretionary reward (LDR), was introduced. The second tranche of the LDR made up to £10m (in 2012-13 prices) available for the DSOs in 2017-18. While all six DSO groups intended to demonstrate the progress that has been made since tranche one (such as losses strategy,

enhanced losses modelling, increased stakeholder engagement, and holistic thinking about how to manage losses), the regulatory authority did not consider any DSO to provide sufficient evidence showing it met each criterion, and they decided that no DSO qualified for a reward. Up to £14m will be rewarded in 2020-21 within the scope of LDR.

Within the scope of the “Guide to the RIIO-ED1 Electricity Distribution Price Control” of 2017, it is stated that Ofgem cannot accurately measure network losses and together with rolling out of the smart meter loss calculations will be accurate. Historically Ofgem incentivised DSOs to reduce losses against a target, however there were major problems with the data, and they had to remove the mechanism for the distribution price control review.

Within the scope of RIIO, each DNO must have a losses strategy. It must keep an up-to-date version on its website, identifying any changes from the previous version and the reasons for them. The strategy should explain the DNO’s overall approach to managing losses. It should also identify specific projects or actions, with timescales, deliverables, costs and benefits. Actions should be justified with the associated benefits (e.g. carbon abatement) using a “whole life costing” approach and cost benefit analysis (CBA).

Electricity theft is dealt with various mechanisms, depending on the circumstances. DSOs are expected to at least maintain their current levels of support for suppliers in identifying and resolving theft. They should also take all reasonable cost-effective steps to resolve any cases of electricity theft from their distribution systems. The core elements of the approach are listed as:

- Where possible the link between the supplier and the customer should be maintained. DSOs are required to tackle theft where a consumer is not responsible.
- DSOs are required to act where someone makes an illegal connection, restores a disconnected supply, or where a supply has never been registered.
- Where DSOs have the right to recover the value of electricity taken, they must take reasonable steps to do so without incurring disproportionate costs. They must also seek to recover the associated costs and share any funds recovered with customers.
- DSOs must regularly report on their actions to deal with electricity theft and publish information on these actions.
- Suppliers’ licenses have been amended to strengthen their obligation to investigate, detect and prevent electricity theft.
- Electricity suppliers have also been directed to implement, by February 2016, a central service to assess the risk of electricity theft at consumer premises. This will help target theft investigations.

Besides, UK Legislation Theft Act, Article 13 states that “A person who dishonestly uses without due authority, or dishonestly causes to be wasted or diverted, any electricity shall on conviction on indictment be liable to imprisonment for a term not exceeding **five years**.” The customer who consumed the lost energy has to pay for the value of energy (calculated to have been consumed but not metered during the period of interference) as well as the costs of investigating the matter and the replacement of any damaged equipment.

In **Austria**, procurement costs of the energy necessary to cover losses are considered in the efficiency measurement of DSOs.

In **Belgium** (Flanders regulator VREG only), a revenue cap is used for TOTEX (total expenditure), including the costs for power losses, for DSOs only.

In the **Czechia**, a normative volume of losses is set by the Regulatory Authority and is adjusted annually using actual annual consumption.

Denmark has set revenue caps that include incentives to reduce power losses.

In **France**, there is an incentive on both volume of losses and procurement price of electricity for covering losses and it applies to both, TSO and DSOs.

In **Slovenia**, the costs of losses are a component of one part of the revenue cap. That part (volatile cost share) is benchmarked regularly.

Poland has separate schemes for DSOs and TSOs; for DSOs, losses are set by a benchmarking model; for TSOs, losses are set in tariffs using historical data and efficiency improvement factor. If that operator reaches a higher efficiency level (reduced losses), it can keep the profit.

The incentive mechanism in **Portugal** allows the DSO to be rewarded/penalized in case of achieving global distribution losses below/above a reference value set by the NRA, on a yearly basis. Until 2014, if losses were under (or above) the reference value,

the DSO was entitled to a financial reward (or penalty) proportional to the difference between those values (capped to a maximum value also set by NRA). From 2015, due to the uncertainties of RES penetration, a neutral zone was introduced.

The **Netherlands** has a yardstick regulation in place; the target is set ex-ante to a regulatory period, based on historical results and, in the case of DSOs, on the average performance as yardstick. The target is set by the NRA's calculations for the TSO.

In **Spain**, DSOs receive explicit loss incentive allowance determined by difference between the target and actual level of network losses valued at a price set by the regulator. Overall reward or penalty resulting from the regulatory scheme at 1% of the allowed revenue. (Royal Decree 1048/2013).

In **Turkey**, tariff regulation, DSOs are responsible for the losses. Loss reductions are incentivized/penalized by setting target loss ratios for the DSOs. If the realized loss is lower than the target loss, the energy cost of the difference is a direct revenue for the DSOs, otherwise a direct loss for the DSOs. DSOs must purchase the losses from EUAS with a set tariff by EMRA.⁶²

In Turkey, Distribution losses is a chronic problem. In 2018 aggregated average distribution loss was reported as 13.1%, where three DSOs (Dicle, Vangolu and Aras) were above the average, two DSOs (Toroslar and Firat) are between Turkey average and threshold ratio (8%) and remaining 16 DSOs were below threshold⁶³. Between 2016⁶⁴ and 2018 DSOs succeeded to reduce losses from aggregated 15.55% and together with 6.15 TWh energy saving. 90% of this saving came from seven highest energy consumed DSOs.

Loss rates of the Turkish distribution companies are shown in the below table. Especially for the three regions (Dicle, Vangölü and Aras) non-technical loss rates or theft are very high and need to be incentivized to be reduced.

Table 1.18 – Realized Loss Ratios of DSOs in the 3rd Tariff Implementation Period

Distribution Region	Realized Loss Rates (%)		Target Loss Rates (%)
	2017	2018	2018
Dicle	64.82	54.94	69.20
Vangölü	53.30	49.16	57.27
Aras	24.55	23.55	25.65
Toroslar	11.35	11.85	12.34
Firat	10.95	10.32	10.47
Çoruh	8.11	7.85	9.02
Yeşilirmak	7.43	7.63	8.06
Gediz	7.25	6.63	7.84
Osmangazi	6.97	6.41	7.55
Boğaziçi	6.74	6.04	7.98
Akdeniz	6.67	5.78	7.63
Çamlıbel	6.59	5.08	7.55
Sakarya	6.41	6.52	7.34
İstanbul	6.10	6.04	7.50
Başkent	6.05	6.11	7.64
Kayseri and surroundings	6.03	6.57	7.00
Meram	5.77	6.69	7.66
Akedaş	5.48	7.28	7.20

62 Source: Electricity Market Law, No. 6446, Article 26/12

63 Source: EMRA 2018 Market Report

64 Source: EMRA 2016 Market Report

Adm	5.26	5.53	7.15
Trakya	5.09	4.37	7.12
Uludağ	4.14	4.20	7.20

Due to the high loss rates of Turkey compared to EU countries, there is a specific regulation for loss reduction “Regulation on Measures for the Reduction of Losses in the Distribution System”. The summary of this regulation is given below:

- High-loss DSOs are defined. These are the DSOs whose loss rates are higher than the country average (based on 2014 values).
- If a High-loss DSO reduces its loss rates below country average, its high-loss status is removed.
- For all the DSOs high-loss status will be removed after 31/12/2025.

For the high-loss DSOs, efficiency parameters are not applied until 31/12/2020. After this date, an efficiency parameter is applied with a value of 50%.

Target loss rates are calculated in three groups; Ultra high (higher loss rate than Nation average loss rate), High (higher than 8%⁶⁵ but lower than Nation average, Low (lower than 8%). Target loss rates are function of average of past three years (i.e.).⁶⁶ For ultra-high group EMRA requires 3% improvement from above aggregated average, 2% improvement for the high group. For low group arithmetic average of aggregated average and threshold loss rate is set for the following year. In any case target loss rate cannot be higher than the current year.

1.6 Tariff Determination for Consumers⁶⁷

1.6.1 Network Tariffs

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

In most of the cases use-of-system charges are based either on energy consumption (volumetric) or on contracted/measured power (capacity-based tariffs). EU tariffs range from purely volumetric tariffs to purely capacity tariffs.⁶⁸

1.6.1.1 Germany

In Germany, network charges are calculated by the network operators and they are based on the allowed revenue caps set by the regulatory authorities. The permissible revenue caps result from the costs of operation, maintenance and expansion of the network, plus regulatory profits as defined in previous sections. Network costs are allocated to the users taking into account each user's contribution to the annual simultaneous peak load. A network user whose individual annual maximum load is likely to contribute to the annual maximum load of the network, pays a higher capacity charge. The probability is derived from a network user's hours of usage and is reflected in the charging scheme by the different charges for more than 2,500 hours and less than 2,500 hours of network usage. A unit charge and, in some cases, a standing charge is set for network users with an annual offtake of less than 100,000 kWh. Those are mainly household customers and smaller commercial customers at LV level.

⁶⁵ EMRA threshold loss rate

⁶⁶ LR: Loss rate.

⁶⁷ CEER, January 2017, Electricity Distribution Network Tariffs CEER Guidelines of Good Practice.

⁶⁸ EC JRC Science for Policy Report, Distribution System Operators observatory 2018, p.6.

Under the legislative provisions in Germany, network charges are only payable when electricity is drawn from a network. Generators feeding electricity into a network who are also “network users” do not have to pay network charges.

The network operators publish their provisional network charges on their websites on 15 October each year for the following calendar year and then publish their final charges on 1 January of the year in which the charges take effect. They are not allowed to make any changes to the published network charges in the course of the year.

The consumption groups are as follows:

- Household customers: since 2016, the network charges relate to an annual consumption of between 2,500 kWh and 5,000 kWh (Eurostat Band DC) and LV supply
- Commercial customers: annual consumption 50 MWh, annual peak load 50 kW, annual usage period 1,000 hours, low-voltage supply (0.4 kV);
- Industrial customers: annual consumption 24 GWh, annual peak load 4,000 kW, annual usage period 6,000 hours, medium-voltage supply (10 kV/20 kV), interval metering

As of 1 April 2018;

- The volume-weighted network charges for household customers, with annual consumption 2,500-5,000 kWh was 7.17 ct/kWh
- Network charge for commercial customers with annual consumption 50 MWh - arithmetic mean 6.27 ct/kWh
- Network charge for industrial customers with annual consumption 24 GWh - arithmetic mean 2.36 ct/kWh

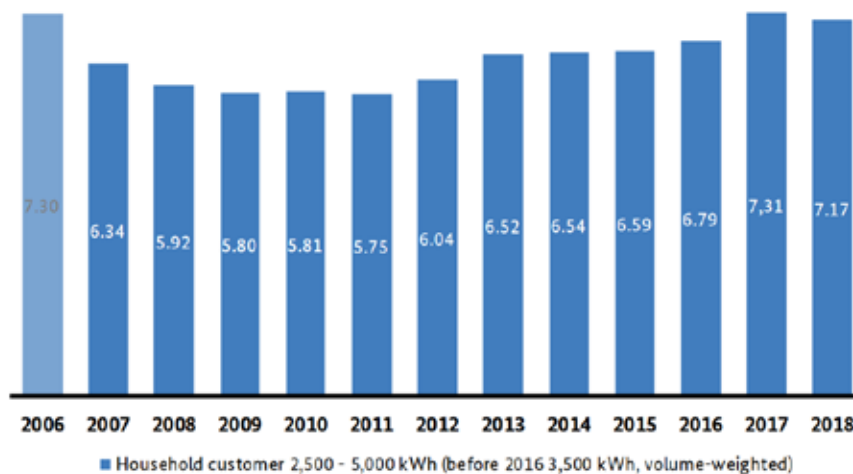


Figure 1.21 – Change in volume-weighted network charges (including metering operations for household customers (ct/kWh))

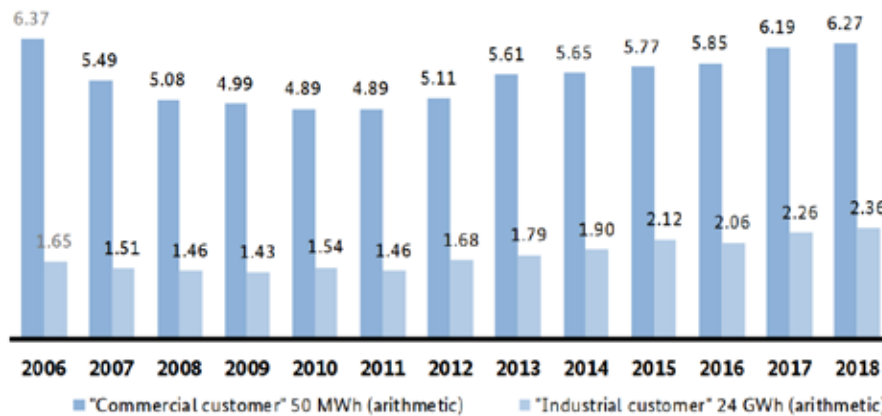


Figure 1.22 – Change in arithmetic net network charges (including meter operation) for “commercial customers” (50 MWh) and “industrial customers” (24 GWh) (ct/kWh)

There are large regional differences in the network charges. The information relating to each DSO’s unit and capacity charges was used to calculate the network charges (in cents per kilowatt hour) applicable for 2018 in different regions.

- The network charges for household customers range from 2.5 ct/kWh to 25.4 ct/kWh, with only very few customers paying this maximum charge.
- The range of network charges for commercial customers is similar to that for household customers, with charges ranging from 2.2 ct/kWh to 24.6 ct/kWh.
- The network charges for industrial customers (without possible reductions) range from around 0.6 ct/kWh to 5.8 ct/kWh



This project is funded by the European Union



1

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Schleswig-Holstein	7.27	4.20	10.03	42
Brandenburg	6.46	3.91	7.84	27
Mecklenburg-Western Pomerania	6.24	4.04	10.43	19
Saxony-Anhalt	6.12	4.86	8.35	27
Baden-Württemberg**	5.92	2.17	9.61	120
Saxony	5.85	3.35	8.48	33
Thuringia	5.75	3.76	8.14	31
Rhineland-Palatinate	5.64	3.30	8.63	51
Saarland	5.51	4.62	13.32	20
Lower Saxony	5.50	3.38	10.27	69
Bavaria	5.49	3.50	9.57	219
Hamburg	5.36	5.36	5.36	1
Hesse	5.15	3.47	8.13	47
North Rhine-Westphalia	4.95	3.18	8.18	95
Berlin	4.76	4.76	5.17	2
Bremen	3.23	2.95	8.14	4

2

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Brandenburg	3.08	2.09	3.68	28
Mecklenburg-Western Pomerania	2.82	1.40	4.19	19
Saxony-Anhalt	2.75	1.88	3.58	27
Saxony	2.65	0.54	3.41	33
Schleswig-Holstein	2.55	1.41	4.12	40
Lower Saxony	2.52	0.69	5.52	69
Hesse	2.50	1.31	3.14	49
Thuringia	2.47	1.63	3.10	29
Berlin	2.44	2.44	2.52	2
Saarland	2.42	1.49	4.98	20
Bavaria	2.28	1.17	5.76	212
North Rhine-Westphalia	2.27	1.24	3.68	94
Hamburg	2.25	2.25	2.25	1
Baden-Württemberg	2.20	1.08	3.81	120
Bremen	2.10	2.04	2.73	4
Rhineland-Palatinate	2.09	1.38	5.67	51

3

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Brandenburg	8.62	4.84	9.28	27
Schleswig-Holstein	8.49	5.40	11.62	42
Saxony-Anhalt	7.48	5.59	8.63	26
Mecklenburg-Western Pomerania	7.09	4.57	10.54	18
Lower Saxony	6.98	4.26	25.38**	69
Saxony	6.94	4.33	9.47	33
Baden-Württemberg***	6.75	2.52	10.33	120
Thuringia	6.75	5.01	9.75	31
Bavaria	6.74	4.23	10.88	219
Saarland	6.67	5.36	13.96	20
Hamburg	6.63	6.63	6.63	1
Hesse	6.59	4.13	8.77	47
Rhineland-Palatinate	6.55	4.53	9.29	51
North Rhine-Westphalia	6.32	4.37	9.24	97
Berlin	5.64	5.64	5.64	2
Bremen	4.56	4.28	6.60	3

1 Net network charges for commercial customers in Germany: 2018 (ct/kWh)

2 Net network charges for industry customers in Germany: 2018 (ct/kWh)

3 Net network charges for household customers in Germany: 2018 (ct/kWh)

Figure 1.23 – Network Charges in 2018

1.6.1.2 Italy⁶⁹

In Italy the mandatory tariff to be applied is defined throughout the national territory by ARERA.

It is divided into two macro categories

- Domestic users (TD)
- Non-domestic users

The **mandatory tariff** for the distribution service covers the costs for the transport of electricity on the distribution networks and for the metering service.

It is applied to all end customers and the components are separated for the services:

- Distribution
- Measurement
- Transmission

The **distribution service mandatory tariff for domestic customers** is called TD. The TD tariff, which values are shown in Table 1.19 for the year 2020, is made up of the three tariff components: σ_1 ; σ_2 ; σ_3 .

Table 1.19 – Distribution tariff; domestic customers; for 2020

s1		s2	s3
<i>Totale</i>	<i>Of which measurment</i>		<i>tras</i>
Euro cents/POD/year	Euro cents/POD/year	Euro cents /kW for year	Euro cents /kWh
2,040.00	1,733.20	2,088.00	0.761

The **distribution service non-domestic tariff** has a trinomial structure and is expressed in euro cents per withdrawal point per year (fixed quota), euro cents per KW per year (power quota) and euro cents per KWh consumed (energy quota).

The mandatory fee for the distribution service is updated annually by the ARERA.



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Table 1.20 – Distribution tariff; non-domestic

NON domestic customers	Fixed quota	Power quota	energy quota	TARIFF CODE
	cents/POD/year	cents /kW for year	cents /kWh	
Public lighting in LV			1.244	BTIP
exclusive power supply of electric vehicle charging points in places accessible to the public in LV			4.969	BTVE
Others <= 16.5 kW in LV				
- <= 15 kW	462.70	2925.01	0.061	BTA1
- from 15 kW to 3 kW	462.70	2770.25	0.061	BTA2
- from 3 kW to 6 kW	462.70	3079.77	0.061	BTA3
- from a 6 kW to 10 kW	508.97	3079.77	0.061	BTA4
- up to 10 kW	508.97	3079.77	0.061	BTA5
Others >16.5 kW in LV	462.70	2925.01	0.059	BTA6
Public lighting in MV			0.646	MTIP
Others <= 100 kW in MV	43,889.43	3261.91	0.056	MTA1
Others from 100 kW to 500 kW in MV	39,500.48	2929.06	0.050	MTA2
Others up to 500 kW in MV	38,164.72	2569.59	0.044	MTA3
HV	1,930,233.86		0.020	ALTA
HV. voltage < 380 kV	1,930,233.86			AAT1
HV. voltage >= 380 kV	1,930,233.86			AAT2

The **non-domestic users mandatory measurement tariff** for MIS is to cover the costs relating to the measurement service and is generally made up of the following components:

- MIS (INS) to cover the costs of the installation and maintenance of the measuring equipment;
- MIS (RAV) to cover the costs of the measurement data management operations; c) MIS (RES) to cover the unamortised residual cost of electromechanical meters replaced with electronic meters, differentiated on the basis of the contractual types.

Table 1.21 – MIS components

NON domestic customers	MIS ₁	MIS ₃
	Euro cents/POD/ year	Euro cents /kWh
Public lighting in LV		0.062
exclusive power supply of electric vehicle charging points in places accessible to the public in LV		0.152
Others in LV	2010.77	
Public lighting in MV		0.059
MV	23,466.13	
HV	95,477.31	
HV, voltage < 380 kV	95,477.31	
HV, voltage >= 380 kV	95,477.31	

Table 1.22 – $MIS_c(INS)$ components

NON domestic customers Euro cents/POD/ year	$MIS_1(INS)$	$MIS_3(INS)$
	Euro cents /kWh	
Public lighting in LV		0.045
exclusive power supply of electric vehicle charging points in places accessible to the public in LV		0.095
Others in LV	1248.89	
Public lighting in MV		0.058
MV	20,197.56	
HV	92,016.08	
HV, voltage < 380 kV	92,016.08	
HV, voltage >= 380 kV	92,016.08	

Table 1.23 – $MIS_c(RAV)$ components

NON domestic customers Euro cents/POD/ year	$MIS_1(RAV)$	$MIS_3(RAV)$
	Euro cents /kWh	
Public lighting in LV		0.010
exclusive power supply of electric vehicle charging points in places accessible to the public in LV		0.043
Others in LV	571.40	
Public lighting in MV		0.001
MV	3268.57	
HV	3461.23	
HV, voltage < 380 kV	3461.23	
HV, voltage >= 380 kV	3461.23	

Table 1.24 – $MIS_c(RES)$ components

NON domestic customers	$MIS_1(RES)$	$MIS_3(RES)$
	Euro cents/POD/ year	Euro cents /kWh
Public lighting in LV		0.007
exclusive power supply of electric vehicle charging points in places accessible to the public in LV		0.014
Others in LV	190.48	
Public lighting in MV		
MV		
HV		
HV, voltage < 380 kV		
HV, voltage >= 380 kV		

1.6.1.3 Portugal⁷⁰

In Portugal energy regulatory authority determines and publishes distribution tariffs for the one national and ten local DSOs. Tariff classes are defined by voltage levels:

Distribution tariffs defined by voltage levels are:

- HV: It consists of voltage level more than 45kV, but equal or less than 110kV. Typical large industrial consumers are within this category.
- MV: It consists of voltage level more than 1kV but equal or less than 45kV. Typical small industrial consumers are within this category.
- LV: It consists of voltage level equal or less than 1kV. There are two subcategories:
 - SpLV with contracted power higher than 41.4kW. Typical small business consumers are within this category.
 - StLV with contracted power equal or lower than 41.4kVA. Typical household consumers are within this category.

Households: The capacity component is charged through contracted power for households. While both capacity and volume components are linear, the latter can be differentiated by static ToU. The options for households are;

- no ToU,
- two-period ToU (peak and off-peak),
- three-period ToU (peak, off-peak and super off-peak).

Industry: Industrial customers are charged on a minimum four-period ToU for their energy consumption;

- peak,
- half-peak,
- off-peak and
- super off-peak
- or more periods if they request it, together with variations between two seasonal periods.

Tariffs for all classes contain the same components, capacity and volume but the weights differ in different classes. Volume for households is 62%, whereas volume for large industry is 17%. Tariffs are not geographically differentiated.

⁷⁰ Source: Lu L., Waddams Price C., Centre for Competition Policy, University of East Anglia, October 2018, designing distribution network tariffs that are fair for different consumer groups.

- Capacity charge:
 - Contracted power for HV, MV, and SpLV and StLV. Corresponds to the maximum average active power in kW, in any uninterrupted period of 15 minutes, during the last 12 months. For StLV corresponds to the apparent power in kVA. (€/kW month)
 - Average peak power for HV, MV and SpLV. Corresponds to the ratio between peak hour active energy and the number of peak hours. (€/kW month)
- Energy Charge: Active energy, differentiated by time period and seasonal period (€/kWh).
 - For HV, MV and SpLV, there are 4 period of active energy (Peak hours, Half-Peak hours, Off-Peak hours and Super Off peak-Hours) in 2 seasonal periods for HV and MV (Season I-IV and Season II-III) and no seasonal period differentiation for SpLV.
 - For StLV, there are 3 tariff options for energy charge, with no seasonal period differentiation:
 - One-period tariff. No time-of-use differentiation.
 - Two-period Tariff. There are two time period differentiation.
 - Three-period tariff. There are three time period differentiation.
- Reactive charge. Reactive energy component which applies to HV and MV voltage levels and also to SpLV. Reactive energy is only billed to the consumer regarding the network and voltage level of connection. (€/kVARh)
 - The Inductive Reactive Energy Supplied: that is the reactive energy supplied which exceeds 30% of the active energy, in peak and half-peak hours.
 - The Capacitive Reactive Energy Received: that is the reactive energy received in off-peak hours.

Static time of use tariffs (ToU) have been in place for a long time in Portugal and consumers representing 80% of the total demand uses them. For all industrial consumers four time periods tariffs are in place and for household consumers one, two or three time periods can be chosen.

As known, static ToU tariffs define certain time periods where the charges for use of the distribution system vary. These time splits usually reflect predicted peak and off peak times and they might provide incentives to permanently shift load from peak periods to off-peak periods, however static ToU tariffs do not take into account actual system conditions such as high levels of intermittent renewables or use of storage and demand-side-response.

In this context, ERSE has created the regulatory framework for the introduction of dynamic ToU grid access tariffs, which may lead to the active participation of users and thus the promotion of demand side flexibility. Before engaging in the use of dynamic tariffs, a Cost Benefit Analysis was carried out. The Portuguese DSO performed a preliminary CBA on the introduction of access dynamic tariffs in Portugal, which concluded that the benefits clearly outweigh the costs. In 2017, a pilot study was performed with industrial consumers for 1 year.

The introduction of dynamic tariffs has the following objectives:

- allow consumers to participate in mechanisms that lead to a more efficient use of the grids and consequently allows minimising grid costs, benefiting all consumers;
- provide the grid operator with an alternative mechanism to minimize costs, which allows the reduction of demand in the situations of higher consumption, and the postponement of new investments;
- allow the minimisation of the production variation impacts namely from intermittent generation to the benefit of the electric system operational security.

With the usage of dynamic tariffs, prices are determined close to real-time consumption of electricity and are based on wholesale electricity prices. Electricity prices are calculated based on at least hourly metering of consumption, or with even higher granularity (e.g., 15 minutes). Such tariffs are mostly composed of the wholesale price of electricity plus a supplier margin.

1.6.1.4 Norway^{71 72}

Network tariffs vary across Norway as the DSOs are responsible for setting their own tariffs, and the tariffs are covering costs within the DSO's area. However, the grid tariffs must be objective and non-discriminatory, and designed and differentiated based on relevant grid conditions. Some DSOs offer reduced grid tariffs to customers that are willing to cut their consumption in short periods when the local grid is overloaded. Tariffs are subject to revenue caps set by the regulatory authority, but not to detailed regulatory approval. Key features are:

- Tariff class is defined by the voltage level to which a customer is connected (high and low voltage)
- Tariffs contain fixed and volume components
- Capacity component usually applies in addition to customers with high consumption (> 100,000 kWh/year) or high installed capacity (> 80 or 125 A)
- For small users the fixed component accounts for around 30% of the total network tariff on average.

Different tariffs are determined for households, vacation homes and small commercial customers and they mainly consist of a fixed yearly charge and an energy charge. On average, the fixed charge constitutes around 30% of the network tariff.

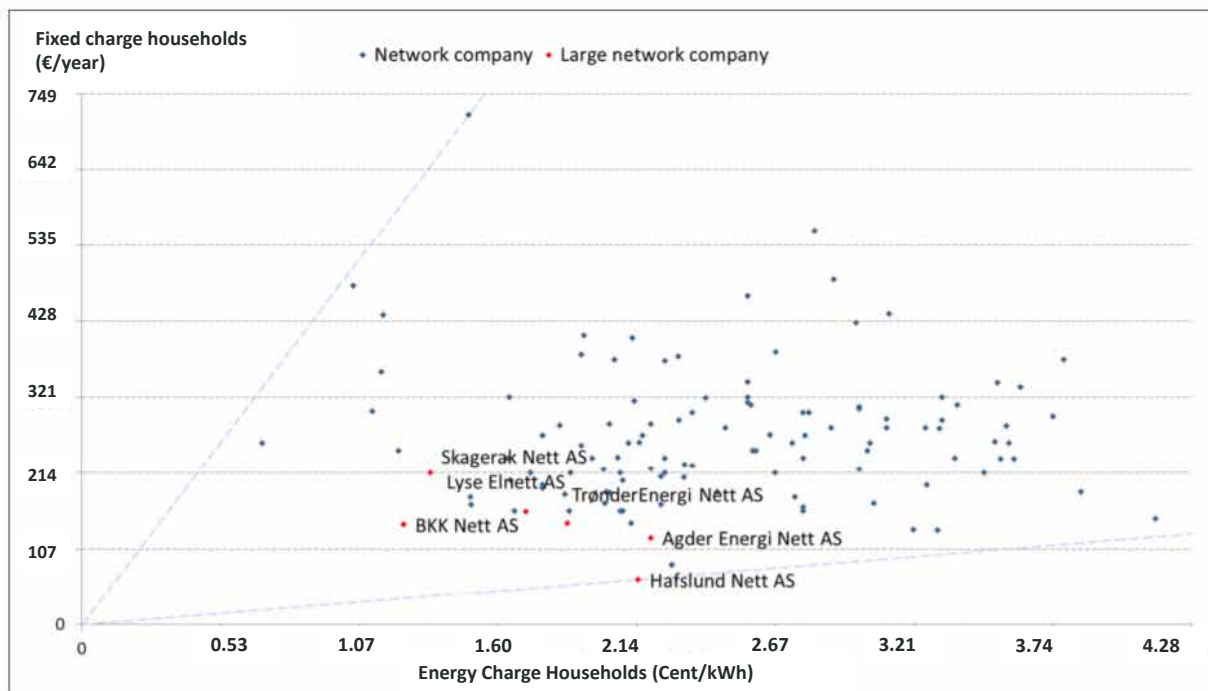


Figure 1.24 – Level of fixed and energy charge in the network tariff for household customers in 2016

Customers with an installed capacity exceeding a set limit, for example over 80 or 125 amperes, or customers with an expected annual consumption exceeding 100,000 kWh, usually have a capacity charge in addition to the fixed and energy charge. The capacity charge is based on used capacity within defined periods of time.

⁷¹ Source: Lu L., Waddams Price C., Centre for Competition Policy, University of East Anglia, October 2018, designing distribution network tariffs that are fair for different consumer groups.

⁷² Mook V. A., Norrie-Moe R., Rudi A. G., 2016, Status of NVE's work on network tariffs in the Electricity Distribution system.

While households in Norway do not currently face capacity charges, NVE intends to make capacity a mandatory component to be included by DSOs in their tariff designs and believes that capacity (kW) requirements are expected to be at least as important as energy (kWh) requirements. In order to achieve this objective, several models for capacity tariffs have been proposed:

- Installed capacity (MW)
- Subscribed capacity, with penalties for over-consumption, or use of smart meters to enforce the subscribed limit (the latter is similar to the Italian experience)
- Measured capacity usage
- ToU tariffs as an alternative to measured capacity

The statistics below show the average network tariffs excluding taxes (VAT and consumer tax) in each county.

Table 1.25 – Network tariffs for household customers as of January 2019

County	Fixed component €/customer (exc)	Energy component €cent/kWh (exc.)	Converted tariff €cent/kWh (exc.)	Fixed component €/customer (inc.)	Energy component €cent/kWh (inc.)	Converted tariff €cent/kWh (inc.)
Østfold	125.33	2.20	2.83	156.66	4.73	5.52
Akershus	108.19	2.22	2.76	135.24	4.75	5.43
Oslo	96.00	2.25	2.73	120.00	4.80	5.40
Hedmark	414.74	1.00	3.07	518.42	3.23	5.82
Oppland	324.26	1.14	2.84	405.33	3.40	5.52
Buskerud	155.30	2.22	3.00	194.12	4.75	5.72
Vestfold	276.00	1.77	3.15	345.00	4.19	5.92
Telemark	270.88	2.02	3.38	338.60	4.51	6.20
Aust-Agder	156.00	2.25	3.03	195.00	4.79	5.77
Vest-Agder	156.00	2.25	3.03	195.00	4.79	5.77
Rogaland	200.34	2.01	3.01	250.43	4.49	5.74
Hordaland	178.65	1.87	2.76	223.31	4.31	5.43
Sogn og Fjordane	229.54	2.95	4.10	286.92	5.67	7.10
Møre og Romsdal	231.17	2.07	3.23	288.96	4.57	6.01
Trøndelag	200.30	2.01	3.01	250.37	4.49	5.75
Nordland	362.42	2.02	3.83	362.42	3.60	5.41
Troms	193.97	2.21	3.18	193.97	3.60	4.57
Finnmark	334.08	2.28	3.95	334.08	2.28	3.95
Landsgjennomsnitt	203.05	2.02	3.04	245.02	4.36	5.59

In 2019, all Norwegian electricity consumers are expected to have new advanced metering systems, where electricity consumption will be measured on an hourly basis. The advanced metering systems is expected to enable customers to adapt their consumption to price signals from the electricity market and from network tariffs to reduce their costs relating to energy consumption. In this way, consumers may contribute to more efficient utilisation of the grid, and with flexibility (demand-response) that may delay or reduce the need for grid investments. This will benefit all customers through lower tariffs than in the case with grid investments. NVE also considers the possibility of deeper connection charges.

There is another discussion that suggests less energy-based and more capacity-based tariffs as mentioned. NVE has undertaken a public consultation for setting network tariffs for customers connected to the grid with a voltage of 22 kV or lower. Stakeholders generally support the need to make changes to the current regulations. The main cost is related to being connected to the network and having the opportunity to use electricity from it. When investing in the network, demand for capacity during peak hours is a cost driver. In NVE's opinion, this should be reflected in the tariff.

1.6.1.5 UK⁷³

DSOs largely recover costs through a simple tariff which includes a standing charge per day and a unit charge per kWh. The standing charge is relatively small, and the majority of domestic distribution revenue is recovered through the unit charge. Distribution charges account for around 15% - 20% of a domestic consumer's total bill. Retailers do not have an obligation to pass the structure of the distribution tariff on to their consumers.

20 % of customers are on a ToU tariff. There exist time-varying tariffs. For instance, Economy 7 tariff offers cheaper electricity at night based on an average load profile.

In UK, DSOs developed common approaches to connections charging and distribution use-of-system (DUoS) charging. These common approaches include:

- from 1 April 2010, all customers connected at the lower voltages (all low voltage (LV) and most high voltage (HV)) have been charged DUoS under the Common Distribution Charging Methodology (CDCM). The CDCM is the Common Distribution Charging Methodology that applies to most customers.
- from 1 April 2012, demand customers at the higher voltages (some HV and all extra-high voltage (EHV)) have been charged DUoS under the EHV Distribution Charging Methodology (EDCM). The EDCM is the extra-high voltage Distribution Charging Methodology which is applied to customers connecting to the network at extra-high voltage levels as designated in their licence.
- from 1 April 2013, generation customers at the higher voltages have been charged DUoS under the EDCM
- from 1 October 2010, the DSOs' connections methodologies have incorporated the Common Connections Charging Methodology (CCCM).⁷⁴

While these methodologies are identical across all DSOs, the inputs to the methodologies reflect the characteristics of the network and the number and characteristics of consumers in each DSO area. EDCM tariffs are set individually for each site, whereas the CDCM tariff for each category of site is uniform across each of the 14 DSO areas. That means CDCM tariffs are different between different DSO areas even within the same DNO group.

An example of CDCM charging model published by Electricity North West is as follows⁷⁵:

⁷³ Source: Brown T., Faruqui A., Lessem N., April 2018, Electricity Distribution Network Tariffs Principles and analysis of options.

⁷⁴ Model maps in Excel for CDCM and EDCM might be reached from <https://www.enwl.co.uk/about-us/regulatory-information/use-of-system-charges/current-charging-information/> for Electricity North West.

⁷⁵ Source: <https://www.enwl.co.uk/about-us/regulatory-information/use-of-system-charges/current-charging-information/>

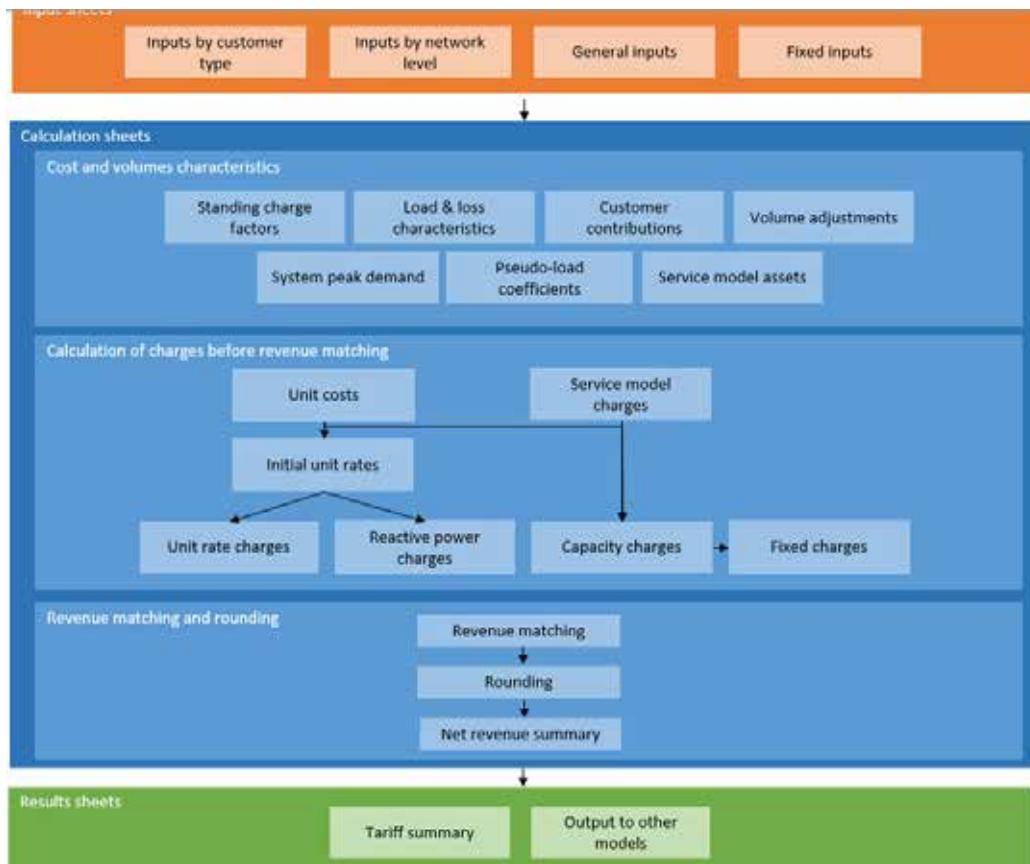


Figure 1.25 – Example CDCM Model Map

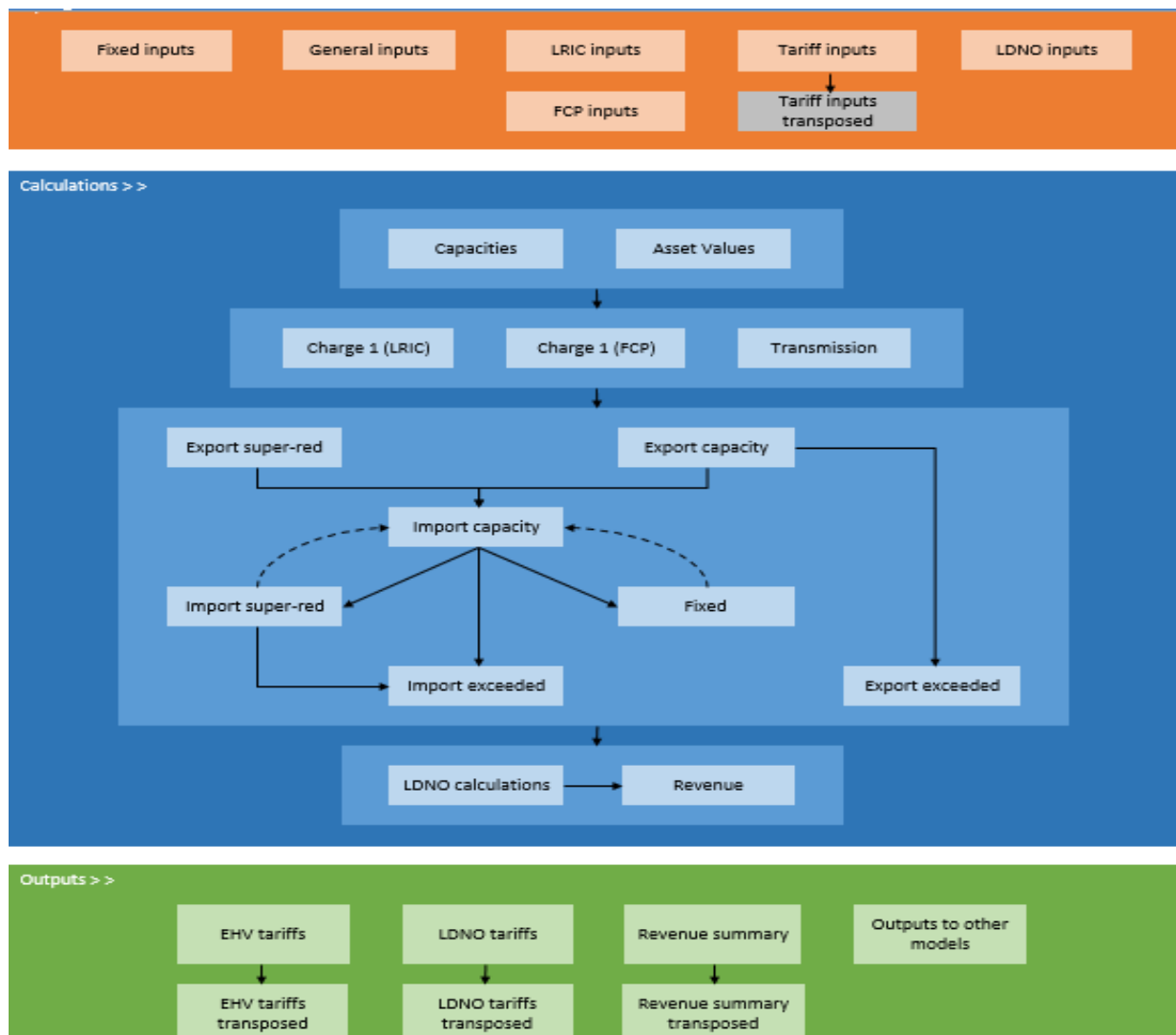


Figure 1.26 – Example EDCM Model Map

The UK energy regulator, Ofgem, recently launched a reform effort focused on the residual charge element of distribution tariffs. This effort aims to address concerns that large commercial and industrial customers can avoid contributing to the residual charge and thereby push the burden onto residential customers. Residual cost recovery charges are bundled with volumetric or demand charges, which incentivizes inefficient consumption.

Price Equalization Mechanism: in France, price equalization is used therefore distribution tariff is the same for all the DSOs.

1.6.1.6 Turkey

In Turkey, there are two tariffs for DSOs, namely distribution tariff and distribution connection tariff.

Distribution connection fee is paid once for the new connections to the grid. This fee is limited with the required costs to construct the connection line between the customer and the grid. Grid investment costs are not included.⁷⁶ If the connection line is built by the customer, this fee is not applied. Connection fee is determined based on the connection capacity, connection type (LV or MV), line type (overhead or cable) and the distance for connection.

Distribution Tariff consists of the DSO investment costs, fair return for the investments, system operation costs, losses, disconnect/connect service fee, meter reading costs, reactive energy cost, transmission costs, etc. These fees can be differentiated by connection type, consumption amount and consumption purpose.⁷⁷

Distribution tariff consists of distribution fee, capacity fee, overcapacity fee, reserve capacity fees and reactive energy fee.⁷⁸

Consumers are mainly grouped as households, industry, commercial, agricultural irrigation and lighting. However, DSOs may suggest new subgroups or groups according to geographical properties and load profiles of the consumers.⁷⁹

Tariff classes consists of double term tariff and single term tariff. Double term tariff class pays for the capacity and consumption. Single term tariff class pays only for consumption.

1.6.2 Retail Tariffs⁸⁰

Although some EU countries still have a policy of retail price regulation, there is a trend towards phasing out regulated prices in recent years, coinciding with the implementation of the requirements of the 3rd energy package which entered into force in 2009. The countries with the price regulation are Belgium, Bulgaria, Cyprus, France, Hungary, Latvia, Lithuania, Malta, Poland, Portugal, Romania, Slovakia and Spain. The countries who phased-out the regulated prices are Sweden, Finland, Germany, Austria, Italy, Croatia (2015), Denmark (2016), Estonia (2013), Greece (2013) and Ireland (2011).⁸¹

Retail electricity prices for both households and industrial consumers vary greatly across Europe as a result of the heterogeneity of national energy and taxation policies. In some of the European Member States electricity prices for household consumers are three times bigger than other countries. In the household segment, the average electricity price fell by 0.4% to 20.4 Euro cents/kWh in 2017, compared to the previous year. In the industrial segment, electricity prices fell, on average, by 1.9% to 10.4 Euro cents/kWh for the same period. Reason of the falling electricity prices are mainly, wholesale electricity and lower taxes in electricity. The next two figures show final electricity prices for households and industrial consumers in the EU MSs and Norway in 2017 (eurocents/kWh) and changes compared to 2016 and 2008 (%).

⁷⁷ Source: Electricity Market Tariffs Regulation, Article 9/2

⁷⁸ Source: Communiqué on the Regulation of Distribution System Revenue, Article 5/4

⁷⁹ Source: Electricity Market Tariffs Regulation, Article 23

⁸⁰ Source: ACER, October 2018, ACER/CEER - Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2017 – Electricity and Gas Retail Markets Volume

⁸¹ Source: Energy Prices and Costs in Europe, Commission Staff Working Document, 2019



This project is funded by the European Union

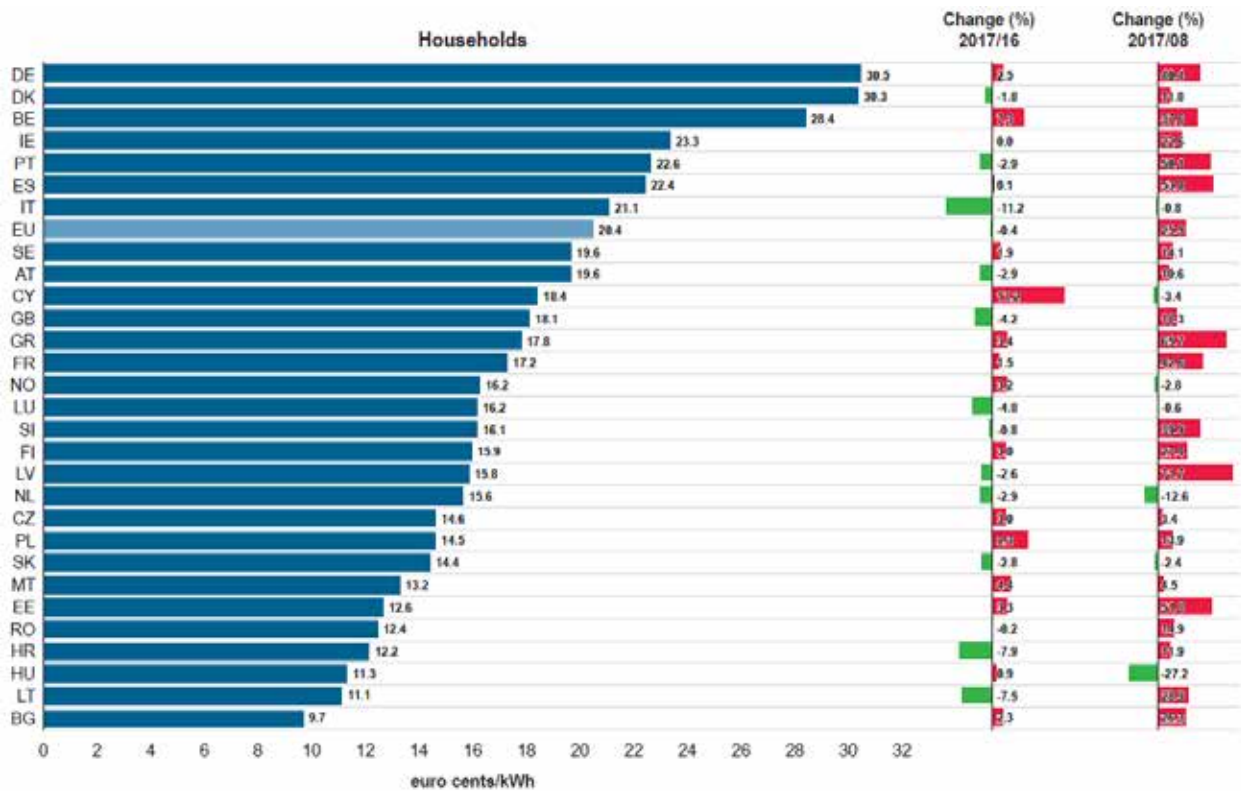


Figure 1.27 – Final electricity prices for household consumers in the EU MSs and Norway in 2017 (eurocents/kWh) and changes compared to 2016 and 2008 (%).

In Germany, the member state that has the highest household prices (305 €/MWh), consumers pay more than three times the price paid by Bulgarian consumers (97 €/MWh). These differences are even higher in the industrial segment, as industrial electricity prices in Denmark (240 €/MWh) are more than five times higher than those in Luxembourg (43 €/MWh). Compared to 2016, the largest price decreases for household consumers were recorded in Italy (-11.2%) and Croatia (-7.9%), while in Cyprus and Poland electricity prices increased by 17.2% and 8.3% respectively. In the industrial segment, prices decreased further in the majority of countries, but increased considerably in Cyprus (26.1%) and Greece (13.1%). Over the 2008 – 2017 period, electricity prices for household consumers decreased in seven countries, with the highest decreases recorded in Hungary (27.2%) and the Netherlands (12.6 %), while prices increased in the remaining countries. Over the same period, industrial prices decreased in many countries, although there were also some notable price increases (i.e. 64.5% in Latvia, 48.6% in Portugal 71.6% in Estonia).



This project is funded by the European Union

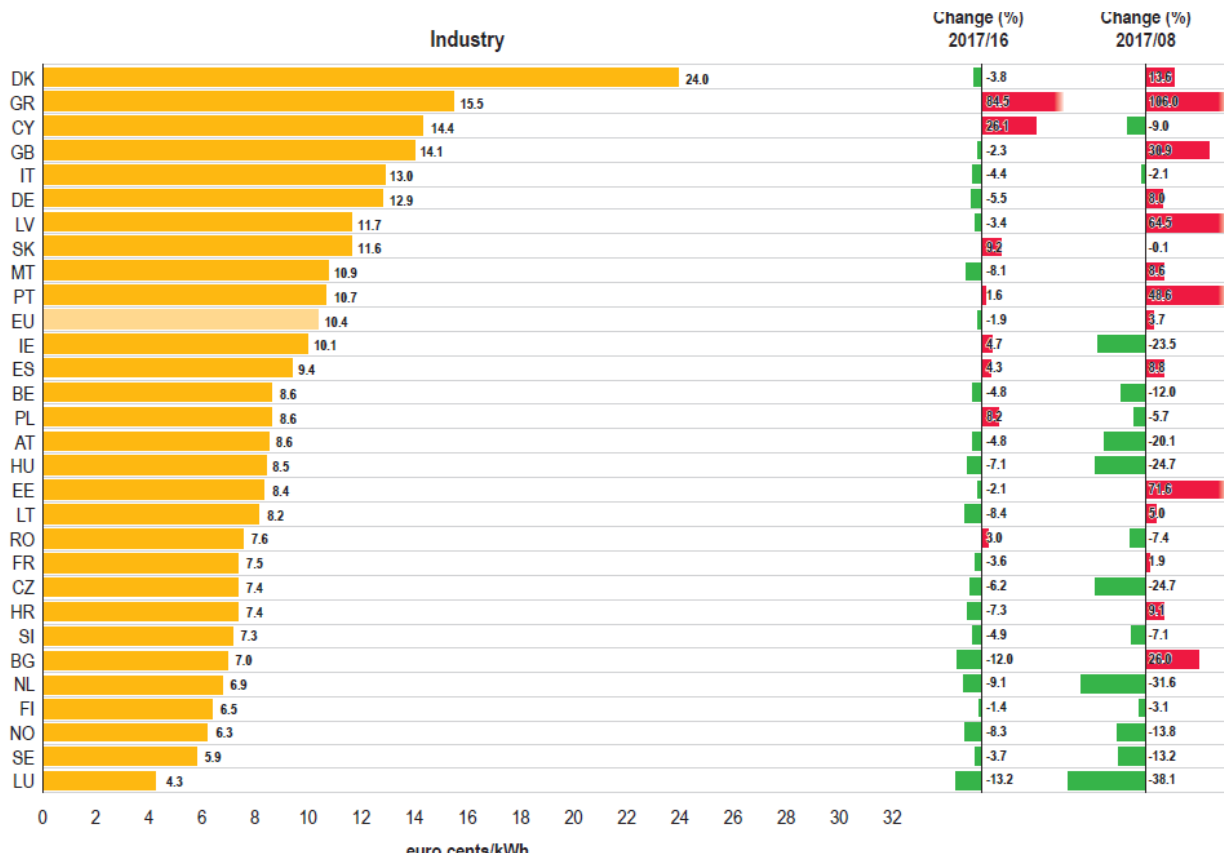


Figure 1.28 – Final electricity prices for household consumers in the EU MSs and Norway in 2017 (eurocents/kWh) and changes compared to 2016 and 2008 (%).

Main components of the electricity prices are energy costs (cost of purchasing electricity on the wholesale market, suppliers' operating costs to run the business, including sales and billing, and profit margin), network costs (transmission and distribution losses, system operation costs (excluding imbalance charges) and metering and meter rental), RES charges (levies for government policies to support renewable energy sources), VAT and other taxes and charges.

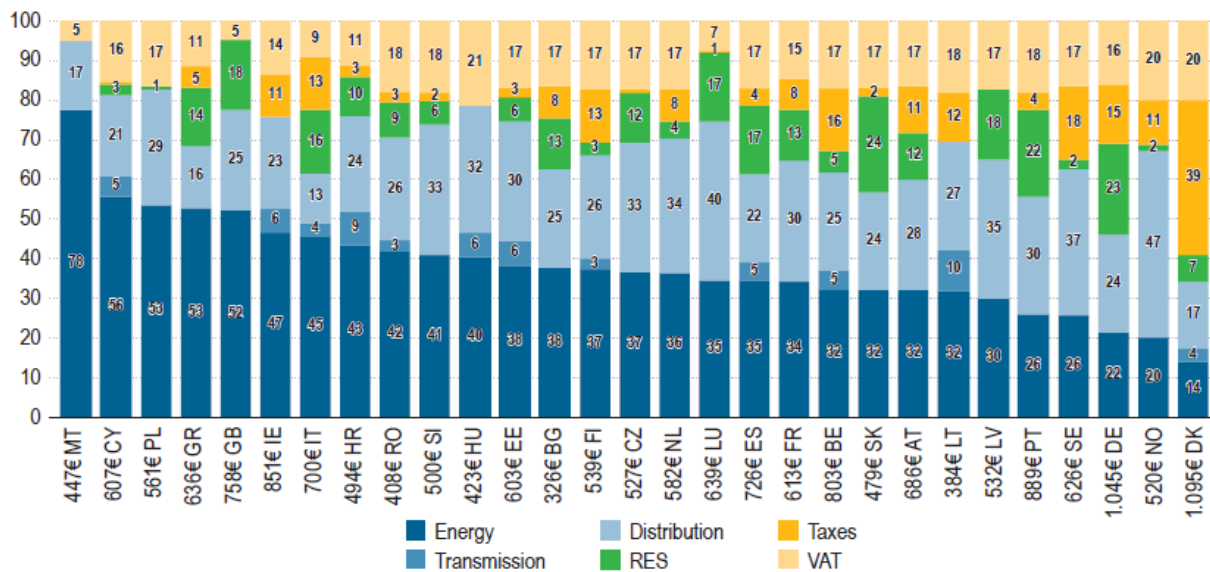


Figure 1.29 – Breakdown of incumbents' standard electricity offers for households in capital cities–Nov/Dec 2017 (%)

The composition of the final electricity bill for household consumers are indicated in the above figure and it varies greatly across countries. The energy component accounted for 78% of the final bill in Malta, but only for 14% in Denmark. The share of network charges in the final price was the highest in Norway, where they accounted for 47% of the standard incumbent offer, and the lowest in Italy and Greece, accounting for 17% of the final price. RES charges accounted for more than 20% in the total incumbent offer in Germany, Portugal and Slovakia, while the retail electricity markets in Hungary, Denmark and Norway had the highest share of VAT in the final price.

Development of the medium household and industry prices (electricity prices charged to the customer) for chosen countries (Germany, Italy, Portugal, Norway, UK and Turkey) are indicated in the following two figures⁸². Electricity prices for household consumers are defined as the average national price in Euro per kWh including taxes and levies applicable for the first semester of each year for medium size household consumers (Consumption Band Dc with annual consumption between 2500 and 5000 kWh).

Electricity prices for industrial consumers are defined as average national price in Euro per kWh without taxes applicable for the first semester of each year for medium size industrial consumers (Consumption Band is with annual consumption between 500 and 2000 MWh).

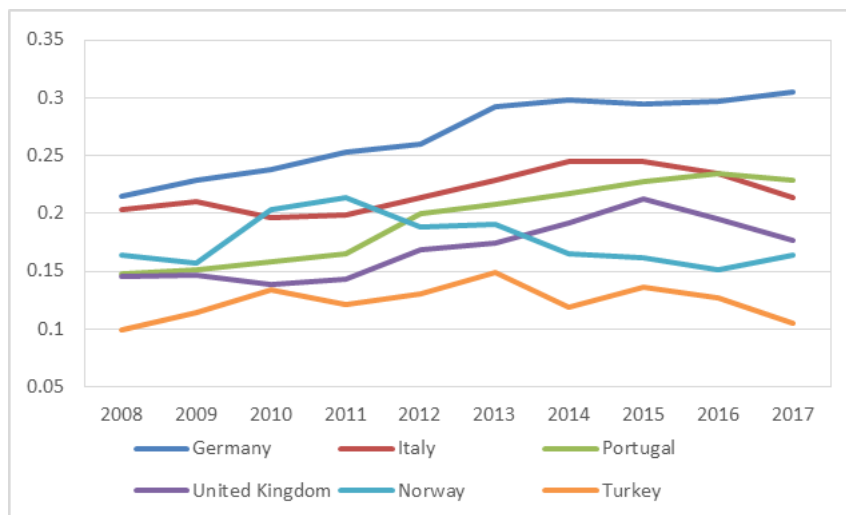


Figure 1.30 – Electricity prices charged to medium household customer (€/kWh)

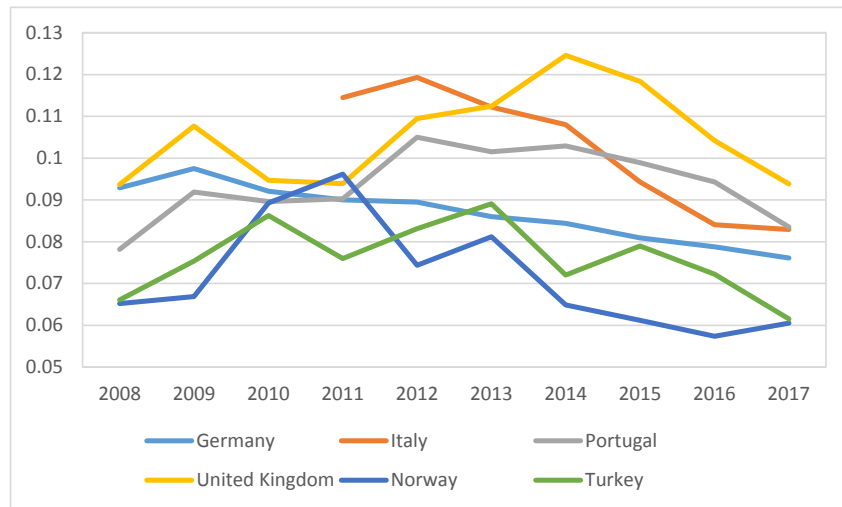


Figure 1.31 – Electricity prices charged to medium household customer

Supplier of Last Resort

EU Directive⁸³ states that “Member States shall ensure that all household customers, and, where Member States deem it to be appropriate, small enterprises, enjoy universal service, namely the right to be supplied with electricity of a specified quality within their territory at competitive, easily and clearly comparable, transparent and non-discriminatory prices. To ensure the provision of universal service, Member States may appoint a **supplier of last resort**.”

Most of the EU member states have implemented a Supplier of Last Resort (SOLR) mechanism covering a variety of functions, amongst which the establishment of a precaution mechanism for the event of a supplier or DSO failure is the most widespread across Europe. This is, for instance, the case when a supplier goes bankrupt or the license of a supplier or DSO is revoked. In most of the member states, the NRA sets the tariff or the law stipulates the tariff levels or the SOLR proposes a price to the NRA for approval or must follow a pre-defined framework. (e.g. a price range, a standard price for any of its conventional products). SOLR energy prices tend to be higher than the prices paid by consumers served by non-SOLR suppliers in the majority of member states.



Figure 1.32 – SoLR energy price comparison to conventional energy prices in EU MSs– 2017

This subject will be further detailed in Task 6 (Preparation of Regulatory Measures and Tariff Structure for SoLR in Turkish Electricity Market).

Vulnerable Consumers

EU Directive⁸⁴ states that “(1) Member States shall take appropriate measures to protect customers and shall ensure, in particular, that there are adequate safeguards to protect vulnerable customers. In this context, each Member State shall define the concept of vulnerable customers which may refer to energy poverty and, inter alia, to the prohibition of disconnection of electricity to such customers in critical times. The concept of vulnerable customers may include income levels, the share of energy expenditure of disposable income, the energy efficiency of homes, critical dependence on electrical equipment for health reasons, age or other criteria. Member States shall ensure that rights and obligations linked to vulnerable customers are applied. In particular, they shall take measures to protect customers in remote areas. They shall ensure high levels of consumer protection, particularly with respect to transparency regarding contractual terms and conditions, general information and dispute settlement mechanisms.

(2) Member States shall take appropriate measures, such as providing benefits by means of their social security systems to ensure the necessary supply to vulnerable customers, or providing for support for energy efficiency improvements, to address energy poverty where identified pursuant to point (d) of Article 3(3) of Regulation (EU) 2018/1999, including in the broader context of poverty. Such measures shall not impede the effective opening of the market set out in Article 4 or market functioning and shall be notified to the Commission, where relevant, in accordance with Article 9(4). Such notifications may also include measures taken within the general social security system.”

In summary, a vulnerable customer concept should be defined, and this concept should not impede the effective opening of the market.

1.6.2.1 Germany

In Germany, power prices are among the highest in Europe. Although wholesale electricity prices on average have been in decline in recent years, surcharges, taxes, and grid fees raise the bill for Germany’s private households and small businesses. Figure 1.33 illustrates power price composition for households.

84 Source: EU Directive 2019/944, Article 28.

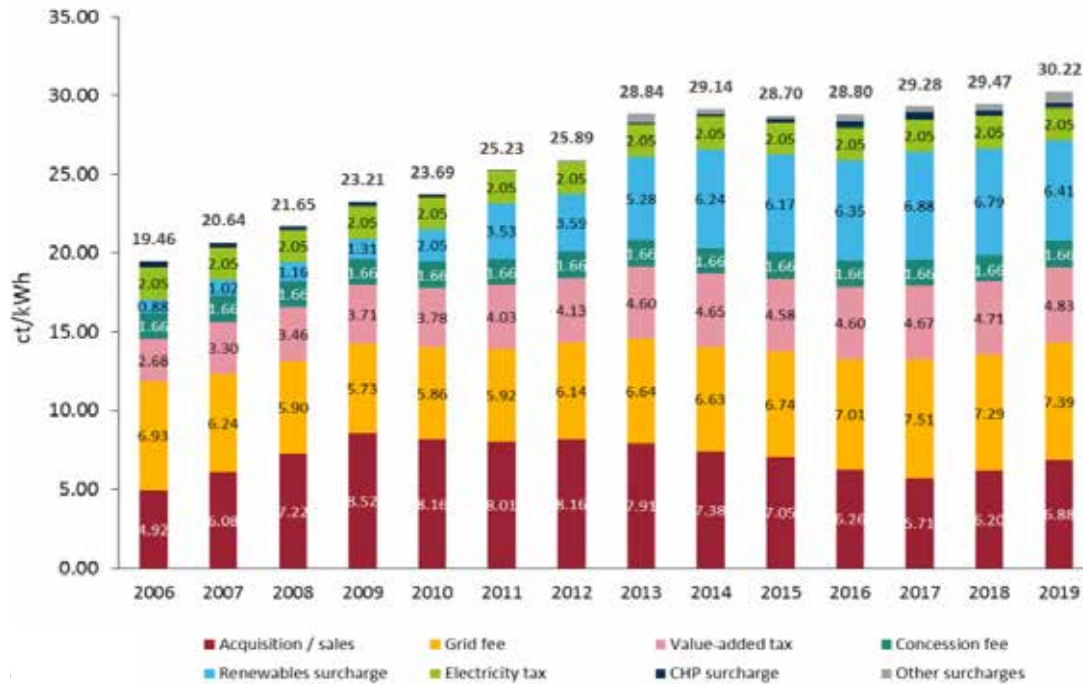


Figure 1.33 – Composition of power price for German HH using 3,500 kWh/year⁸⁵

The following observation can be made for Germany:

- Supplier's cost is the profit margin and supplier's cost of purchasing power on the wholesale market.
- Grid charges are the charges for the use of the power grid, set by the Federal Network Agency (BNetzA).
- The renewable energy surcharge (EEG-Umlage) pays the state-guaranteed price for renewable energy to producers. It fell to 6.4 cent/kWh in 2019. The renewables surcharge accounts for just over 21 percent of a household's electricity bill. It corresponds to the difference between the wholesale price and the higher, fixed price for green energy, which is guaranteed by law to renewable power producers for 20 years. Grid operators pass on the difference to consumers.
- The sales tax is 19% on the pre-tax price of electricity. It makes up 16 percent of the price after tax - 4.9 ct/kWh.
- Electricity tax is on the consumption of power, also known as ecological tax in Germany.
- Concession levy is a levy on the use of public space for power transmission lines that the utility passes on to the consumer - 1.66 ct/kWh, depending on the size of the affected area.
- Offshore liability levy: Grid operators must pay damages if they fail to connect offshore wind farms in a timely manner in order to sell the power they produce. Operators can pass these costs on to consumers through this levy.
- Surcharge for combined heat and power plants (CHP): Operators of CHP plants receive a guaranteed price on the electricity they sell. The difference between the guaranteed price and the actual price they receive on the market is financed through this surcharge
- Levy for industry rebate on grid fees: Large power consumers are partially or totally exempt from grid charges. These costs are distributed among consumers via this levy, amounting to 0.3 ct/kWh.

Commercial customers are exempt from certain components of the power price. Some levies vary according to the consumer's location. While the state directly or indirectly sets more than half of the price, it receives revenues from the two taxes and the

concession levy only. The other levies go to grid operators, renewable power producers, and conventional power generators.

In Germany, SoLR is available as a precaution for the failure of suppliers and/or DSOs. The SoLR price is generally more expensive, because the SoLR has to calculate the risk to supply everybody who fulfils the legal requirements with only few exceptions, even when the customer is unable to pay. Price is set by the SoLR without any restrictions, but it is not allowed to exceed the price of the default supply (§ 38 Sec. 1 German Energy Act).

Vulnerable customers are identified through a welfare system (they are in line with the social security system).

1.6.2.2 Italy⁸⁶

With regard to the electricity bill, a distinction is needed among the users served with greater protection as compared to the users who have freely chosen for the free market.

The users served with greater protection are the ones who have not changed their supplier or supply contract and who therefore take advantage of the conditions and prices of electricity calculated and updated by ARERA every three months.

With the electricity bill, families and small consumers served with greater protection have four main items of expenditure and these values updated every trimester.

For the first quarter of 2020, the total annual expenditure of a 'typical home user' (resident family with consumption of 2700 kWh / year and power of 3 kW), are divided as follows:

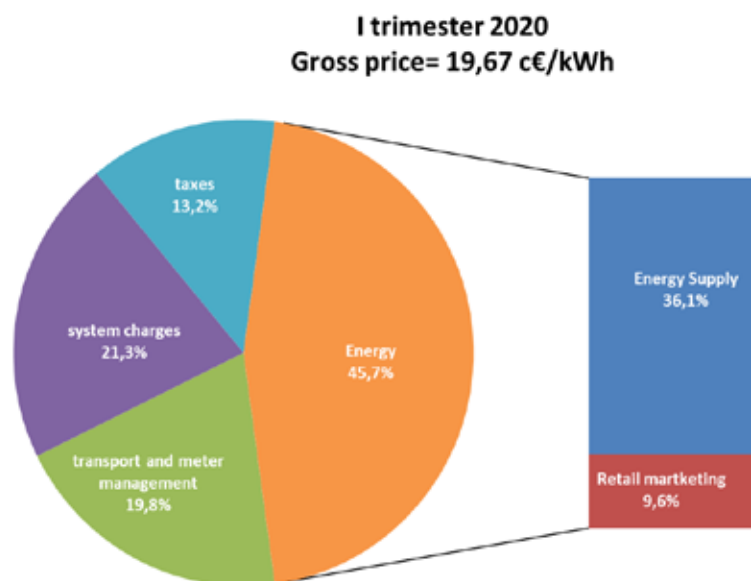


Figure 1.34 – Composition of power price for Italian HH

Energy supply and retail marketing (45.7%) are the main cost item of the home user's bill. They include all the services and activities carried out by the supplier to purchase and then resell electricity to customers.

They are divided into three main expenditure items:

- price of energy (PE);
- marketing costs;
- cost of dispatching.

The **price of energy** is the cost for the purchase of electricity, including losses on the transmission and distribution networks.

The dispatching is an essential activity to ensure the constant balance between the demand and supply of electricity in the national electricity system, or that each quantity of electricity taken from the network to meet consumption corresponds to an equal quantity entered by the production plants. This service is paid in proportion to consumption, according to a value updated every three months by the Authority for customers in greater protection; in free market contracts it can be foreseen differently.

Transport and meter management - network services (19.8%): are the electricity transport activities on national transmission networks, local distribution and include the management of the meter. For network services you do not pay a price (as for energy) but a tariff set by the Authority on the basis of precise indicators, with uniform criteria throughout the national territory (The tariff is mandatory applied by the distributor to the seller; on the free market, as a rule the seller overturns the tariff without changes to the end customer but can also apply a different price / tariff, for example in the flat rate offers).

The rates are updated annually by the Regulator to take into account inflation, the investments made by the distributors and transmission operators and the efficiency recovery targets set by the ARERA.

The difference between sales and network services is substantial. In fact, it is on sales services that the competition is played and therefore the possibility of saving according to the commercial offers of the different suppliers on the free market. On the network services, however, there is no competition because the transport and distribution of energy take place through infrastructures that cannot be replicated and that are used by all suppliers to serve all consumers.

System charge (21.3%) The general system charges are provided for by a plurality of regulations having the force of the law and ministerial implementing decrees. System charges are included in the domestic customer bill under “Network services” but at least once a year they must be detailed in a timely manner.

The revenue collected by the various operators through the application of general charges and additional components, is transferred to the Equalization Fund (CSEA) for the electricity sector which has set up, for each component, a specific Management Account to which the collected money flows. The use and management of the funds available in the management accounts is governed by provisions of the ARERA

An exception is the A3 tariff component, the revenue of which approximately 98% flows directly to the Electricity Service Operator (GSE) which bears almost all of the incentive costs financed through this tariff component and the tariff component (electricity bonus).

The general system charges are divided in the following components:

- incentives for renewable and assimilated sources (**A3**), a part are attributable to renewable sources and the rest to assimilated.
- special tariff regimes for Ferrovie dello Stato (**A4**)
- charges for the safety of nuclear power and territorial compensation (**A2** and **MCT**);
- compensation for minor electricity companies (**UC4**)

- support for system research (**A5**);
- coverage of the electric bonus (component **As**)
- promotion of energy efficiency (component **UC7**).

Taxes: The bill is used to pay the national consumption tax (excise duty), since the municipal / provincial tax surcharge has been abolished in all regions; the tax applies to the amount of energy consumed regardless of the contract or the chosen seller.

Domestic customers with consumption up to 1800 kWh enjoy a facility for the supply in the home of personal residence to reduce this tax.

VAT is applied to the total cost of the bill (cost of sales services + cost of network services + excise duties).

In Italy price for Supplier of Last Resort is set by the Regulator. Consumers that do not choose a supplier remain with a default supplier, the local DSO, which provides electricity according to a standard offer. In this case, the local DSOs buy electricity from the single buyer at wholesale market price. In 2014, the majority (80%) of households and SMEs were served on the base of this standard offer. Other consumers (i.e. other than households and SMEs) are obliged to find a supplier, but if they cannot find a suitable offer, electricity is supplied by a Last Resort Supplier, selected through an open auction.⁸⁷

In Italy, several measures aim to protect customers (vulnerable household customers, utilities, activities relating to 'public service', including hospitals, nursing homes and rest, prisons, schools and other public and private facilities that perform an activity recognized of public service as well as household customers that require electricity powered life-support equipment with severe health problems). Italian decrees establish the "social-electric- bonus" (a social support program) defined by the Government for the benefit of electricity customers whose annual income does not exceed a certain threshold (set up by the law and certified by equivalent economic situation indicator, that takes into account income, assets, the characteristics of a family by number and type). The "social bonus" is a discount (annual amount fixed the same in the free market or in the enhanced protection regime) of the electricity bill each year, dependent upon the use, number of people in the family, and climate zone.

Electric bonus is introduced by the Government and made operational by the Regulatory Authority with the collaboration of the Municipalities, to ensure savings on energy expenditure for families in conditions of economic and physical hardship and large families. Bonus is provided for families with ISEE (yearly income) not exceeding 8,107.5 €, for large families (with more than 3 dependent children), with ISEE not exceeding 20,000 € or for holders of Citizenship Income or Citizenship Pension. The value of the bonus depends on the number of members of the registry family and is updated annually by the Authority. For the year 2019 the values (economic hardship) are:

- Family number 1-2 members: € 132
- Family number 3-4 components: € 161
- Family number over 4 members: € 194

The bonus amount is discounted directly on the electricity bill, not in a single payment, but divided into the different bills corresponding to the consumption of the 12 months following the presentation of the application. Each bill shows a part of the bonus proportional to the period to which the bill refers.⁸⁸

1.6.2.3 Portugal

Portugal removed the end-user price regulation for non-household customers and the transitory period ended in 2016. As part of the phase-out process, which started in 2011 for electricity non-household customers, a transitory period was defined by the government in Portugal in order to enable customers supplied under regulated end-user prices to choose a new market supplier and move to the liberalized market. During this period, the NRA (ERSE), set a tariff (called the 'transitory tariff'), which may include an additional value, whose objective is to promote customers to switch to a market tariff.

⁸⁷ Source: ec.europa.eu, Country Reports Italy, 2014

⁸⁸ Source: ARERA, Italy

In Portugal price for Supplier of Last Resort is set by the Regulator. The end user tariffs from the last resort supplier are obtained by adding the prices of the networks access tariffs to the prices for the energy tariffs and the retail commercial tariff and are only applied to regulated market consumers. These tariffs are approved and published annually by ERSE. The End User Tariffs for Very High Voltage, High Voltage, Medium Voltage and Low Voltage Special (> 41.4 kW) were extinct in September 29th of 2010, by the Decree-Law no. 104/2010. The prices practised in the Free Market are determined by each supplier and negotiated individually with each client.

The vulnerability concept is defined in the energy sector law and corresponds to that of economically vulnerable customers which correspond to people receiving certain social welfare subsidies (social security system) with some contract limitations (e.g. contracted power). These customers have access to a social tariff.

Social tariff is used to provide financial assistance to households to pay their energy bills. Since 2016, it is automatically awarded to households receiving certain social benefits and to low income households (having an equal or lower annual income than € 5,808). The social tariff on electricity is applicable to the following:

- Solidarity support for the elders
- Unemployment benefit
- Family allowance
- Old age social pension
- Social invalidity pension

The following conditions must also be met:

- Hold an electricity supply contract, with the consumption of electricity to be intended exclusively for domestic use in permanent housing.
- Low voltage installation with contracted power less than or equal to 6.9 kVA.

The discount to be applied to the 2019 electricity tariffs corresponds to an amount allowing a 33.8% on the gross price of transitional tariffs in the regulated market (i.e. excluding VAT and other taxes, applicable contributions and or fees). Vulnerable customers who benefit from social tariff are also entitled to apply for exemption from the Special Consumer Tax on Electricity (IEC) and a partial discount on the Audio-visual Contribution (CAV). The costs arising from the application of the social tariff to electricity customers shall be borne by the electricity generation facility owners in proportion to the installed power of each power station.

1.6.2.4 Norway⁸⁹

There are no regulated prices in Norway. Customers who have not yet chosen a supplier shall, the first six weeks, be served by their local DSO (supplier of last resort) at a price that is maximum ct/kWh 0.5 excluding VAT (or ct/kWh 0.625 incl. VAT) above spot price. After 6 weeks, the supplier of last resort is obliged to set the price in a way that gives an incentive to the customers to find a supplier in the energy market.

NVE publishes an overview of the retail market prices on a weekly basis, comparing the average price of the three standard types of contracts the past week, and by presenting an estimation of the average accumulated electricity cost for the customers so far this year.



This project is funded by the European Union



As of January 2012, a mandatory support scheme to stimulate increased investments in the production of electricity from renewable energy sources was in place in Norway. The electricity producers included in the support scheme receive one electricity certificate for each MWh of renewable electricity generated. At the same time, electricity suppliers and certain electricity users are obliged to purchase electricity certificates for a specified proportion of the volume of electricity they deliver or use. The electricity certificates are traded in a common Norwegian-Swedish market, and the price of electricity certificates is determined by supply and demand. The consumers of electricity finance the scheme, as the supplier's costs of purchasing the certificates are added to the electricity price.

The actual additional cost paid by the consumers in 2017 due to the introduction of the system was determined by the price of the electricity certificates, which varied according to supply and demand. On average, a customer paid an additional 0.24 ct/kWh (including VAT) due to electricity certificates in 2017. This means that a household using 20,000 kWh of electricity in 2017, paid a total cost of approximately 48 EUR (including VAT).

There are no particular measures in the Norwegian Energy legislation aimed at protecting vulnerable customers, but they are protected through Norway's well-developed general welfare system. When the social services have guaranteed for a customer's payment, disconnection is prohibited.

1.6.2.5 UK

In UK, price for the last resort supplier is set by the supplier subject to approval/acceptance of the National Regulatory Authority.

A range of factors are taken into consideration in appointing a SoLR aside from their tariff offers, and the appointment process would usually be competitive. Examples of the factors that the NRA considers in appointing a SoLR include: suppliers' proposals to protect customer credit balances, compliance with regulatory obligations, their ability to source and absorb the costs of additional energy required by customers of the failed supplier, the robustness of their plans to handle customer queries etc.

In UK, a household is energy poor if their income is below the poverty line (taking into account energy costs) or their energy costs are higher than is typical for their household type. Vulnerable customers are identified with the welfare system that looks at age and health conditions of household members as well as their income. An energy poverty assessment is carried out (Low Income, High Cost) which also looks at the Standard Assessment Procedure (SAP) score of the property.

1.6.2.6 Turkey

In Turkey, the end-user electricity tariff has the following main components (including taxes and other deductions);

- Retail sales tariff including sourcing cost of electricity, retail sales services tariff and a gross profit margin for the electricity sold
- Distribution tariff including the costs of running the distribution system by the distribution company, including CAPEX, OPEX, loss/theft allowance, transmission tariff.
- Taxes and other deductions is an additional component comprised of VAT (Value Added Tax; 18%), Municipality tax (5% or 1%), energy contribution tax (1%), TRT tax (2%) added onto the tariffs.

Since the beginning of 2007 EMRA announced next quarter's tariff for each customer segment by active energy (one for 24 hours, one for T1 time zone (06-17 hours), one for T2 peak time zone (17-22 hours) and one for T3 time zone (22-06 hours), reactive energy, capacity & over-capacity charges, meter reading, transmission, distribution, retail service (PSH) and losses. Below table illustrates 9-year end user tariff (excluding taxes) evolution. Over the years residential and commercial tariffs converged and irrigation tariff exceeded industry (distribution connected). Although recent active energy portion of both industry tariffs (transmission and distribution connected) are the same, end user tariffs are considerably different.

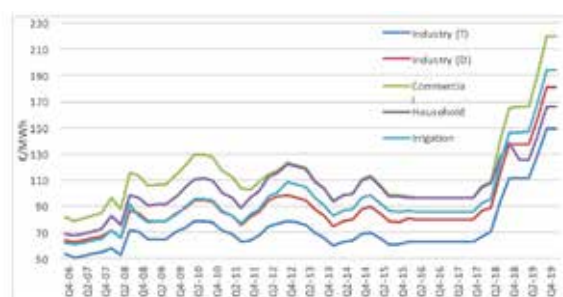


Figure 1.35 – LRT End User Tariff Evolution since 2006 (EUR/MWh)⁹⁰

In Turkey, veterans and martyrs' families have a lower tariff within Residential tariff category.

With the latest electricity market law, incumbent supplier of last resort (SoLR) is defined and secondary regulation was published in January 2018. Calculation methodology for the consumers with high amounts of consumption is as follows:

where,

- $SKTT_d$: LRT determined for invoice period d ,
- PTF_d : weighted average daily market clearing price for invoice period d ,
- $YEKDEM_d$: renewable energy support mechanism unit price determined in line with the regulation,
- KBK : Coefficient determined by the Board considering all the costs other than the energy supply cost and gross profit margin,

KBK is determined as 1.0938% and consumption above 7 million kWh/year for non-residential consumers for the year 2020 is considered as high consumption. The limit is 50 million kWh/year for residential consumers. As for the consumers with low amounts of consumption, incumbent retail price is the LRT.

Besides, customers may choose single-time tariff and multiple-time tariff. Multiple time intervals are day (06:00 – 17:00), peak (17:00-22:00) and night (22:00 – 06:00) in which the electricity prices differ.

1.7 Assessment and Recommendations

Although the general approach to determine tariffs in Electricity Distribution sector show similarities in most of the countries in Europe, the detailed methodology, parameters and incentives might differ. Some basic differences compared to Turkey can be listed in below headings.

1.7.1 Revenue Requirement Model

Revenue Cap Recommendation

Different models are used in Europe in terms of revenue requirement. In some countries such as Austria, Lithuania and the Netherlands price cap model is used whereas in countries such as Estonia, Greece and Latvia cost-based models are preferred to determine allowed revenue. Different from most of the countries, a new output-based model, namely RIIO, where the incentives are linked to the outputs, started to be used in UK in 2015-16. Reliability and availability, service for connections, social obligations, customer service, environment and safety are six main outputs in the model. RIIO is a performance-based framework to set the price controls. The model considers the future national targets and consists of incentives for satisfaction of customers, compliance with health and safety standards, contribution to environmental targets and services provided to poor and vulnerable consumers. Success of the model will be clearer after the first 4+4-year implementation period.

Like most of the EU countries, revenue cap model is implemented in Turkey to determine allowed revenues and Electricity Distribution tariffs. National tariff together with price equalization methodology is somewhat unique process due to very high loss rates in few DSOs. On the other hand, although there was a small amount of incentive-based revenue cap, whole scheme was not able to define real DSO performance. System is based on what was spent in fiscal terms rather than necessity. This was the natural outcome of data inconsistencies, lack of operational data, unreliability of network assets such as lack of GIS data and unable to

measure system quality indices (i.e. SAIDI, SAIFI) correctly. Outsourcing through own companies or third parties was also polluting photo year benchmarking process among DSOs. OPEX budgets were not related to actual assets including number of customers although almost all cost items in the general ledgers are related with those assets.

When the tariff methodologies are assessed, it is concluded that the revenue cap model with performance and quality indicators and efficiency parameters is suitable for Turkey to achieve good EU practices.

Table 1.26 – Revenue cap recommendations

Revenue Cap	
EU Practices	- Incentive Based Models - o Revenue Cap (+RIIO) - o Price Cap - o Cost Based
Turkey Practice	Revenue Cap (with performance and quality indicators and efficiency parameters)
Problem Definition and Gap Analysis	Tariff methodology of Turkey is compatible with the performance-based EU practices.
Recommendation	-

TOTEX Recommendation

In Turkey, similar to many other countries, the parameters of the distribution revenue cap are set to recover;

- OPEX requirement,
- CAPEX requirement
 - Amortization,
 - Return on capital (WACC) calculated over the average RAB value,
 - Corporate tax correction,
- Research and Development budget,
- Non-controllable costs.

OPEX is set by EMRA on an ex-ante basis for each year of the implementation period. Being a part of the revenue cap, it is up to DSOs how to spend it and all savings from OPEX stays with DSO.

Besides, there are five CAPEX categories that are network investments, network operation system investments, meter investments, environment, safety and other investments for legal liabilities and other expenditures having the characteristics of CAPEX.

Since there is a separation between OPEX and CAPEX budgets, current tariff methodology does not give a chance for DSOs to choose the optimal solution, either by OPEX or CAPEX budget.

Different from Turkey, TOTEX approach is used in countries such as UK, Germany, Austria and the Netherlands. It is a concept that is used to avoid debate about what is CAPEX and what is OPEX. Under a TOTEX approach, regulated networks are given a single expenditure allowance, with a pre-determined capitalization rate. In UK, companies have preferred CAPEX solutions historically,

as the cost was capitalized and increased the RAV. However, together with the greater investment anticipated in coming years, and with the smarter solutions for managing and developing electricity grids, there has been an increasing risk that inappropriate CAPEX investments are made so the new model was introduced.

Under the TOTEX approach, when companies spend money on a solution, the same percentage is capitalized irrespective of whether that solution involves OPEX or CAPEX. This means that the companies are more likely to use the overall cost-effective solution. For example, the TOTEX approach might encourage the companies to use maintenance to avoid replacing an asset or use demand-side management to avoid installing new capacity. Ofgem stated that TOTEX incentive mechanism has provided a powerful incentive to encourage smart alternatives in UK.

It is advisable to be inspired by certain RIIO approaches and use the fourth implementation as a transition period to create a sustainable, quality driven and customer centric Electricity Distribution sector. Therefore, it is recommended that the TOTEX approach should be applied in at least certain areas such as IT, vehicles, buildings and network rehabilitation/replacements. Application of this approach in some fields might be a solution for a rational decision-making process between CAPEX and OPEX to increase cost efficiency in the overall DSO quality performance. Also, it should be DSO's decision whether to operate the grid by either CAPEX or OPEX. Technological developments also close the gap between OPEX and CAPEX in some areas such as: data management, smart remote meter installations versus -labor intensive- manual meter reading.

Table 1.27 – TOTEX related recommendations

TOTEX	
EU Practices	- TOTEX approach is used in countries such as UK, Germany and Netherlands.
Turkey Practice	- OPEX and CAPEX is used separately.
Problem Definition and Gap Analysis	- Network operations may be done by OPEX or CAPEX. For example, meter reading can be done by metering staff or smart meter installations, and network replacement costs may be lowered by maintenance expenditures. - Current tariff methodology do not give chance for DSOs to choose the optimal solution, either by OPEX or CAPEX budget.
Recommendation	- TOTEX approach could be experienced in certain areas such as IT/OT, vehicles, buildings and network rehabilitation/replacements.
Comments	- This approach in some fields might be a solution for rational decision-making process between CAPEX and OPEX to increase cost efficiency in overall DSO quality performance. - It should be DSOs decision whether to operate grid by CAPEX or OPEX.
Related Regulations to be Amended	- Electricity Market Tariffs Regulation - Communiqué on Regulation of Distribution System Revenue

Capacity Increase Investments

In Turkey, CAPEX budgets are approved by EMRA at the beginning of the tariff period. As capacity increase CAPEX is driven by external parameters, it is recommended that this budget should not be limited, as treated like non-controllable cost items (i.e. legal and environment investments, expropriation costs, etc.).

Table 1.28 – CAPEX related recommendations

CAPEX	
EU Practices	- Investment plans are prepared by DSOs and approved by regulators.
Turkey Practice	- Investment plans are prepared by DSOs and approved by regulators.
Problem Definition and Gap Analysis	- Methodology is compatible with the EU. - However, since the capacity increase investments are larger in Turkey compared to EU countries, most of the CAPEX is used for network expansion rather than replacement and refurbishment.
Recommendation	- It might be considered to reclassify capacity increase network investments as uncontrollable item like environment and legal investments.
Comments	

Related Regulations to be Amended	- Procedures and Principles on the Electricity Market Distribution System Investments

Business Plans

Also, regardless of the revenue requirement model, DSOs should prepare well-justified Business Plans before the implementation periods, as a good EU practice. In these plans, DSOs should explain their previous activities and related costs, achievements (outputs) of the activity, forecasts for the activity and cost projection, uncertainties and risks for the activities, financing expectations for the following period (equity/debt ratios), impact on customer bills, etc. These Business Plans help EMRA to compare DSOs on activity basis, determine DSO-specific costs or activities and normalize costs between tariff periods (eliminating non-periodic costs, and adding new costs arising in the new tariff period). For instance, due to the age profile of the meters, replacement of 10-year old meters may be more in one tariff period and less in the following period. DSOs explain these situations in their Business Plans, indicating that previous expenses do not reflect the future expenses.

Table 1.29 – Business plan related recommendations

Business Plans	
EU Practices	- Detailed Business Plans in UK
Turkey Practice	- There is no business plan liability and no standard template
Problem Definition and Gap Analysis	- There are costs which do not occur in the past but will occur in the future. Also, due to technological changes, past expenditures may not give signal for future expenses. - Due to different needs of the DSOs, other than the common methodology, specific needs of the DSOs should be evaluated based on their justifications. - Business Plans should be prepared by the DSOs which includes, cost distribution between activities, efficiency plans, investment plans, loss targets, quality targets (technical and commercial), smart grid road maps, conditions assessment of their network, and including cost-benefit analysis for additional OPEX requests.
Recommendation	- Business Plan requirement should be defined (see Annex 9 for a possible template).
Comments	- There is currently no business plan liability and no standard template in Turkey, whereas it can be found in the UK for instance.
Related Regulations to be Amended	- Electricity Market Tariffs Regulation - Communiqué on Regulation of Distribution System Revenue

Cost Accounting

There are four main activities that the DSOs are responsible from;

- Network operations (O&M)
- General (Street) Lighting operations (O&M)
- Meter operations (meter reading, connect/disconnect, meter replacement)
- Non-technical loss operations

Within the context of performance-based tariff regulation, account unbundling is recommended to compare the efficiency of DSOs by activity groups. Since the drivers of each operation is different; separate DEA models may be used for each activity.

In EU practices, metering responsibility may be with DSOs or the suppliers. Therefore, it is a good practice to unbundle the metering operations account from the other DSO operations. This will also allow fully unbundling this activity from DSO operations and make a competitive market for this activity, in case there is a policy in this context. By this way, all metering activities (electricity, natural gas, water, etc.) may be done by a new license holder. Accounting unbundling requires change in communiqué level, while license unbundling requires change in Energy Market Law in the licensing terms, namely Article 9.

General lighting operations are done by the municipalities in EU practices in contrary to DSOs in Turkey. General lighting activities differ from the network operations, such as:

- Failure types are different (generally armature and lamp related failures for general lighting),
- Quality parameters are different (general lighting failures do not affect customer interruption (SAIDI/SAIFI),

Therefore, account unbundling in this activity will help EMRA to compare DSOs for network operations expenses and achievements.

Non-technical loss operations are also different from network operations and metering activities. In EU practices, DSOs or suppliers are responsible for the losses. For this reason, accounting unbundling will be a good practice for Turkey. By this way, direct costs of losses (dedicated loss personnel, vehicles, fuel, equipment, etc.) will be monitored easily. OPEX costs of high-loss DSOs will be easier to compare with the other DSOs.

Table 1.30 – Cost Accounting related recommendations

Cost Accounting	
EU Practices	- There is cost accounting for meter operations
Turkey Practice	- There is no account unbundling for Distribution activities
Problem Definition and Gap Analysis	- For efficiency analysis and OPEX comparisons, due to different cost drivers for the activities (i.e. number of customers for metering operations, number of street lighting lamps for general lighting faults, etc.) and different network structures of the DSOs, an efficient comparison cannot be done by comparing total expenditures with total network assets.
Recommendation	- Costs related to below activities should be separately hold in DSO accounting: - o Meter operations (meter reading, connect/disconnect, meter replacement) - o Non-technical loss operations, - o Street Lighting operations, - o Network operations,
Comments	
Related Regulations to be Amended	- Electricity Market Tariffs Regulation - Communiqué on Regulation of Distribution System Revenue

Regulatory Period

In good EU practices, regulatory periods are between 4-5 years. Shorter periods are not sufficient for efficiency incentives and longer periods are not predictable. Therefore, fixed medium periods or longer periods with parameter updates may be applicable. In UK, 8-year period is applicable with parameter updates in the 4th year however Ofgem also considers shortening the regulatory period to 5 years for the next tariff period. In Turkey, regulatory periods are not fixed with legislation and determined by EMRA Board decisions. In practice, up to date, tariff periods are determined as 5-year periods. Therefore, Turkey can be considered compatible with good EU practices for this subject.

Table 1.31 – Regulatory period related recommendations

Regulatory Period	
EU Practices	- 8 years in UK and Italy (4+4), to be changed to 5 years - 4 years in Spain, Sweden, France - 5 years in Norway, Germany, Austria, Denmark
Turkey Practice	- 5 years
Problem Definition and Gap Analysis	
Recommendation	- 5-year tariff period is compatible with the EU practices.
Comments	- Longer periods are better to reduce the risk of regulation for the DSOs, while it increases uncertainty and revising ability to adapt new conditions for the regulator. Shorter periods reduce the effects of efficiency gains for the DSOs.
Related Regulations to be Amended	

Renewal/Refurbishment Investments

Investments for renewal of aged network components could be set proportional of existing asset size with their theoretical life expectancy as explained in UK example (see Annex 5.2.6). The cost of the renewal/refurbishments, if the asset's economical life is completed (i.e. older than 30 years) is recommended to be paid pass-through (based on well-defined unit pricing methodology for KETs⁹¹). By this way, unforeseen costs arising from renewal/refurbishments will be determined. Also, since the DSOs will replace the assets earlier than faults, continuity of supply indicators will improve.

To summarize, in order to have a sustainable and economically viable distribution sector, regulation should drive the stakeholders (DSOs) to an equilibrium level between profitability and being utility. Therefore, RIIO model in UK could be a role model in many aspects by introducing TOTEX and output-based approach together with encouraging innovations.

1.7.1.1 *Regulatory Asset Base*

In all of the EU countries, network assets belong to DSOs, whether they are state-owned or private. To convert a finite (30 years) distribution financial model into a sustainable one, Turkish Government may consider transferring assets to willing DSOs through a long-term payment term linked to CPI escalation in local currency. This way DSOs would get equity funds to pay back existing hard currency acquisition loans or long-term CAPEX financing.

RAB consists of unamortized network assets, expropriation costs, buildings, vehicles which were constructed or acquired by DSOs and approved by EMRA as CAPEX at the end of each year. Amortization period has been set as ten years. Third party assets are not included in the RAB, however, operating costs related to specific ones are included in overall operating costs since 2013 after the new Law No: 6446. Closing RAB is carried over to the following year by CPI.

In RAB consideration, CAPEX classifications may need to be redefined. Due to high rate of urbanization, domestic migration, transformation town centers with safer and up to date building standards and ever-changing zoning instructions make capacity increase through CAPEX planning very difficult. EMRA might consider reclassifying capacity increase network investments as uncontrollable item like environment and legal investments still applying unit price process and instruct DSOs to invest in refurbishment of the network which exceeds economic life expectancy with a predetermined budget as a percentage of their network replacement value (i.e. minimum 2%). In this way, instead of entire line replacements, partial enhancements would strengthen aged networks with better performance.

As defined in the revenue requirement model section, like in UK, TOTEX approach in some fields might be a solution for rational decision-making process between CAPEX and OPEX to increase cost efficiency in overall DSO quality performance. IT, vehicle and building acquisitions, smart meter deployments (roll-outs) or any asset type which has economic life time shorter than regulatory amortization period could be potential areas for TOTEX application.

To incentivize DSOs to utilize aged network infrastructure (over 30-year age) longer rather than replacement, additional RAB calculations might be considered. Certain percentage of replacement value of over 30-year assets could be added to the initial 2021 RAB (the fourth implementation period's first year). Following each year, 3.33% of the total network asset replacement value in real terms less replacement/refurbishment CAPEX in the year "t-1" shall be calculated and the same percentage shall be added to the initial RAB of that year.

91 KET: Small size network addendums.

Table 1.32 – Regulatory Asset Base related recommendations

Regulatory Asset Base	
EU Practices	- In all the EU countries, network assets belong to DSOs (state-owned or private).
Turkey Practice	- Assets do not belong to the DSOs. Whole system is 30-year concession.
Problem Definition and Gap Analysis	- (see Annex 5 – Revenue Cap Calculations and Data Envelopment Analysis in Norway)
Recommendation	- Assets are recommended to be transferred to DSOs.
Comments	- Natural Gas Distribution network belongs to the DSOs. - Transmission assets belong to TEIAS (TSO).
Related Regulations to be Amended	- <i>Kamu İktisadi Teşebbüsleri Hakkında Kanun Hükmünde Kararname</i> (dated 08/06/1984 with number 233), Annex A - Law on the Privatization Implementations (<i>Özelleştirme Uygulamaları Hakkında Kanun</i>), Article 15 - Electricity Market Law Article 9/6

1.7.1.2 Rate of Return

If there is no or little fluctuation in financial parameters (like the interest rates, inflations rates, etc.) to calculate the cost of capital, WACC can be determined one-time for each regulatory period. However, countries facing volatile inflation rates, the introduction of a dynamic WACC applications may improve this situation. In Turkey, WACC is also static and constant for the determined tariff period. However, in case of unexpected financial situations, it may be updated by an EMRA Board Decision. For Turkey, issues encountered by static WACC might be listed as volatile financial environment compared with EU countries, long-term financial sustainability and long-term foreign currency-based financing.

In Turkey, due to lack of long-term funds for CAPEX with fixed rates in TL currency, it is becoming common practice to borrow in foreign currencies. This adds further complexity in the DSO business for financial sustainability. Therefore, a WACC mechanism which satisfies a foreseeable future is required.

For Turkey, it is recommended to define an updating mechanism for WACC values. This will make the future WACC foreseeable for DSOs and remove the uncertainty for investments. For example, based on the long-term financial parameters, which are used to calculate the WACC, the WACC may be calculated annually and if there is a need for reduction/increase (change above a threshold value), it can be updated automatically.

Table 1.33 – Dynamic WACC related recommendations

EU Practices	- Dynamic WACC is used in Portugal when there were economical fluctuations
Turkey Practice	- WACC is determined at the beginning of the tariff period and there is no automatic update mechanism within the period, in case of the changes for financial parameters. However, EMRA may revise the WACC in any time by Board Decision.
Problem Definition and Gap Analysis	Issues encountered by static WACC: - Volatile financial environment compared with EU countries. - Long-term financial sustainability. - Long-term foreign currency-based financing.
Recommendation	- Dynamic WACC which is updated by financial parameters might be implemented to secure long-term financial sustainability (see Annex 8)
Comments	
Related Regulations to be Amended	- Electricity Market Tariffs Regulation - Communiqué on Regulation of Distribution System Revenue

1.7.1.3 Depreciation

Depreciation durations are parallel with the average economical lifetime of the network assets in nearly all of the EU countries. For instance, in Germany depreciation ratio varies between 1.5% and 4% (e.g. lines & cables: ~2%, stations: ~4%). In Czechia, the ratio is as follows: for buildings 2%, overhead lines and cables 2.5%, transformers HV 4% transformers MV, LV 3.3% metering devices 6.6%. On the other hand, single 10-year depreciation for all network assets is used in Turkey. Considering need for higher CAPEX in the fourth implementation period due to additional needs for replacement of older assets, e-mobility, smart grid and technology, CAPEX portion of the end user tariff may urge EMRA to extend the depreciation period. Depending on Nation's financing environment, WACC and RAB considerations, depreciation of such long-life network assets could be extended to 30-40 years instead of 10 years to reduce CAPEX portion of end-user distribution fee and allow more needed CAPEX for those items.

Table 1.34 – Depreciation related recommendations

Depreciation	
EU Practices	- Depreciation durations are parallel with the average economical lifetime of the network assets (i.e. 30-40 years) - Tendency to assign different depreciation periods for each asset groups.
Turkey Practice	- Single 10-year depreciation for all network assets.
Problem Definition and Gap Analysis	- Depreciation periods should be compatible with the economic lifetime of the network assets. - However, due to the lack of long-term loans, depreciation period should also consider the available payment periods for the bank loans.
Recommendation	- Depreciation period should be extended. - For IT/OT investments depreciation periods should be set shorter.
Comments	- Depending on Nation's financial environment, WACC and RAB considerations, depreciation of such long-life network assets could be extended to reduce CAPEX portion of end-user distribution fee and allow more needed CAPEX for those new items as well as capacity increase and refurbishment investments.
Related Regulations to be Amended	- EMRA Board Decision for the relevant tariff period

In both EU practices and Turkey, straight line depreciation is used. Therefore, depreciation method is compatible with the EU practices.

1.7.1.4 Connection Fees

In Turkey, one-time connection charges are applied as is common in other EU countries. However, deep or shallow connection charges differ with EU practices. In some countries, connection charges do not include network reinforcement costs (shallow pricing), while in others new connection customer also shares the burden of these costs.

As a good practice, like in UK, each DSO may prepare their own connection fees methodology and submit to EMRA for approval. The methodology should consist of the below cost categories:

- Connection asset costs (which will be equal for all DSOs based on EMRA unit prices),
- Network reinforcement costs (new connection application specific),
- OPEX costs related to new connection application (which may be similar for all DSOs),
 - DSOs must utilize OPEX for each connection requirement (accepting applications, document control, site visits for energy permission, reviewing projects, distribution connection agreement works, final acceptance), connection fees should also reflect these costs. By this way, these costs are met by the new connection applicant and not socialized.

Using deep connection charges and taking a part of the network reinforcement costs from the new customer, helps to optimize connection points. If there is spare grid capacity in a region, connection charge will be lower. If there is no spare capacity and a need for reinforcement, connection charge will be higher. This way, new connection demands will be incentivized to locate in spare capacity regions.

Table 1.35 – Connection fees related recommendations

Connection Fees	
EU Practices	- One-time connection charges are applied. - Fees are deep or shallow. - Service fees are also included depending to regions.
Turkey Practice	- One-time connection charges are applied. - Fees are shallow. - Service fees (OPEX costs) are not included in the fee.
Problem Definition and Gap Analysis	- Network reinforcement costs are socialized and there is no incentive for optimal usage of the grid. - OPEX costs for new connections is not charged to the applicant but socialized.
Recommendation	- Each DSO might prepare their own connection fee methodology and submit to EMRA for approval. - Connection fees should include network reinforcement costs (and not the same for all new customers). - Connection fees should include the related OPEX costs.
Comments	- Every customer should bear the cost of its own connection fees, both CAPEX and OPEX of the connection, minimizing socialization.
Related Regulations to be Amended	- Electricity Market Law, Article 17/6/a (indicating connection charges do not include network investments)

1.7.1.5 Performance Indicators

In terms of regulations, in Turkey, performance indicators are defined by separate EMRA Board Decisions and there is no single regulation that contains these rules together. First recommendation could be to cover all performance indicator bonuses (and penalties) in a single communique.

For the supply continuity, SAIDI and SAIFI are the most common used indicators in EU countries and these indicators may continue to be utilized in Turkey also. However, it is a known issue that network performance indicators in Turkey are way above those in average EU figures. Due to lack of sufficient monitoring infrastructure, it is recommended to apply these two indices only on medium voltage levels. Number of customers fed from each transformer and connectivity of each meter and related distribution transformer or MV feeder (for MV meters) correctly by DSOs should be recorded and confirmed by DSO's GIS data.

As an alternative, to give more importance on the lost energy rather than the number of customers, ASIDI and ASIFI can be utilized. These two indicators are mainly used in Germany, Sweden and Austria and indicates the average interruptions weighted by the rated power. In addition, structural differences such as peak load and geographical area are taken into account in when calculating the reference value. By this way, interruption of an industry customer is given more weight than a household customer.

To improve overall quality of supply, monitoring SAIDI/SAIFI at MV grid should also be the focus. For instance in Portugal the incentive for the DSO intends to improve the continuity of supply of the MV customers. This incentive consists of 2 components with different objectives, where the first objective is to improve the overall continuity of supply and the second is to improve the continuity of supply of the worst-served 5% of customers. Together with ASIDI and ASIFI, improvement scheme for the worst served customers should also be implemented as the existing compensation method.

Table 1.36 – Recommendations with respect to Supply Continuity Indicators (Clustering Regions)

Supply Continuity Indicators (Clustering Regions)	
EU Practices	- Unique supply quality indicators are used.
Turkey Practice	- Unique supply quality indicators are used, where high-loss regions are exempted from certain liabilities.
Problem Definition and Gap Analysis	
Recommendation	- Clustering DSO regions for KPIs. - Implementing VOLL based performance indicators in addition to SAIDI, SAIFI for industrial/commercial regions (see Annex 5.6).

Comments	- In order to improve the overall performance, 21 regions could be grouped into categories (i.e. high loss, high consumption, other) to differentiate KPI target setting methodology accordingly.
Related Regulations to be Amended	- Regulation on the Service Quality of Electricity Distribution and Retail Sales

In Turkey, outage data reliability for LV network is not enough to be used as a performance indicator. Therefore, as a first step, MV SAIDI/SAIFI is recommended to be used. Also, GIS network data and Outage Data correctness may be introduced as a performance criterion. After the GIS and Outage data is corrected, then LV SAIDI/SAIFI should be added to the performance criteria.

Table 1.37 – Recommendations with respect to Supply Continuity Indicators

Supply Continuity Indicators	
EU Practices	- In EU, MV indicators are commonly used. Some EU countries also use LV indicators based on the data measurement infrastructure. - SAIDI, SAIFI (most common), ASIDI, ASIFI, CAIDI, T-SAIDI, T-SAIFI, AIT, ENS, TIEPI) are used.
Turkey Practice	- Both LV and MV supply continuity indicators are used.
Problem Definition and Gap Analysis	- Outage data reliability in LV network.
Recommendation	- SAIDI and SAIFI only for MV in the 4 th implementation period. LV is included for the 5 th implementation period (see Annex 5.6).
Comments	- Network faults affecting the most customers are arising from MV network. LV faults are more local and affects less customers. Therefore, firstly MV faults should be targeted to reduce. - Number of customers fed from each transformer and connectivity of each meter and related distribution transformer or MV feeder (for MV meters) correctly by DSOs should be recorded and confirmed by DSO's GIS data.
Related Regulations to be Amended	

While calculating the performance indicators, force-majeure events (i.e. severe weather conditions) should be excluded to normalize the indicator and compare DSOs. In the UK, severe weather conditions are defined as:

- 8 times the average High Voltage (HV) and above daily average incident rate (category 1),
- 13 times the mean HV and above daily average incident rate (category 2),

Severe weather events that cause the daily higher voltage fault rate to go beyond the category 1 threshold of eight times each DNO's daily average higher voltage fault rate are excluded from the indicator calculation. Furthermore, exceptional events that effect 25,000 or more customers and/or cause 2 million or more customer minutes lost are also excluded from.⁹²

Table 1.38 – Recommendations with respect to “worst days” methodology

Force Majeure Methodology	
EU Practices	Force-majeure (severe weather) conditions are defined as excluded from performance indicator calculations. In UK, if the failure count is more than 8 times the average failure rate, the event is defined as exceptional event.
Turkey Practice	- No methodology for exceptional events.
Problem Definition and Gap Analysis	- Extreme cases may occur out of DSOs ability to satisfy performance indicators. - Climate change results micro disasters (short-term and local)
Recommendation	- An exceptional events definition should be defined, like UK case. - Action plans to reduce the affects of worst days may be submitted to EMRA.
Comments	
Related Regulations to be Amended	

Street Lighting: Currently, street lighting performance is satisfied by penalties for each out-of-order bulb.⁹³ If a bulb is not repaired within 24 hours in urban area and 48 hours in rural areas, there is a penalty of 707 TL for each bulb.⁹⁴ In EU countries, street lighting is generally in the responsibility of municipalities. In the UK, the faults are aimed to be repaired within 2 weeks, if there is no emergency. If the fault is caused by the distribution system, due time to repair the single unit is 25 days. Therefore, the time limit for this repair should be extended. Besides, instead of using a case by case penalty, there should be defined a performance indicator for street lighting. Based on the target performance, DSO revenue cap should be decreased.

Table 1.39 – Recommendations with respect to street lighting

Street Lighting	
EU Practices	- In EU countries, street lighting is generally in the responsibility of municipalities. If the fault is caused by the distribution system, e.g. in UK due time to repair the single unit is 25 days
Turkey Practice	- Street lighting performance is satisfied by penalties for each out-of-order bulb. If a bulb is not repaired within 24 hours in urban area and 48 hours in rural areas, there is a penalty of 707 TL for each bulb.
Problem Definition and Gap Analysis	- Inefficiency in operational costs for street lighting.
Recommendation	- Application of street lighting performance criteria, based on the criticality of the failure (such as number of lamps and HSE cases)
Comments	- The time limit for repair regarding street lighting might be extended. Instead of using a case by case penalty, there should be defined a performance indicator for street lighting. Based on the target performance, DSO revenue cap should be decreased. - Alignment is needed between cost-benefit quality indices of street lighting and penalty calculations.
Related Regulations to be Amended	- Electricity Market Law, Article 16/8

Commercial Quality: In EU, there are various indicators used to measure commercial quality. For instance, CENS is a measure of the calculated value of lost load for the customers. It is used in Norway within the scope of allowed revenue calculations. It is an incentive for DSOs to maintain their assets properly and to ensure necessary investments to avoid power outages at a socioeconomic efficient level. On the other hand, in Germany the price of quality is estimated by using a macroeconomic approach which is used to estimate the value of lost load (VoLL).

In Norway, the customers' costs related to interruptions are detected through nationwide surveys and in UK within the scope of Social Obligations and Customer Service incentive, a customer satisfaction survey is performed.

Customer satisfaction should also be measured by proper independent surveys in Turkey instead of the number of letters arriving to EMRA. Bonus and penalty ratios should be defined for the revenue cap.

93 EML Article 16/8

94 General Lighting Regulation, Article 25/3 (penalty is increased by EMRA each year by revaluation rate)

Table 1.40 – Recommendations with respect to commercial quality

Commercial Quality	
EU Practices	- Time for response to customer claim for network connection - Time for connecting new customers to the network - Time for disconnection upon customer's request - Time for a switching of supplier - Response time to customer complaints - Response time to customer enquiries - Response time to customer voltage and/or current complaints - Response time to customer interruption complaints - Call Centers service level - Waiting time in case of personal visit at client centers - Time for giving information in advance of a planned interruption - Time for cost estimation for simple works
Turkey Practice	Indicators used are: - Response time to customer claims - Call center response time limits - Time for connecting new customers to the network - Time for giving information in advance of a planned interruption
Problem Definition and Gap Analysis	- There is no measure for systematic customer satisfaction.
Recommendation	- A methodology for customer satisfaction surveys should be prepared and defined as an indicator for commercial quality. - Customer satisfaction should be measured by proper independent surveys instead of the number of letters arriving to EMRA. Bonus and penalty ratios could be defined for the revenue cap.
Comments	- Client satisfaction surveys are tools used by Energy sales providers to better redesign the service. In contexts where the market is liberalized, network operators use complaints as an indirect indicator of satisfaction. It is understood that being the operators certified according to ISO 9001, the choice of the most suitable indicators to measure customer satisfaction is left to the choice of the individual company.
Related Regulations to be Amended	- Regulation on the Service Quality of Electricity Distribution and Retail Sales - Consumer Services Regulation

1.7.2 Efficiency

In Turkey, DEA is used for the calculation of the efficiency factor, which is in theory, in line with the international practices. Different from most of the other countries, in Germany both DEA and SFA methods are used to determine efficiency scores. Input parameter is generally controllable TOTEX and output parameters are area supplied, customers connected and environmental parameters. However, in Norway, environmental variables play an important role as well. In the first stage DEA, with outputs; number of customers, length of HV network and number of substations is performed. In the second stage Z-factors, which are mountain, coastal and cold environments as well as forest environment are incorporated in the cost norm. Some other countries use simple statistical methods such as COLS (Portugal) and MOLS (Austria) in addition to DEA.

DEA analysis of EMRA depends on the previous OPEX expenditures (as input) of the DSOs and their network assets (as outputs). However, there are data problems with the inputs and outputs used in the model.

Firstly, since the quality parameters were not used until the 3rd implementation period, the achievements among the DSOs was not comparable. For example, if DSO "A" spends money on asset maintenance, its OPEX expenditure will increase compared to the other DSOs, who do not make the required maintenance in the grid. When these DSOs are compared in the DEA analysis, DSO A will become inefficient. If the DEA model input data reliability is satisfied, lost revenue from the efficiency can be compensated by the quality parameter bonuses. Since the DEA model input data reliability is not satisfied in Turkey due to lack of GIS data, while comparing the OPEX of the DSOs, total work done should also be compared. Either by activity counts (i.e. meter connect/disconnect numbers, meter replacement numbers, etc.) or by performance parameters. Because of the data problems, these methods are not suitable and should not be applied.

Secondly, reliability of the quantity of network assets may not be sufficient to be used in the DEA analysis due to lack of GIS systems. For example, if the line length of a DSO is seen to be higher than the real value, the result of the DEA will show it as a more efficient company than it is. Because of these kind of data problems in customer number, line length, transformer count, a comparison among will result in wrong results.

With the increased reliability of data collected by EMRA, it is recommended to use two-stage efficiency analysis following the example of Norway. In the first stage, a DEA model can be used where loss-free OPEX is input and composite variable scores for number of customers (both consumers and distributed generators), line lengths and number of transformers, and age index (share of network assets older than 30 years old) as outputs. In the second stage, the environmental factors, such as the area of the region, forestry area and urbanization rate can be incorporated as Z-scores to reflect the geographical differences between DSOs, by utilizing a regression model which adjusts the efficiencies calculated in the first stage. For the details, please see Annex 5.7.6.

Table 1.41 – Recommendations with respect to efficiency methods

Efficiency Methods	
EU Practices	Methodologies used are: - DEA (+ z factor correction) - SFA - MOLS or COLS - General Productivity Index
Turkey Practice	- DEA is used in Turkey
Problem Definition and Gap Analysis	- Lack of reliable input, - Lack of output (real work done) relation, - Lack of regional parameters
Recommendation	- DEA (+ regional factors correction) may be utilized.
Comments	
Related Regulations to be Amended	

Table 1.42 – Recommendations with respect to efficiency and the quality factor

Efficiency vs. Quality Factor	
EU Practices	- DEA and Quality Parameters are used separately, not affecting each other.
Turkey Practice	- DEA and Quality Parameters are used separately, not affecting each other.
Problem Definition and Gap Analysis	- Imbalance between award (QF-limited) and penalty (X factor-without limit) (see Annex 5.6)
Recommendation	- Relation between the average quality factor and average efficiency factor may be established. - DSOs that do not satisfy a pre-determined level of quality, may not be accounted in efficiency analysis
Comments	- For example, expenditure for network maintenance causes a DSO to lose in X factor calculation while it gains from the QF factor. While another DSO do not spend for maintenance and gains from X factor while losing from the QF factor. Second DSO, should not benefit more from the first DSO to incentivize QF.
Related Regulations to be Amended	- Regulation on the Service Quality of Electricity Distribution and Retail Sales - Consumer Services Regulation

Losses

Due to the high loss rates of Turkey compared to EU countries, there is a specific regulation for loss reduction “Regulation on Measures for the Reduction of Losses in the Distribution System” in the country. DSOs are responsible from losses like in Germany, Austria, Italy etc.

Table 1.43 – Recommendations with respect to loss responsibilities

Losses Responsibility	
EU Practices	- DSOs are responsible for losses - Suppliers are responsible for losses
Turkey Practice	- DSOs are responsible for losses
Problem Definition and Gap Analysis	- DSOs are responsible for losses and no change is recommended.
Recommendation	
Comments	
Related Regulations to be Amended	

To eliminate high loss rate effect on the tariff, loss-free OPEX should be considered to compare DSO expenditures. As EMRA already exempted those three high loss DSOs from several performance obligations through a special decree⁹⁵, there could be two separate DSO performance methodology: one focusing loss reduction, one focusing output (performance). Once realized losses in those three high loss regions are reduced to 8% level (current applied benchmark), the separation may be removed.

Additionally, for the following implementation period, EMRA may ask high-loss DSOs to provide their 5-year, 10-year loss reduction targets and roadmap to secure equal or lower than 8% aggregated loss ratio.

In UK, Ofgem introduced a losses incentive mechanism as part of the Electricity Distribution price control, in order to encourage distribution network areas to manage an efficient level of losses on their network. A losses reduction mechanism consisting of four components, which are license obligation, loss reduction expenditure in the business plans, annual reporting and discretionary reward (LDR), was introduced.

Similar to UK, according to value of lost energy calculations (VoLL) EMRA may provide additional bonus to those DSOs with highest VoLL figures who reduce their loss ratios. Same loss reduction in Boğaziçi region and Vangölü have quite different impact on Nation's economy. Therefore, not only loss reduction ratio, actual loss energy amount needs to be included in the process.

Table 1.44 – Recommendations with respect to losses and cost benefit analyses

Losses (Cost-Benefit Analysis)	
EU Practices	- Loss targets are determined, and DSOs are incentivized /penalized - Network losses are a pass-through to consumers - Cost of losses is part of the general revenue cap (meaning that losses are treated like any other cost component) - Project based loss incentives ▪ License obligation, ▪ Loss Strategy, ▪ Annual Reporting, - Losses Discretionary reward (evaluation of process, action plan and achievement)
Turkey Practice	- License obligation - Loss targets are determined by a predefined formula (based on last 3 years realizations), - DSOs are incentivized /penalized according to the achievements of targets. - CAPEX requirement for loss reduction is approved by EMRA (no ex-post evaluations for realizations).
Problem Definition and Gap Analysis	- There is no Loss Strategy, Annual reporting and discretionary reward mechanism.

Losses (Cost-Benefit Analysis)	
Recommendation	- Current loss target mechanism may be continued as is. (In addition to the specified other mechanisms stated in the report). - Annual action plans and related CAPEX requirements are recommended to be used for ex-post evaluation. If the stated targets are not achieved, some portion of the used CAPEX may not be accepted in RAB calculations. By this way, relation between cost and benefit may be established more effectively.
Comments	
Related Regulations to be Amended	

Network loss could be considered as DSO's carbon footprint. Environmental responsibilities for DSOs (reduction of CO₂ emissions and reduced usage of SF₆) exist in European Countries. Reduction of losses corresponds less natural gas import and less thermal generation. To help this EMRA may allow DSOs to invest in renewable energy to generate electricity up to their losses and add this additional CAPEX into their RAB or meter readings of such plants calculated by average monthly day-ahead prices added to their revenue ceilings in two quarters after.

Table 1.45 – Recommendations with respect to losses and environmental liability

Losses Environmental Liability	
EU Practices	- Environmental responsibilities for DSOs (reduction of CO ₂ emissions and reduced usage of SF ₆)
Turkey Practice	- No specific targets for CO ₂ emissions or SF ₆ gases.
Problem Definition and Gap Analysis	- Introduction of environmental responsibilities.
Recommendation	- EMRA might allow DSOs to invest in renewable energy to decrease technical losses with network operation and reduce total cost of electricity purchased by generation.
Comments	- Loss reduction is the main environmental target for the DSOs, since the lost energy increases energy generation.
Related Regulations to be Amended	

1.7.3 Network Tariffs

In general network tariffs consists of 3 main components, namely fixed costs, capacity and volume related costs. In majority of European countries, for households and small businesses, network tariffs are mainly based on energy volumes (in kWh). In Italy, network tariff is composed of from all three components, whereas in Norway, only fixed and volume components are used, in Portugal capacity & volume components are used, whereas the Netherlands uses fixed & capacity components. Network tariffs are determined by customer types and voltage levels in Turkey. Industry customers who chooses to have a set capacity, pays a fee per MW capacity per month and a lower distribution fee per kWh consumption is applied. Although the methods used in Turkey are compatible with EU countries, to manage congestions and balance the usage of distribution network, peak load charges may be applied to small and large industrial customers.

Table 1.46 – Network Tariff Composition for EU Countries⁹⁶

		0%	0-25%	25-50%	50-75%	75-100%	100%
Households	Energy Charge (%)	NL	ES, SE	NO	IE, IT, PL, PT, SK, SI	AT, CY, CZ, FR, DE, UK, GR, HU, LU, RO	
	Fixed + Capacity Component (%)		AT, CY, CZ, FR, DE, UK, GR, HU, LU, RO	IE, IT, PL, PT, SK, SI	NO	ES, SE	NL
Small industrial	Energy Charge (%)	NL	IT, LU, ES	AT, PL, SI	CZ, FI, FR, HU, SE	CY, DE, UK, GR, SK	RO
	Fixed + Capacity Component (%)	RO	CZ, FI, FR, HU, SE	AT, PL, SI	IT, LU, ES	IT, LU, ES	NL

Besides, since the share of distributed energy is growing, distributed energy will decrease accordingly. If the distribution tariffs are collected per kWh, customers who use less energy from the grid will pay less while the others will pay more. For instance, an industrial plant with rooftop solar or cogeneration may pay less distribution fee than a small customer, while the allocated capacity and workforce for that plant is higher for the DSOs. Therefore, DSO costs should be separated as fixed and variable per customer and reflected to customers as such.

Table 1.47 – Recommendations with respect to network tariffs

Network Tariffs	
EU Practices	- In EU, network tariffs consist of the combination of four main components: - o Fixed costs, - o Capacity charges, - o Peak Load charges, - Volume related costs.
Turkey Practice	- Capacity charges and volume related charges are applied. - Customers who choose the double-term tariff (capacity charge), pays a fee per kW connected capacity and a lower distribution fee per kWh.
Problem Definition and Gap Analysis	- Energy consumption is decreasing due to the increasing share of distributed generation. Therefore, for a customer, energy consumption does not reflect the cost of distribution grid. - However, to manage congestions and balance the usage of distribution network peak load charges may be applied,
Recommendation	- Capacity or Peak-load charges should be introduced for small and large industrial customers.
Comments	- Capacity charges would be two segments; - o Subscribed capacity, - o Peak used capacity,
Related Regulations to be Amended	- Electricity Market Tariffs Regulation - Communiqué on Regulation of Distribution System Revenue

Time-of-Use (TOU) Network Tariffs

Time of Use (ToU) tariffs encourages the reduction of demand in periods of high consumption and minimize the impact of intermittent distributed generation on the electricity network. With the increase of smart meter instalment, use of dynamic ToU tariffs increased. As an example, ToU tariffs represent 80% of the total demand in Portugal and the regulatory authority created the regulatory framework for the introduction of dynamic ToU network tariffs to promote demand side flexibility. Currently there is no ToU for network tariffs in Turkey, but it will increase network optimization if implemented. Distribution fee component of the end user tariff could have ToU consideration. Also, depending on roll out of high speed EV charging infrastructure, a stand-alone charging tariff is recommended.

Table 1.48 – Recommendations with respect to time of use aspect with network tariffs

Network Tariffs (Time of Use)	
EU Practices	- Fixed network tariffs or ToU tariffs are applied
Turkey Practice	- Fixed network tariffs are applied
Problem Definition and Gap Analysis	- Turkey and EU applications are compatible. - However, to manage congestions and balance the usage of distribution network Time of Use (ToU) tariffs may be applied.
Recommendation	- Distribution fee component of the end user tariff could have time of use (ToU) consideration. - Depending on roll out of high speed EV charging infrastructure, a stand-alone charging tariff is recommended.
Comments	If the difference of electricity prices between peak and off-peak hours do not represent network congestions, ToU for network tariffs may be used to balance the system.
Related Regulations to be Amended	

Reactive Fee

In EU practice, reactive power fee is commonly applied except for households whereas in Turkey, reactive fee is applied on a monthly measurement for customers above 9kW installed capacity, except for households. In general, Turkey and EU are compatible for reactive power measurements and charging, however, reactive power increases technical losses. Monthly charges do not incentivize/penalize the customers and DSOs reduce reactive power optimally. Once the DSOs improved reactive compensation, TEIAS could start measuring and charging reactive power hourly and it is recommended that reactive power shall be measured and charged hourly to reduce technical losses.

Table 1.49 – Recommendations with respect to reactive tariffs

Reactive Tariffs	
EU Practices	- In EU practice, reactive power fee is commonly applied except for households.
Turkey Practice	- Reactive fee is applied on a monthly measurement for customers above 9kW installed capacity, except for households.
Problem Definition and Gap Analysis	- Turkey and EU are compatible for reactive power measurements and charging. - However, reactive power increases technical losses. - Monthly charges do not incentivize/penalize the customers and DSOs to reduce reactive power optimally.
Recommendation	- It is recommended that reactive power shall be measured and charged hourly to reduce technical losses.
Comments	- However, due to measurement problems, during the fourth implementation period, TEIAS would continue reactive metering with monthly readings. In the fifth implementation period once DSOs improved reactive compensation, TEIAS could start measuring and charging reactive power hourly.
Related Regulations to be Amended	

1.7.4 Retail Tariffs

In EU, price regulation is being phased out. There are no regulated customers in Sweden, UK, Sweden, Finland, Germany, Austria, Italy, Croatia, Denmark, Estonia, Greece and Ireland, while other countries still have regulated tariffs for some customers. Due to EU regulations and practises, regulated customer category should be narrowed and phased out to increase market openness, evolving of the retail market and competitiveness in the retail market. Only social tariff and last resort tariffs should remain regulated in Turkey too.

Since the EU legislation obliges to define the ‘vulnerable consumer’ concept, this should be in place in the energy legislation of Turkey also. Directive 2019/944 Article 58 states that “Member States should take the necessary measures to protect vulnerable and energy poor customers in the context of the internal market for electricity.” In Italy and Greece there are social tariffs, but there are no regulated tariffs. In Belgium and Latvia social tariff is applied in the form of regulated prices. Some other countries have

social tariffs with a policy of price regulation.

In Turkey, last resort tariffs are differentiated for small (vulnerable) and large customers. In addition, lower energy prices for specified customer groups (martyr and veteran families) exists. The vulnerability of the consumers should be defined by the income levels, the share of energy expenditure of disposable income, the energy efficiency of homes, critical dependence on electrical equipment for health reasons, age or other criteria. Details of this subject will be explored in Task-5 [Preparation of Vulnerable Customer Action Plan and Social Tariff Methodology in Electricity and Natural Gas Markets] of the Tariff Project.

In EU practices, regulated or last resort tariffs are generally under the responsibility of DSOs. On the other hand, regulated and last resort tariff customers are in the portfolio of the Incumbent (Assigned) Retailer Companies in Turkey, which are unbundled from the DSOs. Incumbent Retail Companies have also the right for sales to eligible customers, which means double role of the Incumbent Retailer Companies might give them advantage in the eligible customers market over other suppliers.

Another issue related with retail end user tariffs is dollarization of the feed-in tariffs (YEKDEM). Exchange rate volatility increases pricing risks in the retail sector. As an alternative approach, EMRA could announce YEKDEM tariff in TL at the beginning of each quarter and this may be taken as fixed through the period. This way eligibility usage will increase after lowering the price risks.

Table 1.50 – Recommendations with respect to regulated retail tariffs for the incumbent retailer

Retail Tariffs (Incumbent Retailer)	
EU Practices	- In EU, price regulation is being phased out. There are no regulated customers in Sweden, UK, Sweden, Finland, Germany, Austria, Italy, Croatia, Denmark, Estonia, Greece, Ireland. While other countries still have regulated tariffs.
Turkey Practice	- Regulated tariffs exist. - Last resort tariff is in place.
Problem Definition and Gap Analysis	- For competition and evolving of the retail market, effects of regulated tariffs should be reduced. - Regulated tariffs and Last resort tariffs for small consumers still cover high ratio of customers.
Recommendation	- Regulated tariff segment together with the low-consumption last resort customers may be reduced to serve only as a social tariff.
Comments	
Related Regulations to be Amended	

Table 1.51 – Recommendations with respect to social retail tariffs for a vulnerable customer

Retail Tariffs (Social Tariff)	
EU Practices	- In Italy and Greece there is social tariff but no regulated tariffs. In Belgium and Latvia social tariff is applied in the form of regulated prices. Some other countries have social tariffs with a policy of price regulation.
Turkey Practice	- Regulated tariffs exist. - Last resort tariffs are differentiated for small (vulnerable) and large customers - Lower energy prices for specified customer groups (martyr and veteran families)
Problem Definition and Gap Analysis	- Vulnerable customers should be supported. - Support of the vulnerable customers should not harm the competitiveness of the retail market.
Recommendation	- Within the regulated National tariff, a sub tariff group may be introduced as social tariff or - Coverage of the last resort tariff may be reduced to target only for vulnerable customers. and/or - Vulnerable customers may be supported out of tariff mechanism by other social institutions.

Retail Tariffs (Social Tariff)	
Comments	- Directive 2019/944 Article 58: “Member States should take the necessary measures to protect vulnerable and energy poor customers in the context of the internal market for electricity.” - This subject will be further detailed In Task 5.
Related Regulations to be Amended	

Table 1.52 – Recommendations with respect to retail tariffs for renewable energy

Renewable (YEKDEM) Tariffs	
EU Practices	
Turkey Practice	- YEKDEM fee is charged as is. - Supply companies do not know the effect of YEKDEM fee at the time of contract signature.
Problem Definition and Gap Analysis	- Increase in price volatility due to fluctuating exchange rates and generation volume. - This volatility increases price risks for suppliers. - Retail market is still maturing and requires stability and predictability for bilateral contracts.
Recommendation	- YEKDEM tariff could be announced in TL at the beginning of each quarter and this may be taken as fixed through the period. - Adjustments may be done in the next quarter.
Comments	- This way eligibility usage will increase by lowering the price risks. - However, financing of RES investments will become more difficult as TL-based loans will be needed, which currently have a short tenure.
Related Regulations to be Amended	- Regulations related to YEKDEM Law #5346.

2 Improvement of performance-based tariff setting: Electricity Transmission

2.1 Introduction to the Electricity Transmission Chapter

The Transmission Tariff Chapter of this report includes the description of the transmission tariff structure and the methodologies applied in Turkey and some ENTSO-E (European Network of Transmission System Operators- Electricity) Member States and their comparison. As ENTSO-E Member States, Italy, Norway, Portugal, UK, Sweden and Germany have been chosen, because their TSOs resemble closely the responsibilities of TEIAS, as the Turkish TSO. The reason for this preference is to have a gap analysis between Turkish transmission tariff and all those countries which have the most advanced market structure in Europe.

There is considerable variation in the number, size and structure of Electricity Transmission System Operators (TSOs) in European Countries as well as the methodology they used to determine allowed revenues. The following table shows summary information about TSOs in European countries and TEIAS including number of TSOs, network length and ownership of the network companies.

Table 2.1 – Summary Table for TSOs⁹⁷

Country	# of TSOs	Network length (km)	Ownership
Austria	2	VHV 6,700, HV 11,400	Private and Public
Bulgaria	1	15,130 km	Public ownership
Czechia	1	5,717 (2016)	Public ownership
Denmark	1 (Energinet)	6,913 (2017)	Independent public enterprise owned by the Danish Ministry of Climate, Utilities and Energy (SOV)
Estonia	1	5,348	Public ownership
Finland	1	15,000	Public and private ownership
France	1	~100,000	Mainly public ownership (direct and indirect)
Germany	4	~37,000	Mainly private investors, indirect public ownership
Greece	1	17,340	Public ownership and private investors
Hungary	1	4,856	Public ownership
Iceland	1	~3,400	Indirect public ownership
Ireland	1	~6,711	EirGrid operate the System and ESB Networks own the system
Italy	1	72,900	Public ownership
Latvia	1	5,240	Public ownership
Lithuania	1 (LIT-GRID AB)	7,048	Public ownership
Luxembourg	1	150	Mainly direct and indirect public ownership
Netherlands	1 (TenneT)	21,000	Public ownership (public by law)
Norway	1	~12,500	Public ownership
Poland	1	~15,000	Public ownership
Portugal	1 (REN)	8,863	Private ownership
Romania	1	8,835	Mainly public ownership

97 Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.

Spain	1 (REE)	64,714	Private, except for 20% stake of the Public ownership in REE
Sweden	2	~15,000	Public ownership (SVK) and private (Baltic Cable)
Turkey	1 (TEIAS)	67,273 OHL, 481 Cable	Public ownership
UK	3 (NGET, SPT, SHET)	7,200 km overhead lines, 1,500 km cable	Private ownership

As it is seen from the table, Turkey is 3rd country in Europe in terms of network length, after France and Italy.

The most EU countries only have a single publicly owned TSO, as in Turkey. However, there are more than one TSO in Austria, Sweden, Germany and UK.

2.1.1 Overall Objective and Results to be Achieved⁹⁸

Overall Objective of this Chapter is to have high level gap analysis between ENTSO-E member states' TSOs and TEIAS and to improve the functioning transmission tariff application in line with EU requirements.

As it is known, transmission tariffs are one of the elements of the Electricity Market. It should be noted that this gap analysis is not a direct comparison of transmission tariffs and if used in this way, any conclusions drawn are likely to be misleading. Based on different national policies and circumstances, which transmission tariffs have to meet, there are numerous approaches which includes significant complications in Europe and Turkey. It is outside the scope of this Chapter to analyses all influences that shape the tariffs in each system. As there is no single "correct solution" for the allocation of costs to transmission users, different tariff schemes exist among countries. Differences might include whether market mechanisms are used as part of the regulatory regime, the treatment of transmission losses and of ancillary services, and the level of first connection costs to which transmission grid users are exposed. This gap analysis also considers the differences among countries in areas such as quality of service, market arrangements, technical characteristics, environmental aspects, impact of consumption density, and impact of generation location. These are all factors that influence the level of such tariffs.

2.1.2 First Connection charges

First Connection Charges are borne by new grid users (producer or consumer). They are aiming at a transmission grid connection, consisting of TSO's costs for building a transmission facility to enable such a connection.

The connection charge types are characterized by costs that are included in the calculation of the connection charge. First connection charges are defined as:

- Super-shallow: All costs are socialized via the tariff, no costs are charged to the newly connected grid users,
- Shallow: new grid users pay for the infrastructure connecting its installation to the transmission grid such as line/cable and other necessary equipment,
- Deep: shallow: in addition to shallow charges, all other reinforcements/extensions in the existing network are added. These are required in the transmission grid to enable the new grid user to be connected.

In case applied charging, rules do not exactly suit any of the three above definitions, but are in-between any of them, it is reported as e.g. Super-shallow/Shallow, Shallow/Deep etc. where their meaning can be explained accordingly.

⁹⁸ ENTSO-E's definitions have been used for the transmission tariff parameters.

2.1.3 Use of System Charges

The main characteristics of TSO tariffs are as follows: share of Generation (G) and Load (L), network charges in %, seasonal and locational differentiation, whether the costs of losses and system services are included in TSO tariffs and whether they are charged by TSOs. TSO tariffs applied as a charge to the users of transmission networks may allocate both TSO costs and non-TSO costs. These are summarized below.

Special tariff conditions

Special tariff conditions can exist in some countries e.g.:

- Special tariff conditions for low utilization (auto production or own production units behind the connection site, second connection used for emergency situations, pumping stations...);
- Special tariff conditions for high consumption (for instance over 100 GWh per year);
- Special tariff conditions for users fulfilling defined technical criteria of its production/connection site;
- Special tariff conditions for any group of users (e.g. any public utilities, army, etc).

This Chapter summarizes different charging rules/tariff conditions or exemptions from rules defined as “standard” and applied by TSO’s for specific groups of network users.

Non-TSO components of Transmission Tariffs

Many TSOs across Europe recover additional money from their customers that are not directly related to TSO activities. TSOs are often obliged to recover this additional money as a result of national or regional regulations and the charges may either form part of transmission tariffs directly or form part of separate charging mechanisms.

Non-TSO costs broadly fall into five main categories:

- **RES mechanisms:** these are costs recovered through TSO charges aimed at supporting government targets to increase renewable generation. These costs are used to finance subsidies to grid-connected renewable generators. In terms of level, RES mechanisms represent the most important component of non-TSO costs;
- **Non-RES Support mechanisms:** these are costs recovered through TSO charges generally aimed at providing financial support to other government objectives, such as energy efficiency or subsidizing the costs of maintaining grid networks to rural areas, etc.;
- **National Regulatory Authority / Other institutions:** some costs are recovered through TSO charges that finance the activities of the relevant sector regulator or other institutions associated with the energy industry;
- Stranded Costs;
- Other Costs.

Treatment of Final Customers vs Distribution System Operators

Both DSOs and final customers are seen as Load (L) from TSO’s perspective. However, there may be different tariffs, charge calculation procedures or settlement rules for final customers and distribution system operators. Justification for different treatment may be the load volume of a given network user, the number of connection points to the transmission grid (simultaneous off-take), the network configuration conditions and the co-operation scheme of DSOs with the TSO (often DSOs’ network plays a role in the sub-transmission grid).

This Section summarizes the main features of different treatment /charging mechanisms of final customers and distribution system operators per TSO.

Reactive Energy

In some countries, charges for reactive energy are applied. The tariff rates may be applied to every MVARh of measured reactive energy or only under pre-defined conditions. Two charging schemes for reactive energy exist:

- **Reactive Tariff:** A regular tariff rate is applied to each MVARh of reactive energy produced and/or consumed.
- **Penalty:** Reactive energy produced and/or consumed is charged only if some pre-defined conditions are met. Examples can be excesses of energy off-taken/fed-in during a given period or excess levels of $\cos \phi$ or $\tan \phi$.

This section summarizes main features of charging mechanisms applied by TSO's for reactive energy for users connected to transmission network.

Impact of location

Some transmission tariffs are differentiated by location. Tariff areas in countries for generation/consumption tariffs with locational differentiation is to have cost effective tariff structure and give signal to the new investors.

Load (demand) Component

The Transmission Tariff applied to the generation (G) and load (L), which includes infrastructure costs, the costs of purchasing system services and losses as part of the TSO components of the Transmission Tariff that corresponds to load only.

Generation component

The Transmission charges applied to the generation (G) and load (L) as the part of the TSO components of the Transmission Tariff that corresponds to generation.

Impact of utilization time

Transmission charges paid by network users change due to the utilization time if the applied tariffs have power (capacity) as a revenue driver.

Energy-related and power-related components

The main revenue drivers for Transmission Tariffs are power (capacity), energy (volume) or both.

Netting of flows for the application of transmission tariffs

When there is a situation of connected generation and load at the same connection point to the grid, those cases can be treated differently in transmission tariff settlement.

One example of such case is connection of auto producer generation units, where there are both directions of energy flows possible – injection of energy to the grid during regular generator operation, and extraction of energy from the grid when generator is down or during preparatory regime for the operation.

Second possible example is the situation when grid user is having generation and another separate load connected to the same substation bus bars, acting as connection point. In this case energy can flow from user's generation to user's separate load via substation bus bars, without entering the grid.

2.2 Stakeholder Responsibilities

As it is seen in Table 2.1, ownership of the TSOs is variable in the EU, but it is mainly publicly owned or the majority portion publicly owned, except for Germany, Portugal, Spain and UK. In Germany (indirect public ownership), Spain (20% Public ownership), Portugal and UK mainly private investor TSOs are in operation.

In **Germany**⁹⁹ BNetzA (*Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway*) is responsible for regulating all operators. There are four German transmission system operators; 50Hertz, Amprion, TenneT and Trans-netBW. They are responsible for the secure and reliable operation of the network as well as for the transmission of the electricity. TSOs can also hold special grid facilities in reserve. These plants are intended to restore the stability of the networks in the event of an actual failure of one or more facilities in the transmission system. This is known as curative re-dispatching. The network operator's responsibility for the processing and transmission of metering data, which was legally determined until 31 December 2019, was transferred to the market role of the meter operator in the determination on market communication 2020. BNetzA publishes its assessment of reserve power plant requirements. The assessment confirms the results of the system analyses by the four TSOs in compliance with the Grid Reserve Ordinance (NetzResV) to guarantee the secure and reliable operation of the transmission system. As part of its monitoring role, BNetzA provides quarterly updates on the progress in planning and construction that has occurred for individual projects in the transmission system, as well as transmission links to offshore wind farms during the previous three months.

In **Italy**¹⁰⁰, the remuneration of the transmission and dispatching services is ensured by Terna. It is based on a tariff system established by the Regulatory Authority for Energy, Networks and Environment (ARERA) through specific resolutions. The Italian Regulatory Authority for Electricity Gas and Water (AEEGSI) is the independent regulatory body of the energy markets and the integrated water services. It was established by law on the 14th of November 1995, No. 481 with the purpose to protect the interests of users and consumers, promote competition and ensure efficient, cost-effective and profitable nationwide services with satisfactory quality levels in the electricity and gas sectors. With the Law on 22nd of December 2011, No. 214, new regulatory competences in the integrated water services sector were attributed to the Authority, while Legislative decree dated 4th of July 2014, No. 102, assigned new tasks in the district heating and cooling sector. The current tariff framework covers the period 2016-2023. At 5.3%, Terna's remuneration is the lowest in the Italian electricity sector and is lower than the European average of 6.4%.

In **Norway**¹⁰¹, the Norwegian Energy Regulatory Authority is the national regulator for the Norwegian electricity and downstream gas market. The Norwegian Energy Regulatory Authority's main statutory objective is to promote social and economic development through an efficient and environmentally sound energy production, as well as efficient and reliable transmission, distribution, trade and efficient use of energy. Responsibility encompasses the regulatory area as well as other activities defined by law, regulations and decisions made by the Norwegian Parliament.

The Norwegian Energy Regulatory Authority has delegated powers according to the Energy Act. It has the authority to issue regulations on economic and technical reporting, network revenues, market access and network tariffs, non-discriminatory behaviour, customer information, metering, settlement and billing as well as the organised physical power exchange (Nordpool Spot). In addition, The Norwegian Energy Regulatory Authority issues regulations on system responsibility and quality of supply. The Authority may take necessary actions to fulfil the delegated powers according to the Energy Act.

Statnett SF is licensed as the Norwegian transmission system operator (TSO). Statnett SF is a public enterprise, owned by the Norwegian state subordinate to the Ministry of Petroleum and Energy (MPE). Statnett SF owns most of the transmission grid. The grid is defined by decisions by NVE and includes some grid with voltage level of 132 kV, and all grids with higher voltage levels, where the most common levels are 300 kV and 420 kV. The total length of Statnett's grid is 10,547 km.

The Norwegian regulations for system operation govern the duties and responsibilities related to Statnett's conduct as TSO. It is one of the regulations under the Norwegian Energy Act of 1990. The following principles apply for the TSO's conduct:

99 Source: <https://www.bundesnetzagentur.de/BNetzA/PressSection/ReportsPublications/2019/AnnualReport2018.pdf>

100 Source: <https://www.terna.it/en/electric-system/terna-role/how-electricity-system-works>

101 Source: www.nve.no

The TSO shall:

- Provide frequency regulation – ensure momentary balance at all times
- Act in a neutral and non-discriminatory manner
- Develop market solutions – ensure efficient development and utilisation of the power system
- Make use of means based on market principles to the widest extent possible
- Coordinate and monitor the dispositions of licensees and end-users
- Distribute information of importance to the power market and the general quality of supply

As the Norwegian regulatory authority, NVE controls and audits Statnett's activities as TSO. NVE and Statnett have review meetings biannually. The meetings revolve around the license for system operation, system operation regulations, revenue cap regulations and license for foreign trade.

In [Sweden](#),¹⁰² the Energy Markets Inspectorate (EI) is a supervisory authority on behalf of the government and belonging to the Ministry of the Environment and Energy. The agency has been active since 2008. EI is supervising and developing the ground rules for the electricity, district heating and natural gas markets, in order to strengthen customers' position and ensure society's need of functioning energy distribution and trade is met. This means that on the Government's commission EI regulates the terms and conditions for the monopoly companies that run electricity and natural gas networks. EI also supervises companies on the competitive energy markets, to ensure the market is kept functional and the customers' interests are safeguarded. EI is also responsible for designing the regulation in a way that minimizes the welfare losses from monopoly power. The main objective with the regulation is to ensure that the network operators do not make monopoly profits while retaining efficient operations of the grid with a good quality of supply. In this way high quality and fair prices will be ensured for the customers.

On the electricity market, there are currently two TSOs in Sweden. The Swedish TSO, Svenska Kraftnät (SvK), is a state-owned utility that was established on 1st of January 1992. SvK operates the national transmission grid which in total consists of approximately 15,000 kilometres of 220 kV and 400 kV lines. Baltic Cable (BC) owns one line of transmission connecting the electricity grid between Sweden and Germany.

In the [UK](#),¹⁰³ the regulator Ofgem sets price controls – a ceiling on the amount companies can earn from charges to use the transmission networks. RIIO is Ofgem's performance-based framework to set the price controls. The current network price controls for Electricity Transmission (RIIO-T1) run from 2013-2021.

The market liberalisation of the electricity market in the UK started in 1990. There are 3 licensed Transmission Operators (TOs) and 12 Offshore Transmission Operators (OFTOs) in UK. These operators can develop, operate and maintain the high-voltage system within their own geographical transmission areas, and own OFTO assets.

The three TOs are:

- National Grid Electricity Transmission plc (NGET) for England and Wales
- Scottish Power Transmission Limited (SPT) for Southern Scotland
- Scottish Hydro Electric Transmission plc (SHET) for Northern Scotland and Scottish Islands Groups.

NGET owns and operates the England and Wales Electricity Transmission network and operates the Scottish transmission network. NGET carries electricity from the generators to substations, where the voltage is lowered, ready for distribution to homes and businesses. NGET's network consists of overhead lines, underground cables and substations. NGET is responsible for balancing the

102 Source: www.ei.se

103 www.ofgem.gov.uk

system and managing generation output to make sure it matches demand throughout the day, and that voltage and frequency are kept within acceptable limits. Generators, distribution network operators and suppliers pay NGET for the right to connect to transmission grid assets and to use system to transport electricity on their behalf. NGET aims to transmit a safe, secure and dependable supply of electricity across the country. The connections process is managed by Transmission Network Service (TNS) team, which alongside Market Operations (MO) acts as the System Operator (SO), providing customers with a valuable and transparent service. National Grid as SO, strive to deliver a service to all of customers.

National Grid have access to a lot of data and publish many reports to the market every year. The market then uses this data to make commercial decisions and plans for the future of the industry in the UK.

A new, legally separate electricity system operator (NGESO) was established within National Grid Group, separate from NGET in April 2019. As a result, the allowed TNUoS revenue under NGET's license, is collected by NGESO and passed through to NGET, in the same way to the arrangement with Scottish TOs and OFTOs.

In **Portugal**,¹⁰⁴ transmission activity is mainly controlled by ERSE, which establishes the methodology to be used for calculating tariffs and prices and the ways of regulating the allowed revenues. The transmission network operator REN is a concessionary entity under a public regime from the National Transmission Network of Electrical Energy (RNT), with the following fundamental objectives:

- Ensure the exploitation, maintenance, planning and construction of the RNT;
- Ensure non-discrimination between users.

The mission of ERSE is to regulate the electricity and natural gas sectors, being an effective tool for the efficient and sustainable operation of the respective markets while ensuring the protection of consumers and the environment, transparently and impartially. In the scope of this public service mission, ERSE is given a range of powers by law and its Statutes. These powers include, most notably: protecting consumers' rights and interests regarding prices, services and service quality; monitoring compliance with public service obligations and all other legal, regulatory and similar requirements; guaranteeing economic and financial balance to the activities of the regulated sectors exercised in the public interest companies within the framework of appropriate and efficient management; promoting competition in the energy markets between all their players.

ERSE determines the profit allowed in accordance with the methodologies of regulation defined in the Tariff Code. The approval of the Tariff Code is preceded by a public consultation and an opinion from ERSE's Tariff Board.

The profit allowed gives rise to the electricity tariffs which are defined and published annually by ERSE, in accordance with what is established in the Tariff Code.

The various stakeholders in the Electricity Sector (consumers and electricity industry) are involved in the process for the approval of the tariffs and the Tariff Code.

- The tariff for the Global Use of System must provide profits for the Global System Management activity which includes costs for the operation of the system, costs arising from energy or environmental policy measures, or measures with a general economic interest, and costs from the maintenance of the contractual balance (CMEC).
- The tariff for the Use of Transmission Network must provide profits from the Electricity Transmission activity which includes the establishment, operation and maintenance of EHV transmission networks and interconnections.

The Networks Access tariffs, which includes the tariffs for the Global Use of System, the Use of Transmission Network are paid by each electricity consumer in the Regulated and Free Market, and are included in the sales tariffs of the various suppliers, its value being listed in the electricity bill that the client receives from their supplier.

In **Bulgaria**, the Electricity System Operator (ESO) is the Bulgaria electrical transmission operator (TSO) and it is responsible for

the transmission of electricity in the country. ESO ensures balance in the system, develop market solutions and utilization of the power system as a whole. It holds grid facilities in reserve, and it is intended to restore the stability of the networks in the event of any failure of one or more facilities in the transmission system. ESO is also responsible for the secure and reliable operation of the network.

Besides, 3 DSOs work on the Bulgarian territory, as follows:

- CEZ,
- EVN,
- ENERGO PRO

They operate under licenses issued by Commission of Energy and Water Regulation in Bulgaria. DSOs are responsible for energy network industry in the country. The Bulgarian DSOs are also responsible for the processing and transmission of metering data.

In **Turkey**, transmission activity is regulated, monitored and audited by EMRA according to EML No 6446. EMRA's objective is to establish a financially viable, stable and transparent energy market, which functions as per the provisions of private law and within a competitive environment to ensure the independent regulation and supervision of the market in order to provide sufficient electricity, natural gas, petroleum and LPG of good quality to consumers, at low cost, in a reliable and environment friendly manner.

As a transmission system operator Turkish Electricity Transmission Corporation (TEIAS), owns and operates the Turkey Electricity Transmission network. TEIAS which is a state-owned company is the sole owner of Turkish Transmission System. Being responsible for the operation and maintenance of Turkish Power System, Electricity Balancing Market and Ancillary Services Market, TEIAS undertakes the mission of providing the quality, uninterrupted, secure and economic Electricity Transmission through a strong transmission system. TEIAS exhibits a vision of a reliable company by making the Turkish Electricity Transmission system stronger, contributing to a competitive and transparent energy market and improving its interconnections with neighbouring electricity systems. Moreover, TEIAS undertakes the tasks of:

- Expansion of Turkish Transmission System and investing in its renovation
- Operation and maintenance of Turkish Transmission System
- International interconnections
- Ancillary services
- Balancing and congestion management

The Turkish transmission system is equipped with shunt reactors, series and shunt capacitors for its technical and economic benefits. The transmission voltage levels are standardized as 400 kV and 154 kV¹⁰⁵. All transmission lines belong to TEIAS. The 400 kV network is the back-bone of the transmission grid. The 154 kV network is the sub-transmission system.

TEIAS has interconnections with Greece, Bulgaria, Iran, Iraq, Syria, Georgia and Azerbaijan. Energy exchanges are only ongoing with Georgia, Greece and Bulgaria as of early 2020. Turkey's priority objective is the full integration with European interconnected system ENTSO-E. Presently, Turkish power system has been in synchronous operation with ENTSO-E CESA network since the 18th of September 2010, with commercial operation since June 2011. In addition, TEIAS has joined the ENTSO-E as an observer member. This situation necessitates "follow-up" projects, which aim at improvement of Turkish Transmission system, to ensure complying with the service and commercial quality standards of ENTSO-E.

2.3 Revenue Requirement Model

In many European countries, the revenue cap is used as revenue requirement model. Each country decides for itself on the type and structure of its regulatory system. International benchmarks show that there is a tendency to switch to incentive-based

105 There are also some 66 kV lines and some substations which are planned to be replaced. There are also unused 220 kV lines.

mechanisms recently.

In incentive-based mechanisms, companies aim to reach the targets defined by the regulatory authorities, and they will retain a profit. By setting targets, consumers benefit from increased efficiency and quality, whereas the companies can increase profits by achieving these targets. Following Table shows the revenue requirement models that are currently used in different countries.

Table 2.2 – Tariff Methodology in European Countries among TSOs¹⁰⁶

Country	Tariff Methodology	Period	Main elements for Determining the Revenue Cap
Austria	Cost+ regulation	Yearly	Costs of t-2, ex ante costs according to network development plan
Bulgaria	Revenue cap	Yearly	OPEX + CAPEX
Czechia	Incentive regulation / Revenue cap	Originally set as 3-year (2016-2018), later it was prolonged until 2020	Allowed costs, allowed depreciation, RAB, WACC
Denmark	Strict cost plus	Yearly	Danish TSO regulation doesn't fit to this scheme. There are two mechanisms: revenue caps and benchmarks. Revenue caps set a ceiling on the operating revenues of grid companies. Benchmarking aims at ensuring that consumers do not pay more for the services of the grid companies than they would have done, if the companies were subject to competition. If the actual costs of a grid company are too high, efficiency improvement requirements will be imposed on the company by Danish Utility Regulator, DUR.
Estonia	Rate-of-Return	There is no period	Variable costs, operating costs, depreciation of RAB, justified return of RAB
Finland	Revenue Cap	2 regulatory periods (2016-2019 and 2020-2023) set	Efficiency-, Quality-, Innovation- and Investment incentive, WACC return on RAB
France	Revenue Cap	4 years, current period: 2017-2021	Non-controllable and controllable costs, depreciation costs, taxes and fair margin
Germany	Revenue Cap	5 years, current period: 2019-2023	Non-controllable and controllable costs, TOTEX efficiency benchmark, general inflation and sectoral productivity factor, volatile costs
Greece	Revenue cap	4 years, current period: 2018-2021	OPEX (Non-controllable and controllable costs) Depreciation, RAB (Assets and approved investment plans, working capital), WACC and WACC premium
Hungary	Incentive Regulation	4 years, current period: 2017-2020	They do not use revenue cap
Iceland	Incentive Regulation / Revenue cap	5 years, current period 2016-2020	TOTEX; OPEX (CPI adjusted average 2010-2014) + CAPEX (previous year CPI adjusted book values). + Non-controllable cost (less than 2%) Efficiency factor = 0 for this period.
Ireland	Incentive Regulation / Revenue cap	5 years, current period: 2016 - 2020	Revenue to cover the TSO's and TAO's operational costs during that period; 2 A return on capital invested in the TSO's and TAO's assets; and 3 Revenue to cover depreciation of the TSO's and TAO's assets.
Italy	Price Cap and Cost of Service (TOTEX after 2020)	8 years (4+4)	OPEX + CAPEX
Latvia	Cost Plus	Not determined	OPEX + CAPEX (Depreciation + return on capital)
Lithuania	Price Cap	5 years (2016-2020)	TOTEX, RAB, WACC, technical losses
Luxemburg	Revenue cap / incentive regulation	4-year period, current period 2017-2020	Remuneration on RAB; depreciation, Controllable OPEX; Non-controllable OPEX; Ancillary services
Netherlands	Incentive regulation / Revenue cap	3-5 years (currently 2017-2021)	TOTEX, cpi, cost efficiency benchmark, productivity change, WACC, RAB

106 Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.

Country	Tariff Methodology	Period	Main elements for Determining the Revenue Cap
Norway	Incentive regulation / Revenue cap	Data is updated every year, important factors (i.e. WACC-model) fixed for five years	Controllable and pass-through cost, TOTEX efficiency benchmark. Averagely efficient company receives RoR
Poland	Cost of service with elements of revenue cap	Calendar year	RoC + OPEX, depreciation, property taxes, losses, costs of maintaining the system-related standards of quality and reliability of current electricity supplies
Portugal	Price-cap (OPEX) and standard costs/rate of return (CAPEX)	3 years (current period 2018-2020)	Non-controllable and controllable costs, RAB, WACC, efficiency benchmark, inflation, incentives, general economic interest costs
Romania	Revenue cap / Cost+	5 years, current period: January 2014 – December 2018	Non-controllable and controllable OPEX, variable costs, RAB depreciation, rentability of RAB (RABxWACC)
Spain	Revenue Cap / Incentive Regulation	6 years, next 2020-2025	Investment reference values, OPEX reference values, RAB, rate of return, regulatory lifetime of assets, Incentives
Sweden	Revenue cap	4 Year (Current 2016-2019)	TOTEX (divided into CAPEX, Non-controllable OPEX and Controllable OPEX) Incentives for good quality of supply. General efficiency target of reducing 1 percent of controllable OPEX annually
Turkey	Revenue cap	3 years (current 5 th implementation period 2018-2020)	CAPEX+OPEX (Depreciation + return on capital)
UK	RIIO model	8 years 2013 to 2021	Revenue = Incentives + Innovation + Outputs

Regulatory periods differ among countries. While the period is 8 years (mid-term evaluation is performed for the first 4 years) in UK, Italy and Finland, it is 4 years in Sweden, 6 years in Spain, 5 years in Germany and Norway and 3 years in Portugal and Turkey. In Sweden, the Network Performance Assessment Model was used until 2012, but after that they have used a revenue cap, whereas in the UK the output based RIIO model is implemented.

Main elements to determine the revenue cap shows similarities in most of the countries. TOTEX is used in countries such as Germany, Austria, Iceland, the Netherlands and UK, whereas CAPEX and OPEX is assessed separately in the most of other EU countries and Turkey.

2.3.1 General Overview

2.3.1.1 Germany

Regulation by the BNetzA for Electricity Transmission with respect to incentive regulation and cost approval (TOTEX) is the same as explained in the Chapter on Electricity Distribution.

The revenue caps for network operators are set for a five-year regulatory period. Each cap is composed of the permanently non-controllable costs, temporarily non-controllable costs, controllable costs (applying a distribution factor for reducing inefficiencies), general inflation relative to the base year and a general sectoral productivity factor, and volatile costs. The difference between the allowed revenue and the development of actual volumes over the year is entered into a regulatory account.

Another component of the revenue caps is the general sectoral productivity factor, which is always applicable for one regulatory period. This factor is determined using scientific methods from the divergence between productivity gain in the network industry and productivity gain in the economy as a whole. The idea behind this factor is to imitate market forces and thus simulate competitive pressure. It is assumed that where competition exists, productivity gains will lead to lower costs for companies, and companies will pass on this competitive advantage to customers in the form of lower prices so as to attract customers away from

competitors. The productivity factor has the effect of reducing revenues.

The revenue caps also take account of the development of consumer prices in relation to the base year (CPI-X regime). General price increases lead to an increase in the revenue cap. Following formula shows revenue cap calculation as 3rd building block of incentive regulation.¹⁰⁷

$$EO_t = KA_{dnb,t} + (KA_{vnb,t} + (1 - V_t) KA_{b,t} + B_0 / T) (VPI_t / VPI_0 - PF_t) + Q_t + (VK_{t/0} - VK_0) + S_t$$

Where,

EO_t : revenue cap,

$KA_{dnb,t}$: non-controllable costs,

$KA_{vnb,t}$: generally controllable costs,

V_t : inefficiency reduction per year,

$KA_{b,t}$: inefficiencies,

B_0 : bonus,

T : duration of regulatory period (in years),

$VPI_{t/0}$: CPI,

PF_t : Xgen,

Q_t : bonus/penalty for quality,

$VK_{t/0}$: volatile costs,

S_t : regulatory account,

$t/0$: time index/base year.

TSOs are able to refinance their necessary expansion and restructuring investments through investment measures. Proposed expansion and restructuring investments can be approved provided they are required for the stability of the system as a whole, incorporation into the national or international interconnected grid, or expansion of the network to meet energy supply requirements. Investments approved under the investment measures are factored into the revenue cap as permanently non-controllable costs.

In the event of changes in other permanently non-controllable costs of a network operator in the course of a regulatory period, the revenue cap and thus the network charge can be adjusted accordingly.

The data published on the regulatory authorities' websites include revenue caps and annual adjustments, efficiency scores (together with the relevant cost and output parameters), efficiency bonus, CAPEX in period top-up and permanently non-controllable costs.

There are currently no further plans to develop the incentive-based regulatory regime in Germany. Various changes were made to the regime in 2016. The effects of these changes are to be awaited before any further reforms or changes are made.

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See: https://erranet.org/wp-content/uploads/2017/10/Muller_Case-study-benchmarking-Germany_final.pdf

2.3.1.2 Italy¹⁰⁸

As written in the electrical distribution section (Chapter 1), transmission and distribution are being regulated by a hybrid system.

The OPEX are regulated with a price cap method while the CAPEX with a rate of return method.

Also, for the electric transmission sector, ARERA is slowly evolving the regulatory framework towards the TOTEX model.

The reference resolution of the ARERA is the same for the transmission and distribution with the same mechanism for limiting the revenues and the equalization system of the CSEA.

The structure of the transmission tariff that distributors must pay is binomial with one component in power and one in energy of the transmission tariff (CTR) applied to the distribution companies, attributing a preponderant share of the costs recognized in power (the share of the revenues recognized in energy would amount to at least 8%), exceeding the revenue guarantee mechanism for the National transmission operator.

Table 2.3 – Components of remuneration of the transmission operator; valid for the year 2020

CTR^{PdD}	$CTR^{Premium}$	CTR^{ITC}	CTR^{MIS}
Eurocents/kW	Eurocents/kW	Eurocents/kW	Eurocents/kW
204.3291	232.0192	47.5694	0.2215

The transmission activity is remunerated according the rate-of-return applying the WACC and output-based approaches. In fact, the regulatory framework established that remuneration has to be compatible with network efficiency and security. Losses and network congestion could influence electricity prices. ARERA considers a factor to add to energy price (no more than 10%) to cover losses in transmission and distribution networks.

Transmission tariffs are computed by a tariff called CTR that depend on energy and capacity. The regulation criteria introduced for the current regulatory period include the application of a two-part structure, with a component in energy (10%) and a component in power (90%) with reference to the transmission tariff applied to the distributors at interconnection points.

In Italy, there are six different zonal markets based mainly on physical transmission limits between adjacent zones (Northern Italy, Central-Northern Italy, Central-Southern Italy, Southern Italy, Sicily and Sardinia). When congestion takes place, there is a mechanism that considers different bid prices, while the ask price is unique (PUN) in the whole system. The congestion management is also used in the coupling between Italian power system and its neighbours such as France, Austria and Slovenia to which Italy is interconnected.

The TRAS transmission tariff (*tariffa per il servizio di trasmissione*) covers the costs of energy transmission through the national grid and it is charged to end users as part of their bill (except for low voltage domestic users).

The transmission system operator (Terna) is responsible at national level for ensuring balance between demand and supply and overall stability and safety of the electricity network.

To do this, Terna is active on the ancillary services market which is a kind of energy market, where Terna (as the exclusive and sole buyer) purchases the right quantity necessary to ensure:

- Proper system relief with regard to intra-zonal congestion.

¹⁰⁸ - The creation of energy reserves.
Source: ARERA Annual Report, 31 July 2017.

- Real-time balancing.

In June 2006, the Electricity and Gas Authority passed Resolution No. 111/06 requiring energy producers to provide advance projections about the quantity of electricity they would inject into the grid to create a predictable supply and assist Terna to balance supply and demand.

If an operator fails to comply with the energy injection schedule, a charge will be applied based on the deviation from the relevant schedule (so-called “imbalance costs”), which vary depending on whether the operator is entitled to be on the ancillary services market, the kind of production unit and the kind of energy source involved (renewable/non-renewable).

To date there is no capacity market, but steps have been undertaken to implement one in the near future.

2.3.1.3 Portugal¹⁰⁹

Remuneration of the regulated activities is based on the definition of the allowed revenues, which assure the principle of recovering operating costs (with efficiency targets) as well as the cost of capital. The model is defined for 3-year regulatory periods, during which the relevant parameters remain stable. Allowed revenues are earned through the tariffs charged to final consumers through distribution companies. ERSE sets the regulated tariffs ex-ante every year based on estimated consumption. One of the regulatory guiding principles for the definition of energy tariffs is stability:

- The sector companies’ regulated revenues are not dependent from State payments and
- Transmission/transportation operators do not have consumer credit risk Stable regulatory framework.

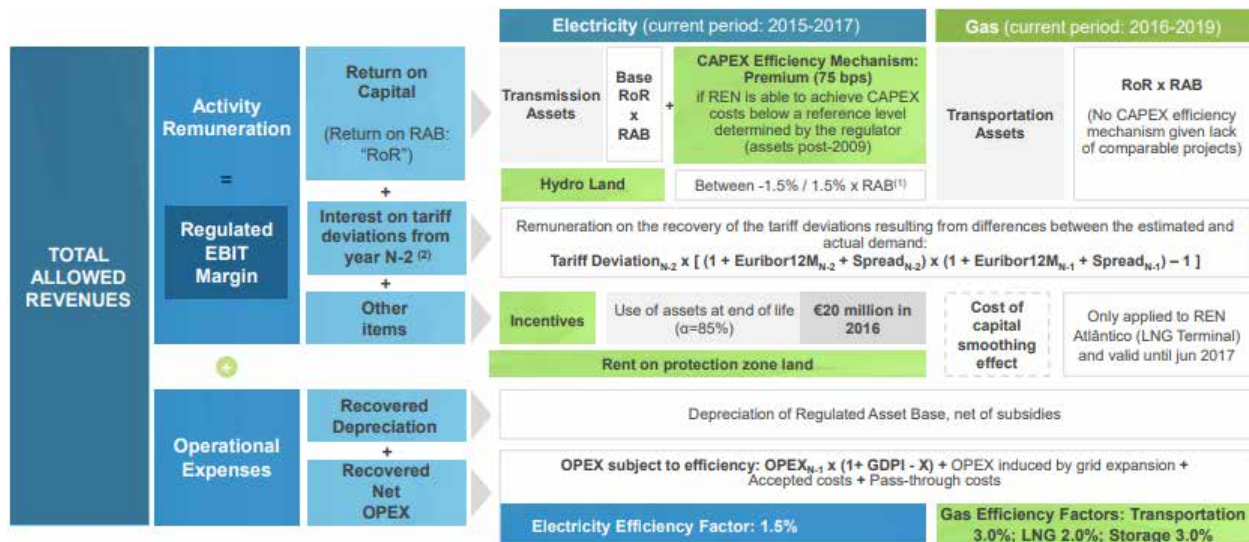


Figure 2.1 – Remuneration regime based on allowed revenues, set by the regulator ERSE for 3-year regulatory periods in Portugal¹¹⁰

(1) Remuneration set for 2015

(2) For Gas, the regulator may decide to set a provisional tariff deviation of n-1 depending on tariffs level

The REN Group has three regulated activities in the electricity sector in Portugal:

- Global use of the System¹¹¹;

¹⁰⁹ Source: www.ren.pt

¹¹⁰ Source “REN Investor Outlook, October 2016” report.

¹¹¹ Tariff charged through the transmission/transportation operator, mostly composed by pass-through costs, such as energy acquisition costs related

- Transmission of Electrical Power; and
- Purchase and Sale of Electrical Power from the Commercial Agent, which consists of trading in the MIBEL generation from two remaining power purchase agreements (CAE in Portuguese) through REN Trading.

The allowed revenues of the first two activities are recovered by the application of two regulated tariffs:

- the tariff of Overall Use of the System (UoS) and
- the tariff of Use of the Transmission Grid (URT in Portuguese).

The revenues of the third activity essentially come from the sale on the market of the generation from non-terminated CAEs. The UoS tariff reflects the positive or negative difference between the cost under CAEs added to the incentives to optimise the management of CAEs and to efficiently manage CO₂ emissions licences and the revenue from the sale on the market of energy and system services supplied by power stations.

Both tariffs are annually fixed by ERSE based on energy and economic forecasts for demand, costs, revenues and capital expenditures.

In the regulatory period (2009-2011), ERSE maintained regulation in the activity of Overall Use of the System for accepted costs and the application of a rate of return of intangible assets allocated to the activity, net of amortizations and subsidies. The regulation of the Transmission of Electrical Power activity was changed.

The main changes introduced in the regulation of the Transmission of Electrical Energy activity were:

- the incentive to efficient capital expenditure in the transmission grid,
- the adoption of a regulation methodology for exploration costs, which sets out maximum limits to be applied to these costs and considers reference costs adapted to the company's activity,
- the incentive to the maintenance of equipment at the end of its useful life and,
- the incentive to increase the availability of the elements of the Portuguese Transmission Grid (RNT).

The incentive to capital expenditure consists of the determination of the RAB and the rate of return as a function of the level of efficiency obtained by the company.

The incentive to increase the availability of the National Electricity Transmission Grid, which was introduced in 2009, aims at promoting the efficiency of the operation and the maintenance of the grid's infrastructure.

For electricity: production, transmission, distribution and sales activities, ERSE determines the profit allowed in accordance with the methodologies of regulation defined in the Tariff Code.

The profit allowed gives rise to the electricity tariffs which are defined and published annually by ERSE, in accordance with what is established in the Tariff Code.

The various stakeholders in the Electricity Sector (consumers and electricity industry) are involved in the process for the approval of the tariffs and the Tariff Code.

The tariff for the Global Use of System must provide profits for the Global System Management activity which includes costs for the operation of the system, costs arising from energy or environmental policy measures, or measures with a general economic interest, and costs from the maintenance of the contractual balance (CMEC).

The tariff for the Use of Transmission Network must provide profits from the Electricity Transmission activity which includes the establishment, operation and maintenance of EHV transmission networks and interconnections.

with the management of the two remaining PPAs (Electricity), hydro land (Electricity), positive or negative adjustments related with costs supported by the supplier of last resort (Gas) and ERSE costs.

The Networks Access tariffs, which includes the tariffs for the Global Use of System, the Use of Transmission Network and the Use of Distribution Network are paid by each electricity consumer in the Regulated and Free Market, and are included in the sales tariffs of the various suppliers, its value being listed in the electricity bill that the client receives from their supplier. These tariffs are approved and published annually by ERSE.

The Tariff Code establishes the rules and provisions needed for the determination of allowed revenues of regulated activities and for the definition of regulated tariffs and prices.

The tariff Code is applicable to the regulated activities of the Portuguese National Electric System (SEN), including Azores and Madeira islands, namely to network operators and last resort suppliers, as well as to liberalized suppliers to all clients.

The tariffs and prices for global use of system, use of networks and end-user prices to be applied by the last resort supplier are set accordingly the Tariff Code.

In the scope of the application of Tariff Code, the following issues are covered:

- tariffs structure, cost recovery and cost-reflectiveness of tariffs;
- regulatory methodologies and incentives, including the formulation for calculating the allowed revenues of regulated activities;
- tariffs convergence of the public electric system of Portugal mainland and the Autonomous Regions of the Azores and Madeira;
- procedures to be adopted for the fixing tariffs and prices of regulated services, their alteration and publication;
- obligations of the entities of the Portuguese National Electric System with the respect to information providing and auditing requirements.

A summary of the regulatory models in force for the 2018-2020 regulatory period by type of network operator are as follows.

For Mainland Portugal:

Transmission system operator (TSO) – for transmission activity: model based on economic incentives:

- application of a price cap¹¹² methodology with efficiency targets for operating costs (OPEX¹¹³);
- incentive for efficient investment in the transmission network through the use of reference prices in valuing new equipment to be incorporated into the network, whose greater risk is offset by a differentiated rate of return;
- incentive to increase availability of the elements of the RTN;
- incentive for maintaining equipment in operation at the end of its useful life. In the Global Technical Management System activity, the revenues are set on an annual basis through a methodology of accepted costs.

For the Autonomous Regions of the Azores and Madeira:

Companies with Electricity Transmission and distribution concessions are subject to regulation based on economic incentives:

¹¹² Operational expenditure.

¹¹³ The cost drivers that determine the evolution of the revenue recoverable by the application of the transmission network use tariff are not very volatile, bringing this methodology closer to *revenue cap*. The drivers are the length (km) of the network lines and the number of panels in substations. The efficiency factor was set at 1.5%.

- regulation of electricity purchase and management activities via a revenue cap methodology¹¹⁴;
- regulation of the Electricity Distribution activity via a price cap methodology¹¹⁵ for calculating allowed revenues;
- definition of reference costs for fuels (fuel oil, gas oil and natural gas) consumed in the generation of electricity, as well as for costs arising from the unloading and storage of those fuels.¹¹⁶

2.3.1.4 Norway¹¹⁷

The Norwegian regulatory model is an ex-ante revenue cap model. The regulator uses the model to decide the total level of allowed revenues for the TSO, taking into account that the TSO should be able to obtain a reasonable rate of return on invested capital, given effective operation, utilization and development of the network. The TSO set the tariffs based on the decision on allowed revenue from the regulator. The economic regulation for transmission network company in Norway, Statnett (TSO) is executed by annual determination of revenue cap. The current revenue cap regulation entered into force on the 1st of January 2007. According to the Energy Act Regulation, the main principles for calculation of revenue cap shall be re-evaluated periodically, but each period shall last a minimum of 5 years. Minor model adjustments can be executed during continuously. The revenue cap for Statnett is based on a yardstick model, as for any other network company. 40 % of the costs included in the revenue cap are based on the Statnett's actual costs (based on book values), while 60 % is based on a norm. This principle applies to costs related to network operations as well as system operations. The cost norm related to network operations is the result of a benchmark analyses. The benchmark of Statnett's transmission grid is based on the results of a European study on the TSOs, the e3GRID study.¹¹⁸ Statnett sets the tariffs based on their allowed revenue each year. The allowed revenue consists of the annual revenue cap decided by the regulator, property tax and tariff costs to other regulated grids. The deviation between actual collected revenues and the allowed revenue is subject to regulatory control. NVE set a yearly excess/deficit revenue balance. This balance is to be adjusted towards zero over time. Excess revenues must be reimbursed to the customers, while deficit revenues may be recovered. The TSO is also subject to incentive regulation related to quality of supply. As for any other network company, this is executed through full integration of the CENS arrangement in the revenue cap. For the TSO, CENS is included in the revenue cap with a norm weighing 60 %, while 60 % of actual CENS costs are subtracted in the calculation of allowed revenue. Actual collected revenues include tariff income from customers, bottleneck income (congestion revenues) and income from system operations. Any revenues generated from bottlenecks are considered to be a part of Statnett's actual collected revenue, and thereby reduces the base for tariffs that can be collected from Norwegian customers. This way of handling bottleneck income implies that this income also indirectly is used to finance investments to eliminate bottlenecks.

Joint revenue cap:

The revenue cap regulation is specified in detail in the Regulation governing financial and technical reporting, revenue caps for network operations and transmission tariffs (Reg. No. 302 of 11 March 1999). According to Section 11, the company appointed as system operator is regulated by a joint revenue cap; including costs related to the TSOs own network components and costs related to the exercise of the role as system operator. Further, it is stated that the sections defining the principles for the calculation of the revenue cap for the network sector shall apply to the revenue cap for the TSO as far as possible. NVE decides a yearly revenue cap for all companies, including the TSO. The revenue cap for Statnett is illustrated by the following formula:

Where,

114 The cost drivers in the distribution activity in both Autonomous Regions are distributed power and the number of customers. In the trading activity, the cost driver is the number of customers. In the Autonomous Region of the Azores, the efficiency targets applied to each of the activities vary between 2% for distribution and 3.5% for trading. In the Autonomous Region of Madeira, the efficiency targets are 4% and 3.5% for distribution and trading, respectively.

115 Efficiency factor set at 3.5%.

116 Electricity generation in the Autonomous Regions of the Azores and Madeira is regulated, and it is not liberalized, because these regions have benefited from a derogation of the application of Directive 2003/54/EC.

117 Source: www.nordicenergyregulators.org

118 Source: Agrell, P. J. and P. Bogetoft e3GRID Final Results (2009)

RC_t = Revenue cap

C_t = Cost base for actual costs related to network components

C_t^* = Cost norm for costs related to network components

$CENS^*$ = Expected level of CENS cost (CENS – cost of energy not supplied)

SO_t = Costs related to system operations

SO_t^* = Cost norm for costs related to system operations

Degree of norm cost/yardstick competition is set to 0.6

NVE notifies the expected revenue cap for TSO before the start of the year, based on estimates for WACC, CPI, the reference price on power related to power losses and system operation costs. These parameters are not known until the revenue cap year ends. When the parameters are known, NVE decides the final revenue cap for the year based on the actual values. The main intention of notification of the revenue cap is to give the companies an approximate figure to base their tariff decisions on for the revenue cap year.

Costs related to network operations:

The revenue cap for the TSO's network operations is calculated by the same principles, and including the same cost elements, as the revenue cap for any other network company.

There is a difference in the treatment of the quality element, due to the lack of comparable companies. For other network companies, the quality element (CENS) in the revenue cap is calculated yearly and included in the ordinary cost base and in the benchmarking analysis. For the TSO, the CENS element is only included in the revenue cap as a norm, ($CENS^*$), calculated as the CPI adjusted average of Statnett's CENS costs for 2001-2005. All economic, and some technical, data are collected annually through NVEs reporting system (eRapp). Total costs that enter into the regulation consist of operation and maintenance costs, capital costs, costs related to network losses and CENS. To be able to notify the revenue cap before the beginning of the year, the revenue cap is based on data from two years earlier, i.e. the revenue cap for 2012 is based on costs in 2012. The cost base is calculated according to the formula:

Where,

OM = operation and maintenance costs

CPI = consumer price index

PL = power loss volume

P = reference price of power

DEP = depreciations

RAB = regulatory asset base

$WACC$ = weighted average cost of capital

Some costs related to system operations are also included in the network operations cost base. This applies to personnel costs and capital costs (e.g. related to the system control center) ordinary included in the ordinary cost base. The cost norm, C^* , is a result of benchmarking analyses. Statnett also owns part of the regional grid, which is benchmarked by DEA, comparing Statnett's data to data for the other regional grid companies. The results from each analysis are weighed together to calculate the cost norm. The weights attached to the results are calculated as the respective shares of the total cost base. The cost norm is then found by multiplying the weighted result with the total cost base.

Operation and maintenance costs:

The operation and maintenance costs mainly comprise of personnel- and material costs related to own production of services and purchase of external services. The following cost units are included: purchases of transmission and system services, purchases of goods and material, salaries and other personnel costs incl. pension costs, other operating costs, bad debts and internally priced services. These costs also include costs related to the system operations responsibility.

Inflation:

NVE use the annual average CPI to inflate the O&M costs and CENS from two years back to reflect the price level in the revenue cap year t . The CPI is collected from Statistics Norway ¹¹⁹.

Capital costs:

The capital costs that enter into the regulated cost base are annual depreciations and return on the RAB. The RAB is based on historical book values for networks and other fixed assets. All accumulated depreciations and write-downs are subtracted from the historical cost. Networks under construction are not included the RAB. When calculating the RAB, NVE use net book values.

RAB:

The RAB for the TSO consists of the following fixed assets: central and regional network components, sites, buildings, customer-specific equipment, means of transport, fixtures, tools and computer equipment, and other fixed assets used in the network business. Components, buildings etc. utilized for the system operations responsibility are also included in the RAB. Leased assets are not included in the RAB. However, the leasing costs of network assets (lines, cables, transformers, switches) which is leased from another regulated network company is allowed to include in the tariffs costs related to other regulated grids (TC). Hence, it will be included into the allowed revenue (AR). To reflect the working capital, NVE add 1 % of the total book value to the RAB. The RAB is then multiplied with the WACC to calculate a reasonable return on the regulatory asset base.

WACC:

The Weighted Average Cost of Capital (WACC) is given by the following formula:

$$WACC_{post-tax} = 0.4[R_f(1-t) + \beta_e \times MP] + 0.6(R_f + P_d) \times (1-t)$$

Where the variables are as follows:

Nominal risk-free rate (R_f): Annual average yield of government bond with 5 years maturity

Tax rate (t): 28 %

Market premium (MP): 4 %

Asset beta: 0.35 (equity beta β_e : 0.875)

Debt/equity share: 60/40

Debt premium (P_d): 0.75 %

The WACC-model applied to the TSO is the same as for the DSOs. A CAPM-model was used to assess the cost of the companies' equity. The gearing ratio is 60 %. An average 5-years maturity government bond is used as a measure of the risk-free interest rate. The asset beta is set to 0.35 and the market premium is 4 %. On the debt-side, a debt premium equal to 0.75 % is used. The WACC formula is post tax, but NVE operate with a pre-tax rate of return. The WACC-formula is rewritten to an easier formula for pre-tax calculation of the rate of return:

$$NVE_{rate} = 1.14R_f + 2.39\%$$

The formula is determined in the Regulation on economic regulation of power networks. All parameters in the WACC formula except for the risk-free rate are fixed. Any amendments in the parameters require an amendment in the regulation. The risk-free rate on the other hand is updated annually when setting the revenue cap.

Depreciations:

The depreciation of capital is linear. The TSO decides the economic life of components based on the conditions in the area they are operated in, and then calculate the depreciation according to the expected economic lifetime of the specific network component.

Time-lag and treatment of capital costs related to investments:

Asset additions in the last and current year (year t and $t-1$) are not included in the RAB as a result of the time-lag in the cost base. However, the TSO can calculate the capital costs related to investments into their allowed revenue the year they are commissioned, as given in above formula for allowed revenue. This implies that investments are also included in the tariff base as of the commissioning year.

Network losses:

Network losses are measured as the difference between metered input and metered output (MWh). The costs related to the network losses are included in the cost base. To calculate the costs, NVE uses yearly reference prices of power. The prices are calculated based on volume weighted monthly area spot prices. In Norway there are currently five price areas. The monthly area spot prices are collected from Nord Pool Spot AS and the weight is based on monthly national consumption volumes collected from statistics published by NVE. The TSO operate in all price areas, as opposed to other network companies, which normally operate in one (or occasionally two) price area(s). To calculate the cost of network losses for the TSO, the reference prices for the areas are summarized and multiplied by the total volume of losses. The summarizing of area prices is done by assigning a weight to each reference price. This weight is calculated as the relative portion of loss volume in the respective areas (i.e. volume of losses in price area1/total volume of losses = weight assigned to the reference price for area1). A mark-up of 1.1 €/MWh is added to the final volume weighted spot price.

Quality dependent revenues:

The revenue cap is quality dependent, by inclusion of the element CENS, which internalize the customers' interruption costs. The net effect of the inclusion of the CENS element in the revenue cap and allowed revenue is that the customers indirectly are compensated for 60 % the socio-economic costs related to poor quality of supply through lower tariffs in the future. For the TSO, this implies an economic gain or loss depending on whether outage level in a given year is better or worse than the average included in the norm. The CENS arrangement is equal for all network companies, including the TSO. Normalized cost data (based on a customer survey conducted in 2001-2003) are used to establish continuous cost functions for the customers, which are divided in six groups: industry, commercial, large industry, public, agriculture, residential. Calculation of interruption costs is based on the mandatory reporting of interruptions. The arrangement includes both notified and non-notified interruptions. The cost of an interruption of duration r at reference time, C_{ref} , is calculated as follows:

where:

C_{ref} = Interruption cost for an interruption at reference time

$c_{ref}(r)$ = Cost rate in for interruptions of duration

P_{ref} = Interrupted power in kW at reference time

The reference time is a working day in January. The interrupted power is defined as the estimated power in kW that would have been supplied at the time of interruption if the interruption did not occur.

Interruption costs are found to vary by season, weekdays, time of day and whether the interruption is notified. Correction factors are therefore established to adjust the calculated cost of interruption, taking these facts into account.

Costs related to system operations:

SO_t is the actual system operation cost in year t , as reported in Statnett's yearly financial statements, where these costs are specified in a separate note. This cost element comprises of the direct costs related to the exercise of Statnett's system responsibility. The main elements are costs for buying reserve capacity from producers for primary regulation, special adjustments to correct for bottlenecks, costs related to buying tertiary reserves (balancing power options) and other system services such as purchase of reactive effect etc.

SO^* is the system operation cost norm, calculated based on a combination of historical costs and assumptions about the cost development for future years. The SO^* was fixed for a five-year period as of 2008; but can be evaluated if special circumstances should occur.

2.3.1.5 Sweden¹²⁰

The Swedish regulatory model is an ex-ante revenue cap model. Ex-ante regulation of network tariffs was introduced in 2012 and underwent changes to the second regulatory period 2016-2019. Despite important changes, the overall structure of the regulation is the same in the first and the second regulatory period. A revenue cap is established in advance of each regulatory period and each regulatory period for the Swedish TSO is four years. The revenue cap is decided based on a process involving an application from the TSO with a proposed revenue cap and economic and technical data and budget. This application is submitted by the TSO and is evaluated by the regulator. The regulator assesses whether the revenue cap budgeted by the TSO is reasonable. The regulator is in this process taking into consideration the customer's interests of low and stable tariffs and that the revenue cap should be sufficient to cover reasonable costs and give the TSO a reasonable rate of return on the capital required to operate the business. When the regulator calculates the cap, the regulator uses the technical and economic information provided by the TSO. The regulator also uses methods to determine cost for capital, rate of return and operations.

Operation costs cover both network operations and grid related system operations. The operating costs are, in the calculating process, divided into controllable and noncontrollable cost. The latter type of costs the company can pass through completely during the regulatory period. For calculating the controllable costs, the regulator uses the information from earlier regulatory periods. The regulator has decided on an annual efficiency requirement of one percent, which forces the TSO to reduce the controllable operating cost if they will keep the rate-of-return at the same level. The capital costs are calculated from the RAB. The calculated operational costs and capital costs are then added together to get a total revenue cap. The cap is then compared to the information in the application and the TSO's current revenue. From this information the regulator decides on a revenue cap for the upcoming regulatory period. The allowed revenue is, after the regulatory period has ended adjusted taking the outcome of the non-controllable operational cost into consideration. The cap is also adjusted to the outcome of quality in the regulatory period.

The allowed revenue includes the incomes from the following activities:

- Grid fees (tariffs) – the tariff for consumers and feed-in tariff and connection.
- Capacity Charges
- Transit revenues
- Other network revenues

If there are any deviations from the decided revenue cap, e.g. if the grid operator's actual revenue during the regulatory period deviates from the EI's decided revenue cap, then the excess/deficit amount will decrease/ increase the subsequent regulatory period's revenue cap¹²¹. If the actual revenue exceeds the cap with more than five percent, an overbilling addition will reduce the revenue cap for the subsequent regulatory period. The overbilling addition is a rate equal to the average reference rate according to Interest Act (1975:635), with an addition of fifteen percentage points¹²².

For the TSO, the capital costs constitute a significant proportion of the total costs due to large investments in infrastructure. EI has decided to calculate capital costs based on the principle of operating capital maintenance (OCM)¹²³. This means that the cost of capital reflects the asset's capacity to generate services rather than its age. The basis is fixed assets replacement value and a reasonable capital cost is calculated with a real annuity method. As long as the TSO is using a network grid component it receives capital cost for the component.

The cap shall cover reasonable cost to conduct network activities taking into account also the quality of the supply and delivery of services. The cap should provide SvK with sufficient resources to maintain its responsibility for system and security of supply and to operate the national grid in an efficient way. The operating cost of the Swedish TSO consists of costs for purchase of network losses, maintenance, operation, administration, etc. These costs are, in the calculation process, divided into controllable and non-controllable cost. The latter type of costs can the company pass through completely. For the controllable cost an annual efficiency requirement has been set. The efficiency requirement is one percent (1%), which in real terms forces the TSO to reduce the controllable operating cost if they will keep the rate-of-return at the same level. The operative and capital cost are then added together to calculate a total revenue cap.

When assessing if the claimed revenue cap is reasonable, EI has to consider the interest of customers of low and stable tariffs and the fact that the revenue cap should be sufficient to cover the grid company reasonable costs and earn a reasonable return on the capital required to operate the business. The calculated cap is therefor compared to the TSO's current revenues. This assessment should guarantee that the customers should not get unjustifiably large changes in the tariff from one year to another.

After the regulatory period, EI compares the cost deemed non-controllable with the TSO's actual costs during the period. The cap can be adjusted accordingly. The cap can also be adjusted if the outcome of quality in the regulatory period is higher or lower than expected. The figure below shows schematically how the revenue cap is determined.

121 Source: Energy Act (1997:857)

122 Source: Energy Act (1997:857)

123 Source: The other principle is financial capital maintenance (FCM).

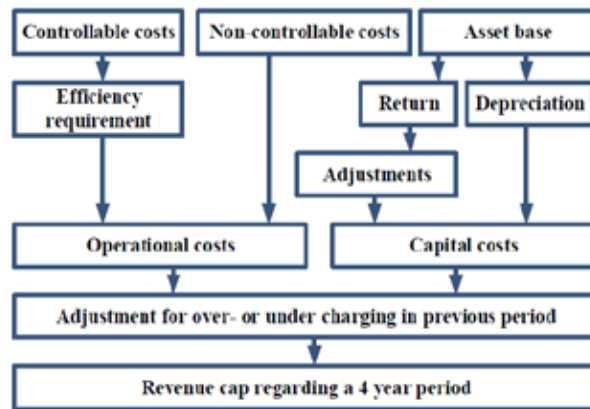


Figure 2.2 – Overview of the Swedish revenue cap regulation¹²⁴

Operational cost:

The operational cost can in turn be divided in two parts: controllable and non-controllable. The latter part is cost which the company in short term has no or little control over in terms of possibility to reduce over time. The first part is costs which the company has the possibility to reduce for given services (output). In a special report EI analysed how the division between different cost items should be done.

Non-controllable operational cost:

The TSO forecasts the expected non controllable cost for the regulatory period. After the end of the regulatory period the non-controllable costs are compared and adjusted if necessary.

Cost that is defined as non-controllable is possible to pass through to the customers and it does not have any efficiency requirement. This requirement on higher productivity is not applied for the non-controllable cost. EI has identified non-controllable costs as below:

- Purchase of loss power
- Cost for transit
- Costs for counter trading
- Energy compensation
- Cost of system operation, primary regulation and disturbance reserve

The grid losses are controllable in the long run, but for the first periods/years it will be regarded and treated as non-controllable cost. The Electricity Act states that the electricity for covering network losses shall be tendered in a competitive way. The grid company must tender the grid losses in an open, non-discriminatory and market orientated way. This cost is possible to examine in an auditing external from the economic regulation of revenue caps.

Since SvK is also the system operator for electricity in Sweden which involves ensuring that the Swedish electricity system functions reliably at the national level and that electricity production and import match consumption and exports throughout the country, the cost related to this business are treating as non-controllable. It means that the cost regarded as primary control, energy

compensation, counter trade, transit and disturbance reserve are non-controllable.

Note that only a part of the cost for primary control and disturbance reserve are treated as a non-controllable operational cost, the remainder belong to other activities that are not grid-related and thus they are not included in the regulation of the Swedish TSO.

Controllable operational costs

The starting point is the report from the TSO, where historical costs are taken from audited data from bookkeeping. The starting value is set to average the two latest years, two years before the regulatory period starts (e.g. the non-controllable operational cost for 2012 was set on the averages of the non-controllable cost 2008 and 2009 inflated to the price level of 2010).

The concept of controllable costs is necessary because those costs will have an efficiency target. The controllable cost is reduced year by year by an efficiency target. The TSO should be able to reduce these costs over time. EI has analysed and defined the cost items in controllable and non-controllable. A typical controllable cost is the cost for the staff and services.

EI has decided that a general requirement shall be applied on current controllable costs. The efficiency target has been set to 1 %.

To determine the size of the efficiency requirement, several analyses have been made. Productivity developments have been studied by calculations for the Swedish electricity grid companies, through comparisons with other sectors and by international comparisons.

Capital Cost

The capital cost is a product of a decided rate of return on assets, the calculated capital base and chosen depreciation times. The main principle to calculate the regulatory asset base is to use replacement values with real annuities. This valuation principle is supplemented by some other methods when explicit values of replacement are not known.

Asset base

The basis for calculating capital cost is fixed assets replacement value. Fixed asset is the physical equipment that the grid company uses to operate the grid.

To determine the regulatory asset base there are four methods which may be used to value assets within electricity networks. The four methods for valuation listed below shall be used in descending order. The standard values are the default mode, then acquisition values, then book-keeping values and at last other valuation methods.

During the regulatory period the asset base is adjusted for inflation. EI uses the development of production cost for buildings' index for this purpose.

1. **Valuation according to standard values:** Fixed asset included in the capital base shall as a first alternative be set to a replacement value that corresponds to a standard value. A standard value on each equipment to be calculated on the basis of the investment expenditure a grid company would have to acquire or produce in a cost-effective manner with due regard to conditions which grid company cannot affect. EI has decided on standard values for network components with voltage up to 220 kV. As SvK operates on the level 220 kV - 400 kV, EI has not standard values for assets on those levels. Instead, SvK has to use the method "acquisition values".
2. **Valuation according to acquisition value:** When there is no standard value for a component, the rules states that the replacement value should be calculated on the basis of the expenditure for the acquisition or the manufacturing of the fixed asset when it originally came into operation in the network. To take into account the change in price mode from the acquisition to present the Development of production cost for buildings index is used. The company must be able to verify that the acquisition value is the original.

3. **Valuation according to book value:** If there are no prerequisites to compute a replacement value based on the standard value or acquisition value, cost is calculated on the basis of the asset's book value.
4. **Valuation by other way:** If none of the above methods are applicable, then the value of the facility has to be determined by a reasonable method. An example could be a rented facility that is not in the list of standard values.

Return-on-capital (cost of capital):

EI has decided to use the Weighted Average Cost of Capital (WACC) method. The WACC method is an established method for determining the rates of return. WACC is used by several regulators for deciding on the normative value of rate of return. When the rate of return is calculated, EI aims to estimate the level of return that is necessary for attracting capital to the industry.

EI is relatively free to decide the WACC, but that often leads to long and complex court proceedings. The government have specified more in detailed how various parts of the WACC calculation should be calculated in the future.

2.3.1.6 UK¹²⁵

RIIO-ET1 is the first Electricity Transmission price control that utilises the RIIO price control model. This price control began on 1 April 2013 and runs for eight years, to 31 March 2021.

For each year of the price control, Ofgem sets network company cost baselines for each network company, which is their allowed TOTEX. This is to enable investment to maintain the existing network and accommodate a new network infrastructure, and to deliver agreed outputs. Network companies are required to report their actual TOTEX, explaining their performance compared to the allowed TOTEX and in relation to their agreed outputs annually. They are also required to forecast their TOTEX performance to the end of the price control.

As TOTEX refers to total controllable expenditure, it comprises both of Capital Expenditure (CAPEX) and Operational Expenditure (OPEX). Therefore, network companies are incentivized to deliver outputs based on total whole life costs, rather than being driven to preferring either OPEX or CAPEX. This better incentivizes them to select the best overall solutions for customers.

There are mechanisms to adjust revenues year-on-year depending on TOs' performance against pre-set targets. There are outputs associated with baseline revenues that TOs must deliver either on an annual or eight-year basis.

Using data and supporting information submitted by the TOs, Ofgem reviews how they are delivering against the financial and output requirements of the price control. In RIIO, the focus is on outputs, incentives and innovation as well as total expenditure (TOTEX), as follows;

- All TSOs expect that output delivery will meet or exceed the targets set against five of the six output categories across the price control period, namely: safety; reliability; availability; customer satisfaction; and environment. For the remaining output category, 'connections and wider works', the licensees are meeting their requirement to provide these (where requested) in a timely manner.
- All of the TOs are expecting to outperform their forecasted allowances over the entirety of RIIO-ET1 by between 5% and 12%. Due to the revenue adjustment mechanisms within the price control, a proportion of these savings will be shared with consumers.
- The financial performance of transmission companies is presented using the return on regulatory equity (RoRE) measure. Based on Ofgem's assessment of TOs' forecast performance for the whole RIIO-ET1 period, Ofgem calculates the RoRE range. This estimate depends on current forecasts and future delivery of outputs and may change during the relevant RIIO-ET period.
- The financial and output performance of TOs affects the Allowed Revenue that they can collect through customer bills. Ofgem estimates the average customer payment per annum to cover Electricity Transmission network costs and system

operation cost (for SO role of NGET). Charges differ depending on the region that a consumer resides in.

- The RIIO innovation mechanisms help to how network companies facilitate the transition to a low carbon economy.
 - o The Network Innovation Allowance (NIA) was established as part of the RIIO-ET1 price control. It is designed to fund small scale research, development and demonstration projects. The NIA provides each licensee with an allowance to spend on innovation projects in line with the NIA Governance Document¹²⁶. If successful, these projects should bring a wide variety of financial, operational, environmental and safety benefits.
 - o The Network Innovation Competition (NIC) is an annual competition to which both Electricity Transmission and Distribution companies can apply. It provides funding to a small number of large-scale innovation projects. Its aim is to encourage network companies to innovate in the design, build, development and operation of their networks. If successful, these projects should bring a wide variety of financial and environmental benefits.

Outputs are at the heart of the RIIO regulatory framework and capture the key areas within which consumers expect the delivery of high-quality services. The outputs framework comprises both primary outputs - visible to and valued by consumers, e.g. reducing energy not supplied - and secondary deliverables - indicators of performance used in support of the primary outputs, e.g. asset health and criticality.

RIIO-2 will be the next price controls for the network companies running the gas and Electricity Transmission and Distribution networks from 2021. They will replace the current network price controls.

RIIO is designed to encourage network companies to:

- Put stakeholders at the heart of their decision-making process.
- Invest efficiently to ensure continued safe and reliable services.
- Innovate to reduce network costs for current and future consumers.
- Play a full role in delivering a low carbon economy and wider environmental objectives.

The business plan incentives were designed as follows:

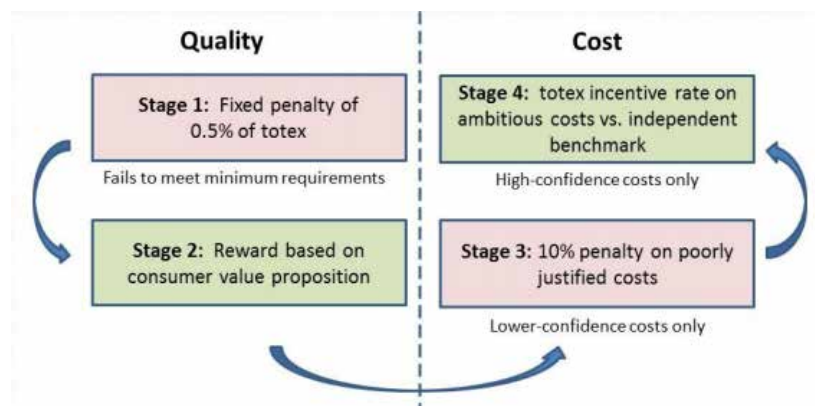


Figure 2.3 – Design of the Business Plan Incentive¹²⁷

The net reward or penalty capped at $\pm 2\%$ of allowed TOTEX.

Transmission losses:

- Develop and adopt strategy to contribute efficiently to fewer losses on network, including over the long term, than would otherwise be the case in the absence of strategy

¹²⁶ <https://www.ofgem.gov.uk/publications-and-updates/electricity-network-innovation-allowance-governance-document>.

¹²⁷ https://www.ofgem.gov.uk/system/files/docs/2019/09/riio-2_business_plans_guidance_september_2019

- Report on key milestones of implementing losses reduction strategy
- Contribute to evidence base on proportion of losses that network companies can influence/control

Ofgem has already launched his consultation on the 'RIIO-2 Framework Review'. The network companies were asked to submit their business plans. By the end of 2020, Ofgem will publish their final view on the price control allowances.

2.3.1.7 Turkey

Revenue cap methodology have been applied to OPEX and rate of return to CAPEX since 2003 in 3-year implementation periods, after 2009. In 2003, 2009, 2012, 2015 and 2018 EMRA set a revenue cap, which is based on actual TEIAS OPEX in "photo years" of previous implementation period and it is based on the expectation for future periods.

The deviation between actual collected revenues and the allowed revenue is subject to regulatory control. EMRA set a yearly excess/deficit revenue balance. This balance is to be adjusted towards zero over time. Excess revenues must be reimbursed, while deficit revenues may be recovered for CAPEX. There is no adjustment for OPEX.

TEIAS is regulated by a joint revenue cap; including costs related to the TEIAS' own network components and costs related to the exercise of the role as system operator. Furthermore, the calculation of the revenue cap for the network sector shall apply to the revenue cap for TEIAS as far as possible. EMRA decides a revenue cap for TEIAS. The revenue cap is efficiency dependent, but it was not applied up to now by EMRA.

The operation and maintenance costs mainly comprise of personnel and material costs related to own services and purchase of external services. The following cost units are included: purchases of transmission and system services, purchases of goods and material, salaries and other personnel costs, other operating costs, taxes, insurances and internally priced services. These costs also include costs related to the system operations responsibility.

EMRA use the annual average CPI to inflate the O&M cost from two years back to reflect the price level in the revenue cap year t. The CPI is collected from Turkey Statistics Authority¹²⁸.

The capital costs that enter into the regulated cost base are annual depreciations and return on the regulatory asset base (RAB). The RAB is based on historical book values for networks and other fixed assets including some intangible assets such as software. All accumulated depreciations and write-downs are subtracted from the historical cost. Networks under construction are not included the RAB. When calculating the RAB, EMRA use net book values.

The RAB for the TEIAS consists of the following fixed as network components, sites, buildings, customer-specific equipment, means of transport, fixtures, tools and computer equipment, and other fixed assets which their life-time is more than one year and used in the network business. Components, buildings etc. utilized for the system operations responsibility are also included in the RAB. Leased assets are not included in the RAB. The RAB is then multiplied with the WACC to calculate a reasonable return on the RAB.

The depreciation of capital is linear. TEIAS decides the economic life of components based on the conditions in the area they are operated in, and then calculate the depreciation according to the expected economic lifetime of the specific network component. 30 years economic lifetime is considered for transmission system components by TEIAS.

In the fourth implementation period OPEX budget is divided into two parts as transmission system usage-operation related part and non-transmission system usage-operation related part.

Cost that is defined as non-transmission system usage-operation related part is possible to pass through to the customers and it does not have an efficiency requirement. This requirement on higher productivity is not introduced for the non-controllable cost. EMRA has identified below as non-controllable:

- Purchase of loss power
- Cost for capacity mechanism to ensure security of supply
- Costs for ancillary services
- Cost of zero balance for market operation,

The grid losses should be as transmission system usage-operation related part in the long run, but for the first periods/years it was regarded and treated as non-transmission system usage-operation related part cost. The Electricity Act states that the electricity for covering network losses shall be tendered in a competitive way. TEIAS must tender the grid losses in an open, non-discriminatory and market orientated way. This cost is possible to examine in an auditing external from the economic regulation of revenue caps.

Network losses are measured as the difference between metered input and metered output (MWh). The costs related to the network losses are included in the cost base.

Transmission system usage-operation related part OPEX consists of 50% fixed, 50% variable linked to length of network lines, number of transformers, number of customers and transmitted energy with corresponding coefficients although controllable OPEX varies average 80% by the asset increases and 20% by the corporate governance fixed costs.

So far, TEIAS submits their CAPEX plans with limited justifications plans which is nearly inadequate to cover all capacity increase needs and network refurbishment as well as required technology investments.

2.3.2 RAB¹²⁹

The structure of individual components included in the RAB and their valuation differ significantly among EU Member States. The RAB can be comprised of several components such as fixed assets, working capital or construction in progress and the RAB value is usually linked with depreciation. Fixed assets, also known as a 'non-current asset' is a term used in accounting for assets and property which cannot easily be converted into cash. Fixed assets normally include items such as lines and substations, land and buildings, motor vehicles, furniture, office equipment, computers, fixtures and fittings, and plant and machinery. In EU countries; all Regulators count the fixed assets into the RAB. Some of the EU Regulators, approximately one third of them, calculate working capital into the RAB, therefore most countries do not include working capital into the RAB.

In Finland, accounts receivables and inventories are allowed into the RAB in book values, however cash equivalents or other receivables are excluded. In Estonia, the level of working capital is determined as 5% of the three years average sales revenue, whereas it is 1% of the book value in Norway. In Germany, only working capital, which is necessary for the operations is included and in Luxembourg the working capital is approved if fully justified. Half of the EU Regulators include Electricity Transmission assets under construction into the RAB. Only UK and Italy take contributions from the third parties into the RAB in their whole regulatory process. Around 40% of EU Regulators include leased assets into the RAB. In Electricity Transmission regulation, most of the EU Regulators (72%) do base RAB exclusively on the historical value of assets. The RAB is exclusively based on the re-evaluated assets in 5 countries: the Czechia, UK, Italy, Poland and Sweden. 7 EU Regulators apply a mix of historical values and re-evaluated assets: Germany, Hungary, Luxembourg, Portugal, Spain, Romania and Lithuania.

The RAB is ordinarily adjusted annually within the regulatory period when the value of the new investments is taken into consideration and the value of the depreciation is deducted. Over half of the EU Regulators adjust RAB during the regulatory period and the annual recalculation of the net book value (new investment depreciation) is the most common approach.

Table 2.4 shows explanation of RAB components, valuation and RAB adjustment in most of the EU Member States.



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Table 2.4 – Components of RAB¹³⁰

Country	Components of RAB	Regulatory asset value	RAB adjustments
Austria	Intangible and fixed assets, book values and ex-ante determination of investments according to the network development plan	Historic cost approach	Non
Czechia	Fixed assets, investments in progress, leased assets, no working capital	The RAB is based on re-evaluated values of assets that are recorded in the annual financial statements	The adjustment is similar to the net book value calculation (investment - depreciation), the formula for RAB adjustment is “investment – depreciation x k”; k is revaluation coefficient which is set annually and which is calculated as the result of dividing the planned value of the regulatory asset base in year “i-1” by the planned residual value of assets in year i-1; k = <0;1>
Denmark	Danish TSO regulation doesn't fit to this scheme. Energinet is ex-post regulated in accordance with a “non-profit” principle, whereby the company's tariffs may only cover the necessary costs incurred in efficient operation and an interest rate to ensure the real value of the company's capital base at 1 January 2005 (strict cost plus regulation).		
Estonia	Fixed assets, working capital, leased assets	Historical costs	The fixed assets do not include: 1) long-term financial investments; 2) intangible assets, except for software licenses; 3) fixed assets acquired with grant aid (including targeted funding); 4) fixed assets acquired with funds obtained from connection fees; 5) fixed assets which the undertaking does not use for the purpose of providing network service.
Finland	Fixed assets, working capital, leased assets	Regulatory asset value is calculated from network replacement value by applying network component-specific average age and lifetime selection	Book values taken to RAB annually from balance sheet
France	Fixed assets	Net book value	Subsidies and grants are removed from the value of assets before entering the RAB
Germany	Fixed assets, working capital, assets under construction	Net substance preservation for business assets capitalized prior to 1st 2006, real capital preservation for business assets as from 1st 2006	By the ordinance defined investments after the base year, e.g. expansions, lead to an adjustment of the non-controllable costs and therefore of the revenue cap
Greece	Fixed assets, working capital, assets under construction	Historical costs since 2009 (last revaluation in 2004)	No adjustment, historical values. Since Allowed Revenue is calculated in real terms, an adjustment of RAB is taken place from one Regulatory Period to another based on CPI.
Hungary	Fixed assets	Network assets: depreciated replacement value; Non-network assets: historical costs.	The assets of the base year are modified yearly with CPI and T-1 year's investments minus depreciation minus connection charges
Iceland	Fixed operating assets	Book value	CPI adjusted book values

¹³⁰ Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.



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Country	Components of RAB	Regulatory asset value	RAB adjustments
Ireland	Fixed assets, assets under construction	Replacement cost approach: Historic cost indexed to present value using inflation	Assets which have been added to the RAB, but have not been energised within 5 years (except in the case where the programme of work was scheduled to be longer than 5 years or where the SO can satisfactorily show that the delay is beyond its control) will be temporarily removed or “paused” from the RAB (with all return and depreciation paused) until the point at which the asset can be energized and utilized)
Italy	Historical revaluated cost	-	-
Latvia	Fixed assets, intangible investment, and does not include inventories and assets under construction.	Book value as per financial reports (taking into account asset revaluations carried out by the operator at replacement cost value)	The RAB is adjusted and set when the operator submits the tariff proposal; during the period the tariff is in force there is no RAB adjustment taking place.
Lithuania	Fixed assets	Value calculated using historical and current (for the main network elements (lines, cables, transformers) assets which will be depreciated until 2020) cost – 363 million Euro (2018)	New investments and depreciation
Luxemburg	Fixed assets containing production costs, work in progress	For assets since 2010: historical costs Before: asset financed by own funds (max 50%): historical costs re-evaluated with published indexes Remaining part: historical costs	Adjustments not foreseen in the method; After activation, new assets also enter the RAB
Netherlands	Fixed assets and certain intangible assets (such as software) are included, no working capital	Annual indexation (with CPI); Also, adjustment for certain specific (expansionary) investments	Annual indexation (with CPI)
Norway	Book values from financial statement adjusted with 1% working capital premium, assets under construction and grants funded assets are excluded.	Book values from financial statements	BV + 1% working capital premium
Poland	Fixed assets, assets under construction, intangible assets	Re-evaluated assets	Annually
Portugal	Fixed assets deducted from third party contributions	2 101 million euros for 2016 (mix of historical costs and standard costs)	Each year the RAB allowed for year t is adjusted in order to consider new investments, write-offs and depreciation
Romania	Historical costs multiplied with index costs. Investments in new assets after the base year lead to an adjustment of the CAPEX	The assets of the base year used as initial RAB. For each year of the regulatory period, the RAB value increases with the investment in new assets and decreases with depreciation and the value of the asset that exits before complete depreciation. For RAB existing in 1 Jan. 2005 or the privatisation date, it was a fair value of the assets, updated with inflation. For the rest of the assets, based on historical costs updated with inflation.	RAB adjusted with CPI.
Spain	Fixed assets (No working capital; No assets under construction)	Electricity: depending on commissioning year: Replacement cost / Average between audited costs and Investment reference values. For TSO singular assets: Audited costs.	Assets built year n-2 are added year n
Sweden	Meters, lines (grid), and network stations	2015: ~€5.7 Billion	Adjusted for inflation, adjustments for new investments and disposals



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Country	Components of RAB	Regulatory asset value	RAB adjustments
UK	RIIO is used as a variation of RAB approach and hybrid between RAB and Net Present Value approaches, as explained in this section.		
Turkey	Fixed assets and certain intangible assets (such as software), no working capital, no leased assets	2019, 10 672 Million ₺. Fixed asset, 15-year depreciation for the old assets in the first implementation period, 30-year depreciation for new assets in the first and consequent periods.	RAB adjusted with CPI.

In **Germany**, new assets (capitalized since 01/01/2006) are valued at historical costs. Old assets (capitalised before 01/01/2006) are valued at replacement costs if they are financed by equity (indexed historical cost, maximum equity ratio of 40%) and at historical costs if they are financed by debt capital (debt ratio at least 60% of all old assets).

Regulatory authority determines the asset life for different asset groups, such as: HV network-underground cables (40–50 years), overhead lines (40–50 years), substation equipment and auxiliary equipment including transformer and switchgear (35–45), protection, measuring and surge protection equipment, remote control, telecommunication, tele-metering and automatic equipment as well as control equipment including coupling, transformer and switching stations (25–30), general fixed assets (buildings (50–70 years), furniture and fixtures (8–10 years), tools/devices (14–18 years), hardware – software (3–8 years), vehicles (5–8 years), among others.¹³¹

In **Italy**, fixed assets are included into the regulatory asset base (RAB), with a one-year lag if investment costs are efficiently incurred and are consistent with system security, follow cost-effective criteria and, with regard to transmission, and are included in the ten-year transmission development plans approved by the relevant authorities. The RAB value is expressed in current costs and is based on depreciated historical costs inflated using a construction-specific index (*‘Investimenti Fissi Lordi’*). In other words, capital costs are based on data from the accounting records of network operators. Assets under construction are not included in the RAB, with some exception for transmission. Italy takes contributions from the third parties into the RAB in their whole regulation. Depreciation is calculated under a straight-line method for all fixed assets in use included in the RAB. In Italy, the gross fixed investment deflator measured by the National Institute of Statistics is used for inflation.

In **Norway** RAB for the TSO consists of fixed assets such as central and regional transmission network components, sites, buildings, customer-specific equipment, means of transport, fixtures, tools and computer equipment, and other fixed assets used in the network business. Leased assets are not included in the RAB. However, the leasing costs of network assets (lines, cables, transformers, switches) which is leased from another regulated network company is allowed to include in the tariffs costs related to other regulated grids (TC). Hence, it will be included into the allowed revenue (AR). To reflect the working capital, NVE add 1 % of the total book value to the RAB. The RAB is then multiplied with the WACC to calculate a reasonable return on the regulatory asset base. Assets that are financed by third parties as investment contributions are not included in the RAB, however, operating costs related to these are not excluded from the overall operating costs. To reflect the working capital, 1% of the total book value is added to the RAB. The RAB is then multiplied with the WACC to calculate a reasonable return on the regulatory asset base.

Asset additions in the last and current year (year t-1 and t) are not included in the RAB as a result of the time-lag in the cost base. However, the companies can calculate the revenue from investments into their allowed revenue the year they are commissioned. This implies that investments are also included in the companies’ tariff base as of the commissioning year.

In **Portugal** all the investments paid by TSO are included in the RAB and therefore accepted in the allowed revenues. Book value of assets is considered in the asset base. Tariffs are annually fixed by ERSE based on energy and economic forecasts for demand, costs, revenues and capital expenditures. The incentive to capital expenditure consists of the determination of the regulatory asset base (RAB) and the rate of return as a function of the level of efficiency obtained by the company. A price cap methodology with efficiency targets for OPEX is applied by ERSE.

In the **UK**, RIIO is a variation of the RAB approach and is hybrid between RAB and Net Present Value approaches. In the UK, the RAB indexed for inflation using RPI (Government retail price index of inflation including interest costs) is applied. UK take contributions from the third parties into the RAB in their whole regulation. As explained in previous sections, for Base Revenue calculations a

¹³¹ Source: ERRA, 2009, Determination of the Regulatory Asset Base after Revaluation of License Holders’ Assets.

portion of allowed TOTEX is directly added to the Base Revenue (Fast Money) and the company collects these revenues during the next allowed revenue year. The remainder of allowed TOTEX is named Slow Money and it is added to the opening Regulatory Asset Value (RAV), where RAV is based on the initial market value of the regulated asset base at privatisation, plus all subsequent additions. RAV is gradually reflected in Base Revenue over multiple decades, reflecting the average lifetime of network assets. Amounts are deducted annually from opening RAV (this is depreciation). The depreciation value is then added to Base Revenue in the next Allowed Revenue year. The average of opening and closing RAV for the year also earns a return (at WACC).

In **Turkey**, as similar to almost most of the EU countries, assets belong to the TSO. RAB consists of unamortized network assets, expropriation costs, buildings, vehicles which were constructed or acquired by TSO and approved by EMRA as CAPEX at the end of each year. Depreciation period has been set as 15 years for the old assets constructed or acquired before EMRA implementation periods and 30 years for new assets. Third party assets are not included in the RAB, however, operating costs related to specific ones are included in overall operating costs since 2013 after the new Law No: 6446. Closing RAB is carried over to the following year by CPI.

2.3.3 Rate of Return

Rate of return for countries is defined in the following table. In most of the countries WACC is used, where the value of WACC changes between 5% and 10% for EU countries. WACC is used as 12.47% (in real terms) for fifth implementation period of TEIAS in Turkey. Countries such as Belgium, Denmark, Germany and Spain do not use WACC in the regulation of electricity TSOs.

Table 2.5 – Rate of Return in European Countries¹³²

Country	Type of WACC	Determination of the rate of return on equity	Rate of return on equity before taxes	Use of rate of return
Austria	Nominal WACC pre-taxes	$Re = (\text{nominal risk-free rate} + \text{levered Beta} \times \text{MRP}) / (1 - \text{tax rate})$	8.16% (nominal pre-tax, set in 2017) = $(1.87\% + 0.85 \times 5\%) / (1 - 0.25)$	WACC nominal pre-taxes * RAB (book values)
Belgium	No use of WACC	Sum of a nominal risk-free rate and a risk premium (market risk premium multiplied with a risk factor) multiplied with (1+illiquidity premium) multiplied with a corporate tax factor	5.76%	Granted for existing assets to a maximum of 33% of the imputed business assets. Any available equity capital in the capital structure in excess of this will be subject to another equity interest rate
Czechia	Nominal, pre-tax WACC	Sum of nominal risk-free rate and a risk premium (market risk premium multiplied by beta factor)	10.28%	The whole RAB is multiplied by the WACC. When setting the nominal pre-tax WACC the D/E ratio of 45.75/54.25 was used.
Denmark	Danish TSO regulation doesn't fit to this scheme. Energinet is ex-post regulated in accordance with a "non-profit" principle, whereby the company's tariffs may only cover the necessary costs incurred in efficient operation and an interest rate to ensure the real value of the company's capital base.			

¹³² Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.



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Country	Type of WACC	Determination of the rate of return on equity	Rate of return on equity before taxes	Use of rate of return
Estonia	Pre-tax WACC nominal	1) Germany 10 years average bonds yield 2) Estonian risk premium 3) McKinsey market risk premium 4) Beta	5.60%	4.46%
Finland	Nominal, pre-tax	Risk-free rate + beta*Market risk premium + Premium for lack of liquidity (+ additional risk premium for natural gas TSO and DSOs)	7.96%	Reasonable return is calculated by multiplying the adjusted capital invested in network operations by the reasonable rate of return. Therefore, company receives reasonable return on adjusted equity and interest-bearing debt invested in network operations.
France	Pre-tax, nominal	Sum of a nominal risk-free rate and a risk premium (market risk premium multiplied by a beta risk factor) multiplied with a corporate tax factor	9.7%	Multiplied with the whole RAB (except assets that were funded through subsidies or grants)
Germany	No use of WACC	Sum of a nominal risk-free rate and a risk premium (market risk premium multiplied with a beta risk factor) multiplied with a corporate tax factor	6.91%	Granted for existing assets to a maximum of 40% of the imputed necessary business assets. Any available equity capital in the capital structure in excess of this will be subject to another equity interest rate
Greece	Real, pre-tax	WACC: a) CAPM & additional country risk premium for cost of equity; and b) cost of debt based on operators' proposal and actual figures of base year	12.6%	WACC is applied on the value of Regulatory Asset Base (RAB) for each year of the Regulatory Period
Hungary	Real, pre-tax	Sum of the real risk-free rate and risk premium (equity beta multiplied by market risk premium)	6.20%	Has a 49% weight in WACC.
Iceland	Pre-tax WACC	$Re = (rf + (rm - rf) \cdot \beta + \text{specific risk}) / (1 - t)$ Sum of real risk-free rate and a risk premium (market risk premium multiplied with a beta risk factor) plus a specific risk premium multiplied with a corporate tax factor	10.7%	The Pre-Tax WACC is the rate of return, it is granted for operating necessary business assets.

Country	Type of WACC	Determination of the rate of return on equity	Rate of return on equity before taxes	Use of rate of return
Ireland	Baseline WACC plus an aiming up allowance	The CAPM methodology is used to calculate the cost of equity using the formula: $ke = rf + \beta \times (rm - rf)$ where: ke is the expected rate of return for the risky asset; rf is the rate of return on a 'risk-free' asset (the "risk-free rate" or "RFR"); β is the 'beta' factor, which is correlation of the return on the risk asset with the expected returns on a diversified portfolio of all investable assets; and rm is the expected rate of return on a market value-weighted portfolio of all assets (the 'market portfolio'). The term $rm - rf$ in the CAPM is referred to as the market risk premium ("MRP").	Cost of equity (pre-tax) – high 7.99% Low 5.62% Point Estimate 6.63%	The Regulatory Asset Base (RAB) is the base to which the rate-of-return is applied when determining the return on capital
Italy	Real, pre-tax	-	-	-
Latvia	Post-tax, nominal	Return on equity: Sum of a nominal risk-free rate, market risk premium multiplied with a beta risk factor, and a sector risk premium.	6.67% (post-tax) 7.85% (pre-tax)	WACC is applied to the value of RAB to calculate the return on capital, which is a part of capital costs in tariff.
Lithuania	Nominal, pre-tax	Return on investment is determined as weighted average cost of capital, calculated according to the formula: $WACC = Rd \times WD + Re \times 11 - m \times WE$	Rate of return on equity = 8.58% WACC = 4.90%	WACC is used to calculate return on investment. WACC is a multiplied with whole RAB
Luxemburg	Nominal pre-tax WACC	Sum of cost of debt and cost of equity. For more details see explanations	6.12%	Granted for self-financed assets in the RAB and for work in progress according with respect to the dispositions of E16/12/ILR and E16/13/ILR

Country	Type of WACC	Determination of the rate of return on equity	Rate of return on equity before taxes	Use of rate of return
Netherlands	Real, pre-tax	Equity risk premium is based on data in individual Eurozone countries over the period 1900-2015 (Dimson, Marsh en Staunton database). An average of both the geometric and arithmetic average is taken.	6.7%	Real WACC is currently based on a 50% debt and 50% equity capital structure. Real WACC is multiplied with the indexed RAB.
Norway	Nominal, pre-tax	CAPM	12%	WACC is multiplied with RAB
Poland	Pre-tax nominal	(Risk-free rate + $\beta_{equity} * \text{equity risk premium}$)/(1-corporate tax rate)	7.84%	In allowed revenue they include: $RoC = WACC * RAB$
Portugal	Nominal, pre-tax	CAPM	7.9%	WACC is currently based on 55% debt and 45% equity applied to RAB
Romania	Real, pre-tax	Sum of risk-free rate and a market risk premium multiplied with beta	7.2%	Granted for initial RAB (privatization value), existing assets and new assets. RRR is multiplied with whole RAB. Debt and equity percentages are 40/60%.
Spain	For the current regulatory period, WACC was not used	For the current regulatory period, the rate of return was set as the average yield of the Spanish 10-year Bond of April, May and June 2013 (4,503%) plus a spread of 200 b.p. resulting 6,503%. For subsequent regulatory periods (year n; year n+5), the Rate of Return will be fixed as the average yield of the 10-year - Spanish Bond from (May year n-3; April year n-1) plus a spread		Rate of return is applied (nominal pre-tax) on RAB
Sweden	Real WACC pre-tax	CAPM: $re = rf + \beta * (rm - rf) + \text{Extra risk premium}$	10.39%	The debt share is derived from market values of European comparison companies that are publicly traded (52% debt 48 % equity for electricity)
UK	Real, post-tax	CAPM	7% for NGET TO	Based on cost of debt and cost of equity
Turkey	Real WACC, pre-tax	CAPM (Weighted Average Cost of Capital)	12.47%	Based on cost of debt and cost of equity

In **Germany** the regulatory authority sets the costs of capital, whereas the cost of debt is defined by law. For the 3rd implementation period, in line with the related regulation in force, the allowed rate of return on equity needed for new installations may not exceed the average current yield¹³³ for the last 10 full calendar years on fixed interest securities of domestic issuers, plus an appropriate mark up to cover entrepreneurial risk specific to network operation. The equity return is determined as 6.91% (pre-

133 Yield in detail - public debt securities, corporate bonds (excluding non-profit institutions at banks [MFIs]), mortgage bonds). These yields are published by the German Central Bank (Deutsche Bundesbank) and as arithmetic means for the last ten completed calendar years.

tax) for the new assets. Cost of debt is treated as pass-through and therefore allows for natural hedge against changes in interest rate environment.¹³⁴

The costs data are supplemented by a calculated return on equity. Anyone investing in a business enterprise expects a return on the capital employed that is competitive and reflects the industry-specific risks. This return is usually a result of market forces and depends on the individual sector and the general level of interest rates. If there is an imbalance between the risk of investment and potential earnings, as a rule there will be no investment. However, since network operators – by virtue of their natural monopoly – are not fully subject to these market mechanisms, yet still need to make vital investments in infrastructure, the rate of return on equity is determined by the regulator.

The return on equity comprises a risk-free rate (determined on the basis of the ten-year average current yield of fixed-interest securities) and a risk premium. The premium covering network-specific risks is determined using the CAPM and is derived from the product of an imputed market risk premium and a risk factor (beta factor).

Corporate tax is accounted for through a factor applied to the sum of the risk-free rate and the risk premium. Trade tax is, by contrast, determined on the basis of the return on equity.

The rate of return on equity is different for new and old assets. The return on equity comprising the risk-free rate, the risk premium and the corporate tax factor is applicable to “new assets” that first existed in or after 2006. A rate adjusted to take account of inflation is applicable to “old assets” that existed before 2006.

The rate of return on equity is granted for existing assets to a maximum of 40% of the imputed necessary business assets. Any available equity capital in the capital structure in excess of this will be subject to another equity interest rate. This “equity interest rate” is aligned with the standard rates of interest for procured capital and is set as a ten-year average based on the yields published by the German Bundesbank (federal bank). Existing borrowed capital is recognised at equal value insofar as any interest on borrowings does not exceed the customary market interest rate for comparable loans.

In *Italy* the rate of return on invested capital is calculated using the same formula described in the Electricity Distribution Section.

In *Norway*, the level of the regulatory rate of return is decided by a weighted average cost of capital model as shown in the below formula:

$$WACC_{pre-tax} = (1 - G) \times [(R_f + Infl + \beta \times MP) / (1 - t)] + G \times (Swap + P_d)$$

Variables	Yıl	Rate
G : 0.6 - Gearing (Debt share of total capital)	2018	6.10%
R _f : %2,5 - Real risk free rate for equity	2017	6.12%
Infl: Moving average of 4 years inflation, observations from previous year and the current year, and expected inflation for the next two years	2016	6.32%
	2015	6.32%
β ₀ : 0,875 - Equity beta	2014	6.61%
	2013	6.90%
MP : %5 - Market Premium	2012	4.20%
Swap : Nominal rate for debt: Annual average of 5-years swap rate	2011	5.31%
P _d : Debt premium: Annual average of credit spread for 5-year bonds for the power sector, minimum rating BBB+	2010	5.62%
	2009	6.19%
t : %25 - Tax rate	2008	7.44%
	2007	7.83%

Figure 2.4 – Determination of WACC in Norway¹³⁵

¹³⁴ Source: Groebel A., (April 2018), BNetzA's role in energy infrastructure regulation and planning/permitting.

¹³⁵ Source: www.nordicenergyregulators.org

Pre-tax nominal WACC is used in **Portugal**: CAPM is used to set the cost of equity and a default spread model, where a spread (debt premium) is added to the risk-free rate is used for cost of debt. In order to deal with uncertainty and financial volatility environment, rate of return is updated ex-post each year. WACC is indexed to the Portuguese 10-year bond benchmark and depends on its evolution with a cap and floor. The floor and cap limits within the annual RoR can evolve over the 2018-2020 period were determined as 4.75% and 9.75% respectively.

For the electricity regulatory period 2018-2020, a 0.75% premium is added to the electricity TSO WACC, for investments after 2009, when their cost is considered efficient, using a methodology where real and standard costs for those investments are compared.

For electricity TSO, ROE parameters are as follows:

- Risk free rate (nominal): 1%
- Tax rate: 31.5%
- Equity risk premium: 7.66%
- Equity beta: 0.58
- Cost of equity (before taxes): 7.94%

Like other countries, WACC is used to calculate allowed return in **UK**. In estimating the cost of equity parameter within the WACC, Ofgem primarily relied on the capital asset pricing model (CAPM) but sense checked the result with other methods, e.g. dividend growth model and market to asset ratios. Cost of debt is based on a long-term trailing average of forward interest rates, and the revenues allowed under the price control is adjusted each year for changes in this trailing. Allowed cost of equity and Vanilla WACC are determined as 7% and 3.95% respectively for NGET (TO) in 2019¹³⁶.

Pre-tax corrected real WACC (corrected real reasonable return on investment) is used in **Turkey**. Time adjustment conversion is used for final real WACC¹³⁷. For conversion of WACC from nominal to real¹³⁸, expected inflation rate (by the Central Bank) is used. However, as in the recent years inflation rate was quite unstable, thus real RoI rates did not meet the expectations.

2.3.4 Performance Indicators¹³⁹

Under a regulatory regime that provides incentives to cut costs, there is a risk that operators will refrain from undertaking the necessary investments or measures in order to achieve the required or potential savings. The TSO is subject to a far softer quality regulation which is only a simple penalty system, and which has not been activated so far. The most common indicators for measuring continuity of supply in transmission networks are ENS (energy not supplied) and AIT (average interruption time). ENS gives the total amount of energy that would have been supplied to interrupted users had there been no interruption. AIT is expressed in minutes per year and is calculated as 60 times the ENS (in MWh) divided by the average power supplied by the system (in MW). Quality indicators in European countries and Turkey for long and short interruptions are presented in the below Table.

Table 2.6 – Indicators for Long and Short Interruptions¹⁴⁰

Country	Long Interruption-Index	Long Interruption-Weighting	Short Interruption-Index
Austria	SAIDI, SAIFI, ASIDI, ASIFI, CAIDI, (CML, ENS)	Weighted by both the transformer stations affected and by the number of customers	No specific indicator

¹³⁶ Source: <https://www.ofgem.gov.uk/publications-and-updates/rrio-et1-price-control-financial-model-annual-iteration-process-november-2019>

¹³⁷ Source: EMRA communiqué dated 19th December 2015. Article 16, Paragraph 7.

¹³⁸ Source: EMRA communiqué dated 19th December 2015. Article 16, Paragraph 6.

¹³⁹ Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.

¹⁴⁰ Source: 6TH CEER BENCHMARKING REPORT ON THE QUALITY OF ELECTRICITY AND GAS SUPPLY, 2016. Energy Quality of Supply Work Stream (EQS WS), CEER Benchmarking Report 6.1 on the Continuity of Electricity and Gas Supply, Data update 2015/2016.



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Country	Long Interruption-Index	Long Interruption-Weighting	Short Interruption-Index
Belgium	SAIDI, AIT	AIT used for HV/EHV and weighted by the power affected	No specific indicator
Bulgaria	SAIDI, SAIFI	By the number of customers	No specific indicator
Czechia	ENS, AID (sum of duration divided by number of interruptions)	not weighted	No specific indicator
Denmark	SAIDI, SAIFI	It is weighted by type of interruption, kilometres of electricity network and by the number of customers	No specific indicator
Estonia	SAIFI, CAIDI, total annual interruption time for each customer	By the number of customers	No specific indicator
Finland	In 400 kV, 220 kV and 110 kV: duration of interruptions and amount of interruptions (in total).	By the annual energy consumption	No specific indicator
France	AIT, SAIFI and ENS for transmission network. There are several versions of each of these indicators, depending on the type of disconnection (planned/ unplanned), the voltage level, and the cause (exceptional event included or not).	Depends on the indicator. For continuity indicators such, it is weighted by the number of delivery points affected (for HV and EHV).	MAIFI
Germany	SAIFI	Not weighted	No specific indicator
Greece	SAIDI, SAIFI	By the number of customers	No specific indicator
Hungary	AIT – ENS/ES (Outage rate)	By the number of customers	No specific indicator
Ireland	Customer minutes lost, customer interruptions	the system minutes lost indicator is related to the power affected	No specific indicator
Italy	ENS, ENW, AIT, SAIFI	number indicators are referred to transmission users	MAIFI, separately for short and transient interruptions.
Latvia	SAIDI, SAIFI, CAIDI, ENS	By the number of customers	MAIFI
Lithuania	ENS, AIT	By the number of customers ENS, AIT – interrupted power	MAIFI
Luxemburg	SAIDI, SAIFI	By the number of customers	No specific indicator
Netherlands	SAIDI, SAIFI and CAIDI	By the number of customers	No specific indicator
Norway	With reference to end-users (all voltage levels): SAIDI, SAIFI, CAIDI, CTAIDI, CAIFI, interrupted power per incident and ENS	By the number of customers By the amount of ENS and by the amount of interrupted power	With reference to end-users (all voltage levels): SAIDI, SAIFI, CAIDI, CTAIDI, CAIFI, interrupted power per incident and ENS.
Poland	ENS, AIT and according to the IEEE Std. 1366-2003: SAIDI, SAIFI	By the number of customers	No specific indicator
Portugal	ENS, AIT, SAIFI, SAIDI, SARI	SAIFI and SAIDI: weighted by delivered points; ENS: estimated; TIE: energy not supplied and energy supplied	MAIFI (EHV, HV and MV).
Romania	ENS and AIT for the whole country	By the number of customers At 220-750 kV, ENS and AIT are used	No specific indicator
Slovenia	SAIDI, SAIFI (implicitly ENS, AIT, AIF, AID)	By the number of customers	MAIFI

Country	Long Interruption-Index	Long Interruption-Weighting	Short Interruption-Index
Slovak Republic	1. N 400 (average number of un-planned interruptions relating to the one transformer on the voltage level 400 kV). 2. N 220 (average number of un-planned interruptions relating to the one transformer on the voltage level 220 kV).	By the number of transformers	No specific indicator
Spain	ENS, AIT and facility available percentage.	By the power affected	No specific indicator
Sweden	Since data on customer level is available regarding interruptions, NIS-tagged information, transferred energy, max effect and transferred energy of the overlying transformer, a large range of customer level and system level indicators can be calculated such as active power not supplied in kW, energy not supplied. ENS and PNS, ENS, PNS are used as indicators.	By the number of customers	MAIFI-E
Switzerland	SAIDI, SAIFI, ENS.	By the number of customers	No specific indicator
UK	The 2 main indicators are Customer Interruptions and Customer Minutes Lost. Ofgem also collects information on the number of transmission incidents and the level of energy not supplied for each incident	By the number of customers	No specific indicator
Turkey	In 400 kV, 154 kV and 66 kV: duration of interruptions and amount of interruptions (in total).	Not weighted	No specific indicator

General reward or penalty schemes or incentives to optimise continuity of supply levels have been introduced in 17 of the 26 countries that provided feedback: Belgium, Bulgaria, Czechia, Denmark, Finland, France, Germany, UK, Hungary, Ireland, Italy, the Netherlands, Norway, Portugal, Slovenia, Spain and Sweden. However, the use of rewards, penalties and a combination of those, differs among countries and is also applied differently to the transmission and the distribution levels. Penalties are usually coupled with rewards and can be applied to distribution or transmission networks or both. As it is seen in the above Table, countries do not use the same indicators. Most of the countries that have not yet implemented a continuity of supply scheme either consider, plan or have intentions to introduce such a regime (e.g. Austria, Greece, Luxembourg and Romania).

In **Germany**, quality regulation was implemented with the beginning of the year 2012. For the time being this system is valid just for Electricity Distribution system operators on LV and MV with more than 30,000 customers although there is no exact legal distinction between DSOs and TSO. That means in general this system is valid for the TSO as well. One reason why it is not applied to the TSO is because there is no reliable data available concerning continuity level on high voltage level and extra high voltage level. The system is an addition to the incentive-based regulation, which was implemented in 2009. No cost estimation surveys, or estimations of an optimal continuity level were conducted. Network operators are able to get a reward or a penalty which is dependent on their overall performance concerning continuity of supply in comparison to the other network operators. Overall performance of the network operator is measured by SAIDI on LV, ASIDI on MV and SAIFI on HV. The aim of the quality regulation system in Germany is to achieve a socio-economic acceptable level of continuity of supply which is not set by NRA.

In *Italy*,¹⁴¹ transmission quality has also been regulated with rewards and penalties since 2008. A survey for estimating customer interruption costs was carried out in 2003 and the results have been embedded for valuating both rewards and penalties.

The quality of Italian transmission system service – and consequently the sustainability of Terna’s work – is constantly monitored and measured by specific indicators, some of which are set by ARERA. Two of the most significant indicators are ASA (Average Service Availability) and ENSR (Reference Energy Not Supplied). The first records service availability – namely its quality and continuity – whereas the second measures the frequency and impact of events occurring to the electricity grid and attributable to external faults or factors, such as specific meteorological events. Based on the ENSR indicator, ARERA sets the incentive/penalty mechanisms, which determine Terna’s regulated revenue.

Table 2.7 – Indicators for measuring Terna’s service quality

Indicator	Terna’s performance	What does it measure?	How is it calculated?	Comment to calculated value
ASA	99.99%	“Average Service Availability” - Availability of the National Transmission Grid (RTN) service	Complement of the ratio between the sum of the electricity not supplied to users connected to the RTN (ENS) and the electricity introduced into the grid.	The figure is close to 100% as in previous years, representing the complement at 100 and confirms the high quality levels of Terna’s service.
ENSR	339 MWh (2016 value)	“Reference energy not supplied” - Electricity not supplied subsequent to events originating on the relevant grid, or the High-Voltage and Extra-High-Voltage grid	Sum of the electricity not supplied to users connected to the RTN (following events originating on the relevant grid).	This indicator also reflects very high quality, considering that the target that should not be exceeded is set at 980 MWh

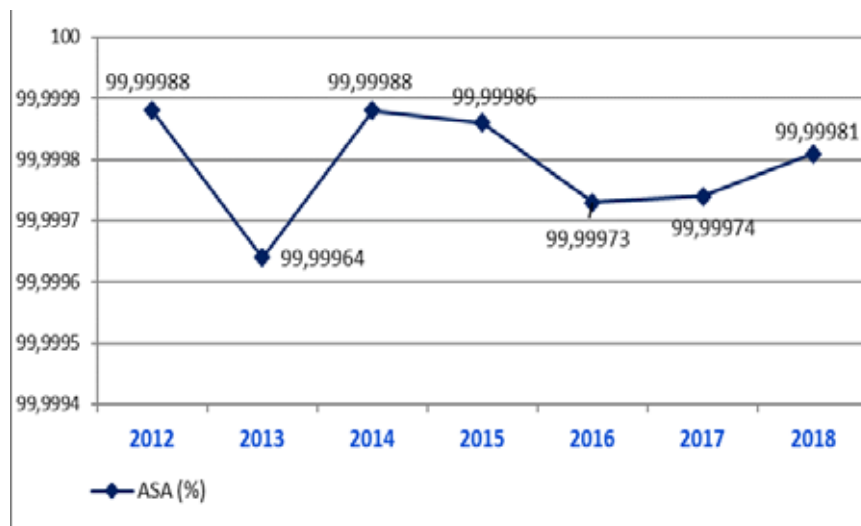


Figure 2.5 – Average Service Availability (ASA) of Transmission System in Italy

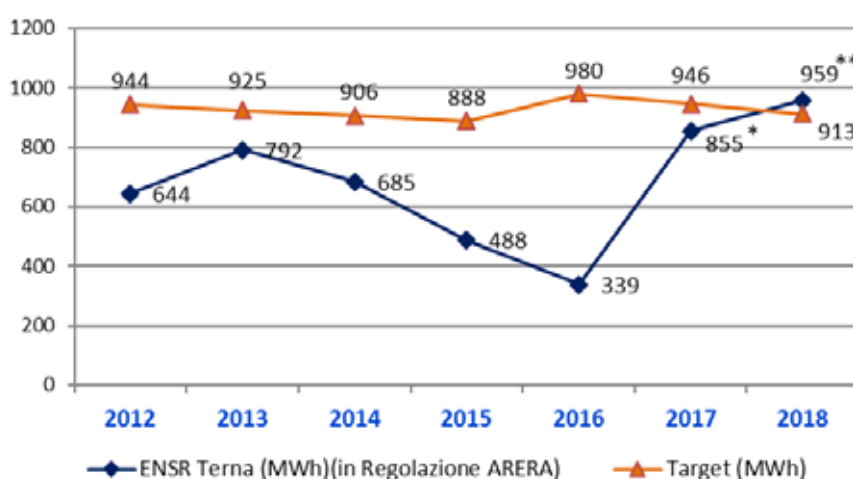


Figure 2.6 – Reference Energy Not Supplied (ENSR) of Transmission System in Italy¹⁴²

To achieve and maintain this service quality, requires multiple efforts on different fronts, each of which are critical. The main activities involved so as to provide a quality, efficient and secure service include:

- Grid maintenance
- Cyber security
- Defence and Resilience Plan

During the current transition phase towards a decarbonised energy paradigm, where the relevant objectives have been defined by the UN SDGs and in the National Energy Strategy (SEN), Terna has a fundamental and enabling role to play for a more sustainable electricity service.

Terna not only has the objective of maintaining the excellent service quality levels achieved for the transmission of electricity, but also to introduce the investments needed for the grid to integrate the increasing portion of production from renewable sources, thus making the grid even more sustainable.

This is a process, where the course is periodically updated by the Development Plan, i.e. the technical scheduling document that Terna prepares each year, which specifies the interventions and investments envisaged for the next ten years, in response to the community's future requirements.

The future of the energy system and achievement of the decarbonisation target are strongly dependent on the ability of players like Terna to innovate, discover new technologies and integrate the various sources of renewable energy and the different infrastructure.

Become a “TSO 2.0”: this is the main target of Terna's commitment in the field of innovation which refers to a new approach to managing the energy system based on a high level of integration with new technologies both in respect of the grid and the market.

Terna is concentrating on 6 main areas in its Innovation Plan:

- Transmission technologies
- Electricity system management
- Development of grids, markets and regulatory framework
- Smart grids& storage

- Business improvement
- Sustainability

Portugal defined 2 incentive schemes for the TSO responsible for HV based on rewards and penalties. Dead bands are used to avoid the activation of the incentives when small performance improvement or deterioration is experienced. The incentive for the TSO has the objective of increasing the availability of network equipment, where the relevant indicator corresponds to the combined average availability rate (TCD), expressed in (%), which results from the weight of the average availability rate of line circuits and power transformers. The parameters of the 2 incentive schemes are defined for each regulatory period (every 3 years), while the values of the incentives (rewards or penalties) are calculated on an annual basis.

The **Norwegian** financial incentive-based regulation on continuity of supply (CENS) gives the network companies, TSO level, economic motivation to ensure an optimal resource allocation when all minimum requirements are complied with. The objective is to achieve the most optimal level of continuity of supply for the society as a whole. The customers' costs related to interruptions are detected through nationwide surveys and will vary between different customer groups, when the interruptions occur etc. The costs related to investments to reduce the extent of interruptions will on the other hand depend significantly on the location of the customers' connection to the power system, including network topology, geography, climate etc. From the Regulatory point of view, it is important that decisions influencing the continuity of supply are also based on cost-benefit analyses¹⁴³. Thus, the costs related to decreasing the extent of interruptions must be lower than the future decrease in customers' interruption costs due to the investment. Incentives to optimise the continuity of supply levels, should take into account all cost elements. Consequently, for some customers this may imply reduced, increased or maintained CoS levels. No minimum requirements and no caps or floor are addressed in the schemes. For TSOs, the indicators used include interrupted power at a specific reference time, duration, time of occurrence (during the day, during the week, calendar month), whether the interruption was notified in advance or not.

Sweden uses a combination of rewards and penalties for the TSO level. Continuity indicators used for TSOs include ENS and PNS. The Regulatory conducted a cost estimation survey to set an incentive rate for the continuity of supply (CoS) indicators. By setting an incentive rate based on data from customer surveys ("bottom up"), the quality regulation aims to give to incentives for a socioeconomic level of CoS. An explicit Q-element is calculated using the mentioned CoS-indicators, whereby the target for TSO no target and no minimum improvement determined for TSOs. The target is predefined during the regulatory period and has to be reached within 4 years. Afterwards it is updated for the next period. The scheme does not involve the use of a dead band. Incentives are calculated in the same manner as for Electricity Distribution.

For TSOs, the scheme is linked to the overall revenue-cap model while quality incentives are capped with 5% of total (capped) revenues. The scheme is funded only by costumers of areas/companies which are entitled to incentives.

In **Turkey**, EMRA does not use quality indicators for TEIAS.

2.3.5 Depreciation

The RAB value is linked with depreciation and straight-line depreciation is applied by EMRA, like other regulators of EU Member countries. However, each regulator uses different depreciation values, with the majority using the historical values in different variations. The lifetime of the typical network asset ranges from 30 to 50 years and the majority of the regulators use the individual depreciation ratio for each type of asset. 30 years depreciation for TEIAS is used by EMRA. However, for the harmonization in EU Member countries, it is recommended to use lifetimes, shown in the following Table.

Table 2.8 – Standard techno-economic lifetimes¹⁴⁴

Asset class	Lifetime (yrs)
Overhead lines	60
Cables	50
Circuit ends	45
Transformers	40
Compensating devices	40
Series compensations	40
Control centers	20
Other assets	20
Equipment	10

Following Table consists of information about depreciation methods applied and the ratios in EU Member Countries and Turkey.

Table 2.9 – Depreciation¹⁴⁵

Country	Depreciation Method	Depreciation Ratio	Consideration
Austria	Straight line	Depending on asset type: lines 2-3%, transformers 4-5%, substations 4%	Pass through
Czechia	Straight line	Electricity Transmission system operator calculates the depreciation in accordance with national accounting standards.	100% of the depreciation is used to determine the allowed revenue.
Denmark	Straight line	Depending on asset type	-
Estonia	Regulatory capital expenditure method	Depending on asset type. For new assets (after year 2003) 2.86%-3.33 from investment cost and for old assets (before year 2003) 7.14% from residual value.	Present regulation started at 2003 legal framework
Finland	Straight line	1.80%	Depreciation level based on average adjusted straight line based on the selected component lifetimes. Imputed straight-line depreciations are always allowed in full as far as the component is in actual use.
France	Straight line	Depending on asset type. Ratio between 2% and 4% for network assets (lines, pipes etc.)	Integrated directly and with 100% (except assets that were funded through subsidies or grants)
Germany	Straight line	Depending on asset type. Ratio between 1.5% and 4% e.g. lines & cables: ~2%, stations: ~4%	Part of the examined controllable costs
Greece	Straight line	Most assets are depreciated over a period of 25-50 years.	Depreciation ratio depends on asset type and it is integrated directly into the revenues

¹⁴⁴ Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.

¹⁴⁵ Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.



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Country	Depreciation Method	Depreciation Ratio	Consideration
Hungary	Straight line	Depending on asset type. Ratio between 2.5 and 7% e.g. lines & cables: ~2.5%, stations: ~3.33%	Based on expected useful lifetime
Iceland	Straight line	Depending on asset type. Ratio between 2 and 20% e.g. TSO lines & cables: ~2%, stations: ~2.5%,	The regulator regularly inspects the RAB and the depreciations
Ireland	Straight line	Depends on asset category	Part of the examined controllable costs
Italy	Straight line	Depreciation for typical network assets are; 35 years for cables, 30 years for network stations, 30 years for transformers, 15-20 years for metering devices, 5 years for intangible assets and control devices.	Depreciation of the tangible and intangible assets based on re-evaluated values are allowed into the regulation.
Latvia	Straight line	Depending on asset type. Ratio between 1% and 20%, electricity lines 2-5%, electricity transformation substations 2.5-12.5%	Depreciation is a part of capital costs in the tariff
Lithuania	Straight line	4-70 years	Depreciation ratio depends on asset type. All depreciation of regulated assets is integrated into revenues.
Luxemburg	Straight line	Depending on the asset type. Useful lifetime 25-50 years for technical assets and constructions, and 3-20 years for IT related fixed assets	Depreciation is fully included in the allowed revenues
Netherlands	Straight line	Most assets are depreciated over a period of 35 – 55 years	Depreciation is part of the total costs, which are subject to an x-factor over the course of the regulatory period.
Norway	Linear depreciations from financial statements	Depending on asset type, must be approved by accountant	Part of examined controllable costs
Poland	Straight line	For transformers and substations economic useful life is 30-40 years. For new investments an average depreciation value of all investments (e.g. transformers, substations, IT systems, meters) equalled 4% is allowed	A component of allowed revenue
Portugal	Straight line	5-40 years	Part of CAPEX
Romania	Straight line	Depending on asset type. Ratio between 2% and 16.6% e.g. lines & cables: 2.5-10% stations: 2%	Part of revenue requirement Depreciation is included directly and 100% in revenue, before the linearization
Spain	Straight Line	Generally, 2.5% (Lines, Cables, Substations, Transformers)	100% of Depreciation is integrated into the revenues
Sweden	Real linear (Straight line) depreciation	Meters: 10 years Lines and Network stations: 40 years (+ up to 25 % extra if the asset is functional after full depreciation)	The depreciation is fully integrated into the revenue cap
UK	Linear depreciation	Generally, 2.5% (reflect the average expected economic life)	Amounts are deducted annually from opening RAV. The depreciation value is then added to base revenue in the next allowed revenue year

Country	Depreciation Method	Depreciation Ratio	Consideration
Turkey	Straight Line	everything is depreciated in 30 years most part of operational technology (OT) assets have around 5-year economic life	Corporate tax effect on regulatory depreciation and tax depreciation is added separately to revenue cap

Straight line depreciation is used in [Germany](#). Depreciations depend on asset type. For instance, the ratio is between about 2% for lines & cables and about 4% for substations.

In [Italy](#), straight-line depreciation based on economic technical life criteria is used. Net book values change due to new investments and depreciation. Depreciation for typical network assets are; 35 years for cables, 30 years for network stations, 30 years for transformers, 15-20 years for metering devices, 5 years for intangible assets and control devices. Depreciation of the tangible and intangible assets based on re-evaluated values are allowed into the regulation.

In [Norway](#), depreciation of capital is linear. The companies decide the economic life of components based on their own experience, and then calculate the depreciation according to the expected technical lifetime of the specific grid component.

In [Portugal](#), straight line depreciation is used. Economic life changes between 5-40 years depending on the asset.

Under the RIIO model in [UK](#), the depreciation rate is expected to reflect the average expected economic life of the asset base. Amounts are deducted annually from opening RAV. The depreciation value is then added to base revenue in the next allowed revenue year. At present linear depreciation is used, however it is being discussed to accelerate depreciation and decrease economic life of assets from 40 to 20 years.

In [Turkey](#), straight line depreciation is utilized in Turkey like other EU Member countries. Regardless of economic life of assets, everything is depreciated in 30 years. IT, most part of operational technology (OT) assets have around 5-year economic life. Rapid changes in technology requires frequent replacement of those assets. Corporate tax effect on regulatory depreciation and tax depreciation is added separately to revenue cap.

2.4 Efficiency

This section will first present the experiences in some EU member states and next summarise the situation with respect to efficiency in Turkey.

In [Germany](#),¹⁴⁶ the BNetzA carries out its efficiency benchmarking on the basis of the cost examination (TOTEX) and structural data validation before the start of each new regulatory period for electricity network operators. The efficiency benchmarking involves assessing the operators' individual costs against the services they provide and determining each operator's cost efficiency compared to the other operators.

Figure 2.7 shows benchmarking building blocks for TSOs.

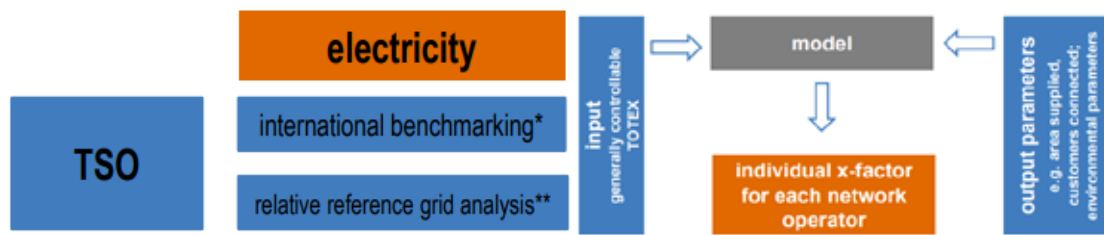


Figure 2.7 – Second Block: Benchmarking in Germany¹⁴⁷

* 2nd regulatory period: 22 TSOs from 17 countries, average efficiency 97.4%

** 3rd regulatory period; national approach

In addition to the (input) cost parameters, structural (or output) parameters are taken into account to replicate the services provided in each case as well as the regional characteristics. Possible structural parameters could include the number of connection points, peak load, the amount of energy delivered or injected, and transformer data. The costs and structural data collected always relate to the base year, which is always the third year of a regulatory period.

The costs data mainly comprise staff and material costs, interest on borrowings, depreciations and other operating costs. Depreciations are prescribed in the regulations and are based on technical asset lives.

The costs known as the permanently non-controllable costs are deducted from this cost pool (materials costs, staff costs, costs of borrowing, taxes, other costs, write-downs and return on equity, minus revenue and income with cost-reducing effect). Permanently non-controllable costs are, for example, upstream network costs, non-wage labour costs and concession fees. Network operators can fully recoup the permanently non-controllable costs as revenue.

The structural cost parameters for all network operators are used to define groups or combinations of parameters that reflect the services provided by the network operators. The optimum size of the parameter groups is also examined and defined. The efficiency scores for the network operators are determined by applying the DEA and SFA methods to the defined parameter groups. Since the efficiency benchmarking is a comparative method, the results for the individual network operators have a mutual influence on each other. A network operator that provides the same scope of services as, but has higher costs than, another operator (100% efficiency) will have an efficiency score lower than 100%. The efficiency scores are then applied to the controllable costs (total costs minus permanently non-controllable costs minus CAPEX subtraction). A network operator with an efficiency score of 80%, for example, will need to remedy the 20% of inefficiencies over the course of the upcoming regulatory period.

Each of the two methods used (DEA and SFA) offers only a restricted approach to determining efficiency scores. This is why both methods are applied to determine more than one efficiency score for each network operator. The network operators' costs are also adjusted to take account of the networks' different lifetime structures. The DEA and SFA methods are then applied to determine further efficiency scores using these standardised costs. Each network operator is then given the highest of the four efficiency scores calculated.

The efficiency scores for the German TSOs were identified ahead of the third regulatory period using a generic network analysis. It was not possible to carry out an international efficiency benchmarking exercise this time.

In the course of designing the model, it became clear that the current situation – with the German transmission systems not being large enough for the ongoing energy transition and the increase in necessary congestion management measures – could only be represented in a strict structural efficiency benchmarking using greatly simplifying assumptions.

As a result, three of the TSOs achieved efficiency scores of 100% and the fourth 99.92%¹⁴⁸.

In *Italy*, productivity targets (X-factors) are differentiated by activity (transmission, distribution and metering) and are basically used as a tool to redistribute to network users the efficiency gains of the previous regulatory periods, which were temporarily retained by network operators under the profit-sharing mechanism. On the basis of this mechanism, at the end of the regulatory period, in order to set tariffs for the following period, efficiency gains are symmetrically shared between network operators and network users.

For what concerns OPEX, there is a substantial confirmation of the method used to build OPEX starting from expenses actually made in 2014, inclusive of some corrections and of the increases regarding greater efficiencies achieved in the third and fourth regulatory period temporarily left to Terna.

The initial level of OPEX recognised as of 2016 is updated every year with respect to inflation and through a progressive return on the 1% extra-efficiencies (X-factor), valid both for transmission and dispatching¹⁴⁹.

Sweden: The regulatory model of Sweden is structured on the different cost items. First the division between capital cost, CAPEX, and operating cost, OPEX. Then latter cost is in turn divided in controllable and non-controllable cost. The controllable cost is reduced year by year by an efficiency target. This requirement on higher productivity is not applied for the non-controllable cost.

TSOs have a general efficiency requirement to annually reduce 1 percent of their controllable OPEX. The reason for a general requirement rather than firm-specific efficiency targets are due to the small number of operators. In a benchmarking analysis based on only a few operators the results are likely to underestimate the technological level, making the operators look more efficient than they are. Due to a lot of heterogeneity and a lack of comparable operators amongst the Swedish TSOs making it difficult to compare them to each other.

In *Portugal*, the cost bases considered in the price-cap and revenue-cap methodologies result from critical analysis of the companies' operating costs (net of additional income), controllable and non-controllable costs and investment costs. It should be noted that there are other costs that are accepted outside the cost bases, therefore not subject to efficiency: this is the case of concession rents and actuarial gains and losses.

The definition of efficiency targets, with the objective of reducing controllable costs, is based on international and national benchmarking studies through the application of parametric and non-parametric methods. Specifically, the COLS and SFA methodologies are used in the parametric models and the DEA methodology is used in the non-parametric models.

Regarding investments, in addition to the analysis of the values sent by the companies each year, ERSE also takes into account the Development and Investment Plan prepared every two years by TSO in HV. In these cases, ERSE must also carry out a public consultation and, in accordance with the result, issue its opinion for subsequent approval by the Government.

In addition to the definition of the accepted costs, incentives are also defined. For the Electricity Transmission activity, there is an incentive to efficient investment in the transmission network, through the use of reference prices in the valuation of the new equipment to be integrated in the network, and an incentive to increase the availability of the elements of the transmission network. In the current regulatory period, the incentive for the maintenance of end-of-life equipment was replaced by incentives to economic rationalization of costs.

In *Norway*, the revenue cap for Statnett is based on a yardstick model, as for any other network company. 40 % of the costs included in the revenue cap are based on the Statnett's actual costs (based on book values), while 60 % is based on a norm. This principle applies to costs related to network operations as well as system operations. All costs are subject to incentive regulation - the economic regulation does not differentiate between controllable and uncontrollable costs.

The cost norm is a result of benchmarking analyses. The benchmarking of Statnett's transmission grid is based on the results of the

148 Bundesnetzagentur, Annual Report 2018

149 TERNA Document-incorporated-by-reference-PRESS-RELEASE-30-12-2015-2016-02-24

international studies on the TSOs, the e3GRID study.¹⁵⁰ Statnett also owns part of the regional grid, which is benchmarked by DEA, comparing Statnett's data to data for the other regional grid companies. The results from each analysis are weighed together to calculate the cost norm. The weights attached to the results are calculated as the respective shares of the total cost base. The cost norm is then found by multiplying the weighted result with the total cost base.

In **UK**, tariff mechanism provides an opportunity for TOs to specify their forecasted efficiency savings over the RIIO T1 period. The efficiency initiatives included here should be explained within the associated commentaries. Assumed efficiency savings should only be recorded where they cannot be allocated to specific schemes with reasonable levels of accuracy. TSOs should use best endeavours to allocate efficiencies to individual schemes and include these savings to their forecasts provided in a table. Reconciliation can also be extended to mechanism-level efficiencies (ie adjust expenditure for non-apportionable efficiencies at the portfolio level to reconcile those stated with the best view. Customer contributions should be entered as negative values.

Where TSOs have identified initiatives to reduce costs then, where possible, these efficiencies should be embedded in the forecasts for the individual schemes.

- Where TSOs overall forecasts embed assumed overall ongoing efficiencies related to NLR investments (that cannot be attributed at an individual scheme level) then these cost savings should be entered as data NLR Scheme Assumed Efficiency Initiatives' to reconcile
- These efficiencies should be appropriately allocated to the relevant asset category.

Efficiency: Associated with projects that deliver outputs exactly as per with the original 'baseline' assumptions at a different cost (or where there have been substitutions the delivery involves like-for-like replacements¹⁵¹).

In **Turkey**, although written in the secondary regulation, the target efficiency levels of the TSO has not yet defined by EMRA.

Please refer to Annex 11 for more details in Cost Efficiency Benchmark for Transmission System Operators.

2.5 Losses

Power losses are an inevitable consequence of transporting electricity across the power grid. Reducing losses, or at least maintaining them at a low level, plays an important role financially, environmentally and technically. Reducing power losses helps with Europe's and Turkey's energy efficiency and security of supply objectives.

Transmission network losses in Turkey and EU countries are shown in the following figures.

¹⁵⁰ Agrell, P. J. and P. Bogetoft *e3GRID Final Results* (2009)

¹⁵¹ For example, a 275kV overhead line project has been substituted with another 275kV overhead line with the same replacement priority and the overall volume of overhead replacement is largely unchanged compared with the original submission.

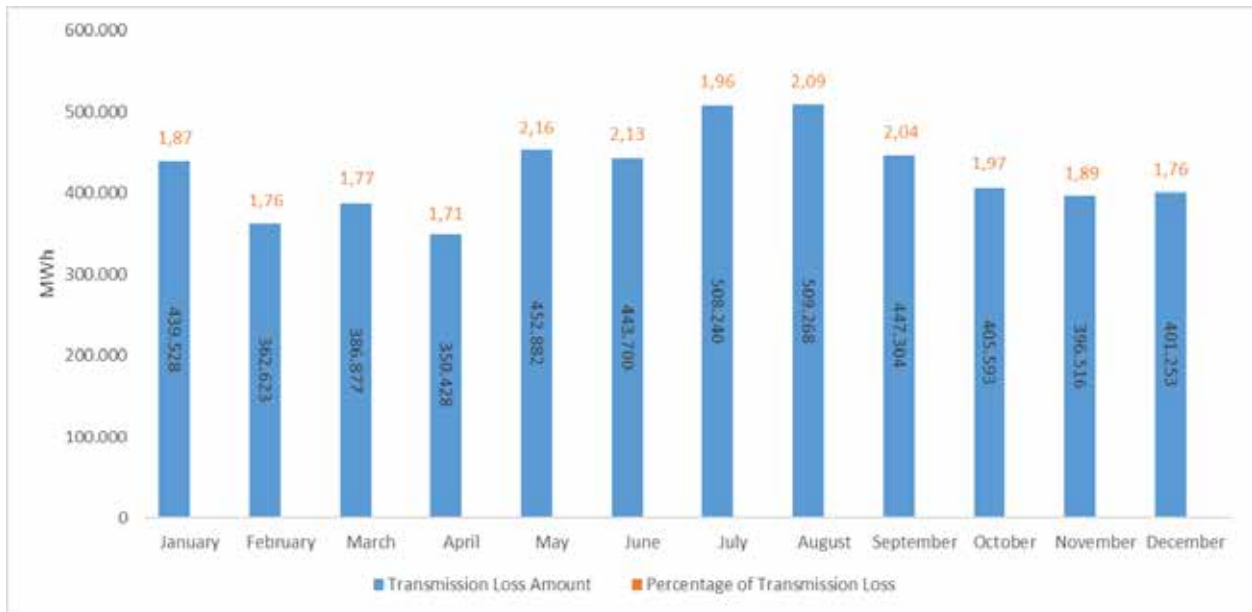


Figure 2.8 – Transmission network losses in Turkey in 2018¹⁵²

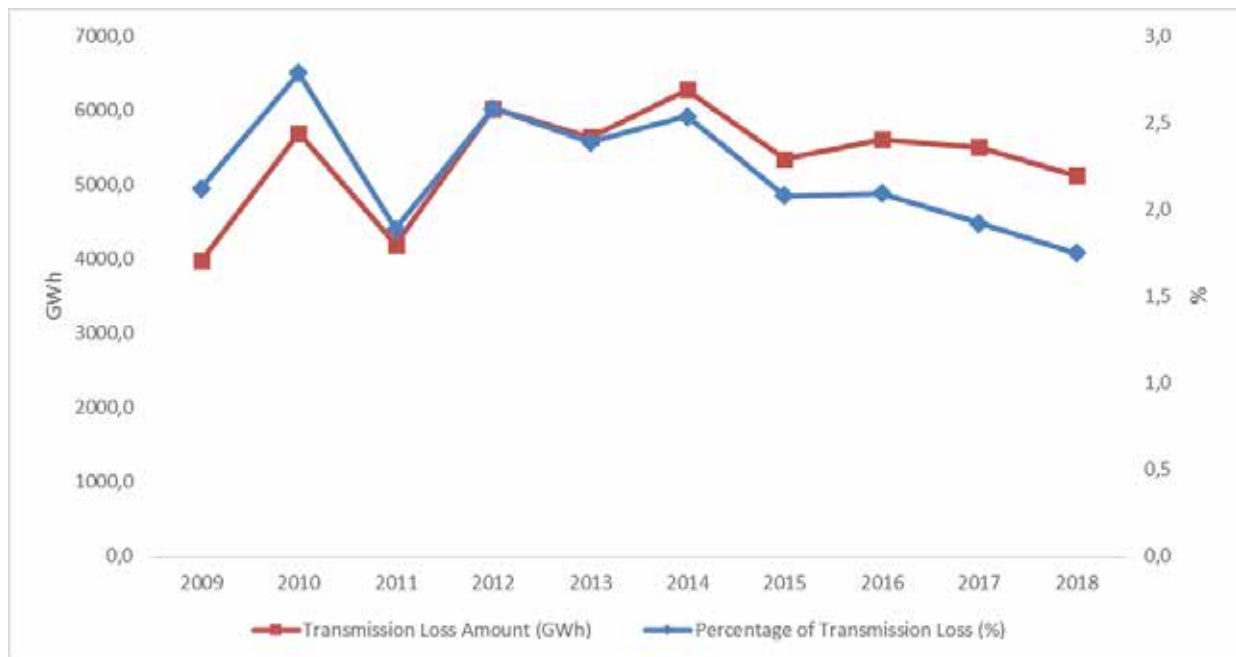


Figure 2.9 – Transmission network losses in Turkey in years 2006-2017¹⁵³

As it is seen from above figure, power losses at transmission level as a proportion of total energy injected across Turkey is a range of between 1.70 % and close to 2.75%.

152 Source: TEIAS Annual Report 2018.

153 Source: EPDK Elektrik Piyasası 2017 Yılı Piyasa Gelişim Raporu.

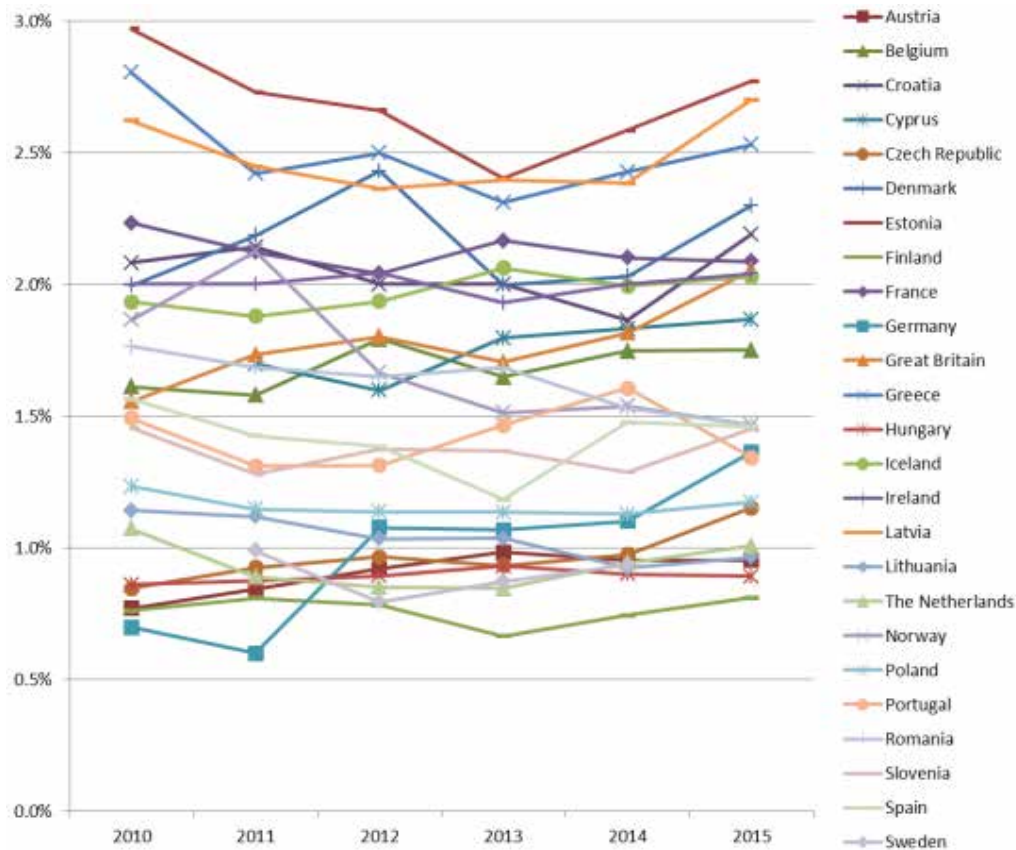


Figure 2.10 – Losses in transmission as percentage of total injected energy in EU Countries¹⁵⁴

As it is seen from above figure, power losses at transmission level as a proportion of total energy injected across the 27 EU countries is in the range of 0.4% to 3%.

The provisions of the European Directive 2009/72/EC¹⁵⁵ oblige electricity system operators to procure the energy they use to cover power losses according to transparent, non-discriminatory and market-based procedures whenever they have such a function.

Procurement of losses, defined as the procedure implemented in each EU country to handle the coverage of power losses, is either the responsibility of network operators (in most countries) or the suppliers (in UK, Ireland, Portugal, Spain and partly in Belgium). Regarding the regulatory treatment of losses, the aim of incentives is to enable EU Regulators to ensure that TSOs implement all the economically efficient operational and investment decisions aimed at limiting/reducing the volume and the costs of the energy necessary to cover power losses. Incentives are not applied to TSOs in almost all EU Member Countries.

In many cases across Europe, the costs for losses are passed on to consumers, giving system operators no incentive to reduce network losses. Proper measures should be introduced to incentivise system operators to reduce losses in their grids or at least maintain them at low levels if they are already efficient. Moreover, different regulatory approaches could be implemented for technical and non-technical losses to facilitate the most efficient regulatory schemes.

In Germany, the costs of losses are included in TSO tariffs and they are charged by TSOs.

In **UK**, 45% of the transmission losses are *deducted* from the metered volumes of generators, and the remaining 55% of the losses

¹⁵⁴ Source: CEER Report on Power Losses, Ref: C17-EQS-80-03, 18-October-2017.

¹⁵⁵ Source: "Directive 2009/72/EC of the European Parliament and of Council", Official Journal of the European Union, August 2009, <http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0072&from=EN>

are *added* to the metered volumes of demand users.

In the calculation of BSUoS charges, transmission losses are allocated by scaling up or down (depending on whether the user offtakes or generates electricity) the metered MWh volume of each BSUoS user. These scaling factors are called Transmission Loss Multipliers (TLMs) and are produced by Elexon. Using these TLMs, transmission users' metered MWh volumes are converted into adjusted BMU MWh volumes. National Grid ESO then uses the adjusted BMU values in BSUoS charging calculations.

Due to network losses, generators must produce more energy to ensure that demand users receive all the energy they need. Rules are in place to make sure that the cost of transmission losses is recovered from all transmission network users in their transmission network charges.

In **Norway**, Network losses are measured as the difference between metered input and metered output (MWh). The costs related to the network losses are included in the cost base. To calculate the costs, NVE uses yearly reference prices of power.

The prices are calculated based on volume weighted monthly area spot prices. In Norway there are currently five price areas. The monthly area spot prices are collected from Nord Pool Spot AS and the weight is based on monthly national consumption volumes collected from statistics published by NVE.

The TSO operate in all price areas, as opposed to other network companies, which normally operate in one (or occasionally two) price area(s). To calculate the cost of network losses for the TSO, the reference prices for the areas are summarized and multiplied by the total volume of losses. The summarizing of area prices is done by assigning a weight to each reference price. This weight is calculated as the relative portion of loss volume in the respective areas (i.e. volume of losses in price area1/total volume of losses = weight assigned to the reference price for area1). A mark-up of around 1.1 EUR/MWh is added to the final volume weighted spot price.

In **Sweden**, variation in losses (energy efficiency) and evolution of thermal losses in the power system. An indicator of energy efficiency correlated with SEW.

In **Turkey**, transmission network losses are measured as the difference between metered input and metered output (MWh). Transmission losses are calculated as the difference between the settlement aggregation amount (UEVM) and the settlement aggregation withdrawal amount (UECM). In other words, the difference between the amount of production produced by the plants and the amount of consumption constitutes the transmission losses. This is the sum of the losses caused by the resistance of the conductors used in transmission lines, corona losses, copper and iron losses of power transformers and autotransformers.

As of 1/1/2016, transmission losses are purchased by TEIAS in **Turkey** from the Day Ahead Market and / or through a bilateral agreement. The costs for losses are passed on to all transmission system users.

2.6 Transmission Tariff Charges

2.6.1 The Main Transmission Tariff Characteristics of EU Countries and Turkey

Electricity Transmission tariffs are used to recover the costs of providing Electricity Transmission services. Internationally, there are many different systems of Electricity Transmission pricing and associated tariff structures.

The main characteristics of Transmission Tariffs in European Countries and Turkey are shown in the following Table, namely the share of Generation and Load network charges in %, seasonal and locational differentiation, whether the costs of losses and system



This project is funded by the European Union



services are included in their transmission tariffs.

Table 2.10 – Main Characteristics of Transmission Tariff in European Countries and Turkey

Country Name	Sharing of Transmission Network Charges		Price Signal		Losses included in the Transmission Tariffs	System Services included in the Transmission Tariffs
	Generation	Load	Seasonal	Locational		
Albania	0.00%	100.00%	No	No	Yes	Yes
Austria	8.00%	92.00%	No	No	Yes	Yes
Belgium	5.60%	94.40%	Yes*	No	No	Yes
Bosnia	0.10%	99.90%	No	No	Yes	Yes
Bulgaria	0.00%	100.00%	No	No	Yes	Yes
Croatia	0.00%	100.00%	Yes*	No	Yes	Yes
Cyprus	0.00%	100.00%	No	No	Yes	Yes
Czechia	0.00%	100.00%	No	No	Yes	Yes
Denmark	4.30%	95.70%	No	No	Yes	Yes
Estonia	0.00%	100.00%	Yes*	No	Yes	Yes
Finland	18.60%	81.40%	Yes*	No	Yes	Yes
France	3.00%	97.00%	Yes***	No	Yes	Yes
Germany	0.00%	100.00%	No	No	Yes	Yes
Greece	0.00%	100.00%	Yes*	No	No	Yes
Hungary	0.00%	100.00%	No	No	Yes	Yes
Iceland	0.00%	100.00%	No	No	Yes	Yes
Ireland	25.00%	75.00%	No	Yes	No	Yes
Italy	0.00%	100.00%	No	No	Yes	Yes
Latvia	0.00%	100.00%	No	No	Yes	Yes
Lithuania	0.00%	100.00%	No	No	Yes	Yes
Luxembourg	0.00%	100.00%	No	No	Yes	Yes
North Macedonia	0.00%	100.00%	No	No	Yes	Yes
Montenegro	37.50%	62.50%	Yes*	No	Yes	Yes
Netherlands	0.00%	100.00%	No	No	Yes	Yes
Northern Ireland	25.00%	75.00%	Yes***	Yes	No	No
Norway	29.00%	71.00%	Yes*	Yes	Yes	Yes
Poland	0.00%	100.00%	No	No	Yes	Yes
Portugal	9.10%	90.90%	Yes**	No	No	No
Romania	3.00%	97.10%	No	No	Yes	Yes
Serbia	0.00%	100.00%	Yes*	No	Yes	Yes
Slovakia	3.10%	96.90%	No	No	Yes	Yes
Slovenia	0.00%	100.00%	Yes***	No	Yes	Yes
Spain	10.00%	90.00%	Yes***	No	No	No
Sweden	36.00%	64.00%	No	Yes	Yes	Yes
Switzerland	0.00%	100.00%	No	No	No	No
UK	16.10%	83.90%	No	Yes	No	Yes
Turkey	50%***	50.00%	No	Yes	Yes	Yes

* There is only a one-time differentiation (for example, "day-night", "summer-winter").

** There are two time-differentiations.

*** There are three time-differentiations.

**** Up to 31/12/2020, 50% fifty percent discount is applied for the transmission system usage fees for a period of five years starting from the date of generation.

Most of the countries charge mainly demand consumers for the provision of transmission network services, except Turkey. Turkey charge both the generators and load side of the system users equally, 50% generator, 50% load side. However, there are many different definitions and approaches that can be applied to the basis on which both electricity generation and demand users are levied for those services. As a result, European countries average annual generation tariffs remain below the 2.50 €/MWh limit as set by the European Commission Regulation (EU) 838/2010.

Most countries include losses in the transmission Tariff, except Belgium, Greece, Ireland, Northern Ireland, Portugal, Spain, Switzerland, UK. Most countries also include system services costs, except Northern Ireland, Portugal, Spain, Switzerland.

Some of the countries also consider locational price signal for their transmission tariff methodology. In UK, Norway and in Sweden locational signal is from north to south. The reason for that is that most production is situated in the north, whereas most consumption is located in the south. It is more expensive to be a producer in the north and less expensive in the south, whereas the opposite applies to consumption. In Turkey, the locational signal is from east to north-west, which includes Istanbul province. Due to that, most production is situated in the east and most of the consumption is in Istanbul and surroundings, which is located in the north-west of Turkey. It is more expensive to be a producer in the east and less expensive in the north-west and the opposite applies to consumption.

More than half of the countries do not consider seasonal price signal for their transmission tariff methodology, whereas Norway, Portugal and Spain do have seasonal price signals.

First Connection Charges

The types of cost recovered through transmission tariffs can also differ depending on the transmission pricing system adopted. Transmission tariffs are typically used to recover the fixed capital and operating (infrastructure) costs of providing the transmission network and the costs of connecting new grid users (generation and load) to the network. For example, deep, shallow or super shallow connection charges can be used to recover the first connection costs of new parties connecting to the network or a use of system (access) tariff used as the principle cost recovery tool.

First connection charges are characterized as “Shallow” / “Super-Shallow” types in Germany, Italy, Portugal, Norway, UK and Turkey. This applies to both generation and load and means that connection charges relate only to the costs of assets installed solely for, and only capable of use by, an individual user and all other assets are assumed to be shared and their costs are included in the wider transmission tariff. However, the first connection charges type in Sweden is characterized as “Deep” type; Generators or demand consumers connecting to the grid pay all costs related to this (lines, sub stations, etc.) system connection and system reinforcement.

Although Super- Shallow Methodology is compatible with the EU, due to very large geography of Turkey, there are investment and operation difficulties, which is similar to Sweden, deep first connection charges methodology shall be implemented. For a smooth transition period, at first shallow and then deep first connection methodology are **recommended** for Turkey.

Energy and Power Components

Transmission tariffs can also be levied either on a capacity (MW) or a production/consumption volume basis (MWh). The main revenue drivers for transmission tariffs of all countries are power (capacity-MW) and energy (volume-MWh). Shares of power and energy components of the transmission tariffs in Germany, UK and Sweden are about 80% power and 20% energy respectively. Shares of power and energy components of the transmission tariffs of TEIAS is about 50:50.

However, in some tariff systems, ancillary service costs and losses may also be either totally or partially charged through transmission tariffs, rather than through market mechanisms.

Impact of Utilization Time

Transmission charges paid by network users change due to the utilization time as a revenue driver in all countries, except Turkey.

TEIAS' applied tariffs have power and energy components as revenue drivers. According to current tariff structure, energy (MWh) component has a revenue driver due to the utilization of transmission system implicitly, but, power component has not. It is **recommended** to consider utilization time impact to transmission charges paid by transmission network users. Thus, utilization time will also be taken into account as a revenue driver for power component of tariff.

Non-TSO Costs

Most countries' TSOs recover additional money from their customers that are not directly related to TSO activities, except for Norway and Sweden. As pointed out before, TSOs are often obliged to recover this additional money because of national or regional regulations and the charges may either form part of transmission tariffs directly or form part of separate charging mechanisms. TSOs in Germany recover money from their customers for RES Support Mechanism and Non-RES Support Mechanism. TSOs in the UK recover money from their customers for Non-RES Support Mechanism and, to support NRA/other Institutions. TEIAS in Turkey recovers money from their customers for Non-RES Support Mechanism (Capacity Mechanism) and to support NRA/other Institutions (surcharge for EMRA).

Netting of flows for the application of transmission tariffs

When there is a situation of connected generation and load at the same connection point to the grid, those cases can be treated differently in transmission tariff settlement. The most of EU Countries consider only load for netting of flows for the application of transmission tariffs.

Regarding with this situation:

- Only Load is considered in the settlement in Germany,
- Generation and Load are treated separately in the settlement in Norway, Portugal and UK,
- Netting between G and L is performed in the settlement, and tariff for predominant value is applied in Sweden.
- Time frame is used for netting (15 min.) in Turkey, as similar to Belgium (15 min.), Finland (60 min.) and France (10 min).
- Netting is not existing / allowed in the Italian grid.

Reactive Energy

Both reactive energy tariff rates and penalties are applied in Portugal and in Germany under pre-defined conditions.

In **Portugal**, penalty: the Inductive reactive energy supplied by the transmission network outside the off-peak hours, is charged as follows: 7.524 €/MVARh, if $0.3 \leq \text{tg}\phi < 0.4$ 22.8 €/MVARh, if $0.4 \leq \text{tg}\phi < 0.5$ 68.4 €/MVARh, if $\text{tg}\phi \geq 0.5$. Tariff: the reactive energy received by the transmission network in the off-peak hours, is charged as 17.1 €/MVARh.

In **Germany**, Reactive Energy charging schemes for reactive energy are not equally applied due to different contractual arrangements between TSOs and customers as reactive energy tariff and penalty. In some particular circumstances, customers are charged for reactive power usage (charge up to 9.20 €/MVARh). Power Plants are reimbursed for the provision of reactive power.

Reactive energy tariff rates are only applied in **Norway**. Reactive power that is detrimental to the system will be invoiced to the customer.

A reactive energy penalty is applied in **Italy** and in **Turkey**, if pre-defined limits are exceeded by transmission system users.

Neither reactive energy tariff rates nor penalties are applied in **UK** and **Sweden**.

In Turkey, current reactive tariffs are monthly applicable to both transmission and distribution customers. To reduce the reactive energy impact on the grid, reactive energy metering should be hourly not monthly and reactive compensation should be applied more to end user side rather than supply side. It is **recommended** that to optimize the load distribution, DSOs should start hourly charging their commercial and industrial customers to urge them to install compensation units at their premises. Reactive tariffs at the transmission level should be stayed as monthly billing in the fourth implementation period and changed into hourly in the fifth implementation period of DSOs. Both usage and penalty tariffs might be adjusted accordingly.

Although, reactive power control ancillary services are paid by TSOs in most of EU countries, these services are not paid by TEIAS in Turkey. Due to very large geography of Turkey, there is reactive power regulation difficulties. Therefore, it is also **recommended** to incentivize generators to provide reactive power control ancillary services.

2.6.2 Transmission Tariff Charges in Turkey

Turkish Electricity Transmission Corporation, TEIAS, owns and operates the Turkey Electricity Transmission network.

TEIAS carries electricity from the generators to substations, where the voltage is lowered, ready for distribution to homes and businesses. TEIAS network consists of overhead lines, underground and sub-marine cables and substations.

TEIAS is responsible for balancing the system and managing generation output to make sure it matches demand throughout the day, and that voltage and frequency are kept within acceptable limits. TEIAS is also responsible to keep interconnection line flows at scheduled value.

The main objective of TEIAS should be ensured through improving its tariff mechanisms and sustainability.

Legal Basis

Legal basis of the Transmission Tariff is as follows;

- Regulation on Electricity Market Tariffs,
- Regulation on Connection and Use of System in Electricity Market,
- Communiqué regarding Regulation of Transmission System Revenue.
- Transmission System Usage and System Operating Tariff Calculation and Application Method Statement

Within this context, two types of Agreement are made with users; Connection Agreement and Use of System Agreement. Those users who are directly connected to the transmission system are obligated to make both Connection Agreement and Use of System Agreement.

Agreements for Use of Interconnectors; Those legal entities that wish to use the Interconnectors operated by TEIAS, are required to sign an agreement therewith. This agreement is the Use of Interconnector Agreement which specifies the conditions and provisions for the use of Interconnector. Interconnectors pay all the related Use of System Charges and System Operation Charges.

Transmission Tariff Categories

There are two categories: 'transmission connected demand' or 'transmission connected generators'.

The transmission connected demand category includes customers who are applying to take power off TEIAS. Demand customers who require large power consumption can also connect directly to TEIAS Grid:21 Distribution regions, large industrial plants, steelworks or electrified railway projects, for instance.

The transmission connected generation category includes customers applying to generate electricity and connect to TEIAS Grid. For example, wind, nuclear, solar, wind, coal, biomass, hydro, Combined Cycle Gas Turbine (CCGT) including TEIAS' substations connected embedded generation and other projects across Turkey.

There are two types of interconnector customer: An interconnector user shall follow the same process;

- If interconnector customer import energy, pay as a generation customer,
- If interconnector customer export energy, pay as a demand customer.

They deal directly with the individual interconnector in the relevant region. They must sign interconnection agreement to use interconnection line and TEIAS Grid.

In line with the objectives regarding transmission tariff, there are two components:

- First Connection Charges
- Transmission System Charges. This is also divided into two as below:
 - o Use of Transmission System charges having capacity (MW) and energy (MWh) components. The capacity related component of the tariff is applied for each MW that is produced or consumed annually and this part of the tariff varies from region to region. Energy related component of the tariff is unique for all regions and it is applied for each MWh that is produced or consumed.
 - o System Operation charges having just energy (MWh) component. This part of the tariff is applied for each MWh that is produced or consumed. System operation tariff is unique for all regions.

First Connection Charges

First Connection Charges borne by new generation and demand grid users aiming to connect to the transmission grid, consisting of TEIAS' costs to build the transmission facility to enable the connection.

TEIAS' first connection charges type is characterized as "Shallow" type; new grid users pay for the infrastructure connecting its installation to the transmission grid such as line/cable and other necessary equipment, as a first connection charge.

Main Costs related with Transmission System Assets are met through the Transmission System Use of System Prices and System Operation Prices to be taken from all the users of the transmission system.

Transmission System Usage Charges

Basic principles of Transmission System Charges;

- TEIAS's transmission system charges basically cover the investments made in the transmission system for the reliable transport of electricity over the transmission system, the costs incurred in relation to the operation and maintenance of the transmission system, zero balance adjustment, losses, Ancillary Services, cost of Balancing and Congestion Management (internal transmission system) and some non-TSO costs to finance the cost of Capacity Mechanism to ensure security of supply, EMRA , etc.
- TEIAS, pursuant to its Transmission License, is responsible for the planning, development and operation of the transmission system in accordance with certain standards. Therefore, capital investment requirements arise from the necessity of complying with these standards.

- Use of System charges levied from all generation and demand users including embedded generation connected to 36 kV or lower voltage level of TEIAS' substations, capital of transmission network investments, installation and maintenance costs of the transmission system by building adequate transmission capacities between areas of connection to ensure supply security and reliability of the transmission system. These activities are carried out in accordance with the standards determined within framework of TEIAS' Transmission License, Electricity Market Grid Regulation and other applicable legislation currently in effect.
- System Operation charges levied from all generation and demand users including embedded generation connected to 36 kV or lower voltage level of TEIAS' substations, to reflect cost of Ancillary Services, Balancing and Congestion Management to ensure stability of system and quality of supply. These activities are carried out in accordance with the standards and rules determined within framework of TEIAS' Transmission License, Electricity Market Grid Regulation, Electricity Market Ancillary Services, Regulation Electricity Market Balancing and Settlement Regulation and other applicable legislation currently in effect.

Investment-Cost-Based Pricing and Transport Model

In order to calculate the capacity related component of the Use of System tariff, "Investment-Cost-Based Pricing and Transport Model" has been used. This model was developed by National Grid (UK) and transferred to TEIAS. More recently the model is run by TUBITAK and the results are used by TEIAS.

The rationale underlying this method is the fact that when the services rendered are priced to reflect the incremental costs associated with these services, the users will be provided with effective economic signals. Use of System Prices have been so designed that, the effects of marginal increases or decreases caused in the amounts of system use by the users in different places of the transmission system, will be reflected in TEIAS's costs.

The transmission capacity required in the different parts of the transmission system depends on the maximum amounts of system use realized in those parts. Maximum system use will occur in certain generation and consumption conditions. These conditions are related in Turkey with summer and winter peak demands. In the Use of System Prices found by this method, the incremental investment cost, which is determined according to needs emerging at the peak time (times) in the transmission system, are taken as basis. The prices may vary with respect to the place where the customer's connection to the transmission system takes place. These discrepancies will reflect the difference between incremental investment costs in different points in the system.

In the calculation of incremental costs, an equivalent model of the transmission system is used. This is the Investment-Cost-Based Pricing and Transport Model. In this model, the network structure is simulated on the basis of real conditions. The model network thus derived, is used in the computation of the incremental costs in relation to additional network capacity at each point called Network Node, provided that the network is of such a capacity as to meet the full need at peak demand times.

Capacity related Generation Use of System Prices are determined as explained below:

- If provisional acceptances of all units of the power plant are done and all of the units are in operation, installed capacity in the licence is taken into account.
- If there is one or more unit having no provisional acceptance, the total capacity of the units having provisional acceptance are taken into account.

Capacity related Consumption Use of System Prices, on the other hand, are determined based on maximum intake capacity. In this context, the prices will be applied on per MW basis.

The revenue obtained from the Investment-Cost-Based Pricing and Transport Model, are so adjusted that, when applied to the MW values expected for generation, the resulting total will ensure the Revenue Cap determined by EMRA. Adjustments to be made in Capacity related Use of System Prices, are performed in such a way that regional signals provided by Investment-Cost-Based Pricing Model are retained.

The points taken into consideration by TEIAS in the determination of Capacity related Use of System charges are as follows:

- Ensuring clearness of the basic principles adopted and the transparency of the pricing procedure,
- Providing accurate and stable price messages regarding costs for the existing users and the parties that will newly join in the system,
- Setting the transmission tariff structure for calculating system usage prices based on services rendered, and in doing so, taking incremental costs, rather than average ones, as the basis; thereby, encouraging the optimal use of the transmission system and optimal investments,
- Adopting practical implementations within the framework of applicable cost parameters and time intervals.

System Operation charges, unlike the Capacity related Use of System Prices, the System Operation Prices do not vary by regions; there exists only one price for the whole system. This, in turn, means that the effect of the user on the system operation costs does not vary especially in respect of user's region.

As explained above, Use of System Prices Consist of two separate components as follows;

- The first component (Capacity related) varies depending on the location of the user. This component is determined to reflect the cost of the capital expenditure for transmission system investments, cost of operation and maintenance of transmission assets and cost of the Capacity Mechanism. In this contends, 14 system usage tariff regions are defined for generation customers and demand customers separately.
- The second component (Capacity related) is the one that is independent from the user's location. The latter is related with the assurance of system reliability due to attainability to revenue cap.

Please refer to Annex 10 for more details in selected EU countries on transmission tariff charges.

2.6.3 ENTSO-E Position on Tariff Structure

ENTSO-E position for tariff structure harmonisation in long term is as follows:

- A clear objective is required (what is the objective of the tariff structure and its harmonisation) ,
- Assessment of the link between tariff structure and market arrangements,
- Assessment of the link between tariff structure and other policy goals,
- Assessment of the methodology/legal basis to be transparent and relatively simple, furthermore there is a need for a sound legal basis to avoid possible future court cases due to ambiguity,
- Existing tariff structures are often a trade-off between various objectives. ENTSO-E stresses that it is important to take note of the impact the tariff structure might have on existing market arrangements and other policy objectives.
- ENTSO-E believes the full implementation of existing network codes is prerequisite for further discussion on tariff structure harmonisation.

With respect to the relevant policy objectives, ENTSO-E mainly focus on the relevant objectives from a network point of view¹⁵⁶:

- The tariff structure should stimulate efficient behaviour for grid users,
- The tariff structures should, among other things, reflect current market development: i.e. an increase in power base of tariffs and growing importance of locational aspects, etc.,

The tariff structure should ensure full cost recovery for the TSO.

2.7 Assessment and Recommendations

Transmission tariffs are one of the important factors of the Electricity Market. As there is no single “correct solution” for the allocation of the standardization of transmission network fees. Different tariff schemes exist in Europe, even in TSOs, as it is seen in Germany. However, the standardization of transmission network fees has commenced and will take place in stages between 2019 and 2022. During this period, the share of the standardized component is to increase by 20 percent annually, while the company-specific share is to decrease with respect to the costs of transmission system users. So that from 2023 onwards, there will be a completely uniform transmission grid fees nationwide in Germany. Differences may still remain due to the market mechanisms are used as part of the regulatory regime, the treatment of transmission losses and of ancillary services, of balancing system, and the level of first connection costs to which transmission grid users are exposed. Electricity Transmission charging arrangements reflect the following two aspects:

- the different features of each national electricity market, for instance the location and mix of generation and planned future investment in the network and
- the emphasis that individual countries have chosen to place on certain policy objectives for their electricity sectors and transmission tariff structure.

2.7.1 General Approach

Different models are used in Europe in terms of revenue requirement. Like most of the EU countries, revenue cap model is implemented in Turkey to determine allowed revenues and Electricity Transmission system usage tariffs. On the other hand, in some other countries such as Portugal (for OPEX), Lithuania and Italy (after 2020-TOTEX) price cap model is used whereas in countries such as Austria, Denmark and Latvia cost-based models are preferred to determine allowed revenue. In Estonia and Portugal (for CAPEX) Rate of Return models are preferred to determine revenue. In Hungary incentive models are preferred to determine revenue.

Different from most of the countries, a new output-based model, namely RIIO, where the incentives are linked to the outputs, started to be used in the UK since 2015-16. Reliability and availability, conditions for connections, social obligations, customer service, environment and safety are 6 main outputs in the model. RIIO is a performance-based framework to set the price controls. The model considers the future national targets and consists of incentives for satisfaction of customers, compliance with health and safety standards, contribution to environmental targets and services provided to poor and vulnerable consumers. The performance of the model will be clearer after the first 4+4-year implementation period.

TOTEX approach is used in countries such as UK, Germany and the Netherlands. However, in Turkey, similar to many other countries, the parameters of the transmission revenue cap are set to recover targeted OPEX, CAPEX depreciation together with a return on capital (WACC) calculated over the average RAB value and corporate tax correction. OPEX is set by EMRA on an ex-ante basis for each year of the implementation period. Being a part of the revenue cap, it is up to TEIAS how to spend it and all savings from OPEX stays with TEIAS. On the other hand, there are several CAPEX categories that are network investments, network operation system investments, environment, safety and other investments for legal liabilities and other expenditures having the characteristics of CAPEX. It is recommended that the TOTEX approach should be applied to at least certain areas, such as IT, vehicles, buildings and network rehabilitation/replacements. Also, it should be TEIAS decision whether to operate the grid by CAPEX or OPEX. Technological developments also close the gap between OPEX and CAPEX in some areas such as remote control of substations, data management, smart meter installations for transmission system connected users, etc.

On the other hand, investments for renewal of aged network components could be set proportional to the existing asset size with their theoretical life expectancy together with refurbishments. This approach would reduce the need of higher maintenance OPEX and certainly improve failure index (very high according to benchmarking with ENTSO-E members) type performance KPIs.

To have a sustainable and economically viable transmission system, regulation should drive TEIAS to an equilibrium level between profitability and being a utility. Therefore, RIIO model in UK could be a role model in many aspects by introducing TOTEX and output-based approach together with encouraging innovations. It is advisable to be inspired by certain RIIO approaches and use sixth implementation period as a transition period to create a sustainable, quality driven and customer centred Electricity Transmission sector.

2.7.2 RAB Conclusions

The RAB can be comprised of several components including fixed assets, working capital or constructions in progress. There are thus different variations among the EU Regulators. Almost all EU Regulators include the fixed assets in the RAB. In contrast, with respect to the working capital, more than half of the EU Regulators do not include working capital in the RAB, or use a derived notion of that, depending on whether the electricity or gas system operator is considered. The “construction in progress” component gives the same result as working capital. Less than half of the EU Regulators surveyed allow assets under construction in the RAB.

The RAB value is usually linked with depreciation, depending on the EU Regulators. In electricity regulation, straight line depreciation is applied by most EU Regulators. The EU Regulators use different depreciation values, with the majority using the historical values in different variations. The lifetime of the typical network asset ranges from 30 to 50 years and the majority of the EU Regulators use the individual depreciation ratio for each type of asset.

From a balance sheet perspective, fixed assets are the most significant items in the energy industry. Also, according to the responses of the energy regulators, fixed assets were unanimously indicated as a component of the RAB. More than half of the regulators in EU countries additionally include working capital in the RAB, albeit with specific rules for its determination and inclusion.

For Electricity Transmission, on the other hand, the ratio is inversed and investment in progress is included in the RAB. The contribution by third parties is deducted from the RAB by all EU Regulators with only two exceptions. Only UK and Italy take contributions from the third parties into the RAB.

From the responses one can conclude that the most common way of calculating the RAB components is the historical costs method, followed by the re-evaluated assets method, with the mixture of these two methods applied only rarely.

For the method of asset valuation, the WACC is the preferred method. Whereas the real WACC was used for the profitability calculation of the re-evaluated assets, the nominal WACC is used for the assets in historical values.

Due to the following reasons:

- Volatile financial environment compared with EU countries.
- Long-term financial sustainability.
- Long-term foreign currency-based financing.

Dynamic WACC which is updated by financial parameters shall be implemented to secure long-term financial sustainability.

2.7.3 Methods Used for the Rate of Return

There are different possible methods to calculate the rate of return. Mostly a WACC factor (Weighted Average Cost of Capital) is used.

In general, WACC can be expressed in a simplified manner by the following formula:

$$WACC = \text{Equity} / (\text{Equity} + \text{Debt}) * \text{Cost of equity} + \text{Debt} / (\text{Equity} + \text{Debt}) * \text{Cost of debt}$$

EU Regulators can distinguish between nominal or real and before and after taxation as well as a “Vanilla” WACC.

In conclusion, for electricity network regulation, the most popular approach is to use nominal WACC before taxation. The otherwise most commonly used method for calculation of the rate of return is the real weighted average cost of capital before taxation, which is used from 25% of the EU Regulators. In addition to that, it is remarkable that 4 EU Regulators do not use WACC in the regulation of electricity TSOs.

2.7.4 Depreciation

The RAB value is linked with depreciation and straight-line depreciation is applied by EMRA, like other regulators of EU Member countries. However, each regulator uses different depreciation values, with the majority using the historical values in different variations. The lifetime of the typical network asset ranges from 30 to 50 years and the majority of the Regulators use the individual depreciation ratio for each type of asset. 30 years depreciation is used by EMRA. This is reasonable from a financial point of

view for TEIAS. However, depreciation ratio is different than lifetime of assets which is not in compliance with EU Countries. It is recommended to use individual lifetimes of assets for depreciation.

2.7.5 Performance Indicators

To improve overall quality of supply in transmission networks, monitoring most common ENS (energy not supplied) and AIT (average interruption time) grid should be the focus. The TSO should be subject to a far softer quality regulation which is only a simple penalty system.

On the other hand, to increase renewables energy connection capacity in Turkey, setting and monitoring a target ratio for connection of renewables should be the focus in 6th implementation period.

2.7.6 Benchmarking efficiency

In Turkey, it is recommended that efficiency factor for TEIAS should be defined. As a first stage, the controllable cost is reduced year by year by an efficiency target.

It is also recommended that cost efficiency of the transmission system shall be assessed by international benchmarking or referring to a reference network¹⁵⁷.

Benchmarking models can be grouped into two alternative designs with an effect on the scope of the benchmarked costs:

- A short-run maintenance model, in which the efficiency of the operator is judged based on the OPEX incurred relative to the outputs produced, which in this case would be represented by the characteristics of the network as well as the typical customer services.
- A long-run service model, in which the efficiency of the operator is judged-based on the TOTEX incurred relative to the outputs produced, which in this case would be represented by the services provided by the operator.

From the point of view of incentive provision, a TOTEX based approach is usually preferred. It provides incentives for the TSOs to balance OPEX and CAPEX solutions optimally.

2.7.7 Losses

The costs for losses are passed on to consumers, giving system operators no incentive to reduce network losses. Proper measures

157 EC/DG Report on “Do current regulatory frameworks in the EU support innovation and security of supply in electricity and gas infrastructure?”

should be introduced to incentivise system operators to reduce losses in their grids or at least maintain them at low levels if they are already efficient.

In order to reduce or maintain them at low levels if they are already efficient technical losses:

- Increase voltage levels
- Apply less transformational steps to deliver electricity to consumers
- Utilise new and improved equipment
- Employ distributed generation in a more efficient manner, including combining it with local storage
- Optimise network flows –apply demand side management to reduce peaking
- In general, pursue network architecture and management that promote the highest efficiency

On the other hand, TEIAS shall procure the energy they use to cover all power losses according to transparent, non-discriminatory and market-based procedures.

2.7.8 Summary of Overall Assessment and Recommendations

Summary of overall assessments and recommendations on Electricity Transmission is given in the following Table.



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Table 2.11 – Overall Assessments and Recommendations on Electricity Transmission Tariff

	EU Practices	Turkey Practice	Problem Definition and Gap Analysis	Recommendation	Comments	Related Regulations to be Amended
Revenue Requirement Model	- Tendency to Incentive Based Models - o Revenue Cap (+RIIO) - o Price Cap - Cost Based	- Revenue Cap (with efficiency parameter according to secondary regulation)	- Introduce quality indicators - Implementing efficiency parameter (already introduced)	- Revenue cap model with performance and quality indicators and efficiency parameter is suitable for Turkey.	- consumers benefit from increased efficiency and quality - to increase TEIAS' profits by achieving these targets. - to achieve good EU practices.	- Electricity Market Tariffs Regulation - Communiqué on Regulation of Transmission System Revenue
	- TOTEX approach is used in countries such as UK, Germany, Austria, Iceland, and the Netherlands.	- OPEX and CAPEX is used.	- Rational decision-making process between CAPEX and OPEX to increase cost efficiency in overall TEIAS quality performance. - TEIAS' decision making process whether to operate grid by CAPEX or OPEX.	- TOTEX approach is recommended to be experienced in certain areas such as IT, vehicles, buildings and network rehabilitation/replacements	- Enabling investment to maintain the existing network and accommodate a new network infrastructure, and to create a sustainable, quality driven and customer centric Electricity Transmission system.	
Regulatory Period	- 8 years in UK, Finland and Italy (4+4), - 6 years in Spain, - 5 years in most of them as well as Norway and Germany, - 4 years in Sweden - 3 years in Portugal	- 3 years	- Shorter periods are not sufficient for efficiency incentives and longer periods are not predictable.	- 5-year tariff period is recommended which is compatible with most common EU practices.	- Fixed medium periods or longer periods with parameter updates may be applicable.	- Communiqué on Regulation of Transmission System Revenue
Regulatory Asset Base	- All of them include the fixed and some intangible assets - more than half do not include working capital, leased assets and "construction in progress" - contribution by third parties is deducted from the RAB by all EU, except UK and Italy - The most of them do not include leased assets - Historical cost approach is used	- Fixed and some intangible Assets are included into TEIAS RAB. - Historical cost approach is used. - Initial RAB was taken into account.		- There is no need for any change.	- Depreciation period has been set as 15 years for the old assets constructed or acquired before EMRA' implementation periods.	



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	EU Practices	Turkey Practice	Problem Definition and Gap Analysis	Recommendation	Comments	Related Regulations to be Amended
CAPEX	- Investment plans are prepared by TSOs and approved by regulators.	- Investment plans are prepared by TEIAS and approved by regulators.		- There is no need for any change.	- Methodology is compatible with the EU.	
Rate of Return	- Most of them use nominal WACC - 25% of them use real WACC - Belgium, Denmark, Germany* and Spain do not use WACC.	- Real WACC methodology is used.	- ROR is higher than EU	- Dynamic WACC which is updated by financial parameters shall be implemented to secure long-term financial sustainability.	Due to the following reasons; - Volatile financial environment compared with EU countries. - Long-term financial sustainability. - Long-term foreign currency-based financing. Dynamic WACC methodology is suitable, for TEIAS.	- Electricity Market Tariffs Regulation - Communiqué on Regulation of Transmission System Revenue
Depreciation	- Straight line depreciation is used. - The individual depreciation ratio for each type of asset is used, - Tendency to harmonize the lifetime of individual assets	- Straight line depreciation is used. - Standard 3.33% depreciation ratio is used	- Depreciation ratio is different than lifetime of assets	- It is recommended to use individual lifetime of assets for depreciation	- Methods used in EU Countries and Turkey are similar. - 30 years depreciation of assets are considered, instead of the individual lifetime which is different than EU Countries. - As a second stage, EU Harmonized lifetimes for assets shall be considered.	- Communiqué on Regulation of Transmission System Revenue
Performance Indicators	- The most common indicators for measuring continuity of supply in transmission networks are ENS and AIT - Continuity of supply levels have been introduced, but not yet implemented in the most of them.	- Performance indicators are not introduced and implemented to measure continuity of supply.	- Failure index is higher than ENT-SO-E countries' TSOs.	- It is recommended to set quality indicators for measuring continuity of supply, - It is recommended to set quality indicators targets and implement reward and / or penalty in 6th implementation period. - setting and monitoring a target ratio for connection of renewables shall be the focus in 6th implementation period to reach EU environmental targets.	- To improve overall quality of supply in transmission networks, monitoring most common ENS (energy not supplied) and AIT (average interruption time) grid should be the focus. - TEIAS should be subject to a far softer quality regulation which is only a simple penalty system.	- Communiqué on Regulation of Transmission System Revenue



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	EU Practices	Turkey Practice	Problem Definition and Gap Analysis	Recommendation	Comments	Related Regulations to be Amended
Efficiency	The efficiency scores for TSOs are determined by applying: - Data Envelopment Analysis (DEA) and Stochastic Frontier Analysis (SFA) methods - efficiency benchmarking	- No efficiency indicator is used in Turkey, although, it is written in secondary legislation. - No efficiency benchmarking	- Increasing UoS tariff	- It is recommended to define an efficiency factor for TEIAS. - It is also recommended to assess cost efficiency of TEIAS by international benchmarking or referring to a reference network	- As a first stage, the controllable cost is reduced year by year by an efficiency target.	- Communiqué on Regulation of Transmission System Revenue
Losses	- The costs for losses are passed on to consumers, - no incentive to reduce network losses in most EU countries. - Tendency to incentivize TSOs to reduce losses in their grids	- The costs for losses are passed on to consumers	- Losses target is not determined, and TEIAS is not incentivized /penalized to reduce losses	- It is recommended to introduce proper measures to incentivize TEIAS to reduce losses in grid or at least maintain them at low levels if they are already efficient.	- Reducing losses, or at least maintaining them at a low level, plays an important role financially, environmentally and technically. - Reducing power losses helps with Turkey's energy efficiency and security of supply objectives.	- Communiqué on Regulation of Transmission System Revenue
Losses	- Environmental responsibilities for TSOs (reduction of CO2 emissions and reduced usage of SF6)	- No specific targets for CO2 emissions or SF6 gases.	- Introduction of environmental responsibilities. There are majority of SF6 CBs and increasing no. of GIS substations	- It is recommended to introduce environmental responsibilities to TEIAS.	- It is necessary to protect environment and for compatibility with the EU.	
Losses	- The most of them include losses in the transmission Tariff, except Belgium, Greece, Ireland, Northern Ireland, Portugal, Spain, Switzerland, UK.	- TEIAS includes losses in the transmission Tariff.		- There is no need for any change.	- Methodology is compatible with the EU.	
System Services	- The most of them include System Services cost to transmission tariff, except Northern Ireland, Portugal, Spain, Switzerland.	- TEIAS includes System services cost to transmission tariff		- There is no need for any change	- Methodology is compatible with the EU.	
Connection Fees	- Super shallow or shallow first connection charges are applied.	- super shallow connection charges are applied.	- Due to very large geography of Turkey, there are investment and operation difficulties.	- Firstly, Shallow for the transition period and then Deep First Connection charges methodology are recommended.	- Methodology is compatible with EU. However, as an example, due to geography difficulty of Sweden, which is similar to Turkey, deep first connection charges methodology is preferred.	- Electricity Market Tariffs Regulation - Communiqué on Regulation of Transmission System Revenue



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	EU Practices	Turkey Practice	Problem Definition and Gap Analysis	Recommendation	Comments	Related Regulations to be Amended
Network Tariff; Sharing of Transmission Network Charges	- Most of them charge mainly demand consumers for the provision of transmission network services, - Remaining ones charge both demand consumers and generators, but, less portion to generators for the provision of transmission network services, - European countries average annual generation tariffs remain below the €2.50/MWh set by European Commission Regulation (EU) 838/2010.	- Turkey charge both the generators and load side of the system users, similar to Belgium, Sweden, Norway, Portugal and UK.	- Turkey charge both the generators and load side of the system users equally, 50% generator, 50% load side. - On the other hand, up to 31/12/2020, 50% discount is applied for the transmission system usage fees for a period of five years starting from the date of generation.	- It is recommended to re-evaluate sharing of UoS charges for 6th implementation period.		
Network Tariff; Energy and Power Components	- The main revenue drivers for transmission tariffs of all countries are power (capacity-MW) and energy (volume-MWh). - Shares of power and energy components of the transmission tariffs of Germany, of UK and of Sweden are about 80% and 20% respectively	- The main revenue drivers for transmission tariffs of TEIAS are also power and energy		- There is no need any change for Methodology	- Methodology is compatible with the EU	
Network Tariff; Locational differentiation	- The most of them do not consider locational differentiation for transmission tariff methodology - Norway, Sweden and UK consider locational differentiation - ENTSO-E strongly emphasize growing importance of locational aspects for transmission tariff	- TEIAS considers locational differentiation	- Existing locational differentiation (14 regions) is not up to date and its resolution is low.	- There is no need any change for Methodology	- Methodology is compatible with the ENTSO-E recommendation, - However, Locational differentiation studies might be improved and reperformed at least for each regulatory implementation period.	



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	EU Practices	Turkey Practice	Problem Definition and Gap Analysis	Recommendation	Comments	Related Regulations to be Amended
Network Tariff; Seasonal differentiation	- The most of half of them do not consider seasonal price signal for their transmission tariff methodology. - Remaining ones consider seasonal price signal for their transmission tariff methodology, as well as Norway, Portugal and Spain.	- Turkey do not consider seasonal price signal for their transmission tariff methodology	- There is an important seasonal difference in consumption and generation.	- Seasonal differentiation price signal methodology is recommended.	- Methodology is compatible with the EU. - However, it is necessary to consider seasonal differentiation to increase efficiency.	- Electricity Market Tariffs Regulation - Communiqué on Regulation of Transmission System Revenue
Network Tariff; Utilization Time	- Transmission charges paid by network users change due to the utilization time as a revenue driver in all EU countries.	- The applied tariff considers utilization time for energy (MWh) component implicitly, as a revenue driver.	- According to current tariff structure, energy (MWh) component has a revenue driver due to the utilization of transmission system implicitly, but, power component has not.	- It is recommended to consider utilization time for transmission charges paid by network.	- The applied tariffs have power (capacity-MW) and energy (MWh) components. - According to current tariff structure, energy (MWh) component has a revenue driver due to the utilization of transmission system implicitly, but, power component has not. - If utilization time is taken into account, not only for energy component, but also for power component of tariff to be had a revenue driver.	- Electricity Market Tariffs Regulation - Communiqué on Regulation of Transmission System Revenue
Network Tariff; Non-TSO Cost	- Transmission tariffs cover some costs that are not directly related to TSO activities in all EU, except in Norway and in Sweden.	- Capacity Mechanism cost and surcharge for EMRA are included to the applied tariff		- There is no need any change for transmission charges paid by network.		
Network Tariff; Netting	- The most of EU Countries consider only load for netting of flows for the application of transmission tariffs - Few of them treated Generation and Load separately or consider predominant value or use time frame.	- Time frame is used for netting in Turkey, as similar to Belgium, Finland and France		- There is no need any change for transmission charges paid by network.	- When there is a situation of connected generation and load at the same connection point to the grid, those cases can be treated differently in transmission tariff settlement.	



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	EU Practices	Turkey Practice	Problem Definition and Gap Analysis	Recommendation	Comments	Related Regulations to be Amended
Network Tariff, Reactive Tariffs	- Reactive energy tariff rates and/or penalty are applied in most of EU countries	- The reactive energy penalty is applied in Turkey, if pre-defined limits are exceeded by transmission system users.	- Current reactive tariffs are monthly applicable to both transmission and distribution customers. - To reduce the reactive energy impact on the grid, reactive energy metering should be hourly not monthly.	- It is recommended to apply hourly reactive tariffs to both transmission and distribution customers. - Reactive tariffs at transmission level should stay as monthly billing in fourth implementation period and changed into hourly in the fifth implementation period of DSOs.	- Reactive compensation should be applied more to end user side rather than supply side to reduce losses and the reactive energy impact on the grid.	- Electricity Market Tariffs Regulation - Communiqué on Regulation of Transmission System Revenue
Reactive Power Control	- Reactive power control ancillary services are paid by TSOs in most of EU countries	- Reactive power control ancillary services are not paid by TEİAŞ in Turkey.	- Due to very large geography of Turkey, there is reactive power regulation difficulties.	- It is recommended to incentivize reactive power control ancillary services.		- Communiqué on Regulation of Transmission System Revenue - Electricity Market Ancillary Services Regulation

3 Improvement of performance-based tariff setting: Natural Gas Distribution

3.1 Introduction to the Natural Gas Distribution Chapter

The ownership of the gas DSOs is variable in the EU, both privately and public owned even the lasting of the concession period is variable from a few years, up to 50 years.

This shows a significant variation in the number, size and structure of Natural Gas Distribution System Operators (DSO) throughout Europe as well as the methodology they used to determine allowed revenues.

The following table shows the summary information about gas DSOs in European Countries, including number of DSOs, network lengths, number of subscribers (number of points of delivery - POD), ownership status, tariff periods, and license validity.

Table 3.1 – Summary Table for Gas DSO's¹⁵⁸

Country	Distribution Pipeline Length-[Km]	Number of Subscribers – Delivery Points	Number of Network Operators	Ownership of grids	License Duration (Year)	Tariff Term (Year)
Austria	46,000	1,349,000	21 Distribution Companies	Private and Public	-	-
Bulgaria	-	-	24 licensed companies operate in the Republic of Bulgaria. They operate in 35 licensed territories, serve 5 Natural Gas Distribution regions and 80 municipalities outside these regions.	Private and Public	-	-
Croatia	20,310	647,000	36 Distribution Companies. 2 Distribution Companies have over 100.000 subscribers.	Private and local public ownership	20-30	5
Czechia	76,910	2,849,000	There are 6 major distribution regions and companies. The company provides 73 small-scale distribution services and operates in 6 large distribution regions.	Private and local public ownership	25	5
Denmark	17,924	-	3 Distribution Companies	Public Ownership	20	4
Estonia	2,880	52,000	-	Private investors	-	-
Finland	3,229	31,000	25 Distribution Companies	State, local public and private ownership	-	4
France	232,094	11,268,000	26 Distribution Companies	Private and public ownership (indirect and local)	20-30	4
Germany	505,000	20,979,000	728 Distribution Companies	Private and local public ownership	20	5
Greece	7,392	325,000	3 Distribution Companies	State ownership and private investors	30	-

¹⁵⁸ Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.



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Country	Distribution Pipeline Length-[Km]	Number of Subscribers – Delivery Points	Number of Network Operators	Ownership of grids	License Duration (Year)	Tariff Term (Year)
Hungary	89,004	-	10 Distribution Companies	2 public, 8 private		4
Ireland	13,685	661,000	1 Distribution Companies			5
Italy	291,038	23,203,000	210 Distribution Companies	Private and Public, and mixed public-private property	12	6
Lithuania	10,507	562,000	-	State owned, private investors	-	-
Luxembourg	3,159	86,000	3 Distribution Companies	Mainly direct and indirect public ownership	Determined by Ministry	3
Netherlands	133,546	7,152,000	There are 9 distribution companies. 2 distribution companies have less than 100.000 subscribers.	Local public ownership (public by law)	-	3, tariffs are revised yearly
Poland	189,949	6,852,000	While 35 distribution companies operate, 34 of 35 companies operates small distribution regions.	Indirect state-owned, public and private	Min 10, Max 50	1
Portugal	18,502	1,382,000	11 Distribution Companies	Private ownership	20	3
Slovakia	35,595	1,506,000	A System Operator	-	-	5
Slovenia	5,515	136,000	16 Distribution Companies	-	-	3
Spain	77,382	7,890,000	19 DSOs grouped in 6 companies. 5 groups account for 99% of the market share.	Private: utilities and investment funds	-	-
Sweden	3,500	37,000	5 Distribution Companies	Municipality and foreign ownership	40	4
Turkey	144,000	16,052,567	72 Distribution Companies	Private and Public	30	5
UK	285,600	-	In UK there are 4 Distribution Network Operators (across 8 licenced regions), 16 Independent Gas Transporters (IGT) and 6 site specific pipeline operators. In Northern Ireland there are 3 licenced distribution networks ¹⁵⁹	Private and Public	-	8 ¹⁶⁰

Natural Gas Distribution is initiated by TSOs or the major state-owned utilities in the majority of the EU countries and likewise in Turkey.

159 Source: https://www.ofgem.gov.uk/system/files/docs/2020/03/gas_registered_or_service_addresses_new_1.0_002.pdf

160 Tariff period will be decreased back to five years with the upcoming price control period in 2021 for Natural Gas Distribution.

3.2 Stakeholder Responsibilities

In **Germany**, similar to electricity market, the task of regulating gas markets is assigned to the BNetzA by the Energy Act. The Regulatory Authority is responsible for providing the most secure, low-priced, consumer-friendly, efficient, and environmentally sustainable supply of gas possible for the general public as well as effective and genuine competition in the supply of gas, and efficient and reliable operation of energy supply systems for the long term. BNetzA also regulates all operators with more than 100,000 customers or whose network area covers more than one federal state.

There are 728 gas DSOs registered with private and local public ownership and almost all DSOs (693) has customers fewer than 100,000. Network charge calculations are based on Gas Network Charges Ordinance (GasNEV) which is binding for all DSOs and revenue cap for each operator is calculated based on the Incentive Regulation Ordinance (AregV).¹⁶¹

In 2018, the amount of network infrastructure investments that were reported by 600 gas DSOs are:¹⁶²

- in new builds, upgrades and expansion €798m (2017: €623m)
- in maintenance and renewal €475m (2017: €408m).
- For 2019, a total investment of €1,371m has been foreseen.
- Service and maintenance expenses, based on the data provided by the DSOs, totalled €1,078m in 2018.
- For 2019, service and maintenance expenses amounting to €1,116m has been foreseen.

In **Italy**, the Regulatory Authority for Energy Networks and the Environment (ARERA) carries out regulation and control activities in natural gas segment. Established with the law No. 481 of 1995, ARERA works to guarantee the promotion of competition and efficiency in the Italian public utility services and to protect the interests of the users and consumers. In addition to guaranteeing the promotion of competition and efficiency in the energy sectors, the Authority's action is directed, for all the sectors subject to regulation, to ensure the usability and distribution of the services in a homogeneous manner throughout the national territory. It defines adequate levels of service quality, to establish certain tariff systems, transparent and based on predefined criteria, to promote the protection of the interests of users and consumers. These functions are carried out by harmonizing the economic-financial objectives of the subjects operating the services with the general objectives of a social nature, environmental protection and efficient use of resources.

Another public economic body is Fund for Energy and Environmental Services - CSEA, controlled by ARERA and the Ministry of Economy and Finance, which also operates in the electricity, gas and water sectors. The CSEA's main task consists of the management of the accounts, collection of the tariff components such as tariff equalization mechanism and the disbursement of contributions, as well as all the activities deriving from them such as application of interest for late payment, activation of procedures debt collection etc..

The gas operators must provide CSEA with the declarations of physical and economic data, on which CSEA is obliged to carry out its own conformity assessment, both with respect to the correct application of the rules, and on the correctness of the economic movements that derive from them.

The CSEA also carries out investigative and ascertainment tasks in relation to some specific subjects (equalization, tariff integration), both to determine the amounts to be collected / paid in respect of the operators concerned, and to provide elements of assessment and support to the Authority's decisions. There are available information tools to operators to be used for these for periodic complex declarations (ELT and GAS data entry - ELT and GAS equalization portals, etc.).

In Italy, Natural Gas Distribution sector is highly fragmented, where the top six DSOs (Italgas, 2i Rete Gas, Hera, A2A, Iren, Toscana Energia) represent nearly 70% of the existing 22 million delivery points, while the remaining 30% is split among more than 200

¹⁶¹ Source: Bundesnetzagentur, Report Monitoring report 2018.

¹⁶² Source: Bundesnetzagentur, Report Monitoring report 2019.

players¹⁶³. Italgas is the leader Natural Gas Distribution company in Italy and third largest in Europe with its 67,470 km network and over 7.5 million live meters¹⁶⁴. On the other hand, 2i Rete Gas serves over 2,000 municipalities in Italy, manages 66,000 kms of network and serves over 4.3 million users¹⁶⁵. Within the last 20 years, as a result of the ARERA's support policy to aggregate the DSOs, the number of network operators has dropped from over 700 to about 210.

In Italy, distributors (DSOs) operate under concession regimes at the local level. Distribution activities are fully regulated (e.g., conditions for access, unbundling rules, applicable tariffs and network code). Concessions must be awarded through public tenders. Government introduced the ATEM (Minimum Concession Area) concept in order to increase companies' efficiency and improve the quality of service delivered and divided the Italian territory into 175 ATEMs; which means minimum concession area (e.g. Natural Gas Distribution zones) for the next tenders and defined an ATEM tender calendar. The size of an average ATEM¹⁶⁶ is around 120,000 DPs, 20% more than DSOs' average size (~100,000 DPs).

The **UK** covers both Great Britain (England, Wales and Scotland) and Northern Ireland. There are separate regimes between the two, though Northern Ireland's regulatory framework is based on the more mature UK system.

Company	Gas Distribution Network (GDN)	GDN abbreviation
Cadent	East of England	EoE
	North London	Lon
	North West	NW
	West Midlands	WM
Northern Gas Networks Limited	Northern	NGN
SGN	Scotland	Sc
	Southern	So
Wales & West Utilities Limited	Wales and West	WWU



There are eight Natural Gas Distribution networks (GDNs), each of which covers a separate geographical region of Great Britain. These eight networks are owned and managed by Cadent Gas Ltd, Northern Gas Networks Limited, Wales & West Utilities Limited and SGN¹⁶⁷

Figure 3.1 – Natural Gas Distribution networks in the UK

In addition, there are 16 independent gas transporters (IGT) and 6 site specific pipeline operators covering a number of relatively small networks. There are 3 gas transporters in Northern Ireland.¹⁶⁸

GDNs are natural monopolies and they are regulated by Ofgem to protect consumers from potential abuse of monopoly power.

¹⁶³ Source Arthur D. Little, 2017, Italian Natural Gas Distribution Tenders

¹⁶⁴ Source: <https://www.italgas.it/en/>

¹⁶⁵ Source: <https://www.2iretegas.it/en>

¹⁶⁶ More detailed information on ATEM is provided in section 3.4.1

¹⁶⁷ Source: <https://www.ofgem.gov.uk/gas/distribution-networks/gb-gas-distribution-network>

¹⁶⁸ Source: https://www.ofgem.gov.uk/system/files/docs/2020/03/gas_registered_or_service_addresses_new_1.0_002.pdf

In order to be able to distribute gas through the systems, GDNs and IGTs must hold a licence. The amount of revenue which these companies can recover from their customers are limited by the related conditions of the license.

In UK, the regulatory body is Ofgem, and it is governed by the Gas and Electricity Markets Authority while in Northern Ireland, the regulatory body is UREGNI (Utility Regulator), and it is governed by a Board of Directors and is accountable to the Northern Ireland Assembly through financial and annual reporting obligations.

Ofgem was constituted in 2000 (under the Utilities Act), merging the previously separate gas and electricity regulators, Ofgas and Offer respectively, that themselves were founded under the Gas Act 1986 and the Electricity Act 1989. Its powers come from these acts with a principal responsibility of protecting the interest of electricity and gas consumers with regard to price and quality of service by promoting effective competition and sustainable development and carrying out its regulatory activities in a transparent, accountable, proportionate, consistent way and targeted only at cases in which action is needed. Its strategic priorities are set out in the strategy and policy statement designated by the Secretary of State

Ofgem is responsible for the whole of the onshore downstream gas industry (excluding the offshore gas industry), and the electricity system.

In relation to distribution system, it monitors and enforces licence conditions on companies, regulates the distribution companies for security and reliability standards, quality of service and supply; monitoring the time taken to connect and repair, access to storage, line pack and other services, safeguard measures; tariffs for connection and access and cross-border issues. It sets the price-controls on distribution system operators (DSO) by determining the allowed revenue these companies can earn, while the DSOs set tariffs and connection charges, subject to Ofgem approving its charging methodology.

Ofgem also recently reintroduced price regulation on retail tariffs: in the form of price cap for safeguard tariffs under a separate regulatory regime, and a further price cap on standard variable tariffs and default tariffs.

Ofgem initiated the RIIO program on 1 April 2013 and has been publishing reports on RIIO Natural Gas Distribution, which review the progress made by the relevant DSOs and provide information on how the DSOs are performing against their obligations and incentives.¹⁶⁹

In Northern Ireland, the regulatory body is UR (Northern Ireland Authority for Utility Regulation) which is the regulator for Northern Ireland's gas, electricity, water and sewerage industries. The UR promotes choice and value for all utility customers in Northern Ireland, in accordance with the statutory duties set out in the Energy Order 2003, the Water and Sewerage Services Order 2006, The Gas Order 1996, and the Electricity Order 1992 and 2013.

UR has the statutory objective of promoting the interest of electricity, gas, water and sewage consumers with regard to price and quality of service by promoting effective competition and sustainable development. Its responsibilities involves issuing and maintaining licence for gas, electricity and water companies, regulates the distribution companies for security and reliability standards, quality of service and supply; monitoring the time taken to connect and repair, safeguard measures, occurrence of restrictive contractual practices (e.g. exclusivity clauses), technical cooperation between Community and third-country transmission system operators. It sets the price-control on the monopoly gas network by reviewing the companies' capital and operating expenses, rate of returns, volumes of gas and incentive mechanisms to grow the network. GD17 is the price control for the Natural Gas Distribution networks in Northern Ireland, which is running since 1 January 2017 for a five-year period (2017-2022).

In **Portugal**, the Natural Gas Distribution ensures the flow of natural gas, coming from the high pressure transport network, in the medium (MP: between 20 and 4 bar) and low pressure (LP: below 4 bar) networks, up to the consumption (delivery points). These networks are also called interconnected networks, as opposed to other local distribution networks, which are supplied by deposits of liquefied natural gas (UAG), supplied by a tanker truck. The distribution activity also includes the reception, storage and re-gasification of natural gas in autonomous gas units and its delivery to supply points through the respective distribution networks.

The distribution network operators operating under a regional concession and through local Natural Gas Distribution licenses are

as follows:

Table 3.2 – Gas DSOs in Portugal

Under regional concession	Through local Natural Gas Distribution licenses
Beiragás - Companhia de Gás das Beiras, S.A.	Dianagás - Sociedade Distribuidora de Gás Natural de Évora, S.A.
Lisboagás GDL - Sociedade Distribuidora de Gás Natural de Lisboa, S.A.	Duriensegás - Sociedade Distribuidora de Gás Natural do Douro, S.A.
Lusitaniagás - Companhia de Gás do Centro, S.A.	Medigás - Sociedade Distribuidora de Gás Natural do Algarve, S.A.
REN Portgás Distribuição, S.A.	Paxgás - Sociedade Distribuidora de Gás Natural de Beja, S.A.
Setgás - Sociedade de Distribuição de Gás Natural, S.A.	Sonorgás S.A.
Tagusgás - Empresa de Gás do Vale do Tejo, S.A.	Dianagás - Sociedade Distribuidora de Gás Natural de Évora, S.A.

Natural Gas Distribution activity is separated from the production or commercialization activity. In this regard, gas network operators with more than 100 thousand customers (Lisboagás, Lusitaniagás, REN Portgás and Setgás) are legally separated from the company, while the rest only have functional and account separation between the distribution activity and the last resort marketing activity.

Gas network operators prepare an investment plan with a 5-year horizon: The Five-Year Plan for the Development and Investment of Distribution Networks (PDIRD-GN) every two years, in conjunction with the transmission system operator. This Plan is subject to public consultation and to an opinion by ERSE and the Directorate-General for Energy and Geology, and is approved by the Government, after discussion in the Assembly of the Republic.¹⁷⁰

Natural Gas Distribution activity is mainly regulated and monitored by Energy Services Regulatory Authority, ERSE. In addition to its roles stated in previous sections of this report, ERSE determines the economic regulation of the Natural Gas Distribution activity, sets the tariffs for the use of the distribution network and the revenues of the operators.

In *Spain*, Spanish regulatory authority CNMC (Comisión Nacional de los Mercados y la Competencia) is a multisectoral agency which comprises all regulatory activities related to the energy sector. Since January 2019, regulatory powers and competences of the CNMC are aligned with EU guidelines (3rd Energy Package) for energy National Regulatory Authorities (NRAs).

The CNMC was established in June 2013 by Law 3/2013 after the integration of several authorities into one single organisation: Telecommunications Market Commission (CMT); National Energy Commission (CNE); Railway Regulation Committee (CRF); National Competition Commission (CNC); State Council of Audio-visual Media (CEMA); National Postal Sector Commission (CNSP); Airport Economic Regulation Commission (CREA).

170 Source: <https://www.erse.pt/en/natural-gas/functioning-pt/distribuicao/>

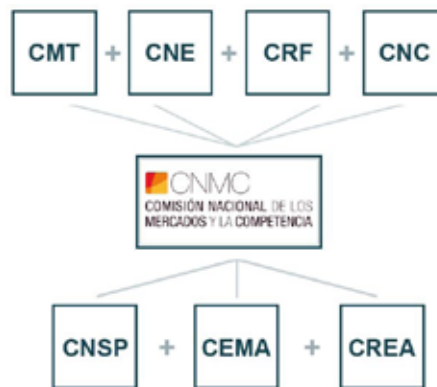


Figure 3.2 – Spain NRA (CNMC) overview

CNMC activities related to the energy sector comprise among others:

- Development of methodologies for revenues determination and tariffs for regulated activities.
- Approval of revenues, tariffs and system settlements.
- Market monitoring and enforcement mechanism (including REMIT activities).
- Reporting and market analysis.
- Electricity and Natural Gas organised market Rules.

As a public agency, its financial accounts are embedded in the State Budget, more precisely in the Ministry of Economy accounts. It is important to highlight that CNMC balances include the capital transfers that the government makes yearly to offset electricity system deficit (3,875 Million € in 2018).

Since the CNMC has competences in several sectors it is hard to assess the operational parameters (i.e. employees and costs) of energy related activities. In the last 3 years, CNMC total headcount has been around 500 employees. ACER assessment of EU energy NRAs quantified CNMC human resources devoted to energy activities in 170 full-time employees¹⁷¹.

The regulatory set up of Spanish energy sector, mainly the activities related to tariffs and revenues have experienced relevant changes during the last 6 years. Some regulatory powers such as tariff setting have been held in some periods by the regulator and in other period by the Government. The alignment of CNMC competences to EU framework has been complex and conditioned by changes of government.

In 2014, the Spanish Government assumed tariff setting competences in order to be able to influence end-user tariffs. This situation contrasted with the European norm (mainly the 3rd Energy Package of 2009) establishing that NRAs shall be in charge of tariff setting. The European Commission initiated an investigation to assess the possible lack of compliance with EU legislation, which culminated in September 2016 with a motivated opinion addressed to Spain, concluding that the Spanish legal system transposed incorrectly European Directives 2009/72&73. This motivated opinion could eventually lead to enforcement actions against Spain in the case non-compliance persisted, but the situation remained stable. At the national level, there were also important litigation and, in 2017, the CNMC initiated a lawsuit under the National Supreme Court to get back energy tariffs-related competences.

After more than 4 years and a new warning of disciplinary proceedings from the EC in 2018, energy competences in dispute returned to the CNMC in January 2019, including tariff setting powers. The Decree 1/2019¹⁷² solved the non-compliance situation, preventing possible appeals to the Court of Justice of the European Union against Spain.

One of the main provisions of the new law is the return of the competences for approving tariffs and revenues of regulated

171 ACER (2016) Taking stock of the regulators' human resources Summary of findings

172 Urgent measures to align CNMC competences to the requirements arising from Community law in relation to Directives 2009/72/EC and 2009/73/EC of the European Parliament and the Council of 13 July 2009, concerning common rules for the internal market in electricity and natural gas.

activities to the CNMC. Until this Decree, these competences were attributed to the Ministry of Ecological Transition, former Ministry of Energy.

The Decree 1/2019 introduced mechanism to guarantee that CNMC role and power are aligned with EU regulation:

- Ensures the consistency and independence of the CNMC in the exercise of its competences.
- Establishes that the CNMC will approve the methodology and the annual remuneration of the activities of transmission and distribution of electricity and natural gas.
- Establishes that the CNMC will approve the methodology and the values of network access tariffs.
- CNMC will establish the conditions for access to the network.
- Organised markets will be regulated and supervised by the CNMC.

Tariffs and remunerations for 2019 were already approved by the Government before the competence were transferred to the CNMC. In any case, electricity and gas network charges had remained frozen over the last 5 years. In 2019 the CNMC started developing all the required methodologies and rules for the next regulatory period: 2020-2025 for electricity and 2021-2026 for gas. The approval of these methodologies was an important source of conflicts between the CNMC, the Spanish Government and key stakeholders, mainly TSOs and DSOs.

Currently there are 19 gas DSOs, which are monitored and regulated by the national regulator. Officially there are 19 DSOs but most of them are grouped under the same parent company, so the real number of different distribution companies is only 6. Natural Gas Distribution is highly concentrated with only 4 groups serving 99% of national supply points and operating 99% of the distribution network length. Moreover, one single group of DSOs (Nedgia) accounts for 70% of the distribution market share.

Table 3.3 – Spain Distribution sector: overview of main DSOs' figures¹⁷³

NG Distribution group	Supply points		Distribution network length		Consumption at supply points	
	Number	%	Kms	%	TWh	%
Nedgia	5,389,065	68%	53,800	70%	191	71%
Nortegás	948,047	12%	8,200	11%	31	11.5%
Madrileña Red de Gas	879,301	11%	5,772	7%	11	4%
Redexis	594,885	8%	8,855	11%	33	12.3%
Gas Extremadura	75,358	1%	737	1%	2	0.8%

Nedgia is, by far, the most important distribution company in the Spanish territory and as it can be seen in the figure below, its service area cover most of the territory. Nedgia is part of the Naturgy holding, former incumbent gas supplier and one of the 3 largest power and gas utilities. Madrileña Red de Gas (not presented in the figure) serves most of the Madrid Region (inside Nedgia area).

173 Source: DSOs' annual reports (2018) and CNMC.



Figure 3.3 – Spanish DSOs by zone¹⁷⁴

In **Turkey**, the regulatory body is the Energy Market Regulatory Authority (EMRA) and is responsible for calculating all aspects of tariffs in Natural Gas Distribution segment. At present, there are 72 DSOs, where all are regulated and audited by EMRA. The number of residential subscribers reached 15.75 million as of December 2019 and the number of eligible consumers in distribution zones reached 614,900 in Turkey.

The length of steel pipelines used in Natural Gas Distribution grids has been 13,500 km and the length of polyethylene and service lines reached 130,000 km, comprising a total length of 143,500 km. As a result of the policies for expanding natural gas grids to rural areas, 66.5 million of the total 83.15 million population (as of end 2019) has access to Natural Gas Distribution grids. The average annual gas consumption per household is around 950 standard cubic meters (Scm), but this might vary depending on the weather affects.

3.3 Revenue Requirement Model

3.3.1 General Overview

Regardless of the methodology used to establish the revenue requirement, in the absence of revenue adjustments, revenues and costs will inevitably diverge over time. Similar to Electricity Distribution segment, EU countries' regulatory bodies use different overall approaches to setting allowed revenues in Natural Gas Distribution segment such as revenue cap, price cap, cost-plus, and rate of return, hybrid and other approaches that might not fit into former examples.

The revenue cap model is the most common model used and it is followed by the hybrid model. Regardless of the overall approach, EU countries are using incentive-based schemes to calculate the required revenue for DSOs. EU countries' regulatory periods and main elements for determining cap are given in Table 3.4.

174 Source: CNMC.

Table 3.4 – Tariff periods and main elements for determining cap for EU countries¹⁷⁵

Country	Tariff Methodology	Period	Main Elements for Determining Cap
Austria	Hybrid	2018-2022	Efficiency scores and general productivity offset, network price index and expansion factors, efficiency dependent WACC
Belgium	Revenue Cap	2016-2019	-
Croatia	Revenue Cap	2017-2021	OPEX and CAPEX OPEX is projected for regulatory period based on 1+CPI-X formula, without ex-post adjustment if realized above, but with profit-sharing mechanism if realized below projected level.
Czechia	Revenue Cap	2016-2018	Allowed costs, Allowed depreciation, RAB, WACC
Denmark	Revenue Cap	2018-2021	Costs in previous period Fixed interest rates; 4-year period.
Estonia	Rate of Return	-	Variable costs, Operating costs, Depreciation of RAB, Justified return of RAB
Finland	Revenue Cap	2016-2019	Innovation- and Investment incentive, WACC return on RAB
France	Hybrid	2016-2020	Cost data (detailed OPEX and CAPEX), WACC and its underlying parameters, quality of service scores, regulatory accounts
Germany	Revenue Cap	2018-2022	Non-controllable and controllable costs, TOTEX efficiency benchmark, efficiency bonus, general inflation and sectoral productivity factor, volatile costs
Greece	Revenue Cap	2017-2021	OPEX (Non-controllable and controllable costs) Depreciation, RAB (Assets and approved investment plans, working capital), WACC and WACC premium
Hungary	Incentive Regulation	2017-2020	Hybrid Model
Ireland	Revenue Cap	2017-2022	Review of historic and forecast OPEX, Review of historic and forecast Capex, Value of Assets in TSO's RAB, Rate of Return and Inflation
Italy	Hybrid System	2014-2019	Hybrid system, partly price cap (OPEX) and partly cost of service (CAPEX)
Latvia	Cost-Plus		OPEX + CAPEX (Depreciation + return on capital)
Lithuania	Price Cap	2014-2018	TOTEX, RAB, WACC, technical losses, efficiency benchmark
Luxembourg	Revenue Cap	2017-2020	Remuneration on RAB; depreciation, Controllable OPEX; Non-controllable OPEX
Netherlands	Price Cap	2017-2021	TOTEX, CPI, yardstick, productivity change, WACC, RAB
Norway	-	-	Under Development
Poland	Revenue Cap	-	Depreciation, local taxes, operating costs, cost of gas losses, pass-through costs and return on capital employed

¹⁷⁵ Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.

Country	Tariff Methodology	Period	Main Elements for Determining Cap
Portugal	Hybrid	2018-2019	Price-cap (OPEX) and rate of return (CAPEX) Non-controllable and controllable costs, RAB, WACC, efficiency benchmark, inflation, mechanism for mitigating volatility of demand
Romania	Revenue Cap	2013-2018	Non-controllable (pass-through) and controllable costs, efficiency factor, general inflation rentability of RAB (RABxROR) depreciation, technological consumption, working capital
Spain	Revenue Cap	2021-2026	The allowed revenue of the preceding year, changes in the number of clients, changes in the volume of gas distributed
Sweden	Revenue Cap	2015-2018	TOTEX (divided into CAPEX, Non-controllable OPEX and Controllable OPEX). General efficiency target of reducing 1 percent of controllable OPEX annually
UK	Revenue Cap	2013-2021	Main elements annual revenue derived from TOTEX efficiency assessment with capitalisation rate determining RAV from which depreciation, slow money (WACC * average of the opening and closing RAV), fast money (expensed in the year it is incurred) is obtained. Additional allowances/adjustments annually reflecting incentives and performance against outputs.

Beside the different revenue requirement models, regulatory bodies employ different methodologies for assessing the cost of services for DSOs. Building blocks (CAPEX and OPEX) approach is the most common one, whereas some countries employ a TOTEX approach.

In addition, the regulatory period also differs among countries. Generally, it is between 3 and 5 years, with some exceptions such as the UK, 8 years which will revert to five years with the upcoming price controls (starting in 2021), and Poland, one year.

The value of existing assets is fundamental to the determination of allowed revenues because both depreciation and return on capital are calculated from it. Details will be provided within this section.

3.3.1.1 Italy

Over the years, the Italian regulator has adopted similar regulatory methodologies for gas and electricity taking into account the peculiarities of the two sectors, whereas the details may differ (for example, the determination of the WACC).

The Italian Natural Gas Distribution tariff regulatory framework is based on clear rules as seen in Figure 3.4.

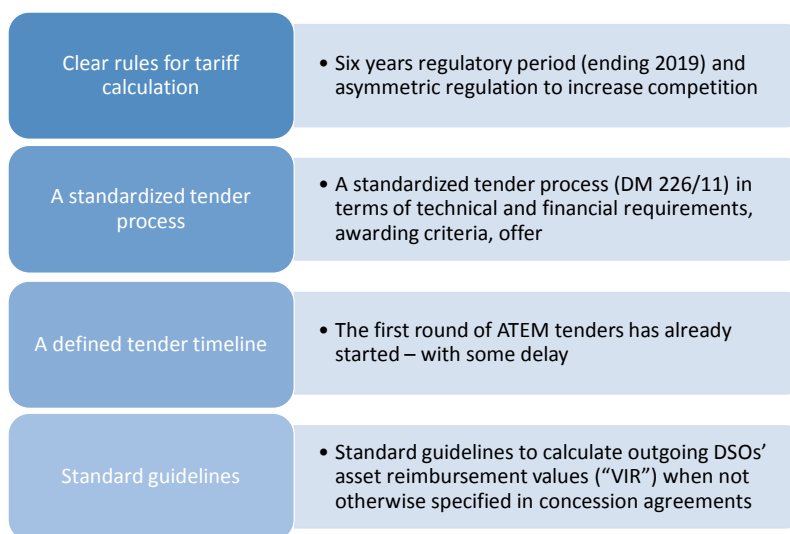


Figure 3.4 – Pillars of Italian Natural Gas Distribution regulatory framework

The current tariff calculation model is based on parametric remuneration of OPEX / central assets and allowed return for local distribution and metering assets (RAB).

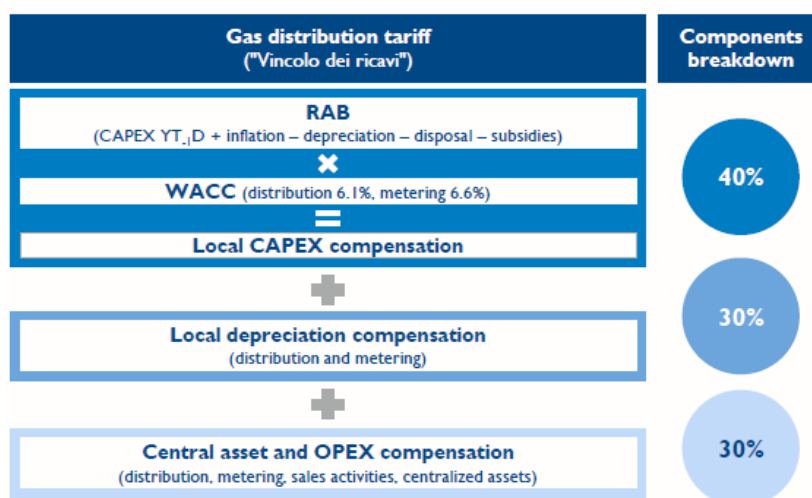


Figure 3.5 – Italian Revenue Model¹⁷⁶

The tariff structure defines a mandatory tariff, applied to end customers, and a reference tariff, which imposes the revenue admitted for each DSO to cover the recognized cost (tariff decoupling).

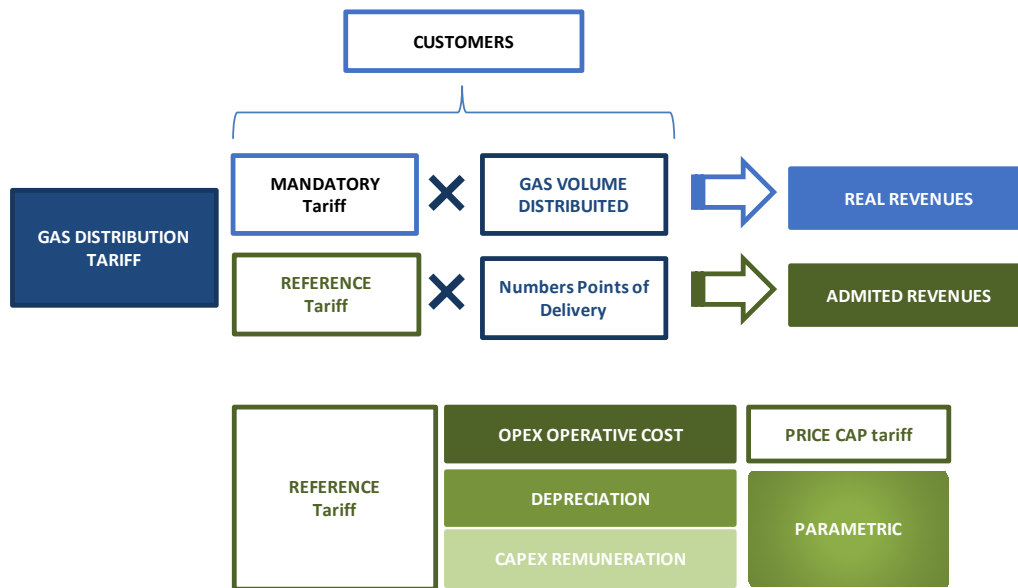


Figure 3.6 – Italian Tariff Model

The level of allowed revenue for each company depends on the reference tariff, divided into a series of tariff components allocated to cover specific cost aggregates (for example Costs of capital of location, centralized capital costs, operating costs, etc.), and from the number of redelivery points served. The reference tariff is divided into distribution service and measurement service.

The tariff applied to end customers, the mandatory tariff, is distinguished by geographical tariff areas and reflects the average level of service costs for companies operating in each tariff area.

The Authority has divided the entire country into six geographical areas, by taking below factors into account:

- Population density
- Load factor assessment for residential, industrial, and power producers
- Status of existing grids

The mandatory tariff is a binomial tariff, divided into a fixed amount and a variable amount, applied according to the volumes of gas served to the individual points of delivery. The variable quota is in levels, with a first level at a price zero and another five with a digressive rate.

Tariff equalization mechanism (responsibility of CSEA) is applied in order to allow the DSOs to cover the imbalances between revenues admitted by the reference tariff and actual revenues obtained by applying the mandatory tariff.

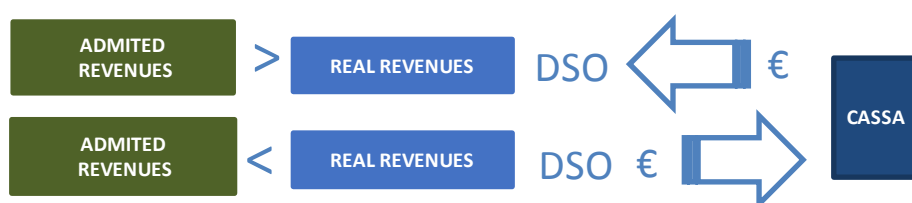


Figure 3.7 – Tariff Equalization Mechanism

To create more intense competition, ARERA introduced first an asymmetric regulation in the definition of the tariff rules that are applicable to the new ATEM concessions (minimum concession areas)¹⁷⁷:

- For the share of ATEM acquired from outgoing DSOs, tariffs will be calculated on the basis of the asset reimbursement values (VIR) effectively paid instead of the RAB previously recognized for the municipalities within the ATEMs, that means actual money spent will be recognized in tariff.
- For the share of the ATEM already managed by the concessionaire, tariffs will be calculated on the basis of the previous RAB (CAPEX remuneration continues as before).¹⁷⁸

In both of these cases, at the end of the 12-year ATEM concession, the DSO will have the right to cash-in the VIR (inflated and depreciated) plus the CAPEX made in the concession period (inflated and depreciated).

For the coming regulatory period, the tariff calculation model is expected to switch to a new mechanism based on standard prices and an output-based model in order to increase the “cost-benefit” balance for the customer

3.3.1.2 UK

TOTEX is the sum of the projected OPEX, CAPEX incurred in that year and the replacement expenditure (REPEX) in Natural Gas Distribution. In distribution, it consists of all the expenditures relating to DSOs’ regulated activities with some exceptions. The TOTEX approach to setting price controls aims to incentivize companies to deliver outputs at the lowest total cost, without preferring cost savings derived from OPEX or CAPEX solutions.

The RIIO-GD1 price control sets out the outputs that the eight Natural Gas Distribution network companies need to deliver for their consumers and the associated revenues they are allowed to collect for the eight-year period from 1 April 2013 until 31 March 2021. Under RIIO, additions to the asset base do not reflect actual CAPEX only; instead they reflect a proportion (the capitalisation rate) of the TOTEX of the company, referred to as ‘slow money’. The capitalisation rate reflects expectations of the future OPEX-CAPEX split and determines the proportion of TOTEX added to RAV in base. This may change over time as the balance of operating and asset-based activities changes. It is set at the outset generally based on the historical and forecast split of CAPEX/OPEX. The residual TOTEX is referred to as ‘fast money’ and is recovered in the year in which it is incurred.

The main financial parameters – the WACC, depreciation profiles, and capitalisation rate are set for the duration of the price-control and follow established regulatory principles. New assets are assumed to be depreciated through a 45-year period while the existing assets through a 20 year period, with sum-of-digits depreciation¹⁷⁹. Weighted-average cost of capital (WACC) is the main parameter determining the return on assets and is calculated from an assessment of the relevant cost of debt and cost of equity of the business.

The RAV is calculated by summing an estimate of the initial market value of each licensee’s regulated asset base (estimated revenues of each regional network for 2002/03 published in Ofgem’s Final Proposals on the separation of Transco’s distribution price control¹⁸⁰), and all subsequent allowed additions to it at historical cost, and deducting annual depreciation amounts calculated in accordance with established regulatory methods and a deduction is also made in certain cases to reflect the value realized from the disposal of assets which are part of the regulatory asset base. RAV is indexed to RPI annually to ensure it is consistent with current cost accounting.

Base revenue is calculated as the sum of a return on an asset base, a depreciation allowance, an operating cost allowance, tax and

177 Source: http://www.adlittle.cn/sites/default/files/viewpoints/ADL_ENUT_Gas%20Distribution%20Tender.pdf

178 Source: http://www.adlittle.cn/sites/default/files/viewpoints/ADL_ENUT_Gas%20Distribution%20Tender.pdf

179 As an example, suppose an asset with an asset life of 4 years. The sum-of-digits method adds together 4 + 3 + 2 + 1 to get 10 years total. In the first year, the asset’s depreciation is 4/10 or 40% of the value, in the second year it’s 3/10 or 30% of the value, and so on.

180 <https://www.ofgem.gov.uk/ofgem-publications/56716/3624-38septdp.pdf>

ex-ante revenue adjustments as seen in the figure below¹⁸¹:

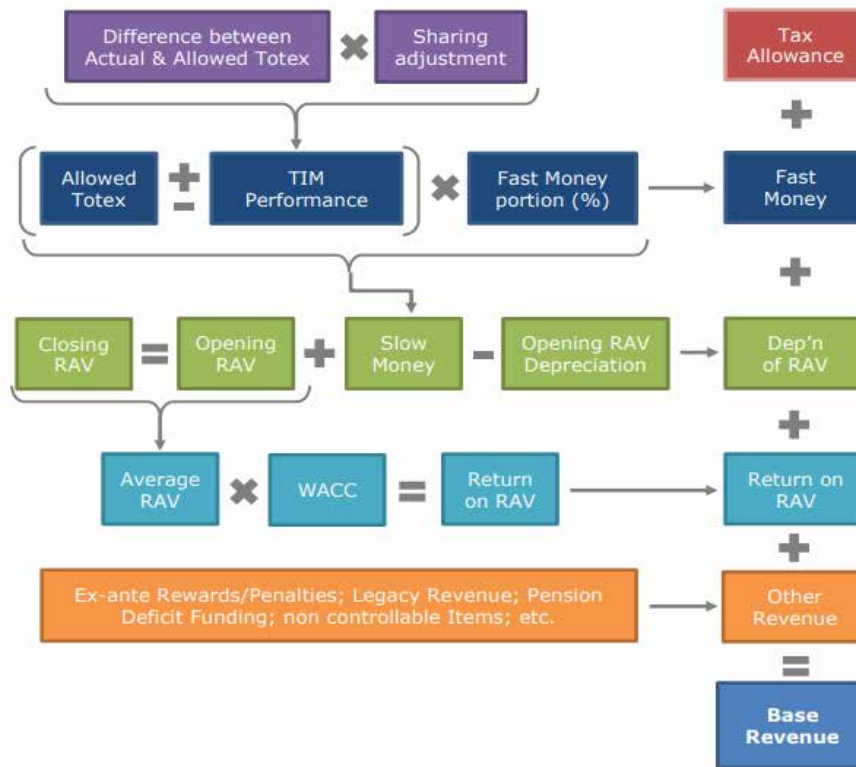


Figure 3.8 – Base Revenue Calculation Diagram

Calculation is similar to RIIO-ED1 base revenue calculations. The financial and output performance of DSOs affects the allowed revenue that they can collect through customer bills, for example, the performance in 2017-18 will impact on allowed revenue, and therefore customer bills, in 2019-20. The output incentives (i.e. rewards/penalties) and adjustments on uncertainty mechanisms are funded with a two-year lag (i.e. the output performance in a year is reported the next year and the reward/penalty feed into allowed revenues the year after) that reflects the delay from reporting/verification to the actual applied adjustment, but that the value is inflated to maintain revenue neutrality. It creates an advance warning for any volatility these may cause in network charges.

The details of the revenue adjustments on allowed base revenue, which is similar to RIIO-ED1, is presented in the next figure¹⁸².

¹⁸¹ Source: Ofgem, RIIO-GD1 Annual Report 2015-16, 2017

¹⁸² Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.

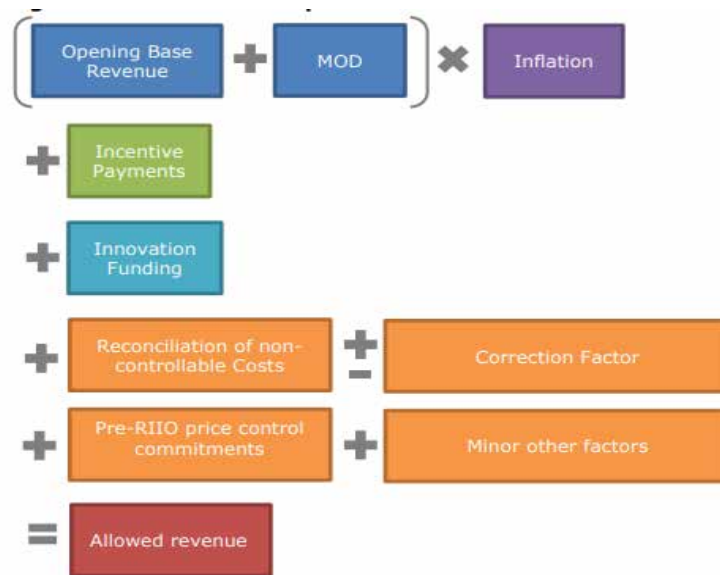


Figure 3.9 – Constituents of Allowed Revenue

3.3.1.3 Germany¹⁸³

In Germany, the objective of the regulatory approach is to enhance the focus on efficiency and quality of supply and provide an adequate environment for efficient investment. Revenue cap is implemented since 2009 and the Sect. 21a EnWG (Energy Industry Law) and Incentive Regulation Ordinance (ARegV) set two regulatory periods for gas DSOs, where the first regulatory period for gas operators lasted 4 years and the others 5 years.¹⁸⁴

The revenue cap is composed of the permanently non-controllable costs, temporarily non-controllable costs, controllable costs (applying a distribution factor for reducing inefficiencies), a possible efficiency bonus, general inflation relative to the base year and a general sectoral productivity factor, a CAPEX in period top-up to take account of the cost of capital for investments after the base year and volatile costs. The difference between the allowed revenue and the development of actual volumes over the year is entered into a regulatory account.

Revenues are decoupled from costs, where more efficient companies are granted higher returns as they can keep the profits until the end of the regulatory period when getting more efficient and less efficient companies receive lower returns. The regulator seeks to incentivize network operators to identify further cost savings and increase profits. Customers also benefit from this efficiency increase. Revenue cap is set for each calendar year of the regulatory period (or “revenue path”) which is based on an efficiency benchmark. Revenue cap avoids giving network operators an incentive to increase sales.

There is no volume risk since an instrument of regulatory account captures significant changes in volumes transported.

Figure below shows how revenue cap changes in years with the mentioned approach.¹⁸⁵

¹⁸³ Source: Groebel A., (April 2018), BNetzA's role in energy infrastructure regulation and planning/permitting. https://erranet.org/wp-content/uploads/2017/10/Muller_Case-study-benchmarking-Germany_final.pdf

¹⁸⁴ Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.

¹⁸⁵ Source: Groebel A., (April 2018), BNetzA's role in energy infrastructure regulation and planning/permitting. https://erranet.org/wp-content/uploads/2017/10/Muller_Case-study-benchmarking-Germany_final.pdf

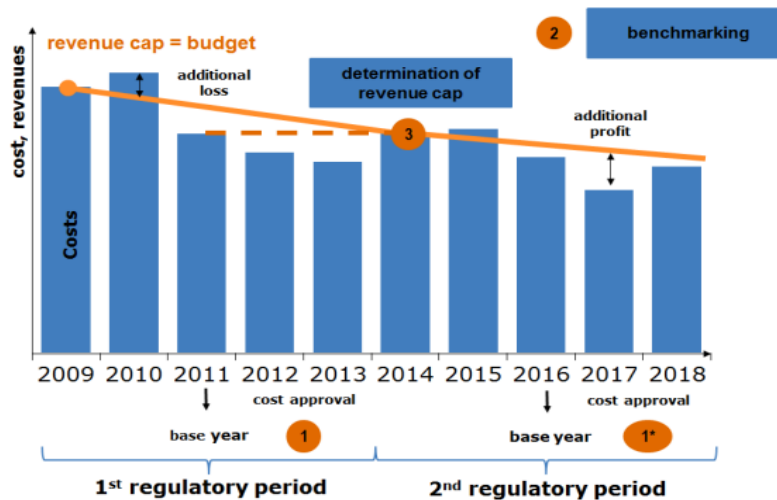


Figure 3.10 – Revenue cap changes¹⁸⁶

In Germany, some network operators operate network areas with structural particularities, such as atypical soil conditions or a larger number of rivers which need to be crossed by systems. These particularities may lead to increased expenses in comparison to other network operators. Thus, network operators are entitled to request a consideration of these structural particularities in the efficiency comparison. Therefore, network operators need to demonstrate to the Federal Network Agency for each particularity, that costs exceed the materiality threshold of 5%. Where such evidence has been proved, it will be taken into account for adjusting the efficiency rating.¹⁸⁷

Methodology for analysing CAPEX and OPEX declared by DSOs and their evaluation methods are as follows:

The Federal Network Agency executes cost examination of network operators every 5 years, in the so-called base years, generally aiming on the proof of operational necessity of costs declared by the network operators. Thus, network operators need to be able to clarify their cost items and the declared amounts.

For several cost items, particular regulations are given:

- Admissible costs are limited to the level of an efficient and structurally comparable network operator.
- Borrowing costs are limited to merchantable interest rates
- Costs for sponsoring, advertising and donations are not admissible due to absence of necessity, since network operators are monopolists
- The 20 largest maintenance and repair measures in terms of value must be explained to the Federal Network Agency in order to enable a cost check
- Declared Provisions must be explained to the Federal Network Agency
- Recognition of working assets usually only up to 1/12 of the year's sales revenue, receivables only up to 3/12.
- Financial assets are generally classified as non-essential and therefore non-admissible
- In case networks are not owned, but leased by the respective network operator, leasing costs should not exceed the admissible costs ("minimum comparison")
- Third party services are limited to costs which would occur, if the DSO would provide them himself. Therefore, disclosure of

186 Source: <http://chairgovreg.fondation-dauphine.fr/sites/chairgovreg.fondation-dauphine.fr/files/attachments/Groebel%20ok.pdf>

187 Source: Bauer et al. 2016, Regulierung in der Energiewirtschaft

the 10 largest service contracts by value with associated companies is necessary.

According to the gas DSOs' reports, expenditure on maintenance and repair in 2017 was €1,084m. The projected expenditure on maintenance and repair for 2018 is €1,074m.

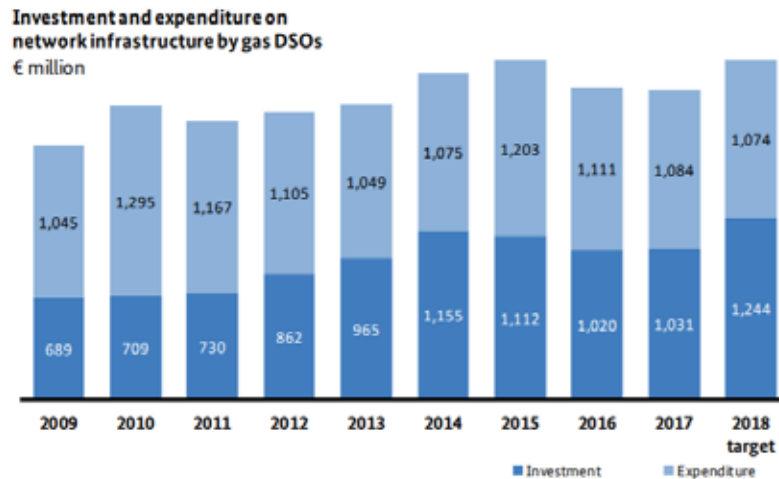


Figure 3.11 – Investment of Gas DSOs¹⁸⁸

3.3.1.4 Portugal

A price cap methodology is used for OPEX and rate of return methodology for CAPEX within the scope of Natural Gas Distribution tariff calculations. At the beginning of the regulatory period 2016-2017 to 2018-2019, a mechanism was introduced in distribution activity that seeks to mitigate the effects associated with the volatility of demand in the amount of allowed revenues to be recovered by tariffs. A similar approach has been followed for Natural Gas Transmission. Current regulatory period is 2020-2023.

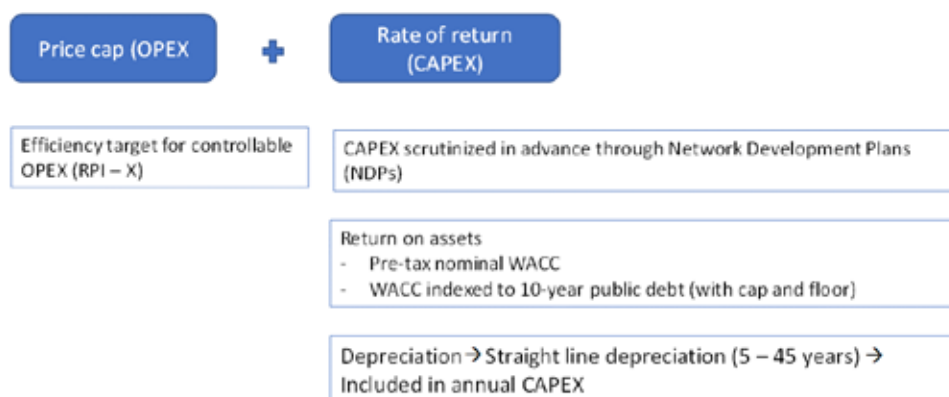


Figure 3.12 – Allowed Revenue¹⁸⁹

188 Source: BNetzA, Monitoring Report 2018

189 Source: ERSE, October 2019, Distribution tariff setting methodologies in Portugal, Course on Gas and Electricity Distribution Tariffs - Theory and

Some properties of the regulation are as follows:

- Uniform D-tariffs (inter-DSO compensations)
- Mechanism implemented for the regulatory period in force that aims at mitigating the effects associated with the volatility of demand in terms of authorized revenues is recoverable via the application of the tariffs.
- Tariffs are differentiated by pressure level: MP, LP> and LP<
- Cost cascading principle is applied
- Investments are divided into central and peripheral assets
- Price signal results from average long term incremental costs
- Billing variables are used capacity, energy, fixed term

Cost drivers for price cap on OPEX, that were determined based on econometric analysis and benchmarking, are as follows:

- Number of clients (45% - 48.75%)
- Distributed energy (15% - 16.25%)
- Fixed component (35% - 40%)

Incremental cost approach is applied where;

Average Long Term Incremental Cost (IC), per cost driver D ;

$$IC_D = NPV(\Delta INV_D) / NPV(\Delta D)$$

NPV : net present value (discounted at average WACC)

ΔINV_D : investments (CAPEX + related OPEX) due to increments in cost driver D .

ΔD : increments in the cost driver (peak power, contracted power)

It is computed for 3 cost drivers that are peak energy (central assets), used capacity (75% of peripheral assets) and # clients/fixed term (25% of peripheral assets)¹⁹⁰

In determination of the Suppliers of Last Resort tariff; price cap methodology plus remunerated working capital is applied. Concessionary companies have the right to additional revenue of 4€ per customer (considering the number of customers at the beginning of the regulatory period). In Portugal for the first time, reference costs were set for the natural gas retail market, in order to comply with the legal framework, set a sustained basis for determining the revenues recoverable by the SoLR and approximate the regulatory approaches in the electricity and natural gas sectors.¹⁹¹

3.3.1.5 Spain

The Revenue Requirement Methodology applicable for Natural Gas Distribution has been one of the most important regulatory discussion topics on the Spanish energy sector in 2019.

Since 2002, the RRM (Revenue Requirement Model) has used a parametric formula based on the allowed revenue of the preceding year and increases in the number of supply points and energy distributed (MWh). In 2014, the CNMC undertook a minor adjustment of the RRM but from a methodological point of view the model is the same.

On July 2019, right after getting back tariff competences, the CNMC opened to public consultation a new methodology for the Practice.

190 Source: ERSE, October 2019, Distribution tariff setting methodologies in Portugal, Course on Gas and Electricity Distribution Tariffs - Theory and Practice

191 Source: ERSE, 2018, Annual report on the electricity and natural gas markets in 2017.

calculation of the remuneration of Natural Gas Distribution activities. This new methodology, instead of considering the revenue of the preceding year, recalculated the base remuneration for 2020 more aligned with EU practices. The proposed new calculation of the base remuneration introduced elements such as the Cost of Capital/Operational expenses distinction, WACC, efficiency incentives, etc. The application of this methodology implied an average remuneration cut for the next regulatory period (2021-2026) of -17.8% with respect previous methodology so it was heavily contested by gas utilities and by the Government.

Therefore, the CNMC developed a new methodology that is yet to get published in the official gazette but has the overall acceptance of stakeholders (new remuneration cut is only -9.6%). This new methodology proposed for 2021-2026 is in line with the one previously in use and maintains the base remuneration (initially calculated in 2002) with an adjustment to end with the remuneration of amortized assets.

In order to provide EMRA with all the regulatory approaches under consideration in Spain, both the existing methodology in use (continuist regulation) and the rejected regulation proposed in 2019 (more aligned with EU practices) are presented.

Table 3.5 – Spain RRM: historical overview

	2002-2013	2014-2020	2019 (proposals)	2021-2026
RRM in use	Initial revenue assessment based on 2000 book values. Adjusted proportionally by inflation, supply points and energy distributed. Parametric Formula.	Updated base remuneration value + unitary remunerations for each supply points and volumes. No inflation. Unitary incremental revenues	Updated base remuneration (glide-path) + unitary remunerations for supply points and volumes. Unitary incremental revenues.	
Proposed new methodology (rejected)			Recalculate base remuneration with 2020 book values: OPEX, RAB, WACC, etc.	

Revenue Requirement Model in use (2014-2020) and new model (2021-2026):

Revenue Requirement Model in use between 2014 and 2020 was developed in Law 18/2014 and was based on the following formula:

$$RD_n = RD_{n-1} + RN_n$$

- RD_{n-1} : Remuneration of the previous year.

For the first year (2014) the base remuneration was calculated applying the parametric formula (in use between 2002-2013) with 2014 values. The resulting remuneration of the parametric formula (1,514 Million €) was decreased to 1,404 Million € to offset excess-remunerations due to amortized assets (the methodology to calculate the adjustment amount was not disclosed).

The objective of the base component is to remunerate distribution assets in service prior 2014.

- RN_n : New Market Remuneration. Additional revenue is added for any increment in the number of supply points and energy distributed (MWh) from the previous year' value. If the number of supply points or the MWh decrease, revenue is cut in the same proportion.

The objective is to remunerate new distribution assets in service after 2014.

The following unitary parameters will be used to calculate new market remuneration:

Table 3.6 – Spain RRM: unitary revenue for each supply point and MWh

50 €/customer	for each new supply point below 4 bar
70 €/customer	for each new supply point below 4 bar in a municipality of recent gasification (municipalities where the first supply point in the was established in the last 5 years).
7.5 €/MWh	for each additional MWh from customers below 4 bar with a yearly consumption below 50 MWh.
4.5 €/MWh	for each additional MWh from customers below 4 bar with a yearly consumption above 50 MWh.
1.5 €/MWh	for each additional MWh from customers above 4 bar

In 2019, CNMC concluded that the base remuneration that distribution companies had received since 2002 led to important excess remunerations that in 2018 reached 586.4 Million €/year¹⁹².

To end with this over remuneration, initially CNMC proposed a new methodology to recalculate base remuneration based on the EU general regulatory approach (OPEX + RAB * WACC + depreciation) with 2020 book values of distribution companies. This new regulatory approach was finally rejected but key elements of this proposal are included in the end of this section.

For the next regulatory period (2021-2026), finally, CNMC opted to maintain the overall principles of the RRM in use but introduced an adjustment factor to the base remuneration to decrease gradually cumulative excess remuneration. The new formula to calculate yearly distribution remuneration is as follows:

$$RD = RDE2020 + RDM + RTD + IM$$

RD: The remuneration for a company for its activities related to Natural Gas Distribution¹⁹³.

$$RDE2020 = \text{Remuneration 2020} - AAD2000$$

Remuneration 2020 = the remuneration in 2020, applying previous methodology (2014-2020).

AAD2000 = Distribution Activity Remuneration adjustment. This element represents the correction factor to decrease the remuneration for assets in operation prior to 2000, already amortized. This component is calculated based on the difference between the unitary cost of the base remuneration (calculated in 2014) and unitary costs for new market:

¹⁹² CNMC (2019) memoria justificativa de la circular xx/2019, de x de diciembre, de la comisión nacional de los mercados y la competencia, por la que se establece la metodología para determinar la retribución de la distribución de gas natural.

¹⁹³ E.g. connection of new supply points are not included in the revenue calculation since the cost are borne by the customer.

Table 3.7 – Spain: unitary revenues comparison

	Unitary remuneration in 2014 for the assets in operation in 2000.	Unitary remuneration for new market (2014-2020)	AAD2000 (negative remuneration) Calculated applying the unitary remuneration difference to 2000 assets
For each new supply point below 4 bar	112 €/customer	50 €/customer	-239 Million €
Customers below 4 bar with a yearly consumption below 50 MWh.	5.07 €/MWh	7.5 €/MWh	
Customers below 4 bar with a yearly consumption above 50 MWh.		4.5 €/MWh	
Customers above 4 bar	1.66 €/MWh	1.5 €/MWh	

□□□= New Market Remuneration. Additional revenue for any increment in the number of supply points and energy distributed (MWh) from the previous year. It is calculated in the same way as explained above for the methodology 2014-2020.

One new component is included to remunerate new supply points devoted to gas supply for vehicle transportation.

□□□= Transitional Distribution Remuneration. Glide path for the application of the remuneration adjustment (AAD2000 component):

Table 3.8 – Glide path for the initial remuneration adjustment 2021-2026: Spain

	2021	2022	2023	2024	2025	2026
RTD(% of AAD2000):	85%	70%	50%	35%	15%	0%

IM = Incentive for loss reduction. If distribution losses of a company are below the allowed losses level (see Shrinkage losses section) distribution companies keep half the value of gas.

It has been seen how Spanish regulatory approach to RRM is based on incremental unitary revenues. The following table contains a recap of how the incremental revenue approach has been applied in Spain and how it will be applied in the next regulatory period:

Table 3.9 – Spain: overview of incremental revenue approaches

	2002-2013	2014-2020	2021-2026
Base remuneration (BR)	Initial revenue assessment based on financial statements (1998-2000) brought to 2002.	BR applying 2013 methodology – 110 Million €	BR in 2020 applying 2014 methodology – AAD adjustment (glide path). AAD adjustment will reach -239 Million €/year in 2026
Incremental methodology	BR * (inflation factor) * (SP factor) * (MWh factor)	BR + (ΔSP*unitary cost) + (ΔMWh*unitary cost)	
- Inflation factor	1 + 0.85*inflation	NA	

	2002-2013	2014-2020	2021-2026
- Supply points (SP) factor	$(1 + \Delta SP * \text{efficiency factor})$	Stable unitary costs for type of customer (see tables above)	
- Energy distributed (MWh) factor	$(1 + \Delta MWh * \text{efficiency factor})$	Stable unitary costs for type of customer (see tables above)	

Proposed Revenue Requirement Model (2019, not implemented):

It is interesting to analyse the initial CNMC proposal even if it was finally rejected due to stakeholders' complaints on the remuneration cuts resulting from its application. This proposal may be considered as the preferred regulatory approach of the CNMC and the key elements of the new regulation were:

- Proposed methodology recalculated completely the base remuneration based on book values (2020) of assets (RAB), depreciation and O&M costs and introduced the application of the WACC to calculate the RoR for the base remuneration.
- A glide path was applied between 2021 and 2026 to the base remuneration of 2020 until reaching the recalculated base remuneration.
- The remuneration associated to new market (incremental unitary revenues) is the same as the one explained above. Incremental revenue for each new supply point and MWh distributed.
- Additional incentives are included related to efficiency and the extension of useful life of assets.

$$\text{Remuneration} = ROD + RDM + ARPE$$

ROD= Ordinary Remuneration

$$ROD = ROD \text{ base} * f^{(\text{year}-2021)}$$

f = reduction factor

$$ROD \text{ base} = \text{Depreciation (A)} + \text{Financial Remuneration (RF)} + \text{O\&M Costs}$$

Depreciation = book value of depreciation in 2020

RF = net fixed assets value (book value)*financial remuneration rate (WACC)

O&M Costs = network length (kms)*unitary average O&M cost (€/km) (average allowed O&M book value between 2018 and 2020).

RDM = New market Remuneration. Based on unitary costs for supply points and MWh (as explained above)

ARPE = Efficiency incentives: extension of useful life of pipelines and O&M costs reduction (these incentives are explained in more detailed in the efficiency section below).

3.3.1.6 Turkey

Models used to calculate the revenue requirement in EU countries are very similar in general, but at the same time, can be quite different in detail and in the sense of application. In contrary to most EU countries, the price cap model is implemented in Turkey since 1st January 2012 for the gas DSOs (the ones that completed 8 year-period following the first tender), as stated in the Natural Gas Market Distribution and Customer Services Regulation.

CAPEX and OPEX model are in use in terms of allowed revenue. Projected OPEX for each year of the tariff implementation period is calculated from historical costs and adjusted through benchmarking with other distribution companies.

Base OPEX is composed of fixed and variable costs. The variable part is adjusted based on the projected expansion. If the company is an inefficient one in the DEA analysis, the sum of fixed and adjusted variable OPEX is discounted with the efficiency factor of the relevant company.

In OPEX and CAPEX analysis, benchmarking among the utilities is a widely preferred methodology by the Regulators. Partial performance indicators are used prominently as they are based on easily accessible data and simplicity of calculation.

OPEX calculation was revised for 2017-2021 tariff period and it became more complex and benchmarking based. OPEX is broken down into several categories by EMRA that are Base OPEX, OPEX Cap-1, OPEX Cap-2, Other OPEX and OPEX for working capital. Non-controllable OPEX is not defined within the scope of the regulation.

Clustering of companies, econometric modelling of costs, partial performance indicator analysis for OPEX, cap-1 limitation for expenses such as consultancy, sponsorships, donations, advertising, hospitality and cap-2 transformed expenses for fixtures, rentals, IT services are calculated separately. Eventually, the efficiency factor applied and increased base OPEX are added to cap-1, cap-2, other OPEX and working capital expenses to get the final total OPEX.

OPEX and CAPEX are divided by some output measures such as length of lines, number of customers, energy delivered, In this method, one dimension of the performance is measured and can be misleading due to several factors such as different business models applied, service quality differences, different conditions DSOs face due to regional, social, political, historical factors and so on. Having some drawbacks, this analysis yet provides very important data for the regulators.

Efficiency benchmarking by using well-known analyses are used together with benchmarking to gain more insight on sectorial performance.

CAPEX calculations also have a performance cut or bonus depending on the actualizations of the company compared to sector average. CAPEX analysis is based on acceptance limit method (some relatively low amount types are analysed differently). Previously, each type of asset was assigned a higher limit of acceptance (derived from sectoral averages using statistical methods) and if for this single type a company exceeded this limit, limit would be applied, and if below the limit, it is accepted as the actual value. This was a one-way method which penalized higher cost assets but did not reward lower cost assets. The current scheme still applies a higher limit of acceptance; however, it also rewards lower cost assets by applying a premium on the actual value.

Regulatory period is 5 years (which can be changed by the EMRA's Board) and depreciation period is 22 years (compatible with fiscal depreciation period, contrary to Electricity Distribution regulations in which fiscal and regulatory depreciation periods differ).

Price cap methodology is applied, however during the 5-year period, regulatory body evaluates the divergence between realized and forecasted consumptions at the end of each year and recalculates the distribution system usage fees if the effect of that divergence caused a divergence in the required revenue of the relevant year by more than 7%, as described above.

However, there is a type of future years review resolution (No. 5120/1) for demand forecast, which is triggered if the effect of the divergence of consumption between realized and forecasted revenues is higher than the determined limit (which was 10% at the beginning and currently stand at 7%). In this case, past revenue differences are either positive or negative, due to the difference between actual and forecasted demand. This difference is the responsibility of the DSO. However, demand forecasts are regularly reviewed and if necessary revised. This regulation is in the way of converting the price cap methodology into a revenue cap methodology.

CAPEX consists of return on capital based on the rate of return (regulated WACC) determined for each tariff period and depreciation over 22 years. WACC is calculated using CAPM methodology, expressed in real values and is pre-tax.

Historical cost accounting method has been in use in Turkey to calculate RAB. This method is based on the cost of acquiring and

renewing assets in the past less the cumulative depreciation on those assets. Most popular method in EU countries is historical cost accounting, but small differences result in hybrid approaches in this calculation.

3.3.2 RAB

Within the scope of tariff calculations, the value of current assets is fundamental to the determination of allowed revenues since both depreciation and return on capital need to be calculated. A major focus is placed on the determination of the RAB.

The structure of individual components included into the RAB and their valuation differ significantly among EU Member Countries and among the electricity and gas sectors. The RAB value is usually linked with depreciation, however it depends on an individual NRA's approach. It can be comprised of several components such as fixed assets, working capital or construction in progress. Other elements such as capital contributions of customers, government (e.g. subsidies) and third parties, the contrary, are usually excluded.

In general, the RAB provides for remuneration of both historic and new investment. The RAB should be formed by the assets necessary for the provision of the regulated service in their residual (depreciated) value.

There are also different valuation methodologies such as;

- historical costs which require the use of a real instead of a nominal WACC
- indexed historical costs
- actual re-purchasing costs.¹⁹⁴

Following table shows different approaches for setting RAB in EU countries.

Table 3.10 – RAB Components and RAB adjustments¹⁹⁵

Country	RAB Components	Regulatory Asset Value	RAB Adjustment
Austria	Intangible and fixed assets, book values	Historic cost approach	RAB developments during a regulatory period are taken into account and lead to changes of the regulated cost base
Croatia	RAB includes both tangible and intangible assets which is in operation and also planned investments which will be put in operation for each year of the regulatory period.	RAB is calculated as historical cost of the assets such as depreciated book value of the assets.	In the last year of the regulatory period, revision of allowed revenues is performed. RAB is revised in way that the revised value of regulated assets at the end of each regulatory year t is equal to the realized value determined on the basis of balance sheet.
Czechia	Fixed assets, investments in progress, leased assets, no working capital	The RAB is based on re-evaluated values of assets that are recorded in the annual financial statements.	The adjustment is similar to the net book value calculation (investment - depreciation), the formula for RAB adjustment is "investment – depreciation $\times k$ "; k is re-valuation coefficient which is set annually and calculated as the result of dividing the planned value of the RAB in year "i-1" by the planned residual value of assets in year i-1; $k = <0;1>$

¹⁹⁴ Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.

¹⁹⁵ Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.



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Country	RAB Components	Regulatory Asset Value	RAB Adjustment
Denmark	Fixed assets, working capital, assets under construction and historical debt	Historical costs included return on capital	Investments in new assets after the base year lead to an adjustment of the CAPEX.
Estonia	Fixed assets, working capital, leased assets	Historical costs	The fixed assets do not include: 1) long-term financial investments; 2) intangible assets, except for software licenses; 3) fixed assets acquired with grant aid (including targeted funding); 4) fixed assets acquired with funds obtained from connection fees; 5) fixed assets which the undertaking does not use for the purpose of providing network service.
Finland	Fixed assets, working capital, leased assets	Regulatory asset value is calculated from network replacement value by applying network component-specific average age and lifetime selection.	Book values taken to RAB annually from balance sheet
France	Fixed assets	Historical revaluated costs (taking into account inflation and depreciation)	Subsidies and grants are removed from the value of assets before entering the RAB
Germany	Fixed assets, working capital, assets under construction	Net substance preservation for business assets capitalized prior to 1st 2006, real capital preservation for business assets as from 1st 2006	Investments in new assets after the base year lead to an adjustment of the CAPEX. No distinction between replacements and enhancements or expansions
Greece	Fixed assets, working capital, assets under construction	Historical costs	There is no adjustment
Hungary	Tangible assets	Network assets: depreciated replacement value; Non-network assets: historical costs.	The assets of the base year are modified yearly with modified CPI and T-1 year's investments which were approved by the Authority
Iceland	Fixed operating assets	Book value	
Ireland	Fixed assets, intangible investment, and does not include inventories and assets under construction.	Replacement cost approach: Historic cost indexed to present value using inflation	RAB adjusted for disposals
Italy	Invested capital of localities (fixed assets), centralized capital and public and private contributions received.	<u>Capital of localities:</u> Book values and State of consistence communicated to the ARERA evaluated on the basis of a 'historical revaluated cost' approach (RAB). <u>Centralized capital</u> parametrically calculated on the basis of the PdR	RAB annually communicated to the ARERA. Every year the value of the DSOs' assets is updated by the inflation index of the price of "investment goods"
Latvia	Fixed assets, intangible investment, and does not include inventories and assets under construction.	Book value as per financial reports (taking into account asset revaluations carried out by the operator at replacement cost value)	The RAB is adjusted and set when the operator submits the tariff proposal; during the period the tariff is in force there is no RAB adjustment taking place.
Lithuania	Fixed assets	Historical values. 160 mill Euro (2017)	New investments and depreciation
Luxembourg	Fixed assets containing production costs		



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Country	RAB Components	Regulatory Asset Value	RAB Adjustment
Netherlands	Fixed assets and certain intangible assets (such as software) are included, no working capital.	Indexed historical costs	Annual indexation (with CPI); Also, adjustment for certain specific (replacement) investments
Poland	Tangible fixed assets in use and intangible assets, deducted by assets financed by subsidy. Remunerated assets include the average value of planned net capital expenditures, deducted by an average planned depreciation.	Set for every tariff	Adjustments of return of capital included in allowed revenue are possible during tariff calculation.
Portugal	Fixed assets deducted from third parties' contributions	626 million euros for 2016 (mix of historical and re-evaluated costs)	Each year the RAB allowed for year t is adjusted in order to consider new investments, write-offs and depreciation
Romania	Fixed assets, working capital	The RAB value consists in historical assets value and value of the new investments. The value of the new investments included in RAB is considered to be the accounting value. For each year of the regulatory period, the RAB value increases with the investment in new assets and decreases with depreciation and the value of the asset that exits before complete depreciation.	Investments in new assets after the base year and assets that exit before complete depreciation lead to an adjustment of the CAPEX.
Spain	Fixed assets (No working capital; No assets under construction)	RAB based on the inflated gross investment value of assets in 2000, since then, the parametric remuneration formula applies.	RAB defined in 2002 and then parametric formula. No RAB adjustments.
Sweden	Meters, lines, stations, storage, and regasification assets	2015: ~€0.65 Billion	Adjusted for inflation, adjustments for new investments and disposals
UK	Agreed proportion (capitalisation rate) of total expenditure (TO-TEX); RAV – historical cost indexed annually by inflation; RAB adjustment – annual adjustments in line with out-turn expenditure plans. .	Estimate of the initial market value of each licensee's RAB (estimated revenues of each regional network for 2002/03 published in Ofgem's Final Proposals on the separation of Transco's distribution price control) for Natural Gas Distribution)	All subsequent allowed additions to initial RAV at historical cost, and deducting annual depreciation amounts and the value realized from the disposal of assets which are part of the regulatory asset base. RAV is indexed to RPI annually to ensure it is consistent with current cost accounting.

In *Italy*, maximum admissible revenues depend on the tariffs whose margins are strictly connected to the remuneration granted on the Regulatory Asset Base (RAB) together with the network development investments, operating costs and depreciation that are recognized as a direct component of revenues.

This method aims at aligning the remuneration recognized as much as possible with what is demanded by the market, to ensure that companies do not make extra profits. Moreover, it is characterized by greater rigidity than the other methods used in utilities because it defines each parameter of the company's revenue-cost structure.

Considering that revenues cannot be changed by companies, if not in a very small part, obtaining an added margin compared to that established by ARERA, essentially depends on the ability of the asset manager to carry out further efficiency improvements.

Net invested capital constitutes the regulatory asset base (RAB) and it is derived from gross invested capital subtracting depreciation

fund. Assets that are under construction are also included in the RAB.

RAB is adjusted for:

- the net real-term (revaluated) value of public grants for infrastructure developments and connection charges
 - the pensionable retirement fund (TFR), calculated parametrically (-1% of net invested capital)
 - the net working capital, calculated parametrically
- RAB is updated also annually taking into account the new investments and divestitures, changes in depreciation fund, changes in public grants and connection charges and revaluation - gross investment deflator index.

The invested capital of the distribution companies is distinguished by function in two categories:

- Centralized invested capital;
- Local capital invested.

Both are divided into invested capital relating to the distribution service and the measurement service, with the sole difference that only the invested capital of the location will be the basis for calculating the local RAB.

The centralized invested capital is identified for each distribution company and consists of the capital conventionally assigned to the distribution service.

Local fixed assets are; land and buildings, citygates, mains, customers connections, conventional meters, electronic meters and volumes converter with a data transmission system whereas centralized assets relative to distribution are tangible assets not classified as local assets and intangible assets.

The value of the centralized net invested capital is determined by the sum of:

- Value of centralized net fixed assets determined on the basis of parametric criteria, using the average cost of the financial statements. Non-industrial buildings and buildings and other tangible assets and intangible fixed assets excluding goodwill are considered centralized assets;
- Value of the net working capital referring to centralized assets, calculated as 0.8% of the value of the gross tangible assets.

The depreciation relating to centralized assets is determined according to parametric criteria, based on a detailed analysis of the accounting data of the distribution companies.

With regard to centralized assets for remote management systems, the tariff recognition of the remote reading / remote management costs and the costs related to concentrators are envisaged for the first two years of the fourth regulatory period. (Local Asset Smart Meters -> Mix of Net Revaluated Historical Cost and Standard Cost)

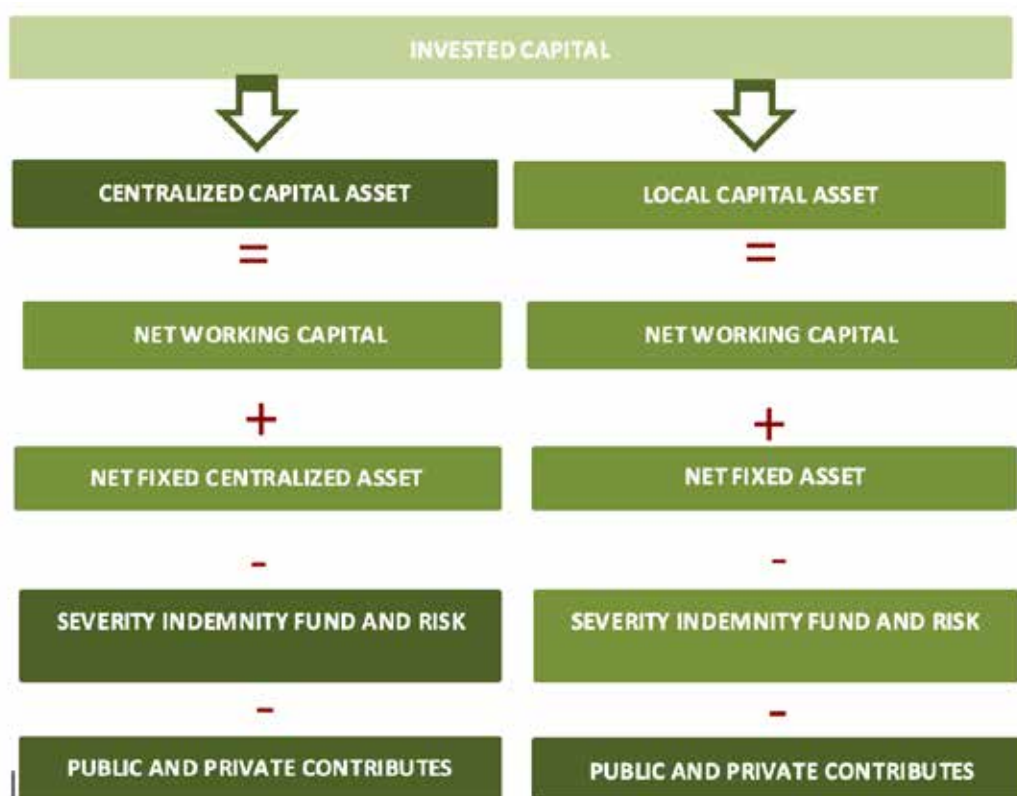


Figure 3.13 – CAPEX

Therefore, the RAB of a distribution company is given by the sum of the capital invested in the location using the revalued historical cost and the value of the centralized invested capital.

To calculate the changes in the RAB, investments and inflation are added to the value at the beginning of the year and depreciation is deducted. The RAB therefore constitutes the basis on which the tariff is applied which, normally, is renegotiated with the regulator every six years, but which is updated in its components every year.

Once the value of the invested capital has been defined for tariff purposes, it is necessary to highlight the general criteria of the rate determinations, because the RAB is at the origin of the cash flows of the company, and represents the starting point for the calculation of the maximum amount of revenue recognized by the regulator.

In **UK**, (Regulatory Asset Value (RAV) is used as the financial balance representing expenditure by the licensee which has been capitalized under regulatory rules.

RAV is indexed to an inflation index (historically this has been the retail prices index (RPI), but the regulator is transitioning to the use of Consumer Price Inflation (CPI) for future control periods) to allow for the effects of inflation on the licensee's capital stock and to ensure it is consistent with current cost accounting. The RAV is calculated by summing an estimate of the initial market value of each licensee's regulated asset base (estimated revenues of each regional network for 2002/03 published in Ofgem's Final Proposals on the separation of Transco's distribution price control¹⁹⁶), and all subsequent allowed additions to it at historical cost, and deducting annual depreciation amounts calculated in accordance with established regulatory methods and a deduction is also made in certain cases to reflect the value realized from the disposal of assets which are part of the regulatory asset base.

The licensee receives a return and depreciation on the average of its opening and closing RAV in its price control allowed revenues.

In **Germany**, fixed assets, working capital, assets under construction are components of RAB. For Natural Gas Distribution companies, investments in new assets after the base year lead to an adjustment of the CAPEX. On the other hand, there is no distinction between replacements and enhancements or expansions.¹⁹⁷

In **Portugal**, fixed assets are deducted from third parties' contributions within the scope of RAB components. Each year the RAB allowed for year t is adjusted in order to consider new investments, write-offs, and depreciation.

RAB is calculated based on historical asset cost in the regulated accounts and additional investments, which are already covered by the approved network development plans, are simply added to RAB, after the investment is fully completed and the relevant constructed sections are put into operation

As explained above, **Spanish** regulatory approach does not include the periodical revision of the Regulatory Assets Base (RAB) based on CAPEX, depreciations, disposals, etc. Applicable methodology consists on a base remuneration and an incremental unitary revenue associated to supply points and MWh. RRM does not consider any assets addition for the revenue determination. That is, any CAPEX without a counterpart in terms of customers and MWh does not produce additional revenue for the company. This approach aims to limit network expansions to those projects with high benefits in terms of gasification of new customers.

In Spain, the incremental revenue approach in use only required an initial assessment of the RAB and it was made in 2002. However, the rejected CNMC methodology for 2021-2026 included a RAB recalculation with book values of 2020.

Table 3.11 – Spain: regulatory approach to RAB adjustments

Base	2002	2014	2019 (proposed)	2021-2026
RRM in use	RAB calculation in 2002 based on the book values of 1998,1999,2000 (last financial statements available) brought to 2002 using inflation and incremental factors. Since then, no RAB adjustments.			
Proposed methodology but not implemented			New RAB calculation based on the book values for 2020 (also 2018-2019 for O&M costs).	

The following table presents the components of the base remuneration calculated in 2002 with the book values of 2000 and applying the same increase factor to all components to bring them to 2002.

Table 3.12 – Spain: Base remuneration as of 2002¹⁹⁸

Remuneration calculated in 2002	2000	2001	2002	Increase factor
Depreciation (Million €)	216.73		250.37	1.1556
Financial Remuneration (RoI) (Million €)	267.75		309.30	1.1556
Operational Expenditures (Million €)	292.1		337.43	1.1556
Financial Statements information	2000	2001	2002	
Assets base (Million €)	3,169	3,523	3,955	NA

For information purposes the proposed methodical approach of the CNMC (2019) to determinate the RAB for the recalculation of the base remuneration 2020 is provided:

¹⁹⁷ Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.

¹⁹⁸ Source: CNMC (2019).

- The following elements are considered for RAB calculation:
 - o Fixed tangible assets: all pipelines, stations, ancillary facilities, buildings, etc.
 - o Intangible assets: software applications.
- The following elements are not included in the RAB:
 - o Work in Progress.
 - o End-users' connection facilities (paid by connection applicants).
 - o End-users measure devices for leasing (special charge applied to end users).
- Audited initial book values only, without taking into consideration possible amendments in FFSS of the next years.

Finally, the new revenue methodology does not require the calculation of RAB so the above criteria will not be used for the next regulatory period.

In **Turkey**, RAB is calculated by depreciated and inflation-adjusted asset value. Asset values considered are EMRA analysed values. Connection fees are also taken into consideration. Producer price index was used as the inflation index in the past, however consumer price index is used at present. Mid-year RAB (average of start and end RABs) is used for return calculations. For that reason, WACC is adjusted for mid-year. In this way, pre-tax WACC set by EMRA is gained by DSOs, in net present value.

3.3.3 Rate of Return

Setting of the allowed or target return on capital, which is the return required by debt and equity holders to finance the investment in capital assets, is one of the fundamental elements of revenue determination process. This return applies both to the existing asset base and new capital expenditure or assets, both of which are enshrined in the RAB. This mainly depends on the economic conditions of the country.¹⁹⁹ The different calculation types that are in use in EU countries are given in Table 3.13 below.

¹⁹⁹ Source: Economic Consulting Associates (ECA), (September 2018), Methodologies and parameters used to determine the allowed or target revenue of Natural Gas Transmission System Operators (TSOs).



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Table 3.13 – Rate of return calculations in EU countries²⁰⁰

Country	Type Of WACC	Determination of Rate of return equity	Rate of Return Before Taxes	Use of Rate of Return
Austria	Nominal WACC pre-taxes (equity share 40%, debt share 60%, beta transformation: Modigliani-Miller)	$rE = (\text{nominal risk-free rate} + \text{levered Beta} \times \text{MRP}) / (1 - \text{tax rate})$	8.16% (nominal pre tax, set in 2017, granted for the average efficient DSO) $= (1.87\% + 0.85 \times 5\%) / (1 - 0.25)$	WACC nominal pre-taxes * RAB (book values)
Belgium	No use of WACC	Sum of a nominal risk-free rate and a risk premium (market risk premium multiplied with a risk factor) multiplied with (1+illiquidity premium) multiplied with a corporate tax factor	$5.76\% = (0.90 + 3.5 \times 0.65) \times (1 + 0.20) \times 1.513$	Granted for existing assets to a maximum of 33% of the imputed business assets. Any available equity capital in the capital structure in excess of this will be subject to another equity interest rate
Croatia	Nominal pre-tax WACC	The rate of return on equity (re) is determined by applying the capital asset pricing model (CAPM), according to the formula: $re = rf + \beta \times (rm - rf)$	Rate of return on equity: 6.84% Risk-free rate of return: 4.25% Coefficient β : 0.54 Market risk premium: 4.80% Rate of return on diversified market portfolio: 9.05% Share of equity in total capital: 50% Rate of return on debt: 4.88% (maximum value) Share of debt in total capital: 50% Rate of return on profit: 20% Amount of WACC for the regulatory period: 6.72% (maximum value)	The nominal weighted average cost of capital before tax (WACC) is used as the rate of return on regulated assets. As a measure of avoiding systemic risk, the rate of return on equity is calculated using the CAPM model, and the rate of return on debt capital is determined as the average weighted interest rate on investment loans used by the system operator to finance regulated assets. The shares of debt and equity capital are defined as target shares in the amount of 50%, which is theoretically optimal capital distribution and approximates the effect of the financial leverage to a good extent.
Czechia	Nominal, pre-tax WACC	Sum of nominal risk-free rate and a risk premium (market risk premium multiplied by beta factor)	$9.66\% = (3.82 + 5.00 \times 0.801) / (1 - 0.19)$	The whole RAB is multiplied by the WACC. When setting the nominal pre-tax WACC the D/E ratio of 38.48/61.52 was used.
Denmark	Nominal WACC pre-tax 4,51 (2017)	Sum of a nominal risk-free rate and a risk premium (market risk premium multiplied with a beta risk factor)	9	A risk-free interest rate calculated as an average of the last three months available daily observations of four-year zero-coupon rates for Danish government bonds.
Estonia	Pre-tax WACC nominal	Germany 10 years average bonds yield, Estonian risk premium, McKinsey market risk premium, Beta	$5.73\% (1.47 + 0.78 + (0.696 \times 5))$	4,58%

200 Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.



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Country	Type Of WACC	Determination of Rate of return equity	Rate of Return Before Taxes	Use of Rate of Return
Finland	Nominal, pre-tax	Risk-free rate + beta*Market risk premium + Premium for lack of liquidity (+ additional risk premium for natural gas DSOs)	$9.41\% = (2.18 + 0.69 \times 5 + 0.6 + 1.3) / (1 - 0.2)$	Reasonable return is calculated by multiplying the adjusted capital invested in network operations by the reasonable rate of return. Therefore, company receives reasonable return on adjusted equity and interest-bearing debt invested in network operations.
France	Pre-tax, real	Sum of a real risk-free rate and a risk premium (market risk premium multiplied by a beta risk factor) multiplied with a corporate tax factor	$7.5\% = (1.6\% + 5.0\% \times 0.66) / (1 - 34.43\%)$	Multiplied with the whole RAB (except assets that were funded through subsidies or grants)
Germany	No use of WACC	Sum of a nominal risk-free rate and a risk premium (market risk premium multiplied with a beta risk factor) multiplied with a corporate tax factor	$6.91\% = (2.49 + 3.8 \times 0.83) \times 1.225$	Granted for existing assets to a maximum of 40% of the imputed necessary business assets. Any available equity capital in the capital structure in excess of this will be subject to another equity interest rate
Greece	Nominal, pre-tax	WACC: a) CAPM & additional country risk premium for cost of equity; and b) cost of debt based on operators' proposal and actual figures of base year	9.23%	WACC is applied on the value of Regulatory Asset Base (RAB) for each year of the Regulatory Period
Hungary	Real, pre-tax.	Sum of the real risk-free rate and risk premium (equity beta multiplied by market risk premium)	$6.14\% = (0.188 + 1.689 + 4.30 \times 0.72) / (1 - 0.19)$	
Iceland	WACC for general (TSO and DSO) = 7,08%	$Re = (rf + (rm - rf) \times \beta) + \text{specific risk} / (1 - t)$ Sum of real risk-free rate and a risk premium (market risk premium multiplied with a beta risk factor) plus a specific risk premium multiplied with a corporate tax factor	General (TSO and DSO) = 10,7% $= ((3.11 + 5.0 \times 0.89) + 1.0) / (1 - 0.2)$ (for 2018)	The Pre-Tax WACC is the rate of return, it is granted for operating necessary business assets.
Ireland	WACC for the period 2017 – 2022 is 4.63% pre-tax real	The CAPM methodology is used to calculate the cost of equity using the formula: $ke = rf + \beta \times (rm - rf)$ where: <i>ke</i> is the expected rate of return for the risky asset; <i>rf</i> is the rate of return on a 'risk-free' asset (the "risk-free rate" or "RFR"); β is the 'beta' factor, which is correlation of the return on the risk asset with the expected returns on a diversified portfolio of all investable assets; and <i>rm</i> is the expected rate of return on a market value-weighted portfolio of all assets (the 'market portfolio').	Cost of equity (pre-tax) 7.22%	Applied to CAPEX



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Country	Type Of WACC	Determination of Rate of return equity	Rate of Return Before Taxes	Use of Rate of Return
Italy	Real WACC, pre- tax		WACC For the regulation period (2014 -2019) is 6.9% for distribution services and 7.2% for measurement services	WACC nominal pre taxes * RAB
Latvia	post-tax, nominal	Return on equity: Sum of a nominal risk-free rate, market risk premium multiplied with a beta risk factor, and a sector risk premium	7.17	WACC is applied to the value of RAB to calculate the return on capital, which is a part of capital costs in tariff.
Lithuania	Nominal, pre-tax	Return on investment is determined as weighted average cost of capital, calculated according to the formula: $WACC = R_{dx} \cdot WD + R_{ex11} \cdot m \cdot xWE$	Rate of return on equity = 11.3% $WACC = 7.09\% = 4.43 \times 0.7 + 11.3 \times 1/(1-0.15) \times 0.3$	WACC is used to calculate return on investment. WACC is a multiplied with whole RAB
Luxembourg	Nominal pre-tax WACC	Sum of cost of debt and cost of equity.	$6.12\% = 0.5 \cdot (2.15\% + 1.45\%) + (1 - 0.5) \cdot (2.15\% + 0.7946 \cdot 4.80\%)/(1 - 30.93\%)$	Granted for self-financed assets in the RAB and for work in progress according with respect to the dispositions of E16/12/ILR and E16/13/ILR
Netherlands	Real, pre-tax	Equity risk premium is based on data in individual Eurozone countries over the period 1900-2015 (Dimson, Marsh en Staunton database). An average of both the geometric and arithmetic average is taken.	6.7% (calculated; based on 5.02% after taxes and 25% tax rate; $6.7\% = (1.28\% + 5.05\% \cdot 0.74)/0.75$)	Real WACC is currently based on a 50% debt and 50% equity capital structure. Real WACC is multiplied with the indexed RAB.
Poland	Pre-tax nominal	$Equity\ pre-tax = (Risk-free\ rate + \beta_{equity} \cdot equity\ risk\ premium)/(1 - corporate\ tax\ rate)$	$7.013\% = (3.256\% + 0.5388 \cdot 4.50\%)/(1 - 19\%)$	In allowed revenue: $RoC = WACC \cdot RAB$ is included
Portugal	Nominal, pre-tax	The WACC (Pre-tax) is indexed to the Portuguese 10-year bond benchmark and depends, in each year, on its evolution, with a cap and a floor.	8.2%	WACC is currently based on 50% debt and 50% equity applied to RAB
Romania	Nominal WACC post-tax determined using CAPM method; WACC is used in determination of rate of return.	$RoR = ((1+WACC)/(1+\pi)-1)/(1+T)$	$8.43\% = ((1+9.91\%)/(1+2.63\%) - 1)/(1-16.00\%)$	Granted for initial RAB (privatization value), existing assets and new assets - RAB value at the beginning of each regulatory period Remaining value of initial privatization RAB and the other existing assets) is multiplied with RoR an included in the regulated revenue - Beginning with the 2nd year of the regulatory period, each year new entries, are multiplied with RoR and included in the regulated revenue
Spain	In current period, WACC is not used.			

Country	Type Of WACC	Determination of Rate of return equity	Rate of Return Before Taxes	Use of Rate of Return
Sweden	Real WACC pre- tax	CAPM: $re = rf + \text{Beta} * (rm - rf) + \text{Extra risk premium}$	$11.93 = (4 + 0.76 * 5 + 1.5) / (1 - 0.22)$	The debt share is derived from market values of European comparison companies that are publicly traded (47 % debt, 53 % equity for gas)
UK	Vanilla WACC (pre-tax debt, post-tax equity)	CoE derived from CAPM and fixed over the period. CoD derived from a 10 year trailing average of benchmark (iBoxx non-financials 10 years + maturity bonds for investment grade credit rating businesses) to update the allowed CoD annually over the price control period (2013-2021)	4.7% vanilla WACC in first year of control, based on 6.7% post-tax cost of equity, 2.92% pre-tax cost of debt for 2013/14 and notional gearing of 65%	WACC is applied on the average of the opening and closing value of Regulatory Asset Base (RAB) for each year of the Regulatory Period

In **Italy** the rate of return on investment coefficient is calculated using the same methodology with Electricity Distribution. The RAB is remunerated, with a return on invested capital, **pre-tax WACC** identified by the Authority. Unlike the one used to calculate the price cap, the RPI (inflation rate) that is used to set the WACC is calculated on inflation expectations.

The rate of return on invested capital is determined as a weighted average of the rate of return on risk capital and that on debt (Weighted Average Cost of Capital, WACC), considering a debt / risk capital ratio of 5/10 and using the following formula (similar to the Electricity Distribution) to determine a real pre-tax rate:

Where:

- **Ke** is the nominal rate of return on risk capital and it must guarantee investors a premium for exposure to systematic risk and is determined on the basis of the CAPM Capital Asset Pricing Model:

$$K_e = R_F + ERP * \beta$$

- **RF** is the rate of return on risk-free assets (12-month average of gross 10-year BTP returns);
- **ERP** is the market risk premium, or the premium, with respect to the return of risk-free assets, which investors require to hold assets with risk equal to the average market risk;
- β is the measure of the systematic risk of the activity;
- **E** is the risk capital;
- **D** is the debt;
- **Kd** is the nominal rate of return on debt (cost of debt);
- **tc** is the tax shield of financial charges (IRES);
- **T** is the theoretical tax rate (including IRAP) on the operating result (corporate tax rate);
- **rpi** is the inflation rate.

The WACC values for infrastructure services in the gas sector, deriving from the application of the previous formulas issued are shown in Table 3.14.



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Table 3.14 – WACC values in Italy

Service	Year	2016	2017	2018	2019	2020	2021
GAS	Transmission	5.4	5.4	5.4	5.7	5.7	5.7
	Distribution	6.1	6.1	6.1	6.3	6.3	6.3
	Measurement	6.6	6.6	6.6	6.8	6.8	6.8

A peculiarity of the Italian system compared to other regulatory regimes concerns the asynchrony of the admission of capital expenditures in the tariff and the approval of the budgets. In fact, the rates are approved at the beginning of each year n ; however, the financial statements for year $n-1$ are approved by the Board of Directors between April and June of the same year n .

Consequently, the most recent data available are those concerning the year $n-2$, that might result in a problem of adequate remuneration of the capital.

Similarly, in addition to investments, the value of depreciation is also recognized with a delay. This asymmetry causes a financial mismatch for the operators, resulting in a loss in economic terms, equal to the monetary value of the RAB for the two years. In other words, the value of the actual calculated WACC (and as a reference for the regulatory period) appears to be lower than the actual cost of capital, because it is recognized after some time.

The biggest risk that the company can find considering the WACC parameter is that the Authority can adopt parameters that underestimate the WACC incurred. This entails the possibility of adopting a remuneration rate that is lower than the cost of capital that the companies have to bear and therefore any investment operation (which is not subject to incentives) would result in value destruction.

In [UK²⁰¹](#), the allowed rate of return is also weighted average cost of capital (WACC). The cost of equity is assessed following the CAPM and is set at the start of the price-control. The real, post-tax cost of equity was estimated as 6.7% for RIIO-1. The cost of debt is updated annually according to a 10-year trailing average of long-term iBoxx indices for sterling-denominated corporate debt of investment grade credit rating. Therefore, the WACC applied to the Regulatory Asset Value (RAV) will change each year across the price-control period. In 2012/13, the cost of debt was calculated as 2.92%.

The WACC is calculated at a notional gearing level for the Natural Gas Distribution companies as opposed to on their actual gearing. This notional level was set at 65% for RIIO-1.

The overall financial performance of network companies is assessed by using a measure called the Return on Regulatory Equity (RoRE) which is a monitoring/performance metric. It is compared to the cost of equity allowed at the start of the price control to demonstrate the extent of out or underperformance within the control.

RoRE measures the return on the notional equity RAV which represents the proportion of average RAV that is funded by shareholders. RoRE is calculated post-tax, and its estimation includes the use of certain regulatory assumptions, such as the assumed gearing ratio of the companies, to ensure comparability across the sector.

To eliminate phasing impacts over the course of the price control, Ofgem uses a mix of actual and forecast performance to calculate eight-year average returns.

The average of opening and closing RAV for the year also earns a return (at the WACC). These returns may not equal the actual returns seen by shareholders. The RAV weighted RoRE across the sector is 10.6%.

In [Germany²⁰²](#), the allowed rate of return on equity needed for new installations may not exceed the average current yield for

201 Source: Ofgem, RIIO-GD1 Natural Gas Distribution Price Control – Regulatory Instructions and Guidance: Version 5.0, 2018.

202 Source: Groebel A., (April 2018), BNetzA's role in energy infrastructure regulation and planning/permitting. https://erranet.org/wp-content/uploads/2017/10/Muller_Case-study-benchmarking-Germany_final.pdf

the last ten full calendar years on fixed interest securities of domestic issuers as published by the Deutsche Bundesbank, plus an appropriate mark up to cover entrepreneurial risk specific to network operation.

The equity return is determined by the Ruling Chamber 4 using CAPM Determination from 05 Oct . 2016 for the 3rd regulatory period. Germany's WACC calculation diagram is given in Figure 3.14Figure 3.12.

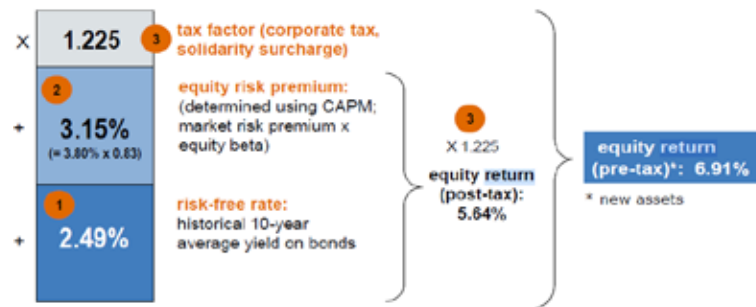


Figure 3.14 – WACC calculation in Germany²⁰³

In [Portugal](#)²⁰⁴, the remuneration of the asset base is calculated using a pre-tax nominal WACC. The methodology used for setting the cost of equity is the CAPM and the cost of debt is set using a default spread model, where a spread (debt premium) is added to the risk-free rate.

ROE parameters for gas DSOs in Portugal are:

- Risk free rate (nominal): 1.73%
- Tax rate: 29.5%
- Equity risk premium: 6.09%
- Equity beta: 0.66
- Cost of equity (before taxes): 8.17%

Due to the remaining of some uncertainty and financial volatility environment, the rate of return is updated ex-post each year in order to reflect the evolution of financial market conditions.

The WACC (Pre-tax) to be applied in the regulatory period, is indexed to the Portuguese 10-year bond benchmark and depends, each year, on its evolution, with a cap and a floor. The floor is 5.40% for Gas TSO and 5.70% for Gas DSO. The cap is 9.00% for Gas TSO and 9.30% for Gas DSO.

The methodology that is being used for indexing the cost of capital, introduced in the 2013-2014 to 2015-2016 regulatory period is also important. This methodology enabled the evolution of the economic and financial context to be reflected, thereby compensating equity and other risks. Therefore, the remuneration rates are updated based on the yields of Treasury Bonds. Given the volatility of the market indicators, a cap and a floor were established.

In [Spain](#)²⁰⁵, a rate of return (RoR) of 10-year bond plus a spread of 150 b.p. was set in 2002 for the calculation of the base remuneration. Since then, the application of incremental revenues based on incremental factors (2002-2013) and unitary incremental revenues (2013-2026) does not require the application of any RoR.

²⁰³ Source: Groebel A., (April 2018), BNetzA's role in energy infrastructure regulation and planning/permitting.

²⁰⁴ Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.

²⁰⁵ Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.

Historically, in Spain, financial remuneration rate for all network assets (both electricity and gas) has been indexed to the 10-year bond yield.

In 2019 the CNMC approved a new methodology to calculate the financial RoR based on the Weighted Average Cost of Capital (WACC). According to the CNMC, the use of the WACC is consistent with European regulatory best practices for calculating the rate of return on electricity and natural gas assets.

It has been explained how the CNMC aimed to apply this WACC for the recalculation of the base remuneration in 2020 for Natural Gas Distribution but finally the methodology was rejected. Therefore, for the next regulatory period of Natural Gas Distribution (2021-2026) the recently approved WACC methodology will have no impact. The new WACC will be used for the revenue determination of Electricity Transmission and Distribution activities and for Natural Gas Transmission and regasification.

The calculated WACC applicable for Natural Gas Distribution during the period 2021-2026 was (finally not implemented):

- Nominal WACC after tax = 4.38%.
- Financial remuneration rate (applicable WACC) = 5.83%

In **Turkey**, WACC calculation is based on the following formula published by EMRA:

: Cost of debt, risk-free rate plus sectoral debt risk premium:

: Weight of debt

: Cost of equity, as defined in CAPM.

: Weight of equity

t : Corporate tax rate

It is set pre-tax and real. Nominal WACC is converted to real WACC by using inflation expectations. WACC is calculated by EMRA and it is set to %14,38 for the rest of the regulatory period. Due to changes in global economic environment in Turkey, WACC was reset by EMRA during current regulatory period. Normally, it is set for regulatory period and all tariff calculations are done using the set WACC.

3.3.4 Depreciation

The depreciation methodology is one of two areas (the other is the cost of equity) where there is broad consensus among the NRAs, in that all jurisdictions apply the straight-line methodology (that is, asset costs are spread evenly over the defined useful life of the assets).

The only exception to this general rule is Belgium which use declining balance (accelerated or sum-of-digits) depreciation for a "limited number of installations" and for all assets, respectively. Depreciation methods applied in EU countries are given in Table 3.15.

Table 3.15 – Depreciation applications in EU countries²⁰⁶

Country	Method	Ratio	Consideration
Austria	Straight line	Depending on asset type: lines 2-3%, transformers 4-5%, substations 4%	Pass through
Belgium	Straight line	Depending on assets: pipes: 2%, compressors: 3%	Non controllable
Croatia	Linear method	2.86 % for gas pipelines, measuring and regulating stations and office buildings, while for other types of assets 5 - 10 %	Amount of annual depreciation of regulated assets is added to the allowed revenue
Czechia	Straight line		100% of the depreciation is used to determine the allowed revenue.
Denmark	Straight line	Depending on asset type	
Estonia	For depreciation of fixed assets Estonia uses a regulatory capital expenditure method, which differs from accounting depreciation. ²⁰⁷	Depending on asset type. For new assets (after year 2003) 2.86%-3.33 from investment cost and for old assets (before year 2003) 7.14% from residual value.	Present regulation started at 2003 legal framework.
Finland	Straight-line depreciation on replacement value of network. Depreciation is inflation corrected annually with CPI.	2.20%	Depreciation level based on average adjusted straight line based on the selected component lifetimes. Imputed straight-line depreciations are always allowed in full as far as the component is in actual use.
France	Straight line	Depending on asset type. Ratio between 2% and 4% for network assets (lines, pipes etc.)	Integrated directly and with 100% (except assets that were funded through subsidies or grants)
Germany	Straight line	Depending on asset type. Ratio between 1.5% and 4%	Part of the examined controllable costs
Greece	Straight line	Most assets are depreciated over a period of 25-50 years	Depreciation ratio depends on asset type and it is integrated directly into the revenues
Hungary	Straight line	Depending on asset type the useful lifetime (years): pipeline 50, compressor station 20, gas delivery station 30	Based on expected useful lifetime
Iceland	Straight line	Depending on asset type. Ratio between 2 and 20% e.g. TSO lines & cables: ~2%, stations: ~2,5%, DSO lines & cables: ~3%-4%	The regulator regularly inspects the RAB and the depreciations
Ireland	Straight line	Depends on asset category	Part of the examined controllable costs
Italy	Straight line	7-50 years and depends on asset category	Coherent with the CAPEX (centralized and localized)

²⁰⁶ Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European

Energy Networks, Ref: C18-IRB-38-03.

²⁰⁷ In the regulatory capital expenditure accounting a principle is used in which, from a certain moment in time, fixed assets are divided into two parts, the old ones and the new investments. All assets acquired before the limit year are considered old ones and for them an accelerated rate of depreciation is applied.

Country	Method	Ratio	Consideration
Latvia	Straight line	Depending on asset type. Ratio between 1% and 20%, gas pipelines 1.7-2.5%,	Depreciation is a part of capital costs in the tariff
Lithuania	Straight line	3-60 years	Depreciation ratio depends on asset type. All depreciation of regulated assets is integrated into revenues.
Luxembourg	Linear method	Depending on the asset type. Useful lifetime 25-50 years for technical assets and constructions, and 3-20 years for IT related fixed assets	Depreciation is fully included in the allowed revenues
Netherlands	Straight-line depreciation, corrected for inflation (CPI) each year.	Most assets are depreciated over a period of 35 – 55 years.	Depreciation is part of the total costs, which are subject to an x-factor over the course of the regulatory period.
Norway	Linear depreciations from financial statements	Depending on asset type, must be approved by accountant	Part of examined controllable costs
Poland	Straight-line	Economic useful life is set according to requirements of accountancy law for adequate groups of fixed assets. Approximate EUL for compressors equals 5 years, measuring stations 15 years, pipelines and buildings 40 years.	A component of allowed revenue
Portugal	Straight-line	5-45 years	Part of CAPEX
Romania	Straight-line	Depending on asset type Buildings: 50 years; Pipes and technical ins.t: 40 years; Other: between 5 and 20 years; Land: no depreciation	Part of regulated revenue. The depreciation calculated for the previous year asset entries is directly and 100% integrated into the regulated revenues. Afterwards, when the tariff adjustments are made, the depreciation already included in the regulated revenues is adjusted with inflation rate and X factor
Spain	Straight-line	For Natural Gas Distribution assets, a 5% depreciation ratio was set in 2002, since then, the parametric remuneration formula applies.	100% of Depreciation is integrated into the revenues
UK	Sum-of-digits	Assuming 20-year asset life for old assets, 45-year asset life for new assets	Amount of annual depreciation of RAB is added to the allowed revenue

In *Italy*, consistent with the approach for determining the invested capital, separate criteria for centralized assets and local assets are used to set the level of depreciation to be recognized in the tariff.

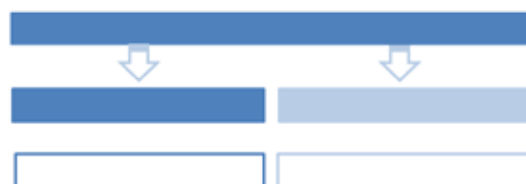


Figure 3.15 – Depreciation

The depreciation relating to **centralized assets** is determined according to parametric criteria, based on a precise analysis of the data of the related distribution companies communicated to ARERA.

Depreciation relating to **local assets** is instead determined on the gross value of fixed assets, calculated by applying the revalued historical cost method, based on conventional lives for tariff purposes.

The level of amortization relating to centralized assets is determined on the basis of a detailed analysis of data relating to a sample of distribution companies.

The average unit value of the depreciation relating to the asset categories is determined in euros per delivery point. Therefore, for each company the value of the depreciation of centralized assets will be equal to the average unit value of the depreciation multiplied by the number of redelivery points served.

In [UK²⁰⁸](#), depreciation amounts are deducted annually from opening RAV. The depreciation value is then added to base revenue in the current allowed revenue year. For Natural Gas Distribution, revenue collected with respect to the depreciation of assets follows a “sum-of-digits” methodology. Compared to linear depreciation, the sum-of-digits depreciation starts faster but then slows year-on-year over the course of the agreed average asset lifetime (45 years for new assets, 20 years for existing assets).

In [Germany²⁰⁹](#), the new CAPEX true-up model is based on actual investments and depreciation. Depreciation method is straight line, and it is considered as part of the examined controllable costs. Depreciation ratio changes between 1.5% and 4% and it depends on asset type; for example, it is around 4% for stations and 2% for lines & cables.

In [Portugal²¹⁰](#), depreciation method is straight line, and it is considered as part of CAPEX. Depreciation ratio depends on assets, and it is 5-45 years.

In [Spain](#) Spanish regulatory framework states that the amortized assets should not continue receiving revenues, neither for depreciation, nor for return on investment.

As presented above, Spanish RRM does not update the RAB since it is based on a stable base remuneration + an incremental revenue for new customers and MWh. Depreciation method applied in 2002 was straight line, and the ratio applied for Natural Gas Distribution assets was 5%. Since then, the base depreciation has remained stable and neither the assets base nor the base depreciation allowed has been modified.

Base revenue aimed to remunerate those assets in operation prior to 2002 (when the incremental approach was first implemented) but according to CNMC own assessment it has produced important excess remunerations of amortised assets.

Table 3.16 – Spain: initial assets value (2001) vs cumulative depreciation (2002-2018)²¹¹

Assets book value (December 2001)	Cumulative depreciation (2002-2018) allowed for assets in operation prior to 2002
3,523 Million €	4,367 Million €

Moreover, if the estimated depreciation revenue for these assets is considered in 2019 and 2020 (201 Million €/year after 2014 adjustment) the overall depreciation allowed will reach 4,769 Million €, that is, an excess remuneration due to depreciation of more than 35% of the assets value. Considering that Return on Investment revenues for these assets has not been updated either, the excess remuneration may be higher.

208 Source: Ofgem, RIIO-GD1 Natural Gas Distribution Price Control – Regulatory Instructions and Guidance: Version 5.0, 2018.

209 Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.

210 Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.

211 Source: CNMC (2019)

The revenue cut included in the CNMC methodologies of the CNMC (2019) try to offset the cumulative excessive revenue received for these amortized assets.

The Spanish case may be considered as an example of the problems arising from not implementing a RAB periodical update approach.

In **Turkey**, depreciation method is straight line and it is 22 years for all assets. Depreciation of investments is a part of CAPEX.

3.3.5 Connection Fees

Connection fees are mostly a one-off charge paid for the connection to the grid. In general, three types of connection charges can be distinguished: super-shallow, shallow, and deep connection charges. The degree to which connection charges fully reflect the incremental cost of providing a user with a new or upgraded connection to the network depends on the type of connection charge.

Super-shallow connection charges	Shallow connection charges	Deep connection charges
No costs are charged for the connection.	- Imply that grid users pay for the local infrastructure connection costs (the pipeline between a house and local network) - These costs are easily attributed to a specific user.	- Consist of the shallow charges all the possibly incurred costs for wider network reinforcements needed to accommodate the connection request. - Deep connection charges are designed to fully reflect the incremental cost of providing a user with a new or increased connection to the network.

Figure 3.16 – Connection Charges

In **Italy**, the DSOs are responsible for the connection of end gas users to the main grid. ARERA has not strictly defined the technical-economic conditions for making the connections to the Natural Gas Distribution networks, so the standard distribution network code refers to the concessions existing between the DSO and the local authority that owns the gas network.

The Regulator has initiated a process to determine connection charges. One consultation paper was issued in 2013 concerning the principles and first proposals on the topic. In general, for small residential installations located not far from the existing network (typically within 10 meters) a uniform one-off connection fee applies. In other cases, connection charges basically depend on the actual costs of the connection.

From the **tariff point of view**, the contributions for connection to the Natural Gas Distribution networks are deducted from the investments for the capitalized portion (a coverage of the “infrastructure” connected), and the operating costs for the portion relating to administrative costs- commercial related to the execution of the connection.

In perfect analogy with the regulation envisaged for the electricity sector, the prices assigned by the application of connection contributions are assigned as capital grants, while the transfers connected to the application of specific components to cover administrative-commercial costs are deducted from operating costs.

The derivation plants (connections) are part of one of the categories recognized among the fixed assets for the Natural Gas Distribution service.

In **UK**²¹², connection charges are levied on new connections to the local distribution zone (LDZ) and reflect the costs incurred by DSO in providing any assets required to connect a user to the LDZ. These connection costs are not determined by the price control review. Ofgem does not set or approve the level of individual charges levied, only the charging methodology used to determine them.

The current charging regime was designed to promote the effective cost structure. All DSOs provide a connection service. Alternative connection service providers operate in all Natural Gas Distribution areas, and connections provided by these organizations are in addition to the connections made by the DSOs. Connections to help vulnerable and fuel poor households that are off the gas grid switch to natural gas by offering funding towards the cost of connecting to the gas network.

LDZ charges are set on 1 April each year and are expressed as follows:

- Commodity - pence per kWh
- Entry/exit Capacity - pence per kWh per day
- Fixed - pence per day

Types of LDZ charges are as shown in Figure 3.17.

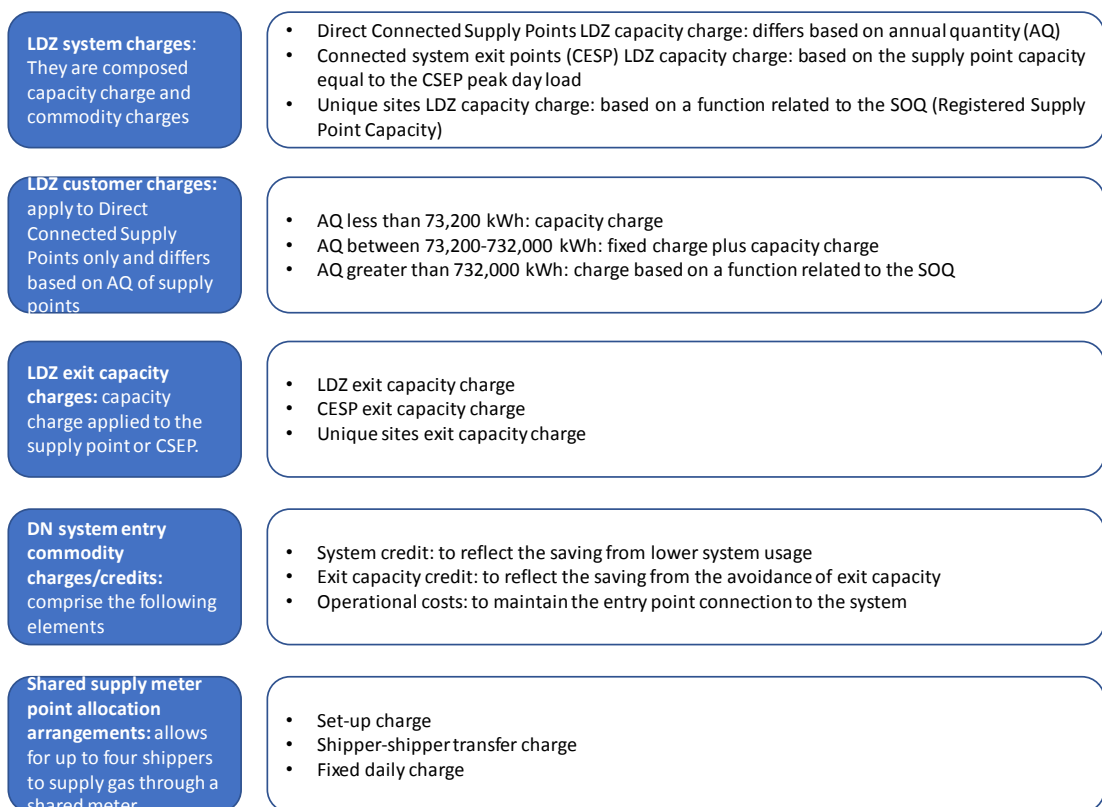


Figure 3.17 – Types of LDZ charges

Under its license, DSO is obliged to develop and maintain a methodology for determining LDZ charges and must comply with objectives below:

- the methodology results in charges reflect the costs incurred by DSO in its distribution business;
- it facilitates effective competition between gas distributors;
- it takes account of developments in the Natural Gas Distribution business; and
- it is compliant with the Gas Regulation and legally binding decisions of the European Commission and/or the Agency.

When DSOs fail to meet the required standard for a particular consumer, they must make a payment to them. The DSOs paid over £537,000 to customers during 2015-16 for not meeting guaranteed standards of performance for connections.

In **Germany**, for an initial connection of a property with a defined capacity to a gas network, several items have been paid directly

to the network operator by the property owner.

First, the network connection subsidy is paid. The cost of the initial network connection of a property are charged by the network operator to the property owner, usually based on a partially flat-rate based cost calculation.

Second, the building cost subsidy is paid. This subsidy charged by the network operator to the property owner contributes to a born of fictional costs resulting from an extension of network assets, based on a standardized flat rate. Since the overall price is based on the capacity of the network connection, the building cost subsidy has a steering effect and aims to ensure that the property owner does not apply for unnecessarily high grid connection capacity. Booked grid connection capacities of property owners are considered by the network operator in grid planning and therefore potentially lead to additional grid expansion costs. Customers were charged an average reconnection fee of about €56 (including VAT), with the actual fees charged again ranging from €2 to €210 (including VAT).

The grid connection becomes property of the network operator subsequent to completion, even costs are (at least partially) borne by the property owner. The same applies to the building cost subsidy. In return, resulting earnings of the network operator based on these two cost items have to be written back on a straight-line basis over 20 years, which reduces the network fees for all network users. Moreover, revenues are deductible capital (interest-free borrowed capital) and therefore lower the interest base of the DSO in the regulatory framework.

In case a property operator decides to increase his connection capacity, both cost items potentially need to be recalculated. If the property owner decides to change the network level he is connected to, both cost items are charged in additional.

Apart from the connection fee, there is another fee; **the guarantee fee**, which is used for protection against lacking liquidity of customers. In this regard, the following points should be considered:

- Payment of deposits to the grid operator has not been customary in Germany to date. A deposit could be viewed as an advance payment of the grid fees, which would possibly be regarded as deductible capital (interest-free borrowed capital) and would therefore not be in the interest of the grid operator under regulatory aspects (see above).
- Smaller consumers usually do not have a direct contract with the grid operator, but the grid usage contract is concluded through all - inclusive contracts via the supplier. Therefore, the supplier is counterpart of the network operator.
- Larger (industrial) consumers might have direct grid usage contracts with the DSO. If a DSO is aware of a customer's serious financial problems, he probably may be able to demand advance payment.

In [Portugal²¹³](#), the natural gas Commercial Relations Code sets the regulatory framework that applies to network connection, including charges. One of the main issues of this framework is the cost setting that requesters have to meet, bearing in mind that the difference between total investment costs and costs met by requesters is paid by consumers through use of the network tariffs. Distribution network operators are subject to a requirement of connection only for customer installations with a minimum annual consumption of 10,000 m³ (n), as well as for installations located within the area of influence of the respective network, defined as the geographic area in the proximity of the existing network, whose boundary is defined by ERSE (currently 100 m).

Natural gas consumers pay DSOs the approved amount by ERSE for network connection, and these charges are considered when setting the use of network tariffs. Regulation codes require that network operators send information to ERSE, on a half-yearly basis, on the number of connections established, network connection charges paid by requesters, broken down by type of connecting elements, total length of elements built, average budgeting deadlines and average execution times, as well as the number of changes made to existing connections.

In [Spain²¹⁴](#), the Royal Decree 1434/2002, approved by the Government, established the deadline to respond to a customer request of connection when major works are needed. The distribution company has six days when no specific project is needed and 15 days when such a kind of project is required. The detailed estimated price offer for a new gas connection is provided between 6 and 15 days. In the case of connection below 4 bar, the payment is established by regulation depending on the meter needed, the connections and the consumption of the new customer. If the connection is above 4 bars, a budget is provided. The DSO connection tariff is set by the regulation, and it is billed by the supplier.

213 Source: ERSE, 2018, Annual report on the electricity and gas markets 2017

214 Source: https://www.cnmc.es/sites/default/files/2168599_2.pdf

In **Turkey**, connection fees are set by EMRA and fees depend on the connection type and the area of the house. For household user's connection fee is calculated depending on the independent unit number of the apartment. Connection fee is €108.5 (including VAT) below 200 m² and an additional €94.2 for every 100 m² above 200 m².²¹⁵

3.3.6 Quality Factor Performance Indicators

Continuity of supply indicators are important tools for making decisions on the management of distribution networks. However safety (leaks, accidents, incidents) is of much greater importance in the case of gas networks since unavailability or interruption of supply in many cases may correspond to some danger.

In natural gas sector, indicators covering continuity of supply cannot be applied and interpreted like in electricity sector and it is not one main scope for decisions for the gas DSO. Nevertheless, the usually used interruption-indicators are good candidates if one wants to describe and compare continuity of supply internationally.

Table 3.17 – Indexes available for Natural Gas Distribution networks²¹⁶

Country	SAIDI	ASIDI	SAIFI	CAIDI	Other
Austria	SAIDI = (sum of all customer interruption durations) / (total number of customers served)		SAIFI = (total number of customer interruptions) / (total number of customers served)	CAIDI = (sum of all customer interruption durations) / (total number of customer interruptions) = SAIDI / SAIFI	
Croatia					Duration of all Interruptions of gas supplies in relation to the number of all end customers which gas supply has been interrupted.
Germany	SAIDI = $\Sigma(Ni * ri) / Nt$ Ni – number of customers interrupted by each incident, Nt – total Number of customers in the system for which the index is calculated, ri – restoration time for each incident (< 100 mbar)	ASIDI = $\Sigma(Li * ri) / Lt$ Li – contracted power interrupted by each incident, Lt – total contracted power in the system for which the index is calculated, ri – restoration time for each incident (< 100 mbar)	SAIFI = $\Sigma(Ni) / Nt$ (< 100mbar) SAIFI = $\Sigma(Li) / Lt$ (≥ 100 mbar)	CAIDI = $\Sigma(Ni * ri) / Ni$ (< 100 mbar) CAIDI = $\Sigma(Li * ri) / Li$ (≥ 100 mbar)	

²¹⁵ The average exchange rate of 2019 is used to convert USD to EUR (1.12 USD per EUR).

²¹⁶ Source: CEER, (2018), 6th CEER Benchmarking Report on the Quality of Electricity and Gas Supply – 2016



This project is funded by the European Union



Country	SAIDI	ASIDI	SAIFI	CAIDI	Other
Italy	The number of interruptions for the end customer is defined by means of the following formula: Number of interruptions for customer = $\sum C_i / C_{tot}$ where the sum is extended to all n interruptions occurred in the calendar year, and where: - C_i is the number of end-users involved in the i-th interruption considered; - C_{tot} is the total number of end customers served by the distribution company at the end of the calendar year.		The overall duration of interruption for the end customer is defined by means of the following formula: Total duration of interruption for customer = $\sum C_i \times t_i / C_{tot}$ where the sum includes all n outages occurred in the calendar year, and where: - C_i is the number of end-users involved in the i-th interruption considered; - t_i is the corresponding duration of the interruption for customers C_i ; - C_{tot} is the total number of end customers served by the distribution company at the end of the calendar year.		
Lithuania	It is average disruption duration for one customer, calculated as: Sum of all customers who encountered planned or not planned disruption times the length of duration (minutes) in the numerator and total number of customers in the denominator.		It is average number of disruption for one customer, calculated as: sum of all customers for who encountered Natural Gas Distribution disruption in the numerator and total number of customers in the denominator.		
The Netherlands	Sum of all customer interruption durations / Total amount of consumers served		Total number of customer interruptions / Total amount of customers served	Sum of all customer interruption durations / Total number of customer interruptions	

Country	SAIDI	ASIDI	SAIFI	CAIDI	Other
Portugal	Average duration of interruptions per exit point (min/exit point): the quotient of the overall duration of interruptions at the exit points over a specific period and the total number of exit points at the end of the period considered.		Average number of interruptions per exit point: quotient of the total number of interruptions at the exit points over a specific period and the total number of exit points at the end of the period considered.		AIT: Average duration of the interruption (min/interruption: Quotient of the overall duration of interruptions at the exit points and the total number of interruptions at the exit points over the period considered

Within the scope of this section, information regarding selected countries are provided in more detail.

3.3.6.1 Italy

ARERA, has developed regulatory instruments with the aim of promoting and progressively increasing the quality, continuity and safety of the Natural Gas Distribution service since 2000.

Safety of the Natural Gas Distribution services:

The regulatory system in Italy regulates the following safety aspects:

- The incentive mechanism for the reduction of localized dispersions on third party reporting by provincial business area.
- The incentive mechanism for the increase in the number of measures of the degree of odorization by provincial area of business;
- The security obligations of the distribution service, with effects also on the incentive mechanisms in the event of their non-compliance;
- Obligations relating to the emergency service.

The first two mechanisms were introduced experimentally for the period 2006-2008, with voluntary participation by the distribution companies of any size. Subsequently, the Regulator made these regulations mandatory in the period 2009-2013, considering the size of the distribution companies and also made it possible for smaller ones upon application (with less than 50,000 end customers), subject to the payment of a compensatory amount proportional to the number of customers served.

A bonus-penalty mechanism have been envisaged to incentivize the improvement of the safety of the distribution service through two components:²¹⁷

- The dispersion component, aimed at incentivizing the reduction of localized gas dispersions on third party reporting, which refers to an improvement scheme of value set ex-ante by the Authority for each geographical Provincial area;
- The odorization component, aimed at rewarding a greater number of measures of the degree of odorization of gas compared to the mandatory annual minimum set by the Regulator.

Participation in the bonus-penalty regulation has been mandatory since 2010 for all enterprises with a number of end customers

²¹⁷ This section is based on: 338/2019/R/GAS consultation document: guidelines for the duration of the regulation period and for the regulation of the quality of the Natural Gas Distribution and measurement services in the fifth regulation period.

greater than 50.000. For enterprises with end customers (delivery points) between 10,000 and 50,000, participation in the penalty-premium regulation has been mandatory since 2011, while for enterprises with less than 10,000 end customers (pod), participation has been mandatory since 2012.

The remote control of the cathodic protection systems of the networks and of the final reduction groups are also encouraged through an increase in premiums or a decrease in penalties depending on the degree of coverage of the remote control itself.

With reference to the incentive regulation, the increase in the number of measures of the degree of odorization, the regulation provides for a minimum number of measures, to be carried out each year in each distribution system, which depends on the size of the system (length of the distribution network and number of end customers served).

The highest number of measurements performed by the enterprise compared to the minimum set by the Authority is rewarded.

The regulation provides the elimination of premium relating to dispersion and odorization components in case of:

- Non-compliance with one or more service safety obligations.
- A gas incident which is the responsibility of the distributing company on a distribution system belonging to the aforementioned provincial area.

The distribution company is required to make an annual minimum number of measurements of the level of odorisation of gas per thousand end customers served. Such measures must be carried out in a distributed fashion throughout the year at the critical points of the network in accordance with the provisions of the applicable technical standards. In more detail; service security obligations include:

- Inspection of a minimum annual percentage of the high and medium pressure network (HP and MP);
- Inspection of a minimum annual percentage of the low-pressure network (LP);
- A minimum percentage of calls to emergency services with arrival time at the place of call within a maximum time (60 minutes);
- Carrying out a minimum annual number of measures of the degree of odorization;
- The replacement (or rehabilitation or decommissioning) of the cast iron net with hemp and lead joints;
- The cathodic protection (or replacement or decommissioning) of non-cathodically protected steel nets, according to a time schedule differentiated by the operating pressure levels of the grids.

There are obligations relating to the emergency service for which the enterprise must:

- Have adequate resources to deal promptly with requests for prompt intervention;
- Have one or more fixed-line telephone numbers dedicated exclusively to the emergency service;
- Publish the telephone numbers for the emergency service on its website and communicate them to the sellers and the Authority;
- Send the personnel to the site following a telephone call for emergency intervention;
- Suspend the supply of gas in the event of a leakage signal downstream of the redelivery point until the elimination of the gas leakage;
- Ensure the guaranteed recording of telephone calls received at the emergency telephone numbers, from 1 July 2009 also in vocal form.

Finally, the ARERA introduced obligations regarding the continuity of the Natural Gas Distribution service, in particular regarding the recording of the number and duration of interruptions with and without notice in the supply of gas to end customers. As regards the Natural Gas Distribution the minimum time of notice in cases of scheduled interruption is equal to 3 working days.

The distribution company annually prepares the Annual Report on the risks of gas emission for each distribution system, considering the number of gas leaks reported by third parties during the reference year and the year prior to reference, specifying for each

distribution system material type and the class of the pipeline pressure and road, as required by Technical Specification UNI / TS 11297 Evaluation procedures against gas leakages risks. It is monitored by NRA.

Incentive of the investments envisaged by the tariff regulation

In order to encourage faster convergence towards the long-term target level relating to dispersions localized on third party reports, the tariff regulation have provided, for the following categories of investments, most of the remuneration rate of the 2% invested capital for a period of eight years:

- modernization of odorization systems at REMI booths;
- Replacement of cast iron pipes with hemp and lead joints.

Technical analysis and the results of the regulation of the safety and continuity of the Natural Gas Distribution service show that:

- The number of dispersions located on third party reporting (both miles of end customers), both underground and overhead, shows a good decreasing trend;
- Over a third of end customers are served in provincial areas where the number of localized dispersions on third party reporting has already reached the long-term target level set by the Authority;
- The number of dispersions located on third party reports (per thousand of end customers) records similar performances for networks with different degrees of concentration (customer density per unit of network length);
- Small perimeters record a greater volatility of the dispersion indicator localized upon reporting by third parties (per thousand of end customers), while those of a larger size record greater stability;
- There is a good correlation between the percentage of network inspected and the number of localized leaks on third party reporting (per km of network);
- The number of measures of the degree of odorization (per thousand of end customers) shows an increasing trend;
- There is a good correlation between the number of measures of the degree of odorization (per thousand end customers) and the number of dispersions localized on third party reports (per thousand end customers);
- The recovery plans for the cast iron mesh with hemp and lead joints and the cathodically protected steel mesh are in line with the agreements established by the Authority;
- The coverage of the remote control of the cathodic protection systems of the networks and of the final reduction groups is growing;
- The number of outages per customer records almost negligible values, with a decreasing trend for those with notice and an increasing trend for those without notice.

Commercial quality of the Natural Gas Distribution service

The commercial quality standards relating to the sales process mainly concern the measurement of the quality of communication tools such as call centres, physical and online branches.

The provisions in force provide general and specific quality standards that are mandatory for distribution companies and that aims protecting customers and promoting the overall average improvement of services rendered at national level. According to the resolution no. 108/06 (Network Code of the Natural Gas Distribution service) the distribution company must publish a price list for regulated commercial services, such as the execution of simple works, complex works, activation of the supply, etc.

The regulator has set specific standard levels (referring to the single requested service) and general standard levels ²¹⁸(referring to the complex of requested services) regarding commercial services. In the event of violation of the specific standard levels (failure to provide the service within the time required by the regulation), due to the distributing company, automatic compensation is provided for the applicants. Also, for the issue of commercial quality, the DSO is obliged to fulfil registration and communication obligations.

Specific standard levels related to commercial quality of the distribution services and measurement services are stated in Table 3.18.

Table 3.18 – Specific standard levels– commercial services

Specific standard levels– commercial services	Time
Estimate for the execution of simple works	15 days
Estimate for the execution of complex works	30 days
The execution of simple works	10 days
Activation of the supply, deactivation time of the supply upon request of the end customer	10 days
Reactivation of the supply following suspension due to arrears	5 days
Reactivation of the supply following suspension for situations of potential danger to public safety	2 days
Verification of the measurement group at the request of the end customer	20 days
Replacement of the faulty meter	5 days
Verification of the supply pressure at the request of the end customer, time to restore the correct value of the supply pressure	10 days
Punctuality band for appointments with the end customer	1 hour
Time for making available the technical data requested by the seller	2 days

The regulation provides the maximum time limit and percentage of services to be provided such as;

- Minimum rate to carry out complex within 60 working days shall be 90%
- Minimum rate to respond written complaints or written requests for information within maximum 30 calendar days shall be 95%

The purpose of the commercial quality regulation is to guarantee and improve the protection of end customers in terms of timeliness, punctuality and accuracy in handling commercial requests, as well as making available data relevant for commercial purposes and adapting some standards on basis of actual levels recorded over the past few years. Based on the analysis of actual times and their comparison with current standards, it emerges that in many cases the performance of companies is far better than the standard.

In this regard, ARERA reduced the time limits provided by the standards in the fourth regulatory period, bringing them back to levels closer to the actual levels found, in order to make the conditions for providing the service as homogeneous as possible, from a commercial point of view, reducing the gap between the best served customer and the worst served customer.

Regarding the performance of the measurement service²¹⁹, ARERA has introduced the definitions of self-reading, of the

218 This section is based on: Resolution 569/2019/R/Gas Quality Regulation of Natural Gas Distribution And Measurement Services For The Regulation Period 2020-2025 (RQDG) Effective January 1, 2020

219 This section is based on: Resolution ARG/gas 64/09 Integrated text of retail sales of natural gas and gas other than natural gas distributed via urban

measurement data, of an accessible, non-accessible and partially accessible meter, as well as the detection intended as an activity that includes the collection and validation of the measurements, as well as the provisions on measurement and availability of data.

The regulator establishes the methods for detecting and storing the measurements of the redelivery points by the distribution companies by setting the minimum number of attempts to collect the measurement, the frequencies and the occurrences of these, the obligations of making available of the measurement data by the distribution companies to the vendors content to be made available, and standard timings and formats as well as the treatment of the self-reading results.

As for the commercial distribution services, the regulator has set specific standard levels. In the event of violation of the specific standard levels (failure to provide the service within the time required by the regulation), due to the distribution company, automatic compensation is provided for the applicants. Also, for the issue of measurement performance, the DSOs are obliged to meet some standards.

Table 3.19 – Specific standard levels– measurement services

Specific Standard – measurement services	Frequency
Number of attempts to collect the measurement of natural gas	
For delivery point up to 500 Sm3/year of consumption	1 attempt per year
For delivery point from 500 up to 1,500 Sm3/year of consumption	2 attempts per year
For delivery point from 1.500 up to 5,000 Sm3/year of consumption	3 attempts per year
For delivery point from 5,000 Sm3/year of consumption	Monthly

In case of failure to meet the required timing and occurrence conditions, the distribution company is required to pay compensation to the end customer.

With the succession of the various regulatory periods, ARERA has changed the target values of the incentive mechanism and has introduced different standards for operators. These changes were always made through the consultation mechanism and after the analysis of the data obtained from the periodic monitoring system. The standards described pertain to the fifth regulatory period, however, they were gradually introduced on the basis of market needs and on the overall quality level of the assets and the service provided.

3.3.6.2 UK²²⁰

In the RIIO (Revenue = Incentives + Innovation + Outputs) system, incentives on outputs are an important part of the regulation system of the UK. Distribution companies are expected to achieve agreed primary outputs and secondary deliverables (i.e. interim actions that are expected to lead to benefits in future regulatory periods) and to justify their business plans and submitted revenue requirements in relation to these outputs. The output categories are linked to licence obligations, existing standards of performance and policy objectives that networks can facilitate. Outputs fall into six categories in the current RIIO price control period which Ofgem decided to consolidate under three categories for RIIO-2 in order to put the consumer interest at the heart of the regime; which are:

- To meet the needs of consumers and network users – Network companies deliver high quality reliable services to all network users and consumers, including those in vulnerable situation.
- to maintain safe and resilient networks – Network companies must deliver a safe and resilient network that is efficient and responsive to change
- to deliver environmentally sustainable network – Network companies must enable the transition to smart, flexible, low cost and low carbon energy systems for all consumers and network users

networks (TIVG).

220 Source: Ofgem, RIIO-GD1 Annual Report 2015-16, 2017. https://www.ofgem.gov.uk/system/files/docs/2017/02/riio-gd1_annual_report_2015-16_0.pdf

As the overarching output framework. Ofgem will:

- use the enhanced engagement framework to inform network companies' licence obligations
- establish price control deliverables where appropriate by providing a revenue allowance to enable delivery
- apply output delivery incentives where service quality improvements beyond the minimum standard may be in the interests of consumers and other network users.

There are various forms of incentives that are linked to target outputs such as financial/reputational; marginal/fixed; symmetric/asymmetric or automatic/manual. RIIO applies symmetric²²¹ financial incentives as well as reputational incentives mainly on environmental and social outcomes of the results achieved to the network companies based on their outputs. Financial incentives are more appropriate where there is clarity on delivery of output and measurement of performance and when the output is considered to be important. Reputational incentives are non-financial incentives that rely on the publication of the data which can be used in transition to financial incentives. It may be used in case other regulation is driving good behaviour in the area.

Financial incentives for output delivery reward service level improvements by setting target service levels, rewards, and penalties. The Regulator intends to equalise the incentives by setting baseline service quality levels to ensure that the marginal benefit to consumers is proportionate to the marginal cost in higher network charges. The rewards/penalties regarding the output incentives are funded with a two-year lag and reflected to baseline revenue annually.

Table 3.20 shows Ofgem's recent decision on RIIO-GD2 outputs reflecting its greater emphasis on supporting customers in vulnerable situations, improving service levels, embedding significant customer satisfaction improvements seen in existing RIIO-GD1 and rewarding them and responding to unplanned supply interruptions

Table 3.20 – Ofgem decision on the RIIO-GD2 outputs

Output name	Output Type*	Company Driven Target**
Common outputs (will apply to all companies)		
Consumer vulnerability minimum standards	LO	No
Consumer vulnerability reputational incentive	ODI(R)	Yes
Consumer vulnerability and carbon monoxide safety use-it-or-lose-it allowance	PCD	Yes
Fuel Poor Network Extension Scheme	PCD	Yes
Stakeholder Engagement Incentive	ODI(R) and bespoke outputs	Yes
Customer satisfaction survey	ODI(F)	No
Complaints metric	ODI(F)	No
Guaranteed standards of performance	LO	No
Emergency response time	LO	No
Average restoration time for total unplanned interruptions	ODI(F)	Yes
Bespoke outputs (companies may consider other areas for inclusion in their business plan)		
*ODI(R/F) = Output Delivery Incentive (Reputational/Financial) , PCD=Price Control Deliverable, LO=License Obligation		
** Company driven target signifies output where it is expected to see extensive company-led engagement (including with their Customer Engagement Group (CEG)) to justify performance targets. This could lead to performance targets varying by company.		

²²¹ The same reward/penalty for over/under delivery of the targeted outputs.

Figure 3.18 shows the output performance of the Natural Gas Distribution companies in 2018-19 against six output categories.

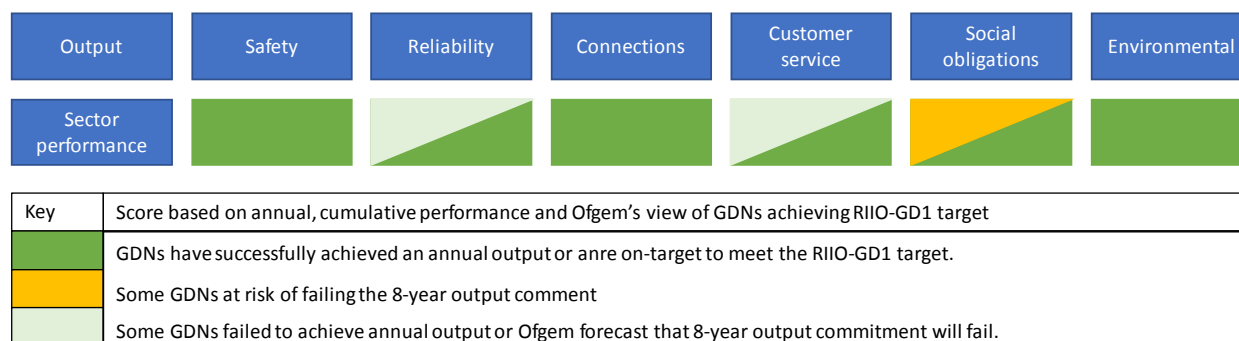


Figure 3.18 – Output performance of Natural Gas Distribution network in 2018-19²²²

Below are examples set under the existing six output categories;

Network safety

Iron mains risk reduction (mains replacement): To comply with safety legislation and requirements, DSOs are engaged in a long-term program to replace risky iron mains on their networks.

Emergency response: Uncontrolled escapes: where the source of the leak cannot be confirmed as having been isolated by turning off an emergency control valve. DSOs must attend at least 97% of uncontrolled escapes within one hour of them being reported.

Controlled escapes: where the source of the leak is confirmed as having been isolated by turning off the emergency control valve. DSOs must attend 97% of controlled escapes within two hours of them being reported.

Management of repairs: DSOs are required by legislation 25 3.15. to prevent reported gas escapes within 12 hours, unless they can prove it is not reasonably practicable to do so (in which case the escape must be monitored and repaired as soon as it is practicable).

Repair risk: The repair risk output requires companies to manage the risk of gas escapes that have been assessed as not requiring emergency action. DSOs monitor these escapes until it is reasonable and proportionate to carry out the necessary repair work.

Major accident hazard prevention: This output requires DSOs to prepare a safety case as required by GS(M)R for approval by HSE, and to submit a safety report for approval by HSE (Health and Safety Executive) in accordance with the Control of Major Accident Hazards Regulations 2015.

Sub-deduct networks off-risk: A sub-deduct network has an unusual configuration consisting of a primary meter and one or more secondary meters. The ownership of such networks is sometimes unclear, presenting a safety issue. DSOs are required to remove the safety risk associated with these networks by the end of RIIO-GD1.

Network reliability

Loss of supply (duration and number of interruptions): There are four measures for this output; the number of planned interruptions, duration of planned interruptions, number of unplanned interruptions duration of unplanned interruptions. Each DSO has targets in each of the mentioned measures.

²²² Note: Light Green: DSOs failed to achieve an annual or 8-year outputs, Orange: DSOs at risk of not meeting annual or 8-year outputs, Green: DSOs met or on-target to meet annual or 8-year outputs.

Achieving the one-in-20 supply capacity obligation: DSOs are required to maintain supplies for the daily demand conditions that are statistically experienced in the worst winter in 20 years. This ensures DSOs will safely and securely distribute gas to consumers even when demand is high.

Maintaining operational performance: Maintaining operational performance is measured through five secondary inputs.

Deliverables; number and value of offtake meter errors, duration of telemetry faults, pressure systems safety regulations fault rate, gas holder demolition, health, criticality and risk metrics.

Customer service

Customer satisfaction survey: The customer satisfaction survey asks customers to score DSOs' service out of 10. DSOs can be rewarded or penalized by up to 0.5% of base revenue, depending on how well they perform against their target.

Customer complaints: DSOs can be penalized up to 0.5% of base revenue for not meeting target scores for customer complaints. Complaints performance is measured against four indicators based on the percentage of; complaints resolved in one day, complaints resolved in 31 days, repeat complaints, Energy Ombudsman (EO) decisions against the DSO.

Stakeholder engagement: The stakeholder engagement incentive encourages DSOs to engage with stakeholders to inform their business decisions. DSOs can be rewarded up to 0.5% of base revenue where they meet the minimum standard.³⁹ Performance under this incentive is then assessed by an independent panel. The panel is comprised of experts in communications and stakeholder engagement.

New connections

Introduction of voluntary distributed gas entry standards: Gas entering the network from alternative sources is known as distributed gas, for example from a biomethane plant. DSOs have developed voluntary standards for distributed gas connections which they report on annually.

Guaranteed standards of performance: Customers seeking a new connection rely on the DSOs to provide a good service. Guaranteed standards of performance related to the timely delivery of connections services.

Social obligations

Fuel Poor Network Extension Scheme: The Fuel Poor Network Extension Scheme (FPNES) helps vulnerable and fuel poor households that are off the gas grid to switch to natural gas by offering funding towards the cost of connecting to the gas network.

Carbon monoxide (CO) awareness: Ofgem considers it vital that DSOs contribute to increasing awareness of the effects of CO. To incentivise DSOs to go above and beyond these outputs, Ofgem also has a gas discretionary reward (DRS) scheme.

Protection of the environment

Bio methane connections information: Biomethane is a renewably sourced substitute for natural gas, which can be injected into the gas network, bringing environmental benefits. DSOs introduced a set of voluntary connection standards that they would meet when connecting biomethane, which is monitored annually.

There are no targets set for the capacity of biomethane each DSO must connect, but DSOs must report on the following areas; the total capacity of biomethane inquiries and applications currently in progress, but not yet connected, and the total capacity of biomethane connected.

Shrinkage (leakage) commitments

Shrinkage refers to gas, which is lost from the transportation network, of which leakage is the main contributor. DSOs must meet annual leakage targets. There are two incentives for reducing shrinkage (leakage). The two incentives are; The Shrinkage Incentive and The Environmental Emissions Incentive (EEI).

Business carbon footprint

There is no financial incentive associated with this metric. DSOs also reported on other environmental aspects; land remediation, the quantity of virgin aggregate used the amount of spoil sent to landfill, ISO 14001 major non-conformities²²³.

DSO's output performance is given in the table below.²²⁴

Table 3.21 – Output performance in UK

Company	Network	Environment	Connections/ Wider works	Customer Satisfaction	Social Obli- gations	Safety	Reliability/ Availability
CADENT	EoE	Meeting	Meeting	Meeting	Meeting	Meeting	Meeting
	Lon	Meeting	Meeting	Missed customer satisfaction target on main gas connections	Off track from FPNES connections 8 year target	Meeting	Challenges in meeting unplanned interruptions duration target
	NW	Meeting	Meeting	Meeting	Meeting	Meeting	Meeting
	WM	Meeting	Meeting	Missed customer satisfaction target on duration of planned works and main gas connections	Meeting	Meeting	Meeting
NGN	NGN	Meeting	Meeting	Meeting	Meeting	Meeting	Meeting
SGN	Sc	Meeting	Meeting	Meeting	Meeting	Meeting	Meeting
	So	Meeting	Meeting	Meeting	Off track from FPNES connections 8 year target	Meeting	Meeting
WWU	WWU	Meeting	Meeting	Meeting	Meeting	Meeting	Meeting

3.3.6.3 Germany

In Germany, the safety and operation of the gas supply system is based on a self-administration principle and state supervision is at minimum. The energy authority within the Federal Ministry of Economic Affairs and Energy, and additional offices in the federal states are responsible for technical safety in gas. According to the principle of self-administration, the Energy Authority normally observes the gas sector and intervenes only if deficits or critical incidents show up. However, communication and information exchange between the authorities and the gas sector is continuous.

²²³ Source: Ofgem, RIIO-GD1 Natural Gas Distribution Price Control – Regulatory Instructions and Guidance: Version 5.0, 2018.

²²⁴ Source: Ofgem, RIIO-GD1 Annual Report 2015-16, 2017.



This project is funded by the European Union



Quality regulation provides incentives for network operators to fulfil their supply obligations in high quality. In the revenue cap formula, the quality element (Qt) is included. Although quality regulation should have been implemented during the second regulatory period (2013-2017), quality regulation for gas network operators in Germany has not been implemented, since the Federal Network Agency does not consider the data collected to be appropriate for such a valuation. This is different from electricity networks, where quality regulation is common practice.

The Federal Network Agency recommends in its evaluation report to leave the introduction of the quality element in the gas sector to its discretion, as the supply quality in this sector is particularly high anyway and other regulations leave hardly any leeway to the network operators.^{225 226 227}

In Germany, customer satisfaction is currently neither a relevant criterion in calculating network charges nor in the efficiency rating of gas network operators. In contrast to supply quality (in electricity networks), the service quality of network operators is not included in any assessment. The evaluation report published by Federal Network Agency contains no proposals for change in this context.²²⁸

Indexes that are available for Natural Gas Distribution are SAIDI, SAIFI, CAIDI and ASIDI. Continuity of supply indicators in 2013 has been 0.573 for SAIDI and 0.072 for ASIDI. The NRA conducts a comprehensive survey of all gas supply interruptions throughout the Federal Republic of Germany every year. As a result, average duration of supply disruptions experienced by a customer over a period of one year has been 0.99 minutes per year in 2017 compared with 1.03 minutes per year in 2016.

There are also subindicators for planned/unplanned interruptions and for causes of interruptions. In the country, causes of interruptions that are recorded might be as follows²²⁹:

- Atmospherically influence
- Caused by third party
- Responsibility of the network operator
- Others (planned)
- Feedback effects caused in other networks
- Exchange of meter

- Force majeure

In the country, there is an obligation to odorise natural gas and DSOs have obligations as far as gas odourisation is concerned.

Methodology for compensating the consumption deviations for DSOs

Compensation for the consumption deviation is not commonly applied in the EU, a few examples are provided as follows:

In **Germany**, within the compensation of gas consumption deviations, several parties are included. The role of network operators

225 Source: https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Netzentgelte/Gas/Qualitaetselement/Qualitaetselement_node.html

226 Source: https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Netzentgelte/Anreizregulierung/WesentlicheElemente/IndivEOG/IndividuelleEOG_node.html

227 Source: https://www.bdew.de/media/documents/Awh_20191209_FAQ-Qualitaetselement-Schaden.pdf

228 Source: Source: Bauer et al. 2016, Regulierung in der Energiewirtschaft

229 Source: CEER, (2018), 6TH CEER BENCHMARKING REPORT ON THE QUALITY OF ELECTRICITY AND GAS SUPPLY – 2016

is to take over gas quantities provided by Transport Customers (in particular suppliers and wholesalers) at entry points of the market area and to deliver them to consumers located at exit points with the same energy content.

Transport Customers take over the role of suppliers of gas for final customers, in some cases large industrial final customers take over this role directly themselves. Transport Customers insert gas capacities in balancing groups.

The usage of the gas network is regulated by several contracts. Transport Customers closes an entry-/ exit contract with the Entry/ Exit Network operator. This contract includes booking of network capacities and the access to the market area.

The Market Area Coordinator does not operate own physical entry- or exit-points, but the virtual trading point of the market area. In this function the Market Area Operator is involved on behalf of the network operators.

The Balancing Group Manager, who is often a Transport Customer, closes a Balancing Group Contract with the Market Area Coordinator regarding the actual flow of gas through the network.

Exit Network Operators, who are the last link in the supply chain to deliver gas to the final consumers, provide gas quantities based on an estimated consumption of each exit point. This estimation of gas consumption per exit point is also called 'allocation' and regularly deviates from the actual gas consumption, resulting in surplus or shortfall quantities. Deviations are settled by control energy.

The Market Area Coordinator procures the gas quantities required for compensation of surplus or shortfall quantities from traders on the balancing energy market and makes them available to the Exit Network Operators in his market area.

Surplus or shortfall quantities are considered as provided or received by the Exit Network Operator and are invoiced between the Exit Network Operator and the Transport Customer with a reference price. This settlement takes place at least annually or at the end of the contract period (usually with the grid usage settlement).

The Exit Network Operator, in turn, settles expenses and income from the compensation of surplus and shortfall quantities with the Market Area Coordinator who provides the control energy.

The Balancing Group Manager is responsible to the Market Area Coordinator for the daily settlement of the balancing group. The underlying balancing group contract between the Market Area Coordinator and the Balancing Group Manager regulates the operational handling of transport, the transfer of gas quantities between balancing groups as well as the balancing and settlement of deviations, which is executed in the framework of balancing group settlement. If the Balancing Group Manager fails to meet its obligation to ensure a balanced balancing group, the Market Area Coordinator bills the corresponding difference quantities as positive or negative balancing energy.

Balancing energy is therefore the difference between entry and exit of each balancing group in the market area, determined ex post at the end of a balancing period. For the provision of positive control energy quantities, the Balancing Group Manager pays a surcharge on the reference price, whereas he receives a deduction from the reference price if the provided quantities are not used (asymmetric pricing system). In order to prevent abuse of the daily balancing system, the Market Area Coordinator charges a structuring fee to the Balancing Group Manager for the difference arising from the balancing of surplus and shortfall quantities. In case balancing leads to losses or additional revenues for the Market Area Coordinator, they are compensated by a levy.

The settlement in particular of Surplus quantities appears to be critical from the perspective of Transport Customers/ Balancing Group Managers, since they are not able to control the allocation quality of network operators. In comparison, the overall process of balancing is financially neutral for Exit Network Operators and Market Area Coordinators.^{230 231}

230 Source: https://www.bundesfinanzministerium.de/Content/DE/Downloads/BMF_Schreiben/Steuerarten/Umsatzsteuer/Umsatzsteuer-Anwendungserlass/2014-07-01-UStI-Behandlung-Abrechnung-Mehr-Minderungen-Gas.pdf?__blob=publicationFile&v=2

231 Source: Bauer et al. 2016, Regulierung in der Energiewirtschaft

3.3.6.4 Spain

Spanish regulatory framework does not include any incentive/penalization mechanisms related to the Quality of Service in the revenue cap methodology for Natural Gas Distribution operators. However, a discount system applies to network charges when supply interruptions exceed a threshold. In the end, these discounts on distribution tariffs may be considered as a penalization for distribution companies if quality of supply standards are not met.

Quality standards for Natural Gas Distribution and supply in Spain are governed by Royal Decree 1434/2002 and may be classified under one of the following elements:

- Physical quality of the natural gas.
- Odorization.
- Continuity of Supply.
- Quality of services: connections, inspections, etc.
- Commercial quality.

Natural gas physical quality standards such as the composition, calorific value, Wobe index, etc. correspond to those applicable for gas of group H, according to the norm UNE-EN-437. These parameters are included in the Technical Management Standards of the Spanish Gas Network.

Natural gas must be odorized, so that any leakage can be detected easily by human smell when volumetric concentration of natural gas is one fifth of the lower flammability concentration limit. It is responsibility of the TSO to deliver odorized natural gas in the distribution networks, but DSOs must ensure that natural gas delivered to consumers has the characteristic smell, adding odorization compounds if necessary. Currently, the CNMC (regulator) does not perform any monitoring activity related to gas odorization so there are not regulatory performance indicators in use.

Spanish regulation defines tolerable pressure levels to identify any interruption of supply. The tolerance levels for continuity of supply depend on the maximum operational pressure level and are defined as follows:

- High pressure B (>16 bar). Any pressure below 16 bar is considered a supply disruption.
- High pressure A ($4 \text{ bar} < P \leq 16 \text{ bar}$). Pressure below 3 bar is considered an interruption.
- Medium pressure B ($0.4 \text{ bar} < P \leq 4 \text{ bar}$). Pressure below 0.4 bar is considered an interruption.
- Medium pressure A ($50 \text{ mbar} < P \leq 0.4 \text{ bar}$). Pressure below 50 mbar is considered an interruption.
- Low pressure ($P \leq 50 \text{ mbar}$). Pressure below 18 mbar is considered an interruption.

If a customer suffers any supply disruption, as specified above, different discounts shall be applicable to the network charges. The discount applies to the network charges paid by the supplier to the DSO when the supplier is not responsible for the interruption. The way these discounts are transferred to end-users depends on the commercial arrangements between suppliers and customers.

Applicable discounts on network charges are as follows:

- 1 basic supply disruption (less than 5 hours): no discount.
- 2 or more basic supply disruption: 10% of monthly charge for each two basis supply disruptions.
- If a disruption lasts more than 5 hours and less than 1 day accounts as 2 basic supply disruptions.
- If a disruption lasts more than 1 day, it is accounted as 3 basic disruptions for each day with supply disruption.

The maximum applicable discount is set at 50% of the monthly network charge. When the supply disruptions are due to force majeure or scheduled maintenance works, they do not involve tariff discounts. Except for emergency situations (force majeure), the DSO shall inform in due time for the affected users and it shall try in all cases to minimize the impact that the interruption would cause to users affected. The DSO will include in such information, the cause that originates the interruption and the expected date to recover the supply.

The most important instrument of the CNMC to monitor the quality of services related to Natural Gas Distribution is the collection of customers' complaints. Upon approval of CNMC Order 2/2016, all suppliers and distribution companies must send to the CNMC all the complaints received together with the time required to response, final resolution and other elements.

Information related to customers' complaints helps the CNMC to evaluate the level of satisfaction of end users and to benchmark each distribution company.

For each distribution company the CNMC calculates the following indicators:

- Average number of complaints presented to the distribution company for each 100 supply points.
- Number of complaints by typology:
 - o Delay on the periodical maintenance inspections.
 - o Incorrect customer services.
 - o Disconformity with the quality of the maintenance inspection.
 - o Connection: delay on initial supply date.
 - o Connection: complaints on the quality of the installation/works.
 - o Disconformity with a fraud report.
 - o Delay on the suspension of supply date.
 - o Disconformity with the consumption measure.
 - o Supply disruptions.

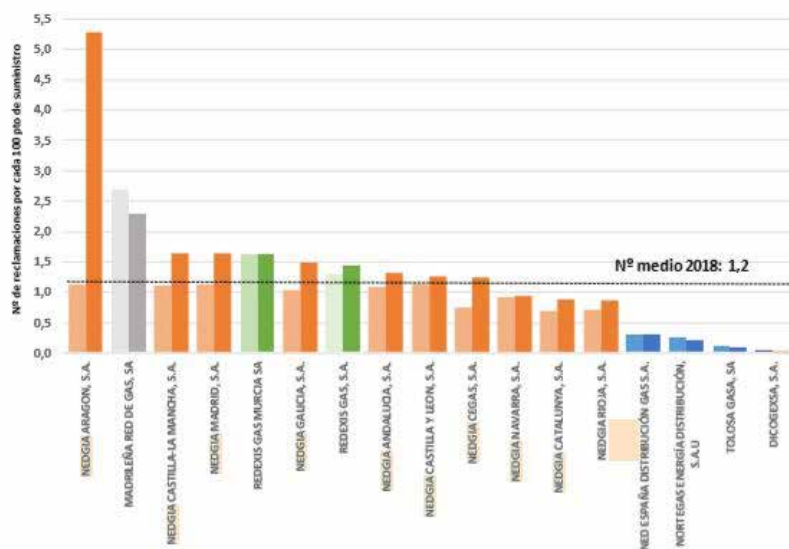


Figure 3.19 – Spain: DSOs' average customers' complaints per each 100 supply points²³²

3.3.6.5 Portugal²³³

In Portugal Natural Gas Distribution network, performance is evaluated through indicators that consider the number and duration of interruptions. SAIDI, SAIFI and AIT are used as indicators. In 2016, there were no interruptions in 3 out of the 11 existing distribution networks (Beiragás, Sonorgás and Paxgás) and only 0.6% out of approximately 1.45 million customer installations suffered interruptions. No customer was affected by more than one interruption. Nearly 72% of the interruptions that occurred in the distribution networks were due to fortuitous events or cases of force majeure, caused by third-party interventions in the networks. The average duration of the interruptions per customer was less than 3 minutes in all the distribution networks.

²³² Source: CNMC (2018)

²³³ Source: CEER, 2016, 6TH CEER Benchmarking Report on the Quality of Electricity and Gas Supply – 2016.

Portugal has obligation for giving advance notice (36 hours) of planned interruptions.

The RQS establishes that the monitoring of the characteristics of natural gas should be carried out by the infrastructure operators and sets limits for the following characteristics: Wobbe index, relative density, dew point, hydrogen sulphide and total sulphur. In 2017, there was full compliance with the regulatory limits for natural gas characteristics, by transmission network monitoring point.

All distribution network operators presented information on the monitoring of the pressure in their networks. In 2017, the pressure supplied was monitored at 296 points in the distribution networks. There were one-off incidents of non-compliance with the pressure limits set out in the applicable legislation and in the monitoring methodologies which, according to the distribution network operators, had no impact on the supply of natural gas to customers.

In accordance with the RQS for the natural gas sector, ERSE publishes a quality of service report on a yearly basis, to present and assess the quality of service for the activities covered by the natural gas sector.

In terms of commercial quality, Portugal monitors the response time separately for complaints and requests. Some of the criteria and obligations by which the response to customer request is monitored is as follows:

- Limit: 15 working days
- Standard that must be met: 98% DSO
- Number of cases for which the limit was fulfilled: 11,863
- Value of the indicator: 96%
- Compensation for non-compliance: N/A
- Pressure level: LP, MP, HP

In the country call centres must allow customers to leave their contact and purpose of the call in case the waiting time is expected to be over 60 seconds; in such cases, companies have to call back those customers within 2 working days. In addition, assistance and emergency numbers are monitored separately from commercial calls.

On the other hand, criteria and obligations by which the punctuality of market participants regarding appointments with customers is monitored is as follows:

- Limit: within a 2.5 hours interval agreed with the customer
- Number of cases for which the limit was fulfilled: 112,691
- Compensation for non-compliance: 20 €
- Pressure level: LP, MP, HP

In Portugal, appointments are made between the customer and the supplier (USP/SP). If the DSO does not arrive within the 2.5 hours interval set with the customer, then the customer must receive €20 compensation from either the USP/SP or DSO, depending on whose fault it was. If customers are not present when the DSO arrives, then the DSO has the right to receive €20 compensation. Cancellation of the visits is possible, by either part, up to 12 hours before the appointment hour. The time for reactivation after disconnection following non-payment is 12 hours for domestic customers, 8 hours for non-domestic and 4 hours if customer pays

for urgent reactivation. Since 2014 the time is not counted between 20:00 and 8:00, and this rule applies only to simple works.

Call backs to clients must be made within 2 working days after the client -having waited more than 60 seconds- has left his contact details and stated the purpose of the call.

3.3.6.6 Turkey

In Turkey, currently quality factor is not implemented in distribution tariffs. Distribution sector is very young in Turkey, so EMRA has focused on the expansion of network so far. However, it is thought that the sector is mature enough to apply quality factor.

Therefore, EMRA may use quality factor in the next tariff implementation periods. For that purpose, the performance indicators used by UK as explained in detail above may be implemented to Turkey. With the application of quality factor, the level of service quality may be increased in the sector.

Electricity tariffs has been prepared without a quality component until 2016, before when QF was to be applied in theory. However, some problems such as lack of data have delayed setting QF mechanism within the tariffs. In 2016, EMRA has created a QF-like parameter: General Quality Indicator (GQI).

This is a proxy variable assumed to represent overall service quality level (even quality in wider terms) of companies. First GQI was zero death from work accidents. This GQI applied only for reward. Later on, EMRA adopted call center performance as the second GQI (call center performance in fact is a QF of commercial quality, and this shows QF and GQI is accepted to be same concepts by EMRA).

Beginning from 2018, QF is being started to be in the tariffs. It also included some proxy variables, however as stated above, EMRA used these concepts interchangeably. As in the case of Electricity Distribution tariffs, EMRA can use some GQIs at the beginning and later on enhance quality factor reward/penalty or only reward schemes during several periods.

Natural Gas Distribution is considered as more suitable for GQI approach than Electricity Distribution as QF is widely based on continuity of supply indicators in electricity.

For incentivizing better service quality, below indicators can be used, inter alia, as QF in Turkey:

- Fast connection: Time targets can be set.
- Specific targets: Gasifying a district until a certain date or gaining new subscribers there until a certain date etc.
- Indoor installations controlled by DSO, each as a QF.
- Number of low-income customers that is connected to network with joint financing programs of DSO and domestic and/or international partners.
- Contribution of DSO to carbon footprint reduction.
- Not outsourcing to sister companies.

Call center performance and other commercial quality indicators.

3.4 Efficiency

Cost approval approach in *Italy* gives NRA the opportunity to eliminate the costs that are not related with network business. Regulatory body has set some rules to make the distinction between non-controllable and generally controllable costs.

Non-controllable costs are:

- Not under the influence of the network operator, e.g., special HR costs, legal payment obligations, curtailment, operating taxes, etc.
- Not subject to efficiency targets
- Defined in Incentive Regulation Ordinance
- Intra-periodic adjustment (deviation from the budgetary approach)

Generally, controllable costs are:

- Subject to efficiency benchmarking
- Under the influence of the network operator

The recognized operating costs or allowed OPEX in Italy are the cost of labour, the costs for the purchase of consumables, the cost that are not investments and other specific operating costs. Once the OPEXs have been determined for the first year of regulation, the OPEX for the following years are calculated by applying the following items to those of the previous year:

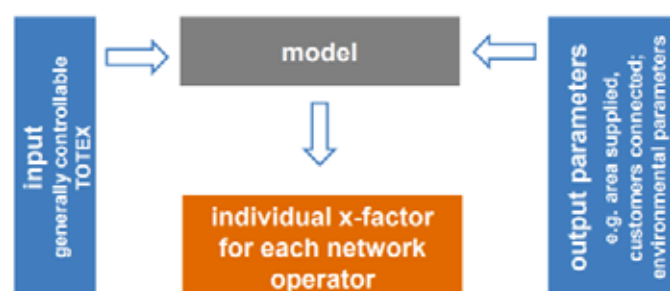
- The average annual rate of change, referred to the previous twelve months, of consumer prices of workers 'and employees' families recognized by Istat;²³⁴
- X-factor efficiency recovery;
- The rate of change linked to changes in recognized costs resulting from unforeseeable and exceptional events, changes in the regulatory framework and changes in the obligations relating to the universal service.

The component covering these costs is based on operating costs for a base year, revalued annually on the basis of inflation and reduced by a factor (X Factor) of efficiency according to the price-cap mechanism.

For these data it usually refers to the last available balance sheet of the company and to parametric formulas established by ARERA.

This mechanism aims to limit the profits of the operators and, at the same time, to reward the efficiency recoveries obtained with the optimization and containment of the management costs.

The X-factor efficiency recovery, determined by ARERA, remains constant throughout the regulatory period.



234 <https://www.istat.it/>, the Italian statistical institute

Figure 3.20 – Role of factors in calculations

ARERA's regulation to incentivize the consolidation (aggregation) of DSOs - Aggregation incentive²³⁵

The corporate aggregation process is the acquisition of business branches by another distribution company, the merger of two or more distribution companies or the incorporation of a distribution company by another distribution company. The acquisition of shareholdings nor the transformation of a legal entity is not considered a corporate aggregation process.

Since the entry into force of liberalization, the more or less conscious effect of some measures adopted by the National Regulator (ARERA) has led to the natural reduction in the number of operators: in fact, distribution operators from around 850 in 2000s have gone to 210 in 2019s.

The process of aggregation of operators was not only guided by the liberalization process with the Letta Decree, but also by the acquisition strategies of the main operators, both national and foreign: it can be said that some utilities have started an external growth path, acquiring small and medium-sized operators, mainly addressing those geographically adjacent to their territory.

So, the decrease in the number of operators was both partially due to the strategies followed by the operators, and it was an effect of various causes, some supported by targeted actions to regulate others.

The following list summarizes the main key factors:

1. Incentive tariff for the aggregation due to the introduction of a lower efficiency factor in the operating costs of managing the service for companies with a PdR number greater than 300,000.

Table 3.22 – Reduction rate of the distribution operating cost

		Reduction rate of the distribution operating cost		
Regulatory period (ARERA RTDG Resolution)		III 2009 -2012 – (159/2008/gas)	IV 2014-2019 – (573/2013/R/gas)	V 2020-2025 – (570/2019/R/gas)
Size class DSO	Less than 50,000 PdR	5.2% -2010	2.5%	6.59%
		5.0% - 2011		
		4.8% - 2012		
	More than 50,000 less than 300,000 PdR	4.4% -2010	2.5%	4.79%
		4.2% - 2011		
		4.0% - 2012		
	More than 300,000	3.0% - 2010	1.7%	3.53%;
		2.8% - 2011		
		2.6% - 2012		

2. Extension of the tariff territorial base (from local tariff base to only six geographic areas).
3. Introduction of the tenders for the management of the distribution service.
4. Need to invest in human and instrumental resources (for example management software for the management of data from the provision of services, obligations to replace the meter fleet with meters called smart meters, with the consequent need to introduce digitization processes and indispensable dematerialization for big data management, need to acquire new skills in non-core business fields of the distributor).
5. Monitoring and control system and consequent sanctioning mechanism introduced by ARERA's specific regulations.

At the dawn of the issue of the fifth tariff period, ARERA announced that it would like to push further the allocation mechanism of the distribution plants through the tenders.

²³⁵ Documento per la Consultazione 410/2019/R/GAS – Criteri per la Regolazione Tariffaria dei Servizi di Distribuzione e Misura del Gas Nel Quinto Periodo di Regolazione Testo Unico delle disposizioni della regolazione della qualità e delle tariffe dei servizi di distribuzione e misura del gas per il periodo di regolazione 2020 – 2025 (TUDG).

As a matter of fact, from the begging the mechanism slowed down due to the numerous appeals generated following the issuing of the calls and the natural and existing conflict of interest between some players and companies owned by local authorities that should ban the tenders.

In this latter regard, it was therefore proposed to maintain an incentive for the aggregation between operators by means of an appropriate reduction of the X-factor, in order to extend the benefits deriving from the aggregations also to those situations, which cannot benefit from the aggregation promotion mechanism defined by the Authority.

In drafting the final provision, the Authority deemed it appropriate to favour the aggregation of operators, specifically of small and medium size, by promoting mergers that entail the creation of new entrepreneurial realities such as to foreshadow a recovery of overall efficiency of the sector.

In the years of the third regulatory period, following the one in which a concentration between companies takes effect, such as to reduce the overall number of the same companies and increase the number of active customers served by the same legal entity, the component covering the distribution operating costs service is determined by applying the X-factor specific to the size class of the legal entity resulting from the concentration.

This rate of reduction of recognized unit costs is applied to the unit values of operating costs which in the year of effectiveness of the concentration operation have found a distinct application within the concentration perimeter.

At the same time, the Authority deemed it inappropriate to provide similar incentive tools for large companies (more than 300,000 redelivery points served), believing that in such cases the assessment of convenience to the combination could be performed without introducing promotional formulas.

The aggregation processes observed in recent years have seen mainly large-scale operators who have mostly acquired small-sized enterprises. These processes, according to the Authority, which, while promoting the improvement of efficiency, do not require specific incentives.

In order to strengthen competition for the market, which passes through an expansion of the audience of those who can participate in the tenders being able to compete from a position of adequate strength, the Authority evaluates the possibility of providing targeted incentives that can sustain aggregations between medium-small sized companies, promoting the creation of larger companies and competitive strength.

Specifically, the Authority evaluates the possibility of introducing forms of incentive aimed at aggregations between small distribution companies (under 50,000 redelivery points) or between medium-sized companies (under 300,000 redelivery points) and small companies that do not belong to corporate groups under the control of larger companies.

In the consultation document, as for the form of the incentive, the Authority was oriented towards providing both an incentive on operating costs and an incentive on capital costs.

In relation to operating costs, the Authority intended to provide:

- For business combinations between medium-sized companies: to provide for the application of unit fees to cover the operating costs relating to the network infrastructures of the distribution service calculated, for the years subsequent to 2020, using the price- cap method, providing for the introduction of a specific rate of variation equal to + 1.5%, to be applied until the end of the fifth regulatory period, as a premium for the aggregations to be added to the other elements of the update formula;
- For aggregations involving one or more medium-sized enterprises and one or more small enterprises, the application of the extraordinary events mechanism which has already found application in the third regulation period.

In relation to the capital costs, starting from the first year in which the aggregation takes effect, the Authority intended that the incentive would be based on the level of the capital invested that would have been calculated as component to cover the operating distribution costs of the outgoing distributor company in the same location reimbursement.

The incentives would apply to business combinations effective from 2019.

At the end of December, finally, the resolution relating to the fifth regulatory period was issued, but only one DSO shared the Authority proposal on the incentive to the aggregation.

Taking into account what emerged in the context of the consultation, ARERA decided that it is necessary to carry out an in-depth analysis, to be done in terms of proposal by June 30, 2020, to evaluate the competitive profiles, and assessing for specific measures to strengthen operators in the individual ATEMs, as well as to identify measures for the generalized aggregations or for any other modulations according to the size of the subjects involved in the business combinations.

In **UK**, efficiency is an important part of the distribution system regulation. Costs are assessed comparatively with a ‘Toolkit Approach’ given that there is no single metric or analytical tool that will provide a full and robust overview of the efficiency of cost projections due to the varying levels of data disaggregation and availability

Cost data is adjusted based on regional factors (such as labour, sparsity, urbanity and other environmental factors) and real-price effects (e.g. inflation) to ensure the like-for-like comparability among NCs. Following these adjustment, three cost assessment analysis are conducted:

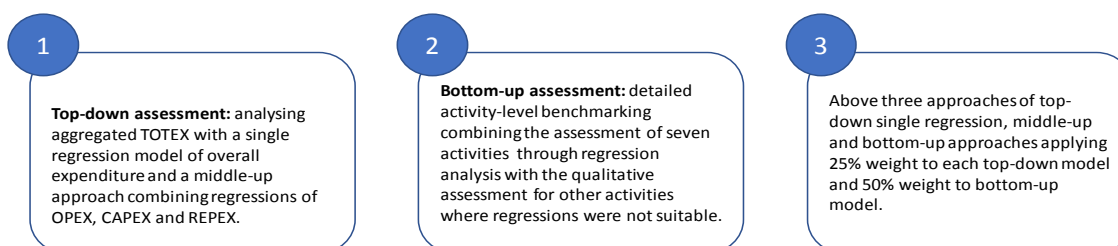


Figure 3.21 – Cost assessment analysis²³⁶

Econometric models used in above stages establishes a relationship between NC costs and chosen driver of those costs. The following benchmarking techniques are used by to measure efficiency across external, cross-sectoral or internal comparators:

- Ordinary Least Square (OLS or pooled OLS=POLS) Models: Use ‘pooled’ data (ie. using the data without accounting for the year data point is observed). Identifies average cost levels for comparators based on the cost drivers/explanatory variables. COLS (corrected OLS) is a type of POLS which is adjusted to a chosen efficiency benchmark.
- Random effects (RE) models: Allows for the identification of inefficiency via an error term by exploiting the pooled nature of the data (accounting for the year data point is observed).
- SFA model: Allows for the identification of inefficiency via separating the residual into a symmetric noise component; and an asymmetric inefficiency component.

DSOs are incentivized to outperform their TOTEX allowance set in the beginning of the price control period as part of the TOTEX Incentive Mechanism (TIM).

Through the TIM, any underspend compared to the allowed TOTEX is shared between the DSO and its customers, according to the sharing factor. Under the IIO framework, DSOs are encouraged to deliver their outputs in a cost-effective manner, using innovation and efficiency improvements to deliver savings compared to their spending allowances. Since this is an adjustment to TOTEX, it alters the revenues from both ‘fast’ and ‘slow’ money in line with the capitalisation ratios. DSOs are allowed to retain a part of any savings achieved, with the rest being passed on to consumers.

The strength of the incentive can differ across companies and between regulatory periods. In the RIIO scheme the strength is linked to the Information Quality Incentive (IQI) ratio – the closer the company projections are to the regulator’s expected expenditure baseline, the higher the incentive rate. IQI is an incentive mechanism, which is built around the savings/costs sharing between the company and customers in the event of a deviation between the allowed revenue and the actual cost amounts. It provides financial incentives to companies in order to encourage the submission of more accurate forecasts (to minimize the deviation between the company forecast and Ofgem’s cost assessment) and remove the incentive to inflate expenditure forecasts; and the submission of high-quality and well-justified business plans.

The IQI mechanism relies on a matrix showing the rewards/penalties the company will receive under different variants adjusted

²³⁶ Seven activities within the scope of bottom-up assessment are; work management, emergency, repairs, maintenance, mains reinforcement, connections and Repex.

in a way to reward the companies with well-justified business plans reflecting true costs by setting upfront efficiency incentives based on the differences between the company forecast and Ofgem's expectation on their costs. The companies with a lower deviation (meaning a forecast closer to Ofgem view) will receive a higher efficiency incentive rate (sharing factor) and the incentive is symmetric (i.e., the same proportion of overspend and underspend is retained by the company). The business plan forecasts line does not directly compare with the Ofgem adjusted allowances line due to changes to requirements following business plan submissions.

The Natural Gas Distribution network has an allowance of £16.7 billion over the RIIO-GD1 period to deliver their outputs, which is £2.1 billion (11.2%) less than their allowances.

Through the TOTEX incentive mechanism, DSOs will retain approximately 63% of this underspend, and the remainder will go back to consumers after allowing for corporation tax.

Innovation: DSOs have reported that this has been important in driving down costs and allowing them to be more efficient and cost-effective in how they carry out their work. This has had an impact on all areas of work, but DSOs expect to see the most significant savings in the mains replacement program area. For instance, the use of robots has reduced costs associated with digging and reinstatement.

In RIIO-1, Ofgem provided allowances (e.g. Network Innovation Allowance, Network Innovation Competition) to fund certain innovation projects. During RIIO-2, network companies will also be expected to finance short-term, lower-risk operation and maintenance innovation as a business as usual activity (which will be rewarded through the TOTEX innovation mechanism).

In [Germany](#)²³⁷, gas network operators with less than 15,000 customers are entitled to choose between participation in an efficiency comparison or to obtain a standardized efficiency rating (89.97% in 3rd regulatory period). Larger network operators have to participate in an efficiency comparison.

The model for calculation of efficiency ratings is based on a cost driver analysis, including cost parameters and comparison parameters. Cost parameters take permanently non-controllable costs out of consideration, because the respective network operator is not responsible for externally caused costs.

Since costs are based on CAPEX such as depreciation and equity capital interests as well, to avoid a discrimination of network operators with a larger share of newer assets, a standardization of CAPEX is necessary. Thus, all assets are valued by their current value with uniform useful life and a default capital structure. OPEX are included at their recognized level.

The consideration of structural parameters is done to consider the supply task and area characteristics (in particular geographical, geological or topological features) and structural features within the supply area. Since the 3rd regulatory period, mandatory structural parameters are not given any more by legislation. Mandatory structural parameters in the 1st and the 2nd regulatory period were the number of connection or exit points, the supplied area, the system length and the simultaneous annual peak. Additional parameters are used at the regulating authority's discretion.

The analysis of cost parameters (input) and structural parameters (output) is based on two methodologies, SFA and DEA. These two methodologies are applied for standardized costs as well as for approved costs. This results in four efficiency ratings, of which the highest is chosen ("Best-of-four"). A cap is set to a maximum of 100% and a minimum of 60%.

237 Source: Groebel A., (April 2018), BNetzA's role in energy infrastructure regulation and planning/permitting. https://erranet.org/wp-content/uploads/2017/10/Muller_Case-study-benchmarking-Germany_final.pdf

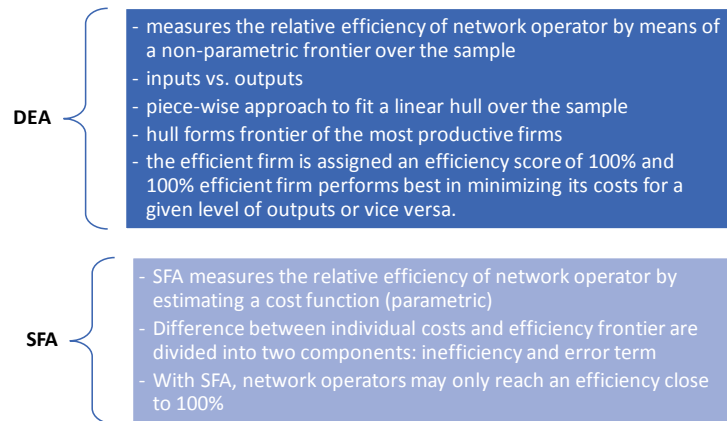
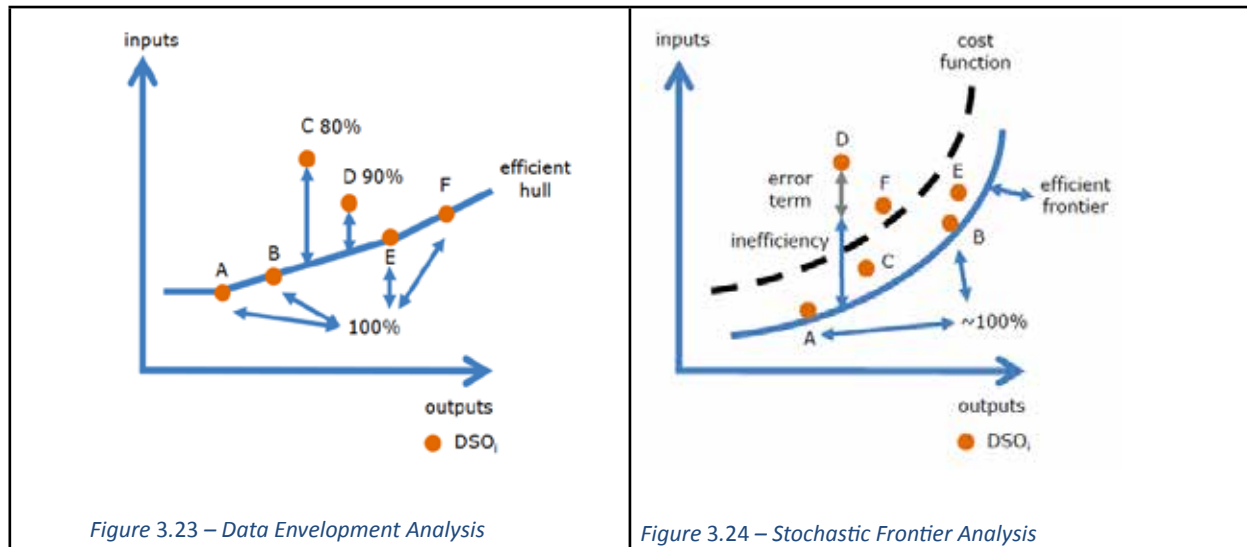


Figure 3.22 – Properties of DEA and SFA methods

Efficiency factor assigned to the network operator is based on best-of-four. The highest value is taken from two runs with DEA and two runs with SFA, with and without standardized costs and the lower cap is the efficiency of 60%. When a network operator can prove that specific features of his distribution task, which are due to specific structural circumstances, are not adequately reflected by the output parameters, the efficiency value will be adjusted. When a network operator can prove that he is unable to reach its individual efficiency target, the target will be set differently. Comparison of two techniques are given in the following figures.



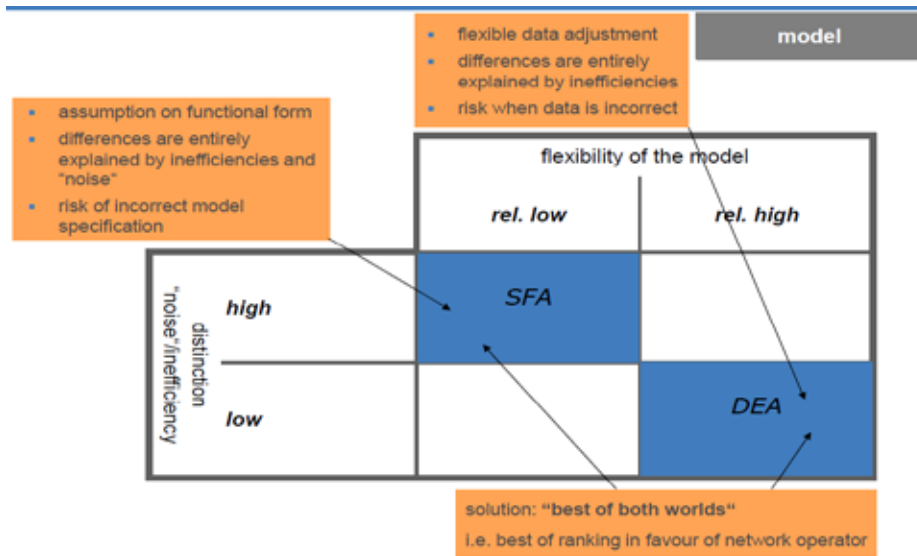


Figure 3.25 – Comparison of SFA and DEA

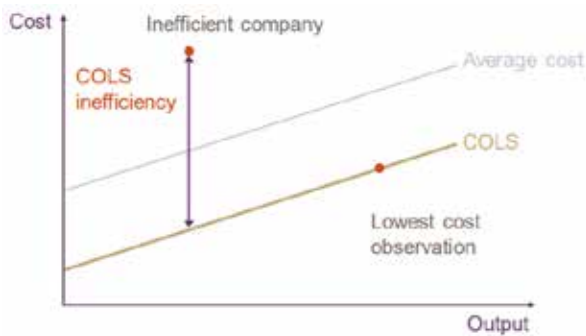
Since the 3rd regulatory period, particularly efficient network operators may receive a premium of up to 5% on their temporarily non-influenceable costs for the duration of a regulatory period. This Super-Efficiency bonus of a network operator is the difference between the individual efficiency rating from the Super-Efficiency analysis minus the individual efficiency rating from the nonparametric method (DEA). Methods that can be applied for Super-Efficiency analysis are in particular Cooks-Distance, DFBETAS, DFFITS, Covariance-Ratio or Robust Regression.

Network operators, that can demonstrate structural particularities in their supply area that have a significant impact on costs can request to consider this in the efficiency comparison.

In [Portugal²³⁸](#), the efficiency targets imposed on the operating costs of the activities associated with the infrastructure is an important factor to decrease the tariffs. The annual efficiency factors applied to OPEX varied between 2% and 7%, per company.

The definition of efficiency targets, with the objective of reducing controllable costs, is based on international and national benchmarking studies through the application of parametric and non-parametric methods. Specifically, the COLS and SFA methodologies are used in the parametric models, and the DEA methodology is used in the non-parametric models.

238 Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.



Similar to SFA and DEA, COLS is an econometric approach based on the simple regression model known as ordinary least squares. COLS requires data on domestic, national or international comparators.

Frontier is derived by shifting the line of best fit from the estimated cost function of the industry derived by efficiency frontier, so that instead of representing the average cost of the industry, line represent the efficiency frontier.²³⁹

Figure 3.26 – COLS frontier and efficiency

In Portugal, costs other than operating costs, controllable costs, non-controllable costs, and investment costs, which are analysed in detail, are not subject to efficiency.

In **Spain**, under current regulation there is no direct incentive to efficiency improvements in DSOs' activities. However, the RRM based on a base remuneration + unitary incremental revenues for each new supply point and MWh encourages DSOs to increase the efficiency since any cost reduction leads to higher profits for the company.

This is the main reason why the CNMC maintains the remuneration for new market during the next regulatory period (2021-2016). This mechanism incentivises operators to plan its operations and network expansion in a prudent manner taking into consideration only the potential for market expansion. Offering the same unitary incremental revenue nationwide, the regulator encourages operators to expand the network and customer base seeking the lowest marginal cost for each new supply point.

Spanish RRM in use (2014-2020) and the one for the next regulatory period (2021-2026) does not remunerate network operators for investments directly. If a network investment does not increment the number of customers of the energy distributed it will become a sunk cost that the company will never recover since it will generate no additional revenue.

This unitary revenue approach could hamper the network expansion to new municipalities. To avoid this, the methodology allows higher unitary revenues for new supply points in municipalities recently connected to the gas grid.

Apart from the efficiency incentive that arises from the general RRM, in 2019 the CNMC proposed additional revenue mechanism directly linked to efficiency improvements. Even if these mechanisms will not be implemented in the following regulatory period²⁴⁰ they can be considered as examples of Spanish regulator preferred approach to efficiency incentives. Two mechanisms were proposed by the regulator:

- Additional remuneration for the extension of useful life of assets.
- Additional remuneration for productivity increases in Operation and Maintenance (O&M) activities.

The first efficiency incentive is the additional remuneration for the extension of useful life of assets. This incentive introduced an extra remuneration for those network segments that have exceeded the regulatory useful life (20 years) provided that the

²³⁹ Source: Oxera, (2012), How can NMa assess efficiency of an Electricity Transmission System Operator

²⁴⁰ As explained in the Revenue Requirement Model introduction, stakeholders complains on the initial CNMC methodology led to a complete amendment of it and finally the CNMC proposed the same methodology that the one applied in 2014-2020 with only changes on the base remuneration.

company proves that they are still operating. Factors applied to calculate the additional revenue are as follows:

- 0.15 for those assets in operation with 20-25 years of useful life.
- 0.175 for those assets in operation with 26-30 years of useful life.
- 0.25 for those assets in operation with 31-35 years of useful life.
- 0.50 for those assets in operation with more than 35 years of useful life.

The application of the above parameters to the network length in operation gives the number of kms that receive an additional remuneration based on the unitary O&M cost (historical book value of O&M costs/total network length).

The remuneration for productivity increases aims to reward operational efficiency gains achieved in the previous regulatory period. The periodical update (each 6 years) of O&M unitary costs based on the book value of O&M cost could penalise those companies achieving large productivity gains in the last years. To avoid this, the CNMC wanted to allow those companies to retain a share of the O&M costs reduction achieved in the last years. This incentive aimed to promote structural efficiency gains over temporary spending cuts since any cost reduction allows a stable extra revenue in the long-term.

Under initial CNMC proposal, DSOs were allowed to receive 20% of the O&M costs reduction achieved between 2020-2014 during each year of the next regulatory period (2021-2026).

The two incentive mechanisms explained above will not be implemented in the next regulatory period in Spain but have been included for information purposes and to provide EMRA with additional information on the efficiency incentives considered by EU NRAs.

Spanish RRM for the next regulatory period includes a penalization mechanism to promote the financial prudence of Natural Gas Distribution companies. In the end, the objective of efficiency incentive mechanisms is to make the distribution sector sustainable in the long-term promoting productivity gains. But if productivity gains are achieved at the expenses of the financial health of the company that will hamper distribution sector operations in the long-term.

To this aim, the CNMC introduces a penalization for those companies whose financial ratios exceed a threshold. The penalization could reach 1% of the total yearly remuneration of the company. Ratios under consideration are:

- Debt ratio.
- Financial interest payments over remuneration.
- Debt over fixed assets.
- Debt/EBITDA.
- Debt/operating margin.

In [Turkey](#), Efficiency analysis is based on some factors including change in number of city gate stations, towns, consumers and network length during a tariff period. These are set for tariff period and efficiency is calculated depending on the actualization.

Efficiency is calculated relative to DSO's category. There are a variety of distribution companies with different characteristics like in some industrial consumption is very high whereas in others household is the main source of consumption. Also, size of companies varies. Therefore, EMRA ranks companies in terms of consumption, number of consumers, etc. An efficiency score is calculated using DEA, companies with similar qualities were compared with each other, by looking into variable return of scale.

Each DSO must eliminate inefficiency in a ten-year period of time. Efficiency value is used to reduce the calculated OPEX of the DSOs, so that DSO shall be operated more efficiently.

Efficiency analyses also applied to CAPEX via investment costs. Average and standard deviation of each investment item is calculated depending on the yearly reports submitted by DSOs. Any cost below the standard deviation is rewarded by a bonus, and any cost above the standard deviation is not accepted as part of CAPEX.

3.5 Shrinkage (Losses)

Improving energy efficiency implies the minimization or at least a significant reduction of losses in Electricity Transmission and Distribution networks. This concerns gas as well, however losses in gas networks, often referred to as “shrinkage.” Shrinkage refers to gas, which is lost from the network, of which leakage is the main contributor. In other words, although specific definition of network losses varies across countries, it might be defined as the absolute difference between the volume of gas entering the system (metered or estimated at the point of entry) and the customer related amount of gas exiting the system (metered or estimated at the point of exit).

Leakage occurs in natural gas in case of loss during commissioning, breakage or explosion and in case of damage to the network and leakage from the connection points. In addition, there are measurement losses due to measuring equipment in the natural gas system, which poses a major problem for the operator. The permissible error limits of the measuring equipment used are 0.5-2%, however, when the errors during selling and buying are combined, these errors can add up to 4%.

Since it does not affect the user as it affects in Electricity Distribution and Natural Gas Distribution is considered as 100% continuous, regulatory measures against shrinkage (losses) are not as detailed. Some regulatory bodies even accept the costs as part of OPEX.

Table 3.23 indicates the regulate on and implementation related to natural gas losses in some European countries.

Table 3.23 – Methodology to compute network losses ²⁴¹

Country	Any method implemented	Methodology to compute network losses in gas networks	Regulation in force to decrease losses
Austria	No	-	
Belgium	No	-	
Croatia	Yes	Annual gas losses are determined as difference of the total amount of gas that is taken into the distribution system and the total amount of gas that is delivered from the distribution system to end customers. The total amount of gas that is delivered to the distribution system is calculated as the total measured amount of gas entering the distribution system for a period of 6 hours of June 30 last year to 6 pm on June 30 of the year in which annual gas losses are determined.	The methodology of determining the amount of tariff items for Natural Gas Distribution prescribing that gas losses are within OPEX which includes the cost of purchasing gas for covering allowed losses of gas amounting to a maximum of 3 % of the total amount of gas entering the distribution system.
Czechia	Yes	Yes, according to the Public Notice 195/2014.	-
Estonia	No	-	-
Finland	No	-	-

241 Source: CEER, (2018), 6th CEER Benchmarking Report on the Quality of Electricity and Gas Supply – 2016



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Country	Any method implemented	Methodology to compute network losses in gas networks	Regulation in force to decrease losses
France	Yes	The Gas Losses and Diverse Discrepancies (LDD) of GrDF equals to the difference between: - Quantity of energy injected by the TSOs at the entrance of the DSO (Removals from the TSOs); and - Quantity of energy metered by GrDF to its customers (metered energy to the customers). Real GrDF LDD = Σ (Removals from the TSOs – metered energy to the customers) To estimate this, the following is used: - The daily allocations = energy breakdown among customers supplied by GrDF of “Removals from the TSOs – LDD bought by GrDF” in which “LDD bought by GrDF” is the quantity of energy bought every day by GrDF to compensate its average LDD (2.4 TWh per year); and - Distribution spread account (DSA): calculated after each reading, they equal for each customer to the difference between its quantity of metered energy and the quantity of energy which was allocated to him/her during the same period. DSA = metered quantities – allocated quantities Then: Σ DSA = Σ (metered quantities – allocated quantities) = Σ metered quantities – Σ (Removals from the TSOs – LDD bought by GrDF) = Σ (metered quantities – Removals from the TSOs) + Σ LDD bought by GrDF = Σ LDD bought by GrDF – Real GrDF LDD and Real GrDF LDD = Σ LDD bought by GrDF – Σ DSA Example: in 2013, the LDD bought by GrDF equaled 2,414 GWh and Σ DSA -656 GWh. It then came Real GrDF LDD = 3,070 GWh.	Ministerial order on multi-fluids of 05/03/2014 (article 6) aims at reducing the vented gas in planned works on the transmission network. Use of reduction venting technics is mandatory if the estimation of losses reaches 40 t CH₄. If the utilisation of such mitigation measure is not possible, the transporter has to justify it.
Germany	No	-	



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Country	Any method implemented	Methodology to compute network losses in gas networks	Regulation in force to decrease losses
Hungary	Yes	High pressure system: the TSO measures continuously the entry and exit volumes. The metering differences and the transmission losses are defined in a balance sheet form on a daily basis, taking into account the transmission system operator's own consumption and change in its line pack, as well as the input to and off-take from the system. Medium and LP system: the losses are computed with the help of an expert model which defines several subcategories of loss.	The accepted loss level is determined by the NRA and its level is under the actual loss level to incentivise the system operators to cut their losses.
Ireland	Yes	GNI calculates gas shrinkage losses on a monthly basis across the network. Shrinkage gas includes both fuel gas usage in compressor stations and water bath heaters on the transmission network as well as UAG.	Incentive to reduce this.
Italy	Yes	High pressure system: Natural Gas Transmission network codes define losses (measured, calculated and estimated). Balancing equation takes into consideration losses. Tariff regulations recognise average losses.	
Latvia	Yes	High pressure system: Natural Gas Transmission network codes define losses (measured, calculated and estimated). Balancing equation takes into consideration losses. Tariff regulations recognise average losses.	Every year JSC "Latvijas Gaze" elaborates and submits to the Public Utility Commission the plan of decrease of natural gas losses for the next year and the report on performance in the previous year in reference to the plan.
Lithuania	N/A	-	NCC confirmed the methodology for price calculation which indicates that technical losses projected for the regulatory period (5 years) must be proved by operators when setting the prices-cap. They should also prove any changes in technical losses each year when adjusting price-cap.
Netherlands	No	-	-
Portugal	No	-	-
Slovenia	No	-	There is a regulative limit of 2%.
Spain	Yes	Yearly balancing among entries and exits to the transport and distribution grids.	TSO and DSO have an economic incentive to reduce losses, as they can keep half of the value of the gas if the losses are less than the standard losses recognised by the regulation: Standard losses Distribution grids (≤ 4 bar) 1 % Distribution grids (4 to 16 bar) real losses up to a maximum of 0.39 % Transport grids (> 16 bar) 0.2%

Country	Any method implemented	Methodology to compute network losses in gas networks	Regulation in force to decrease losses
Sweden	Yes	Annual gas losses are determined as difference of the total amount of gas that is taken into the distribution system and the total amount of gas that is delivered from the distribution system to end customers	-

In **Italy** these losses are charged to trading companies as a conventional factor even though it is the responsibility of the DSOs.

In fact, among the obligations of the service relating to the gas continuity that the distributor must ensure as a public service operator is the search for leaks. Every year it must carry out a research on the low pressure and medium pressure network, completing the control of the entire network in respectively 3 years or 2 years. In the event of a leakage, the distributor, with timing dependent on the concentration of gas and other boundary conditions, is obliged to eliminate the gas loss.

Annually, the distributor is obliged to communicate the research data of the leak detection and elimination process. In this regard, the authority carries out specific inspections.

In **UK**²⁴², shrinkage is the dominant element of DSOs business carbon footprint and accounts for more than 0.75% of UK's greenhouse gas emissions. Shrinkage is comprised of leakage from pipelines (approximately 95%), theft from the DSO network (approximately 3%) and own-use gas (approximately 2%). DSOs must meet annual leakage targets. There are two incentives for reducing shrinkage (leakage).

- The shrinkage incentive is an annual rolling incentive based on the reference gas commodity price. In 2018-19 the DSOs earned £3.1 million through the shrinkage incentive.
- The Environmental Emissions Incentive (EEI). The EEI incentivizes DSOs to further reduce environmental emissions below their leakage targets and rewards them with a financial value based on the government's non-traded carbon value. DSOs continued to reduce their environmental emissions in 2018-19, leading to an incentive revenue of £18.5 million through the EEI.

The price of gas used to calculate the cost of shrinkage is considered non-controllable pass-through costs of TOTEX. However, the volume of gas lost through shrinkage is within DSOs' control and is therefore not subject to pass-through.

In RIIO-2 A refined financial reward and penalty output delivery incentive (ODI) is proposed by Ofgem to incentivise DSOs to continue to take action to reduce shrinkage on their networks. Also, a reputational ODI is introduced to encourage strong, ongoing reduction in overall shrinkage.

In **Spain**²⁴³, the Revenue Requirement Methodology in use (2014-2020) and the one for the next regulatory period (2021-2026) include an incentive for distribution network losses reduction. Spanish regulation sets reference losses percentages (allowed losses) for each pressure level and those DSO achieving lower losses than the threshold can keep half the gas value. It is responsibility of the Gas System Operator (Enagás) to calculate the gas balance of each distribution company in order to obtain the losses balances.

Spanish regulatory approach to distribution losses was established by the Order IET/2446/2013. This order contains the methodology to calculate the losses balance of each distribution company, the allowed losses parameters and how to allocate any negative losses balance (actual losses - allowed losses) between DSO's revenues and end-users.

Allowed losses charged to end-users are set at national level and depend only on the pressure level of the supply point:

- Distribution losses at pressure levels ≤ 4 bar: 1%

242 Source: Ofgem, RIIO-GD1 Natural Gas Distribution Price Control – Regulatory Instructions and Guidance: Version 5.0, 2018.

243 Source: CEER, (2018), 6th CEER Benchmarking Report on the Quality of Electricity and Gas Supply – 2016

- Distribution losses at pressure levels ≤ 4 bar supplied from satellite plants: 2%
- Distribution losses at pressure levels > 4 bar: 0.39%
- Distribution losses at pressure levels > 16 bar: no allowed losses unless the operator proves it.

Actual losses are calculated for each DSO as the balance between the entries in its distribution networks and the consumption at the supply points.

Based on the above parameters, DSOs send yearly to the Gas System Operator an annual report with the actual losses, the allowed losses, the resulting loss balance and the allocation of the losses balance among the users (suppliers).

The DSO with an aggregate positive annual losses balance (higher losses than allowed) shall pay its network users (suppliers) with positive loss balance the value of the losses balance at reference price (operational gas price). Users with negative losses balance shall pay the difference to the distribution company.

Those DSOs with an aggregate negative balance (lower losses than allowed) value its losses balance at the reference price (reference price for operational gas) and pay half of the amount to suppliers proportionally to the MWh. The DSO retains half of the amount collected from negative losses balances.

DSOs revenues from losses settlement with negative balance or costs due to higher losses are included as a specific component of the new revenue methodology (CNMC, 2020). This component is considered as an incentive/penalization for distribution losses reduction.

For information purposes, below the losses balance for 2018 of the 5 distribution companies of Spain are presented.

In 2018, the actual losses in the distribution networks accounted for 1,192 GWh what represents 0.45% of total consumption. it can be seen how the % of losses differs considerable among DSOs. While Madrileña Red de Gas reported in 2018 1.8% of actual distribution losses, Nedgia (70% of the market) only reported 0.49%.

Table 3.24 – Spain distribution network actual losses by DSO (kWh)²⁴⁴

Group Distribution	2013	2014	2015	2016	2017	2018
Nortegas Energia Distribucion S.A.U	54,624,750	29,113,808	32,645,130	128,420,697	7,384,529	96,239,466
Madrilena Red de Gas, S.A	177,746,023	150,808,485	86,306,996	326,832,736	192,097,045	199,109,522
Nedgia Catalunya S.A	1,245,421,707	645,132,857	86,306,996	326,832,736	192,097,045	199,109,522
Distribucion y Comercialization de Gas Extremadura S.A	7,216,977	1,150,099	1,662,101	1,103,962	-350,761	935,113,072
Redexis Gas Distribucion S.A	33,494,600	-175,412,909	-117,879,714	-95,094,775	-52,563,772	1,119,995
Gas Directo S.A	4,107,546	-7,400,723				-39,667,507
Total Mermas Reales	1,522,611,603	643,391,617	1,112,274,631	2,409,491,499	1,193,774,783	1,191,914,548

Table 3.25 – Spanish DSOs actual losses as % of total consumption²⁴⁵

244 Source: Enagas (2018) Losses balances report

245 Source: Enagas (2018) Losses balances report



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Group Distribution	2013	2014	2015	2016	2017	2018
Nortegas Energia Distribucion S.A.U	0.10%	0.11%	0.12%	0.48%	0.03%	0.31%
Madriena Red de Gas, S.A	1.70%	0.96%	0.96%	3.32%	2.00%	1.80%
Nedgia Catalunya S.A	0.70%	0.40%	0.66%	1.17%	0.56%	0.49%
Distribucion y Commercialization de Gas Extremadura S.A	0.60%	0.07%	0.09%	0.06%	-0.02%	0.05%
Redexis Gas Distribucion S.A	0.30%	0.00%	-0.42%	-0.37%	-0.17%	-0.12%
Gas Directo S.A	1.10%	-2.01%				
Total Merzas Reales	0.60%	0.00%	0.48%	1.01%	0.46%	0.45%

Table 3.26 – DSOs' losses balances (kWh)²⁴⁶

Group Distribution	2013	2014	2015	2016	2017	2018
Nortegas Energia Distribucion S.A.U	-115,035,337	-110,317,067	-112,984,442	-16,883,221	-145,344,592	-62,996,842
Madriena Red de Gas, S.A	80,945,691	67,464,683	493,599	232,371,335	100,568,873	93,330,202
Nedgia Catalunya S.A	538,734,605	23,762,432	468,550,192	1,393,908,816	364,741,050	205,934,015
Distribucion y Commercialization de Gas Extremadura S.A	-371,499	-7,963,981	-7,765,068	-9,016,678	-10,732,075	-10,343,406
Redexis Gas Distribucion S.A	-21,192,191	-232,648,143	-181,635,768	-164,617,532	-126,655,776	-119,465,452
Gas Directo S.A	2,245,606	-9,384,569				
Total Merzas Reales	0.60%	0.00%	0.48%	1.01%	0.46%	0.45%

Note: Negative (Lower losses than allowed level) Positive (higher losses than allowed level)

In [Turkey](#), at the moment, since the lines are newer, the leaks on the line can be kept below a certain level, but since the investment period is still progress, the amount of gas thrown into the air are greater than the leakage during commissioning or measurement.

Leakage from measuring equipment in the sense of technical loss is expected to be 1-2% in optimum, but with the new network and good operation, this rate can be reduced to below 1% or, it could go up to 4% depending on operating performance. Limiting this loss to a certain level by additional regulation will ensure that future losses are kept at a certain point.

Unlike the practice in EU technical losses (leakage) in Turkey is completely operator's liability, so the transmission or distribution company bears the financial and legal responsibility of the gas lost in the network.

In Europe, in some countries, these losses are charged to trading companies, and in some countries are directly charged the customer. Trading companies in Turkey, or the user does not have such a responsibility, it is the responsibility of the DSOs.

3.6 Tariff Determination for Consumers

Tariff determination for consumers is another responsibility of the NRAs, whereas in some EU countries regulatory body and DSOs determine tariffs in collaboration. Table 3.27 provides information about the responsible parties related to natural gas tariff determination.

Table 3.27 – Determination of consumer tariffs in EU countries²⁴⁷

Country	DSO	Government	The NRA	Main Responsible
Austria	Providing opinions	Providing opinions	Sets principles, methodology, values and approves tariffs	NRA
Belgium	Main responsibility	Defines main principles	Approves DSO proposals	NRA/DSO
Croatia			Sets tariff structure after public consultation	NRA
Czechia			Main Responsibility	NRA
Denmark	Main Responsibility	Sets rules	Set rules and approved tariff	NRA/DSO
Estonia	Main Responsibility	Defines main principles		NRA/DSO
Finland	Sets the tariff levels			NRA/DSO
France		Defines main principles	sets rules and monitors ex-post	NRA
Germany	Implements	Issues tariff structure rules	Main Responsibility	NRA
Greece			The tariff is defined by the maximum allowed revenues	NRA
Hungary		Defines main principles	Main Responsibility	NRA
Ireland	Calculates for NRA Approval		Main Responsibility	NRA
Italy	Provides the regulator with data on its cost and quality levels	Defines main principles	Issues tariff structure	NRA
Lithuania	Proposes after consultation	Defines main principles	Sets principles, methodology, values and approves tariffs	NRA
Luxembourg			Main Responsibility	NRA
Poland	Proposes tariff structure to NRA	Sets general rules	Takes decision on tariff structure based on DSO proposal	NRA/DSO
Portugal		Defines main principles	Main Responsibility	NRA
Slovakia	Calculates for NRA Approval	Defines main principles	Sets principles, methodology, values and approves tariffs	NRA/DSO
Slovenia		Issues primary law	Sets a general act with methodologies and charges	NRA
Spain			Sets tariff structure	NRA
Sweden	Decides on the tariff structure		May take decisions on tariff structures in individual cases, according to non-discriminating requirements	NRA/DSO
Netherlands	Proposes tariffs to the NRA	Sets the principal of the tariff structure	Makes final decision on proposed tariffs	NRA/DSO
UK	Proposes distribution tariffs to the NRA which is not linked to end users whose charging structures can vary ²⁴⁸ .		Takes decision on tariff structure based on DSO proposal	NRA/DSO

Calculation of the consumer tariffs depends on the methodology that includes the decision of which charges to include consumer

²⁴⁷ Source: https://ec.europa.eu/energy/sites/ener/files/documents/20150313%20Tariff%20report%20final_revREF-E.PDF

²⁴⁸ Regulation on retail tariffs (i.e price caps) were removed in 2002. Later in 2017, Ofgem reintroduced price regulation on retail tariffs in the form of price cap for safeguard tariffs under a separate regulatory regime, and a further price cap on standard variable tariffs and default tariffs in 2018-2019.

tariffs. In addition, Table 3.28 shows charges applied within the scope of distribution tariffs in EU countries.

Table 3.28 – Charges that are a part of consumer tariffs in EU countries²⁴⁹

Country	Consumer Group	Fixed Charge	Capacity Charge	Energy Charge	Other
Austria	Household	Yes, depending of annual consume	Yes, depending of annual consume	Yes	No
	Industrial	No	Yes	Yes	No
Croatia	Household	Yes	No	Yes	No
	Industrial	Yes	No	Yes	No
Czechia	Household	Yes	No	Yes	No
	Industrial	Yes	No	Yes	No
Denmark	Household	No	No	Yes	No
	Industrial	No	No	Yes	No
Estonia	Household	No	No	Yes	No
	Industrial	No	No	Yes	No
Finland	Household	Yes, varies depend- ing on DSO	No	Yes, varies depending on DSO	No
	Industrial	Yes, varies depend- ing on DSO	Yes, varies depending on DSO	Yes, varies depending on DSO	Yes, varies depending on DSO
France	Household	Yes	No	Yes	No
	Industrial	Yes	Yes	Yes	No
Germany	Household	Yes, if annual con- sumption up to 1.5mkWh and a maximum exit load of 500 kwh/h	Yes, if Annual consump- tion above 1.5m kWh/a	Yes	Yes, Metering
	Industrial	No	Yes	Yes	Yes, Metering
Hungary	Household	Yes	No	Yes	Yes, Metering
	Industrial	No	Yes	Yes	Yes, Metering
Ireland	Household	No	Yes	Yes	No
	Industrial	No	Yes	Yes	No
Italy	Household	Yes	No	Yes	No
	Industrial	Yes	No	Yes	No
Lithuania	Household	No	No	Yes	Yes
	Industrial	No	No	Yes	No
Luxem- bourg	Household	No	No	Yes	Yes, Metering
	Industrial	No	Yes	Yes	Yes, Metering
Poland	Household	No	Yes	Yes	No
	Industrial	No	Yes	Yes	No
Portugal	Household	Yes	No	Yes	No
	Industrial	Yes	Yes	Yes	No
Slovakia	Household	Yes	No	Yes	No
	Industrial	Yes	Yes	Yes	No
Slovenia	Household	Yes	No	Yes	Yes, Metering
	Industrial	Yes	Yes	Yes	Yes, Metering



This project is funded by the European Union



Country	Consumer Group	Fixed Charge	Capacity Charge	Energy Charge	Other
Spain	Household	Yes	No	Yes	No
	Industrial	No	Yes	Yes	No
Sweden	Household	Yes	No	Yes	No
	Industrial	Yes	No	Yes	No
Netherlands	Household	Yes	Yes	No	Yes, Metering
	Industrial	Yes	Yes	No	No
UK	Household	No	Yes	Yes	Yes, Metering
	Industrial	No	Yes	Yes	Yes, Metering

Gas prices for households and industry are indicated in the following figure. Household consumers in 2018 witnessed the first increase in the final price since 2015, reaching 2016 levels again. On the other hand, the industrial gas segment saw the first sharp upward change in prices reversing the downward trend since 2014.

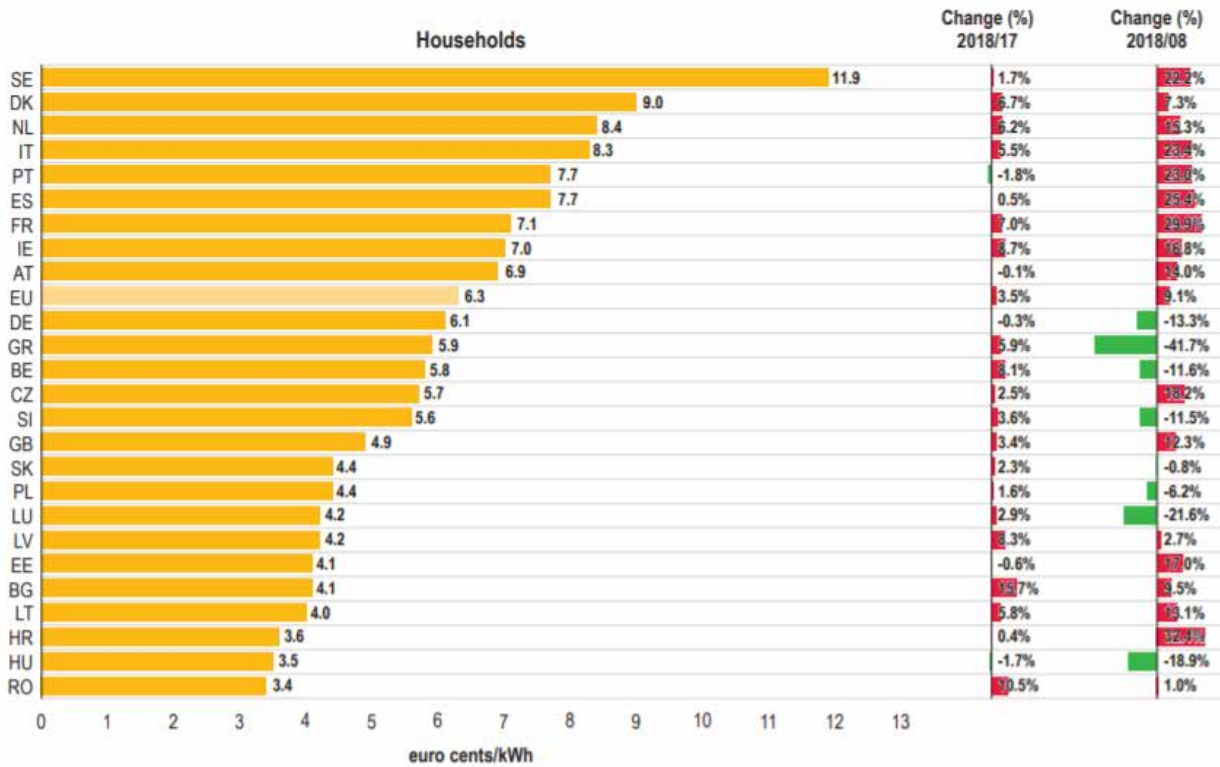


Figure 3.27 – Final gas prices for household consumers in the EU MSs in 2018 (euro cents/kWh) and changes compared to 2017 and 2008 (%)²⁵⁰

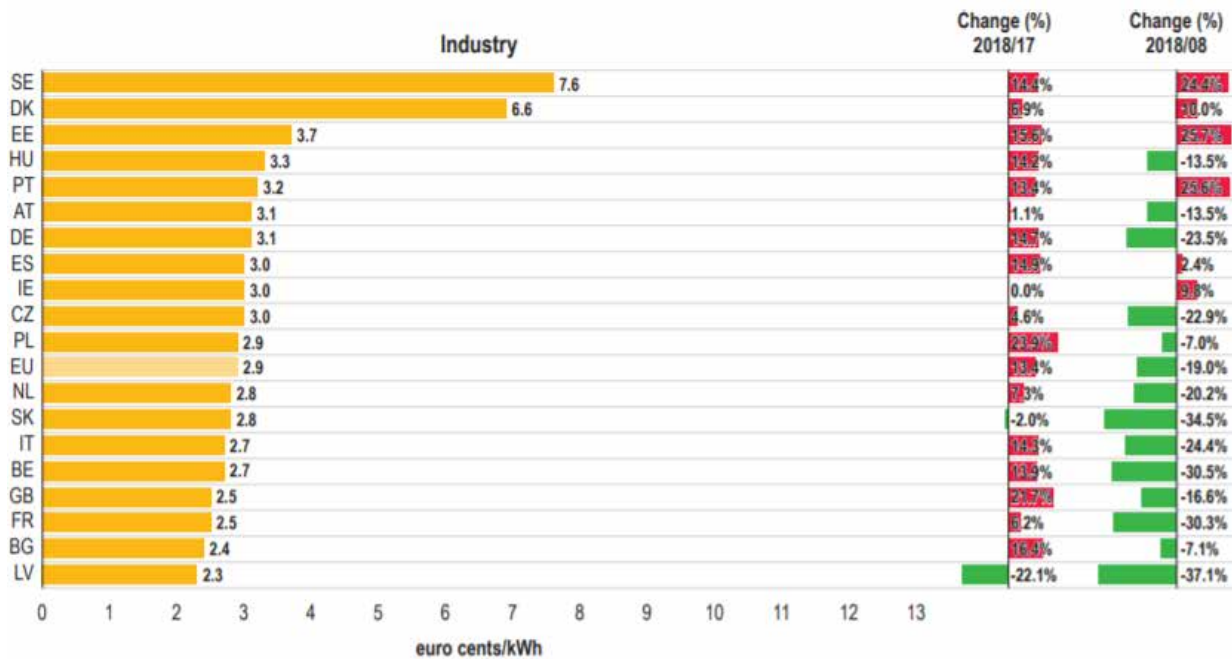


Figure 3.28 – Final gas prices for industrial consumers in the EU MSs in 2018 (euro cents/kWh) and changes compared to 2017 and 2008 (%)²⁵¹

Figure 3.29 shows the breakdown of the gas prices, based on the standard incumbent gas offer available to households in each capital city at the end of 2018, where data were available and where a gas retail market exists. It illustrates that the composition of the final gas bill for household consumers continued to vary greatly across MSs. For example, the energy component accounted for 70% of the final bill in UK, while it represented only 27% of the final bill in Finland.

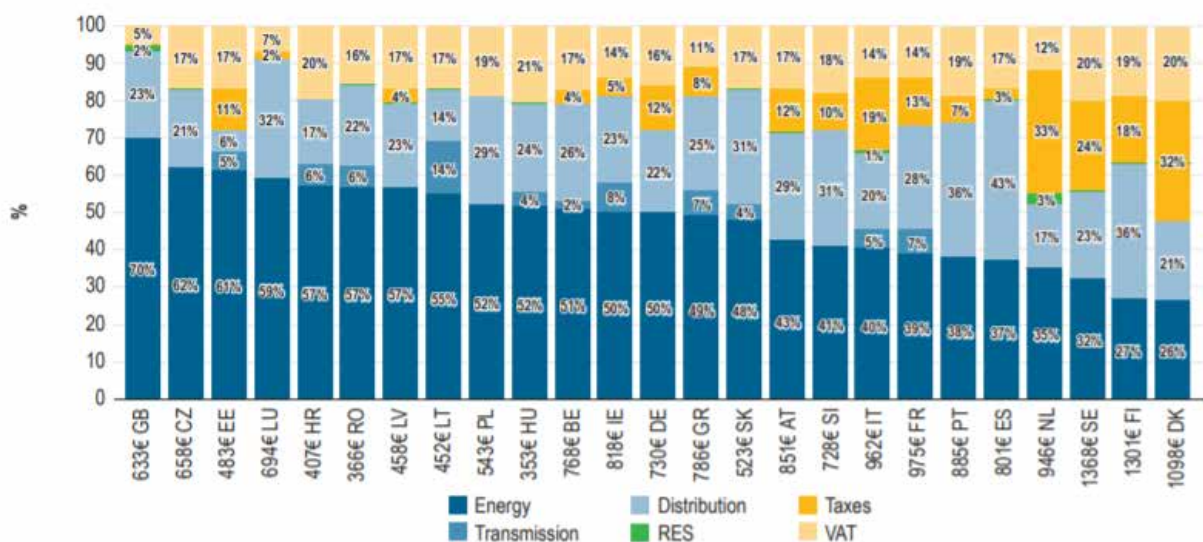


Figure 3.29 – Breakdown of incumbents' standard electricity offers for households in capital cities – NOV/DEC 2018²⁵²

²⁵¹ Source: ACER/CEER, (October 2019), Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2018 Electricity and Gas Retail Markets Volume

²⁵² Source: ACER/CEER, (October 2019), Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2018 Electricity and Gas Retail Markets Volume

3.6.1 Italy²⁵³

The distribution tariff is itemized separately to end-users. Basically, the tariff paid by the consumers consists of a fixed component and a variable component.

It covers the costs for the Natural Gas Distribution service to the final customer, as well as the measurement service, which consists of the installation and maintenance functions of the meters, the detection, recording of measurement data and commercial activities.

The fixed part is defined for each tariff area. From 2015 onwards, fixed component of the tariff has been split in three categories, depending on the meter type.

There are six areas in the national territory. The variable part is defined for each tariff area and varies according to the amount of gas consumed, and is differentiated by eight consumption classes (that is, based on consumed volume and not based on categories such as 'residential', 'industrial', etc.): there is no distinction between residential, industrial and other consumers.

Tariffs are published as an Annex to the Regulator's Resolutions and are publicly available on the organisation's internet website.

In addition to the fixed and variable components of the tariff paid by customers, the tariff consists of other components aimed at financing:

- Energy efficiency interventions and RES development (RE),
- Quality of services (RS),
- The social tariff system (GS),
- Coverage of any adjustments (UG1);
- Compensation for retail costs (UG2)

The component relating to the distribution, measurement and relative marketing service represents approximately 14.5% of the gas bill.

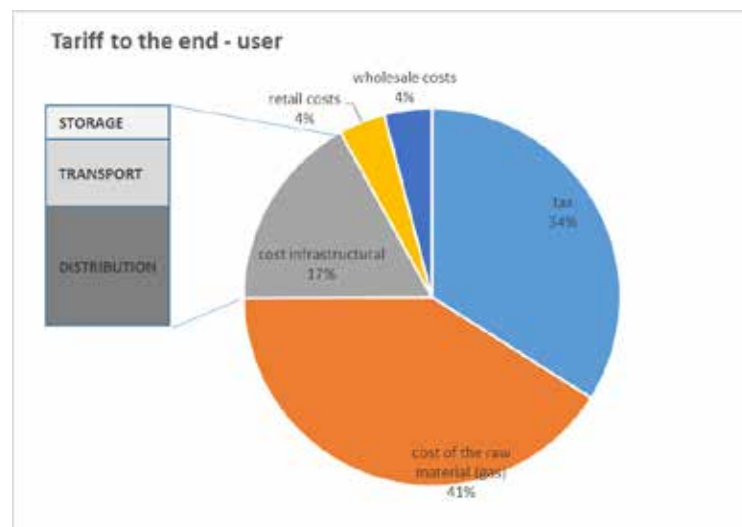


Figure 3.30 – Gas bill to end user

In December 2016, the Regulation of the tariffs for Natural Gas Distribution and metering services (RTDG) was approved for

three-years period 2017-2019, which introduced new provisions on recognised operational costs, the determination of the tariff component to cover the costs of the metrological checks, recognition of the costs of remote metering/remote management systems and concentrators and definition of the standard costs of electronic metering units. And in December 2018, the tariffs for 2019 were approved. In line with the approach adopted in previous years, the relevant volumes of gas used in the determination of the variable rates of the tariffs were determined as the moving average of the data relating to the gas distributed over the last four years.

In April 2018, the Authority illustrated the guidelines regarding tariff issues relating to the coverage of the infrastructure costs necessary for the distribution of LNG through isolated networks.²⁵⁴

Vulnerable Consumers: Domestic customers, non-domestic customers with consumption below 50,000 S(m3)/year and end customers that own utilities related to public service activities are defined as vulnerable (i.e. utilities owned by a public or private structure that carries out a recognised assistance activity).

On the other hand, concerning the perimeter of the concerned customers, the following categories are entitled to obtain last resort supply services:

- disconnectable end customers, that is domestic customers, including multioccupancy buildings with consumption that is not over 200,000 S(m3) per year, and other customers with consumptions below 50,000 S(m3) per year, who have no supplier, for reasons that are beyond their will;
- the non-disconnectable end customers, or the utilities related to public service activities that, for whatever reason, do not have a supplier.

The entity providing the last resort service is identified through a public procedure, managed by the Single Buyer based on the rules approved by the Authority.

In the gas sector, the default service is also present, which has the purpose of guaranteeing the balancing of the distribution network and is destined to customers who are not entitled to benefit from the FUI service, since they do not fall within the types of customers mentioned above. The default service was fully launched in the thermal years 2013-2014.

A social protection mechanism has also been active since 2009, designed specifically for domestic customers who are in situations of economic hardship or serious health conditions, by which they receive a gas bonus. To cover the fees deriving from the application of the gas bonus, the Authority has created the GS component for non-domestic customers, within the compulsory tariff for the distribution services and natural gas metering. The value of the component is defined at the same time as the tariff update. The funds from the State Budget are added to the funds collected from the customers.

519,375 customers had benefited from the gas bonus through economic hardship at 31 December 2018, with an increase of 3.9% compared to the previous year; after all the controls related to the eligibility requirements by the Municipalities, their requests for the subsidy were accepted after verification by the Natural Gas Distribution companies. Over 1.7 million families benefited from the subsidy, at least once, since the activation of the mechanism.²⁵⁵

3.6.2 UK²⁵⁶

There are elements of the final price that are attributable to the regulated aspects of the market, in particular distribution, and transmission charges, which continue to be price controlled. There are also a number of other costs that influence how suppliers set retail gas prices, including wholesale energy costs and the costs of the UK government's environmental and social policies such

²⁵⁴ Source: ARERA, (31 July 2019), Annual report to the agency for cooperation between European energy regulators and the European Commission on the business carried out and the tasks of the Italian regulatory authority for energy, networks and the environment.

²⁵⁵ Source: ARERA, (31 July 2019), Annual report to the agency for cooperation between European energy regulators and the European Commission on the business carried out and the tasks of the Italian regulatory authority for energy, networks and the environment

²⁵⁶ Source: Ofgem, RIIO-GD1 Annual Report 2015-16, 2017. https://www.ofgem.gov.uk/system/files/docs/2017/02/riio-gd1_annual_report_2015-16_0.pdf

as the Renewable Obligation and the Warm Home Discount (WHD), which can vary over time.

Suppliers face a range of costs that influence how they set retail natural gas prices. These costs can vary within and between years, and include wholesale energy costs, the costs of UK government environmental and social policies, and transmission and distribution costs. Ofgem reintroduced price regulation on retail tariffs in the form of price cap for safeguard tariffs under a separate regulatory regime, and a further price cap on standard variable tariffs and default tariffs. The default price cap on standard variable and default energy tariffs was introduced in January 2019, which is updated at every six-months and will be in place up to 2023. The cap is applied on the unit rates which is the price set for each kWh of energy used plus the standing charge (p/day).

The following figure shows the average gas bill components as of January 2020.²⁵⁷

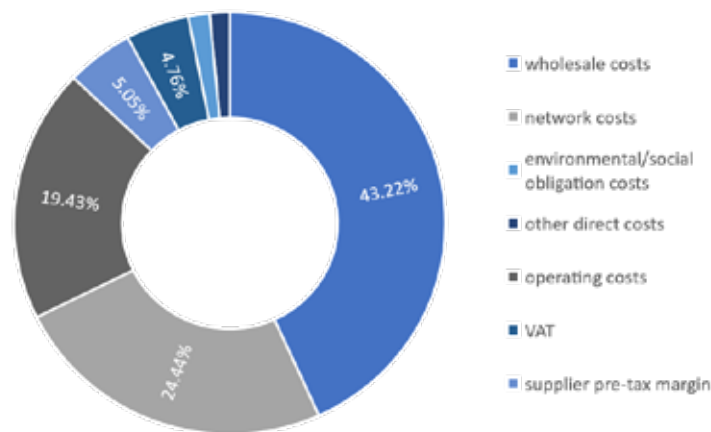


Figure 3.31 – Components of consumer tariffs

3.6.3 Germany²⁵⁸

In principle, the regulatory body allows for two different tariff systems to be used for cost unit accounting. Of those two systems, entry and exit capacity charges are the norm and are calculated using the entry-exit access model. No entry tariffs are charged in this case. A few regional distribution networks use the entry-exit tariff system. The network charge system for gas networks thus differs significantly from the system for electricity networks, which currently has neither entry tariffs nor capacity charges.

The exit tariffs charged by all other DSOs comprise two components, a capacity price, and a commodity price. The so-called network participation model is used very often to form these prices. This entails dividing the distribution network and its associated costs into two parts, a local transport network, and a local distribution network. A mathematical function is used to determine the share of the local distribution network apportionable to a customer with given consumption. Customers with lower consumption require a larger share of the local distribution network, while it is more probable that customers with higher consumption are connected to local transport capacity.

This results in a degression of the specific network charge at higher levels of consumption. The procedure is carried out separately for the capacity price and the commodity price. For non-interval-metered customers (all household customers and many small commercial customers) an average reserve capacity is used, so the capacity component is represented by a base price.

Other systems, apart from the network participation model, are also used to calculate tariffs. In the main, these systems yield comparable results with respect to tariff degression and likewise do not depend on an individual customer's specific connection situation.

²⁵⁷ Source: Ofgem, Retail gas prices, Infographic, January 2020.

²⁵⁸ Source: Bundesnetzagentur, Monitoring report 2018.

The gas network charges have seen only minor fluctuations during the recent years, with household customers currently paying on average approximately 1.49 €/kWh (around 22% of the overall gas price). As of 1 April 2018, retail prices for gas has again fallen slightly compared to 1 April 2017.

The average price for household customers across all three contract categories (i.e. default supply contract, non-default contract with the default supplier, and contract with a supplier other than the local default supplier) decreased by 1.3% to 6.07 €/kWh (including VAT) as of 1 April 2018 (1 April 2017: 6.15 €/kWh).

The gas price for default supply dropped 1.3% to 6.64 €/kWh (including VAT) as of 1 April 2018. The gas price for non-default contracts with the default supplier fell only slightly by 0.2% and was 6.06 €/kWh (including VAT) as of 1 April 2018. Likewise, the gas price for a contract with a supplier other than the local default supplier fell by 1.2% to 5.71 €/kWh (including VAT) as of 1 April 2018. Gas prices for consumers under contract with a supplier other than the local default supplier thus reached the lowest level they have been since the first survey on 1 April 2008.

With regard to the main component of the gas price for household customers in band II, which is the price component that can be controlled by the supplier: “energy procurement, supply and margin”, it is notable that in 2018 this price component for customers with a supplier other than the local default supplier hit the lowest level since the survey started of 2.66 €/kWh. Moreover, the price component “energy procurement, supply and margin” for default supply customers fell to 3.29 €/kWh as of 1 April 2018. This price component was steady at 3.01 €/kWh as at 1 April 2018 for customers with a non-default contract with their default supplier

Customers on default tariffs can make savings by switching tariff or supplier. The average household customer with gas consumption of 23,250 kWh could save an average of €135 a year as at 1 April 2018 by changing the contract. The average potential saving for the year through changing supplier was €216.

In addition, special bonuses offered by gas suppliers, including one-off bonus payments, are an added incentive for customers to switch supplier. These one-off bonus payments amount to an average of €70. Changes in network charges for household and business consumers are given in figure below.

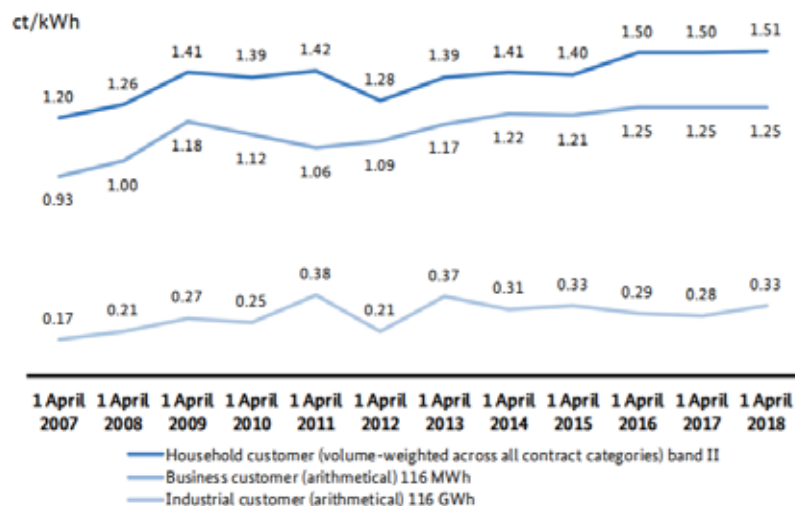


Figure 3.32 – Development of network tariffs for gas, including charges for metering €/kWh²⁵⁹

The reasons for the regional differences in network charges are manifold. Key factors are lower levels of utilization of the networks and the average age of the networks in the respective regions.

The modernization of networks in the new federal states following German reunification often resulted in networks which, from 259 Source: Bundesnetzagentur, Monitoring Report 2018.

today's perspective, are oversized. In some cases, these networks are now insufficiently utilized, while still incurring costs in line with their size.

Another cost driver is population density: in sparsely populated regions, the network costs have to be spread over a small number of network users, whereas the opposite is the case in densely populated regions. The age structure of individual networks also has an impact on tariffs.

ct/kWh

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Saxony-Anhalt	1.52	0.96	2.40	27
Saarland	1.42	0.95	2.09	19
Mecklenburg-Western P.	1.39	0.83	2.10	18
Saxony	1.34	0.55	1.98	37
Baden-Württemberg	1.30	0.80	2.60	100
Brandenburg	1.25	0.79	3.51	28
North Rhine-Westphalia	1.21	0.37	2.82	122
Thuringia	1.19	0.68	1.84	29
Bavaria	1.16	0.68	2.62	105
Hesse	1.13	0.81	1.59	44
Rhineland-Palatinate	1.10	0.62	2.01	35
Schleswig-Holstein	1.07	0.75	2.03	40
Berlin	0.98	0.98	0.98	1
Lower Saxony	0.98	0.48	1.67	61
Hamburg	0.95	0.95	0.95	1
Bremen	0.92	0.87	1.04	2

* The number of meter points belonging to the operators in the respective network areas was used as the basis for weighting.

Figure 3.33 – Net network charges for business customers in Germany for 2018

More recently built networks have higher residual values, which increases specific capital costs and in turn leads to higher tariffs. As a result of their greater depreciation, older networks have lower residual values and therefore lower capital costs, thus in turn, leading to lower tariffs.

However, with advancing age, networks incur higher costs for maintenance and repair, which have a corrective effect that tends to equalize the tariffs.

Methodology for determining revenue requirements for each industrial grade is as follows²⁶⁰:

Local network operators may allow individual network fees to specified final consumers to avoid the construction of a direct pipeline, which could potentially lead to additional, potentially economically inefficient pipeline infrastructures. By reducing the possible financial advantage resulting from the construction of the direct pipeline by a reduction of the fee to be paid compared to the regular network fee, there is an incentive to refrain from building direct pipelines. Beside industrial consumers, this can also be offered to downstream network operators if they would otherwise implement direct line construction, i.e. the construction of their own connection line to the usually upstream network level.

²⁶⁰ https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Netzentgelte/Gas/Sonderentgelte/sonderentgelte-node.html

Subject to the regulatory authority's review of the individual case, offering an individual network fee by the local network operator is considered as admissible if

- direct line construction is predominantly likely
- the special charge is appropriate and
- the principles of transparency and non-discrimination have been respected.

To prove compliance with the criteria, an investment calculation must be carried out in accordance with a guideline issued by the Federal Network Agency, which distinguishes between end consumer groups of industrial customers and downstream distribution system operators on the basis of different duration and return expectations.

The amount of the individual network fee is calculated, in accordance with the provisions of this guideline, on the basis of the annual costs for the construction and operation of a direct pipeline, including the upstream grid costs. A special charge that is lower than these costs is not appropriate

Redeeming in Germany's Natural Gas Distribution tariffs

At the level of transmission, network charges are based on capacity fees.

Several capacity products exist. Firm entry and exit capacities are auctioned at border and market area points on an annual, monthly, quarterly and daily basis. Interruptible capacities and entry and exit capacities to final consumers, storage facilities and generators are marketed according to principle "first-come-first-served".

If transport customers book too much capacity, they can return it to the network operator. However, they are only reimbursed the amount that the network operator achieves by remarketing capacities, but not more than the regulated fee. Otherwise, a transport customer can independently market unneeded capacities to a third party via a platform without the consent of the network operator. This is called secondary trading.

In order to actually use booked capacities, a nomination by the respective transport customer is necessary. In case this does not proceed in time, the network operator can still market the capacity at short notice. Nonetheless, the fee entitlement of the network operator for the original capacity booking remains unchanged.

In the local distribution network, billing is based on commodity price and capacity charge, similar to the electricity network.

3.6.4 Portugal

As far as infrastructure access tariffs are concerned, access is paid for by all the natural gas consumers, so network access tariffs are included in the prices paid by natural gas consumers, both in market prices and in transitional tariffs for end-customers. Tariff evolution for high-pressure infrastructure, the use of networks and the global use of the system for the gas year 2018-2019, by activity are given in table below.²⁶¹

Table 3.29 – Consumer prices for Portugal

Tariffs per activity	Average price 2017-2018 (EUR/MWh)*	Average price 2018-2019 (EUR/MWh)	Change
Use of the LNG Terminal (Sines)	1.66	0.88	-46.7%
Use of the Underground Storage	12.13	8.12	-33.0%
Use of the Transmission Network	1.92	1.57	-18.3%
Use of the Distribution Network	9.17	8.37	-8.8%
Global Use of the System	0.51	0.08	-84.9%

* Application of 2017-2018 tariffs to the demand forecasted for 2018-2019

Table 3.30 – Tariff evolution for network access by type of client at each pressure level²⁶²

Network access tariffs per pressure level	Average price 2017-2018 (EUR/MWh)*	Average price 2018-2019 (EUR/MWh)	Change
Power plants	2.67	1.84	-31.1%
HP customer	1.66	0.91	-45.1%
MP customer	3.66	3.07	-16.3%
LP customer with an annual consumption above 10,000 m3	15.05	13.84	-8.1%
LP customer with an annual consumption lower than or equal to 10,000 m3	32.51	32.30	-0.6%

* Application of 2017-2018 tariffs to the demand forecasted for 2018-2019

The connection of a facility to the natural gas network creates costs that depend on the type of the facility to be connected, the network itself, the pressure level, the distance, technical requirements, route, etc.

The natural gas RRC sets out the regulatory framework that applies to network connection, including charges. One of the main elements of this framework is the determination of the costs that petitioners have to meet, bearing in mind that the difference between total investment costs and costs met by petitioners is paid by consumers through use of the network tariffs.

The following figures show the disaggregation and the structure of the average price of network access tariffs by the various tariffs which compose them, for each pressure level. The average price of the high-pressure access tariff does not include power plants.

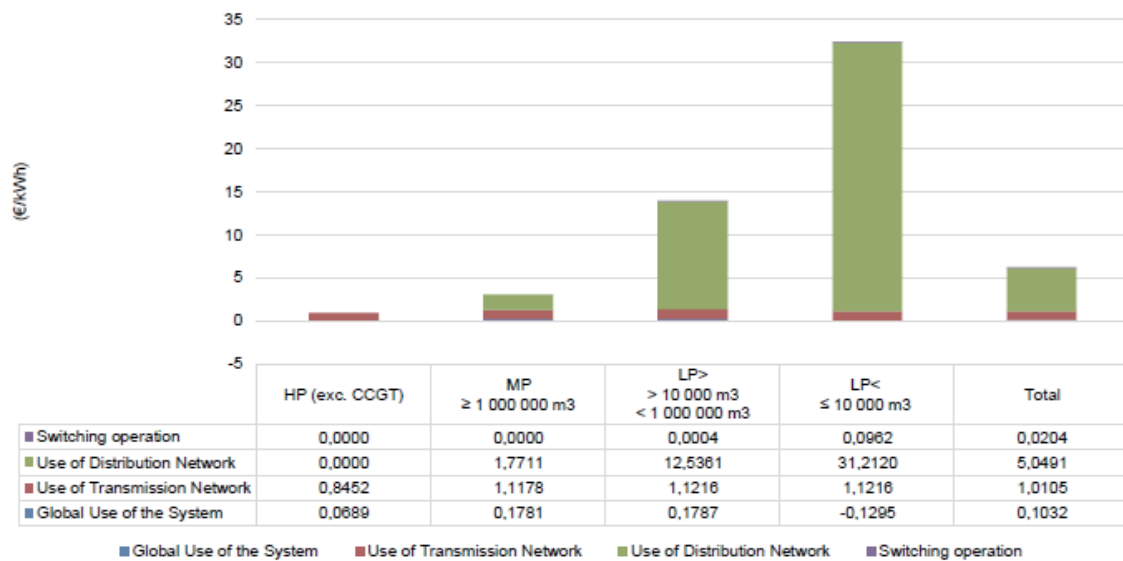


Figure 3.34 – Breakdown of the average price of network access tariffs, in the tariff year 2018-2019²⁶³

The decrease in the tariffs is justified by different factors, of which the following is highlighted:

- the efficiency targets imposed on the operating costs of the activities associated with the infrastructure, as well as the downward revision of the rates of remuneration applied to them;
- the regulatory mechanisms for promoting tariff stability, in particular by controlling the impact of demand volatility on high-pressure infrastructures;
- the greater adequacy of the investment level to the current level of demand and, consequently, the use of infrastructure;
- money transfer from the Extraordinary Contribution on the Energy Sector and the Fund for the Systemic Sustainability of the Energy Sector to the National Natural Gas System, reducing to the costs of the Global System Use tariff; and v) the increase in demand for natural gas at the high-pressure level, due to the increased use of natural gas combined-cycle plants.

Billing variables are selected so that they are compatible with other regulated tariffs (transmission, system use, energy, ...) and they are the cost drivers of the regulated activity.

Table 3.31 – Billing variables for distribution²⁶⁴

Billing variable	Unit	Rationale
Max. used daily capacity	€/kWh/day/month	Relevant for use of assets close to individual end-users Recovers CAPEX on peripheral assets (close to end-users)
Energy (Off-Peak)	€/kWh	Relevant for costs that are proportional to distributed energy in off-peak periods (off-peak = August)
Energy (Peak)	€/kWh	Relevant for use of assets used by a large number of users Recovers CAPEX on central assets (shared by a large number of end-users)

²⁶³ ERSE, (July 2019), Annual report of the electricity and natural gas markets in 2018

²⁶⁴ Source: ERSE, October 2019, Distribution tariff setting methodologies in Portugal, Course on Gas and Electricity Distribution Tariffs - Theory and Practice.

Fixed Term	€/day	Recovers administrative costs and costs on peripheral assets that depend on the number of delivery points

With the sector's liberalisation, the natural gas supply was opened to market players that fulfil the necessary requirements and corresponds to the last step in the electricity supply chain, which is the one that relates directly to the consumers. Consumers can choose their supplier and switch at no cost, wherever they find a more suitable commercial offer for their type of consumption. Suppliers, who form their commercial offers freely. In each geographical area, there is a supplier of last resort (SoLR), whom guarantees the supply of natural gas in that network area to vulnerable customers or in zones or market segments where there are no offers in the liberalised market.²⁶⁵

Since 1 July 2012, regulated tariffs for supply of natural gas to end-customers with annual consumptions lower or equal to 10 000 m³, published by ERSE for Mainland Portugal, have a transitional nature. In 2018, these tariffs applied to the supply of the retail supplier of last resort (CURR) in low and minimum pressure; transitional high-pressure tariffs were abolished. Transitional tariffs for end-customers are determined by the sum of network and infrastructure access tariffs with the transitional energy tariff and the regulated commercialisation tariff, all approved by ERSE.²⁶⁶

3.6.5 Spain²⁶⁷

The CNMC is in charge of setting Natural Gas Transmission and Distribution tariffs since 2019. Before the next regulatory period (2021-2026) the CNMC should approve the new tariff structure for Natural Gas Distribution, but as of March 10th, 2020 there is no information disclosed related to it.

In fact, Natural Gas Distribution tariffs have been frozen since 2014 when the Government approved the tariff order (IET/2446/2013). The methodology used at that time is not publicly available so the only information available is the final tariff structure and applicable charges. It must be stressed out that applicable tariffs are bundled tariffs, so it is not possible to know the transmission and distribution components of end-user charges.

Table 3.32 – Spain end-users network charges 2020 (Transmission & Distribution)

		Fixed components	Variable component
		Tfij	Tvij
		€ cent/kWh/day/month	€ cent/kWh
Group 1 (P>60 bar)			
1.1	≤ 200GWh/year	3.46	0.0847
1.2	200GWh/year <Consumption ≤ 1000 GWh/ year	3.09	0.0682
1.3	> 1000 GWh/year	2.87	0.0615
Group 2 (4 bar < P<= 60 bar)			
2.1	≤ 0.5 GWh/year	2.53	0.1934
2.2	0.5 <C ≤5 GWh/year	6.87	0.1543
2.3	5 < C ≤30 GWh/year	4.50	0.1249
2.4	30 <C ≤ 100 GWh/year	4.12	0.1121

²⁶⁵ Source: <https://www.erse.pt/en/natural-gas/retail-suppliers/>

²⁶⁶ ERSE, (July 2019), Annual report of the electricity and natural gas markets in 2018

²⁶⁷ Source: SPANISH ENERGY REGULATOR'S NATIONAL REPORT TO THE EUROPEAN COMMISSION 2018. https://www.cnmc.es/sites/default/files/2168599_2.pdf

2.5	100 < C ≤ 500 GWh/year	3.79	0.0983
2.6	> 500 GWh/year	3.48	0.0852
Group 3 (P ≤ 4 bar)			
		€/month	
3.1	≤ 5,000 kWh/year	2.53	2.8813
3.2	5,000 < C ≤ 50,000 kWh/year	5.79	2.1939
3.3	50,000 kWh/year < C ≤ 100 MWh/year	54.22	1.5643
3.4	> 100 MWh/year	80.97	1.2538
		€ cent/kWh/day/month	
3.5	> 8 GWh/year	5.93	0.1536

The following table presents the average T&D charge paid by each group of customers according to CNMC assessment²⁶⁸:

Table 3.33 – Average network charges by customer category 2019 (Spain)

Tariff Group	Customers (#)	Million € (T&D)	Consumption (GWh)	Contracted capacity (MWh/day)	Average network charge (€ cent/kWh)
Group 1 (P > 60 bar)	126	271.4	124,452	540,385	0.2181
Group 2 (4 bar < P ≤ 60 bar)	3,734	377.1	131,551	487,629	0.2867
Group 3 (P ≤ 4 bar)	7,983,440	1,735.2	70,059	23,694	2.4768

At the retail level, CNMC monitors retail prices through the commercial offers that are published in the CNMC's price comparison tool. There is an obligation for the suppliers to communicate to CNMC all public offers of gas or electricity, including any change in tariffs to the price comparison tool. The suppliers are responsible for the data presented, as they have to send the updated information.

Regarding the offers for households (those with the right to TUR, the last resort tariff), the spread between the maximum and the minimum gas offers shows difference in turnover of between 96 €/year and 183 €/year depending on the type of consumer.

The following figure shows the spread between maximum and minimum offers in the CNMC's price comparison tool for different natural gas -household and commercial- consumers.

- Spread between maximum and minimum offer for different natural gas -household and commercial- consumers.
- Spread*: without considering offers significantly out of rank (figure below).²⁶⁹

²⁶⁸ CNMC (2018) Acuerdo por el que se emite informe sobre las previsiones de demanda de ingresos y costes en el sector del gas natural para el cierre de los ejercicios 2018 Y 2019

²⁶⁹ Source: SPANISH ENERGY REGULATOR'S NATIONAL REPORT TO THE EUROPEAN COMMISSION 2018.

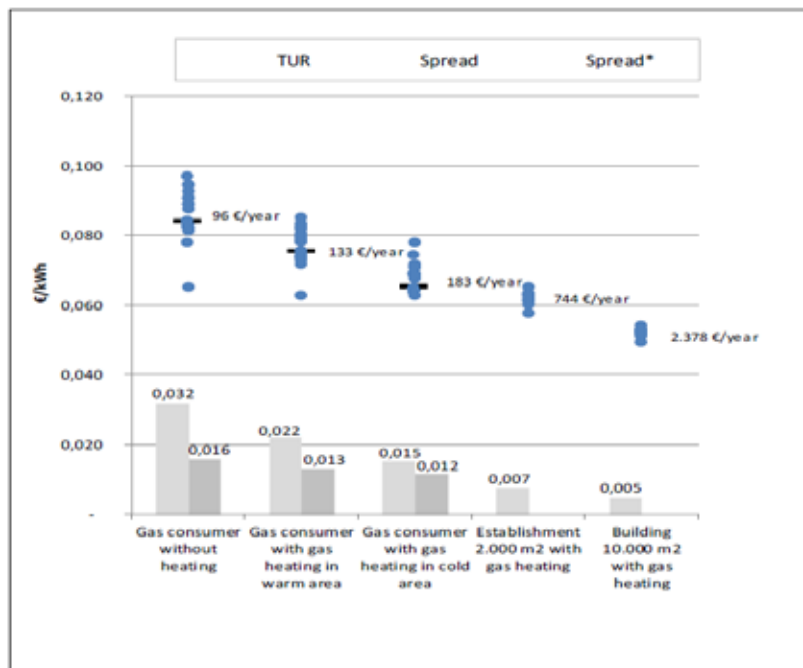


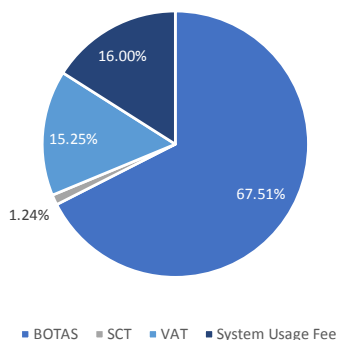
Figure 3.35 – Net network charges various customers in Spain

3.6.6 Turkey

End user household prices occur as an outcome of below main key parameters:

- The cost of natural gas: DSOs purchase price is set by the state-owned company BOTAS
- System Utilization Fee: Set by EMRA depending on the tariff calculations and varies for each DSO,
- Taxes: Special Consumption Tax (SCT) and 18% VAT (value added tax)

The cost of natural gas comprises the 67.5% of the consumer price as an average, and it heavily depends on the price of imported natural gas. However, BOTAS, the main gas importer of Turkey, is subsidizing its tariffs for residential segment, and determine the tariffs lower than its estimated weighted average cost of gas.



The System Utilization Fee is calculated by EMRA in five groups which are subjected to the amount of consumptions. The System

Utilization Fee decreases with the increasing consumption and vice versa increases with the lower level of consumption.

Table 3.34 – Consumer group categories

0-100,000 Sm ³
100,001-1,000,000 Sm ³
1,000,001-10,000,000 Sm ³
10,000,001-100,000,000 Sm ³
100,000,001 Sm ³ and above

Figure 3.36 – Consumer tariffs' spread

3.7 Assessment and Recommendations

This section summarises the main assessments within the scope of Natural Gas Distribution and recommendations are given towards performance-based tariffs in the Natural Gas Distribution sector Turkey.

3.7.1 Revenue Requirement Model

Various methods are utilized in the EU countries for distribution tariffs. Revenue cap and price cap models are the most preferred methods, followed by the hybrid model. Turkey's distribution tariff methodology is based on a revised price cap model in a way that a price cap for the tariff implementation period is determined, but it is revised if there is a big difference in revenue as a result of higher or lower consumption levels as compared to forecasted amounts. In addition to that, after the end of the implementation period, there are very limited correction mechanisms for CAPEX and OPEX.

The price cap model applied in Turkey is considered as a successful investment model for building greenfield networks. This model has enabled an investment rate above the global average rates, and thanks to this model, Turkey has achieved a significant growth rate for nearly every distribution region.

Some of the important growth factors are as follows:

- Demand factors such as population,
- Successful tendering,
- Political stability,
- Robust tariff methodology,
- Access to finance,
- Grid extension policy to districts.

Turkey's Natural Gas Distribution sector is still in its expansion phase. After completing major grid investments in almost every distribution region, it is expected that the UK experience with the "slow money - fast money", could be adopted into Turkey's tariff system, in future tariff implementation periods.

"Fast money", which could be explained as OPEX, could be used to compensate the effects of economical fluctuations both to DSOs and consumers via balancing and adjusting operational expenditures. "Slow money", could be explained as CAPEX, can be used to incentivize DSOs to give better service to consumers and repair and manage the network to last longer, which, in the end, will benefit consumers.

For the current and next tariff periods, **TOTEX** approach does not fit for Turkish methodology, as still great amounts of CAPEX are needed in Turkey to fulfil government policy of widening the network to new districts or even new provinces. TOTEX is basically designed to direct DSOs to OPEX in case it is a more efficient solution for operating the DSO, as CAPEX is more profitable and may cause inefficient choice of CAPEX in certain cases.

Turkish methodology of this issue (SHDV, *Şebeke harici düzenlenmiş varlıkları*) incentivized DSOs towards OPEX instead of CAPEX in the past tariff period.

Also, the Turkish Natural Gas Distribution network is still growing and not close to maturity for many of DSOs. Extending the service to districts is a state policy and also there is a great appetite of the society towards natural gas access. Having these properties, **TOTEX** is by no means of importance or priority for Turkish tariff methodology.

Besides, EMRA designed a special solution to switching from OPEX to CAPEX or vice versa according to operational needs: Cap-1 (Technology) and Cap-2 (Other). Basically, this methodology is targeting at a fair balance between DSOs choosing OPEX solutions or CAPEX solutions in both possible areas.

Having a new and still expanding gas network, Turkish utilities can be subjected to **TOTEX** in future phases of regulation, when RABs become lower and extra actions will be needed to support DSOs' continuity. Instead of **TOTEX**, integrating the service quality component into the tariff design is more important and more urgent.

Price cap is considered to be a legally binding methodology for EMRA as it is put as a commitment during tenders, unless DSOs themselves agree on another methodology. Companies are exposed to volume risk and also risk of earning, much more than being exposed to a regulatory risk. Turkey's extension policy of the natural gas network to the district level should also be considered in evaluating which incentives should be chosen in tariff design. Moreover, the price cap methodology makes line extensions, which are risky in nature, even riskier. More prompt and certain cost recovery is more preferable for a utility to reach new regions. Share of capacity-based prices can be increased in order to lower these risks.

Here, it is recommended to use **revenue cap** methodology instead of **price cap**. In this way, EMRA can be more flexible in allowing errors in the demand forecast, there will be less requirements for tariff revisions, and there can be more focus on methodology development, instead of having a high workload for frequent tariff calculations.

As it is a legal issue, some **incentives** can be applied to persuade DSOs to become subject to a different methodology. Below actions may be taken, inter alia, to incentivize switching from price cap to revenue cap:

1. Apply revenue cap for existing DSOs: From a legal point of view, the first 7 companies were founded prior to EMRA's foundation. These DSOs are not bounded by the price cap methodology.
2. Incentivising revenue cap for tendered DSOs (change method for those DSOs that agree):
 - a. Calculate an implied profit margin of price cap from a time period (5 years for instance). This average profit amount can be converted into a profit allowance on BOTAS wholesale price.
 - b. Increase in total customers served can be a QF indicator.
 - c. Number of DSOs in a merger can be a QF each.

The current 5120/1 methodology implies an implicit profit opportunity for DSOs. Calculating a mid-term (e.g. 5 years) profit for DSOs gain due to price cap method, EMRA can find out a reasonable profit margin. Applying this margin for DSOs accepted revenue cap can be for the interest of both tariff methodology and DSOs. Similar to many EU countries, DSOs in Turkey make profit on CAPEX, but also from efficiency gains. As the distribution grid expansion nears completion, the CAPEX will eventually start to decrease, and so will the benefits. However, an adaptation of UK's RAV (Regulatory Asset Value) could be implemented

into Turkey's tariff mechanism in such a way that DSOs in Turkey can also make a profit via OPEX. This might be applied as $OPEX \times (WACC/\alpha)$, α being a constant determined by EMRA for each regulatory period or for each DSOs. This constant could be a way to incentivize efficiency improvements in the OPEX.

With the inclusion of new districts into the distribution regions, the investments will accelerate again, and an ongoing expansion process has started. The ability of distribution companies to generate additional revenues through the price cap mechanism is considered to be a mechanism that increases the investment appetite. However, as mentioned above, it also creates a volume risk for DSOs.

Regression models for predicting costs using panel data is a popular approach by European regulators. It is also used by EMRA effectively. As the sector companies are very heterogeneously distributed according to their geographical area, network length, number of customers, economic activities of their regions, working conditions, financial sizes etc., the use of a clustering approach of EMRA could also be very appropriate in cost analysis.

Furthermore, capping (Cap-1) method is an efficient way of regulating and balancing interests of parties. For improving the existing scheme, non-controllable OPEX category can be defined for issues like changes in regulations affecting costs; unforeseeable future costs can also be managed within this category.

Capping an expense, instead of covering totally in tariffs implies that EMRA is not willing to add such expenses into revenue requirement, as they are not clearly reasonable enough and also, as they have some merit in their nature, they should be not excluded completely from the tariffs. Legal expenses are part of the right to legal remedies, which is a right protected by the Turkish Constitution. In case a company wins the case, expenses are covered by the counterpart (in official limits), and in case of losing the case, legal expenses are left to the suing company. OPEX items need to be related with distribution activity and should be related to redundant items, in other words, creating value for the business. For using the right of legal remedies, legal expenses are related to potentially value creating activity for DSOs. However, these expenses have a nature of being very unpredictable and for that reason require being treated differently than major OPEX items. Overall legal expenses during a fiscal year may either be positive or negative for a distribution company. It is almost impossible to predict whether it will be positive or not for a single company in a single year, or during a period of years. Capping these expenses at a reasonable percentage is recommended. This would enable setting a balance between two opposite point of views, in which they are not totally included or excluded from the tariff methodology.

PPI & CPI

Inflation rate to be used is also an important issue in tariff design. **Producer Price Index (PPI)** and **Customer Price Index (CPI)** are two prominent alternatives to be evaluated.

PPI is a pre-indicator of inflation, while Customer Price Index (CPI) indicates inflation rates observed by consumers. In a competitive marketplace, it is reasonable to convey inflation to prices of final goods and services. In that manner, adjusting regulated prices based on CPI is a competition-like regulatory action.

Therefore, CPI has an advantage over PPI in price adjustments. Secondly, inflation index used in calculation of other variables such as WACC and cost of debt, should be consistent with the index used in price adjustments. As CPI is the mostly used inflation indicator for economies worldwide, use of CPI is much more justifiable than that of PPI in price and RAB adjustments.

Evaluating alternatives in terms of cost adjustment within the tariff period in question, CPI and PPI can have a converging impact in the long run.

Regardless of the price index used, certain actual costs, such as material costs incurred, can have their own dynamics both from supply side and demand side, resulting in unique price movements which cannot be reflected by either of the indexes. However, since CPI is used as reference in some decisions, such as wage increases, it has a relation with changes in costs.

As a result, when assessing CPI and PPI, CPI is clearly preferred from a financial perspective. Designing an index created for

adjustment of costs/prices will be difficult to execute, due to lack of real market conditions in any model designed to predict future cost movements of the regulated utilities. Past figures do not necessarily guide costs as reasonably accurate as unpredictable supply and demand dynamics.

Natural gas grid expansions

Natural gas grid expansion policy of Turkish government is also an important component of EMRA's tariff model. Electricity is widely assumed within universal service goals by countries, but this is not the case for natural gas. Natural gas extension to remote areas therefore is not agreed upon as a public interest.

However, natural gas line extensions to districts have some benefits related to general government policies such as regional economic development and job creation. Also, environmental policy especially carbon footprint reduction targets are in line with natural gas extension policy. In Turkey, not only conventional natural gas lines are extended, but also the city Natural Gas Distribution model, which includes utilizing LNG/CNG vehicles in transportation of natural gas instead of transmission lines, to reach (remote) districts.

Grid expansions in all forms creates a cost allocation problem, whether the costs incurred will be shared between existing and new customers, or whether all costs will be borne by new customers. Unless supporting funds from other sources such as local administrations or national government are used, this allocation problem will occur.

For example, The New York State Energy Plan of 2009 stated that, in situations where expansion of natural gas facilities into new areas is not economically viable, it may be possible to receive contributions towards the costs of the expansion facilities from potential customers, interested municipalities in the region, and state economic development funds.²⁷⁰ As municipal administrations are exempt from some infrastructure costs which otherwise would be paid by Natural Gas Distribution companies and are passed on to the tariffs, a similar method is partially in use in Turkey. This method of funding by out-of-tariff sources can be extended with various funding mechanisms to better manage line extensions in terms of tariffs.

According to current methodology, costs of line extensions to districts are borne by all customers either existing or new within a distribution region, regardless of the method (pipeline or LNG/CNG method) to extend service to those districts.

In extensions to districts, a demand collection process can be carried out to guess probable demand of gas in a certain district. This can help extension decisions of distribution companies. In tariff design, costs directly attributable to a line extension of a certain district can be solely passed on to the tariff of this district. However, such differentiation of tariffs is against current legislation and may require a law revision to be enabled.

For unserved or underserved areas of the distribution region, some utilities can spend money for marketing and assistance programs to promote fuel switching or provide management support for facilitating fuel switching in order to lower the transaction cost for energy consumers to switch to natural gas. Upon the approval of EMRA, these activities can be included in tariffs as long as they benefit existing customers.²⁷¹

Table 3.35 – Revenue Requirement Model

Revenue Requirement Model	
EU Practices	- Various methods are utilized in the EU countries for the calculation of the revenue requirement method. Revenue cap and price cap models are the most preferred methods after the hybrid model
Turkey Practice	- Price cap

270 Source: Contello, K., 2013, Line Extensions for Natural Gas: Regulatory Considerations, National Regulatory Research Institute, Report No: 13-01
271 Ibid.

Revenue Requirement Model	
Recommendation	- It is thought that it is time to change the structure of distribution tariffs namely, to use pure revenue cap as the distribution tariff which is used in the electricity sector. With a large amount of RAB, revenue cap method will decrease the risk of the financial sustainability of the distribution companies. The bigger portion of the required revenue is CAPEX, the amount of fixed cost is high, whereas natural gas consumption is fluctuating a lot. To decrease that risk, it is recommended that EMRA revises the methodology in the following tariff period, using incentives for DSOs. - Another important issue is the approach of cost components realized in tariff implementation periods. - Even though the TOTEX approach is not suitable for the current situation, it is proposed that the TOTEX approach may be used in the future when network expansion reaches a saturation phase and allocate total allowed revenue into two parts as CAPEX and OPEX. - In around the year 2030, TOTEX can be a practical alternative approach for Turkish natural gas distribution tariffs. In that phase of the sector with more maturity, TOTEX approach will incentivize companies to spend wisely in a way that they will allocate allowed revenue between network investment and operation expenditure without focusing to maximize tariff by inflating inefficient investments. In addition to that, the right allocation between OPEX and CAPEX will provide sustainable revenue inflow. TOTEX approach will also eliminate the risk of low level of RAB for some companies with a low opportunity to expand the network. Thus, some portion of OPEX will be accepted as CAPEX and the companies will have a chance to get return. Currently, in tariff methodology of EMRA there are some regulations to eliminate the risk of low return by calculating return from OPEX. TOTEX approach will be much fairer to increase return portion of the required return. - EMRA currently take historic operation expenditure and network investment costs and analyze them by benchmarking with historic values of the company itself and unit costs of other companies in the same period. This approach can be used also in TOTEX approach at the time EMRA starts practicing it. EMRA can determine accepted operation expenditure and investment costs in a similar way, then calculate total of those two components and allocate that total accepted costs between OPEX and CAPEX based on predetermined shares for each of them. OPEX and CAPEX share can be determined as the fixed single ratios for the whole sector or can be determined different ratios for different categories of companies. - For the calculation of expenses of the DSOs, the EU countries Sweden, Netherlands, and Germany uses TOTEX, whereas the remaining countries including Turkey mostly prefer building blocks method. For the current stage the sector has reached, it is recommended to continue existing methodology in Turkey for about 10 years on. - In addition to switching to revenue cap and continuing existing building blocks methodology, another important issue is the integration of quality factor into the tariff structure. The Quality Factor has not been applied yet, although it is defined in the tariff regulations. The Quality Factor can be implemented as a component of the price cap model by establishing common service quality standards.
Comments	- Turkey's distribution tariff methodology is based on a revised price cap model in a way that a price cap for the tariff implementation period is determined but it is revised if there is a big difference in revenue as a result of higher or lower consumption level compared to the forecast (which is limited to future revision only). In addition to that, after the end of implementation period, there are very limited correction mechanisms for CAPEX and OPEX. - The price cap model applied in Turkey is considered as a successful investment model for building greenfield networks. This model has enabled an investment rate above the global average rates, and thanks to this model, Turkey has achieved a significant growth rate for nearly every distribution region. - With the inclusion of new districts into the distribution regions, the investments accelerated again, and an ongoing process started. The ability of distribution companies to generate additional revenues through the price cap mechanism is considered to be a mechanism that increases the investment appetite. Application of price cap is considered to be beneficial for the sustainability of the enterprise quality and the access of consumers to the service until the investments reach the plateau and continue in a balanced manner. - However, the expansion period for distribution networks is getting closer to the end. Distribution networks have been extended to almost all large cities and towns. Therefore, high growth in network investment will not be possible in the following periods.

3.7.2 Rate of Return

Most of the EU countries utilize WACC (pre-tax) and Dynamic WACC for their rate of return calculations. In Turkey, WACC is calculated by the regulator EMRA based on various economic parameters. An increase in the overall rate of return in Turkey is expected to strengthen the sustainability of the DSOs.

Tariff Calculation Methodology for Natural Gas Storage Companies has set a minimum WACC of 10% for storage companies. This lower limit approach can be used also for DSOs as a protection. Market risk premium component which determines the

cost of equity is in correlation with the country risk. So, for the upper side, a parametric design of WACC based on country risk can automatically adjust any unforeseeable financial conditions in the future. Any unexpected increase in interest rates can be considered as uncontrollable OPEX and added to revenue requirements of DSOs to compensate volatile financial conditions, without changing regulatory WACC determination method.

Other than remuneration of CAPEX, WACC can also be used for incentivising certain issues, such as consolidation of the sector or for voluntarily switching to revenue cap.

Employing RoRE as in the UK model is not an appropriate match for Turkey. The price cap methodology applied in Turkey causes DSOs revenues to become too much dependent on their actual expenses and EMRA forecasted demand. As a monitoring tool, EMRA applies 5120/1 resolution, according to which EMRA calculates revenue diversion caused by forecasted demand and actual demand and if diversion is $\pm 7\%$, revises the demand forecast.

Instead of RoRE, EMRA may set rules regarding how to compensate material losses or profits that might be corrected to protect both companies and customers in extraordinary situations. For monitoring financial performance of companies to ensure their sustainability, EMRA may employ various analyses, such as debt/equity ratio, return on assets (as dependent on debt levels) etc. For Turkish Natural Gas Distribution sector, financing of investments is a major issue, and risks such as interest rate risk, maturity mismatch risk, refinancing risk should be managed duly.

Risk-free rate selection can be based on nominal yields of long-term government bonds (e.g. 10 year). Yields and inflation expectations are normally expected to be compatible, however, in adverse financial conditions and volatile economic conjunctures, EMRA should pay extra attention to choose consistent financial data to consider as risk-free rate.

CAPM method is the main theoretical basis for the cost of equity calculation in Turkey as it is for other regulators in the world. In fact, CAPM is not used in a pure theoretical approach by regulators but rather it is used in a simplified way and the biggest advantage of this model is making WACC calculation very practical and obtaining necessary variables from a wide set of alternatives. For instance, Beta values or ERP values can be benchmarked from international sources and adjusted by using country risk. For that reason, any alternative other than CAPM is not reasonable to use instead of CAPM.

The most important drawback of the current methodology is that an industry-level rate of return is allowed by EMRA, instead of company-specific rates.

If EMRA would prefer differentiating the allowed rate of return, existing CAPM methodology might not fit for WACC calculation. However, it is an incentive-based approach that companies can be incentivized by a single rate of return to make profit and create company value by lowering their cost of capital. This is the theoretical background of the industry-level rate of return which makes existing WACC methodology compatible with incentive-based regulation.

In choosing risk-free rate, yields of long-term treasury bonds such as 10-year or even 30-year bond are preferred in many countries. Cash-flow period and the bonds maturity period (which are proxy variable for risk free rate) are expected to be compatible with each other. For the case of Turkey, EMRA can choose the same approach and use longest available bonds' maturity period.

Real and pre-tax WACC is applied with actual inflation rate which eventually yields nominal rate of return. In normal financial periods, nominal WACC is expected to be well above cost of debt. In financially volatile periods, in which interest rates rise very much compared to previous periods, nominal annual rate of return may be below cost of debt. In such periods, WACC can be revised by EMRA to at least cover cost of debt of DSOs during these abnormal periods.

In case EMRA decides enforcing such a WACC revision model, possible future scenarios can be determined by a financial markets-based search in Turkey's financial history, for example, figures in the year 2018, in which currency exchange rates and interest rates have been very volatile, can be a basepoint for that purpose. In that example, nominal annual interest rates have hit the 40% levels in actual loan offers to energy sector companies. In such extraordinary periods, real WACC can be adjusted to make cost of debt and rate of return realized catch breakeven point. In this recommended scheme, the lower limit is a real rate to incentivise DSOs for their CAPEX, while the upper limit will be determined by the difference between actual loan rates and nominal return provided

by the tariff methodology which is a product of real WACC applied and inflation rate realised. This kind of difference happening is not a usual circumstance, however, as it is possible to be observed, an ex-ante mechanism in place which ensures that EMRA will act accordingly to secure financial sustainability of the DSOs will contribute to long term investment climate in the sector.

EMRA can prefer an uncontrollable OPEX component to compensate such extra costs to abstain from a WACC revision. In case such periods last longer than 1 year, EMRA can revise WACC without using uncontrollable OPEX approach. To sum up, country risk and lag between actual cost of debt and nominal WACC can be two control variables to decide on WACC revisions.

Table 3.36 – Rate of Return

Rate of Return	
EU Practices	- WACC (pre-tax) and Dynamic WACC
Turkey Practice	- WACC
Recommendation	- In Turkey, WACC is calculated by the regulator EMRA based on the various economic parameters. An increase in the overall rate of return in Turkey is expected to strengthen the sustainability of the DSOs and sustain further financial steps such as IPOs. - WACC can be set to be 10% minimum as in the storage tariffs and can be adjusted according to changes in country risk and other relevant components of WACC. In pre-determined conditions, non-controllable OPEX method can be used for ensuring financial sustainability of DSOs. For example, losses due to unexpected interest rate increases, non-controllable OPEX can be added to revenues to compensate DSOs, instead of revising WACC.

3.7.3 Depreciation

Both Turkey and the EU countries use the Straight-Line depreciation model. However, the depreciation term in Turkey is 22 years, while the EU countries mostly set depreciation terms longer, even up to 50 years.

Expanding the depreciation term may reduce cash flows in the short term but would offer a more financially sustainable revenue structure in the mid and long term. The longevity of finance is another factor in the determination of depreciation period because distribution companies need loan to finance network investments.

In Turkey loan payment period is lower compared to European countries, so lower depreciation period is needed. This causes a dilemma for Turkish DSOs: Shorter depreciation period is wished for financing, however, longer terms are more advantageous for long term revenue structure. Therefore, it is suggested to continue with the current depreciation term of 22 years. Only in case a DSO requires shorter depreciation period for gaining more financeability for CAPEX, it can be considered by EMRA, current scheme in Electricity Distribution can set an example for the decision in that case.

Table 3.37 – Depreciation

Depreciation	
EU Practices	- Straight-Line
Turkey Practice	- Straight-Line (22 years)
Recommendation	- The depreciation term in Turkey is 22 years, while the EU countries mostly set depreciation terms longer, even up to 50 years. - Expanding the depreciation term may reduce cash flows in the short term but would offer a more financially sustainable revenue structure in the mid and long term. The longevity of finance is another factor in the determination of depreciation period because distribution companies need loan to finance network investments. - In Turkey loan payment period is lower compared to European countries, so lower depreciation period is needed. Therefore, it is suggested that continuing with the current depreciation term of 22 years. In case individual DSOs require shorter terms for financeability reasons, EMRA can decide individually. TOTEX approach in the future can compensate some of the disadvantageous aspects of shorter terms.

3.7.4 Connection Fee

“One-time connection fee” is the most common methodology used in Turkey and the EU countries. The connection fee model applied in Turkey may be diversified by considering below parameters as a premium of the fixed one-time fee:

- Subscriber status
- Delivery pressure
- Capacity booking
- Load factor

The connection fees collected by the DSOs do not generate revenue for the DSOs as the connection fee revenues are extracted from the value of realized investments during RAB calculations. The connection fees only support the cash balance of the companies.

Outsourcing Connection

For service lines, regardless of the actual connection cost, a fixed fee determined by EMRA is paid by consumers, difference between assumed cost by the fix fee and the actual cost born by the DSO is corrected by the tariff mechanism.

For connection lines other than service lines, consumers are eligible to choose either DSO or any certificated firm for connection. In this scheme, competition issues emerge between DSO and other firms. Also, any shareholder relationship between DSO and certificated firms, either explicit or implicit, is a concern.

EMRA and Competition Authority is under a responsibility to ensure if DSOs treat fairly to certificated firms and comply with competition regulations. For instance, whether DSOs inform consumers duly for their eligibility to choose, their procedures are non-discriminatory in either case, calculated costs are in the equal base in either case etc.

Ensuring removal of all these drawbacks is a very difficult and time-consuming task. Instead of this, in accordance with EMRA’s and other regulators incentive based regulation methodology, all connections should be subject to a EMRA-determined fee, as in the

case of service lines, in which fix amount should be related to features of the connection (as in the case of electricity connection fees determined by EMRA).

EMRA also has to analyze reported connection costs with the same approach as the distribution CAPEX costs. This methodology can require change of law as fixed fee is only for service lines according to law n.4646.

Utilizing certificated firms for connections

Existing scheme legislated by No 4646 requires involvement of certificated firms in connections. EMRA sets tariff principles and prices are negotiated by parties freely.

As for the CAPEX issues of distribution network, connections can be sole business of DSO as well, if EMRA sets the rules in that way if law n.4646 is changed accordingly. For protecting consumers from drawbacks explained above, EMRA can set fixed tariffs based on certain features such as length of connection lines, then consumers can be left eligible to get connection made either by DSO for the EMRA-determined connection fee or by a certificated firm for a negotiated price. Even in this case, competition concerns can still occur. For instance, approval and project design powers of DSO can still be abused to gain advantage by DSO itself or by sister companies. For that reason, it is recommended to implement a mechanism same as service lines.

Expanding the implementing of connection fees

To achieve a competition and consumer friendly mechanism under existing scheme, EMRA and Competition Authority might involve in a more intense way.

To achieve the same objective with lesser involvement in connections, case by case or without overregulation concerns, existing mechanism has to be changed as explained above.

Allowing DSOs to determine their connection fees

By assessing the Natural Gas Distribution environment of Turkey, allowing the DSOs to determine their connection fees is not considered as an appropriate regulation. In case EMRA prefers to do so, it can collect connection fee determination rules proposals from several DSOs (can be biggest 10) and then take examples of real-life connections from these companies in order to use them as a basis for approval. Any general rule to ensure appropriate fees already exists within the scope of the current legislation and it is clear that problems encountered are not due to lack of necessary principles in the legislation but rather due to lack of mechanisms effective enough to prevent above mentioned drawbacks.

Formula based connection fee instead of a constant fee

Implementing a formula-based connection fee rather than determining a constant fee for all of the DSOs is an option and also a practicable method, as long as necessary law changes are done. In a formula-based connection fee, length of the line, complexity of the work (e.g. standardized or not), type of materials used, labor needed, other relevant costs (infrastructure fees etc.) should be concerned in the formula setting stage.

Differentiating connection fee in LNG/CNG fed regions

Differentiation of connection fee to promote households in LNG/CNG fed distribution regions is considered as a theoretical option for incentivizing new consumers. However, by considering the various geographical and demographic facts, it seems more appropriate to incentivize prospected consumers either in already reached neighborhoods (underserved areas) or in not reached neighborhoods (unserved areas), by using financeability programs, instead of differentiating connection fees. Financing programs can include payments by installments and/or solution partners' involvement such as local administrations or local development agencies, etc.

Table 3.38 – Connection Fee

Connection Fee	
EU Practices	- One-time connection fee
Turkey Practice	- One-time connection fee
Recommendation	- The connection fee model applied in Turkey may be diversified by considering below parameters as a premium of the fixed one-time fee: ○ Subscriber status ○ Delivery pressure ○ Capacity booking ○ Load factor - The connection fees collected by the DSOs do not generate revenue for the DSOs as the connection fee revenues are extracted from the value of realized investments during RAB calculations. The connection fees only support the cash balance of the companies. - For service lines, regardless of the actual connection cost, a fixed fee determined by EMRA is paid by consumers, difference between assumed cost by the fix fee and the actual cost born by the DSO is corrected by the tariff mechanism. For connection lines other than service lines, consumers are eligible to choose either DSO or any certificated firm for connection. In this scheme, competition issues emerge between DSO and other firms. Also, any shareholder relationship between DSO and certificated firms, either explicit or implicit, is a concern. EMRA and Competition Authority is under a responsibility to ensure if DSOs treat fairly to certificated firms and comply with competition regulations. For instance, whether DSOs inform consumers duly for their eligibility to choose, their procedures are non-discriminatory in either case, calculated costs are in the equal base in either case etc. Ensuring all these drawbacks are removed is a very difficult and time-consuming task. Instead of this, In accordance with EMRA's and other regulators incentive based regulation methodology, all connections should be subject to a EMRA-determined fee, as in the case of service lines, in which fix amount should be related to features of the connection (as in the case of electricity connection fees determined by EMRA). EMRA should also analyze reported connection costs in the same approach with the distribution CAPEX costs. This methodology can require change of law as fixed fee is only for service lines according to law n.4646. To achieve a competition and consumer friendly mechanism under existing scheme, EMRA and Competition Authority can involve in a more intense way, which can raise questions of detailed examinations or overregulation. To achieve the same objective with lesser involvement in connections case by case or without overregulation concerns, existing mechanism should be changed. Connection fees determination rules should be not left to DSOs. In case EMRA prefers to do so, it can collect connection fee determination rules proposals from several DSOs (can be biggest 10) and then take examples of real-life connections from these companies in order to use them as a basis for approval. Any general rule to ensure appropriate fees already exists is the current legislation and it is clear that problems encountered are not due to lack of necessary principles in the legislation but rather due to lack of mechanisms effective enough to prevent above mentioned drawbacks. Instead of low connection fees as an alternative incentive, it could be better to help prospected consumers either in already reached neighbourhoods (underserved areas) or in not reached neighbourhoods (unserved areas), all of which can be both pipeline or LNG/CNG covered areas, by using financeability programs, instead of differentiating connection fees. Financing programs can include payments by instalments and/or solution partners' involvement such as local administrations or local development agencies, etc.

3.7.5 Quality Factor Performance Indicators

In terms of technical quality indexes such as SAIDI, SAIFI, ASIDI etc. available for Natural Gas Distribution networks in EU countries. As the most important quality factor indicator there are safety measures.

In terms of commercial quality, most of the EU countries apply indexes related to customer information, customer care, grid access, invoices, meters and activation, deactivation, reactivation of supply.

Table 3.39 – Quality Factor Performance Indicators

Quality Factor Performance Indicators	
EU Practices	- Various indexes are available both in terms of commercial and technical quality.
Turkey Practice	
Recommendation	- In Turkey, currently quality factor is not implemented in Natural Gas Distribution tariffs. Distribution sector is in its early stages in Turkey, so EMRA has focused on the expansion of network so far. However, it is thought that the sector is mature enough to apply quality factor. - Therefore, it is suggested to use quality factor in the next tariff implementation period. For that purpose, it is suggested to use performance indicators used by the UK as explained in detail above. With the application of quality factor, the level of service quality can be increased in the sector. Country-specific QF indicators or GQIs can also be applied as recommended above.

3.7.6 Efficiency

Indicators used in efficiency analysis in the Natural Gas Distribution sector are mostly set by taking the general characteristics of each country or region into account.

In Turkey efficiency indicators are network length, number of city gate stations build in tariff period, consumption and number of consumers. Those parameters mostly effect the level of OPEX, so they are right choice for that purpose.

EMRA has already applied efficiency factor to the tariff, but so far only used efficiency scores resulted from DEA analysis. Alternative methods like SFA and using a combination of the results of those methods may be utilized by EMRA for further implementation. This will eliminate the shortcoming of one method.

Table 3.40 – Efficiency

Efficiency	
EU Practices	- Various
Turkey Practice	- Factors including change in number of city gate stations, towns, consumers and network length during a tariff period
Recommendation	- Indicators used in efficiency analysis in the Natural Gas Distribution sector are mostly set by taking the general characteristics of each country or region into account. - In Turkey efficiency indicators are network length, number of city gate stations build in tariff period, consumption and number of consumers. Those parameters mostly effect the level of OPEX, so they are right choice for that purpose. - EMRA has already applied efficiency factor to the tariff, but so far only used efficiency scores resulted from DEA analysis. It is suggested to use alternative methods like SFA and use a combination of the results of those methods. It will eliminate the shortcoming of one method.

3.7.7 Losses (Shrinkage)

The shrinkage volumes in Turkey are at reasonable levels at the moment due to concrete network construction quality and the

relatively new grid. But in the mid and long term, the shrinkage volumes are expected to exceed reasonable levels due to the nature of Natural Gas Distribution activity. By taking this fact into account, the shrinkage losses would be implemented into the tariff methodology as a partial cost for maintaining sustainability. For promoting precautions to reduce shrinkage, the shrinkage rate would be set as one of the performance indicators for the DSOs.

Shrinkage caused by leakage is not expected to be major issue for Turkish Natural Gas Distribution network during the next two tariff periods. However, shrinkage caused by theft can be an issue as it is in the Electricity Distribution in Turkey. For that reason, EMRA should closely monitor natural gas volumes enters the network and that is billed, in order to detect any major shrinkage issue as early as possible.

EMRA has an impressive experience in regulation of loss and theft issues in Electricity Distribution: Target rates (known as HKO), lost energy correction component (known as KEDB), loss accruals (sharing the revenue and also collection risk via revenue correction known as GFDB).

In case EMRA finds out that shrinkage is in place in the network, it can easily transfer its knowledge and experience in dealing with the issue to Natural Gas Distribution. It is considered essential for EMRA to handle shrinkage not with as a theoretically possible problem but as an empirically proven fact.

Having the figures from DSOs, EMRA is to decide whether to include such a component in the tariffs or not. In the case of Electricity Distribution, main reference for target levels is past actualizations by the DSO itself. In the case of natural gas, EMRA may implement an engineering model in the future, to set maximum allowable cost of shrinkage for each DSO.

Table 3.41 – Losses

Losses	
EU Practices	
Turkey Practice	
Recommendation	- The DSOs in Turkey are responsible for the technical losses, leakages, and shrinkage, unlike the practices in most of the EU countries. Some EU countries reflect the cost of shrinkage and losses to the consumers. However, the shrinkage volumes in Turkey are at reasonable levels at the moment due to concrete network construction quality and the relatively new grid. But in the mid and long term, the shrinkage volumes are expected to exceed reasonable levels due to the nature of Natural Gas Distribution activity. By taking this fact into account, the shrinkage losses shall be implemented into the tariff methodology as a partial cost for maintaining sustainability. - For promoting precautions to reduce shrinkage, the shrinkage rate would be set as one of the performance indicators for the DSOs. EMRA should deal with shrinkage issue as a matter of empirical evidence. If it is proven that a major issue of shrinkage is existing in the network, which is not expected in a near future EMRA can transfer its knowledge from Electricity Distribution to Natural Gas Distribution. In the case of Electricity Distribution, main reference for target levels is past actualizations by the DSO itself. In the case of natural gas, EMRA can choose an engineering model in the future, to set maximum allowable cost of shrinkage for each DSO

3.7.8 Tariff Determination for Consumers

The Price Cap methodology makes the annual and level-based consumption forecasts important for the DSOs. Since the Price Cap method does not apply the retrospective correction of revenue realizations, deviations in consumption forecasts may have a serious impact on the financial structure of the companies. Besides, the System Utilization Fee set separately for each of the 5 consumption levels, and in-term switches between levels may lead to deviations in the revenues of DSOs.

Most of the EU countries, such as Germany and Czechia, have broader consumption levels, as Germany has three levels for low load, high load, and residential. Even Czechia has residential, industry, and others. But it is necessary to emphasize that the consumption in many of the EU countries is nearly flat with less fluctuations.

Table 3.42 – Social Tariff Determinations for Consumers

Social Tariff Determinations for Consumers	
EU Practices	- Tax exemptions - Discounts in invoices - Direct support
Turkey Practice	- N/A
Recommendation	- Most of the EU countries and Turkey apply different pricing mechanisms for each consumer segment based on the fixed and variables costs. Social tariffs are implemented in Europe in different ways. In some countries, this consumer group is protected by providing tax exemptions, discounts in invoices, and in others by direct support. - In general, it would be appropriate to provide natural gas support to households to be determined by the Ministry of Family and Social Policies or the Governorships instead of applying a discounted natural gas sales tariff method to the low-income citizens by Natural Gas Distribution companies. - The application of a discounted price to a certain group of consumers by Natural Gas Distribution companies will create difficulties in the pursuit of the group determined in the medium term, in managing and implementing the similar demands of the new concession consumer groups. - For implementing social tariff in Turkey, the annual support requirement for an average household can be calculated, and the length of support period can be identified by the consensus of relevant central and local authorities. And the amount of natural gas, that will be supplied to households under the social tariff application, would be given as a credit to be used in their pre-paid metering counters.

Table 3.43 – Tariffs for Distribution Region Expansions and CNG /LNG Applications

Tariffs for Distribution Region Expansions and CNG /LNG Applications	
EU Practices	
Turkey Practice	
Recommendation	- External sources to fund line extensions can be widened. Currently, municipalities waive infrastructure fees for the benefit of the prospected customers in the region. - Before extending the license region by adding a new district, a demand collection process (which may include some monetary contribution from demandants) can be carried out to make investment plans more realistic. - Spending of DSOs to encourage fuel switching in both unserved or underserved areas can be included in tariffs upon pre-approval of EMRA. This can help increasing utilization of the network. - Differentiated tariffs for existing and new customers to reflect costs to those causing them can be fairer in tariff design. However, this can require a revision of the law.

Demand Forecast

Together with more precise demand forecast in Turkey, the impact of the forecasting deviations may be reduced.

Table 3.44 – Reliability of Demand Forecasting for the Industrial Consumers in Distribution Regions

Reliability of Demand Forecasting for the Industrial Consumers in Distribution Regions	
EU Practices	
Turkey Practice	

Reliability of Demand Forecasting for the Industrial Consumers in Distribution Regions	
Recommendation	- For having a more precise demand forecast in Turkey, the forecast of the DSOs based on the below variables may be considered as the main component of the estimates, conducted by EMRA. - Annual grid expansion expansions - Gas consumption profiles of the industrial facilities - Seasonal effects on consumptions - Consumption forecast for residential consumers is made more predictable than estimations for industry and power plants. For industrial consumers, considering the 5-year tariff period, it is difficult to make a predictable consumption estimate. Therefore, reducing the share of industry and power plant's consumption in the revenue requirements may lower the deviations in the revenue realizations of DSOs. - Since the industrial consumers, which has regular consumption, has a high network usage rate and a low load, the revenue requirement allocated to this group may be lower than the revenue requirement of the residential segment, which has seasonal and variable consumption pattern. - As a result of this improvement, the impact of the forecasting deviations may be reduced.

Last-resort tariff

DSOs in Turkey are the last-resort suppliers as they are authorized for retail sales in their regions. In the EU countries, gas trading companies act as the last-resort supplier, particularly in the fully liberalized markets. The DSOs in Turkey procure their annual natural gas demand by bilateral contracts, and all of them are obliged to purchase gas from the 'cheapest' source available in the market.

Since BOTAS is the dominant player in the market, DSOs can supply gas either from other suppliers or directly from BOTAS by setting the BOTAS's sales as the cap for fulfilling the cheapest gas procurement of the Natural Gas Market Law. The cheapest gas procurement obligation of the Law does not define a specific term such as a month or a quarter and covers the whole year. However, BOTAS has the right to change its sales price every month. Therefore, DSO's gas procurements from the private suppliers compulsorily follow a price formula based on BOTAS's tariffs.

Since the last-resort tariff is not defined and included in the existing legislation and regulations, DSOs mostly supply gas from the main supplier BOTAS with the price that BOTAS releases every month, to meet the demand of an instant request.

Table 3.45 – Last resort tariff practices in Natural Gas Distribution

Last resort tariff practices in Natural Gas Distribution	
EU Practices	
Turkey Practice	
Recommendation	- By considering the market structure and development pattern of Turkey, DSOs may be allowed to make intraday, day-ahead, and futures transactions for securing their last-resort demand, when the liquidity of the market is increased to a certain level by progressing towards a liberalized market structure. - Allowing DSOs to benefit from a reasonable margin from the compulsory last-resort sales may improve the sustainability of the companies.

4 Improvement of performance-based tariff setting: Natural Gas Transmission

4.1 Introduction to the Natural Gas Transmission Chapter

There is considerable variation in the size of Natural Gas TSO throughout Europe as well as the methodology they use to determine allowed revenues. The following table shows summary information about the TSOs in European countries, including number of the TSOs, network length and ownership of the network companies.

Table 4.1 – Summary Table for gas TSOs²⁷²

Country	# of TSOs	Network length	Ownership
Austria	2	3,100 km	Private and Public
Belgium	1	4,200 km	Public
Bulgaria	1	2,756	Public
Croatia	1	2,693	Public
Czechia	1	3,821 (2016)	Private
Denmark	1	861 km (2017)	Independent public enterprise
Estonia	1	885 km	State owned
Finland	1	1,300 km	State owned
France	2	38,000 km	Private and public ownership
Germany	16	40,000 km	Mainly private investors, indirect public ownership
Greece	1	1,466 km	State ownership and private investors
Hungary	2	5,874 km	1 public, 1 private owners
Iceland	No gas TSO		
Ireland	1	2,427km	Public
Italy	9	34,200	Private
Latvia	1	1,188 km	Mainly private
Lithuania	1	2,113 km	State owned
Luxemburg	1	282km	Mainly direct and indirect public ownership
Netherlands	1	12,000 km	State owned
Norway	No gas TSO		
Poland	1	11,427 km	State owned
Portugal	1	1,375km	Private ownership
Romania	1	13,381	Private and public ownership
Slovakia	1	2,273	Public
Slovenia	1	1,156	Public
Spain	1 large TSO, 1 small TSO and 12 transport co.	13,749	Private, except for 5% stake of the State in ENA-GAS.
Sweden	1	601	Public
UK	1	7,000	Private
Turkey	1	19,000 km	State owned

As it can be derived from the table, the gas TSOs are generally state-owned companies and there is single gas TSO in most of the

272 Source: CEER, February 2019, Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks.

countries. Germany could be seen as unique case for multi TSO structure. There are 16 licensed gas TSOs are active in German gas market.

In Turkey, the Natural Gas Transmission activity, among other activities, is regulated, monitored and audited by EMRA according to Natural Gas Market Law (NGML) which is enacted in 2001. EMRA published the Natural Gas Tariff Regulation, first in 2002. The methodologies for preparing the tariffs have been published through EMRA Board Decisions.

The Tariff for the Natural Gas Transmission is referred as “Transmission and Shipping Control Tariff” (the Tariff) in the secondary legislation. The related legislative documents in effect are:

- Natural Gas Tariff Regulation, dated 13/10/2016;
- Principles and Procedures for Determining the Revenue Caps to be taken as basis to the Tariffs of Natural Gas Transmission License Holding Companies, EMRA Board Decision dated 03/10/2010 with the number 4638-1; and
- EMRA Board Decision dated 29/12/2016 with the number 6821 specifying the methodology for the second implementation period for the transmission and shipping tariffs of BOTAS during the term 01/01/2017-31/12/2019.

In the EU, the NRAs have similar roles and responsibilities defined under the Third Gas Directive for the governance of gas market activities. The relevant legislation with tariff can be stated as follows:

- The 3rd Gas Directive; “Directive 2009/73/EC of the European parliament and of the council of 13 July 2009 concerning common rules for the internal market in natural gas”
- The Regulation 715; “Regulation (EC) No 715/2009 of the European parliament and of the council of 13 July 2009 on conditions for access to the Natural Gas Transmission networks”
- ENTSG Capacity Allocations Methodologies (CAM) Network Code; “Commission Regulation (EU) 2017/459 of 16 March 2017 establishing a network code on capacity allocation mechanisms in Natural Gas Transmission systems”
- ENTSG Balancing Network Code; “Commission Regulation (EU) No 312/2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Networks”
- ENTSG Tariff Network Code.

The features of the Natural Gas Transmission tariff applied in Turkey and the relevant legislation in the EU are elaborated in the Annex, “**Applied Natural Gas Transmission Tariff Structures in Turkey and the EU**”. The essential features of the Natural Gas Transmission tariff applied in Turkey can be summarized as follows.

- Tariff based on Entry/Exit capacity reservation,
- Transmission System Operator may propose different tariffs for firm, interruptible and reverse flows,
- Capacity and Commodity split,
- Revenue Cap regulation,
- Weighted Average Cost of Capital (WACC, pre-tax) methodology in determining the Internal Rate of Return,
- The depreciation period is 22 years for all assets,
- 3 years of implementation periods, to be determined through EMRA Board Decisions (may go up to 10 years),
- Reconciliation of the determined revenue requirements are handled in accordance with inflation effect, investment adjustments, realized flows and/or capacity bookings and unforeseen expenses. The transmission system operator submits relevant data 6 months prior to the beginning of tariff year (calendar year),
- Transmission System Operators are required submit their proposed methodologies for the definition of transmission and shipping control services latest 8 months prior to the commencement of each tariff implementation period. EMRA publishes the applicable Tariff within 2 months upon receipt of the submittal,
- The Regulatory Asset Base (the RAB) for BOTAS Transmission Network is determined each year in accordance with new investments and realized depreciations. The RAB figure specified for the 2011 - 2013 implementation period has been taken as the reference.

In the EU case, there are limited rules which binds all member states in terms of tariff setting. There can be seen many differences in setting the revenue requirement model, determining the regulatory asset base and other features. The specifically relevant legislative document, the ENTSG Tariff Network Code even does not require the regulators to adopt certain regulatory regime from the alternatives as price cap and non-price cap regimes (revenue cap, rate of return and cost plus). As of date, the majority of the EU countries apply incentive based Revenue Cap Regulation. However, the TAR NC does not define a methodology for setting up the incentive mechanisms and efficiency targets. A table relating to type of regulation, application period and methodology for determining revenue requirements as applied by EU countries is given below.



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Table 4.2 – Natural Gas Transmission Tariff Methodologies in European Countries²⁷³

Country	Tariff Methodology	Period	Main Elements for Determining the Revenue Cap
Austria	Incentive regulation – price cap	4 years	Efficiency scores, increase in WACC for taking full volume risk
Belgium	Incentive regulation / revenue cap	4 years	Non-controllable and controllable costs, depreciation costs, taxes and fair margin
Croatia	Incentive Regulation / Revenue cap	5 years	OPEX and CAPEX. OPEX is projected for regulatory period based on 1 + CPI-X formula. Budgeted-planned CAPEX, with an ex-post adjustment based on real values (only up to the economically efficient level).
Czechia	Incentive regulation/Revenue cap, Price cap	3 years	Allowed costs, Allowed depreciation, RAB, WACC
Denmark	Strict cost plus	4 years	Danish TSO regulation doesn't fit to this scheme
Estonia	Rate-of-Return	No period	1) Variable costs 2) Operating costs 3) Depreciation of RAB 4) Justified return of RAB Legal framework
Finland	Revenue Cap	4 years	Efficiency-, Quality-, Innovation- and Investment incentive, WACC return on RAB
France	Incentive Regulation/Revenue cap	4 years	Non-controllable and controllable costs, depreciation costs, taxes and fair margin
Germany	Incentive Regulation / Revenue cap	5 years	Non-controllable and controllable costs, TOTEX efficiency benchmark, general inflation and sectoral productivity factor, volatile costs
Greece	Cost plus	4 years	OPEX (Non-controllable and controllable costs) Depreciation, RAB (Assets and approved investment plans, working capital), WACC
Hungary	Incentive Regulation	4 years	Hybrid model
Iceland	No Gas TSO	N/A	N/A
Ireland	Incentive Regulation / Revenue cap	5 years	1. Review of historic and forecast OPEX; 2. Review of historic and forecast CAPEX; 3. Value of Assets in TSO's RAB; 4. Rate of Return; and 5. Inflation
Italy	(Hybrid) Cost plus for capital expenditure with a price cap for operating expenditure / Incentive regulation	4 years	At the beginning of each regulatory period allowed OPEX allowances are aligned to actual OPEX expenditure, net of: ☐ A profit-sharing mechanism, if efficiency targets have been met ☐ A loss sharing mechanism, if efficiency targets have not been met For CAPEX, ex ante business case analysis is required as part of the process of developing a National Development Plan
Latvia	Cost-plus	1 year	OPEX + CAPEX (Depreciation + return on capital)
Lithuania	Price cap	5 years	TOTEX, RAB, WACC, technical losses, efficiency benchmark
Luxemburg	Revenue cap / incentive regulation	4 years	Remuneration on RAB; depreciation, Controllable OPEX; Non-controllable OPEX
Netherlands	Incentive regulation / Revenue cap	3-5 years	TOTEX, CPI, cost efficiency benchmark, productivity change, WACC, RAB
Norway	No Gas TSO	N/A	N/A

273 Source: CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks, Ref: C18-IRB-38-03.



This project is funded by the European Union



Poland	Cost of service with elements of revenue cap	Calendar year	Reasonable operating expenditures, depreciation, local taxes and other fees, cost of gas losses and return on capital employed
Portugal	Price-cap (OPEX) and rate of return (CAPEX)	3 years	Non-controllable and controllable costs, RAB, WACC, efficiency benchmark, inflation, mechanism for attenuation of tariff adjustments
Romania	Revenue cap	5-7 years	Non-controllable (pass-through) and controllable costs, efficiency factor, general inflation rentability of RAB (RABxROR) depreciation, technological consumption, working capital
Slovenia	Revenue cap/incentive regulation	3 years	Bottom-up assessment with OPEX and business cases (CBA) for major infrastructure projects
Spain	Revenue Cap/ Incentive Regulation	6 years	Investment reference values, OPEX reference values, RAB, rate of return, regulatory lifetime of assets, Revenues for continuity of supply and extension of asset's useful life
Sweden	Revenue cap	4 years	TOTEX (divided into CAPEX, Non-controllable OPEX and Controllable OPEX). General efficiency target of reducing 1 percent of controllable OPEX annually
UK²⁷⁴	Revenue cap	8 years	OPEX: Ofgem uses an overall TOTEX approach to determine allowed revenues. However, benchmarking and bottom-up assessments are also used to assess the robustness of NG-GT's business plans. CAPEX: A TOTEX approach is generally used. However, other analytical tools, i.e. bottom-up assessments, detailed project reviews and business case analysis, amongst others, are also used to assess the rigor of the proposed capital expenditure

Currently, there are several different reference price methodologies in Europe:

Postage Stamp: It foresees the same reference price at all entry and exit points.

Matrix: This methodology is based on the principle that the reference price at each entry (or exit) point should reflect the actual investment costs of the TSO.

Capacity Weighted Distance (CWD): It is based on the principle that the reference price at each entry (or exit) point should be set considering the contribution of that point to the total cost of the system. The 'weight' of each entry (or exit) point is measured by its capacity-weighted distance from all exit (or entry) points.

Distance to Virtual Point: It is similar to the CWD; however, the 'weight' of each entry (or exit) point is calculated according to the distance of that point from a focal virtual point of the network.

274 Source for UK, Italy and Slovenia country info: Methodologies and parameters used to determine the allowed or target revenue of Natural Gas Transmission System Operators (TSOs) Final report September 2018 Submitted to ACER by: Economic Consulting Associates

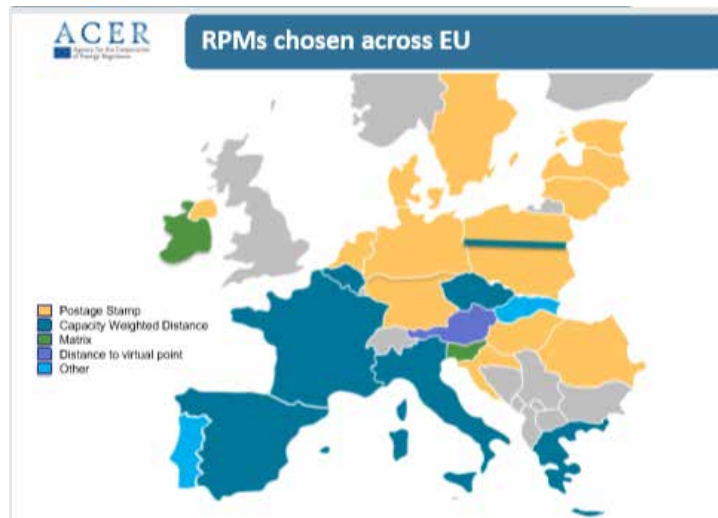


Figure 4.1 – Natural Gas Transmission Reference Price Methodologies in the EU²⁷⁵

Special Note – 1: Capacity Booking Methodologies Applied in the EU and More About the Reference Price Methodology Associated with Capacity Weighted Distance; the Case for Turkey

Although the majority of the EU members with liberal gas markets were applying the Entry Exit Capacity booking regime for long time, there were distance-based applications like Point to Point or Zonal tariffs in some countries until the release of the third energy package in 2009. Entry Exit capacity booking became compulsory for the member states with the publication of Regulation 715 in 2009. With this approach, the transmission costs should be no longer directly associated to specific routes, revenues should come from capacity bookings on entry and exit points and the TSOs are kept responsible for transporting gas in the most efficient way. In the past, distance-based systems like Point to Point were seen in the networks where the vast majority of supply is through a single entry-point. Considering the goal of the EU in terms of creating single EU wide gas market with harmonised rules in every country, Point to Point system cannot be applied in such a meshed market with hundreds of entry points and thousands of exit points. Still, there can be seen very limited examples in certain exempted pipelines and those are applicable for only the exempted part of the capacity (like TAP).

The reference price methodologies (RPM) introduced by the ENTSOG Tariff Network Code (TAR NC) provides a guidance on transmission tariff calculation which ensures cost reflectivity and predictability using predefined cost drivers. Consistency and transparency are the key requirements for all RPMs and in order to ensure those principles the TAR NC sets the “Capacity Weighted Distance” as a counterfactual. This method assumes that the share of allowed/target revenue among the entry and exit points should be proportionally distributed according to the cost of the capacity that point brings. The cost drivers are distance and capacity. All costs are tried to be distributed in a cost reflective way taking into account both the location of the point and the booked capacity at all points. Article 8 of the TAR NC provides the description of the methodology in detail.

Turkey applies the Entry-Exit capacity booking methodology since the beginning of third-party access (TPA) to the transmission grid in September 2004. The methodology well suits to the conditions of Turkey where there are 13 major gas supply points to the network and those are located at various directions surrounding the country. Apart from the requirements in EU case to apply Entry-Exit System, application of distance based capacity bookings, like the Point to Point system would never suit for such a meshed structure of Turkey and even tried, it would have brought too much complexity in defining the routes and the distances between each Entry and Exit Point. Point to Point system may have application for the networks with single or few entry points and unidirectional flow. Application of the system for TANAP Network is an example.

Regarding the requirement of Regulation 715 and TAR NC to specify a dedicated tariff for each network point by applying certain cost allocation methodology, it can be deemed that such approach is preferred for the sake of transparency and to allocate the transport charges to the points in proportion with the cost and burden such points bring to the transmission services. For the case of Turkey, such approach has not been adopted yet and there is unique capacity and service charge applicable for all exit points. There are already more than 500 exit points in the transmission system and in terms of the technical difficulties in transmission services, there would not be a strict separation among those points. This is due to the well organised supply structure of the Network. The Exit Points are densely located at the western part and 4 LNG Terminals and two underground storage plants are practically feeding this part. The congestions during peak consumption days are not likely to occur since the technical throughput capability of the network is considerably higher than the peak demand. The peak demand recorded was daily 243 million m³ and the technical deliverability is 320 million m³ and this figure expected to exceed 400 million m³ soon. In light of this, there is no ground for a separation among the exit point for unit charges due to special technical constraints. Such separation in later term would be linked with certain incentives for the investments in certain regions of the country and social tariff applications.

Within the scope of this report, summary tables regarding operation of Natural Gas Transmission sector are provided for most of the countries, whereas some countries Germany²⁷⁶, Italy²⁷⁷, Portugal²⁷⁸ and the UK²⁷⁹ are analysed in more detail in terms of Natural Gas Transmission revenue requirement and tariffs with efficiency involvements.

The TAR NC or other relevant legislation do not require the regulators to adopt certain regulatory regime from the alternatives as price cap and non-price cap regimes (revenue cap, rate of return and cost plus). Also, there is no obligation for the member countries' NRAs to apply certain rules or methodologies in determining the basic parameters of the tariffs like, Regulatory Asset Base, Depreciation Period, Rate of Return, etc. As of date, the majority of the EU countries apply incentive based Revenue Cap Regulation. However, the TAR NC does not define a methodology for setting up the incentive mechanisms and efficiency targets.

The above stated countries' existing structure in terms of Natural Gas Transmission activities, regulatory authorities' approaches to the certain components of the incentive-based Natural Gas Transmission tariffs and their methodologies in determining the efficiency parameters are summarized below.

4.2 Stakeholder Responsibilities

In **Germany**, in 2005 the legal framework was changed in order to abolish the system of cost-plus regulation for electricity and gas network operators, which was in place at that time, and replaced with an incentive regulation scheme. An incentive-based regulatory regime was introduced in 2009 to replace cost-plus regulation. Under this regime, the revenue that network operators are allowed to earn within a certain period (regulatory period) is determined using a mathematical formula and fixed for the period.

In the gas market, there are 16 Transmission System Operators whose activities are regulated by the regulatory authority "Bundesnetzagentur" (BNetzA). 'BNetzA' applies the same reference price methodology ('RPM'), a postage stamp methodology, jointly for all transmission system operators ('TSOs') in each of the two entry-exit zones, NetConnect Germany ('NCG') and GASPOOL. While the entry-exit split is not a parameter of the methodology, the shares of revenues allocated to entries and exits are, respectively, 32% and 68% for NCG, and 38% and 62% for GASPOOL.

In **Italy**, the National Regulatory Authority – ARERA establishes the methodology and sets allowed/target revenues in terms of Natural Gas Transmission tariff. There are 9 licensed TSOs in the country, however, the most significant TSO is Snam Rete Gas S.p.a. who owns more than 95% of the entire Natural Gas Transmission network.

ARERA issued a Resolution on 28 March 2019 (114/2019/R/GAS) for the 5th Regulatory Period, named, "Tariff regulatory criteria for the Natural Gas Transmission and metering service for the fifth regulatory period (2020-2023)". With this new Resolution the ARERA confirms intends to:

a) Ensure an increasing coordination between tariff regulation and the assessments of the national Ten-Year Transmission

276 Germany related text of the sections 4.2.1 through 4.2.5 is prepared by referring to "CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks", " Methodologies and parameters used to determine the allowed or target revenue of Natural Gas Transmission System Operators (TSOs)- Final report September 2018 Submitted to ACER by: Economic Consulting Associates", "Agency Report Analysis of the Consultation Document on the Natural Gas Transmission Tariff Structure for Germany-13 February 2019" and Bundesnetzagentur web site.

277 Italy related text of the sections 4.2.1 through 4.2.5 is prepared based on the references: "ARERA Annual Report 2017", "ARERA ANNUAL REPORT 2019-Summary-State of Services and Regulatory Activities", "ARERA Resolution on 28 March, 2019 (114/2019/R/GAS) for the 5th Regulatory Period", Methodologies and parameters used to determine the allowed or target revenue of Natural Gas Transmission System Operators (TSOs)-Final report September 2018 Submitted to ACER by: Economic Consulting Associates" and Snam Rete Gas Web Site.

278 Portugal related text of the sections 4.2.1 through 4.2.5 is prepared by referring to "CEER Report, (18 January 2019), Incentive Regulation and Benchmarking Work Stream Report on Regulatory Frameworks for European Energy Networks", " Methodologies and parameters used to determine the allowed or target revenue of Natural Gas Transmission System Operators (TSOs) Final report September 2018 Submitted to ACER by: Economic Consulting Associates".

279 The UK related text of the sections 4.2.1 through 4.2.5 is prepared based on the information through Ofgem Web Site, the publications "Ofgem-Handbook for implementing the RIIO model October 2010", "Ofgem - RIIO-T1 Natural Gas Transmission Price Control – Regulatory Instructions and Guidance: Version 6.2, 7 May 2019", "National Grid Gas (NTS) - System Operator Incentives 2018/19 Supporting Information, October 2018 and the CEER and ECA Consulting Reports.

Network Development Plans set up by TSOs;

- b) Initiate a specific monitoring of the investments made and of the objectives achieved, also to check if they are consistent with the provisions of the Plans, requiring operators, starting from 2020, to provide reports that compare the outputs actually achieved with those declared in the Plans and used for cost-benefit analysis (CBA);
- c) Require operators to also provide, in the reports described in point b) above, information on any discrepancies between the costs estimated in the Plans and used for the CBA and the costs actually incurred.

In addition, ARERA deems that for the 5th Regulatory Period, incentives might be designed on an experimental basis aimed at increasing the efficiency of the investment expenditures, related in particular to the additional remuneration granted.

In **Portugal**, regulation for gas market began in gas year 2007-2008 for the high-pressure activities and in gas year 2008-2009 for the remaining activities. There is single TSO (*Redes Energéticas Nacionais*) operating the high-pressure transmission grid. At the beginning of the regulatory period 2016-2017 to 2018-2019, a mechanism was introduced in the transmission and distribution activity that seeks to mitigate the effects associated with the volatility of demand in the amount of allowed revenues to be recovered by tariffs. In the same period, for the reception, storage and regasification of LNG activity and subterranean storage activity, a mechanism was applied to mitigate tariff adjustments, recognizing the positive externalities this activity brings to all the Natural Gas National System. In the global system management activity, regulation changed from an accepted cost model to an incentive regulation model (revenue cap).

The methodologies and parameters for the tariff calculation are evaluated and fixed at the beginning of each regulation period to be applied during that period, which has a duration of 3 years. The NRA, ERSE established the methodology and sets the allowed revenue target. ERSE must also consult with 'Tariff Councils', which include TSO and consumer representatives. The Tariff Councils also provide a non-binding opinion to the NRA. A variety of assessments are used to determine the appropriate allowed revenues for OPEX, including bottom-up and top-down assessments.

In **the UK**, the Regulatory Authority Ofgem has put into application the performance-based framework to set the price controls, the RIIO, in 2013 and the first regulatory period was set as 8 years (2013 – 2021). There is single TSO, *National Grid Natural Gas Transmission Plc (NGGT)*, operating the Natural Gas Transmission grid. The price control set by the Regulatory Authority Ofgem for the National Grid Natural Gas Transportation Services (NTS) is divided into Transportation Owner (TO) and System Operator (SO) controls.

There are three price controls under RIIO-1, covering four sectors. RIIO-T1 is the price control for Natural Gas Transmission and Electricity Transmission. RIIO-GD1 is the price control for Natural Gas Distribution. RIIO-ED1 is the price control for Electricity Distribution. Each of the current price controls are set to run for an eight-year period.

The next network price controls will start from 2021, under RIIO-2.

RIIO-T1 is the price control for the high voltage Electricity Transmission networks and high-pressure Natural Gas Transmission networks which transmit energy across the UK from where it is generated. The price control runs for eight years, from 2013-2021.

Each year, transmission and distribution network owners report to Ofgem on their performance against the RIIO price control. Ofgem publishes annual reports and interactive charts and data on their performance as part of its market monitoring.²⁸⁰

3.8 Revenue Requirement Model, Allowed Expenditures

3.8.8.1 Germany

The revenue caps for network operators are set for a five-year regulatory period. Each cap is composed of the permanently non-

controllable costs, temporarily non-controllable costs, controllable costs (applying a distribution factor for reducing inefficiencies), and volatile costs. The difference between the allowed revenue and the development of actual volumes over the year is entered into a regulatory account.

The revenue cap for each operator is set on the basis of the operator's base level of costs **and its efficiency level**.

The base level costs are divided into:

- permanently non-controllable costs; and
- generally controllable costs.

The regulatory authority issues an official notice stating the revenues allowed in each year of the regulatory period; this marks the end of this step of the process.

The starting point for setting the revenue caps and, in turn, the network charges is based on each network operator's actual costs. Prior to the start of a regulatory period, the regulatory authorities determine the base level used to set the revenue cap. This is done by means of a cost examination carried out in accordance with the provisions of the network charges ordinances. All network operators – regardless of their size – are subject to these cost examinations. The base level determined, applies for the whole of a regulatory period. Each cost examination takes place in the last but one calendar year before a new regulatory period begins. It is based on the operators' annual financial statements for the last full financial year, which is referred to in the Incentive Regulation Ordinance (ARegV) as the "base year".

The costs data mainly comprise of staff and materials costs, interest on borrowings, depreciations and other operating costs. Depreciations are prescribed in the regulations and are based on technical asset lives.

The costs, which are known as the permanently non-controllable costs, are deducted from this cost pool (materials costs, staff costs, costs of borrowing, taxes, other costs, write-downs and return on equity, minus revenue and income with cost-reducing effect). Permanently non-controllable costs are, for example, upstream network costs, non-wage labor costs and concession fees. Network operators can fully recoup the permanently non-controllable costs as revenue.

The CAPEX subtraction is also deducted from the cost pool. The remaining controllable costs data and the structural data are then taken for the efficiency benchmarking model.

Return on investment with conditions:

The Bundesnetzagentur calculates a rate of return on capital for each regulatory period that reflects the risks involved and the current conditions in the financial markets.

The return on investment currently comprises the following:

- Risk-free rate: – determined on the basis of the ten-year average current yield of fixed interest securities;
- Risk premium: – this indicates the premium demanded by an investor to invest in gas and electricity networks instead of an alternative, risk-free project and is determined using scientific methods.

The regulated rate of return on equity before corporate tax is obtained by summing the risk-free rate and the risk premium. The imputed rate of return on equity before taxes is obtained by adding the corporation tax rate. **A company can only achieve this desirable rate of return if an efficiency level of 100% has been determined (in efficiency benchmarking) and the actual costs of the company at the most correspond to the set revenue cap.** In the case of debt, account is taken of the actual cost of debt. There is no guaranteed rate of return that applies regardless of real efficiency levels and hence no "monopoly" yield.

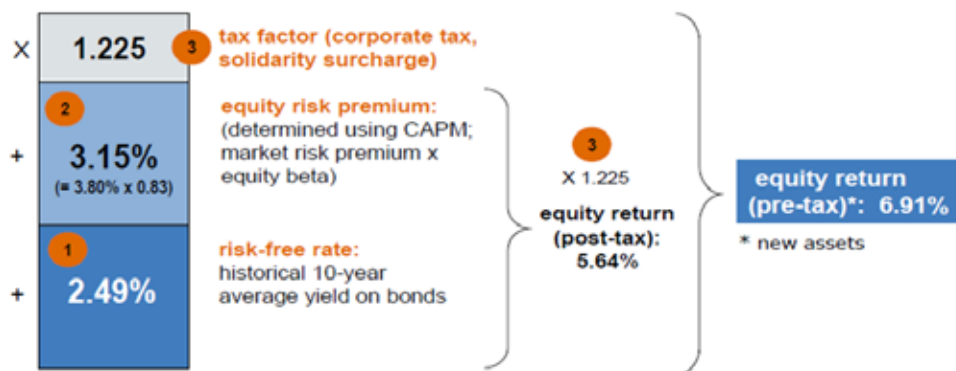


Figure 4.2 – Germany/Determination of the rate of return on equity²⁸¹

The costs data are supplemented by a calculated return on equity. The return on equity comprises a risk-free rate (determined on the basis of the ten-year average current yield of fixed-interest securities) and a risk premium. The premium covering network-specific risks is determined using the capital asset pricing model (CAPM) and is derived from the product of an imputed market risk premium and a risk factor (beta factor).

Corporate tax is accounted for through a factor applied to the sum of the risk-free rate and the risk premium. Trade tax is, by contrast, determined on the basis of the return on equity.

The rate of return on equity is different for new and old assets. The return on equity comprising the risk-free rate, the risk premium and the corporate tax factor is applicable to “new assets” that first existed in or after 2006. A rate adjusted to take account of inflation is applicable to “old assets” that existed before 2006.

The rate of return on equity is granted for existing assets to a maximum of 40% of the imputed necessary business assets. Any available equity capital in the capital structure in excess of this is subject to another equity interest rate. This “equity interest rate” is aligned with the standard rates of interest for procured capital and is set as a ten-year average based on the yields published by the German Bundesbank (federal bank). Existing borrowed capital is recognized at equal value insofar as any interest on borrowings does not exceed the customary market interest rate for comparable loans.

As stated above, Germany treats the cost of equity and debt separately, actual debt costs are recognised in allowed revenues subject to assessing their reasonableness against interest costs that are “customary in the financial markets for similar borrowings”; the cost of equity is determined employing a conventional CAPM approach, however given that ‘old’ (pre-2006) assets are valued at replacement cost, the cost of equity is set in real terms, whereas for ‘new’ assets (2006 onwards) it is set in nominal terms (both costs are in pre-tax terms).

The Risk-Free Rate (RFR) is set by reference to German government bonds, so the RFR will necessarily reflect the variability between different government bond yields.

The market risk premium (MRP) adopted by Bundesnetzagentur is 3.8%.for the current tariff period and that has been determined in accordance with the study “Credit Suisse Global Investment Returns Sourcebook 2016 (Dimson, Marsh, Staunton), data of 23 countries, 1900-2015”.

The method used for establishing the equity beta is applying Modigliani-Miller theorem (using a gearing ratio of 60%) and take into account taxes to calculate the equity beta based on the asset beta. Estimation periods of 1-year, 3-years, and 5-years are used together with daily observations.

²⁸¹ Source: Presentation by Dr. Annegret Groebel, “BNetzA’s role in energy infrastructure regulation and planning/permitting” on 10 April 2018, Paris Dauphine University.

4.3.1.2 Italy

The applied tariff regulation is: “Cost plus for capital expenditure with a price cap for operating expenditure”.

At the beginning of each regulatory period, allowed OPEX are aligned to actual OPEX expenditure, net of:

- A profit-sharing mechanism, if efficiency targets have been met; and
- A loss sharing mechanism, if efficiency targets have not been met.

For determining and setting capital expenditures, ex ante business case analysis is required as part of the process of developing a National Development Plan.

RAB is determined through the historical cost of the assets (i.e. the depreciated book value of the assets) as per the TSO’s statutory accounts at the time of the beginning of each regulatory period.

The method for updating the price cap tariffs is applied only to revenues related to operating costs, which is updated for inflation and reduced by an annual recovery coefficient set at 2.4%. The revenue component relating to the return and amortization and depreciation is updated on the basis of an annual recalculation of net invested capital (RAB) and additional revenue from the higher rate of return for investments realized in previous regulatory periods. Amortization and depreciation are calculated based on the useful economic and technical life of the transportation infrastructure.

Cost-plus approach is used for capital expenditures. An adjustment is not applicable.

The target revenues are as the sum of:

- a) An appropriate return on the regulatory net invested capital, including any additional remuneration allowed as incentive for new investments, starting from the second regulatory period;
- b) Economic and technical depreciation;
- c) Allowed operating expenditure;
- d) Costs incurred by TSOs for the operational balancing service of the system.

WACC method (Pre-tax WACC set in real terms) and CAPM are applied in determining the cost of the capital and the cost of equity, respectively. The RFR is set based on the historical yields of other government bonds. Currently, it is based on the average yields of France, Belgium, Netherlands and Germany bonds (10 years), as long as these countries have maintained a rating level of at least AA according to S&P’s classification for the period 1st October 2017 – 30th September 2018. The market risk premium is based on actual returns over a period of time. It was computed as the difference between the rate of Total Market Return (TMR) and the real Risk-Free Rate (RFR). TMR represents the market’s total return and it is computed as a weighted average of the historical data of returns in four countries with AA S&P rating (Belgium, France, Germany, the Netherlands) over the period 1900-2014. In the TMR computation, a combination of arithmetic and geometric average is used (respectively, 80% and 20%).

A Country Risk Premium (CRP) for Italy is also added, which is computed by estimating the difference between the yields of bonds issued by Italian utilities and the yields of bonds issued by utilities based in Eurozone high-rated countries. This parameter is then adjusted with the volatility of the Italian stock market. Currently, CRP is set to 1%.

4.3.1.3 Portugal

The activities of the gas TSO are mainly subject to incentive regulation (price-cap and revenue-cap) for OPEX and on the application of the rate of return to investments in CAPEX. However, TOTEX approach has been applied in some activities and standard investment cost in others. There are also other incentives, such as incentives for quality of service, losses reduction and smart

grids. However, throughout the regulatory periods there has been a need to change to other methodologies.

An ex-ante allowance is set based on the best forecast available to the NRA (typically based on the requirements of a National Development Plan). However, the ex-ante allowance is also assessed ex-post based on realised data.

The cost of capital is determined through pre-tax nominal WACC method. CAPM is used in determining the cost of equity. For setting the RFR the historical yields of other country government bonds with AAA rating (Germany, Finland, Austria and Netherlands when risk free rate was set, namely in June 2016). The Market Risk Premium is determined as the summation of the Risk Premium for Mature Market and the Country Risk spread.

Adjustments to OPEX are made to correct the difference between forecasted costs and actual costs. Adjustments are made in the year following the forecast, based on estimated values and two years after the forecast, based on actual values. The year before the start of each regulatory period, the NRA defines the OPEX bases for the first year of each regulatory period. At this point a sharing of gains is made between regulated companies and consumers.

Determining the Revenue Caps:

The allowed revenues are calculated based on the information sent annually by the regulated companies, real audited data and estimated data. This information includes financial data, operating costs and depreciation, investments and subsidies and technical data, such as quantities. At the beginning of each regulatory period the companies send their cost forecasts for the entire new regulation period.

Regarding investments, in addition to the analysis of the values sent by the companies each year, ERSE also takes into account the Development and Investment Plan prepared every two years by each sector's transmission and distribution network operators. In these cases, ERSE must also carry out a public consultation and, in accordance with the result, issue its opinion for subsequent approval by the Government.

The remuneration of the asset base is calculated using a pre-tax nominal WACC. The methodology used for setting the cost of equity is the CAPM and the cost of debt is set using a default spread model, where a spread (debt premium) is added to the risk-free rate.

The WACC (Pre-tax) to be applied in the regulatory period, is indexed to the Portuguese 10-year bond benchmark and depends, each year, on its evolution, with a cap and a floor. The floor is 5.40% and the cap is 9.00% for the Gas TSO.

4.3.1.4 UK

Under a Revenue cap regulatory regime, Ofgem uses an overall TOTEX approach to determine allowed revenues. However, benchmarking and bottom-up assessments are also used to assess the robustness of the National Grid Gas plc - NGGT's business plans. Uncontrollable expenses are fully passed through (subject to approval) such as license fees, business rates, security costs (for 'critical' infrastructure).

National Grid has appropriate commercial incentives to operate the gas NTS in an economic and efficient manner, as they are required to do under the terms of their license as the System Operator. To achieve this, Ofgem works to develop incentive schemes that provide National Grid with an appropriate balance of risk and reward. At the same time, the interests of present and future consumers, who ultimately pay for the costs of system operation, are tried to be protected. Cash out arrangements and the System Operator incentive schemes form part of Ofgem's overall work to regulate the NTS monopolies and to work towards maintaining market efficiency.

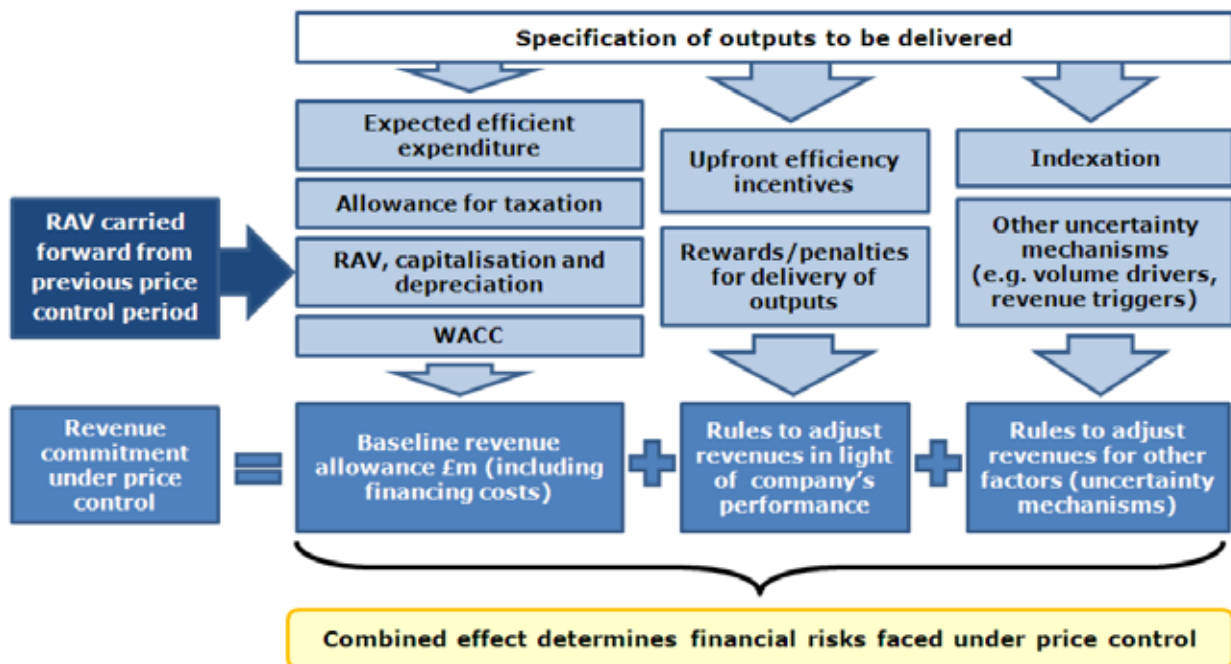


Figure 4.3 – The Building Blocks of the RIIO²⁸²

The annual net additions to RAV are calculated as a percentage of TOTEX. TOTEX consists of all the expenditure relating to a licensee's regulated activities with certain exceptions such as:

- Pension Scheme Administration and Pension Protection Fund (PPF) levy costs;
- All statutory or regulatory depreciation and amortization;
- Profit margins from related parties (except where permitted as defined below);
- Costs relating to rebranding NGGT's assets or vehicles following a name or logo change; fines and penalties incurred by the licensee (including all tax penalties, fines and interest) except if, exceptionally Traffic Management Act costs can be shown to be efficient;
- Compensation payments made in relation to standards of performance;
- Bad debt costs and receipts (subject to an ex post adjustment to allowed revenues);
- Any costs relating to the System Operator for external purposes (i.e. balancing services activity) Interest, other financing and tax costs (except for business rates on non-operational buildings and stamp duty land tax).

Costs added to RAV are all intended to refer to costs incurred by the licensee or a related party of the licensee undertaking regulated business activities. Where those costs are recharged to the licensee, they do not include any internal profit margins of the licensee or related party, except where permitted.

Ofgem reserves the option to disallow costs from the RAV for any of the TOTEX expenditure if they do not relate to the regulated business or are demonstrably inefficient or wasteful.

Additions to the RAV are calculated as a set percentage of TOTEX. TOTEX is dealt with as follows:

- An agreed percentage of TOTEX (see below) will be funded as slow money (i.e. as an addition to RAV)
- The remainder will be funded as fast money (i.e. which is spent and funded in the year of expenditure)

At the end of each year of a price control, as part of the Annual Iteration Process, Ofgem publishes an updated GT1 Price Control Financial Model (PCFM) which gives an indicative updated RAV for each licensee. In ascertaining these values, it is important that

the treatment of expenditure that licensees incur in this period is consistent with the principles and specific issues set out in the Final Proposals – that is, the same constituents of costs are included as TOTEX. Costs are added on a normal accrual's basis.

Analytical tools, i.e. bottom-up assessments, detailed project reviews and business case analysis, amongst others, are also used to assess the rigor of the proposed capital expenditure.

Any change in the TOTEX amount for the licensee under the TOTEX Incentive Mechanism (TIM) is included as an adjustment to fast/ slow money;

- pension deficit repair payments relating to any incremental deficit (i.e. not part of the established deficit) are considered to be part of the licensee's labor costs and as such are part of TOTEX; and
- customer contributions (which mainly relate to connection works) and other proceeds received (including from legal and insurance claims) that relate to the transmission business are treated as an offset to TOTEX expenditure.

Related with the cost of capital, an allowed WACC is set on a vanilla basis in real terms. In applying CAPM there is no defined method to set the MRP/ERP. Ofgem uses various techniques, proposes a premium, offers NGGT (and others) an opportunity to comment on the proposals before finalising. The equity beta is established by reference to regulatory precedent elsewhere and by calculation. The cost of debt is set on a trailing basis using an index of corporate bonds. Ofgem uses the 'iBoxx non-financials index' for A and BBB credit ratings.

4.3.2 Revenue Adjustments

4.3.2.1 Germany

Independent of the regulatory period, the difference between revenue allowed and revenue generated by network operators in light of actual consumption volumes and the difference between changes in (some) volatile and some permanently non-controllable costs set based on planned values and actually incurred is entered annually in the regulatory account.

The differences entered are to carry interest at the level of the average amount committed in the particular calendar year (average current yield, for the last ten full calendar years, of fixed interest securities of domestic issuers as published by the Deutsche Bundesbank). The average amount committed is obtained from the average of the amount at the beginning of the year and the final balance at the end of the year.

Related with the adjustments of the operating expenditures, no adjustments are done for controllable costs (non-controllable or volatile costs are adjusted via the regulatory account as explained above).

TSOs are able to refinance their necessary expansion and restructuring investments through investment measures. Proposed expansion and restructuring investments can be approved, provided they are required for the stability of the system as a whole, incorporation into the national or international interconnected grid, or expansion of the network to meet energy supply requirements. Investments approved under the investment measures are factored into the revenue cap as permanently non-controllable costs.

In the event of changes in other permanently non-controllable costs of a network operator in the course of a regulatory period, the revenue cap and thus the network charge can be adjusted accordingly

4.3.2.2 Italy

Tariffs are adjusted within period as well as over periods by taking into account under and over recoveries through the 'reconciliation process'. Reconciliation takes place through tariff adjustments in year 'y+2'. To avoid steep tariff changes, if the reconciliation is more than 2% of the allowed revenues, the amount of reconciliation exceeding that threshold is spread out over four years. When over or under recoveries are moved to a different year, then a risk-free rate plus a premium is applied. For differences between forecasted or allowed operating expenditures and realized expenditures, a profit-sharing mechanism is in place. If during

a regulatory period an operator reduces its OPEX, the allowed OPEX for the next regulatory period is set to recover actual operating costs plus a decreasing share of half the efficiency gains obtained during the previous period (over 8 years). Efficiency gains are defined as the difference between allowed OPEX (net of profit sharing) and actual costs in the last year of the regulatory period.

4.3.2.3 Portugal

The allowed revenues from each activity are adjusted after two years based on real, audited values. The adjustments made, result from changes in the level of cost drivers. Costs accepted outside the cost base are also recalculated on the basis of actual values. For the natural gas sector, all activities undergo adjustments at the end of 1 year (estimated adjustment) and at the end of 2 years (actual adjustment).

Over or under recoveries are typically adjusted within the regulatory periods, but if needed it could be adjusted between them as well. The difference between realized costs or parameters and the revenues recovered through tariffs are accounted for in the tariffs two years later, including the estimated financial costs or gains generated by these deviations. These over or under-recoveries are carried forward using the CPI. Adjustments related to demand forecast deviations and which are equal to more than 20% of allowed revenues are spread over three years.

Investments and amortizations considered in the rate of return methodology are updated, in a first stage, based on estimated values, and after two years based on actual and audited values.

The values of the actual adjustments are deducted from the estimated adjustments in the activities where this calculation is made. The values of the adjustments are incorporated into the allowed revenues of the year with the appropriate financial update.

The CAPEX is treated with cost-plus methodology and no adjustment is applied for the differences between forecasted or allowed capital expenditures and realized expenditures.

4.3.2.4 UK

Over or under recoveries are adjusted within the regulatory period, annually with a two-year lag. The adjustments are carried forward using the WACC, unless they are material in which case a 'penalty' rate applies (broadly, WACC minus 1 percentage point).

No differentiation is made between the operating expenditure and capital expenditure under the TOTEX approach. The adjustments are made symmetrically and apply to over and underperformance symmetrically. The sharing rate of over and underspending is 44.36%, i.e. the share that NGGT bares. Adjustments are made using the allowed WACC.

Related with capital expenditure deferrals, various mechanisms are used to ensure deferrals are efficient e.g. use of volume or output drivers (if these are not met, then revenue from deferrals is clawed back), no allowances are given again for the same expenditure in future, re-openers are possible if underspend is material, etc.

4.4 Efficiency, Performance Indicators

Generally, the issues like efficiency benchmarking, defining performance indicators are applicable at DSO level rather than gas TSOs. For instances, there are no commonly adopted quality indicators like the case for distribution sector; such as SAIDI and SAIFI. Some technical parameters for a gas TSO in terms of performance can be classified as Incidents (damages), Gas Leaks, Asset Maintenance, Corrosion and Emergency Response. Other than technical quality, another main category could be the commercial quality involving certain parameters like the Cost of Fuel Gas and Balancing Services, Demand Forecasts, Stakeholder Satisfaction, Congestion Management etc.

There seen limited examples in Natural Gas Transmission sector where the NRA's define specific performance indicators and associated incentives as part of TSO revenues. The UK case is a good example for that, and the study will focus onto only the UK case for the involvement of performance indicators.

4.4 Germany

The Bundesnetzagentur carries out its efficiency benchmarking on the basis of the cost examination (TOTEX) and structural data validation before the start of each new regulatory period for gas and electricity network operators separately. The efficiency benchmarking involves assessing the operator's individual costs against the services they provide and determining each operator's cost efficiency compared to the other operators.

The efficiency level is applied to the generally controllable costs to create a block of efficient and a block of inefficient controllable costs. The operator is required to gradually reduce only the inefficient controllable costs over the course of a regulatory period.

In addition to the (input) cost parameters, structural (or output) parameters are taken into account to replicate the services provided in each case as well as the regional characteristics. Possible structural parameters could include the number of connection points, peak load, the amount of energy delivered or injected and compressor station data. The costs and structural data collected always relate to the base year, which is always the third year of a regulatory period.

The structural cost parameters for all network operators are used to define groups or combinations of parameters that reflect the services provided by the network operators. The optimum size of the parameter groups is also examined and defined. The efficiency scores for the network operators are determined by applying the data envelopment analysis (DEA) and stochastic frontier analysis (SFA) methods to the defined parameter groups.

Benchmarking:

The Bundesnetzagentur carries out its **national efficiency benchmarking** on the basis of the assessed costs before the start of each new regulatory period. The benchmarking takes place separately for electricity and gas, as well as for distribution system operators and transmission system operators. Key here is that a total cost benchmarking approach is adopted that takes both capital and operating costs equally into account.

The benchmarking does not take into account any costs that a network operator cannot control, such as costs for the use of the upstream network. The Incentive Regulation Ordinance (ARegV) lists the costs that are deemed to be non-controllable.

In Germany, the efficiency factor is TSO-specific, and each TSO must eliminate any inefficiencies compared to the industry benchmark within a regulatory period. Germany also applies an efficiency factor, currently set at 0.49% per year. A network operator's efficiency is not determined solely on the basis of the absolute level of the operator's costs. Rather, the costs recognized as necessary for network operation are assessed in relation to the operator's supply obligations. The efficiency benchmarking determines each operator's relative cost efficiency compared to other operators, taking into account the individual supply tasks. The network operators are compared only with each other.

National efficiency benchmarking of twelve Natural Gas Transmission system operators was carried out to determine the efficiency levels for the second regulatory period. All except one operator – with an efficiency of 95% – achieved an efficiency level of 100%.

4.4.1 Italy

Inclusion of efficiency or productivity improvements are applicable only for the OPEX (not for CAPEX) and the efficiency factors used in most recent regulatory period is 1.3% per year (being an average for the sector, as company-specific factors are set).

Efficiency Targets:

The allowance covering operating costs is subject to annual updating based on the following formula and clarifications in the ARERA Resolution as follows:

$$RT_{COR,t} = RT_{COR,t-1} \times (1 + RPI_{t-1} - X + Y + Z)$$

where:

- RPI_{t-1} is the annual average growth rate of consumer prices for the families of blue- and white-collar workers measured by ISTAT, with reference to the year before the presentation year of the tariff proposal;
- X is the predefined annual productivity recovery rate (*X-factor*);
- Y is an additional variation parameter of allowed operating costs which takes into account costs resulting from unforeseeable and exceptional events and changes in the regulatory framework;
- Z is an additional variation parameter of allowed operating costs which takes into account incremental costs resulting from new investments.

With reference to the X -factor, ARERA intends to define a productivity recovery coefficient for each company, essentially in continuity with the criteria adopted in previous regulatory periods. This parameter is determined with the sole objective of absorbing in a period of 4 years the share of the greater efficiencies (or possible inefficiencies) achieved in the 4th Regulatory Period and included in the operating expenditure of the first year of the regulatory period without therefore setting further efficiency targets. In particular:

- a) For companies that recorded actual operating expenditure for 2017 lower than the allowed operating expenditure for 2017, determine the efficiency target to absorb the greater efficiencies achieved during the 4th Regulatory Period over a 4-year period;
- b) For companies with actual operating expenditure for 2017 that is higher than the allowed operating expenditure for 2017, determine the efficiency target to return the operator back to a level of efficient costs (assumed to be equal to the allowed operating expenditure in the reference year 2017) over a 4-year period.

With reference to the Parameter Y and operating expenditure related to new investments, for the annual update of the allowed operating expenditure, ARERA intends to confirm the possibility for operators of:

- a) Requesting the activation of parameter Y to adjust the level of the allowed operating expenditure in relation to costs arising from unforeseeable and exceptional events and changes in the legislative framework; companies that apply for the activation of this parameter must prove that these costs are incremental with respect to the actual costs considered in the base year as well as the actual unpredictability and exceptionality of the events considered or, in case of changes in the legislation, any activities already carried out and any further activities that become necessary to comply with this new legislation;
- b) Exceptionally, for building and commissioning new infrastructures, requesting the allowance of a revenue RT component to cover incremental costs if the actual operating expenditure (in year $t-2$ compared to the tariff year) is higher than the allowed operating expenditure in year t , to the extent that this difference in costs can actually be attributed, on the basis of the company's analytical accounting data, to the operation of the new infrastructures.

4.4.3 Portugal

The definition of efficiency targets, with the objective of reducing controllable costs, is based on international and national benchmarking studies through the application of parametric and non-parametric methods. Specifically, the Corrected Ordinary Least Squares (COLS) and Stochastic Frontier Analysis (SFA) methodologies are used in the parametric models and the Data Envelopment Analysis (DEA) methodology is used in the non-parametric models.

As of date, the inclusion of efficiency or productivity improvements in determining and setting operating expenditures has not been affected yet. An annual efficiency factor of 3% is used in the tariff relating to OPEX.

There is no Inclusion of efficiency or productivity improvements in CAPEX evaluation.

4.4.4 UK

For both CAPEX and OPEX allowances, efficiency or productivity improvements are included in evaluation. There is no single “efficiency/productivity factor” but many factors are embedded in cost allowances.

Ofgem collects data from NGGT and monitors NGGT’s performance against the outputs required to deliver, to calculate any rewards or penalties associated with incentive mechanisms, and to determine adjustments to allowances determined within period, i.e. costs determined through uncertainty mechanisms. The data provided in accordance with the “Regulatory Instructions and Guidance” documents (the RIGs) of Ofgem provides a database of NGGT’s performance which Ofgem draws on to set cost proposals at subsequent review periods. The RIGs inform NGGT about the information Ofgem plan to collect, guide them on how to provide this information and enable NGGT to put systems in place to collect the data to the detail Ofgem requires. The framework also allows Ofgem to collect data on provisional TOTEX expenditure for use in the annual iteration process and the calculation of the incremental change to base revenue .

In order to enable Ofgem to effectively monitor the performance of the Natural Gas Transmission networks including in relation to system flows and asset health during RIIO-T1, the operators are required to prepare worksheets with the following sections.

- System Characteristics
- Activity Indicators
- Utilization and Performance
- Demand Capability
- Compressor Utilization
- Environmental
- Asset data
- Forecast Scenarios

This is to enable Ofgem to effectively monitor the performance of the Natural Gas Transmission System Operator against the gas system operator incentive schemes.

National Grid Gas, System Operator Incentives

National Grid Gas (National Grid) operates the high-pressure Gas National Transmission System (NTS) in the UK. This System Operator (SO) function is subject to a license obligations and several financial incentive arrangements. These incentive arrangements encourage National Grid to minimize the overall cost of system operation to consumers, to consider environmental impacts and to support the efficient operation of the wholesale gas market.

These arrangements are designed to encourage National Grid to deliver outputs which provide benefits to the industry and consumers. These benefits include direct financial benefit from reductions in the costs associated with operating the Natural Gas Transmission network and other benefits from meeting key performance targets.

The various incentive schemes provide a focus on key areas where National Grid can create value for the industry and consumers, allowing National Grid to retain a share of any value created (or to be penalized should targets not be met).

The incentives defined for NTS are as follows:

- NTS Shrinkage
- Residual Balancing
- Day Ahead Demand Forecasting
- Greenhouse Gas Emissions
- Maintenance
- Demand Forecasting (D-2 to D-5)
- Entry capacity and Exit Capacity Constraint Management
- Customer and Stakeholder Satisfaction

NTS Shrinkage:

NTS Shrinkage covers the gas and electrical energy which is used in operating NTS compressors, and the gas that cannot be accounted for and billed in the measurement and allocation process.

The form of the NTS Shrinkage incentive is a bundled cost minimisation incentive across all components of shrinkage, with a target principally derived from an energy procurement cost benchmark.

The overall cost target is also subject to:

- An adjustment for comparison of outturn Compressor Fuel Usage and Calorific value Shrinkage (CVS) volumes compared to 'efficient' levels;
- An allowance for the Transmission Network Use of System charges incurred in respect of electrically driven compressors; and
- An adjustment for other shrinkage costs, including environmental scheme compliance, electricity supply charges and other energy trading costs.

The shrinkage incentive scheme is currently in place from 01 April 2013 until 31 March 2021 to minimise overall costs it incurs in its role as NTS shrinkage Provider. The incentive scheme measures the NTS shrinkage costs incurred against a target. This target is principally determined by multiplying forecast and actual volumes by benchmark energy procurement prices.

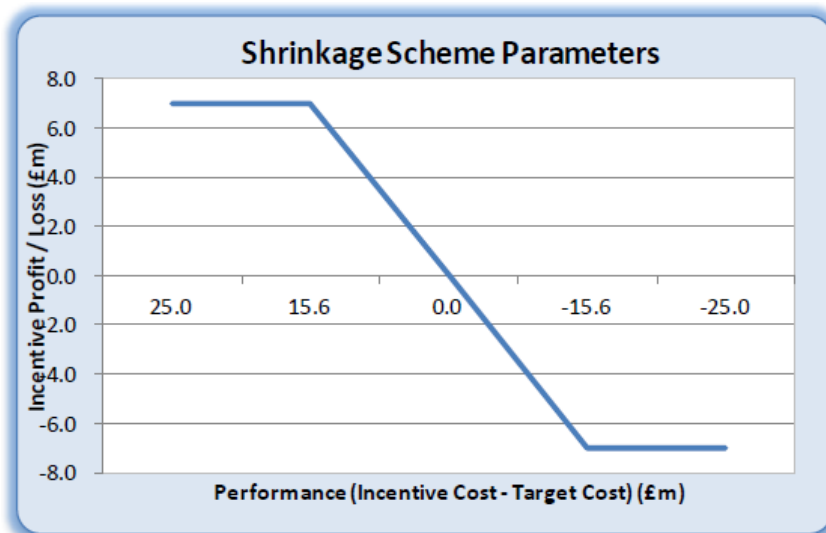


Figure 4.4 – UK NTS shrinkage scheme parameters

Residual Balancing:

The purpose is to incentivize the daily balancing of supply and demand whilst minimizing the impact of any actions on market prices.

The incentive contains two elements; the Price Performance Measure (PPM) and the Line pack Performance Measure (LPM).

The PPM incentivizes National Grid to execute any residual balancing trades at prices that are in a small range compared to the System Average Price (SAP) for the day. The PPM is defined as the difference between the highest and lowest prices at which National Grid trades, divided by SAP. The target is a price spread of 1.5% of SAP.

The LPM incentivizes National Grid to minimize any changes between starting and closing NTS line-pack over a Gas Day (i.e. to

achieve a balance between the supply and demand on the Gas Day). This is intended to ensure that any system imbalances are resolved on the relevant day, so that the costs of resolving any imbalances are targeted to those responsible for the imbalance. The target is a line-pack change of 2.8 mcm.

Demand Forecasting:

This incentive aims at improvements in the accuracy of the Demand Forecasts issued by National Grid. These forecasts assist the industry in making efficient physical and commercial decisions to balance supply to, and demand from, the NTS.

National Grid has an incentive target of an annual weighted average absolute forecast error of 8.5mcm. The daily forecast error is calculated as the difference (in mcm) between the D-1 forecast NTS throughput value and the actual throughput value on the appropriate day of the year.

If National Grid has a demand forecast error below the target, an incentive payment will be received. However, if the forecast error is greater than the target, an incentive penalty will be applied.

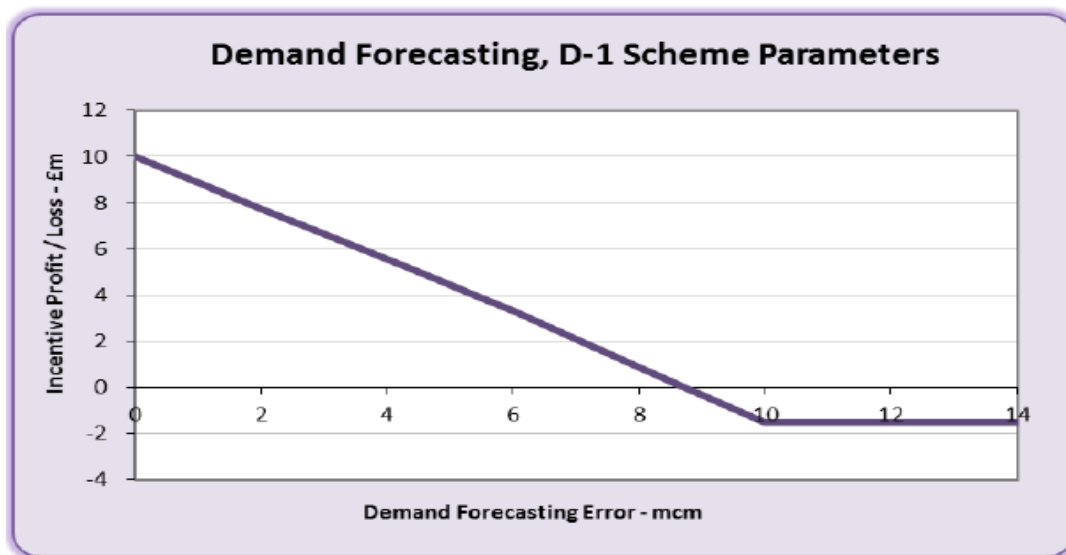


Figure 4.5 – National Grid Demand Forecasting D-1 scheme parameters

Greenhouse Gas Emissions:

The incentive aims at the consideration of the environment when venting gas from NTS compressors.

The scheme incentivises National Grid to make the trade-off between choosing to depressurise compressor units (venting the gas within them) or to keep units on standby, which incurs costs associated with ancillary electrical equipment (vent fans, oil pumps etc.) and a level of emissions through the shaft seal. The incentive applies to both gas and electrically driven compressors. The incentive compares actual venting quantities against a target level. For every ton vented above this target, National Grid is subject to a penalty.

The GHG calculation methodology is externally audited on an annual basis.

Maintenance:

The purpose is to incentivise the efficient planning and execution of network maintenance impacting customers at direct exit connections from the NTS.

To minimise the impact of maintenance work on customers, National Grid should plan maintenance activities to align with periods which minimise disruption to customer operations. Where National Grid can align maintenance to periods which have no impact on customer contractual rights, National Grid will communicate the maintenance period as “Advice Notice Days”. Where this is not possible and an outage or restriction on customer operations is required, a “Maintenance Day” will be called.

The target number of Maintenance Days or Advice Notice Days, subject to change initiated by National Grid (excluding changes made by National Grid pursuant to customer’s request), is equal to 7.25% of the total number of maintenance plan days within the year.

If the actual number of days changed is equal to target, the incentive revenue is zero. If the actual number of days changed is less than the target, then a payment of £50,000 per change below target is accrued up to a scheme cap of £0.5m (for 10 changes or more below target).

Entry Capacity and Exit Capacity Constraint Management:

The purpose is to incentivize an efficient overall cost of System Operator constraint management actions through efficient system operation and optimization of strategies and to encourage balanced risk versus reward decisions in the release of additional capacity.

The current regulatory and commercial frameworks oblige National Grid to release obligated levels of capacity significantly more than peak demand at both entry and exit points on the network. Flows of gas at these levels of capacity cannot occur concurrently, so National Grid takes a view of the likely combinations of supply and demand patterns likely to occur and assesses the most efficient solution to meet customer capacity requirements. National Grid considers the rules, tools and asset options available.

There are numerous commercial tools available to manage Operational and investment constraints, which include:

- Capacity Buybacks – buying back Firm Entry or Exit Capacity previously sold to system users;
- Locational Energy Trades – buying gas into NTS line-pack or selling gas out of NTS line-pack at specific locations on the network; and
- Turn Up/Turn Down Contracts – contracts to manage specific planned outages or where specific flow requirements need to be confirmed in advance.

Incentive performance is driven by the difference between the net constraint management costs over a year (i.e. constraint management costs less revenues from the sale of certain capacity products) and a target value for such costs. National Grid receives an incentive revenue or penalty depending on whether actual net costs are higher or lower than the incentive target. This revenue or penalty feeds through charges two years after the financial year to which the incentive performance relates.

Customer and Stakeholder Satisfaction:

Customer and Stakeholder Satisfaction is an indicator of how satisfied customers and stakeholders are with National Grid. To reflect the importance of customer and stakeholder satisfaction, National Grid is incentivized to survey its customers and stakeholders to measure their overall satisfaction.

The incentive scheme provides an incentive reward or penalty to National Grid of up to +/- 1% of National Grid’s annual allowed revenue.

4.5 Losses, Fuel Gas, Unaccounted for Gas

Losses, Fuel Gas and Unaccounted for Gas (altogether the Shrinkage) is among major cost elements under OPEX. Usually the cost of the Shrinkage is pass through except for the cases that the gas losses attributable to the TSO’s failure and leaks resulting from external damages to the pipeline. Besides, the amount of the Unaccounted-for Gas is subject to certain cap (as a percentage of the throughput, typically between 0.2-0.5 %).

The NRAs require the TSOs purchase shrinkage gas through transparent and competitive procedures. There are limited applications where the shippers provide the shrinkage gas to the TSO in kind.

Germany

Gas used in compressor stations (fuel gas) is considered a 'volatile cost', which is treated as pass-through. The costs of the reference year are included in the efficiency benchmark.

Italy

For network gas losses, fuel gas and unaccounted for gas, ARERA confirms the intention to modify the current structure where users provide such quantities in kind to the TSOs, requiring instead TSOs to procure the necessary quantities within the centralized natural gas market. The costs incurred by TSOs in supplying these resources will therefore be covered by the commodity-based charge.

With reference to technical network gas losses, also in relation to the objectives of limiting Greenhouse Gases (GHG) emissions, ARERA confirms the proposal of completing the regulatory framework set out in the 4th Regulatory Period, that requires the introduction of incentives to reduce the levels of physical and accounting losses at the delivery points of the transmission network. ARERA intends to confirm the determination of the level of allowed losses through efficient emission factors per plant unit, on the basis of the currently applicable unitary factors.

Regarding the Fuel Gas, ARERA intends to confirm the rules for determining the allowed quantities of fuel gas, which require TSOs to define in advance, on the basis of the planned network arrangements, the quantities of gas necessary to cover this requirement.

With regard to the handling of the unaccounted for gas (hereinafter, also: UAG), ARERA, also in view of the fluctuations of UAG from one year to the next, intends to allow for each year of the regulatory period an average level of UAG. This is determined on the basis of the levels of UAG recorded in recent years, without implementing (in line with the current regulatory criteria) any quantity risk correction mechanism to provide an incentive for TSOs to take all necessary actions to improve the quality and reliability of metering data and to limit UAG values, with a view for a gradual reduction of such allowance.

Portugal

Gas shrinkage is paid for by network users (ie losses are passed through) and there is no distinction made between types of shrinkage.

UK

As it was mentioned above, NTS shrinkage is incentivised to minimise the cost of gas and electricity procurement for shrinkage components and operate the compressor fleet efficiently. National Grid forecasts the baseline volume target the year before according to the Ofgem approved NTS shrinkage methodology which determines how to forecast: Compressor Fuel Usage for gas and electricity, Unaccounted for Gas and CV shrinkage. The short-term ('Prompt') volume target is based on the difference between forecast and outturn volumes. Benchmark target prices are determined for forwards and prompt procurement. The scheme is designed to minimise risks associated with volume forecasting and, therefore, reduce windfall gains and losses over the eight-year period.

National Grid is incentivised to investigate the causes of Unaccounted for Gas (UAG), one of the components of NTS Shrinkage. This is gas that is lost, or otherwise not accounted for, as delivered to or off-taken from the NTS.

The TSO must regularly report on its activity to investigate potential causes of UAG. These reports cover the latest UAG trends and provide updates of TSO data analysis and meter validation activities. National Grid has been publishing daily UAG data on its website since October 2012, making weekly updates to this information and cover the period from 1 March 2007 up to seven days

previous. National Grid also provides a range of UAG related data including:

- all previous UAG reports;
- daily data on the components of NTS Shrinkage including UAG

which are available on the National Grid website.

National Grid Natural Gas Transmission (NGGT) has undertaken a review of the extent that the Shrinkage Incentive Methodology Statement is delivering against the key principles of:

- Ensuring cost minimisation for customers
- Delivering appropriate cost risk management
- Incentivising reductions in volumes where NGGT is able to influence.

A table is given below to compare various elements of Natural Gas Transmission Tariffs as applied in Germany, Italy, United Kingdom and Turkey.

Table 4.3 – Natural Gas Transmission Tariff Comparison

	Germany	Italy	United Kingdom	Turkey
Type of Regulation	Revenue Cap	(Hybrid) Cost Plus for CAPEX and price cap for OPEX	Revenue Cap	Revenue Cap
Capacity/Commodity Split	NA	Yes, limited share of commodity 15%	NA (no specific ratio)	Yes, 45/55
Asset valuation	WACC is not applied, CoE and CoD are treated separately	WACC	WACC, vanilla basis	WACC
Method for setting Cost of equity	CAPM	CAPM	CAPM	CAPM
Method for setting Cost of depth	Set ex ante, considering the interest payments for debt capital that the TSO paid in the base year according to its financial statement	Debt costs are determined in advance and are by reference to the specific TSO and comparator companies to the TSO.	Set on a trailing basis using an index of corporate bonds	Risk Free Return Rate + sectoral borrowing risk premium
Depreciation Period	Varies 15 to 65 years, according to the asset; pipelines 45-65 years	Varies for different assets, pipelines 50, compressors 20, SCADA 5 years	45 years	22 years
Depreciation Method	Straight line depreciation	Straight line depreciation	Straight Line for new assets, acceleration for older assets in RAB	Straight Line
Duration of Tariff Periods	5 years	8 years	4 years	3 years, may go up to 10
Method used for setting the opening value of RAB	The historical cost of the assets as per the TSO's statutory accounts at the time.	The historical cost of the assets ie the depreciated book value of the assets as per the TSO's statutory accounts at the time	Independent valuation	Historical cost accounting

	Germany	Italy	United Kingdom	Turkey
Revaluation of the RAB	No	No	No, but inflation is applied, given it is a real price regime	Allowed Revenue is set with respect to the average of RAB's specified at the beginning of year and at the end of year
Allowed Expenditures	TOTEX, benchmarking and other methods as well; costs are set using a reference or base year and a number of methodologies are employed to calculate costs	Building Block, OPEX allowances are aligned to actual OPEX expenditure, a profit-sharing mechanism; if efficiency targets have been met gain, otherwise loss	TOTEX, benchmarking	Building Block, CAPEX and OPEX separately, Bottom-Up
Inclusion of Efficiency Parameter in CAPEX	Yes (factored at TOTEX level)	No	Yes	NA

4.6 Natural Gas Transmission Tariff Charges²⁸³

Except for the certain main principles set by the ENTSOG TAR NC, such as the application of Entry/Exit Capacity Booking, the methodologies and cost elements in transmission tariff settings vary significantly. As an example, the fuel gas is not part of the tariff (i.e. the Shippers provide in kind with a capped percentage) in some countries, whereas the fuel gas is purchased by the TSO (being a cost element in the tariffs) in the other countries. While the daily regime is applied by the majority of the countries, the hourly regime has limited application. A summary information is given below for the selected countries and individual TSOs.

4.6.1 Germany (TSOs in NetConnect Germany and GASPOOL)

The current methodology for reference price mechanisms (RPM) is based on a separate application of the RPM to each TSO. The Regulatory Authority ('BNetzA') proposes to apply the same reference price methodology ('RPM') from 2020 on, a postage stamp methodology, jointly for all transmission system operators ('TSOs') in each of the two entry-exit zones, NetConnect Germany ('NCG') and GASPOOL. With the application of new methodology, there shall be no differentiation between cross border gas transport and regional distribution. While the entry-exit split is not a parameter of the methodology, the shares of revenues allocated to entries and exits are, respectively, 32% and 68% for NCG, and 38% and 62% for GASPOOL. BNetzA proposes to apply a 75% discount at entry points from and exit points to storage facilities, which also applies to storage facilities connected to neighbouring entry-exit systems, unless the specific capacity booking allows for a transfer of gas to the neighbouring entry-exit-system. Four non-transmission tariffs are proposed, whereas no commodity-based transmission tariffs are used.

For the calculation of the cost allocation assessment (CAA), BNetzA proposes several scenarios to assess the impact of storage on the cross-system and intra-system use of the network. The CAA index for the different scenarios are calculated per market zone and are within the 10% threshold laid out in Article 5(6) of the NC TAR, except for an outlier. When calculated following the NC TAR rules as laid out in Article 5, the result of the CAA is 2.6% for NCG and 1% for GASPOOL.

Commodity charge is not included in the tariffs.

The NCG system is over 21,000 km long with 149 physical entry points and 77 bookable entry points, as well as 2,533 physical exit points and 873 bookable or orderable exit points. There are 6,418 branches and 1,152 pipeline loops.

The GASPOOL system is over 16,000 km long with 121 physical entry points and 79 bookable entry points, as well as 961 physical exit points and 360 bookable or orderable exit points. There are 1,197 branches and 146 pipeline loops.

²⁸³ This section is prepared by using ACER consultations for Germany, Italy, Portugal and the information from the web sites of the NRA's and TSO's of the selected countries.

There is extensive use of conditional capacities in the German system. In particular, some transmission assets allow TSOs to offer point-to-point capacity, and only offer interruptible access to the rest of the entry-exit zone.

BNetzA does not assess the unit cost characteristics of the network. In Germany, some TSOs' activity is mostly based on large pipelines that are mainly used to transport gas across borders and have been largely depreciated. Such TSOs usually have lower capacity unit costs.

Table 4.4 – Price list of GASCADE Gastransport GmbH for the use as of January 1st, 2020

Type of Network Point	Flow Direction	Tariff unit rate (kwh/h)/y
Interconnection Point (International)	Entry	3.36
Interconnection Point (Other TSOs)	Entry	3.36
Interconnection Point (DSO)	Entry	3.36
Storage	Entry	0.84
Biogas	Entry	0.0
Exit Zone	Exit	3.36
End Consumer	Exit	3.36
Interconnection Point (DSO)	Exit	3.36
Interconnection Point (International)	Exit	3.36
Storage		0.84
Biogas		0.00

Italy

ARERA published the resolution for the 5th Regulatory period of 2020-2023 (Resolution of 28 March 2019 114/2019/r/gas tariff regulatory criteria for the Natural Gas Transmission and metering service for the fifth regulatory period) on 26 March, 2019. The resolution brings a capacity weighted distance ('CWD') methodology. The tariff set for the new Regulatory Period includes 50% discount at entry points from, and exit points to, storages, 15% commodity charges, and two non-transmission charges for metering. The Entry/Exit split is set as 28-72%, attributing the entry points a revenue ratio equal to 40% of the national network revenue and the exit points a revenue ratio equal to the sum of 60% of the national network revenue and 100% of the regional network revenue. The equalisation of the charges is applied to all delivery points. The commodity charge is applied to the quantities of gas withdrawn from the network at the network delivery points, the exit points to storage facilities and the connection points with foreign facilities.

Snam Rete Natural Gas transmission tariff T for firm service on annual basis is defined by the following formula:

$$T = (K_e * C_{Pe}) + (K_u * C_{Pu}) + (V * CV) + (VFC * CVFC);$$

where:

- K_e is the capacity booked by the user at entry point e of the national transmission network, expressed in Sm³/d;
- C_{Pe} is the capacity charge for the national transmission service related to the capacity booked at entry point e of the national transmission network, expressed in Euro/y/ Sm³/d;
- K_u is the capacity booked by the user at exit point u of the transmission network, expressed in Sm³/d;
- C_{Pu} is the capacity charge for the transmission service related to the capacity booked at exit point u of the national transmission network, expressed in Euro/y/ Sm³/d;
- V is the gas quantity withdrawn to exit point u of the national transmission network, expressed in Sm³;
- CV is the commodity charge, expressed in Euro/Sm³;
- VFC is the gas quantity withdrawn to exit point u of the national transmission network, with the exception of exit points interconnected with foreign countries, expressed in Sm³;

- CVFC is the commodity charge for revenue recovery, expressed in Euro/Sm3;

The capacity charges CPe, CPu, are applied to booked capacity independently from its actual utilization, while the commodity charges CV and CVFC are applied to the actual gas quantities withdrawn to exit point u of the national transmission network.

Table 4.5 – Snam Rete Natural Gas Transmission tariff applicable for 2020

2.1 Commodity charges			
CV _u (€/Smc)	0.0038471		
CV _{pe} (€/Smc)	-		
2.2 Capacity charges			
CP	(€/Smc/d)	CP	(€/Smc/d)
Mazara del Vallo	3.336104	Redelivery point <15 km (*)	2.369115
Gela	3.059651	Redelivery point >15 km (*)	2.544273
Passo Gries (CH)	1.329998	Hub storage	1.048537
Tarvisio (AT)	1.347678	Bizzarone (CH)	2.634365
Gorizia (SI)	1.269090	Gorizia (SI)	2.322863
Melendugno TAP	2.324951	R. S. Marino	1.907283
GNL Panigaglia	1.071598	Passo Gries (CH)	2.955869
GNL Cavarzere	0.977377	Tarvisio (AT)	2.945218
GNL OLT Livorno	1.329109		
Production Hub 1 – Nord-Occid.	0.860716	(*) The following fees apply for the transitional	
Production Hub 2 – Nord-Orient	0.874678	period January – September 2020	
Production Hub 3 – Rubicone	0.904030	Exit point from RNG	1.772696
Production Hub 4 – Falconara	1.026245	Redelivery point <15 km	1.136524
Production Hub 5 – Pineto	1.196342	Redelivery point >15 km	1.311682

Portugal

The Regulatory Authority ERSE applies a reference price methodology ('RPM') which is based on a capacity weighed distance ('CWD') methodology to which a cost driver related to the costs of the network is added. An entry-exit split of 40/60 is applied. Resulting from this methodology, exits to LNG, to storage facilities and at the VIP with Spain are set to zero. The reference prices calculated with the proposed RPM are higher at domestic exits and lower at entries from LNG and the IP (Spain). The application of adjustments (equalisation of domestic exits; discounts to points from and to storage facilities; and rescaling), commodity charges set at exits, and no non-transmission charges are proposed. The commodity-based transmission tariffs contribute 1.4% of the transmission services revenue.

Table 4.6 – Portugal Natural Gas Transmission Reference Prices applicable for 2020-2021

	Entry	Entry	Entry	Exit	Exit	Exit
	IP-Spain	LNG Terminal	Storage	IP-Spain	Storage	Domestic
Capacity Charges	0.2289	0.2187	0.0059	0.2212	0.0063	0.1420
€/[(kWh/d)/year]						

UK

The price control set by the Regulatory Authority Ofgem for the NTS is divided into TO and SO controls. Transportation charges are split to reflect these price control arrangements. Exit Capacity charges are administered and set to recover the TO target Exit revenue.

For NTS TO revenue, the target is to recover 50% from Exit Capacity bookings and 50% from Entry Capacity auctions. Charges for Entry Capacity are determined by auctions which apply to all System Entry points.

The unpredictability of Entry auction revenue and Exit Capacity bookings means that the 50:50 TO revenue split between Entry and Exit may not be achieved in practice. In the event of a forecast under-recovery of auction revenue against the Entry target level, a TO Entry Commodity charge may be levied on entry flows and a TO Exit Commodity charge may be levied on Exit flows where

revenue from Exit Capacity bookings is forecast to be under-recovered. The TO Commodity charges are the same at all Entry and Exit points.

The SO revenue is recovered through the NTS SO Commodity charge. This is a uniform charge, independent of Entry and Exit points, and is levied on both NTS Entry and NTS Exit flows. A distance-related Commodity tariff, the Optional NTS Commodity charge, is also available as an alternative to both the SO and TO Commodity charge.

NTS Capacity Charges

Capacity charges consist of charges for Entry, Exit and credits payable for constrained Liquefied Natural Gas (LNG). This section also includes details of the Interconnector Point (IPs) auctions. Entry and Exit Capacity charges are payable when a right to flow gas is purchased irrespective of whether or not the right is exercised.

NTS TO Entry Capacity

National Grid is obliged to make available for sale System Entry Capacity by means of five related auction mechanisms. For each of the System Entry points, Capacity is made available on a Firm and Interruptible basis. All Entry Capacity is offered on a pence per kWh per day basis, where the quantity is measured in terms of an end of day entitlement.

Firm Entry Capacity is offered in bundles of quarters, months and days. All System Entry Capacity auctions are subject to reserve prices. Daily reserve prices are calculated by applying the following discounts to the Monthly System Entry Capacity (MSEC) prices: Day Ahead Daily System Entry Capacity (DADSEC) 33.3%, Within Day Daily System Entry Capacity (WDDSEC) 100%, Daily Interruptible System Entry Capacity (DISEC) 100%.

NTS TO Exit Capacity Charges

There are four Capacity products available – Enduring Annual NTS Exit (Flat) Capacity, Annual NTS Exit (Flat) Capacity, Daily Firm NTS Exit (Flat) Capacity and Daily Off-Peak NTS Exit (Flat) Capacity. The Enduring and Enduring Annual products are released by means of application windows, whilst the Daily Firm and Off-Peak products are released through auctions.

Reserve prices for the Daily Firm Capacity auctions are equal to the Enduring Annual/Annual Capacity charges. The reserve price for Off-Peak Daily Capacity, which is auctioned on a daily day ahead basis, is zero.

Exit Points are classified as Natural Gas Distribution Network (GDN), Direct Consumer (DC) and Storage. There are 224 Exit points (published as of 2019) and a dedicated Exit Capacity Charge is applicable for each Exit Point.

NTS Interconnection Point Capacity Charges

Those prices are set through specific auction mechanisms for “Entry Interconnection Points” and “Exit Interconnection Points” for the capacity booking periods defined as Annual, Quarterly, Monthly, Rolling Day Ahead and Within Day.

NTS Commodity Charges

NTS Commodity charges are payable on gas allocated to shippers at Exit and Entry. Commodity charges on gas flows at NTS Storage facilities, other than on the amount of gas utilised as part of the operation of any NTS Storage facility, known as storage “own use” gas is zero. The NTS Commodity charges are uniform rates, independent of Entry or Exit points.



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Table 4.7 – NTS Entry Capacity Reserve Prices for Capacity for use from 1 October 2019

MSEC Reserve Prices pence per kWh per day		
Entry Point	Y	Y+1
Coastal Terminals & LNG Importation	From 1 Oct 19 to 30 Sep 20	From 1 Oct 20 to 30 Sep 21
Bacton	0.0095	0.0095
Barrow	0.0032	0.0015
Easington&Rough	0.0147	0.0149
Isle of Grain	0.0001	0.0001
Milford Haven	0.0235	0.0235
St Fergus	0.0530	0.0532
Teesside	0.0087	0.0087
Theddlethorpe	0.0133	0.0134
Onshore Fields and Connections		
Burton Point	0.0001	0.0001
Canonbie	0.0022	0.0022
Hatfield Moor	0.0035	0.0035
Wytch Farm	0.0001	0.0001
Storage		
Barton Stacey	0.0001	0.0001
Caythorpe	0.0127	0.0128
Cheshire	0.0001	0.0001
Dynevor Arms	0.0091	0.0091
Fleetwood	0.0001	0.0001
Garton	0.0130	0.0130
Glenmavis	0.0138	0.0128
Hatfield Moor	0.0035	0.0035
Hole House Farm	0.0001	0.0001
Hornsea	0.0143	0.0140
Partington	0.0001	0.0001
Avonmouth	0.0001	0.0001
Biomethane Plant		
Murrow	0.0001	0.0001

“PARCA Entry Weighted Average Price” is calculated based on the weighted average price of the registered quarterly NTS Entry Capacity Reserve Prices. Entry Weighted Average Price from 1 October 2019 on is 0.0109 pence/kWh/day.

“PARCA Exit Weighted Average Price” is calculated based on the weighted average price of the registered annual and enduring NTS Exit (Flat) capacity for the applicable year. Exit Weighted Average Price from 1 October 2019 on is 0.0105 pence/kWh/day.

Table 4.8 – NTS Commodity charges as applicable from 1 October 2019

	TO Entry	SO Entry	Combined	TO Exit	SO Exit	Combined
			Entry Rate			Exit Rate
NTS Commodity Charge	0.0447	0.0122	0.0569	0.0226	0.0122	0.0348
(pence per kWh)						

4.7 Assessment and recommendations

4.7.1 Identified Gaps between the Existing Performance Tariff Structures in Turkey and the EU

As a general conclusion, the methodologies applied by EMRA in setting the Natural Gas Transmission tariff are similar to those applied by many EU member states.

There can be noted certain differences between the cases for Turkey and the EU whereas such differences might be considered as minor and those are detailed below. Practically, the main gap stands as the application of a specific methodology and principles in determining the efficiency of the TSO and adjustment of its revenue allowance accordingly.

Tariffs for Short Term Capacity Products and Interruptible Capacity Products

Although the EMRA's Regulation on Natural Gas Transmission Network Operation refers to offering such products by the TSO, the BOTAS Network Code (shortly GTNC or the "SİD") does not yet include Day Ahead and Intra Day Capacity booking mechanisms as defined in the EU Regulation 715. Hence, there are no defined terms published in the transmission tariff for short term capacity booking and interruptible capacity tariff mechanisms.

Capacity / Commodity Split

ENTSOG Tariff Network Code requires application of single component, the capacity booking payments, in setting the revenues for transmission and conditionally allows for the commodity component in the tariff. In Turkey case, the transmission tariff is composed of both the capacity and commodity components and still the commodity part constitutes bigger portion of the allowed revenues (55%).

Transparency, Non-Discrimination and Consultation Requirements

Regarding the transparency requirements, although the existing situation cannot be regarded as non-compliant to the EU applications, there can be improvements related with certain issues. Determination of the Regulatory Asset Base for BOTAS Natural Gas Transmission System, determination of the capacity charges for the Export Exit Point and the required data from the TSO for tariff setting are among those. Publication of Consultation Document (English version is available as well) and Stakeholder engagement (other than the TSO) accordingly prior to each Tariff Application Period can be considered as the needed improvements relating to Consultation requirements.

Unit Tariff Rates for each Entry and Exit Point

The Article 13 of the Regulation 715 states that the Tariffs for network users shall be non-discriminatory and set separately for every entry point into or exit point out of the transmission system. The reference prices should be determined taking into account the actual costs incurred for the provision of transmission services considering the level of complexity of the transmission network; as per the requirements of the Article 7 of the TAR NC.

The current application for BOTAS' Natural Gas Transmission system is such that, separate capacity charge is applied for the Entry Points and the same capacity charge is applicable for all domestic Exit Points (i.e. single exit zone, with Postage Stamp for all Exit Points).

4.7.2 Recommendations for Changes to EMRA's Tariff Structure, Establishing a Methodology towards a Performance-Based Natural Gas Transmission Tariff Structure

Current secondary legislation relating to Natural Gas Transmission tariff has a reference to an efficiency involvement in tariff derivation under Revenue Cap regime. However, there has not yet been developed an established methodology to set out efficiency parameters and their involvement in the allowed revenue (determination of the X Factor).

On the other side, in the EU case there are limited binding principles for the Regulatory Authorities in setting out the Natural Gas Transmission tariffs. Application of Entry/Exit capacity booking methodology, setting the specific tariffs for short, mid and long-term capacity products and certain transparency requirements for the NRA's and TSO's in terms of tariff derivation and applications are among those. While there may be seen some common approaches for certain areas (like the application of the incentive-based Revenue Cap regulation); still, there is no common approach for many different aspects of Natural Gas Transmission tariff among the EU members. In relation to performance evaluations of the gas TSOs in terms of efficiency, the benchmarking with other TSOs is a very limited application. It should be noted that, the majority of the countries has single gas TSO structure and comparison across countries would not provide reliable outcomes since each country and TSO has its special network features and operating environment. Germany would be considered as a unique example applying benchmarking among the 16 gas TSOs in the country.

The Annex "Performance Benchmarking among the Gas TSOs Across Europe" is given to further detail the efficiency benchmarking in the EU. The Annex provide information about certain studies carried out by ACER and CEER. A special note related with the benchmarking of the fuel gas costs is also included in the Annex.

There can be noted certain differences between the cases for Turkey and the EU whereas such differences are related with minor details; such as the transparency regarding certain issues (like the discrimination for the export exit point when setting the capacity charges, lack of detailed tariff information in BOTAS' web site) etc. Practically, the main gap is the application of a specific methodology and principles in determining the efficiency of the TSO and adjustment of its revenue allowance accordingly.

Facilitating the gas trading between Turkey and the EU is one of the most focused elements in the energy area since a long time. Foreseeable approach in tariff settings for the interconnection points to the EU (i.e. Greece and Bulgaria) would provide positive signals to the interested parties.

Relating to the setting of specific tariff rates for each Entry and Exit Point with special cost allocation methodology, it should be taken into account that the supply sources are located in all directions of Turkey and differentiations between the regions in terms of gas supply risk would lead to minor differences. Considering the goal of the EU to create an EU wide single gas market, such complexity in tariff studies would be necessary to allocate the costs and rates at all interconnection points, separately, in a transparent and nondiscriminatory manner. As an initial step for Turkey, creating several zones for Exit Points could be considered. Together with cost allocation methodology, promotions for more economical use of natural gas in certain regions may be considered in defining different zones.

To develop the above-mentioned methodology, defining the incentives, performance criteria and/or success criteria for certain targets related with the below stated areas shall be elaborated in this section, taking into consideration the applications in the EU.

- Operating Expenditures
- Investments
- Operational Success

Specific analysis and recommendations shall be carried out in accordance with BOTAS Natural Gas Transmission activities. Subject assets can be shortly classified as pipelines, line valve stations, pigging stations, compressor stations and pressure reduction and metering stations (Entry and Exit Points). Vast majority of the metering stations are the Exit Points for the distribution systems interconnected with Natural Gas Transmission grid and those stations are owned and operated by the DSOs. As per the requirements of the GTNC, the DSOs should sign a Connection Agreement with the TSO for the connection of metering stations as exits from the transmission grid. The technical design, construction and operation of these metering stations should comply with the requirements defined by BOTAS.

4.7.3 Operating Expenditures

Cost reductions related with certain operational expenditures can be directly linked to efficiency outputs. Incentives for the TSO can be defined to reduce its costs related with subject matters stated below.

Transporter's Own Use of Gas (the OUG)

The OUG constitutes the major part of operational expenses for BOTAS Natural Gas Transmission System. The vast majority of it is used for fueling the compressor stations all of which is gas turbine driven. Minor portion of the OUG is used for heating purposes in the facilities and in pressure reduction stations. The OUG is defined in the GTNC as follows:

“Transporter’s Own Use Gas” means the gas used for the operation of the Natural Gas Transmission system including gas used in the compressor stations and other applications;

The current figure of the OUG is approximately 0.5 % of the transported gas volume (a figure of roughly 250 million cubic meter). The amount of the OUG is mainly dependent on the below stated parameters

- Amount of transported volume,
- Amount of line pack,
- Individual efficiencies of the compressor stations,
- Central Optimization of the operating parameters of the compressor stations; both on individual basis and altogether,
- Delivery pressures from upstream import interconnections.

Currently, there are ongoing Technical Aid Projects for BOTAS where system optimization is one of the subject matters. The outputs of the project may assist the Authority in determining the efficiency targets related with the OUG. In any case, benchmarking would be possible by comparing the OUG’s pertaining to years with similar transported figures.

Unaccounted for Gas (the UAG)

The UAG is an important cost element in both Natural Gas Transmission and Distribution Systems. It mainly refers to the uncertainties in gas measurement. In high pressure Natural Gas Transmission systems, the gas measurement is a very complex process which involves the management of many gas quantity and quality measurement instruments together. Typical accuracy design figure of a metering station is at the order of +/- 1 %. Inevitable gas leaks through flanges and other unmeasurable gas leaks are also part of the UAG. Those leaks normally constitute minor part of the UAG compared to the risk of measurement uncertainty.

As a common practice, the Measurement Uncertainty risk (up to specified cap by the regulatory authority) is borne by the Shippers and the Transporter is kept neutral against to measurement uncertainty risks.

The UAG is defined in the GTNC as follows:

“Unaccounted for Gas” means the Natural Gas leaked from any part of the Transmission Network or the gas disregarded due to the tolerance limits of the Metering Equipment;

The combination of the OUG and the UAG is referred as “Internal Utilization Gas” in the GTNC. It is among significant operational cost items in tariff calculations. The related article of the GTNC is copied below

“4.1.4 Internal Utilization Gas Costs

The Transporter shall take into consideration the Internal Utilization Gas costs in the Tariff proposals to be submitted to EMRA. In the Tariff proposals, the Quantity for Unaccounted for Gas shall be determined by taking the average of the values of the previous five Gas Years and it shall not exceed 2% (two percent) of the Natural Gas Quantity planned to be transported in the Gas Year.”

Considering the allowed cap of 2 % (of the transported volume), the UAG is very important parameter to be handled in terms of efficiency. Under ideal circumstances, the figure must be as close as possible to zero. The typical calculation of the UAG pertaining to a certain day is as follows:

$$UAG = \text{Total Entry Quantity} - \text{Total Exit Quantity} - \text{Transporter’s Own Use Gas} - \text{Variation in Line Pack Quantity}$$

Although the cap set for the UAG in the GTNC seems as a big allowance for the Transporter, it must be noted that ensuring proper measurements in all metering stations (connected to the transmission grid) is much more related with the satisfactory operation of the Distribution System Operators who owns and operates hundreds of those metering stations.

Determination of the Variation in Line Pack Quantity is also very critical element. The amount of gas existing in the transmission system at certain moment is calculated via special simulation software embedded in the SCADA System. Effectiveness of the simulation software and proper use of it by competent staff are critical elements.

Reducing the UAG figure would be considered as a straightforward target. However, in light of above stated, reduction of the UAG cap for the transmission system also involves reduction of the UAG's in all distribution areas. So, such target requires a combined study for transmission and distribution systems.

Vented (disposed) Gas

In Natural Gas Transmission systems, gas is vented to the atmosphere during some typical cases stated below:

- Commissioning of the assets (pipeline, compressor stations, line valves etc.)
- Decommissioning of the assets
- Control and Safety requirements in the compressor stations
- Disposal of unqualified gas (like wet gas) that entered into the system
- Repair/replacement of damaged or leaking pipeline segments

Considerable amounts of gas are vented in compressor stations, much of which would occur during the shutdown of the compressor stations due to the operational defaults of the Transporter. The amount of vented gas in such circumstances is usually determined by manual approximation method and recorded.

It can be an item in efficiency targets to reduce the vented gas in the compressor stations. Such an incentive is necessarily considering that as per the provisions of the GTNC, the vented gas is part of the UAG and not an economic loss for the Transporter, as long as the allowed cap is not violated. On the other side, methane is a greenhouse gas and the release of it to the atmosphere is very harmful. Vented gas shall be further handled in terms of environmental concerns and incentives accordingly.

Maintenance

Certain maintenance works are critical for the efficient and reliable use of the Natural Gas Transmission system. Among those, the below stated ones are most outstanding planned maintenance activities.

- Heavy maintenance in compressor stations (like gas turbine overhauls)
- In Line pigging through pipelines (smart pigging)

Those activities are planned well before the commencement of the work. Timely and successful implementation of those can be included in performance indicators.

The Transporter is relieved from its obligations to a certain extent during "Scheduled Maintenance" works which can cover maximum 15 days in a Gas Year. The related article of the GTNC is as follows.

"13.5 Obligations of the Transporter

If there happens a reduction in the transportation capacity of the Transmission Network as a result of the maintenance under the Scheduled Maintenance or any Force Majeure event, the obligations of the Transporter to receive, transport and deliver gas according the GTNC and Standard Transportation Contract shall be suspended to the same extent"

Not causing capacity reduction in certain part of the network and reductions in nominated quantities during Scheduled Maintenance works can be included in the performance indicators.

4.7.4 Capital Expenditures, Investments

Investments for Natural Gas Transmission system generally covers the capacity expansion requirements, new connections to supply sources and connections for new consumption points. The Transporter is required to prepare the capacity expansion planning covering 10 (ten) year period in accordance with the data from the Shippers and gas market conditions. The related GTNC article is given below.

“12.1. For the planning purposes, each shipper shall submit its non-binding short, medium and long terms supply/demand projections to the Transporter. In accordance with such data, the Transporter shall prepare its non-binding 10 (ten) year capacity expansion report including the related projects each year till the end of June and publish the report through its web site.”

The investments of the Transported Gas is reasonably expected to be in parallel with the 10 years capacity expansion report of ENTSOG. Eventually, the investments for the Natural Gas Transmission system are subject to the approval of both the Presidency Strategy Development and Budget Control Department and EMRA; a process which requires the Transporter to show rationales behind and the feasibility of the planned investments.

The incentives in CAPEX side and applications of certain performance criteria is rarely seen among the EU members. Similarly, there would be no need to establish efficiency parameters in that area. But still, the timely completion of the investment projects can be taken as a performance indicator. The subject projects could be specifically determined in case of failure to provide requested capacity by the Shippers or by the interconnected upstream facilities.

Benchmarking for the costs of the investments can be deemed as unnecessary taking into consideration that the Public Procurement Law itself provides the terms against other costs.

The investments for reducing the greenhouse emissions and improving energy efficiency might be promoted by EMRA by approving such measures in investment plans. Use of the waste heat at the compressor stations in electricity generation could be an example.

4.7.5 Operational Success

The Operational Success can be categorized in two areas; one is related with the physical operation of the transmission network and the other is related with commercial operations.

4.7.5.1 Physical Operations

Compressor Outages, Pipe Breaks

Regardless of the consequences of such events related with capacity reductions, each event attributable to the inefficient operation of the Transporter could be regarded as a penalizing item in determination of the efficiency parameter. Considering that important amounts of gas are vented during such outages, such criteria are needed to be in place.

Scheduled Maintenance Works for the Critical Assets

Timely completion of the scheduled maintenance works for the critical assets (such as overhauls, smart pigging) is important for maintaining the integrity and reliability of the transmission system. Tracking of such works by the Regulatory Authority and including such timely completions among the performance indicators incentivizes the Transporter to timely complete such critical works.

Not causing capacity reduction in certain part of the network and reductions in nominated quantities during Scheduled Maintenance works can be included in the performance indicators.

Reductions in the Scheduled Quantities, “Service Interruption Fees”

The Transporter is penalized when the delivered quantities less than the nominated quantities of the Shipper for a certain Exit Point and also the delivery pressure is less than the minimum delivery pressure stated in the Standard Transportation Contract. As per the provisions of the GTNC, Transporter pays to the Shipper the “Service Interruption Fee” which is calculated as the multiplication of undelivered quantity with the unit charge specified in the Tariff.

A cap for the paid Service Interruption Fees throughout the years can be considered as a performance indicator. Benchmarking with the past years may also be an option.

Maintaining the Line Pack Level within Limits

Maintaining proper level of line pack in all segments of the transmission grid in meeting the delivery of the nominated quantities by the Shippers and it is a must for reliable operation. Ideally, the line pack limit is continuously kept within lower and upper limits.

The GTNC defines a reference line pack level to be maintained.

“Reference Stock Level” means the level of line pack in transmission system required for the proper operation of the system”

The Transporter purchases balancing gas for the purpose of maintaining the line pack level at “Reference Stock Level” and such purchase (or sell) of gas by Transporter is required to be through Continuous Trading Platform of EPIAS via daily auctions. Although there may be a Balancing Gas Agreement in place with a certain Shipper (existing case BOTAS trading part), purchase of line pack gas through trading platform has a priority.

4.2.1 In order to maintain the level of line pack at the Reference Stock Level, The Transporter may sell or purchase gas. Such purchase or sales of gas shall be first tried using the Continuous Trading Platform.

Maintaining the line pack level at reference level is both a physical and commercial action. Proper supervision and Intra Day forecasts via SCADA system is a must. The records denoting the level of line pack at the beginning of each gas day show the success of the Transporter for this mission and can be classified as a performance indicator.

4.7.5.2 Commercial Operations

The commercial arrangements of the Transporter, mainly the Network Code and Interconnection Agreements are very critical for the efficient use of the transmission grid, it facilitates gas trading and hence it is important for meeting the requirements of a liberal gas market. The improvements relating with the flexibilities provided for the Shippers and economic performance of the TSO out of its commercial arrangements can be included in the performance indicators.

Short Term Capacity Products

The GTNC allows daily capacity booking only for the points interconnected with the underground storage facilities. Intra Day Capacity Booking (as applied in the EU) has not any reference.

Taking into account the requests from the Shippers in past forums and also the technical capacity and market experience gained by the Transporter, it would be reasonable to request the Transporter to implement the arrangements for Daily Capacity Booking and Daily Capacity Transfers through secondary market in its arrangements. A due date can be determined for such implementation by the Transporter and it can be included among the performance indicators.

Long Term Capacity Products

While defining a priority for the capacity utilization at the interconnections with foreign transmission systems under Intergovernmental Agreements, the maximum duration of capacity booking is one year in the GTNC. Long term capacity bookings by the Shippers are very much related with the feasibility of investments for capacity expansions. Large scale investments of the Transporter in terms of capacity expansion can be linked with long term capacity bookings through an auction process.

Interruptible Capacity Products

Interruptible Capacity Products can be very useful instruments for the economic utilization of the transmission systems. The Transporter may avoid not feasible investments and also may create extra earnings by selling not nominated capacities on interruptible basis. A due date can be determined for such implementation by the Transporter and it can be included among the performance indicators.

Offering Bundled Capacity Products

Offering Bundled Capacity Products is the common application at the interconnections of transmission systems in the EU. The TSO's at either side of the interconnection jointly offer the capacity and one of those conducts relations with the Shippers in terms of capacity booking. Mismatches at the two sides of the interconnection are avoided and this provides Shippers with comfort. Such a target is mainly related with the Interconnections with Greece and Bulgaria.

Integration of Turkish gas market with the EU and transfer of significant volumes is the main interest of the market players in either side. The recent amendment to the 3rd Gas Directive introduces strict rules for new gas entries to the EU borders. Conformity of the interconnection agreements with the EU gas legislation shall be required at the interconnections for new gas entries. Although it seems to be a matter of the Interconnection Agreements between BOTAS (Transporter) and Greek and Bulgarian counterparties, the concept can be included in the GTNC and a due date can be set by the regulatory authority.

Operational Balancing Arrangements

Operational balancing arrangements are typically the subject of the Interconnection agreement between two TSO's. An operational balancing account is mutually established, and it is used for the purpose that, at the end of gas day, the Shippers are allocated as they nominated as long as the difference is between defined limits. This facilitates the relations of TSO's with the Shippers and minimizes the risk of imbalances for the Shippers. Such arrangements can be designed by the Transporter with other interconnected upstream operators (storage, LNG Plant, production site) as well.

The Transporter can be incentivized to establish such arrangements at the interconnections with other transmission systems, storage facilities and LNG Terminals.

Balancing Gas Agreement

Transporter's Own Utilization of Gas needs to be procured by the Transporter by entering into Balancing Gas Agreements with certain Shippers. The Transporter can be incentivized to reduce its costs for procuring the Balancing Gas.

Currently, BOTAS Trading part provides the Balancing Gas to the Transporter (as per the Article 4.2.6 of the GTNC) and such incentive would come into consideration when unbundling of BOTAS is realized.

Residual Balancing

Organized Wholesale Market started its activities on 1st September 2019 and the Transporter has been appointed with a role as a residual balancer in this market. The definition of "Residual Balancer" in the Organized Wholesale Market Regulation is given below.

“Residual Balancer: The residual balancer is the Transporter. The Transporter shall act as a market participant when it becomes necessary in maintaining the physical integrity of the Transmission System, as per the requirements of the GTNC.

The cost of such balancing gas is referred as the “Residual Balancer Price”. Benchmarking with the “Daily Reference Price” could be made and a performance indicator may be set related with these actions of the Transporter.

Forecasting for Daily Demand and Line Pack

With the commencement of the activities of the Organized Wholesale Market, the Transporter is required to forecast and announce (through its Electronic Bulletin Board) daily demand for the following day and the level of line pack at the beginning of the day in accordance with the submitted nominations. This information is also transmitted to the Market Operator (EPIAS).

Relying just on the nomination data may lead to significant errors in forecasted quantities. The Transporter may be incentivized to forecast more precisely by developing the appropriate methods.

Accuracy of the forecasts may be included among the performance indicators.

Table 4.9 – Overall Assessments and Recommendations on Natural Gas Transmission Tariff

Key issues	EU Practices	Turkey Practice	Recommendation	Barriers for recommendation
NRA's capability in setting tariffs	All the EU Authority set the tariff with the exception of Spain (Government only in Spain)	EMRA sets the gas tariffs	-Stakeholder participation, more transparency -Procedures for auditing the TSOs -Capability Sanction and inspective role	Stated owned structure of the National TSO
Grid ownership	Majority single National TSOs, some countries (like Germany, France and Italy) several TSO's	Single TSO; however, the legislation allows multi TSO structure	No Recommendation. Existing terms are proper	NA
Tariff structure	- Revenue Cap - Building Blocks - Price Cap - Hybrid - TOTEX	Revenue cap model including an efficiency parameter. However, a methodology for the determination of the efficiency parameter (X factor) is not in place yet. Similar to most of the EU countries, Building Blocks model is in use in Turkey. CAPEX consists of return on capital with a set rate of return and amortization. OPEX consists of fixed costs and variable costs.	Development of a methodology for the determination of efficiency parameter (X factor) and putting it into operation.	Difficulties in benchmarking
Rate of Return	- WACC pretax - Dynamic WACC	WACC pretax	Dynamic WACC to be updated by financial parameters, because it depends heavily on the economic conditions of the Country	-
Depreciation	Straight Line	Straight line	Straight Line	-
Depreciation Period	Depends on the asset, pipelines 50-70 years, compressor stations 30-40 years, metering stations 30 years, SCADA 10-20 years	Same for all assets, 22 years	Apply similarly with the EU cases	Other existing legislation related with tax
Cost Efficiency	- Parametric evaluation of CAPEX - X factor for OPEX - Efficiency for TOTEX (sharing factor)	Not applicable yet (see above); the TSO tenders are subject to Public Procurement Law	See above	-
Efficiency OPEX	- X factor (efficiency ratio)	Setting of X-factor (referenced as the Efficiency parameter) has not been practiced yet	Define certain incentives in applying rewards/penalties for both physical and commercial operations	Complexity of the methodology for the supervision of the performance and required manpower



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Key issues	EU Practices	Turkey Practice	Recommendation	Barriers for recommendation
Performance Indicators*	(UK Case*) NTS Shrinkage, Residual Balancing, Demand Forecasting, Greenhouse Gas Emissions, Maintenance, Constraint Management and Stakeholder Satisfaction	NA, see above.	Defining performance indicators as Fuel Gas, Unaccounted for Gas, Demand Forecasting, Vent-d Gas, Maintenance, Compressor Outages and Shortfalls as a first step	Complexity of the methodology for the supervision of the performance and required manpower
Financial incentives for quality of service	- Premiums and penalties	NA, see above	Premiums and penalties set in accordance with specified performance indicators	Complexity of the methodology for the supervision of the performance and required manpower
Shrinkage (Fuel Gas + Unaccounted for Gas-UAG)	Shrinkage is usually part of operational expenditures. In some applications it is provided as in kind by the Shippers. Fuel Gas Part: Usually pass through element (TSO neutral) in gas transmission tariffs. The unit cost of Fuel Gas and the amount are included among efficiency indicators in some countries Unaccounted for Gas: Mostly pass through subject to a certain cap. Some NRA's (like the UK) require the TSOs to submit special reports for tracking of UAG (i.e. Measurement Uncertainty factor plus unmeasured losses), regularly.	The cost of shrinkage is included among the allowed expenditures, as a pass through. However, TSO is required to purchase Fuel Gas through market-based competitive procedures. The UAG is also pass through subject to certain cap.	Unit cost of the Fuel Gas and the amount can be included in performance indicators when setting the methodology for the determination of X Factor. A benchmarking can be done by using the Daily Reference Gas Price in the Organized Wholesale Market and similar throughput conditions in past years. The cap for the UAG as specified in the GTNC may be revised as a lower figure.	UAG improvement for the gas transmission grid involves both the TSO and DSO's, since the measurement stations at exit points are owned and operated by the DSOs.
Capacity/Commodity Split	The Revenue of the TSOs should be essentially through capacity bookings.	Revenues out of Capacity booking fees and Commodity fees are close to each other	Adopt a similar approach as in the EU and set the capacity booking based revenue as at least 80% with a cost allocation methodology.	Concerns related with the likely impact of increased retail tariff for residential consumers.
Tariff Period	3-8 years	3-10 years	No recommendation, keep existing	-

*Use of commonly adopted performance indicators for Natural Gas Transmission is not a generally applied practise. The application in the UK for performance indicators (the Incentives) is regarded as a good reference for the recommendation.

Special Note - 2: Probable Effects of the Change of the Ratios in Capacity/Commodity Split

The evaluation shall be based on the above recommended figure of 80/20 for capacity / commodity split respectively; meaning that the 80 % of revenues of the Transporter are aimed to be provided through fixed capacity payments and the rest through commodity payments.

In the Turkish case (and also for the vast majority of other country cases) the capacity is booked separately for each Entry and Exit Point on a daily basis. The Shippers are required to book capacity conforming to their peak delivery/receipt at subject Entry and Exit Point(s). There is a special provision in the GTNC (Article 2.9 Obligation to Increase the Booked Capacity) stating that if the Shipper exceeds its booked capacity at a certain Point during the period 1st January and 31st March 8 times, then the Shipper's transportation contract shall be amended automatically revising the booked capacity to the peak value recorded for the whole contract period. The consequence of this application may be seen as the payment by the Shippers for the unused capacity for many days throughout the year. On the other side, it should be taken into consideration that the Transporter realizes the network investments to provide for the peak demands at all Entry and Exit Points and there is a rational to request for standard capacity payment for the peak demand.

The effect of proposed application on different consumer groups can be summarized as below under two categories:

- 1- **Benefiting from decreased transmission tariff exposures in gas cost:** Those final consumers are typically individual industrial consumers with dedicated connections to the transmission grid (like cement factories) and group of industrial consumers located in an Organised Industrial Zone and are fed by distribution lines within the zone. Their consumption profiles do not so much dependent on seasonal conditions.
- 2- **Suffering from increased transmission tariff exposures in gas cost:** Those final consumers are typically gas fired power plants, eligible consumers fed by city distribution lines and households. As of today, the gas fired power plants do not have a regular offtake regime and their profile varies day by day in accordance with the demand for electricity and other market conditions. Most of the eligible consumers (industrial, service providers etc.) are fed by city distribution lines together with the households at the downstream of a certain Transmission System Exit Point and those will be contributing to the payments for the unused capacity together with households.

Existing Transmission Tariff applies unique capacity charges to all exit points. When such a unique exit capacity charge for all exit points is continued to be applied, the households in small cities are likely to be the most severely affected ones. This is valid especially for the towns/cities where there are very limited large consumer groups (like industrial plants) located inside the city. In selling gas to non-eligible consumers, the distribution system operators apply the cost of purchase and the cost of transmission as pass through in the bills. The increase in the transmission capacity charge may lead to considerable variation in the invoices of the households in comparison to the existing application. Then, it may come to agenda that a new application for the exit capacity unit charges should vary depending on the locations and the type of city gate stations. Such a change would later be associated with geographical incentives by the governmental decisions or social tariff applications.

4.8 Proposed Amendments to the Existing Legislation

Currently applied the Revenue Cap Regulation for Natural Gas Transmission tariff is generally adopted as the convenient regulation for incentive/efficiency basis tariff applications. On the other side, similar to EMRA case, separate assessments for the OPEX and CAPEX expenditures are seen in the majority of the EU countries whereas the TOTEX approach has limited application (UK, Germany and the Netherlands). Bottom up assessment for OPEX, as applied by EMRA, is the most widely followed method by the regulators in the EU and cost benchmarking has limited adoption. Considering the complexity and potential objections, the TOTEX approach together with benchmarking application would not be a preferable option. Considering the single TSO in Turkey, benchmarking with the past performance would be considered where applicable.

The Natural Gas Tariff Regulation (NTGR) refers to the concept of the “efficiency target” for Natural Gas Distribution and there is no clear indication of the requirement for the involvement of efficiency targets in the transmission tariff. Although the “Principles and Procedures for Determining the Revenue Caps to be taken as basis to the Tariffs of Natural Gas Transmission License Holding Companies” sets out the use of “efficiency parameter” in Natural Gas Transmission tariff, clear definitions for efficiency related concepts should be included in the NGTR separately for distribution and transmission.

The proposed amendments can be classified in two items:

4.8.1 Secondary Legislation to be prepared by EMRA

A specific methodology (as EMRA Board Decision) for the determination of “efficiency parameter” needs to be developed and published. This methodology should define the maximum level of revenue adjustment out of efficiency parameter. Such methodology may also detail certain incentives and indicators of the success and select targets for the Transporter for a certain tariff period. Determination of the efficiency parameter would require big efforts to analyse many statistical data related with the past realizations. There can be applied a transition period during which an incentive payments/penalties regime is annually set and the TSO’s allowed revenue is increased or decreased accordingly, at the end of each year. The application of the incentive, “rewards and penalties for output delivery performance” in the UK (RIIO) case may provide good reference for this purpose.

A table denoting the proposed incentives and criteria for the performance evaluation is given below. It should be noted that, the table is indicative for guiding purposes and actually evaluation of each incentive element, its performance indicator and contribution to the efficiency parameter requires detailed study in consultation with the Transporter and other stakeholders. A regulatory instructions guidance needs to be developed which clarifies the content and the format of the annual reports to be prepared.

Table 4.10 – Proposed Incentives for Natural Gas Transmission Tariff

Incentive	Performance Criteria (Annual Records)	Performance Evaluation
Own Use Gas	Reducing the amount used by the Transporter	Benchmarking with past data with similar conditions. Needed data is available in operational logs of the Transporter
Unaccounted for Gas (UAG)	Decreasing the percentage with respect to annual throughput	Cap, typically 0.5% or a gradual decrease over the years. The Transporter should prepare UAG reports annually for this purpose.
Vented Gas	Reducing the vented amount (recorded in the compressor stations)	Benchmarking with past data of the Transporter. Such vents are logged in the compressor stations and the SCADA System. The amounts are calculated manually in most cases by the designated staff of the Transporter.
Maintenance	Timely implementation of critical maintenance (like smart pigging, compressor overhauls)	Comparing the Planned dates and actual implementation. Realizations after a certain time allowance or failure to implement those by EMRA may be penalized.
Maintenance	Reducing the number of planned maintenance works that require capacity reduction	The amount of reduced capacity due to planned maintenance. Normally no such reduction would be needed by the Transporter. This can be tracked via nomination process with the Shippers through the EBT. The Transporter can also be requested to prepare report if such a capacity reduction is done.

Incentive	Performance Criteria (Annual Records)	Performance Evaluation
Service Interruptions (shortfalls)	Shortfalls attributed to TSO defaults	Amount of Service Interruption Fee paid by the Transporter. This data is available in the Shippers' Invoices as per GTNC provisions.
Compressor Stations Outages	Reducing outages arising from operational defaults and line pack level reductions	Number of outages recorded. The data is available in each compressor station and the SCADA System
The cost of the OUG	Unit average price of the Own Use of Gas paid by the Transporter	Benchmarking with the average Daily Reference Gas prices in the Organized Wholesale Market
Demand Forecasts	Successful day ahead demand forecasts by the Transporter	Cap as percentage. Violation of the cap for a certain day is regarded as a failure. Money wise penalization can be applied if the total number of failed days exceed a certain figure for a year. The data is available through the EPIAS system.

The necessary data for the evaluation of above-mentioned incentives and the performance of the TSO for those are available in the TSO's operational log-books, EPIAS' records and the TSO's regular reports to EMRA. A guiding methodology related with the Own Use Gas (amount) is proposed as follows.

An overall cap for total rewards or penalties may be set every year and effectively this has very similar to effect to the setting of efficiency parameter, X factor in the Tariff. On the other side, the proposed application may also provide the authority with a helpful data base in the future in determining the efficiency parameters.

"A Descriptive Methodology for Own Use Gas Efficiency Incentive"

The cost of OUG is among the major OPEX expenditures of the TSOs. The amount of the OUG is linked with the amount of transported gas and other factors. As stated before, in the Turkish gas network, the vast majority of the OUG is used for compressor stations gas turbines' fuel and the figure for 2018 was 280 million m³.

The success of the Transporter in reducing the amount of OUG or actually efficient utilization of OUG is difficult to assess. This is mainly due to the reason that the amount of OUG does not vary linearly with the throughput. For the same network, the percentage of the required OUG over throughput differs significantly with varying throughput volumes and practically such a percentage is much bigger for the big throughputs close to the technical deliverability limit of the network as compared to small throughputs, which are much lower than the technical delivery capacity of the network. Then there remains the option to compare between similar throughput figures over the years.

Table 4.11 – A descriptive table for setting the OUG Incentive

Throughput (bcm)	Level of OUG (Most Recent)	Incentive for Improvement for upcoming years	Upper cap (TSO earns)	Lower cap (TSO Loses)
44-46		1000 TL per million m ³ consumed less (TSO earns) and 300 TL per million m ³ consumed more	10 Million TL	3 Million TL
46-48		"	11	3,3
48-50		"	13	4
50-52		"	15	4,5
52-54		"	17	5
54-56		"	20 Million TL	6 Million TL

Such a table can be prepared with the assistance of the Transporter and can be updated in the future for larger throughput volumes. Since the records for the OUG are on a daily basis, benchmarking with exactly the same past throughput figures is possible. The success of the Transporter relating to this incentive is related with the efficient optimization of the compressor stations' operational parameters altogether and maintaining ideal levels of the line pack in different segments of the transmission network to minimize the fuel gas required by the compressor stations.

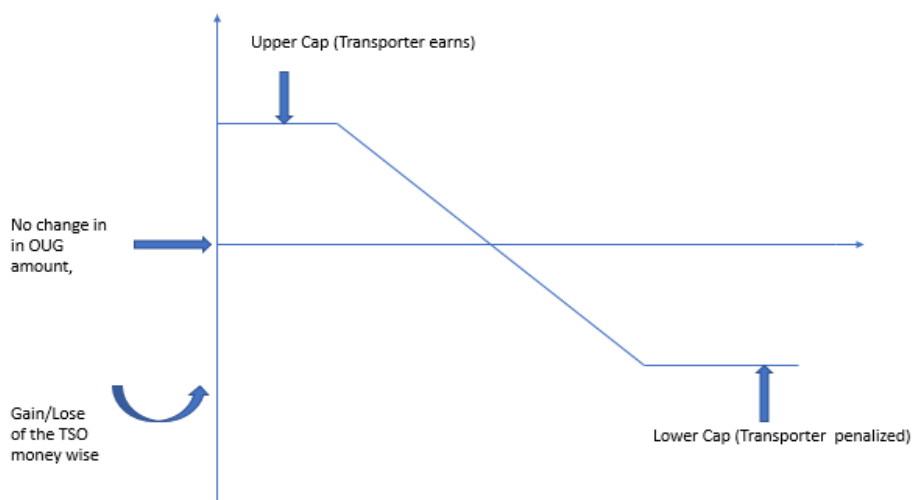


Figure 4.6 – Descriptive logic for the OUG Incentive

4.8.2 Amendments to the BOTAS Natural Gas Transmission Network Code

These amendments are mostly related with the facilitation of gas trading (both in land and across the borders) and efficient use of the network. Such amendments are also very much related with the alignment with the EU applications.

Introducing Short Term and Long-Term Capacity Products

Short Term Capacity products refer to the Day Ahead and Intra Day capacity reservations. Long Term Capacity products refer to the capacity bookings for multiple years. Together with the provision of new capacity products, new terms and conditions for capacity booking via auctions can be included in the amendments. The duration of the Standard Transportation Contracts would stay as minimum one month whereas the maximum duration would be set as the duration of the existing Tariff Application Period. Long term capacity booking requests might be considerable in the case of specific capacity expansions at a certain point by a certain Shipper. Critical principles like the percentage allocated to short term products and priority orders for different products must be in place and those require revision of the Capacity Reservation section as a whole and also other relevant articles.

Introducing Interruptible Capacity Products

Offering of interruptible services is not included yet in the GTNC. However, it can be a very useful instrument for efficient utilization of the network and avoiding unnecessary investments for capacity expansion. A new section can be included in the GTNC for interruptible services and such services can be conditionally offered when total capacity reservation request from the Shippers for a certain Entry or Exit Point exceeds the technically available capacity at that point. Certain discount would be applicable for such conditionally reservable (interruptible) capacities.

Special Terms and Conditions Applicable for the Interconnections at EU Borders

Harmonization of the operational rules for the TSOs at Turkey and EU sides is strongly needed to facilitate trading. Actually, the last amendment to the 3rd Gas Directive and putting it into force in May 2019 has already brought an obligation to structure the Interconnection Agreements between Turkish and Greek and Bulgarian TSOs in accordance with ENTSG Network Codes, to the extent possible. Special provisions to be applicable for only the interconnections with the Greece and Bulgaria networks can be added to the GTNC and accordingly to the transmission tariff document. It must be noted that, development of those terms and keeping them in application (especially for the cases of Bundled Capacity and Incremental capacity) require mutual coordination of the respective TSOs and as well as the NRA's. The main issues to be handled can be stated as:

- Incremental Capacity



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- Bundled Capacity
- Bidirectional Flows
- Nomination Procedures

Operational Balancing Arrangements

A new section can be added to the GTNC setting out the operational balancing arrangements with all interconnected transmission systems, LNG terminals, underground storage facilities, and production sites. The TSO should be required to establish operational balancing accounts with the interconnected system operators. There can be terms to allow the Shippers using the same Entry Point to nominate a “Balancing Shipper” among them to conduct allocation procedures with the TSO. All subject system operators would benefit from risks against their commitments for daily deliveries whereas the Shippers would benefit from eliminating their risks in terms of imbalance positions and commitments for daily contract quantities.

5 ANNEXES

5.1 Annex 1 – EU SAIDI/SAIFI indicators

In section 1.3.6 (on Performance Indicators), supply quality indicators of the EU countries are shown. Most of the countries use SAIDI and SAIFI as supply quality indicators, but other indicators such as ASIDI, ASIFI, CAIDI and ENS are also utilized in some countries. As the major quality indicators, in the below tables, SAIDI and SAIFI outputs of the EU countries are shown between 2002-2016.

As a comparison, SAIDI and SAIFI indicators for Turkey is also stated in the below tables for the EU.

Table 5.1 – Planned and unplanned SAIDI, including exceptional events (minutes per customer)

Country	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Austria											50,41	53,64	68,31	62,76	54,86
Bulgaria									485,20	470,10	455,10	435,20	350,80	346,90	291,30
Croatia											664,00	559,46	661,72	516,32	412,24
Czech Republic						351,36	351,59	295,28	268,82	272,65	354,76	283,22	316,07	258,29	
Denmark									20,42	21,98	19,49	20,56	16,64	20,51	19,38
Estonia											255,79	465,32	182,82	237,74	222,23
Finland											94,36	186,72	79,79	169,13	80,56
France	48,00	74,60	63,70	13,90	94,20	72,40	93,50	197,00	119,10	72,80	78,50	99,50	67,30	73,80	70,50
Germany					38,35	49,52	30,13	26,82	29,67	27,37	29,20	39,98	21,06	22,19	23,55
Great Britain					73,22	108,44	87,64	82,17	88,14	76,70	74,75	68,70	98,23	55,74	50,43
Greece											299,00	289,00	258,00	248,00	244,00
Hungary														228,00	216,00
Ireland														183,30	162,40
Italy	102,71	626,75	153,15	138,63	114,34	104,05	138,99	122,25	144,55	169,81	198,70	160,68	153,40	195,65	143,74
Latvia						506,00	497,00	678,00	1.292,00	944,00	636,00	621,00	466,00	350,00	286,00
Lithuania				280,26	290,29	326,36	231,50	256,63	421,64	460,50	467,33	366,69	361,49	300,71	345,96
Luxembourg												33,64	25,09	28,81	21,84
Malta			556,11	520,15	405,52	490,40	262,18	763,74	693,00	260,00	366,60	421,08	777,60	227,59	163,82
The Netherlands											31,50	29,42	25,89	37,66	27,28
Norway											106,76	181,41	161,12	172,82	128,83
Poland						531,00	589,69	518,68	515,88	478,81	410,51	420,94	324,81	363,32	272,00
Portugal	520,19	468,57	266,95	237,89	261,89	143,31	164,74	282,03	277,61	133,48	95,83	260,26	97,34	77,47	77,65
Romania												761,00	710,00	582,00	555,00
Slovakia												298,06	254,36	257,52	258,62
Slovenia							253,35	264,65	186,12	202,39	286,04	224,41	1027,19	199,95	191,92
Spain											69,18	108,38	63,36	69,12	65,82
Sweden											105,11	170,81	101,89	134,81	94,42
Switzerland									28,00	29,00	34,00	25,00	22,00	21,00	19,00



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Table 5.2 – Planned and unplanned SAIDI, without exceptional events (minutes per customer)

Country	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Austria											48,67	47,96	49,79	42,31	37,91
Croatia													416,49	404,42	325,25
Czech Republic			250,83	286,69	247,20	274,46	252,52	243,30	265,64	261,83	257,36	257,69	246,71	253,32	233,00
Denmark									20,37	21,04	19,44	15,90	16,65	19,55	19,34
France	46,00	56,30	57,30	60,20	79,40	68,50	82,00	90,40	86,90	71,50	75,70	84,00	66,00	67,90	66,60
Germany					36,63	33,10	30,06	26,16	24,56	25,43	27,74	22,55	19,84	19,73	23,09
Great Britain					69,61	82,99	79,92	79,91	76,74	74,63	62,14	60,39	58,94	49,89	42,30
Greece											250,00	252,00	228,00	199,00	208,00
Hungary														250,00	232,00
Ireland														158,70	144,90
Italy	186,85	177,50	139,14	124,51	107,63	98,63	102,45	93,03	103,48	105,44	111,42	97,55	100,92	112,02	115,96
Latvia											520,00	472,00	409,00	332,00	260,00
Lithuania				208,35	199,63	167,18	145,33	124,29	211,09	217,43	234,90	264,16	266,89	238,76	220,98
Luxembourg												33,64	25,09	28,81	21,72
Poland							503,56	456,77	445,96	462,15	401,32	393,97	311,17	340,04	260,36
Portugal	386,75	366,14	197,97	181,98	170,78	111,64	135,15	187,62	174,55	99,30	80,16	90,16	77,48	69,20	65,99
Romania							1.025,0	959,00	963,00	880,00	876,00	697,00	591,00	519,00	474,00
Slovenia										128,44	119,68	121,44	122,96	133,43	121,77
Spain											63,24	61,26	64,68	69,12	65,82
Sweden											100,70	101,06	92,66	100,25	87,90
Switzerland									28,00	29,00	34,00	25,00	22,00	21,00	19,00

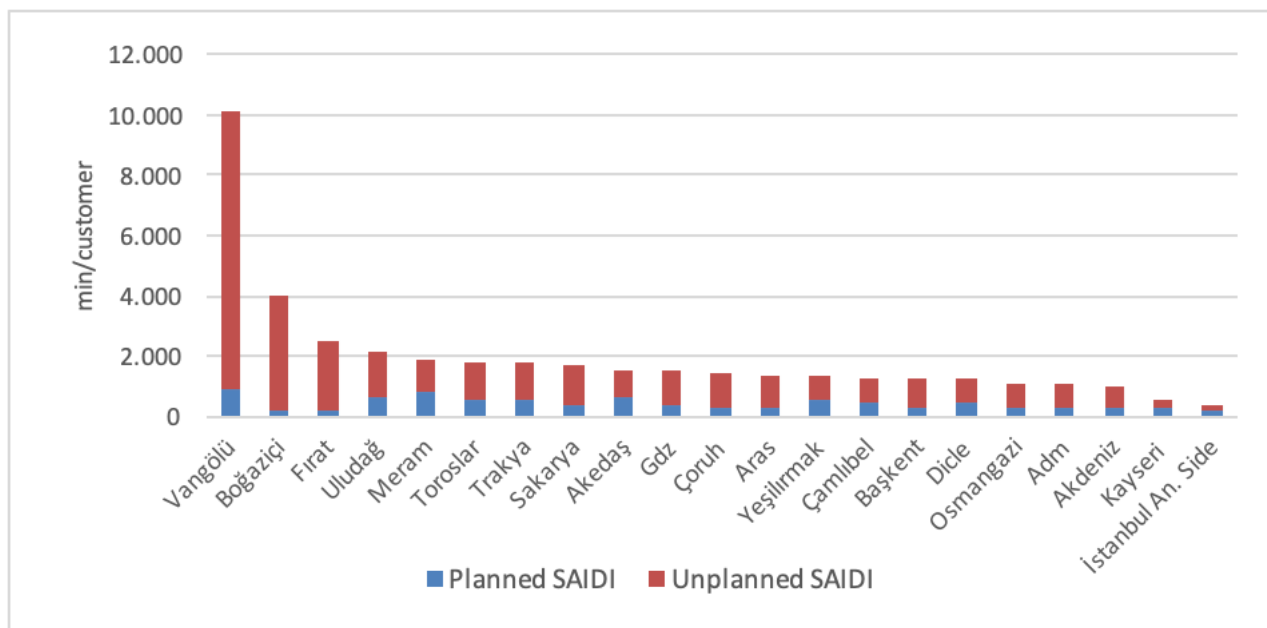


Figure 5.1 – SAIDI for Turkish DSOs (2018)



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Table 5.3 – Planned and unplanned SAIFI, including exceptional events (interruptions per customer)

Country	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Austria											0,69	0,78	0,77	0,70	0,72
Croatia													3,46	3,60	2,95
Czech Republic			2,68	2,49	2,42	2,91	2,32	2,17	2,23	2,19	2,31	2,21	2,11	2,09	1,95
Denmark									0,44	0,44	0,44	0,36	0,35	0,41	0,42
France	0,11	0,18	0,16	0,13	0,15	0,19	0,32	0,31	0,27	0,19	0,19	0,23	0,20	0,22	0,22
Germany						0,45	0,43	0,39	0,35	0,41	0,39	0,55	0,42	0,88	0,59
Great Britain					0,73	0,80	0,76	0,74	0,72	0,70	0,63	0,61	0,62	0,56	0,50
Greece											2,43	2,50	2,40	2,10	2,07
Hungary														1,64	1,52
Ireland														1,31	1,30
Italy	3,23	3,17	2,82	2,71	2,52	2,40	2,27	2,24	2,19	2,04	2,15	2,00	2,00	2,12	1,91
Latvia											4,34	3,86	3,37	2,97	2,88
Lithuania				1,18	1,17	1,38	1,20	0,96	1,22	1,29	1,32	1,26	1,23	1,25	1,20
Luxembourg												0,40	0,38	0,43	0,28
Poland							4,82	4,46	4,42	4,96	4,12	3,64	3,51	4,10	3,45
Portugal	6,22	5,11	2,92	2,90	2,82	2,10	2,38	2,78	3,15	1,95	1,63	1,76	1,57	1,46	1,46
Romania							8,32	7,87	7,38	6,90	6,48	5,74	5,15	4,96	4,48
Slovenia										1,04	1,07	1,00	1,11	1,05	0,92
Spain											3,34	1,43	1,29	1,30	1,18
Sweden											1,47	1,44	1,46	1,34	1,33
Switzerland									0,40	0,40	0,45	0,37	0,30	0,32	0,30

Table 5.4 – Planned and unplanned SAIFI, without exceptional events (interruptions per customer)

Country	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Austria											0,83	0,81	0,96	0,80	0,86
Croatia											5,09	4,32	4,34	4,15	3,51
Czech Republic							2,84	2,54	2,37	2,36	2,39	2,65	2,37	2,65	2,21
Denmark									0,44	0,44	0,44	0,41	0,35	0,42	0,42
Estonia											2,32	3,06	1,13	1,73	1,96
Finland											1,96	2,35	1,76	2,78	1,58
France	0,11	0,18	0,16	0,13	0,15	0,19	0,32	0,34	0,28	0,19	0,19	0,23	0,20	0,22	0,22
Germany						0,55	0,44	0,40	0,40	0,44	0,41	0,58	0,45	0,91	0,59
Great Britain					0,76	0,90	0,79	0,75	0,74	0,72	0,68	0,63	0,74	0,58	0,54
Greece											3,30	3,20	2,80	2,90	2,80
Hungary														1,55	1,43
Ireland														1,50	1,30
Italy	3,25	4,45	2,88	2,79	2,58	2,46	2,73	2,66	2,65	2,46	2,74	2,57	2,35	2,81	2,17
Latvia						3,01	2,95	1,80	5,00	5,59	4,78	4,48	3,77	3,18	3,13
Lithuania				1,57	1,73	2,44	1,89	1,89	2,45	2,67	2,36	1,97	1,85	1,72	1,83
Luxembourg												0,40	0,38	0,43	0,28
Malta											5,05	4,76	5,34	3,13	2,60
The Netherlands											0,33	0,33	0,31	0,47	0,32
Norway											1,63	2,22	2,44	2,17	1,89
Poland						3,50	4,88	4,60	4,45	5,04	4,14	3,94	3,52	4,11	3,46
Portugal	7,64	6,26	3,89	3,73	3,90	2,66	2,82	3,64	4,33	2,42	1,89	3,10	1,90	1,55	1,65
Romania												6,23	5,86	5,49	5,00
Slovakia												2,58	2,24	2,14	2,26
Slovenia						3,81	3,46	2,67	2,79	3,87	3,09	5,17	2,66	2,49	
Spain											7,03	1,19	1,29	1,30	1,18
Sweden											1,47	1,48	1,46	1,36	1,34
Switzerland									0,40	0,40	0,45	0,37	0,30	0,32	0,30

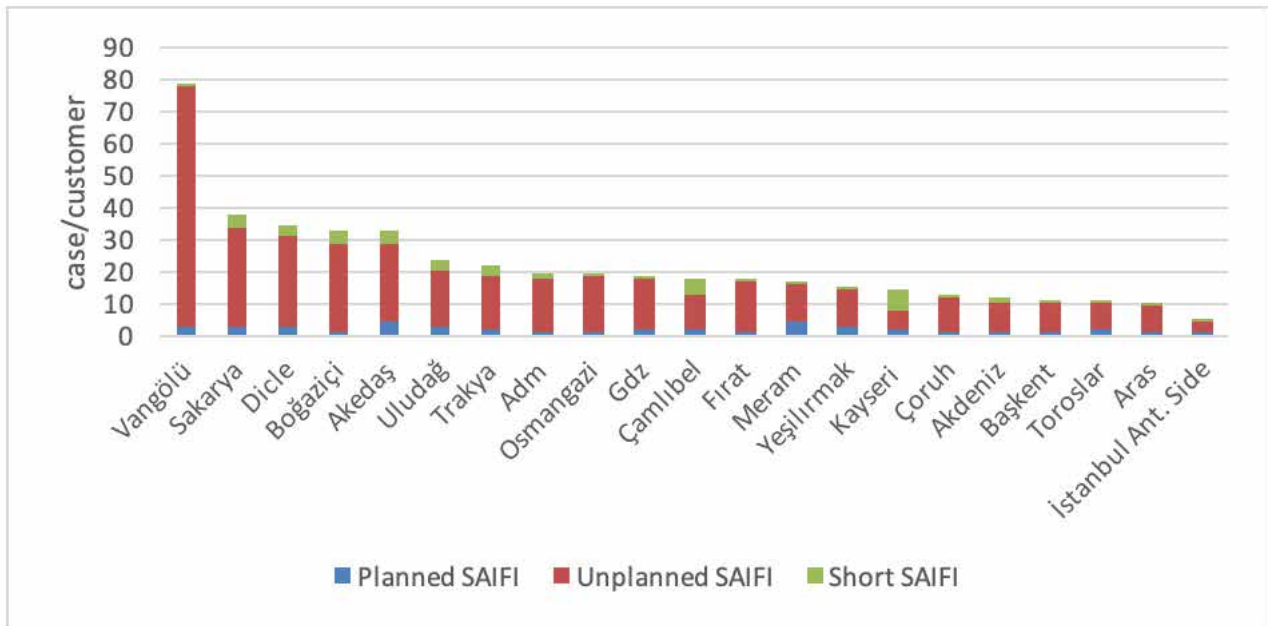


Figure 5.2 – SAIFI for Turkish DSOs (2018)

5.2 Annex 2 – More about RIIO and TOTEX approach in UK

The current price control for the 14 Electricity Distribution network operators (DNOs) under the RIIO framework runs from 1 April 2015 to 31 March 2023. RIIO focuses on innovation, incentives, and output delivery, as well as the DNOs' total expenditure (TOTEX). Ofgem regulates the revenues that DNOs can recover from consumers and incentivise them to innovate and improve their efficiency and quality of service.

The following figure indicates an overview of the process that was followed in setting price controls for the first implementation period of RIIO, ED1.

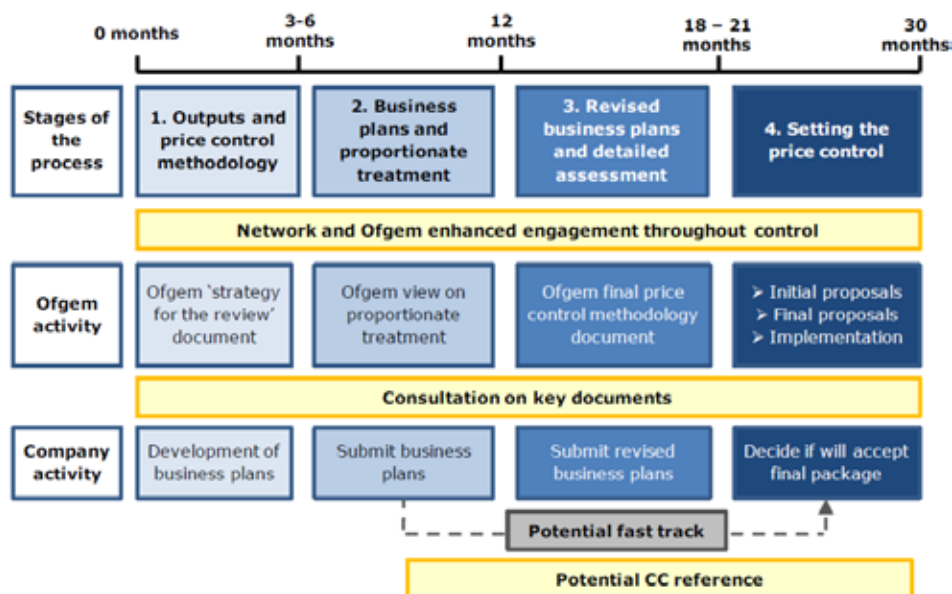


Figure 5.3 – Overview of Price Setting Process in ED1

In the first stage, the timetable for the review was set to understand key issues and establish the outputs to be delivered and parameters for the price control. In the second stage network companies engaged with stakeholders and they developed and submitted their business plans. In the third stage, network companies submitted their revised business plans which should address the comments from Ofgem in stage 2. The objective of this stage is to finalise business plans for the network companies and confirm the methodology to be used to set the price control. In the last stage, Ofgem developed initial and final proposals for the network companies and associated licence drafting, in accordance with the final price control methodology, to provide transparency on how the proposals will be implemented.

Within this scope, In March 2013 Ofgem published their strategy decision on the key elements of the regulatory framework for RIIO-ED1. This included the outputs the DNOs need to deliver, the incentive framework and financial parameters. The strategy decision provided the basis for the DNOs to develop their business plans. In July 2013, DNOs submitted their business plans and published them on their websites. Under RIIO, where a DNO submits a realistic and well-justified business plan that clearly provides value to consumers and if the plan is sufficiently high quality and provides good value overall, Ofgem considers it for fast-tracking. In this case, they accept the business plan as submitted and conclude the company's price control review early. The other case is slow track where the business plans need revisions. 13 companies submitted revised business plans in March 2014. Finally, Ofgem published fast-tracked companies' modified licence in May 2014 and the slow-track DNOs' licence modifications in February 2015

5.2.1 Assessment of the Business Plans

In one of their Strategy Decision documents, Ofgem identified 15 criteria that they would use to assess the Business Plans of the Regulated Companies. These 15 criteria contribute to five broad indicators with which the business plans are reviewed: Process, Outputs, Resources (efficient expenditure), Resources (efficient finance) and Uncertainty and Risk. These criteria are summarized in the following table:

Table 5.5 – Criteria for Assessing the Business Plans of Network Companies

Criteria	Description
Process - Has the company followed a robust process?	
Criteria 1: Key content?	Has the company included main elements of a well-justified business plan?
Criteria 3: structure and proportionality	Is the business plan well-structured?
Criteria 8: Effective engagement	Has the company engaged with stakeholders and explained how this has influenced its business plan?
Criteria 11: Accurate, timely and complete business plan templates	Has the company submitted and justified all templates and the financial model?
Outputs: Does the plan deliver the required outputs?	
Criteria 2: Reflection of Ofgem policies	Does the business plan conform to the outputs specified in the Strategy Document and are any departures well-justified?
Criteria 5: Long-term context	Does the business plan provide a strategy for long term delivery
Criteria 7: Output delivery	Has the company explained resource implications for output delivery and demonstrated output baseline/forecast?

Criteria 12: Quality of info on primary outputs	Has the company explained how it will deliver outputs and justified output baseline/forecast?
Criteria 13: Quality of info on secondary deliverables	Has the company explained and justified use of secondary deliverables?
Resources (efficient expenditure): Are the costs of delivering the outputs efficient?	
Criteria 4: Efficiency of costs	Has the company demonstrated that cost projections are efficient?
Criteria 10: Reflecting best practice	How does the plan compare with others/best practice?
Criteria 14: Evidence	Has the company provided evidence that costs (including financial costs) are efficient, for example through market testing?
Criteria 15: Linking forecasts to historical performance	Has the company explained cost projections in the context of historical performance?
Resources (efficient financing): Are the proposed financing arrangement efficient?	
Criteria 2: Reflection of Ofgem policies	Does the business plan conform to the outputs specified in the Strategy Document and are any departures well-justified?
Criteria 4: Efficiency of costs	Has the company demonstrated that cost projections are efficient?
Criteria 15: Linking forecasts to historical performance	Has the company explained cost projections in the context of historical performance?
Uncertainty and risk: How well does the plan deal with uncertainty and risk?	
Criteria 6: reflect uncertainty	Has the company considered how it will address uncertainty (for example by including uncertainty mechanisms)?
Criteria 9: Risk	Has the company considered risk and how to mitigate that risk?

For larger scale projects Ofgem requires companies to demonstrate that they have considered all possible options. Furthermore, companies have to demonstrate efficiency of cost forecasts by internal or external benchmarking analysis. For certain expenditure items Ofgem may require itemizing unit costs, conducting a full engineering reassessment of asset replacement strategy or requiring companies to undertake further market testing.

5.2.2 Calculation of Allowed Revenue

Ofgem sets the baseline revenues that DNOs can collect from customers, at the start of the price control. Ofgem regulate how much DNOs can earn, using price controls. DNOs decide how to spend their baseline expenditure to manage their networks, and deliver against the set outputs, associated incentives, and their wider business plan commitments. These revenues are adjusted year-on-year depending on how efficiently DNOs incur expenditure and how effectively they deliver their outputs.

The following figure shows allowed revenue calculations:

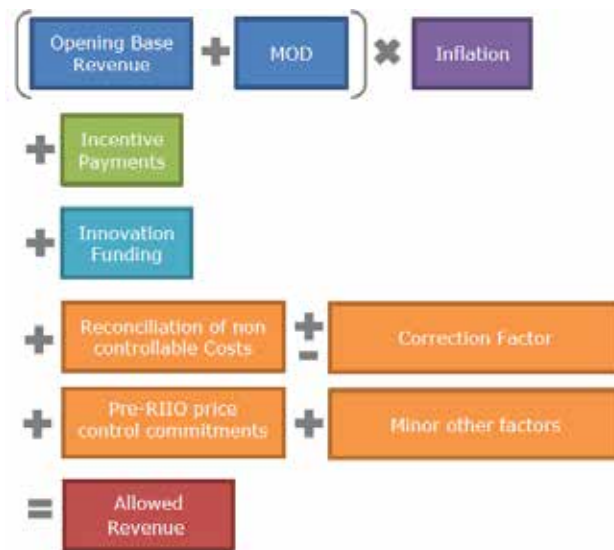


Figure 5.4 – Calculation of Allowed Revenue

- The DNO's allowed revenue comprises:
 - base revenue (the core amount of money that a network company can earn on its regulated business in order to recover the efficient costs of carrying out its activities (the includes the amount it has to fund, or is allowed to keep, for any over- or under-spend against its allowance): Base revenue can be described in three categories that are:
 - an allowance for some DNO costs which is set at the time of the price control review. These costs are called TOTEX.
 - an allowance for depreciation and a fair return which reflects past funding of assets from investors in the network company
 - tax (which is calculated each year, depending on the DNOs' performance and circumstances)

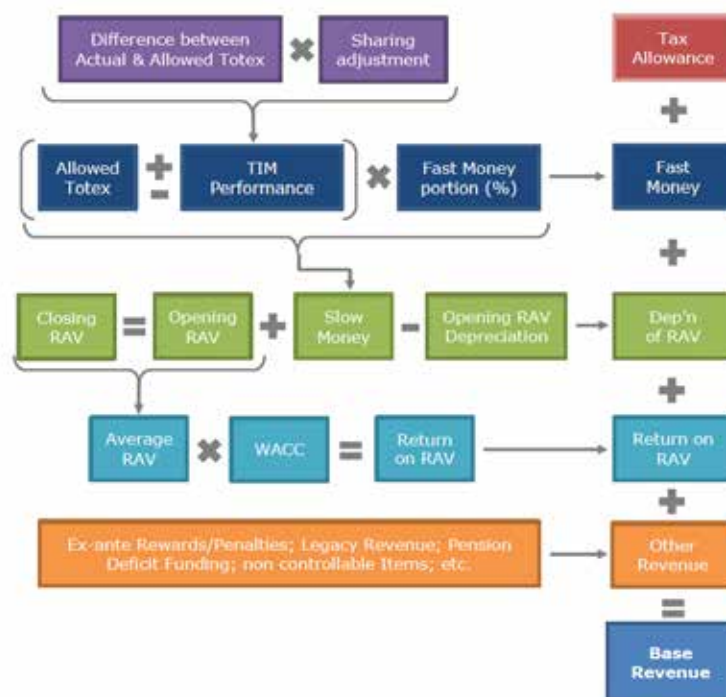


Figure 5.5 – Determination of Base Revenue

- mechanisms for funding elements that Ofgem could not set upfront (uncertainty mechanisms)
- incentive rewards or penalties for over - or under - delivery of the outputs it must deliver (RIIO has six groups of outputs which customers want network companies to deliver. These cover safety, reliability, environmental impact, customer service, connections service and social considerations)
- To calculate the allowed revenue each year, the forecast Opening Base Revenue is adjusted for a number of factors. Opening Base Revenue is the amount of money a DNO needs to earn on its regulated business to recover the efficient cost of carrying out its core activities. It is determined through ex-ante forecasts conducted by Ofgem and the DNO, prior to the start of the price control.
- Opening Base Revenue is modified annually during the price control by the “MOD” term in the licences. This takes place as part of Annual Iteration Process (AIP).
- The AIP process takes account of uncontrollable market uncertainties, as they become known, such as the cost of debt and changes to taxation rules. It also measures financial performance against pre-determined output incentives. Where a company under or over performs relative to the ex-ante expectation a percentage of the difference is shared with consumers.
- The MOD term is the difference between the updated Base Revenue (recalculated using the latest available performance data, including revisions to that data for previous years) and the Opening Base Revenue. Two key variables to the MOD value are TOTEX performance and Regulatory Asset Value (RAV).
- Allowed Revenue is also adjusted for outputs incentive payments, innovation funding and other costs such as differences between previous years’ Allowed Revenue and the actual amount that has been collected.

5.2.3 TOTEX

DNOs’ allowances set for each year of the price control makes up their allowed TOTEX. This includes only the controllable costs and uncontrollable costs, such as business rates and licence fees, are excluded. This enables the DNOs to invest in maintaining their networks, accommodate new infrastructure, and deliver their agreed outputs.

The most significant expenditure categories are:

- *Operational support*: the cost of supporting direct activity on the network, such as network design, project management, engineering management, clerical support, operational training, call centres and control centres.
- *Replacing and refurbishing equipment*: the cost of maintaining the existing network by replacing and refurbishing assets.
- *Network faults*: the cost of repairing faults on the network.
- *Business support*: the cost of running the DNO business, such as those associated with HR, finance and the CEO, and non-operational training.
- *Network reinforcement*: the cost of managing the load on the network, for example the installation of new assets to accommodate changes in the level and/or pattern of electricity demand and generation.
- *Other operational CAPEX costs*: This combines eight single cost categories; resilience (excluding tree cutting), legal and safety compliance, rerouting, IT, other operational costs, service quality, high value projects and environment.

DNOs must report their actual TOTEX annually, explaining their performance compared with their allowed TOTEX. They are also required to forecast their TOTEX performance to the end of the price control.

As TOTEX refers to the total controllable expenditure, it comprises both CAPEX and OPEX. DNOs are incentivized to deliver outputs based on whole-life costs, rather than being driven to prefer either OPEX or CAPEX solutions. TOTEX is made up of fast money and slow money. Fast money is funded in the year incurred. It is equivalent to OPEX. Slow money is added to the regulatory asset value (RAV) and is funded over time through allowances for depreciation and return on capital. Slow money is equivalent to CAPEX. In previous price controls the RAV was depreciated over 20 years. In RIIO-ED1 Ofgem have changed this to 45 years for new assets – with a transition from 20 to 45 years over the RIIO-ED1 period. Existing assets are still depreciated over 20 years.

CAPEX solutions have, historically, been preferred as the cost was capitalized, therefore increasing the DNO’s RAV. Under the TOTEX approach, when a company spends money on a solution, the same percentage is capitalized irrespective of whether that solution involves OPEX or CAPEX. This better incentivizes the selection of the best overall solutions for customers. The TOTEX

approach might encourage the companies to use maintenance to avoid replacing an asset, or use demand-side management to avoid installing new capacity. The capitalization rate is a percentage, and is fixed for each DNO for the total RIIO-ED1 period. For the duration of RIIO-ED1, the DNOs proposed **capitalisation rates** ranged from 68 to 80% in their business plans.

Ofgem sets the same TOTEX incentive rate (the percentage that the licensee bears of an under or overspend against allowances) for both OPEX and CAPEX solutions.

The difference between actual TOTEX and allowed TOTEX (whether the actual TOTEX is underspend or overspend) is shared between the DNO (via modifying to Base Revenue) and customers and tax obligations. This process forms the TIM.

TOTEX Incentive Mechanism (TIM): The DNOs are incentivized to outperform their TOTEX allowances. DNOs that submit better forecasts of the costs in their business plans receive a higher TOTEX efficiency incentive rate, meaning they get to keep more of any underspend. The efficiency incentive rate is used to calculate the revenue adjustment a DNO receives following overspend or underspend against allowances. It is fixed for the whole of the price control. The higher the rate, the more the company bears of any overspend and retains of any underspend. Therefore, efficient spending leads to better returns for investors and lower network charges for customers.

For Base Revenue calculations a portion of Allowed TOTEX is directly added to the Base Revenue (this is known as Fast Money). The remainder of Allowed TOTEX (known as Slow Money) is added to the opening RAV, which is based on the initial market value of the regulated asset base at privatization, plus all subsequent additions.

RAV is gradually reflected in Base Revenue, reflecting the average lifetime of network assets. Amounts are deducted annually from opening RAV (depreciation). The depreciation value is then added to Base Revenue in the next Allowed Revenue year. The average of opening and closing RAV for the year also earns a return (at the WACC). As TIM performance becomes known, the RAV is recalculated using the updated Slow Money value.

Smart Grid Solutions Assessment: As part of their annual environmental reports, DNOs report on the smart grid solutions they have deployed and the savings they have delivered for customers. These reports will be published and will allow stakeholders to assess DNOs' progress against the smart grid savings in their settlements. This will also provide evidence for assessing the potential level of smart grid savings achievable in RIIO-ED2

5.2.4 Outputs

As explained before, 6 output categories are:

- Safety: ensuring the provision of a safe network in compliance with Health and Safety Executive (HSE) safety standards.
- Environment: encouraging companies to play their role in achieving broader environmental objectives, namely the reduction in carbon emissions, as well as minimising the narrow environmental impact of the company's activities by managing their own carbon footprint, visual amenity and pollution.
- Customer satisfaction: maintaining high-levels of customer satisfaction and improving service where required. Undertaking effective stakeholder engagement and reflecting stakeholders' views in the day-to-day operation of their business.
- Connections: connecting customers in a timely and efficient way, including responding to different customers' specific needs, while enabling competition.
- Social obligations: taking a strategic approach and adopting a coordinating and partnership role with other networks, suppliers and agencies so data and knowledge is used more effectively to help vulnerable consumers.
- Reliability and availability: providing long-term reliability, minimising the number and duration of interruptions and ensuring adaptation to climate change.

For many of the outputs Ofgem set levels (or targets) that the companies need to deliver based on the costs and benefits to consumers. For each output category, a range of incentive mechanisms are also considered to encourage DNOs to deliver the primary outputs and secondary deliverables in ways which provide value for money to current and future consumers. These

incentives include financial rewards and penalties and reputational incentives.

Smart Grid and Smart Meter: The DNOs will face costs from both the smart meter roll-out and the use of the data. DNOs will pay a fixed cost to access smart meter data (a licence fee) and variable costs per transaction. OFGEM assumed that the benefits to the DNOs of using the data will cover the variable costs, however allowed the DNOs to reclaim (“pass through”) the fixed costs up to the end of 2019. While some of the benefits will start coming through during the roll-out period, OFGEM expects that DNOs will be able to realise the full benefits from this data by 2019. After 2019, DNOs have to fund the fixed costs from the benefits realised. OFGEM’s assessment of the level of savings which DNOs can deliver through smart grids took account of the fixed and variable data costs required to deliver those savings.

As part of their annual environmental reports, DNOs will report on the smart grid solutions they have deployed and the savings they have delivered for customers. These reports will be published and will allow stakeholders and OFGEM to assess DNOs’ progress against the smart grid savings in their settlements. This will also provide OFGEM with evidence for assessing the potential level of smart grid savings achievable in RIIO-ED2.

For the first 2 years of the implementation period, DNOs performed strongly against four of the six output categories:

- reliability and availability,
- customer satisfaction,
- social obligations, and
- safety

There is still scope for improvement for the connections and environmental outputs. Below is an example of Electricity Northwest Group’s expenditure and output performance in the second year of RIIO-ED1.

Expenditure and financial performance					
2017-18	To date	RIIO-ED1	Totex efficiency incentive rate	Forecast 8-year RoRE	
Total spent: £255m Underspend: -£3m or -1% of allowances	Total spent: £733m Underspend: -£47m or -6% of allowance	Total forecast: £2,010m Forecast underspend: -£84m or -4% of allowance	58%	6.51%	
Outputs performance					
Reliability & availability	Connections	Social Obligations	Customer Service	Environment	Safety
✓ number of interruptions ✓ duration of interruptions	✓ time to quote & connect ✓ connections GSoP	✓ stakeholder engagement	✓ BMCS ✓ complaints	✓ BCF ! oil leakage ✓ SF ₆ Emissions	✓ compliance with HSE obligations
Innovation					
Spent all of their NIA allowance and increased the number of projects from 18 to 21.					

Figure 5.6 – Electricity Northwest Group’s Expenditure and Output Performance

5.2.5 Financing (WACC and Depreciation)

The WACC comprises two elements, an allowance for the cost of debt and an allowance for the cost of equity. Companies can finance themselves in two ways; by taking out loans (debt) on which they pay interest, or by selling shares in the business (equity) and paying the shareholders dividends. The cost of debt is the interest payable on loans and the cost of equity is the dividends paid to shareholders.

Companies normally have a mixture of debt and equity. The ratio of a DNO’s debt to its RAV is called its gearing. For RIIO-ED1,

a notional gearing of 65% for all DNOs is used. It is for the DNOs to choose their actual financial structure and they (and their investors) bear the risks associated with the choice made. The regulatory framework is about identifying an appropriate allowed return, reflecting an assumed notional gearing.

Cost of Debt	Cost of Equity
- It is based on the historical average cost of debt for a broad range of companies. It is calculated as the trailing average of a cost of debt index and the DNOs' revenues are updated in the Annual Iteration Process to reflect changes in the index. - As for WPD, cost of debt index based on a 10-year trailing average of the iBoxx series is accepted, whereas for the other DNOs, a trailing average period that increases by an extra year each year, from 10 years to 20 years is used.	- Greater weight to current market conditions are given. - WPD's settlement includes an allowance for a cost of equity of 6.4%, while the slow-track DNOs have 6%.

Figure 5.7 – Cost of Debt and Cost of Equity²⁸⁴

For RIIO-ED1 Ofgem allowed the DNOs transition arrangements for asset lives from 20 to 45 years in equal steps over the eight years of RIIO-ED1 to assist financeability.

5.2.6 Network Maintenance Model

As part of the RIIO-ED1 price control review, DNOs provided forecasts of their asset health and criticality positions 'with intervention' and 'without intervention'. Ofgem used these to create secondary deliverable targets, setting out the required improvements in asset health, criticality and monetised risk.

Standard License Condition 51 of the License requires the DNOs to have a Common Methodology for asset health, criticality and monetised risk. The DNOs have worked together to develop the Common Methodology and following a series of consultations, and Ofgem approved v1.0 on 21 October 2016.

DNO Common Network Asset Indices Methodology sets out a common methodology for assessing condition-based risk for Electricity Distribution assets. It has been developed by the six UK DNO groups.

The summary of the methodology is as follows:

- Initial Health Index of a network asset is calculated based on its age and expected life.
- Expected life of a network asset is the normal life reduced by location factor and load factor.
- Location factors are taken as:
 - o Distance from coast,
 - o Altitude,
 - o Corrosion Category,
 - o Environment (indoor/outdoor),
- Load factor is the utilization of the network asset relative to its normal electric load.
- Health Score is calculated in such a way that, as the aging occurs, asset health decreases more, due to corrosion, oxidation and deterioration of protection. Deterioration ratio is calculated as follows:

284 WPD: Western Power Distribution Co.

- Initial Health Score is 0,5 for new asset, 5,5 for the asset whose economical life is completed and 10 for the asset in a very poor condition. Initial Health Score is capped at 5,5, because an asset should not be classified as deteriorated only by looking its age.
- Health Score is finalized by taking samples from the network and observing the condition of the sample assets.
- DSOs submit Ofgem the below table for its assets:

Table 5.6 – Network Assets Table that DSOs submit to Ofgem

		Health Index 1	Health Index 2	Health Index 3	Health Index 4	Health Index 5
Asset (e.g. Low Voltage Over-head Lines)		New or As New	Good or serviceable condition	Deterioration requires assessment and monitoring	Material deterioration, intervention requires consideration	End of serviceable life, intervention required
Criticality – 1	Low	...	...	...	...	...
Criticality – 2	Average	...	...	...	...	...
Criticality – 3	High	...	...	...	...	...
Criticality – 4	Very High	...	...	...	...	...

Probability of Failure (PoF) of network assets due to aging and deterioration is determined in the document, so that for each equipment PoF can be calculated by the parameters. As an example, PoF graph of a pole, with an expected life of 55 is given below:

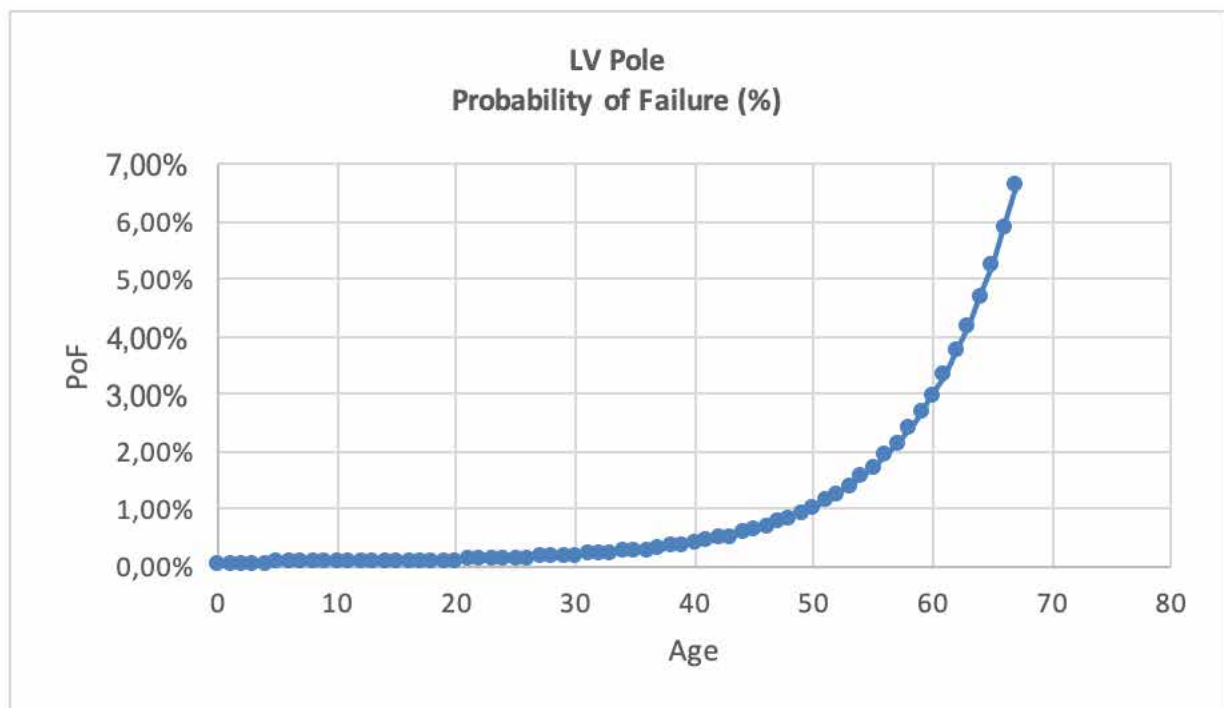


Figure 5.8 – Probability of Failure for LV Pole

- In the methodology; average replacement, refurbishment and minor fault costs are also determined for failure classes. Failures are classified as Incipient, Degraded and Catastrophic. Relative proportion of failure classes and likely cost of failure modes are also specified. Therefore, **total maintenance budget** can be calculated by this methodology.

5.2.7 Customer Surveys

The aim of the customer satisfaction survey is to capture customers' experience of the interruption, minor connection and general enquiry services delivered by DNOs.

Basics for the customer surveys is such:

- All DSOs are required to contract with the same independent survey company,
- Questionnaire is defined by Ofgem and the survey company must use this form,
- Customer Satisfaction Survey Questionnaires can be seen on the Appendix 1 of the RIIO-ED1 regulatory instructions and guidance document.²⁸⁵
- To avoid any bias, the data provided by the DSO to the survey company must contain the contact details of all customers who have experienced an activity specified in the questionnaire, in a weekly period,
 - o However, some customers are extracted from the list, such as a customer who identified of electricity theft or customers who have stated that they do not want to participate in any form of market research or customers who are already surveyed within the determined time period.
- The survey company must interview all customers within ten days of contact being made or service being experienced.
- Number of surveyed customers are chosen such that the statistical error is below 3%.
- Customers give scores one to ten. '1' indicates that the customer is very dissatisfied and '10' indicates that the customer is very satisfied.
- Simple average scores for each category is taken as the overall score.

Ofgem requires DNOs to record and report Complaints on these categories:

- Connection quotations,
- Delivery of connections services (incl. reinstatement and excavation complaints),
- Loss of supply (planned and unplanned) and emergency situations,
- Other complaints,

Ofgem also defines which claims are counted as complaint and which are not. For example, if a customer notifies the DSO about the outage in his town, it is not counted as a complaint. If that customer says that there are frequent outages in that region, then it is counted as a complaint. DSOs also have to record the number of:

- resolved complaints,
- repeat complaints,
- deadlock letters,
- Energy Ombudsman Findings Against the DSO

5.2.8 Efficiency Benchmarking

Ofgem refers efficiency benchmarking as cost assessment in the RIIO framework. In "RIIO-ED1: Final determinations for the slow-track Electricity Distribution companies Business plan expenditure assessment" document published on 28 November 2014, Ofgem stated that "Our work includes quantitative and qualitative assessment, reviewing DNO narrative and supporting evidence, including historical cost and performance data and company forecasts. We have done both comparative analysis and company-specific assessment" and define their approach as a toolkit approach.

In the toolkit, Ofgem has three cost assessment models to carry out comparative analysis: two at a TOTEX level -a top-down and a bottom-up TOTEX models- and one on a cost activity level basis using disaggregated activity-level modelling. They explain the usage of both TOTEX and disaggregated models as "TOTEX models internalise operational expenditure (OPEX) and capital expenditure (CAPEX) trade-offs and are relatively immune to cost categorisation issues. They give an aggregate view of efficiency.

The bottom-up, activity-level analysis has activity drivers that can more closely match the costs being considered.”.

While combining the results of these three models, they apply a 25% weighting to each of the TOTEX models and a 50% weighting to disaggregating modelling. (In RIIO-ED1 for the fast-tracked companies, they applied different weights, 12.5% weightings to each of the TOTEX models and 75% weighting to the disaggregated model. Whether this will be the case in RIIO-ED2 is currently in discussion.) After combining these three methods, in order to consider any other factors that may influence the DNOs’ costs, they use upper quartile -which is the 25th percentile in the distribution of efficiency scores- rather than the frontier while benchmarking the efficiency level of TOTEX.

For all models, thirteen years of data was used, five years of Distribution Price Control Review data (DPCR5, 2010-11 to 2014-15) and eight years of RIIO-ED1 forecast data (2015-16 to 2022-23). They consider the usage of both historical and forecast data since the efficiency savings can be captured in line with RIIO approach of placing more weight on forecasted data. Also, using a longer time period has its own advantages like recognition the trade-offs between different responses of DNOs’ approaches like investment or innovation, and levels the difference between periodic expenditure plans of DNOs like tree cutting cycles. For RIIO-ED1, they included regional wage adjustments. In addition, the modern equivalent asset value (MEAV) is used as the cost driver and they normalised the atypical costs associated with certain assets out of analysis which were removed from MEAV also, to ensure the same cost basis.

MEAV is explained as reflecting the scale and composition of a DNO’s network and describes as “It is a proxy for the cost of replacing every asset that is currently on a DNO’s network.”. The calculation is done by multiplying each asset by unit cost of that asset determined by Ofgem. The following assets are excluded in the MEAV calculation in order to provide consistency between the DNOs:

- rising and lateral mains (RLM),
- LV service associated with RLM,
- batteries at ground mounted HV substations, 33kV substations, 66kV substations, and 132kV substations,
- pilot wire overhead,
- pilot wire underground,
- cable tunnels (DNO owned),
- cable bridges (DNO owned),
- electrical energy storage.

Details of the three models are explained below.

Top-Down TOTEX Model

They use OLS to determine the efficient costs relative to a composite scale variable (CSV). In this regression equation, standardized log MEAV and standardized customer number are used as follows:

Standardization is done by subtracting the average of these variables from each observation and dividing by the standard deviation.

For both TOTEX models the following costs are excluded from TOTEX:

1. transmission connection point (TCP) charges,
2. critical national infrastructure (CNI),
3. rising and lateral mains (RLM),
4. improved resilience,
5. quality of service (QoS),
6. smart meter roll-out (including smart meter call out costs),
7. new streetwork costs.

Also, again both TOTEX models include a dummy variable for the time trend of costs.

Bottom-Up TOTEX Model

In this model the CSV is calculated in a different way than top-down TOTEX model. The cost drivers used in the disaggregated models are aggregated into a single CSV in the bottom-up TOTEX model constructing some type of a bridge between the top-down TOTEX model and the disaggregated model.

In this model, the weights for costs are determined based on industry spend proportions for the activity level cost areas to which the drivers apply. The weights can be found in the following table.

Table 5.7 – Weights used to construct the bottom-up TOTEX driver²⁸⁶

	Activity Area	Identified Driver	Weight
1	Connections	Units distributed	2.9%
2	Diversion	Total length	2.5%
3	Reinforcement	Units distributed	7.5%
4	ESQCR	Overhead LV and HV line length	0.5%
5	Asset replacement	MEAV_SPMWSF	18.2%
6	Refurbishment	MEAV_SPMWSF	2.5%
7	Civil works	MEAV_SPMWSF	2.8%
8	Operational IT&T	Total length	1.4%
9	Non Op Capex	MEAV_SPMWSF	2.4%
10	Legal & Safety	MEAV_SPMWSF	1.5%
11	HVP Asset replacement	Units distributed	0.5%
12	HVP General Reinforcement	Units distributed	0.6%
13	HVP Fault Level Reinforcement	Units distributed	0.6%
14	HVP Legal & Safety	Units distributed	0.5%
15	HVP BT 21st Century	Units distributed	0.4%
16	HVP Other	Units distributed	0.0%
17	Flooding	MEAV_SPMWSF	0.3%
18	Business Support	MEAV_SPMWSF	12.1%
19	BT 21st Century	MEAV_SPMWSF	0.3%
20	CAI	MEAV_SPMWSF	22.5%
21	Losses and other environmental	MEAV_SPMWSF	0.4%
22	NOCs Other	MEAV_SPMWSF	1.0%
23	Tree Cutting	Spans cut	3.1%
24	Black Start	MEAV_SPMWSF	0.2%
25	Inspection & Maintenance	MEAV_SPMWSF	3.9%
26	Troublecall	Total faults	9.5%
27	ONIs	Total ONIs	1.9%
28	Severe Weather 1 in 20	Overhead LV and HV line length	0.3%

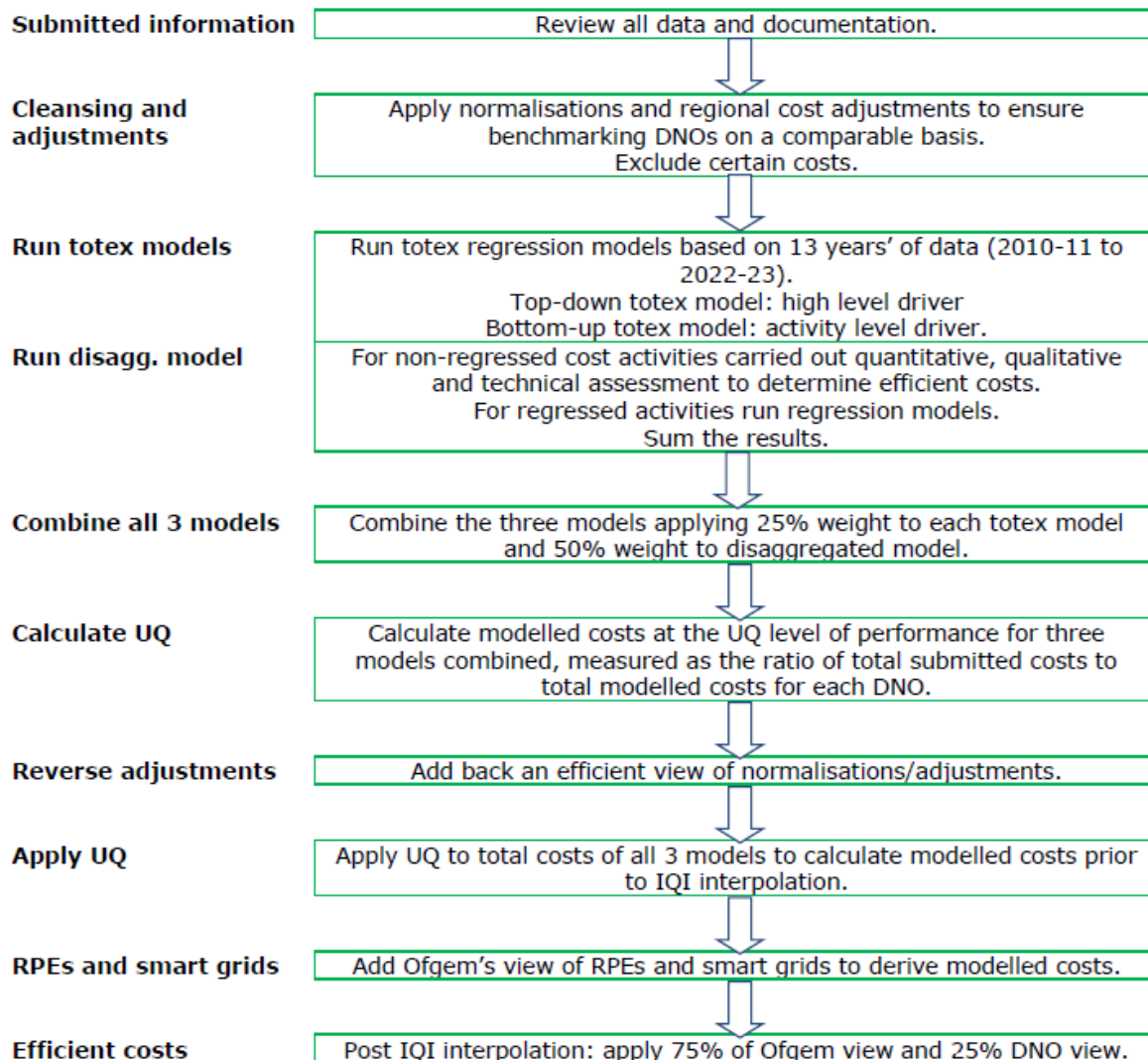
286 Source: Ofgem (2014). RIIO-ED1: Final determinations for the slow-track electricity distribution companies Business plan expenditure assessment, pp 199.

Disaggregated model

In the disaggregated model, a mixture of cost assessment techniques including regression analysis, ratio analysis, trend analysis and technical assessment is included. To clarify, they use tailored approaches for different activities as explained below.

- *Asset Replacement*: “A bespoke age-based model” is used to assess two-thirds of the asset replacement category costs. Consulting with DNV GL expert engineers, detailed qualitative assessments of the DNOs’ costs and volume justifications are carried out. In these assessments, “cross-checking the model results against historical and forecast information, condition information contained in the secondary deliverables for asset health and criticality, scheme papers and other justification” are carried out. Also, qualitative adjustments are made where necessary.
- *Refurbishment*: Ofgem evaluates the efficient volumes by running run rate analysis and qualitative assessments and based on median unit cost analysis and technical review, they establish unit costs. Also, they keep the consistency between refurbishment and replacement.
- *Load-Related Expenditure*: The assessment is done using the analysis of a range of scheme papers by engineering consultants in the aim of whether particular schemes are justified.
- *Network Investments*: Again, the engineering consultants provide evidence regarding the network investments, then a bespoke approach is utilized.
- *Closely Associated Indirect (CAI) Costs*: A combination of regression analysis, ratio analysis, run rate analysis and qualitative review is conducted. In the regression analysis, eight categories of CAI costs are aggregated.
- *Business Support Costs (BSCs)*: Ratio benchmarking is used, and an aggregated level assessment is carried out. MEAV is used as the cost driver. IT and telecoms are assessed separately, using a combination of ratio analysis and qualitative views of consultants.
- *Network operating costs (NOCs)*: A combination of regression analysis and ratio analysis is used. For fault costs DNOs’ historical fault rates are used.

Table 5.8 – A high level summary of the cost assessment approach taken²⁸⁷



The adjustments made by Ofgem are described as follows; first of all they divide the adjustments into four broad categories:

1. *Regional labour costs*: This adjustment done to the significantly different labour costs across the country and is applied to all three models. In this adjustment process, it is stated that some Standard Occupational Classification (SOC) codes are not included due to consideration of not relevant to the specific activity areas. Also, notional weighting on the DNO average labour to gross expenditure ratio is used when applying the regional labour adjustment to each individual activity.
2. *Company specific factors*: The additional costs associated with operating a specific network are considered as an adjustment. These costs are not considered in the TOTEX models. In order them to be included in the disaggregated model; no qualitative assessment have been done at the disaggregated level to account for the specific factor or they were not included in the base model.
3. *Costs excluded from TOTEX models*: If the costs are not adequately explained by cost drivers that are included in the TOTEX models or there exist "a substantial change in the nature of the activity" between regulatory periods, then these costs are considered as not appropriate for efficient benchmarking. This exclusion is applied for only TOTEX models. At the disaggregated level, using the most intuitive cost drivers and accounting the changes in historical and/or forecast

287 Source: Ofgem (2014). RIIO-ED1: Final determinations for the slow-track Electricity Distribution Companies Business plan expenditure assessment, pp 32.



This project is funded by the European Union



- cost, a bespoke model is constructed for each cost activity. These costs are specified in Top-Down TOTEX Model section.
4. *Other adjustments:* In the content of other adjustments, Ofgem includes three subjects in all three models. First is removal of costs outside the price control where they specifies the cost activities that should not be funded through the price control. Second is removal of non-controllable costs which are subject to pass-through mechanisms, these costs are assessed as separate arrangements in place to fund DNOs. Last adjustment is accounting for the indirect cost allocation, this item includes the cost activities that are carried out at a group level, rather than individual DNOs, like business support costs. Since each company has different approach for cost allocation drivers for such costs, Ofgem uses the companies' own allocations for the benchmarking. After running sensitivity analysis with common allocation drivers, they concluded that using the companies' own allocations did not distort the models.

After estimating the costs for each activity, the regional labour adjustments and company specific adjustments are reversed and added back an efficient view of those cost items that excluded from benchmarking analysis.

Since RIIO-ED2 is currently under review, there is no definite decisions, yet they will most probably keep this toolkit approach for RIIO-ED2 cost calculations.

5.3 Annex 3 – More about Germany's DSO Tariff Structure²⁸⁸

5.3.1 Revenue Cap Calculations

The revenue cap is set each regulatory period for each DSO according to his total costs that are determined following a financial review. The base year is the business year occurring three years before the start of the respective regulatory period. For instance, 2011 is the base year for the 2014–2018 regulatory period. The revenue cap is set ex-ante and the profits depend on the actual costs of the DSOs for the respective year:

- In case there is profit resulting from the operating and capital costs, then this profit can be used in the financing of new investments. However, the costs for new investments are only taken into account when the new revenue cap for the following regulatory period is set, according to the base year amount.
- If the costs in the new base year are higher relative to the previous base year, the revenue cap will increase as well.
- If the base-year costs are lower, then the revenue cap will decrease in the following regulatory period.

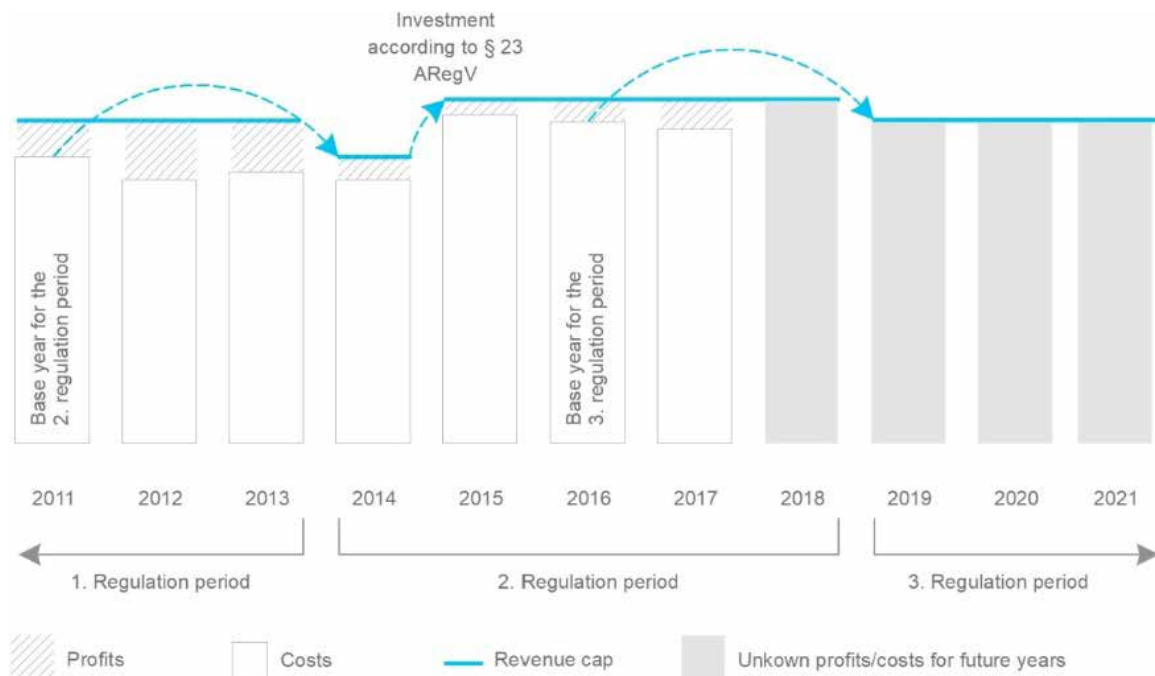


Figure 5.9 – Revenue Cap

The following formula shows revenue cap calculation methodology:

²⁸⁸ Source: Matschoss P., Bayer B., Thomas H., Marian A. (2019) The German incentive regulation and its practical impact on the grid integration of renewable energy systems.

$$EO_t = KA_{dnb,t} + (KA_{vnb,0} + (1-V_t)KA_{b,a}) \left(\frac{VPI_t}{VPI_0} - PF_t \right) EF_t + Q_t + (VK_t - VK_0) + S_t$$

Revenue cap in year t

Temporarily non-controllable cost in base year

Controllable cost in base year

General sectoral productivity factor

Quality element

Account balance from previous period

Permanently non-controllable cost share

Distribution factor for reduction of inefficiency

Consumer price overall index

Expansion factor

Volatile cost share

- **Revenue cap and grid charges (EO_t):** The revenue cap represents an absolute value that is allocated to the network users.
- **Permanently non-controllable cost share:** Permanently non-controllable costs include the ones such as costs of the overlying grid levels, EEG remuneration for owners of distributed renewable energy systems or concession fees. On the other hand, it also includes firmly defined cost positions of grid operation, such as approved investments at the 110 kV level. The permanently non-controllable cost share is adjusted on an annual basis, with the adjustments leading to a corresponding annual change in the revenue cap.
- **The temporarily non-controllable cost shares and the controllable costs** are costs that can be redeemed by the DSO during the five-year regulatory period. Both parameters remain constant during the regulatory period. Their values are determined on the basis of historical costs in the base year. Total cost is the sum of permanently non-controllable costs in year t, temporary non-controllable costs in base year and controllable cost in base year.
- The level of the shares of temporary non-controllable costs in base year and controllable cost in the residual costs is determined through efficiency benchmarking (e.g if the DSO has an efficiency value of 80%, this corresponds to a temporarily non-controllable cost share $KA_{vnb,0}$ of 80% and a controllable cost share $KA_{b,0}$ of 20% of the residual costs.
- **The distribution factor V_t** ensures that the DSOs reduce their costs by the inefficient controllable cost share $KA_{b,0}$. DSOs have a clear incentive to gain the highest possible efficiency rating in efficiency benchmarking since the term $(1-V_t) KA_{b,0}$ leads to a lowering of the revenue cap over the duration of the regulatory period.

Year	V_t	$(1 - V_t)$	$KA_{b,0}$	$(1 - V_t) KA_{b,0}$
2014	0.2	0.8	200000 €	160000 €
2015	0.4	0.6	200000 €	120000 €
2016	0.6	0.4	200000 €	80000 €
2017	0.8	0.2	200000 €	40000 €
2018	1.0	0.0	200000 €	0 €

Figure 5.10 – Reduction of inefficient cost shares (example)

- For availability reasons, the calculation of **consumer price index value (VPI_t)** is based on the consumer price index of the year two years prior to the respective regulatory year. This value represents the overall economic inflation rate relative to the base year.
- **The general sectoral productivity factor (PF_t)** is an efficiency target applied in distribution sector. This mechanism is intended to pass on the productivity increases within this sector to network users. PF_t value for the 2nd regulatory period is 1.5% p.a.. Consequently, the revenue cap is raised not by the total overall economic inflation value but only by the inflation value less the sector-specific productivity factor.

Year	VPI_0 (2012)	VPI_t	VPI_t/VPI_0	PF_t	$VPI_t/VPI_0 - PF_t$
2014	102.1	104.1	1.020	0.015	1.005
2015	102.1	105.7	1.035	0.030	1.005
2016	102.1	106.6	1.044	0.046	0.998
2017	102.1	106.9	1.047	0.061	0.986
2018	102.1	107.2	1.050	0.077	0.973

Figure 5.11 – Development of the consumer price index, inflation rate, sectoral productivity factor (example)



This project is funded by the European Union



output of the DSOs. On the one hand, efficiency benchmarking showed that not all mandatory parameters help explain the cost differences between DSOs. On the other hand, the mutual dependency of these parameters plays an important role. This can be illustrated by the parameter power line length. Since a greater line length justifies higher costs, there is an incentive to increase the line length. This can lead to an improvement of the DSO's own score in efficiency benchmarking, regardless of whether or not additional lines represent the most efficient integration measure.

The amendment also introduced a DEA *super efficiency bonus scheme*, as DSOs with a 100% efficiency rating previously had no incentive to further lower costs. In the newly introduced model, DSOs with an efficiency rating of 100% can receive a mark-up on the revenue cap. The mark-up amounts to a maximum of 5% and is evenly distributed over the regulatory period, so that in practice the efficiency value can amount to a maximum of 101%.

Lowering of interest on equity capital: The Electricity Grid Charges Ordinance stipulates that a permissible rate of interest on equity capital must be determined for each regulatory period. For the second regulatory period this was 9.05% (before taxes) with a permissible equity capital quota of 40%. It will be lowered to 6.91% (before taxes) for new installations in the third regulatory period. The rate of interest on equity capital is determined using a specific method, and it is composed of a basic share and a risk allowance. The basic share is derived from the ten-year average of the current yield on fixed-interest securities. The risk allowance is calculated using a capital asset pricing model, which is intended to determine the appropriate risk/yield ratio. The lowering of interest on equity capital for the third period is supposed to reflect the fall in interest rates for comparable low-risk investments on the capital markets.

5.3.3 Efficiency Benchmarking

The importance of cost efficiency is stated in the Electricity Act, effective July 13, 2005, as "Regulation should be based on the costs of an efficient and structurally comparable operator and provide incentives based on efficiency targets that are feasible and surpassable." This Act started an ambitious development process by the regulatory authority.

At first, full-scale trial estimations of different model specifications were conducted. The non-parametric Data Envelopment Analysis (DEA) and the parametric Stochastic Frontier Analysis (SFA) models were developed based on more than 800 DSOs in both sectors. It is stated that²⁹⁰ "This development served several purposes, some of which were to train the regulatory personnel in benchmarking methodology, to guide future data collection, to define a detailed implementation plan and to facilitate an informed discussion with industry members". The regulator then wrote the Ordinance which provides guidelines for German regulation of electricity. The high level of technical specifications in the German Ordinance is considered as remarkable and uncommon in an international context.

For the efficiency benchmarking, there is a standard procedure in place, effective in 2009, for DSOs with a customer base larger than 30,000 and a simplified procedure for small DSOs of up to 30,000 customers. Among all of the DSOs, less than 1/4 of them are subject to the standard procedure. For participants in the simplified procedure, the efficiency level was 87.5% in the first regulatory period, and from the second regulatory period it was updated as the weighted average of all efficiency levels established in nationwide efficiency benchmarking, that was set as 96.14%.

The Ordinance includes a minimal set of cost drivers such as connections, areas, length of lines and peak flow, and also some cost drivers covering other aspects of service provision. It also includes the estimation techniques to use benchmarking and how to combine the results of multiple models.

According to Sect. 12 of the Ordinance, four efficiency scores are calculated: the Farrell efficiency calculated with a non-decreasing return to scale DEA model and the Farrell input efficiency calculated using a SFA model, for both on the basis of the actual capital costs and standardized capital costs to account for distortions that may arise in particular from the different age structures of the grid equipment. Also, there exists a minimum limit of 60% for DSOs demonstrating particularly low efficiency. In the end, the maximum of these five values is established as the efficiency of a DSO.

For both methods, the legislation stipulates a set of parameters. The main distinction between the two methods lies in the different weighting of these parameters.

Table 5.9 – Efficiency parameters

	Optional parameters for the third regulatory period	Required parameters for the first two regulatory periods
Number of connection points	X	X
Size of area supplied	X	X
Total length of power lines (system length)	X	X
Simultaneous annual peak load	X	X
Annual energy feed-in	X	
Distributed energy systems, especially number and capacity of wind and solar power systems	X	

Unlike the DEA method, the influence of the parameters on the respective costs of each DSO is estimated in the SFA method using statistical methods (regression model). On the other hand, there is no bias correction for the DEA scores. The parameters are weighted with the aim of taking structural differences between the DSOs more explicitly into consideration. These differences relate both to the supply responsibilities and to the environmental conditions of the DSOs.

For instance, a structural difference in relation to the supply responsibility could be the higher installed capacity of rooftop photovoltaic systems in Southern Germany. In terms of their environmental conditions, other DSOs may have a particularly large supply area. These factors must be considered in the efficiency analysis.

Also, the Ordinance is specific about how to identify outliers. Two outlier criteria are applied for each DSO, and if either of them flagged the DSO as an outlier, then it cannot be included in the calculation in order not to affect the efficiency of the other DSOs. Firstly, the regulator requires that a single DSO should not have too large of an impact on the average efficiency, by evaluating the ratio of the sum of squared inefficiencies in a model estimated with and without the DSO in question. If this ratio is small, it can be considered an outlier. Secondly, if a DSO is super-efficient in the sense that it exceeds the 75% fractile of the distribution of super-efficiencies by more than 1.5 times the difference between the 75% and 25% quartiles, it should not be included in the calculations. In addition to these outlier rules, common econometric outlier detection methods such as Cook's distance can be applied.

It is also worth noting the important phases of the model as follows:

- Variable standardization and aggregation: In order to standardize the data set gathered from DSOs having different internal processes, accounting standards, cost allocation rules, in/out of scope rules, asset definitions and operating standards should be defined in a clear way. Also, in order to reduce the dimensionality, relevant combined cost driver calculated by engineering models can be applied. For the calculation of standardized capital costs, aggregation parameters can be defined such as interest and inflation rates.
- Data Monitoring: Some simple KPIs are defined and together with them, more advanced econometric outlier detection methods can be used to constantly monitor the collected data.
- Model specification: The subjects regarding which cost drivers best explain and how many drivers are necessary are investigated using econometric model specification methods, expert and engineering models.
- Frontier model estimation: Significance of the cost drivers established is assessed and the relevant DEA and SFA models are estimated, evaluated and tested on full-scale data sets.
- Model validation: After calculating the efficiency scores, a second-stage analyses is carried out to examine the other non-included variables whether to include them. The second-stage analyses are typically done using graphical inspection, non-parametric Kruskal–Wallis tests for ordinal differences and truncated Tobit regressions for cardinal variables. In Germany, the followings are tested in this stage: whether there was an impact on the DSO's possible involvement in water, district heating, gas or telecommunication activities using the Kruskal–Wallis method, and a series of alternative variables related to cables, connections and meters, substations and transformers, towers, energies delivered, peak flows, decentralized generation, injection points, population changes, soil types, height differences, urbanization and areas using Tobit

regressions.

After setting the efficiency scores for each DSO, a distribution factor for reducing inefficiencies and a general productivity development till that year reflecting the cumulative change in the general sectoral productivity factor for that year of the particular regulatory period relative to the first year of the regulatory period are applied to the revenue cap formula directly.

5.4 Annex 4 – More about Portugal’s DSO Tariff Structure

5.4.1 Portugal – Electricity and Natural Gas Distribution summary

The following table gives a brief summary of the key aspects of gas and power distribution systems in Portugal:

Table 5.10 – Portugal Electricity and Natural Gas Distribution summary²⁹¹

Subject	Explanation
Regulator	ERSE - National Regulatory Authority. A Tariff Board was established from stakeholders including regulated companies, members of consumer associations and institution entities. ERSE receives the opinion of the Tariff Board before taking its own decision.
Tariff Period	3 years (2018-2020) both for gas and electricity
Tariff Methodology	For HV/MV and gas : Price Cap for OPEX and rate of return for CAPEX For LV : Price Cap to TOTEX
Efficiency Factor	2.5% per year
Cost Drivers	For MV/HV: network length and distributed energy For LV: network length and number of customers
Incentive Mechanism	• Incentive for investment in smart networks • Incentive to improve service continuity • Incentive to reduce losses
Rate of Return	5.42%
Number of Distributors	• HV/MV Distribution System Operator is a single concession assigned by the State, • Municipal low voltage (LV) concessions granted by the country's 278 municipalities for 20 years
Ratio of Regulated Customers	20% of the customers (3% of the consumption)
Supplier Switching Ratio	16% of customers (26% of volume)
SAIDI for LV	Planned: 0.23 min Unplanned (operator): 80.98 min Unplanned (exceptional events): 119.65 min
SAIFI for LV	Planned: 0 Unplanned (operator): 1.55 Unplanned (exceptional events): 0.35
Distribution Pipeline Length	18,502 km
Gas subscribers	1,382,000
Gas DSOs	11
Licence validity	20 years

5.4.2 Revenue Requirement Model

Tariff methodology for Portugal is the Price-cap and rate of return for gas pipelines and electricity HV/MV and TOTEX for LV.

As for CAPEX, in addition to the analysis of the investment values sent by the companies each year, the regulatory authority also takes into account the Development and Investment Plan prepared every two years by each sector's DSO. Moreover, there are also

291 Data is for 2018, if not specified otherwise.

incentives for quality of service, losses reduction and for investments in smart grids.

Part of examined controllable costs for gas: Non-controllable and controllable costs, RAB, WACC, efficiency benchmark, inflation, mechanism for mitigating volatility of demand.

5.4.2.1 Rate Fixing Frequency

Tariffs are set and fixed once a year. Exceptionally, by decision of ERSE, an early revision may occur.²⁹²

ERSE establishes the amount of allowed income for each of the activities of the TSO, DSO, last resort supplier, by October 15 of each year and prepares a proposal for the regulated tariffs for the following year.²⁹³ The proposal is sent to the Tariff Board, DSO and TSO for the purpose of issuing an opinion. The Tariff Council shall issue its opinion on the tariff proposal by November 15th. ERSE, considering any comments and suggestions from the stakeholders approve the tariff for the following year and publish by December 15.

5.4.2.2 Regulation Period

Tariff implementation period is three years. For each adjustment period the values of the parameters are included in the expressions that establish the amount of income allowed in each of the activities provided for in this Regulation. By way of exception, the parameters of a given period may be reviewed during that period.²⁹⁴

5.4.2.3 Submitted Information to ERSE²⁹⁵

DSOs should submit the information about costs each year:

- Operating and maintenance costs by voltage level,
- Legal charges,
 - o rents and other charges related to the concession scheme, namely: exploration fees,
 - o Other legal charges, namely charges related to the linked licenses,
- Capital costs related to distribution assets, separated by conventional and innovative, by voltage level:
 - o Amortization of the distribution network and other equipment related to the distribution,
 - o Financial charges attributed to the operation of the Energy Distribution activity Electric,
- Commercial structure costs by type of end customer,
- Costs related to the management of the supplier change process,
- Costs incurred with the promotion of environmental performance, according to the implementation of the “Environmental Performance Promotion Plan”,
- costs arising from the implementation of optional DRR services, with the indication of the number of occurrences for each type of service,
- other costs for the year, broken down by stress level, with the breakdown allowing identify the various types of costs,

DSOs should submit the information about incomes each year:

- Income from the application of the Distribution Network Use tariff to deliveries customers by individualizing deliveries to last resort suppliers,
- Income from the provision of regulated services, namely readings and interruption and restoration of electricity supply by fact attributable to the customer,
- Income from the Electricity Distribution activity that does not result from the application of Distribution Network Use tariff,
- Income from the Electricity Distribution activity arising from the implementation of optional services under the DRR, with an

²⁹² Source: Portugal Tariff Regulation, Article 164.

²⁹³ Source: Portugal Tariff Regulation, Article 196.

²⁹⁴ Source: Portugal Tariff Regulation, Article 165.

²⁹⁵ Source: Portugal Tariff Regulation, Article 175.

- indication of the number of occurrences per kind of service,
- Extraordinary income related to amortization of reimbursed fixed assets,

DSOs should also submit the information about:

- The information necessary for the determination and valuation of losses,
- The information necessary for determining the incentive to improve continuity of supply,
-

5.4.2.4 Rate of Return

WACC calculation is based on Capital Asset Pricing Model (CAPM) method and currently 8.5%. WACC is currently based on 55% debt and 45% equity applied to RAB.

In order to deal with uncertainty and financial volatility environment, rate of return is updated ex-post each year. WACC is indexed to the Portuguese 10-year bond benchmark and depends on its evolution with a cap and floor. The floor and cap limits within the annual RoR can evolve over the 2018-2020 period were determined as 4.75% and 9.75% respectively²⁹⁶. For electricity DSO, ROE parameters are as follows:

- Risk free rate (nominal): 1%
- Tax rate: 31.5%
- Equity risk premium: 7.66%
- Equity beta: 0.63
- Cost of equity (before taxes): 8.5%

Type of WACC for gas: Nominal, pre-tax. Determination of Rate of return equity: the WACC (Pre-tax) is indexed to the Portuguese 10-year bond benchmark and depends, in each year, on its evolution, with a cap and a floor.

- Rate of Return Before Taxes for gas is 8.2%.
- Use of Rate of Return for gas: WACC is currently based on 50% debt and 50% equity applied to RAB.

Depreciation

For depreciation method, straight-line is used, where assets lifetime is between 5-40 years. for electricity and 5-45 years for gas. Depreciation consideration: part of examined controllable costs.

5.4.3 Performance Indicators

In the Natural Gas Distribution networks, performance is evaluated through indicators that consider the number and duration of interruptions. In 2016, there were no interruptions in 3 out of the 11 existing distribution networks (Beiragás, Sonorgás, and Paxgás), and only 0.6% out of approximately 1.45 million customer installations suffered interruptions. No customer was affected by more than one interruption. Nearly 72% of the interruptions that occurred in the Natural Gas Distribution networks were due to fortuitous events or cases of force majeure, caused by third-party interventions in the gas networks. The average duration of the interruptions per customer was less than 3 minutes in all the Natural Gas Distribution networks.

5.4.3.1 Continuity of Supply

In Portugal, used interruption indexes are SAIDI, SAIFI, MAIFI, TIEPI and NDT. The indicator values for 2018 is shown in Table 1. The performance assessment of the distribution network is done in terms of continuity of supply consists of long interruptions (longer than 3 minutes) and short interruptions (between 1 second and 3 minutes). ERSE sets annual standards for the indicators.

Table 5.11 – Continuity of supply indicators in Mainland Portugal, 2018²⁹⁷

Voltage Level	Indicator	Interruptions		
		Planned	Unplanned	
			Operator Responsibility	Exceptional Events
HV Distribution	SAIDI	0	44.40	1542.40
	SAIFI	0	0.19	0.08
	MAIFI	0	1.37	0.18
MV Distribution	SAIDI	0.05	84.95	146.05
	SAIFI	0	1.77	0.46
	MAIFI	0	11.57	0.79
	TIEPI	0.08	57.51	80.32
LV Distribution	SAIDI	0.23	80.98	119.65
	SAIFI	0	1.55	0.35

The incentive for the DSO intends to improve the continuity of supply of the MV customers. This incentive consists of two components with different objectives, where the first objective is to improve the overall continuity of supply and the second is to improve the continuity of supply of the worst-served 5% of customers. Dead bands are used to avoid the activation of the incentives when small performance improvement or deterioration is experienced. The parameters of the incentive scheme is defined for each regulatory period (every 3 years), while the values of the incentives (rewards or penalties) are calculated on an annual basis.

$$\text{Incentive Amount}_{t-2} = \text{Component1}_{t-2} + \text{Component2}_{t-2}$$

Component 1 : Promoting the global continuity of electricity supply,

The value of “component 1” of the incentive depends on the annual value of non-distributed energy and is determined using the function set out in the RQS. In 2018, the maximum value of the premium or penalty corresponded to 4 million euros.

The value of component 1 of the incentive to improve service continuity in the MT distribution network is calculated as such:

Quando $END_{t-2} < END_{REF,t-2} - \Delta E$:

$$RQS1_{MT,t-2} = \text{Min}\{RQS1_{\text{máx},t-2}, [(END_{REF,t-2} - \Delta E) - END_{t-2}] \times VEND_{t-2}\}$$

Quando $END_{REF,t-2} - \Delta E \leq END_{t-2} \leq END_{REF,t-2} + \Delta E$:

$$RQS1_{MT,t-2} = 0 \quad (2)$$

Quando $END_{t-2} > END_{REF,t-2} + \Delta E$:

$$RQS1_{MT,t-2} = \text{Máx}\{RQS1_{\text{mín},t-2}, [(END_{REF,t-2} + \Delta E) - END_{t-2}] \times VEND_{t-2}\}$$

where;

END_{t-2} : Energy not distributed in year t-2 in the MV (1-45 kV) network, expressed in kWh, for all incidents excluding those security

297 Source: Portugal Annual Report on the Electricity and Natural Gas Markets in 2018, p.10.

reasons, RNT outages, and incidents classified as exceptional;

END_{ref} : Reference value for energy not distributed in MV in year t-2, expressed in kWh.

ΔE : Dead band value (tolerance for punishment/reward)

$RQS1_{max, t-2}$: Maximum value of the premium to be awarded in component 1 of the incentive to improve service continuity in year t-2, expressed in euros.

$RQS1_{min, t-2}$: Maximum penalty to be awarded in component 1 of the incentive to improve service continuity in year t-2, expressed in euros.

$VEND_{t-2}$: Value of undistributed energy in year t-2, expressed in euros per kWh.

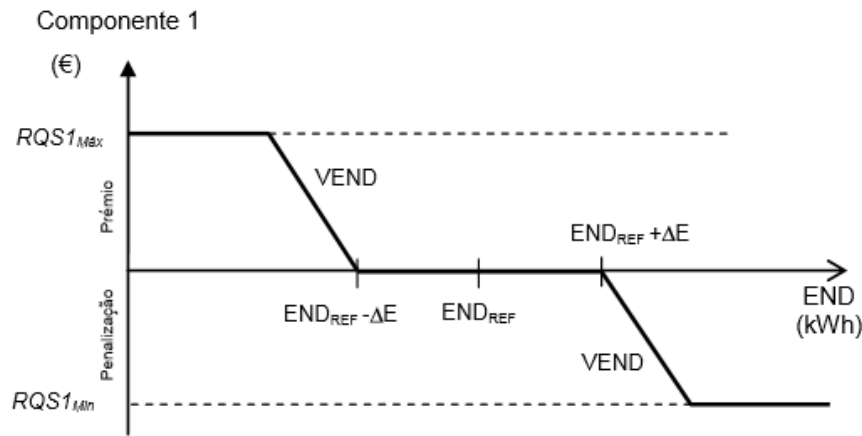


Figure 5.13 – Implementation of Component 1

Component 2 : Encouraging the improvement of the continuity of supply level among the worst-served customers.

The value of “component 2” of the incentive depends on the moving average of the last three years of the SAIDI MV indicator that covers 5% of distribution transformer stations and MV customers with the worst SAIDI MV value each year. In 2018, the maximum value of the premium or penalty corresponded to 1 million euros.

Quando $SAIDI\ MT\ 5\%_{t-2} < SAIDI\ MT\ 5\%_{REF, t-2} - \Delta S$:

$$RQS2_{MT, t-2} = \text{Min}\{RQS2_{m\acute{a}x, t-2}, [(SAIDI\ MT\ 5\%_{REF, t-2} - \Delta S) - SAIDI\ MT\ 5\%_{t-2}] \times V\ SAIDI\ MT_{t-2}\}$$

Quando $SAIDI\ MT\ 5\%_{REF, t-2} - \Delta S \leq SAIDI\ MT\ 5\%_{t-2} \leq SAIDI\ MT\ 5\%_{REF, t-2} + \Delta S$:

$$RQS2_{MT, t-2} = 0 \quad (2)$$

Quando $SAIDI\ MT\ 5\%_{t-2} > SAIDI\ MT\ 5\%_{REF, t-2} + \Delta S$:

$$RQS2_{MT, t-2} = \text{Máx}\{RQS2_{mín, t-2}, [(SAIDI\ MT\ 5\%_{REF, t-2} + \Delta S) - SAIDI\ MT\ 5\%_{t-2}] \times V\ SAIDI\ MT_{t-2}\}$$

where;

$RQS2_{MT, t-2}$: Component 2 of the incentive to improve service continuity in the MV distribution network in year t-2, expressed in euros.

$RQS2_{max, t-2}$: Maximum value of the premium to be awarded in component 2 of the incentive to improve service continuity in year t-2, expressed in euros.

$RQS2_{min, t-2}$: Maximum penalty to be awarded in component 2 of the incentive to improve service continuity in year t-2, expressed in euros.

$SAIDI\ MT\ 5\%_{t-2}$: Moving average of SAIDI MV in year t-2, year t-3 and year t-4, expressed in minutes, for 5% Transformation Stations that have the worst value of SAIDI MV.

$SAIDI\ MT\ 5\%_{REF, t-2}$: Reference SAIDI MV for year t-2.

$V\ SAIDI\ MT_{t-2}$: Valuation of SAIDI MV 5% in year t-2.

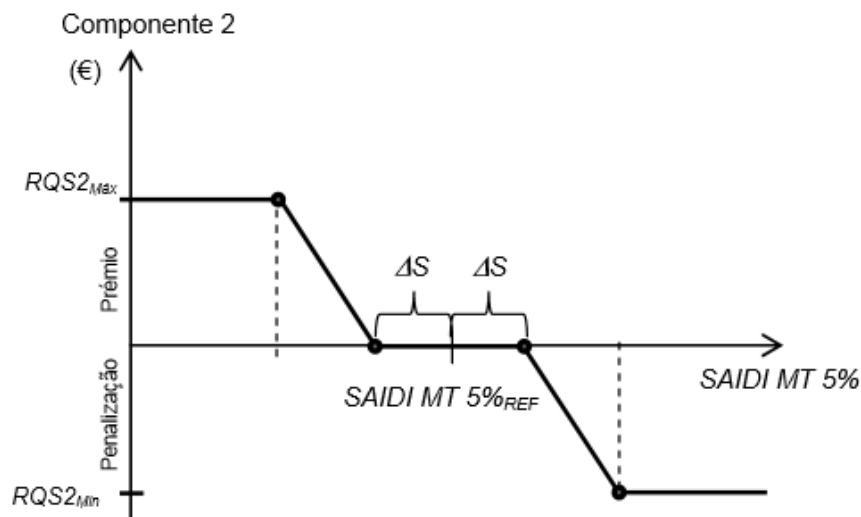


Figure 5.14 – Implementation of Component 2

In addition to global incentive/punishment for continuity of service, individual compensation mechanism is applied for number of interruption and total duration of interruptions for the customers.

DSOs should include a quality of service improvement plan in the preparation of the Development Plans and Investment of the respective networks, when they identify the existence of specific difficulties to comply with the power quality thresholds or the general or individual quality of service standards set forth in this regulation. Quality of service improvement plans should provide the cost-benefit analysis that underlies them and should be duly scheduled and budgeted.

5.4.3.2 Commercial Quality

Commercial quality indicators measured in Portugal are listed as follow²⁹⁸:

298 Source: CEER, 2016, 6TH CEER Benchmarking Report on the Quality of Electricity and Gas Supply – 2016.

- Time for response to customer claim for network connection
- Time for connecting new customers to the network
- Punctuality of appointments with customers
- Response time to customer complaints
- Response time to customer enquiries
- Percentage of customers with a waiting time below the limit in call centers
- Percentage of customers attended within the waiting time limit in customer centers
- Percentage of customers' requests answered within the time limit
- Average response time to customer complaints and/or requests
- Time until the start of restoration of supply following failure of fuse of DSO
- Time for restoration of power supply following disconnection due to non-payment
- Percentage of meter readings made within less than a certain amount of time after the last one

Planned interruptions should be announced to the customers minimum of 36 hours advance.

5.4.3.3 Technical Quality

In Portugal, the cost for performing **voltage quality** measurements upon receiving a complaint of the voltage quality is born by DSO only if the quality does not conform to national legislation or EN 50160. The customer pays if the quality voltage level meets the standard, or when it is not justified.

5.4.4 Losses

The incentive to reduce losses is intended to induce the DSO to MV and HV to reach a reference loss level established by ERSE. The loss reference level ($P_{REF, t-2}$) is set for each of the years of the reporting period taking into account the objectives set out in the National Program for Climate. The incentive formula is as follows:

When: $P_{t-2} < P_{REF, t-2} - \Delta Z$:

$$PP_{URD,NT,t-2} = \text{Min}\{IRP_{max,t-2}, [(P_{REF,t-2} - \Delta Z) - P_{t-2}] \times E_{t-2}^D \times V_{p,t-2}\}$$

$P_{t-2} > P_{REF, t-2} + \Delta Z$:

$$PP_{URD,NT,t-2} = \text{Max}\{IRP_{min,t-2}, [(P_{REF,t-2} + \Delta Z) - P_{t-2}] \times E_{t-2}^D \times V_{p,t-2}\}$$

$P_{REF, t-2} - \Delta Z \leq P_{t-2} \leq P_{REF, t-2} + \Delta Z$:

$$PP_{URD,NT,t-2} = 0$$

Where;

$$IRP_{\max,t-2} = -IRP_{\min,t-2} = (\Delta P - \Delta Z) \times E_{t-2}^D \times V_{p,t-2}$$

$PP_{URD,NT,t-2}$: Incentive to reduce distribution network losses in year t-2

$IRP_{\max,t-2}$: Maximum amount of premium to be awarded as incentive to reduce losses in the year t-2

$IRP_{\min,t-2}$: Maximum penalty amount to be attributed as an incentive to reduce losses in the year t-2

$V_{p,t-2}$: Valuation of losses in the distribution network in year t-2, in Euros per kWh, to be defined by ERSE

$P_{REF,t-2}$: Reference level of distribution network losses in year t-2, in percentage

P_{t-2} : Loss level in year t-2, as a percentage, given by the quotient between losses and the active energy delivered by the distribution grid

E_{t-2}^D : Total electricity delivered to distribution network in year t-2, in kWh

5.4.5 Smart Grid Incentives

The incentive for smart grid investment is intended to stimulate network operators to carry out pilot projects and investments in distribution networks within the scope of the concept of smart grids, with the objective of reducing operating costs and improving obtaining other quantifiable benefits.

Each project accepted by ERSE as smart grid is entitled to obtain this incentive. for a period, equivalent to two regulatory periods. The main idea is to encourage smart grid investments to reduce costs and share the benefit between company and the consumers.

The incentive formula is as follows:

$$RI_{URD,j,t} = C_{j,t} \times \sum_{k=1}^{N_{RI}} RI_{k,t}$$

$$RI_{k,t} = \begin{cases} \alpha_{RI} \times Bdemo_{k,t} & , \text{ se } \alpha_{RI} \times Bdemo_{k,t} \leq \Delta r_{RI} \times Inv_{RI,k} \\ \Delta r_{RI} \times Inv_{RI,k} & , \text{ se } \alpha_{RI} \times Bdemo_{k,t} > \Delta r_{RI} \times Inv_{RI,k} \end{cases}$$

$RI_{URD,j,t}$: Incentive for smart grid investment in year t, allocated at the level of voltage level j,

t : tariff calculation year,

j : Voltage levels $j = 1$ for HV and MV, ie $RI_{URD,NT,t} = RI_{URD,1,t}$, and $j = 2$, for LV,

ie $RI_{URD,BT,t} = RI_{URD,2,t}$,

k : Index assigned to projects accepted by ERSE as smart grid,

$C_{j,t}$: Incentive allocation variable at voltage level j, in year t, proportional to the supplies by voltage level,

N_{RI} : Total number of smart grid projects accepted by ERSE in which the incentive period has not yet been exceeded,

- $RI_{k,t}$: Encouraging smart grid investment associated with project k accepted as smart grid by ERSE and with the current incentive, given in year t,
- Δr_{RI} : Parameter, to be defined by ERSE, which limits the incentive value associated with each smart grid project accepted by ERSE, with reference to the value of investment of this project,
- $Inv_{RI,k}$: Value of the project investment k allocated to the Energy Distribution activity Electricity, accepted by ERSE as smart grid and still with the current incentive,
- α_{RI} : Parameter, to be defined by ERSE, for company-consumer sharing real benefits of smart grid projects that are quantified by the distribution system operator and accepted by ERSE,
- $Bdemo_{k,t}$: Value of real benefits associated with project k accepted as smart grid ERSE and with the incentive in force, determined from the perspective of the Electricity, which are quantified by the distribution system operator and accepted by ERSE for incentive calculation purposes in year t,

5.4.6 Consumption Efficiency Promotion Plan

The Plan for the Promotion of Efficiency in Consumption aims to improve efficiency in electric power consumption. The regulation and operation of the Consumption Efficiency Promotion Plan are supplementary regulations, notably in the “Promotion of Consumer Efficiency”, approved by ERSE.

Costs other than operating costs, controllable costs, non-controllable costs, and investment costs, which are analysed in detail, are not subject to efficiency.

5.4.7 Customer and Tariff Groups

As far as infrastructure access tariffs are concerned, access is paid by all natural gas consumers, so network access tariffs are included in the prices paid by natural gas consumers, both in market prices and in transitional tariffs for end-customers.

Table 5.12 – Gas tariffs

Tariffs per activity	Average price 2016-2017 (EUR/MWh)*	Average price 2017-2018 (EUR/MWh)	Change
Use of the LNG Terminal (Sines)	1,98	1,94	-1,9%
Use of the Underground Storage	11,59	11,13	-3,9%
Use of the Transmission Network	2,01	1,94	-3,5%
Use of the Distribution Network	9,44	9,18	-2,8%
Global Use of the System	1,14	0,49	-56,6%

* Application of 2016-2017 tariffs to the demand forecasted for 2017-2018.

The decrease in the tariffs is justified by different factors, of which is highlighted as the following: i) the efficiency targets imposed on the operating costs of the activities associated with the infrastructure, as well as the downward revision of the rates of remuneration applied to them; ii) the regulatory mechanisms for promoting tariff stability, in particular by controlling the impact of demand volatility on high-pressure infrastructures; iii) the greater adequacy of the investment level to the current level of demand and, consequently, the use of infrastructure; iv) money transfer from the Extraordinary Contribution on the Energy Sector and the Fund for the Systemic Sustainability of the Energy Sector to the National Natural Gas System, reducing to the costs of the Global System Use tariff; and v) the increase in demand for natural gas at the high-pressure level, due to the increased use of natural gas

combined-cycle plants.

Table 5.13 – Electricity access tariffs and billing variables

Network access tariffs	Billing variables	LV	LVs	MV	HV	EHV
		Customers	Customers	Customers	Customers	Customers
Overall Use of the System	Capacity	•	•	•	•	•
	Active energy	•	•	•	•	•
Use of the Transmission Network	Capacity	•	•	•	•	•
	Active energy	•	•	•	•	•
	Reactive energy					•
Use of the Distribution Network	Capacity	•	•	•	•	
	Active energy	•	•	•	•	
	Reactive energy		•	•	•	
Switching Operation	Capacity	•	•	•	•	•

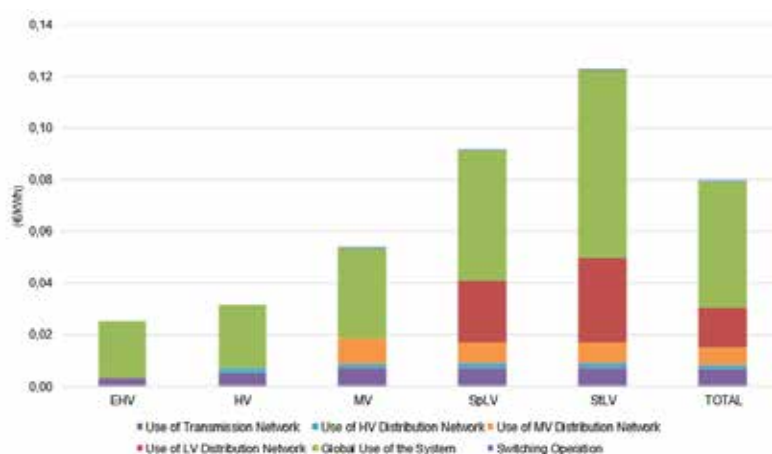


Figure 5.15 – Breakdown per activity of the average price of network access tariffs in 2018²⁹⁹

5.4.7.1 Social Tariffs

The Social Network Access charge is calculated by applying a discount on the LV Network Access tariff. The discount to be applied to the 2019 electricity tariffs corresponds to an amount allowing a 33.8% on the gross price of transitional tariffs in the regulated market (ie. excluding VAT and other taxes, applicable contributions and or fees). Vulnerable customers who benefit from social tariff are also entitled to apply for exemption from the Special Consumer Tax on Electricity (IEC) and a partial discount on the Audiovisual Contribution (CAV). The costs arising from the application of the social tariff to electricity customers shall be borne by the electricity generation facility owners in proportion to the installed power of each power station.

5.4.7.2 Switching Operator

For switching operations, there is a separate operator “Logistics Operator for Switching Electricity and Gas Supplier” (OLMC) created on 31 March 2017, common to the electricity and natural gas sectors.

5.4.7.3 Tariff Periods

Tariff periods in Portugal are as:

- Quarterly Periods,
 - Period I from 1 January to 31 March,
 - Period II from April 1st to June 30th,
 - Period III from 1 July to 30 September,
 - Period IV from 1 October to 31 December,
- Time periods,
 - Peak hours,
 - Full hours,
 - Normal empty hours,
 - Super empty hours,

The empty hour period applicable to the two- and three-hour tariffs comprises the normal and super-empty hourly periods. The non-empty off-duty hourly rate applicable to two-hourly tariffs comprises peak and full hour periods. For customers in MV, HV and EHV with weekly cycle the national holidays are considered as periods of emptiness.

Table 5.14 – Weekly Cycle of Tariff Periods

Winter time	Summer time
Monday to Friday	Monday to Friday
Peak : 5 h/day	Peak : 3 h/day
Full : 12 h/day	Full : 14 h/day
Normal Empty : 3 h/day	Normal Empty : 3 h/day
Super Empty : 4 h/day	Super Empty : 4 h/day
Saturdays	Saturdays
Full : 7 h/day	Full : 7 h/day
Normal Empty : 13 h/day	Normal Empty : 13 h/day
Super Empty : 4 h/day	Super Empty : 4 h/day
Sundays	Sundays
Normal Empty : 20 h/day	Normal Empty : 20 h/day
Super Empty : 4 h/day	Super Empty : 4 h/day



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Table 5.15 – Daily Cycle of Tariff Periods

Winter time		Summer time	
Peak	: 4 h/day	Peak	: 4 h/day
Full	: 10 h/day	Full	:10 h/day
Normal Empty	: 6 h/day	Normal Empty	: 6 h/day
Super Empty	: 4 h/day	Super Empty	: 4 h/day

5.5 Annex 5 – Revenue Cap Calculations and Data Envelopment Analysis in Norway

5.5.1 Allowed Revenue Calculation

In Norway annual revenue ceiling is set so that the income over time covers the cost of operating and depreciating the network, as well as provide a reasonable return on invested capital, given efficient operation, utilization and development of network. Allowed revenue and cost-base calculation has already been defined in Section 1.3.2 and will be summarized here too.

The following figure shows a general representation of allowed revenue calculation:

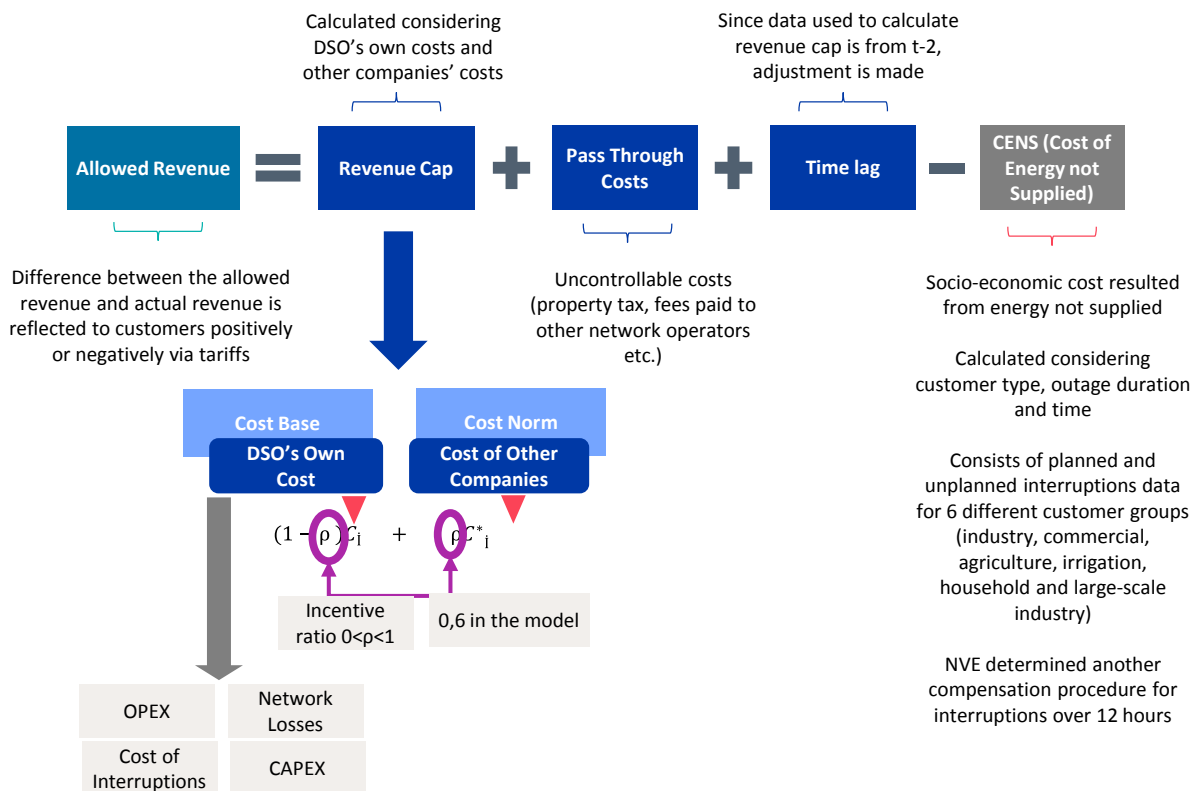


Figure 5.16 – Allowed Revenue Calculation

NVE calculates the revenue cap based on expected total costs using inflation adjusted cost data from two years prior. The deviation between the expected total costs and the actual total costs for all companies in one year is included in the revenue cap calculation two years later (e.g. correction for the deviation between expected and actual costs for 2016 in the revenue cap for 2018). NVE distribute the total cost deviation among the companies using their share of the sector's total regulatory asset base.

Items of the cost base are:

- Operating and maintenance costs*
- Depreciation on invested net capital
- Book value of net capital at 31 December, plus 1% for net working capital
- Net loss in MWh
- Payment in case of very long interruptions*
- CENS (known also as KILE)*

Values indicated with * are adjusted for inflation.

When determining the annual revenue cap, 40% of the cost basis and 60% of cost norm is included in the calculation.

NVE annually set a cost norm for each company, that is set on the basis of comparative efficiency analyzes that take into account relevant differences in the companies' framework conditions. When setting the cost norm, socioeconomic costs are taken into account as far as possible in addition to the company's own costs.

The following costs should also be covered as an addition to the revenue cap:

- Costs of purchasing internet services from other online companies, and costs of renting other online companies' revenue-generating facilities
- Paid property tax
- Changes in depreciation and return as a result of a changed return basis in relation to the values included in the cost basis. If the changes are negative, they should be deducted from the annual revenue cap
- Costs for specific R&D projects that have been approved in advance by the NVE. The surcharge cannot exceed 0.3% of the grid company's return basis for the current year. (incentive mechanism for innovation projects)

NVE notifies the expected revenue cap before the start of the year, based on estimates for WACC, CPI and the reference price on power related to power losses. These parameters are not known until the revenue cap year ends. When the parameters are known, NVE decides the final revenue cap for the year based on the actual values. The main intension of notification of the revenue cap is to give the companies an approximate figure to base their tariff decisions on for the revenue cap year.

Any Costs of Energy Not Supplied (CENS) during the year are deducted from the allowed revenues. CENS is a measure of the value of lost load for the customers. The CENS arrangement provides an incentive for network operators to have a socio-economic maintenance and investment level in order to minimize power outages.

5.5.2 OPEX and CAPEX

The operation and maintenance costs mainly comprise of personnel and material costs related to own production of services and purchase of external services. The following cost units are included:

- purchases of transmission and system services,
- purchases of goods and material,
- salaries and other personnel costs incl. pension costs, other operating costs,
- bad-debts and internally priced services.

A network company can charge a customer for costs related to existing network when the customer asks for quality or services that are usually not expected to be delivered as a network service. Revenues following these kinds of services can be kept out of actual revenue, but are also subtracted from the cost base.

The capital costs that enter into the regulated cost base are annual depreciations and return on the regulatory asset base (RAB). The RAB is based on historical book values for networks and other fixed assets of the network companies. All accumulated depreciations and write-downs are subtracted from the historical cost. Networks under construction are excluded from the RAB.

5.5.3 Efficiency Benchmarking

The cost norm Ct^* of each network operator is calculated as a result of a DEA benchmarking analysis. Norway is the only country where the regulator has systematically examined the effects of environmental factors on the performance of the quality of service and reflected these in the efficiency benchmarking models. Differences in geographical and climate conditions between companies may give different cost levels. For instance, a company that operates in an area with forest has to carry out forest cleaning close

to their lines on a regular basis. Another company operates close to the sea and might have to maintain or replace components relatively often due to corrosion. The purpose of including geographical variables in the model is that companies with similar conditions shall be compared in the analysis.

An example of efficiency scores for the years 2005-2006 are shown in the figure and it shows that the effects on the efficiency scores from introducing geography variables as outputs are considerable.

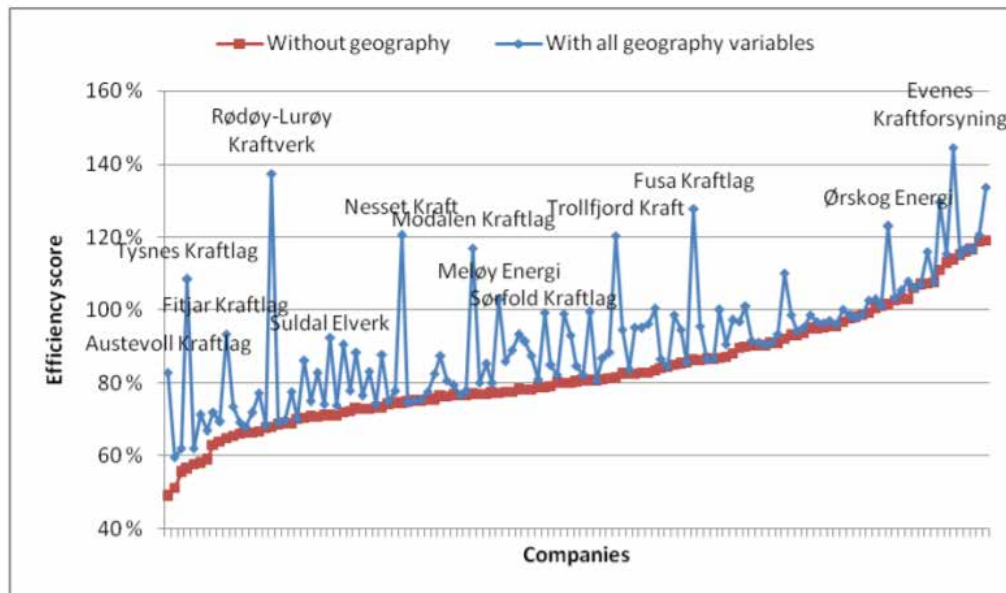


Figure 5.17 – Total effect from geography outputs – forest, snow, coast (name shown if effect is at least 20 %-points)³⁰⁰

The process within the scope of benchmarking is as follows:

- In the first analysis, the companies are benchmarked using data from two years back.
- The results from this analysis rank the companies' efficiency from 0 to 1 using the most recent data available.
- The efficient companies get a DEA result equal to 1. To rank the efficient units from this analysis, historical data from the last 5 years available is made use of in a second DEA analysis.
- The efficient companies are here benchmarked to see if they have become more efficient, e.g. spend less resource on the same deliverables, than they did on average the last 5 years.
- The companies are rewarded with a DEA result larger than 1 if the analysis show improvement, if not, they get a DEA result equal to 1.
- In order to ensure that the network sector obtains a reasonable rate of return on invested capital, calibration of the DEA results and the cost-norm is performed.
- First, the DEA results are calibrated in each of the two models, using total costs, so that the weighted average result equals 1.
- Then the DEA results from both analyses are weighted together for the companies that have both distribution and regional grid, so the company ends up with an overall DEA result.
- This final DEA result is multiplied with the company's cost base to get the cost norm. The cost norm is calibrated setting the sum of cost norms for the sector equal to the sum of the companies cost bases. These calibrations make sure that the total revenue cap for the whole sector is equal to the total cost base.

Input of the DEA model is total cost, including capital costs and the nine output variables are:

Table 5.16 – Output variables of the DEA Model

Variable	Unit of Measurement
Energy delivered	MWh
Customers (except cottages)	No. of customers
Cottage customers	No. of customers
High voltage lines	Kilometers
Net stations (transformers)	No. of stations
Interface	Cost weighted sum of equipment in the interface between the distribution network and the regional transmission network
Forest	Proportion (0-100) of area with high-growth forest × HV-lines through air (kilometers)
Snow	Average precipitation as snow (mm) × HV-lines through air (kilometers)
Coast	Average wind speed (m/s) / Average distance to coast (meters) × HV-lines through air (kilometers)

The output variables (except energy delivered and the number of customers connected) do not measure direct outputs from the production activity of the distribution companies, but rather represent structural and environmental conditions that may influence the cost of the companies. HV-lines, net stations and interface represent demographical and topological conditions, as well as transmission functions, that influence the costs of a particular company. The last three variables (forest, snow, coast) describe environmental conditions that may influence the cost of the companies and are the only variables that are not based on data reported by the companies.

5.5.4 Calculation

The tariff requirements and calculation methodology are subject to NVE regulation. All network companies are responsible for determining tariffs within their revenue cap according to the regulation of the tariff structure.

All tariffs are based on costs referring to the consumer's connection point. An agreement with the network company at the point of connection provides access to the entire network system and the power market. All houses, apartments and vacation homes are to be metered and settled individually since 2010. According to the regulation on tariff structure, tariffs consist of a consumption-based energy component based on marginal network losses, and a fixed annual amount per customer. The fixed component covers customer-specific costs and network costs that are not covered by the consumption-based tariff components.

Consumers in the distribution network are charged a fixed component that covers customer-specific costs and a share of the other fixed costs in the network. The energy component for customers without maximum demand metering in the distribution network may in addition to network losses also cover a share of the other fixed costs in the network. The network companies calculate separate tariffs for high-voltage and low-voltage connections.

5.6 Annex 6 – Cost-Benefit Analysis between Performance Indicators and OPEX

As a general rule, marginal cost of quality increases with the quality level. In other words, achieving a higher quality level costs more and more as the quality level increases. On the other hand, marginal consumer benefit of the quality increase, diminishes as the quality level increase. Therefore, there is an optimal quality level where, beyond this point, increasing the quality level costs more than the benefit of the quality increase. This effect is shown in the below graph.

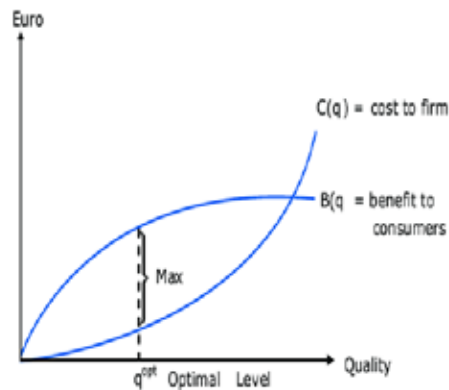


Figure 5.18 – Quality Cost vs Benefit³⁰¹

To determine the optimal quality level, Willingness to Pay (WTP) amount of the consumers plays a key role. Ofgem's Willingness to Pay (WTP) studies found that customers are keener to receive compensation for receiving a poorer service than they are for paying more for receiving a better-quality service. This states that, the level where the customers are satisfied with the outage level (do not want to pay anything for a better quality) **implies a cap for quality incentives**. Therefore, using the WTP is recommended to be used for supply quality incentives/penalties.

In **UK**, SAIDI incentive is capped at 1.2% and SAIFI incentive is capped at 1.8% of the allowed revenue. The level of the **bonuses and penalties has been set for each DSO on the basis of the results of Willingness to Pay surveys and value of loss load (VoLL)**. SAIDI and SAIFI incentives work independently, so that a DSO may get bonus for SAIDI and penalty for SAIFI in the same year. There are separate targets for planned and unplanned outages. Before RIIO-ED1, Ofgem used single target for planned and unplanned outages, weighting 66,6% for unplanned outages and 33% for planned outages.³⁰²

Unplanned outage targets are defined such that 75% of the benchmark target calculated by Ofgem and 25% of the average performance of the DSO is used. The calculation is done for each voltage level (LV, MV and EHV) and then aggregated to a single target for each DSO. Benchmarks for voltage level is different, such that:

- EHV and 132 kV: Very few incidents each year and high volatility among years and DSOs. Therefore, for SAIFI, Ofgem set the benchmark as the last 10-year average for each DSO. For SAIDI, Ofgem used each DSO's SAIDI/SAIFI ratio (average outage duration per outage) multiplied by 10-year average SAIFI.
- HV: Benchmark for SAIFI is the latest 4-year average for each DSO. SAIDI benchmark is the SAIFI-benchmark multiplied by the upper quartile of the SAIDI/SAIFI ratio among all DSOs.
- LV: Benchmark for SAIFI is the latest 4-year average for each DSO. SAIDI benchmark is the SAIFI-benchmark multiplied by the average of the SAIDI/SAIFI ratio among all DSOs.

³⁰¹ Yardstick competition for multi-product hospitals, Copenhagen Business School, Department of Economics, Working Papers, 2007/1/1

³⁰² Northern Ireland Utility Regulator, Reliability Incentive (<https://www.uregni.gov.uk/sites/uregni/files/media-files/Annex%20M%20-%20Reliability%20Incentive.pdf>)

As the planned outages are more predictable and mostly depends on the capital expenditure, Ofgem set this target specific for each DSO. Ofgem derives the forecast of the work that needs to be undertaken by the DSO and impact of each work category for outage number and duration. The works are categorized as load, non-load, inspection and maintenance, tree cutting. Calculated planned outages are distributed among the regulatory period equally.

5.6.1 Reliability and Resilience

The ability to deliver uninterrupted service to customer is defined as DSO's network **reliability**. The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such events defines **network's resilience**.

Electricity reliability is becoming ever more important and visible to consumers. Providing light, heat, cooling and power to household appliances have all vastly increased customers' expectations for uninterrupted electric service. The economic growth and development of a country depends heavily on the reliability and quality of the electric power supply.

Distribution reliability is one of the most important topics in the electric power industry due to its high impact on the cost of electricity and its high correlation with customer satisfaction.

The distribution network operators are expected to provide continuous and quality service to their customers at a reasonable rate by making economical use of available system.

5.6.1.1 Variables That Affect Reliability

Reliability of electricity grid (continuity of delivery to customers) depends on many factors that are **impossible to accurately capture mathematically**. They usually change from year to year or they are dependable on how to solve technical operating and maintenance problems. The principle of the effect on the continuity of the supply may be divided as follows:

- Detailed network design standards and criteria
- Quality of hardware and workmanship to be procured, lack of DSO's surveys and control over the contractors
- Network topology (mesh network, insufficient ring topology)
- Lack of sensors, intelligent fault indicators (IFIs), RTUs to monitor the state of the grid and SCADA infrastructure for fast power restoration
- Excessive power usage (theft), overloading the grid
- Lack of proper grid observations and planned maintenance, ineffective and insufficient corrective maintenance. Ineffective maintenance procedures
- Ineffective field crew geographic coverage
- Aging devices and network
- Atmospheric conditions:
 - o Heavy rain, flood, landslide
 - o Ice load and extreme wind, thunderstorm
 - o Humidity and high temperature
- External parameters:
 - o Faults originating from third party assets (irrigation pumps, non-standard customer connections, etc...)
 - o Lack of tree trimming
 - o Avian caused faults

5.6.1.2 Enhancement of Reliability

As described in the previous section, reliability of the distribution network depends multiple parameters and is rather impossible to represent a mathematical equation to formulate SAIDI/SAIFI improvements as a function of variables including expenditures in a year.

Prerequisite of all index definitions and dependants is availability of quality of interruption statistical data, root-cause analyses, GIS based asset data including age, meteorological statistics for a period to benchmark among DSOs and link reliability performance with annual OPEX ceilings.

In fact, small improvement might improve the quality indices unproportionable.

Over the coming years, a statistical regression model could be created for this purpose, providing the most common interruption variables, proper data recording definitions and methodologies are decided.

5.6.1.3 Recommended Data Set

Variables of below Table could be considered as an inclusive list of variables which comprises of monthly past data (if available). On the other hand, in order to obtain reliable results, at least 3 years of data is required. After obtaining 12 months data to represent the year, first primitive results can be obtained. After gathering more data, the model can be updated, so that more precise results can be calculated, and model will begin the learn the pattern in the data.

The data regarding the network should be gathered from DSOs and for these weather conditions, the row data can be gathered directly from Meteorology and the indicated variable in the table can be calculated accordingly. Exclusions such as transmission black-outs, planned interruptions (planned maintenance), third party induced (street constructions, car crashes, customer connections, etc...) faults and extreme weather-related events should also be considered. Intergovernmental Panel on Climate Change describes an extreme weather event as “an event that is rare within its statistical reference distribution at a particular place. Definitions of “rare” vary, but an extreme weather event would normally be as rare as or rarer than the 10th or 90th percentile” in IPCC Third Assessment Report - Climate Change 2001. Also, it is added, this definition can be changed based on region. Thus, a definition of region-specific extreme weather event can be established and can be excluded in SAIDI/SAIFI calculations if these conditions cause the outages.

The data that will be used in the regression model can be collected for each district or operational region. This data resolution enables analyst to construct models district/operational region based, distribution region based and Turkey as a whole.

During the Fourth Implementation period it would be better off if SAIDI and SAIFI indices are calculated based on only MV grid including individual transformer failures. Yet, the data related to LV grid can be collected during the Fourth Implementation period.

Quality criteria for individual customers could still be monitored and calculated penalties are paid using existing procedures. Starting from 2026, indices shall include LV interruptions.

In the following Table, the variables affecting SAIDI and/or SAIFI are marked, also the variables that can be controlled by DSOs are indicated. The detailed description of some variables is presented after the table.

Table 5.17 – Sample Data Set per Operational Region/District per Year

Variable (units)	SAIDI (min) (Y _i)	SAIFI (#) (Z _i)	Controllable
HDD ³⁰³ (# of Days)	X	X	
Weighted Average of HDD using temperature	X	X	
CDD ³⁰⁴ (# of Days)	X	X	
Weighted Average of CDD using temperature	X	X	

303 Number of warmer days over the long-term historical data.

304 Number of colder days over the long-term historical data.



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Variable (units)	SAIDI (min) (Y _i)	SAIFI (#) (Z _i)	Controllable
Precipitation ³⁰⁵ (kg per m ²)	X	X	
# of Rainy days ³⁰⁶	X	X	
Weighted Average of # of rainy days using kg per m ²	X	X	
WDD ³⁰⁷ (# of Days)	X	X	
Weighted Average of Windy Days using force	X	X	
SDD ³⁰⁸ (# of days)	X	X	
Weighted Average of Snowy Days using thickness	X	X	
Ice Load Region (1-5)	X	X	
Seaside (0/1)	X	X	
Geographical Area (km ²)	X		
Avian Routes (0/1)	X	X	
Traffic Effect (0/1)	X		
Slope (°)	X		
Ratio of Forestry MV Overhead Lines over Total MV Overhead Lines (%)	X	X	
Distributed Energy per customer (MWh)	X	X	
Renewal CAPEX of the previous year (MMTL)	X	X	X
OT CAPEX of the previous year (MMTL) ³⁰⁹	X		X
Maintenance Budget in OPEX of the previous year (MMTL)	X	X	X
Number of field crew ³¹⁰	X		X
Total material and outsourced OPEX for Maintenance (MMTL)	X	X	X
Theft & Loss Ratio (%)	X	X	X
GIS Data Correctness Level (%)	X		X
Existence of Workforce Management (0/1)	X		X
Health Index (Condition of Assets)* (1-5)	X	X	X
Number of Reclosure/senctionalizers	X		X
Number of SCADA RTUs	X		X
Number of FPIs	X		X
Number of DMs per main feeders	X		X
Number of KÖKs per distribution transformers	X		X
Number of Connection Points	X	X	X
Number of Irrigation Transformers	X	X	X
Number of Pole Type Transformers	X	X	X
Number of DG Connections (MV Level)	X	X	

305 Precipitation over the long-term historical data.

306 Number of rainy days over long-term historical data.

307 Number of windy days over long-term historical data.

308 Number of snowy days over long-term historical data.

309 OT: Network Operation Technology Investments.

310 Number of field blue collars in repair and maintenance departments.



Variable (units)	SAIDI (min) (Y _i)	SAIFI (#) (Z _i)	Controllable
Ratio of Third-Party Transformers over Company Owned	X	X	
Customers per MV line Length	X	X	X
Share of MV underground (%)	X	X	X
Weighted Average Age of MV Overhead Lines	X	X	X
Weighted Average Age of MV Underground Cable	X	X	X
Weighted Average Age of Transformers	X	X	X
Ratio of the Length of Ringed MV Overhead Lines over Total Overhead MV Lines	X		X
Ratio of the Length of Ringed MV Underground Cable over Total MV Underground Cable	X		X
Customers per LV line Length	X	X	X
Share of LV Underground (%)	X	X	X
Weighted Average Age of LV Overhead Lines	X	X	X
Weighted Average Age of LV Underground Cable	X	X	X

Firstly, number of warmer, windy and snowy days can be calculated as the number of days in a month that are higher than the historical average of the highest measurement in a specific month. For the number of older days, the other way around is applicable.

Health Index is an indicator of condition of the network. This index can be calculated by implementing conditional assessment methodology for network assets such as transformers, overhead lines and underground cables. This methodology takes into account the following annual measurements when calculating the health index:

- Real-time Measurements:
 - Transformer winding temperature
 - Transformer oil temperature
 - Transformer oil level
 - Mechanical vibration measurement
 - Acoustic vibration measurement
 - Substation temperature
 - Humidity of substation
 - DC system monitoring sensors
- Periodic Tests
 - Circuit Breaker DCRM (dynamic contact resistance measurement) test
 - SF6 circuit breaker tests
 - Transformer oil leakage tests
 - Oil particle analysis
- Basic parameters
 - Transformer Kind
 - Transformer Type

- Transformer Condition
- Transformer Age Interval
- MV Switchgear Type
- MV Cubicle Conditional Status
- Substation Building Type
- Substation Building Conditional Status
- LV Panel Type
- LV Panel Conditional Status
- Consistence of Fuse-LV Conductor Ratings
- Accessibility
- Protection Earthing
- MV Bushing Isolation
- LV Bushing Isolation
- Thermometer Availability
- Silica gel Status
- DC System Conditional Status
- Switchgear Type
- Pole Type
- Conditional Status
- Route Problems
- Availability of Service Line on a single pole
- Availability of Line Isolator at Junction Point
- Availability of Interlock on Disconnecter
- Properness of Fuse Rating
- Availability of Protection Earthing at Pole Locations
- Number of faults passed
- Average short circuit magnitude current exposed (main components only)
- Number of circuit breaker operations in normal load
- Number of circuit breaker operations under fault
- Average loading of transformers
- Average loading of lines
- Maximum loading of transformers
- Maximum loading of transformers
- Availability/density of pulsed loading

In addition, Ofgem requires Network Asset Risk Metrics derived from the probabilities and expected consequences of asset failure in Business Plans of DNOs in the format of Business Plan Data Templates. In one of these templates, DNOs are required to report the minimum and maximum points of the Risk and Probability of Failure bands for each Asset Category. In the PoF calculations, the expected deterioration of assets and risk of any new assets to be installed on the network should be considered. DNOs are required to explain their approach while calculating the PoF/Health Indicator measures. Risk, PoF and Volumes for total population of each Asset Category should be reported.

In essence, the distribution profile of Monetised Risk on a network should be provided. At first, these risks are provided on the high level as the following breakdown:

- Total Risk Forecast
- Total Risk without Intervention
- Total Risk with Interventions

The interventions are divided into six categories:

- Replacement
- Refurbishment
- Maintenance and Repair
- Removal
- Addition
- Indirect Intervention

Then, the disaggregation of total risk by Asset Category and by component elements of risk (i.e. Environmental Risk, Safety Risk, System Risk, Financial Risk) are provided, again as the breakdown of total, with and without intervention.

The following factors which have an impact on monetised risk and distribution of assets in Risk and PoF are required from DNOs. These factors contribute to the risk movements, so the factors forecast are depend on them.

1. Asset additions that are not part of a replacement or refurbishment,
2. Asset disposals that are not part of a replacement or refurbishment,
3. Deterioration,
4. Manual Over-ride on PoF or CoF (Consequence of Failure): Any change based on engineering judgement
5. Extension of Expected Asset Life: Any change due to revised view on the expected life of an asset or a revision of the deterioration curve.
6. Asset Replacement – PoF, CoF and Other Driven
7. Asset Refurbishment – PoF, CoF and Other Driven
8. Indirect Interventions: Since the network assets are interdependent to each other, an intervention to one asset affects the PoF/CoF of another asset.
9. Asset Replacement Due to Early Life Failures
10. Methodological Changes
11. Data Cleanse: Data errors corrections
12. Other Factors

Now, for the model construction, except SAIDI and SAIFI indices all other variables could be obtained historically. Through data mining and missing value handling approaches, missing indices could also be available for at least in some DSOs.

Using this comprehensive variable set, the following regression models can be constructed where SAIDI (Y) and SAIFI (Z) are dependent variables. Because of the easiness in the interpretability of coefficients, taking natural logs of dependent variables can be applied in these models, also.

$$\ln(Y) = \beta_0 + \sum_{i=1}^k \beta_i X_i + \varepsilon$$

$$\ln(Z) = \gamma_0 + \sum_{j=1}^l \gamma_j V_j + \varepsilon$$

where X and V represent the variables indicated in the above table accordance with whether they have an effect on SAIDI or SAIFI. ε is the error term of the models which is assumed to be distributed normally with mean zero and constant variance.

In the model construction phase, a variable selection method can be applied which tries to obtain the optimal model, such as AIC, BIC, stepwise selection by p-value, stepwise selection by AIC or BIC and regularisation such as LASSO. It is very important to deploy expert knowledge in this phase also. Despite being statistically insignificant, a variable can be included in the model relying on expert knowledge. In the case where district/operational region-based modelling, the variables should be the same for all regression equations.

After the construction of the models, the assumptions of linear regression should be checked, namely:

- v

Using all or the most significant ones, a regression model could be derived after a reasonable period. Only after this model, it is feasible to set up CAPEX and OPEX budgets linked to service quality output. We recommend calculating the distribution region SAIDI by first calculating SAIDI of districts/operation region using the model, then taking weighted average by weighting them by number of customers in the related region, i.e., using the following formula:

$$SAIDI_{DSO} = \frac{\sum_{n=1}^m \text{Number of customers in district/operation region}_n * SAIDI_n}{\text{Total Number of DSO Customers}}$$

where n represents the district or operation region. The same approach applies for SAIFI, also.

After realization of the data indicated in the above table (X and V), above model (the coefficients) can be used to calculate a new SAIDI or SAIFI which can be compared with the realization of SAIDI and SAIFI and the link between CAPEX and OPEX budgets to service quality output can be established.

5.6.1.4 Recommendations

- To enhance quality indices DSOs should have a 5 year-plan to cover the fourth implementation period based on their historical network interruption statistics, root cause analyses, vulnerable network parts to extreme weather conditions, asset condition and aging as well as past meteorological data for each district town. The last but not the least, MV GIS data must be within acceptable completeness and correctness limits (i.e. better than %95).
- DSOs would submit a 5-year quality enhancement plan to EMRA with an estimated target level (+/- 20%) for the year 2025.
- A new uncontrollable OPEX item would be created for unit price-based repair activities with annual reporting procedures like CAPEX.
- DSO investments in network sensors, recloser/senctionalizers, FPIs, programmable relays, SCADA RTUs, asset management tools and distribution transformers smart metering should not be limited.



This project is funded by the European Union



5.6.1.5 Network Resilience

- Due to global warming, increased number of extreme meteorological events have been observed in the last couple of years. To increase the resilience of the network, DSOs need to take certain actions including reviewing the ice-load maps, identify risky regions for flooding, land sliding, earthquake, heavy snow, ice-load and thunderstorm. Apply proper network design criteria for the new investments and install robust network components even with higher costs with EMRA's consent.
- Obtain heavy duty mobile generator sets to provide emergency power during restoration after such extreme event.
- Prepare an emergency action plan and review every year,
- Complete cyber security investments and implement internal procedures according to ISO standards,

5.7 Annex 7 – Efficiency Measures

5.7.1 Introduction

Efficiency is described as the “comparison between observed and optimal values of its output and input”. The input-oriented models make the comparison of the ratio of minimum potential to observed input required for the given output. On the other hand, output-oriented models use the ratio of observed to maximum potential output obtainable from the given input. Besides from input or output-oriented models, for the several inputs and outputs, an aggregation process should be defined in some economically sensible way in order to calculate efficiency.

In these definitions, efficiency is considered as technical, which refers to minimization of waste while producing as much output as input allows or using as little input for the required output. Thus, measurement of technical efficiency can have an output-augmentation or input-conserving directions.

If the comparison is made between observed and optimum cost, revenue, profit, then the efficiency is economic. Optimum cost, revenue or profit are determined by the behavioral goal of the organization and they can be subject to some quantity or price constraints. Thus, in a way, a combination of inputs and outputs in optimal proportions regarding to the prevailing prices. Also, an economic objective and information on market price is needed for economic efficiency measurement. For example, if the unit is set as cost minimization, then efficiency is calculated by the ratio of minimum cost to observed cost. It attains 100% if the company is cost efficient, otherwise a smaller value is attained.

In order to measure efficiency, there arise issues of how many and which outputs and inputs should be included in the analysis, how should they be weighted in the aggregation process, and how should the potential of the unit be determined. In order to assess these issues, the definition of useful output and useful input is established, where usefulness is represented with weights incorporating market prices, and this definition generates a modern economic efficiency measure.

If these issues are not handled correctly, like not including enough outputs and inputs, measured inefficiency may be the result of wrongly related variables and constraints and wrongly specified the right economic objective of the unit.

5.7.2 Efficiency Measurement Techniques

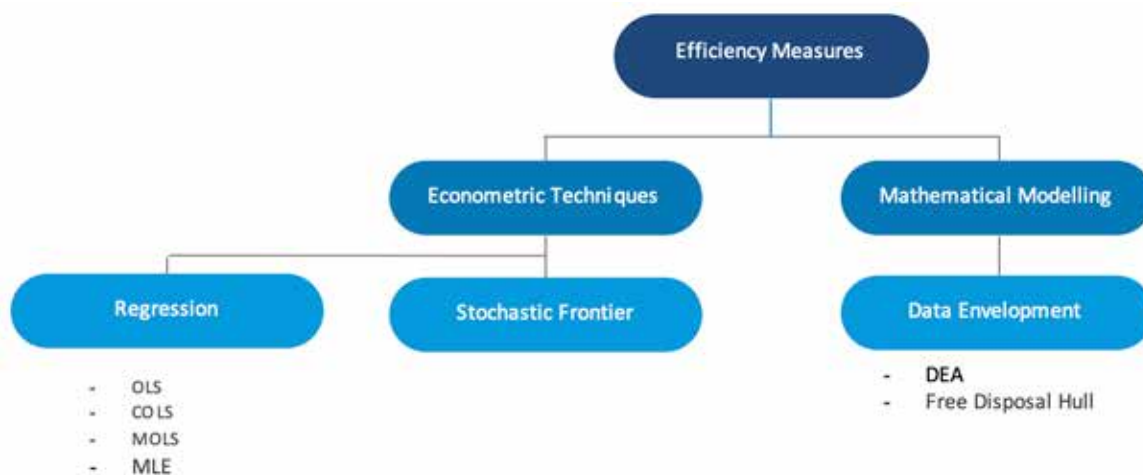


Figure 5.19 – Efficiency Measures

It is stated that economic theory is based on efficient subsets of the whole set while pairing them with minimum cost functions and maximum revenue or profit functions and using envelopment properties yielding cost minimization input demand functions, revenue maximizing output supply functions, profit maximization output supply and input demand functions. Thus, the term “frontier” is used to refer the boundaries of these functions and efficiency and its consequences can be measured using these frontiers.

Fundamentally, two main approaches are present to measure efficiency; econometric approach and mathematical modelling approach. The econometric approach which constructs frontiers and the efficiency is measured relative to the constructed frontiers is different than the mathematical programming approach. In the former, the emphasis is on the central tendency, while in the other boundary values are important. Essentially, different approaches are used in the two approaches to envelope data, that results the envelopment more or less tightly, which make different accommodations to random noise (unexplained variability in the data) and the flexibility in the structure of the model.

In the academic literature it is stated that, frontier models attend to explain boundary behaviour which is the optimal rather than average behaviour as in regression models. Thus, they are considered as more informative than other techniques since, they can present which company outperform which other companies. In addition, there are methods that combine frontier models and regression models, which allow the comparison of performance across different categories and determination of the ability of companies to accommodate themselves with the best practice of the sector.

The strengths and weaknesses of these two approaches at a glance can be summarized as follows:

1. In the econometric approach, the effects of noise and effects of inefficiency is distinguished. On the other hand, the mathematical programming approach combines noise and inefficiency together, calls it as combination inefficiency.
2. The econometric approach is parametric, that leads to mixing the effect of inaccurate description of functional forms with inefficiencies. Besides, the programming approach is less sensitive to this type of specification errors because it is a non-parametric method.

Obviously, making the mathematical programming approach stochastic or the econometric approach more flexible to its parametric structure is desirable.

5.7.2.1 The econometric approach

The econometric approach divides into two categories: i) deterministic frontier models and ii) stochastic frontier models. In deterministic models, the explanatory variables are not random, whereas in stochastic models they are random.

The following two assumptions are made by both of these models:

- Efficient sets can be represented by distance, revenue, cost and/or profit functions and
- The functional forms of related functions are known.

Also, deterministic frontier models assume that all relevant quantities, prices and variables are observed and measured without error, which makes these models deterministic. This assumption reduces the deterministic models to determination of the structure of model only. When this assumption holds, then the deterministic frontier can be estimated using single regression model where the error term represents inefficiency.

In stochastic frontier models, there exist two error terms, one representing the statistical noise (measurement error) and the other representing the inefficiencies. Hence, the stochastic frontier includes both estimation of the model and the external events which are in or out of control of the company. The degree of efficiency of a company is calculated by the ratio of observed to maximum feasible output, where the maximum feasible output is given by the stochastic frontier.

Now, if it is assumed that inefficiency is actually zero, then simple 'ordinary least squares (OLS)' estimation of parameters of regression model is sufficient. Whereas, if the measurement is assumed to be zero, then stochastic frontier models are simplified to estimation of the parameters of deterministic frontier models.

Fundamentally, three estimation techniques exist: corrected ordinary least squares (COLS), modified ordinary least squares (MOLS) and maximum likelihood estimation (MLE).

The COLS approach makes no assumption regarding the functional form (distribution) of the error that measures efficiency. It estimates the model parameters by OLS, in which the intercept is estimated smaller than the true parameter (downward bias). The COLS approach then corrects the lower estimation of intercept by shifting it up until all corrected residuals are nonpositive and at least one is zero.

Secondly, MOLS makes an assumption of the functional form of the error that measures efficiency. The most popular assumption in the literature is half normality. This assumption requires an estimation of additional parameter which is the variance of the normal distribution that is truncated above at zero. Also, other distributions can be assumed like exponential, gamma, Weibull, lognormal or log-logistic distributions. Similar to COLS, MOLS estimates the parameters using OLS, then it modifies the estimated OLS intercept by shifting it up by minus the estimated mean of efficiency errors, which is subtracted from the moments of the OLS residuals. In this technique, there is no guarantee that the estimated intercept is shifted up enough to cover all observation. Also, it is possible to get efficiency more than 100%, if an observation has a sufficiently large positive OLS residuals.

As a third technique, MLE can be implemented. MLE, also, assumes a functional form of the nonpositive efficiency component. Then, it simultaneously estimates all model parameters and the parameters of the distribution of the efficiency component. The MLE frontier envelops all observations.

Deterministic frontier models can be estimated using any of these three techniques. Yet, it is stated that deterministic frontier models combine the disadvantages of both econometric and mathematical modelling approaches by being deterministic and parametric.

All these estimation techniques for deterministic frontier models including OLS are illustrated in the below figure.

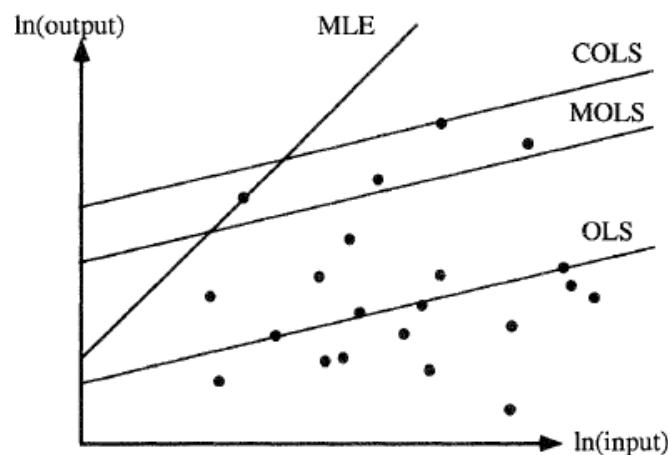


Figure 5.20 – OLS, MOLS, COLS, and MLE deterministic production frontiers

All these techniques for deterministic frontier models make no accommodation for noise and so all deviations from the frontier is considered as inefficiency. Also, both COLS and MOLS are considered as further deficient since only the intercept is adjusted, and the remaining parameter estimates are kept unchanged from their OLS estimates. This structural similarity eliminates the possibility of efficiency occurs precisely because of exploiting the available economies. MLE technique leads to dissimilarity of structure of OLS and frontier techniques. Also, as an important consequence, the structure of efficient frontier model and the structure of model of the less efficient company is the same. For this reason, the same efficiency rankings are assigned by COLS and MOLS as OLS.

However, when stochastic frontier models are estimated, COLS is not a feasible technique while the other two are. MOLS and MLE

behave as in deterministic frontier models with the assumption of the functional form of the nonpositive efficiency term. Unlike the deterministic case, though, the residuals after estimating the parameters contain both inefficiency and noise, thus they must be decomposed. So, a decomposition method also be needed to utilize.

5.7.2.2 Mathematical programming approach

The mathematical programming approach usually is mentioned as the data envelopment analysis (DEA). The envelopment process mentioned in the econometric approach is considered as 'nearly' envelopment. Yet, DEA actually envelops the data and makes no accommodation for noise. Also, it is possible to envelope data as tightly as possible under some assumptions (constraints) about the structure of the model. Again, using prices economic efficiency can be measured.

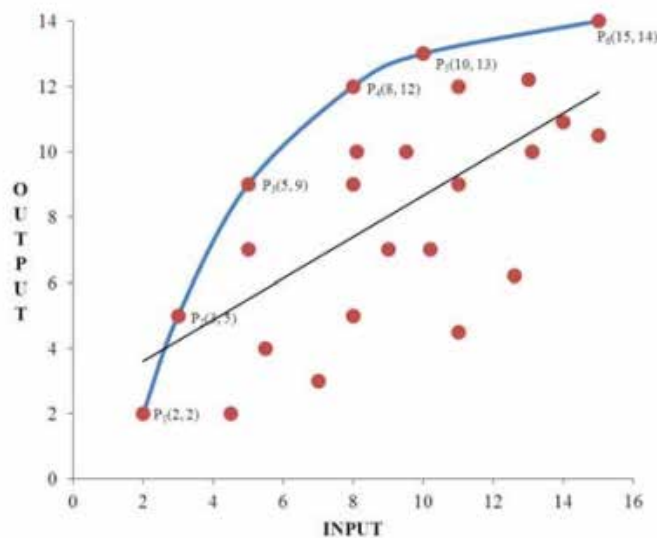


Figure 5.21 – Comparison of DEA and regression

The objective in DEA is to measure the performance of each company relative to the best observed practice in the sample of companies. Therefore, weights are attached to each company's inputs and outputs so as to solve the minimization problem. In other words, nonnegative weights are sought when applied to every company's inputs and outputs, minimizes the weighted input output ratio for the company that is evaluated.

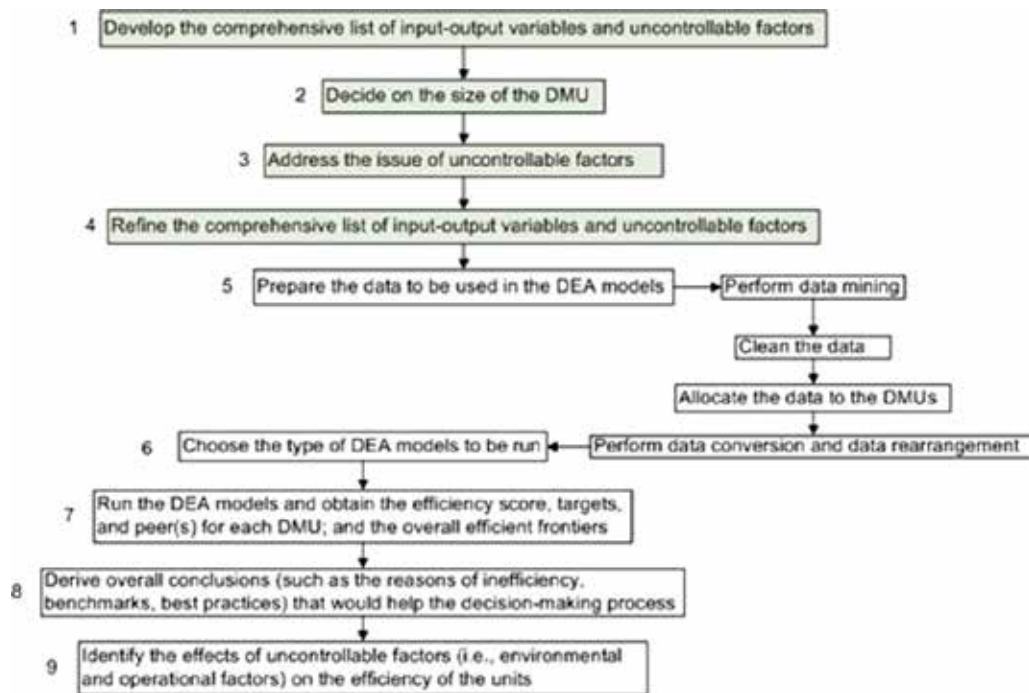


Figure 5.22 – An example of DEA Framework, Data and Modeling Issues Faced during the Efficiency Measurement of Road Maintenance Using Data Envelopment Analysis ³¹¹

Three restrictions are imposed on frontier model by the DEA prior to solving the envelopment problem for each company. These restrictions are; constant returns-to-scale, strong disposability of inputs and outputs and convexity of the set of feasible input output combinations. Yet, all of these restrictions can be relaxed.

By adding appropriate constraints, a nonincreasing returns-to-scale or variable returns-to scale models can be obtained. In addition, for output or input-oriented efficiency scores calculated by these three frontiers can be ordered, which can provide information for each company of potential scale economies available at any observed inputs. The output-oriented and input-oriented approach can provide different signals regarding the economies of scale, because they are obtained for different directions toward different points on the frontier. Each approach is based on an ordering of efficiency scores and thus qualitative information can be gathered on returns-of-scale.

311 Source: Ozbek, M. E.; Garza, J. M.; Triantis, K. 2010. Efficiency measurement of bridge maintenance using data envelopment analysis, Journal of Infrastructure Systems 16(1): 31–39. [http://dx.doi.org/10.1061/\(ASCE\)1076-0342\(2010\)16:1\(31\)](http://dx.doi.org/10.1061/(ASCE)1076-0342(2010)16:1(31))

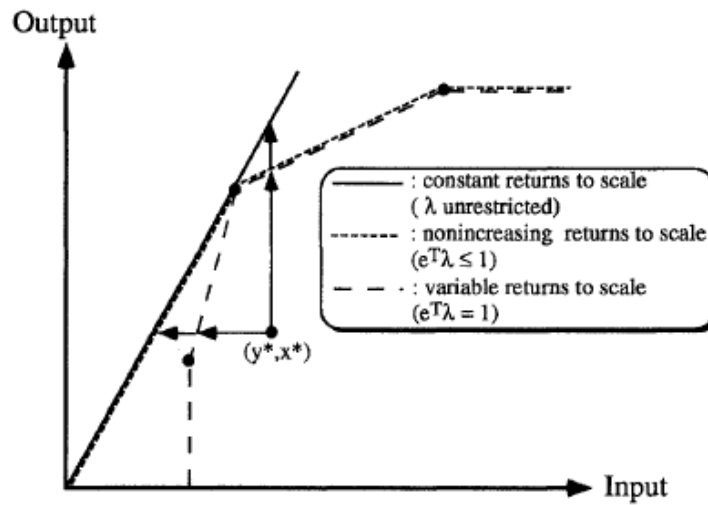


Figure 5.23 – Returns-to-scale in DEA

Variable returns-to-scale frontier requires strictly positive input to produce nonzero output, see the above figure. This results in not allowing the inactivity of companies.

Relaxation of convexity of the set of feasible input output combinations restriction is defined as ‘free disposable hull (FDH)’ but maintains the strong disposability of outputs and inputs as well as variable returns-to-scale by adding again another constraint. Although this additional converts the problem to a mixed-integer programming, the envelopment problem becomes easier to solve. The FDH frontier envelops the data more tightly and domination of companies is more restrictive than the DEA frontier. In FDH, a company is dominated by a single observed efficient company, whereas, a company can be dominated by a linear combination of a set of efficient companies in DEA, which is not an actual observed value. The below figure illustrates these two frontiers.

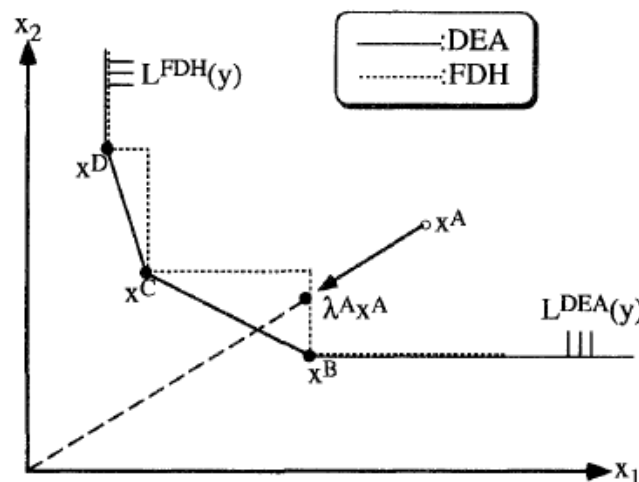


Figure 5.24 – Input-oriented efficiency measurement relative to DEA and FDH frontiers

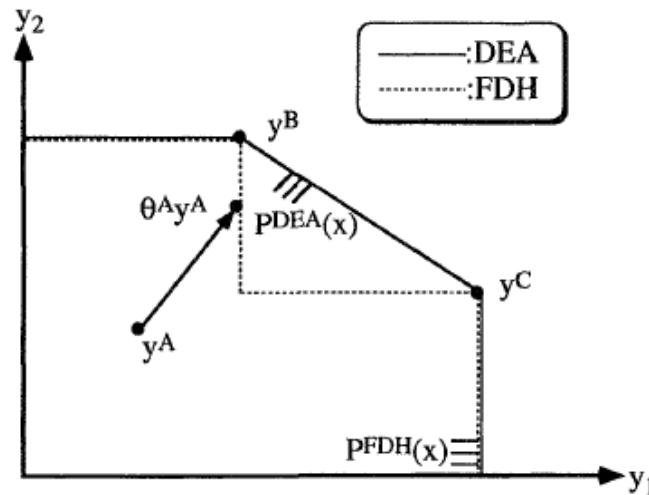


Figure 5.25 – Output-oriented efficiency measurement relative to DEA and FDH frontiers

In addition, Stochastic Non-Smooth Envelopment of Data technique tries to overcome the shortcomings of the previously mentioned techniques.

Being nonstochastic can be considered as a disadvantage, because calculated efficiency scores via nonstochastic models are contaminated by omitted variables, measurement error and other noises. Therefore, collecting all the relevant variables and accurate measurements gain more importance.

The problem of data envelopment becomes a nonlinear programming in this case, which is solved for each company. The aim is to increase outputs of the company being evaluated, subject to constraints imposed by the observed data and the confidence in the collection of the data. However, if a sample data point significantly differs from its expected value due to perhaps bad or good circumstances, then this information is added to the model and efficiency measurements not affected from these circumstances can be achieved. Similarly, if there is evidence of inaccurate measurement of one variable, the greater likelihood of measurement error can also be included in the model, since the measurement error in one variable's contamination of the efficiency measure of any company is not desired.

Thus, in this model, the data requirement is severe. In addition to inputs and outputs matrix, expected values and variance-covariance matrices of all variables and probability levels at which constraints are to be satisfied is needed.

Figures are from The Measurement of Productive Efficiency: Techniques and Applications by Harold et al, 1993.

5.7.2.3 Other approaches

In the literature, there exist nonparametric and nonstochastic models that uses again mathematical programming approaches.

One of these approaches is goal programming, which tries to select a nonnegative parameter vector that minimizes the sum of deviations under the parametric frontier. These deviations occur due to noise and inefficiency. This method includes a linear and a quadratic programming problem.

Schmidt (1976) showed that if these nonnegative deviations are distributed exponentially or half normally, then this problem becomes equivalent to MLE of the deterministic frontier approach.

In addition to the frontier (envelopment) methods described so far, nonfrontier efficiency measurement techniques also exist.

The frontier methods all treat efficiency in terms of some kind of a distance to an appropriate frontier. This distance is calculated using one-sided deviations from the frontier. The main difference is the construction of the frontier and the measurement of the distance. In nonfrontier models, the aim is to capture the effects of the variation in the unobserved management input.

5.7.3 Scores

After calculating the efficiency scores, a two-stage procedure can be conducted where this analysis can help public policy and assist managerial decision making. The two-stage procedure can be explained as follows: in the first stage the efficiency scores are calculated using any of the techniques described above. In the second stage, the efficiency scores are regressed against a set of explanatory variables.

Yet, there are important topics to note here. First of all, efficiency scores are bounded by zero and one, which makes a transformation necessary before using them as dependent variable in the second stage or limited dependent variable regression techniques can be used. Secondly, the distinction between the variables to include in the first or second stage must be made. The controllable variables advised to be included in the first stage and the uncontrollable variables to be included in the second stage. In the second stage, some location specific, socioeconomic and demographic characteristics can be spanned.

The main difference between one stage and two stage model is the former measures efficiency while controlling the influence of exogenous variables and the other variation in efficiency is attributed to variation in the exogenous variables.

5.7.4 Adding External Variables

Environmental factors can affect the efficiency of a company, where such factors are considered as not traditional inputs and assumed not under control of the company. Thus, they can be referred as external variables. Fried, Schmidt and Yaisawamg (1999) gives examples of external variables as the form of ownership (such as public/private or corporate/non-corporate), location characteristics (such as population density and average customer size), labor relations (such as union power) and government regulations. Also, they state that, in this context, inefficiency can be due to managerial inefficiency, ownership inefficiency and regulatory inefficiency, and “the nature of inefficiency is important for designing policies to improve resource allocation”. In the literature, work on external variables regarding the measurement of efficiency is divided into three categories: *the frontier separation approach, the all-in-one approach and the two-stage approach*.

Coelli et al. (2005)³¹² divides *the frontier separation approach* into two according to whether the environmental variables can be ordered from the least to the most detrimental effect upon efficiency. Banker and Morey (1986)³¹³ offers a method in this case, where the efficiency of the i^{th} company is compared with those companies in the sample that have a value of the environmental variable which is less than or equal to that of the i^{th} company. For example, city centers can be considered as the most favorable and the country as the least favorable locations. Then, the comparison set is restricted so that no company is compared with another that has a more favorable environment.

If the ordering is not possible, then another approach for division of sample into subsamples can be followed. The sample is divided according to a single categorical variable that characterizes the different external environments, like ownership structure. This method was proposed by Chames, Cooper and Rhodes (1981). The sample is divided into subsamples and DEA's are solved and reference frontiers are obtained for each subsample. Also, using the pooled data set, another reference frontier is calculated. Assessment of the companies are done relative to their subsample and pooled frontiers. All inefficient companies are projected onto their respective frontier and the impact of the operating environment on inefficiency is determined by comparing subsample and pooled efficiency.

In the frontier separation approach, some problems occur, such as the reduction of comparison set which results in too many companies being efficient. This problem reduces the discriminating power of the analysis. In addition, only one environmental variable can be considered in this approach, it also needs to be categorical in the second case. Thus, *a priori* selection of the single

312 Source: Coelli, T.J., Prasada-Rao, D.S., O'Donnell, C.J. and Battese, G.E. (2005) An Introduction to Efficiency and Productivity Analysis. 2nd Edition, Springer, Berlin.

313 Source: Banker, RD, and RC Morey (1986), Efficiency Analysis for Exogenously Fixed Inputs and Outputs, *Operations Research*, 34, 513-521.

most important feature of the operating environment is required. Also, in the first case, the direction of the effect of environmental variable upon efficiency is required *a priori*. Besides, in many situations this direction is not known, determining the influence of ownership status open efficiency might be the subject of interest.

In the *all-in-one approach* the external variables are included directly in the linear programming formulation (DEA). Unlike the frontier separation approach, more than one environmental factor can be included in this formulation and the requirement of the environmental variable being a categorical is no longer needed. In this approach, an environmental variable can be included as either along with the traditional inputs and outputs or as a neutral variable. In the former, first the direction of the influence of the environmental variable should be decided, whether the higher values of the variable increases or decreases the efficiency. Coelli et al. (2005) provide the example as the customer density in the service area of the company is likely to have an increasing effect on the efficiency since a shorter network is needed to distribute electricity to a particular number of customers. On the other hand, the number of thunderstorms per year is likely to have a detrimental effect due to extra repair needs. However, whether to include the environmental variable as input or output should be decided *a priori* to the analysis. If the variable is considered as having a positive effect on the efficiency, then it should be included in the linear program as an input. Since, this implies that more outputs could be produced. In this way, “the i^{th} company is compared with a theoretical company that has an environment that is no better than that of the i^{th} company”. On the other hand, if the environmental variable has a negative effect upon the efficiency, then it should be included as output in the model. Since, this implies that more inputs are required, suggesting that the operating environment is unfavorable. Also, the mixture of these two models can be applied if there exist environmental variables having positive and negative effects. Yet, if the favorability of the environment is subject to test, this prior classification is not suitable. If the direction of the effect of the environmental variables cannot be determined, the formulation can be altered ensuring that the i^{th} company is only compared with a theoretical frontier company that has the same environment. Again, in this case, the reference set is reduced, which can result in more efficient companies. In all these cases, the environmental variables are continuous. Thus, if there exist also categorical environmental variables, then mixed integer linear programming models should be utilized.

In addition, the classification of the external variables as controllable and uncontrollable can be suggested as a variant of this approach. Controllable variables are considered as adjustable by management. Uncontrollable variables are assumed fixed in the calculation process. This approach requires a prior classification between external variables and efficiency in terms of significance.

As the third method, the *two-stage approach* involves solving a DEA problem in the first stage with the traditional inputs and outputs. Then, in the second stage, the efficiency scores that are calculated in the first stage are used as the dependent variable in a regression model, where independent variable is the environmental variable. In the literature, some studies use OLS to estimate the regression model. However, since most of the efficiency scores can be calculated as one and OLS can predict scores greater than one. Therefore, it is suggested that a Tobit regression model can be used, since it accounts for truncated data (limited by one from above or from below regarding the orientation of the model) and provides unbiased and consistent parameter estimates. It is assumed that the random term in the regression model represents the “pure” efficiency after-effects of uncontrollable factors have been removed. This efficiency is not bounded, and its interpretation as follows: if it is zero, then the company performs as well as the average company with the same environmental conditions, if it is not equal to zero, then its performance differs from the average company with the same environmental conditions. In the output-oriented models, the higher the value of efficiency score, the poorer the performance of the company. For the input-oriented models, the other way around is true.

In this approach, the signs of the coefficients of the environmental variables indicate the direction of the effect of them. Coelli et al. (2005) state that, “The second-stage regression can be used to “correct” the efficiency scores for environmental factors by using the estimated regression coefficients to adjust all efficiency scores to correspond to a common level of environment (e.g. the sample means)”. In this approach, both more than one continuous and categorical variables can be included. Also, the effects of external variables upon efficiency can be tested in terms of sign and significance. This approach has no assumption regarding the direction of the effect of the external variable. However, this approach may have a disadvantage as if the variables used in the first stage are highly correlated with the second stage variables, then the results will most probably be biased. This bias can lead to misinterpreted conclusions about the effect of each external variable upon efficiency.

Also, the two-stage approach can be used to determine the directions of the effect of external variables and then this information can be used in all-in-one approach.

5.7.5 Advantages and Disadvantages of Efficiency Measurement Techniques

Table 5.18 – Advantages and Disadvantages of Efficiency Measurement Techniques

	Advantages	Disadvantages
OLS	- It can distinguish the effects of different variables on the output. - Interpretation of coefficient regarding how inputs contribute to output is applicable.	- To obtain reliable results, large data set is needed. - It assumes the distribution of the error term.
COLS and MOLS	They have the same advantages as OLS since they are variations of it.	Addition to the disadvantages of OLS, the results are especially sensitive to outliers.
SFA	- It is not sensitive to outliers. - It separates random noise from inefficiency. - Data errors and omitted variables are accounted for. - Standard statistical tests can be used to test significance of the variables included on the model.	- Assumes functional forms of the frontiers. - The assumption about the distribution of error terms affect the separation of noise and inefficiencies. - Samples should be large to get powerful results.
DEA	- Multiple outputs and inputs are analyzed simultaneously. - A priori definition of frontier is not needed. - Relative efficiency is based on the comparison to the best observation. - No information is needed on prices. - There is no assumption regarding the mathematical form of frontier.	- The effect of exogenous variables on the operation is ignored. - It cannot measure the statistical errors. - There is no information on how to improve efficiency. - Statistical tests are difficult to conduct using the results. - It is sensitive to outliers. - It is sensitive to selection of inputs and outputs. - The number of efficient companies on the frontier tends to increase with the number of inputs and output variables.
Goal Programming	- It can handle large-scale problems. - There is no limit on the alternatives that can be produced.	It cannot weight the coefficients, so a weighting approach is needed.

5.7.6 Details of the Recommended Efficiency Measurement in Turkey

As mentioned in Section 1.4 (Efficiency), it is recommended to use a two-stage method for the calculation of efficiencies of DSOs, similar to the approach followed by Norway. In the first stage, DEA can be used to calculate initial efficiencies of DSOs. Our recommendation includes a little adjustment of input and outputs of DEA. First of all, as recommended in Section 1.7 (Assessment and Recommendations), variable OPEX can have two parts, one for loss related and one for loss-free related OPEX. As the input of DEA model, the OPEX which includes constant and loss-free variable OPEX can be considered, since the effect of loss related activities are calculated separately and, in this way, the comparison between DSOs can be made depending on network assets and geographical features of distribution regions rather than demographical features. As outputs, it is recommended to use a composite variable score for number of customers, line lengths, number of transformers and the share of network assets older than 30 years old.

The number of customers which includes the consumers and distributed generators, due to their needs of workload, consumer groups may need different approaches, also the distributed generators. Thus, a weighting approach can be followed here using 7 coefficients:

Number of Customer Effect

$$= k_1 * (k_2 * MV DG + k_3 * MV Irr + Other MV) + k_4 (k_5 * LV DG + k_6 * LV Irr + k_7 * Lighting + Other LV)$$

where k_1 is the coefficient of MV customers, k_2 is the coefficient of distributed generators connected to MV grid, k_3 is the coefficient of MV irrigation consumers, k_4 is the coefficient of LV customers, k_5 is the coefficient of distributed generators connected to LV grid, k_6 is the coefficient of LV irrigation consumers, k_7 is the coefficient of lighting consumers.

A similar approach is applicable for the line lengths to obtain the line length effect, 4 coefficients can be specified considering their required O&M workloads. The formula can be defined as follows:

$$\begin{aligned} \text{Line Length Effect} \\ = l_1 * (l_2 * \text{MV Overhead Line Length} + \text{MV Underground Cable Length}) + l_3 * (l_4 \\ * \text{LV Overhead Line Length} + \text{LV Underground Cable Length}) \end{aligned}$$

where l_1 is the coefficient of MV lines, l_2 is the coefficient of MV overhead lines, l_3 is the coefficient of LV lines and l_4 is the coefficient of LV overhead lines.

Again, a similar approach can be followed while using the number of transformers as an output. In this variable, the number of transformers on the top of a pole, number of transformers inside the buildings and third party owned transformers can be weighted because of the condition they encounter and their maintenance needs. Thus, the following formula can be defined, where m_i representing the weights of related transformers:

$$\begin{aligned} \text{Number of Transformers Effect} \\ = m_1 * \# \text{ of Pole Type Transformers} + m_2 * \# \text{ of Building Type Transformers} + m_3 \\ * \# \text{ of Third Party Transformers} \end{aligned}$$

After the calculation of efficiency scores of DSOs using DEA method, the environmental factors can be incorporated in the second stage. In this stage, the calculated efficiency scores are used as the dependent variable in regression model, and the environmental factors are included as independent variables, such as the area of the region, forestry area and urbanization rate (the ratio of customer number in the countryside to the total). These factors are described as Z-factors in the Norwegian model, and they are considered as factors that cannot be controlled by DSOs and they constitute the geographical differences between distribution regions. Because the regression model can result in values more than unity (100%), Tobit Regression Model application is advised in this context. By utilizing this second stage, the efficiency scores are adjusted to correspond to a common level of environment. Also, the constraint on the number of variables in DEA model is overcome by applying this two-stage methodology. More details are described in Section 5.7.4.

In addition to company-based efficiency calculation, a sectoral efficiency can be applied. The average improvement in the ratio of OPEX realizations to customer number in the third implementation period's last 4 years can be applied as the Electricity Distribution sector efficiency.

5.8 Annex 8 – Dynamic WACC

Dynamic WACC

It has always been an issue to determine how to set the weighted average cost of capital (WACC) for regulatory price-setting purposes. Since the start of the global financial crisis, a number of unusual events have affected capital markets and macroeconomic conditions across the world and some countries in Europe have suffered from worsening public sector balance sheets and deteriorating credit ratings. This has led to significant movements in interest rates in all jurisdictions. In this context, estimating the required return became more challenging.

Most of the countries apply pre-tax nominal WACC in Europe. However different from most of the other countries, in Portugal, the rate of return is updated ex-post each year in order to reflect the evolution of financial market conditions due to the uncertain and financially unstable environment. By this way, the existing regulatory scheme in the Country tackles an issue that can jeopardize

system stability.

The following formula shows general formula for WACC and Capital Asset Pricing Model (CAPM):

$\text{Cost of capital} = r_d \times \frac{D}{D + E} + \frac{r_e}{1 - t} \times \frac{E}{D + E}$ r_d – debt interest rate D – Debt capital E – Equity r_e – equity interest rate t – tax rate	CAPM (Capital Asset Pricing Model) $r_i = r_f + \beta(r_m - r_f)$ r_i – return on the capital asset r_f – risk-free rate of interest β – Equity beta r_m – market rate of return

Figure 5.26 – WACC and CAPM Formula

In Portugal, the WACC is indexed to the Portuguese 10-year bond benchmark and depends, in each year, on its evolution, with a cap and a floor. The methodology used for setting the cost of equity is CAPM and the cost of debt is set using a default spread model, where a spread (debt premium) is added to the risk-free rate.

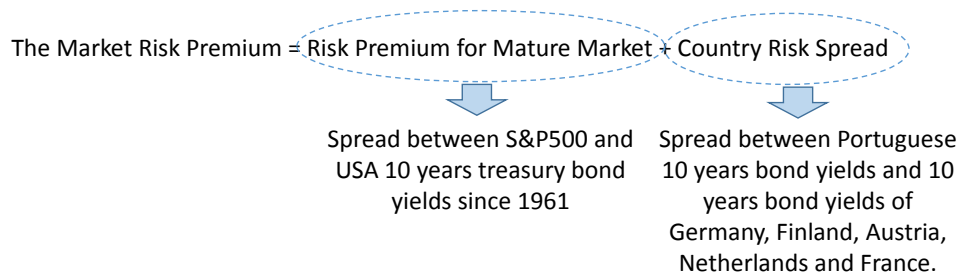


Figure 5.27 – Market risk premium calculation

Between May 2011 and June 2014, Portugal was under the framework of Economic and Financial Assistance Program. Given the high volatility and levels of Portuguese bond yields, an indexation methodology was established and started to be used in 2012 to provide balance between economic signals provided by the high rates and the need for regulatory stability.

This indexation implied one other main change to the definition of the nominal risk free rate and the rate is no longer based on long-term Portuguese Government Bond yields but on the yields of long term Euro Zone Government bonds with AAA ratings.

In the regulatory periods that followed and for both the electricity and gas sector, ERSE decided to maintain the indexation methodology due to the maintenance of some economic uncertainty and financial volatility.



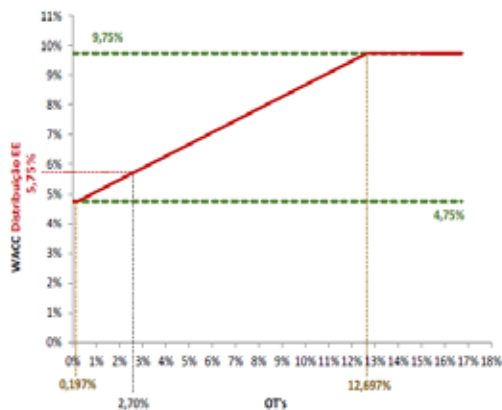
Figure 5.28 – Indexation methodology

The indexation mechanism includes a set of parameters that are defined ex-ante and that are fixed for the regulatory period:

- An initial estimated WACC value for the first year of the regulatory period
- Cap and floor values for the maximum and minimum values of the allowed rate of return RoR
 - The floor was 5.00% and the cap was 10.00% previously, however, the cap and floor limits within the annual RoR over the 2018-2020 period were revised downwards: The floor limit moved from 5.0% to 4.75% (this annual RoR floor will be in force in scenarios of average annual yield of 10-Year PGBs below 0.2%) and the cap limit moved from 10.0% to 9.75% (this annual RoR cap will be in force in scenarios of average annual yield of 10-Year PGBs above 12.7%).
- An initial estimated value for the indexation variable defined for the first year of the regulatory period.
 - The indexation variable is, currently, the Portuguese 10-year bond yield
- The ratio between the incremental variation of the RoR and the incremental variation of the index variable (the slope of the line in the indexation mechanism)

As mentioned, the rate of return is updated ex post each year in order to reflect the evolution of financial market conditions, through the index variation.

An example that shows the application of the indexation mechanism to the Electricity Distribution is shown as follows:



- Initial estimated WACC value for the first year of the regulatory period: 5.75% (bond yields=2.7)
- Cap value for the maximum value of the RoR: 9.75% (where bond yields yields ≥ 12.697 Yield_H) and the floor value for the minimum value of the RoR: 4.75% (where bond yields ≤ 0.197 Yield_L)
- Rule for the incremental variation of the RoR (the slope of the line), a 1 pp change in the bond yields implies a 0.4 pp change in the RoR:

$$SLOPE = \frac{CAP - Floor}{Yield_H - Yield_L} = \frac{9.75 - 4.75}{12.697 - 0.197} = \frac{5}{12.5} = 0.4$$

As another example, the Italian Regulatory Authority, AEEGSI updates the risk-free component of the WACC every two years, while keeping the other parameters unchanged during the period for which the WACC is set for.

5.9. Annex 9 – Business Plan Template

Each DSO should submit a draft 5-year business plan before the start of next regulatory period.

1. In business plans DSOs should state their long-term vision together with a demand forecast followed by broader description of their Region (i.e. Geography, Demography, Climate and any other relevant regional facts).
 - a. DSOs may assist the business plan with a strategic data analysis including the following draft subtitles:
 - i. Activity Chain Analysis
 - ii. Consumption Loop & Pain Analysis
 - iii. Customer Value Proposition
 - iv. PESTEL Analysis
 - v. SWOT Analysis
 - vi. Strategic Initiatives
 - vii. Strategic Intent
 - viii. Value Chain Analysis
 - ix. Strategic Activities
 - x. Collaborative Activities

2. To assess the overall performance improvements in all aspects in the next regulatory period, realizations of the previous period should be presented.
 - a. IP3 detailed fiscal realizations in OPEX and CAPEX such as;
 - i. Average annual gross salary cost of white and blue collar together with outsourced headcount
 - ii. O&M (exc. Street lighting) (manpower, Component level material usage (distribution transformers, poles, lamp fixtures, DM cells, electronic meters, modems, etc...), outsourced works, vehicles and any other O&M related costs)
 - iii. O&M (Street lighting) (manpower, Component level material usage (distribution transformers, poles, lamp fixtures, DM cells, electronic meters, modems, etc...), outsourced works, vehicles and any other O&M related costs)
 - iv. Customer operations (Meter Operations, Connections/Disconnections, Customer Contact Centers, Call Center Costs and its statistics)
 - v. Loss Reduction Costs,
 - vi. Non-O&M Vehicles (amortization, rentals, fuel, maintenance, etc)
 - vii. Uncontrollable and other Expenses
 - b. Plan must have CAPEX realizations of network (capacity increase, replacement, street lighting, environment and safety, meters, IT&OT and other) together with CAPEX Unit costs per main asset class (i.e. cost per MVA, per MV O/H line, MV UG line, LV O/H line, LV UG line, electronic meter, Smart meter (including modem), DM and KÖK).
 - c. Last ten years number of customers (Vulnerable, Residential, SMEs, large commercials, industry, irrigation, DER, roof-top solar, EV charging stations, per consumption level), Distributed energy (per voltage level, per customer type), realized loss rate statistics should also be provided.
 - d. A separate chapter stating assets described in ANNEX 5.6 (including third party assets, street lighting, IT&OT and meters), their age histogram (per 5 years) and operating conditions (asset health data, see 5.6).
 - e. Human resources and organizational structure of DSO need to be covered in a separate chapter together with own headcount evolution, outsourcing strategy,
 - f. Continuity of supply statistics would be another important topic that plan should address. Interruption statistics and reason of interruptions (including TEIAS, exceptional meteorological events and third party related) per asset class, SAIDI/SAIFI Evolution, DSO's carbon footprint and Commercial Quality Realizations would be main headlines in this part of the plan
 - g. Quality level of DSO would be the main driver to improvements in all areas. GIS data quality (availability and accuracy of MV and LV assets) must be stated in the report.
 - i. Based on year-end results, business plan should include a 5-year operational and fiscal plan together with 2025 targets in continuity of service, fiscal efficiency, carbon footprint and commercial quality.
 - h. How to achieve those targets need to be described in separate chapters. Some of the main planning topics that DSOs should address are;
 - i. Loss reduction,
 - ii. SAIDI/SAIFI improvement,
 - iii. Smart meter deployment plan together with Cost Benefit analyses (CBA)
 - iv. Smart grid road map
 - v. Digital Utility road map
 - vi. Carbon foot-print reduction plan
 - vii. EV fast charging station deployment plan
 - viii. LED Conversion strategy and roadmap with CBA analyses

- ix. Electronic meter (over ten years) replacement forecast
 - x. Emergency action plan
- i. Based on updated 10-year master plans, DSOs must prepare a CAPEX plan with justification covering new capacity, CBA based IT/OT CAPEX, third party asset acquisition,
 - j. Special section must be left for asset maintenance. DSOs must present a strategic action plan for replacement of aged or unreliable network components either in OPEX or CAPEX. A Cost Benefit Analysis (CBA) approach is expected to be conducted in this plan. This part should also cover a network resilience enhancement based on recent extreme weather events. Cyber resilience is another topic to be included in this section.

Finally, DSOs are expected to provide additional supporting tasks, including but not limited to CSR (Corporate Social Responsibility) and customer survey plan.

5.10 Annex 10 – Transmission Tariff Charges of Six Selected Countries

5.10.1 Italy

Starting from 2016 the Italian transmission tariff ("CTR") - applied to distributors by the Italian TSO Terna - is binomial and it is split into an energy-related component, covering ~10% of the transmission costs, and a capacity-related component, covering ~90% of the transmission costs.

Both DSOs and final customers are seen as Load (L) from TSO's perspective. However, there is different tariffs, charges calculation procedures and settlement rules for final customers and distribution system operators in Italy. Justification for different treatment might be the load volume of a given network user, the number of connection points to the transmission grid (simultaneous off-take), the network configuration conditions and the co-operation scheme of DSOs with the TSO (often DSOs' network plays a role of sub-transmission grid).

The tariff has a two-components structure and it is applied to non-domestic customers:

- The TRASE (transmission tariff applied on the energy at point of delivery to non-domestic and domestic high voltage users) charged as eurocent per kWh.
- The TRASP (transmission tariff based on connection capacity (*potenza impegnata*) charged only to high voltage users as euros per kW per year.

The transmission tariff for any particular year is determined by the ARERA by 30 November of the year before.

Table 5.19 – TRAS components for the transmission services to the end customers (year 2020)

NON domestic customers	TRAS _p	TRAS _E
	Euros/kW per year	Euro cents/kWh
Public lighting in LV	-	0.761
exclusive power supply of electric vehicle charging points in places accessible to the public in LV	-	0.761
Others in LV	-	0.761
Public lighting in MV	-	0.709
MV	-	0.709
HV	20.8846	0.069

HV, voltage < 380 kV	20.8846	0.069
HV, voltage >= 380 kV	20.8846	0.069

The section below summarizes the main features of different treatment /charging mechanisms of final customers and distribution system operators by TSO.

Losses: losses on the Italian transmission network are purchased by load service entities on the basis of standard loss factors.

System services: The Transmission activity (mainly aimed at providing system security), are paid by dispatching users (load) (i.e. not directly invoiced to the final consumers) and are pass-through for the TSO. The value includes the system services/ancillary services.

Infrastructure component: this has been estimated by considering the sum of the unitary fees related to transmission (based on the “TRAS” tariff, which is applied by distributors to final users) and dispatching (DIS tariff).

By taking the energy component into consideration, it is applied on a monthly basis to the net energy withdrawn from distribution companies connected to the NTG. The transmission fee is applied only if the resulting balance is a withdrawal. For transmission fee purposes, the energy injected in the distribution grid at HV level (virtual interconnection points) is also considered as energy withdrawn from the NTG.

The first connection charges types are characterized as shallow in Italy.

Connection of production plants - G:

When first requesting the connection, applicants pay upfront Terna a fixed amount of 2,500 € to get a general appraisal of the possible connection solution (“STMG”). Once obtained the authorization, applicants pay upfront Terna an amount of 2,500 €+ 0.5 €/kW (max 50,000 €) for a more detailed project plan (“STMD”). Grid user bears costs for building the grid connection plant. Enhancements of the National Transmission Grid are socialized in tariff.

Reduced fees apply in case of connection of production plants powered by renewable sources and for high-performance co-generation plants.

Connection of consumption units – L:

Applicants pay Terna the same amounts foreseen for STMG and STMD of production plant and a connection fee equal to 50% of the expenditure for building grid connection plant including cost of the materials and labour costs as well as overheads, assumed equal to 20% of these amounts.

Connection of DSO:

The DSO/TSO that implements the connection plant recovers the incurred costs through tariff.

5.10.2 Norway

5.10.2.1 Transmission Tariff Charges

TSO is responsible for determining tariffs within their income cap according to the tariff structure regulation. The tariff level is to be set in a way that stimulates efficient utilisation and development of the network, and in a way that is non-discriminatory. Tariffs can be differentiated based on network related criteria that are objective and verifiable.

All tariffs are based on costs referring to the consumer's connection point. An agreement with the network company for the connection point provides access to the entire network system and the power market. Since 2010, all consumers are to be metered and settled individually.

According to the regulation on tariff structure, tariffs consist of a use dependent energy component set on the basis of marginal network losses and a fixed annual amount per customer. The fixed component is to cover customer-specific and network costs that are not covered by the use dependent tariff components.

5.10.2.2 Transmission network tariffs:

The Norwegian TSO levies a locational charge for marginal losses to all users of the system. The marginal loss factors are recalculated weekly in order to reflect changing system conditions. At connection points with both outtake and input, loss rates are to be symmetrical around zero. In areas with input surplus, input has a positive loss rate and outtake a negative loss rate, and vice versa. The marginal loss rates are capped by 15%.

Outtake in the transmission network is charged with an energy component based on marginal network losses and a fixed component that depends on the proximity to power production plants and amount of load that can be disconnected within a given response time.

5.10.2.3 Generators:

G-charge consists of an energy component that varies with the generator's current input of energy and a fixed component. Tariffs are set independently of end-user.

The energy component depends on the generator's current input of energy. Energy components are calculated individually for each separate input point and determined based on marginal network losses in the whole network system.

The fixed component for generators connected to the transmission level, set by Statnett, is to be normative for the fixed component for generators connected to the regional and distribution networks. The settled production volume is based on the power plant's median annual input the last 10 years. For power plants with installed capacity below 1 MW, settled volume must be maximum 30% of installed load capacity multiplied by 5,000 hours.

5.10.2.4 Prosumers:

Since March 2010, NVE has given a general exemption to simplify the processes related to end-use customers that generate electricity for their own consumption, and in some hours have a surplus, referred to as 'prosumers'. The exemption simplifies the process of selling surplus electricity. It implies that the local network company can purchase the surplus electricity and that the prosumer pays a simplified input tariff. It is not mandatory for the network company to offer the suggested arrangement to prosumers. The exemption does not apply to generation that requires a license or generators that supply electricity to other end-users.

In 2014, NVE initiated work on incorporating provisions regarding prosumers in the current regulation. Suggestions for regulation of prosumers have been on public consultation in 2014, with an additional consultation in 2015. The new regulation will enter into force in 2017.

5.10.2.5 First Connection Charges

TSO may require a connection charge to cover the costs of connecting new customers to the network or costs of reinforcing the network for existing customers. Connection charges are 'shallow' because it is generally not allowed to set connection charges for investments in the meshed network.

The objective of the connection charge is to make the customer responsible for the costs related to a new connection or an upgrade

of the customer's existing network connection. Costs not covered by the responsible customer, but by the network Company, will increase the network company's allowed income and, hence, be dispersed to all customers through increased tariffs.

5.10.3 UK

5.10.3.1 Legal Basis

Legal basis of the Transmission Tariff is as follows;

- European Commission Regulation (EU) 838/2010
- The Electricity Act 1989 (as amended by the Utilities Act 2000 and the Energy Act 2004),
- Transmission Licence,
- Grid Code,
- Balancing and Settlement Code and
- Connection and Use of System Code (CUSC).

5.10.3.2 Transmission Tariff Charges

Electricity Transmission charges contain a locational element. This recognizes that customers in different locations use different amounts of the transmission network, and therefore impose different costs on it. Highest generation and lowest demand charges occur in the north (surplus area). Lowest generation and highest demand charges occur in the south (shortage area). For example, customers located in areas where there is more demand than there is generation, such as in South East England, pay higher transmission charges for the energy they consume than those in areas where there is excess generation capacity, such as Scotland. This is because the electricity has to be transported over longer distances, using more of the transmission system, to reach them. Similarly, generators who only have to transport the electricity they generate over a short distance to reach customers will pay lower charges than those generators who are located a long way from them. This cost reflective approach is designed to promote efficient use of the network by larger users, for example, by providing a signal to generators that are located close to their customers requires less transmission network to be built.

There are four different types of charges, as follows:

1. **First Connection Charges:** Connection Charges recover the cost of installing and maintaining connection assets. These charges apply to generators. The connection charge is calculated annually and consists of a capital component and a non-capital component.
2. **Transmission Network Use of System (TNUoS) charges:** TNUoS recovers the cost of installing and maintaining the transmission system. These charges apply to suppliers and generators. Tariffs are forecasted annually. Generators are charged according to their TEC. Suppliers are charged based on their demand forecast.
3. **Balancing Services Use of System (BSUoS) charges:** BSUoS recovers the cost of day-to-day operation of the transmission system. These charges apply to suppliers and generators. These charges are calculated daily as a flat tariff for all users. BSUoS charges depend on the balancing actions that are taken each day.
4. **Assistance for Areas with High Electricity Distribution Costs (AAHEDC):** AAHEDC charges recovers assistance costs for The North of Scotland which is currently the only area specified to receive assistance. These charges apply to suppliers. The Tariff is calculated annually, and this scheme recovers the assistance amount through a charge on all suppliers. This is passed on to Scottish Hydro Electric Power Distribution Ltd, so distribution charges in the North of Scotland can be reduced.

5.10.3.3 First Connection Charges

First connection charges enable National Grid to recover, with a reasonable rate of return the costs of installing and maintaining assets which connect individual users to the UK Transmission Network. Connection assets are non-sharable assets installed for and only capable of use by an individual user and hence represent a "shallow" charging regime (known as PLUGs). All sharable assets are classed as Infrastructure assets and the costs associated with them are recovered through TNUoS charges.

Connection/Infrastructure (Use of System) Boundary

There are standard rules to distinguish Connection assets from Infrastructure assets for double busbar, teed or mesh connections, cables, overhead lines etc. However, customer choice can influence the application of these rules. Such variations are more common in Scotland e.g.

- National Grid does not normally own busbars below 275kV in E&W whereas a lot of Transmission network in Scotland at voltage below 275kV is classified as Infrastructure.
- Usually Generators do not have connection assets in E&W (as they own the assets right up to NG transmission busbars) but this is different in Scotland due to application of non-standard boundary rules by Scottish Transmission Owners.

The Statement of First Connection Charging Methodology

National Grid was obligated under the Transmission License to produce a statement of Connection Charging methodology approved by Ofgem. The License conditions further required that the charges in the statement fulfil the three standard obligations of facilitating competition in electricity market, cost reflectivity and taking account of developments in the UK transmission network. Furthermore, National Grid is required to facilitate competition in the construction of Connection assets. This obligation is commonly referred as Contestability i.e. allowing third party to build connection assets if the user requests it. The Statement of Connection Charging Methodology allows all CUSC parties to propose modifications to the methodology. Earlier, it was National Grid's responsibility to keep the methodology under review.

Basic Connection Charge

The connection charge is calculated annually and consists of a capital component and a non-capital component. The components are mainly calculated using the Gross Asset Value (GAV) and the Net Asset Value (NAV) of the connection assets. The GAV represents the total initial cost of constructing the connection assets, whilst the NAV represents mid-year depreciated GAV of the asset. As the connection charge is recalculated annually, each year the GAV has to be rebased to account for inflation and the NAV has to be reduced to account for the value paid off in the previous year.

- **Capital Component:** The capital component recovers the cost of installing and commissioning connection assets. This is charged over the depreciation period of the connection assets, and also includes the Transmission Owner's agreed rate of return. Users can optionally make a capital contribution to pay off some or all of the GAV, reducing the capital component of the connection charge
- **Non-Capital Component:** The non-capital component recovers the cost of maintaining the connection asset. It is made up of two parts, the Site-Specific Maintenance (SSM) charge and the Transmission Running Cost (TRC) charge.

$$\text{Non-Capital Component} = (\text{SSM Factor} * \text{GAV}) + (\text{TRC Factor} * \text{GAV})$$

- **SSM factor** is calculated each year based on the forecast of total site-specific maintenance for UK divided by the total GAV of the Transmission Licensees UK connection assets, to arrive at a percentage of total GAV. The 2012/13 figure is 0.51%. The transmission running cost (TRC) factor is the only part of the connection charge that is not calculated annually, but rather at the previous Price Control Review. It is a proportion of the forecast of TRCs for the transmission licensees that corresponds with the proportion of the transmission licensees' total connection assets as a function of their total business GAV.

5.10.3.4 Other Charges

In addition to the basic first connection charge, users may pay for certain other costs related to their connection, which are set out in their bilateral connection agreements.

Transmission Network Use of System Charging

National Grid ESO sets Transmission Network Use of System (TNUoS) tariffs for generators and suppliers. These tariffs serve two purposes: to reflect the transmission cost of connecting at different locations and to recover the total allowed revenues of the onshore and offshore transmission owners.

To reflect the cost of connecting in different parts of the network, NGESO determines a locational component of TNUoS tariffs using two models of power flows on the transmission system: peak demand and year-round. Where a change in demand or generation increases power flows, tariffs increase to reflect the need to invest. Similarly, if a change reduces flows on the network, tariffs are reduced. To calculate flows on the network, information about the generation and demand connected to the network is required in conjunction with the electrical characteristics of the circuits that link these.

The charging model includes information about the cost of investing in transmission circuits based on different types of generic construction, e.g. voltage and cable / overhead line, and the costs incurred in different TO regions. Onshore, these costs are based on 'standard' conditions, which means that they reflect the cost of replacing assets at current rather than historical cost, so they do not necessarily reflect the actual cost of investment to connect a specific generator or demand site.

The locational component of TNUoS tariffs does not recover the full revenue that onshore and offshore transmission owners have been allowed in their price controls. Therefore, to ensure the correct revenue recovery, separate non-locational "residual" tariff elements are included in the generation and demand tariffs. The residual is also used to ensure the correct proportion of revenue is collected from generation and demand. The locational and residual tariff elements are combined into a zonal tariff, referred to as the wider zonal generation tariff or demand tariff, as appropriate.

For generation customers, local tariffs are also calculated. These reflect the cost associated with the transmission substation they connect to and, where a generator is not connected to the main interconnected transmission system (MITS), the cost of local circuits that the generator uses to export onto the MITS. This allows the charges to reflect the cost and design of local connections and vary from project to project. For offshore generators, these local charges reflect revenue allowances.

Generation charging zones

The generation charging base National Grid is forecasting less than contracted TEC. It excludes interconnectors, which are not chargeable, and generation that National Grid does not expect to be contracted during the charging year due to closure, termination or delay. It also includes any generators that National Grid believes may increase their TEC.

National Grid is unable to break down its best view of generation as some of the information used to derive it could be commercially sensitive. Average annual generation tariffs remain below the €2.50/MWh set by European Commission Regulation (EU) 838/2010.

Generation charging zones Wider tariffs are the part of Transmission Network Use of System (TNUoS) that relate to the geographic location that the generator is connected. There are 27 generation zones in UK with their own specific wider tariffs. Generation zones are reviewed at every price control period. The next price control period begins on 1 April 2021.

Ireland: The GTUoS capacity charge is calculated individually for each generator based on the location of its connection to the system. This GTUoS charge is capacity based (i.e. based on MEC of generator), there is no energy (MWh) component for GTUoS. The GTUoS tariff has a locational element; which is calculated considering the usage of current generation on future network using a "reverse MW mile" methodology.

Northern Ireland: The GTUoS capacity charge is calculated individually for each generator based on the location of its connection to the system. This GTUoS charge is capacity based (i.e. based on MEC of generator), there is no energy (MWh) component for GTUoS. The GTUoS tariff has a locational element; which is calculated considering the usage of current generation on future network using a "reverse MW mile" methodology. Figure 5.29 shows both the generation and demand tariff zones in the UK.

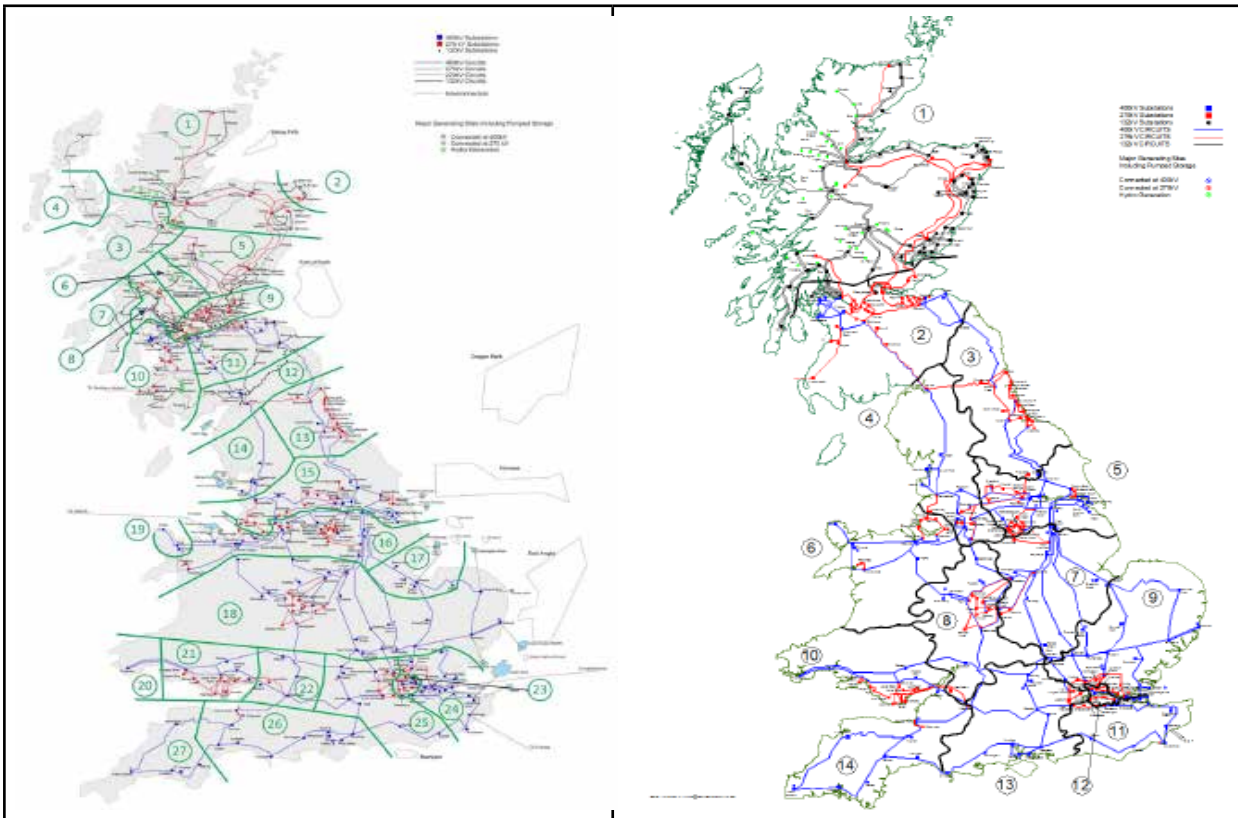


Figure 5.29 – Generation (left) and Demand (right) Tariff Zones in the UK³¹⁴

Demand Charging Zones

To forecast chargeable half hour (HH) and non-half hour (NHH) demand and Embedded Export Tariff (EET) volumes National Grid uses a Monte Carlo modelling approach. This incorporates our latest data including³¹⁵:

- Historical gross metered demand and embedded export volumes (August 2014-March 2018)
- Weather patterns
- Future demand shifts
- Expected levels of renewable generation.

Following National Grid review of the metered demand and export data, National Grid has seen a relatively high level of embedded export volumes over triads in 2017/18 compared to previous years. National Grid also recognizes there will be an expected demand shift between NHH to HH under Balancing and Settlement Code (BSC) modification. These changes in our outturn charging base have been factored into National Grid projections for 2019/20 and future years.

Every electricity supplier that has:

- domestic customers or
- customers who are likely to take half-hourly metered demand over the Triads

must pay Transmission Network Use of System (TNUoS) charges under the current Charging Methodology.

314 Source: www.nationalgrideso.com

315 TNUoS Tariff for 2019-20.

One of the conditions in the electricity supply license states that supplier must 'be a party to and comply with the Connection and Use of System Code' (the CUSC). This is the contractual framework that regulates use of the National Electricity Transmission System.

Supplier has to sign and obey the CUSC accession agreement and other documents that form the contractual arrangements.

TNUoS charges are based on the supplier forecast of half-hourly (HH) 'Triad' demand and non-half-hourly (NHH) consumption.

The TNUoS charging team at National Grid ESO will provide an excel form for supplier to enter your HH and/or NHH forecast. The form will list for the consumer registered with Elexon. This forecast will form the basis of the customer's initial TNUoS invoice,

Overall, National Grid assumes that recent historical trends in steadily declining volumes will continue due to several factors including the growth in distributed generation and "behind the meter" microgeneration.

5.10.3.5 Generation charging principles

Generators pay TNUoS (Transmission Network Use of System) tariffs to allow NGESO to recover the capital costs of building and maintaining the transmission network on behalf of the transmission asset owners (TOs).

The TNUoS tariff specific to each generator depends on many factors, including the location, type of connection, connection voltage, plant type and volume of TEC (Transmission Entry Capacity) held by the generator. The TEC figure is equal to the maximum volume of MW the generator is allowed to output onto the transmission network.

Under the current methodology there are 27 generation zones, and each zone has four tariffs. Liability for each tariff component is shown below:

TNUoS tariffs are made up of two general components, the Wider tariff, and local tariffs.

The Wider tariff is set to recover the costs incurred by the generator for the use of the whole system, whereas the local tariffs are for the use of assets in the immediate vicinity of the connection site.

Embedded network system charges are only payable by generators that are not directly connected to the transmission network and are not applicable to all generators.

The Wider Tariff

The Wider tariff is made up of four components, two of which may be multiplied by the generator's specific Annual Load Factor (ALF), depending on the generator type. These components are Peak Element, Year-Round Shared element, Year-Round not Shared element and Residual element.

The Peak element reflects the cost of using the system at peak times. This is only paid by conventional and peaking generators; intermittent generators do not pay this element.

The Year Round Shared and Year-Round Not Shared elements represent the proportion of transmission network costs shared with other zones, and those specific to each particular zone respectively.

ALFs are calculated annually using data available from the most recent charging year. Any generator with fewer than three years of historical generation data will have any gaps derived from the generic ALF calculated for that generator type.

The Residual element is a flat rate for all generation zones which adds a non-locational charge (which may be positive or negative)

to the Wider TNUoS tariff, to ensure that the correct amount of aggregate revenue is collected from generators as a whole.

Local Tariff

Local substation tariffs: A generator will have a charge depending on the first onshore substation on the transmission system to which it connects. The cost is based on the voltage of the substation, whether there is a single or double ('redundancy') busbar, and the volume of generation TEC connected at that substation.

Local onshore substation tariffs are set at the start of each TO financial regulatory period and are increased by RPI each year.

Local circuit tariffs: If the first onshore substation which the generator connects to is categorized as a MITS (Main Interconnected Transmission System) in accordance with CUSC 14.15.33, then there is no Local Circuit charge. Where the first onshore substation is not classified as MITS, there will be a specific circuit charge for generators connected at that location.

Embedded network system charges

If a generator is not connected directly to the transmission network, they need to have a BEGA if they want to export power onto the transmission system from the distribution network. Generators will incur local DUoS charges to be paid directly to the DNO (Distribution Network Owner) in that region, which do not form part of TNUoS.

Embedded connected offshore generators will need to pay an estimated DUoS charge to NGET through TNUoS tariffs to cover DNO charges, called ETUoS (Embedded Transportation Use of System).

Offshore local tariffs

Where an offshore generator's connection assets have been transferred to the ownership of an OFTO (Offshore Transmission Owner), there will be additional Offshore substation and Offshore circuit tariffs specific to that OFTO.

5.10.3.6 Billing

Suppliers are billed against these forecast volumes, and two reconciliations of the amounts paid against their actual metered output take place, the second of which is once the final metering data is available from Elexon up to 16 months after the financial year in question.

National Grid Electricity Transmission (NGET) also recovers revenue for its role in balancing the electricity system (making sure that supply of electricity equals demand) through Balancing Services Use of System charges. These charges are paid by all suppliers and transmission-connected generators and do not vary by region.

TNUoS is charged annually and costs are calculated on the highest level of TEC held by the generator during the year. (A TNUoS charging year runs from 1 April to 31 March). This means that if a generator holds 100MW in TEC from 1 April to 31 January, then 350MW from 1 February to 31 March, the generator will be charged for 350MW of TEC for that charging year.

Generators with negative TNUoS tariffs

Where a generator's specific tariff is negative, the generator will be paid during the year based on their highest TEC for that year. After the end of the year, there is a reconciliation, when the true amount to be paid to the generator is recalculated.

The value used for this reconciliation is the average output of the individual generator over the three settlement periods of highest output between 1 November and the end of February of the relevant charging year. Each settlement period must be separated by at least ten clear days. Each peak is capped at the amount of TEC held by the generator, so this number cannot be exceeded.

Small Generator Discount

The Small Generator Discount is defined in National Grid's Electricity Transmission license condition. This licence condition was due to expire on 31 March 2019, but the deadline has now been extended to 31 March 2027 following an Ofgem statutory consultation on the proposal.

A discount will continue to be applied to TNUoS tariffs for transmission connected generation <100MW, connected at 132kV until 31 March 2021.

Demand charging principles

Demand is charged in different ways depending on how the consumption is settled. HH demand customers now have two specific tariffs following the implementation of regulation namely CMP264/265, which are for gross HH demand and embedded export volumes; NHH customers have another specific tariff.

HH gross demand tariffs

HH gross demand tariffs are charged to customers on their metered output during the triads. Triads are the three half hour settlement periods of highest net system demand between November and February inclusive each year. They can occur on any day at any time, but each peak must be separated by at least ten full days. The final triads are usually confirmed at the end of March once final Elexon data is available, via the NGESO website. The tariff is charged on a £/kW basis.

Embedded export tariffs

The EET was introduced under regulation (CMP264/265) and is paid to customers based on the HH metered export volume during the triads (the same triad periods as explained in detail above). This tariff is payable to exporting HH demand customers and embedded generators (<100MW CVA registered).

This tariff contains the locational demand elements, a phased residual over 3 years (reaching £0/kW in 2020/21) and an Avoided GSP Infrastructure Credit. The final zonal EET is floored at £0/kW for the avoidance of negative tariffs and is applied to the metered triad volumes of embedded exports for each demand zone. The money to be paid out through the EET will be recovered through demand tariffs.

Customers must now submit forecasts for both HH gross demand and embedded export volumes. Customers are billed against these forecast volumes, and a reconciliation of the amounts paid against their actual metered output is performed once the final metering data is available from Elexon (up to 16 months after the financial year in question).

Embedded generators (<100MW CVA registered) will receive payment following the final reconciliation process for the amount of embedded export during triads. SVA registered generators are not paid directly by National Grid. Payments for embedded exports from SVA registered embedded generators will be paid to their registered supplier.³¹⁶

NHH demand tariffs

NHH metered customers are charged based on their demand usage between 16:00 – 19:00 every day of the year. Suppliers must submit forecasts throughout the year of their expected demand volumes in each demand zone. The tariff is charged on a p/kWh basis.

5.10.4 Sweden

³¹⁶ HH demand and embedded export is charged at the GSP, where the transmission network connects to the distribution network, or directly to the customer in question.



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Sweden has divided the electrical grid into three categories: the national grid (transmission grid), regional grids and local grids (distribution grids). The transmission grid can be compared to a motorway system where large amounts of electric energy can be transferred over long distances with very small losses. The regional grid can be compared to trunk roads where electric energy is distributed to cities and large towns. Sweden's national grid is managed by the government agency and authority Svenska Kraftnät (SvK), which also has overall responsibility for the entire Swedish electricity system. Because there is no competition between grid companies, the Swedish Energy Markets Inspectorate (EI) oversees the situation to make sure grid companies do not overcharge. The Inspectorate sets a ceiling for how much grid companies can charge all customers in their area over a four-year period – a so-called revenue framework. This revenue rule establishes the total revenue, i.e. not how much individual customers are charged. That is determined by a tariff structure. The revenue framework is set in advance for a four-year period and the current period is 2016–2019.

The part of the electrical grid called the national grid maintains a voltage of between 220 kV and 400 kV. The national grid is managed by the public enterprise and authority SvK, which is responsible for the entire Swedish electricity system. This means that SvK is responsible for maintaining the balance between production and consumption of electricity throughout the country. Responsibility for planning is delegated to a number of companies who have undertaken to plan to ensure a balance is maintained within their respective areas. Ensuring that sufficient electricity is produced to match the amount consumed in the country is the responsibility of the electricity suppliers. Under the current Electricity Act, an electricity supplier is responsible for supplying as much electricity as its customers consume hour by hour (SvK, balansansvar, 2015). The electricity suppliers may take on this responsibility themselves or transfer it to another company.

Sweden Government has appointed a national system operator. Since January 1st of 1995, SvK has this responsibility which largely comprises:

- short-term planning and operation of the national transmission network with regard to voltage quality, continuity of service etc.
- short-term planning and co-ordination of the national balance between generation and consumption, taking into account electricity imports and exports.

This responsibility gives SvK, which has no generating resources, the authority, in emergency situations, to order generating companies to rapidly increase or decrease production to help balance the system. SvK can also stipulate the technical requirements for generating plant, transformer stations, or other networks to be connected to the national transmission network. Under normal conditions however, SvK tries to minimize the need for such stipulation. As far as possible the system is managed in a business-like way by voluntary agreements with generating companies, regional and local network owners, and other parties on the electricity market. An example of this is the balance agreement, which regulates how the short-term balance in the system can be managed using the balance service. SvK, owning no generating resources, has to somehow gain access to such resources in order to meet its responsibility as the national system operator. This is achieved by means of a standard voluntary agreement (the Balance Agreement) between SvK and a number of players, including the large generators. The companies who sign such an agreement are referred to as balance-responsible companies. This means that, as regards balance, the Swedish electricity market has three levels of responsibility, as follows;

- Firstly, SvK has the national balance responsibility by law. This entails keeping the electricity balance between generation and load on a momentary, or minute-by-minute, basis. In order to manage this SvK has built up a mechanism - the balance service. On the basis of the system frequency the system controller performs a "marginal dispatch" of regulating resources made available by balance-responsible players. The balance service co-ordinates with the equivalent mechanism in Norway (the regulating market) and the system operators in Finland and Denmark. By keeping the area control errors within limits, they can ensure that each country is performing its share of the necessary joint regulation.
- The next level of responsibility is that of the balance-responsible players who have a responsibility in accordance with the balance agreement, to keep their company balances on an hourly basis. The companies' physical input (generation) and any power purchased by agreement from other players, from the spot market, or from SvK (regulating power), is compared to the physical output (load) and any power sold by agreement to other players, to the spot market or to SvK (regulating power). The difference is settled with SvK as "balance power".
- The third level of responsibility concerns the vast majority of players on the electricity market, who have no relationship with SvK in this context. They allow another player, for example their supplier, who is balance responsible, to handle their balance for them. This is usually handled in the form of take-and-pay agreements. The balance service has two

main functions, to allow SvK to manage the country's electricity balance, and to distribute the costs for this among all the players on the electricity market who have signed a balance agreement. In addition, it makes it possible to deal with network constraints.

5.10.4.1 Legal Basis

Legal basis of the Transmission Tariff is as follows;

- The Electricity Act (Ellagen)
- The Swedish Energy Markets Inspectorate's regulations, EIFS 2013:01
- Grid Regulation

Legal entities involved in electricity generation or trading are not allowed to operate networks. Network operation must always be carried on as a separate business and an annual report shall be submitted to the Network Authority and shall also be made publicly available. Special permission (a network concession) from the Government or from the Network Authority is still required to erect or operate high-voltage power lines. According to the law, holders of network concessions are obliged to connect customer's lines and installations on reasonable terms. Terms for the transmission of electricity, irrespective of its supplier or purchaser, shall also be reasonable. If there are special reasons, such as limited capacity, the Network Authority can grant exemption from the obligation to connect or transmit. Network tariffs shall consequently be unbiased and non-discriminatory. They should be based on objective calculations and provide a reasonable rate of return. The Network Authority will examine network tariffs in this respect, not only as a result of complaints received from customers, but also on a spot-check basis. If a network company is found to have unreasonable tariffs, the Authority will serve it with an injunction to adjust its prices. A network company wishing to appeal against such a decision must go to a court of law.

Both the government and SvK had known since the early 2000s that the pace of investment needed to increase, but it was not until 2007 that investment decisions started to be made. One explanation why investment had been so slow is that SvK in the late 1990s and the beginning of the 2000s interpreted its role as "to manage the existing national grid to avoid driving up costs and thus increasing network tariffs" (Swedish National Audit Office 2013a; Swedish National Audit Office 2013b: 3). The Swedish NAO also found that public control of investment decisions had been lacking, but that this has improved. However, this improvement had been initiated by SvK and not by the government.

5.10.4.2 Transmission Tariff Charges

On January 1st of 1995, SvK introduced a new tariff system for the national transmission network. The aims when deciding upon a new tariff were that it should:

- promote competition on the electricity market, e.g. by being flexible enough to allow for new types of customer and contracts,
- be simple, open and predictable, so that users can estimate their transmission costs,
- cover SvK's costs for managing the transmission network, and
- provide economic and technical signals to the users as regards losses, constraints etc.

The final choice fell on the point-of-connection tariff which was considered most suitable in an open-network situation. Subsequently the new legislation also prescribed the point-of-connection principle for the entire network system.

The basic principle is that payment in one point, the point of connection, gives access to the whole network system, and thus the whole electricity marketplace. This means that consumers or producers connected to a local network pay network fees only to the owner of that network. They can then trade electricity with any other player within the entire national network system. In fact, since January 1st, 1996, thanks to the creation of the joint Norwegian-Swedish electricity market they can trade freely within the combined networks of both countries. Similarly, the local-network owner will pay network fees to the appropriate regional-network owner. This cost, along with the other costs for running the local network, is taken into consideration while setting the



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local-network tariff. Finally, the regional-network owner pays network fees to SvK for use of the national transmission network and take this cost into consideration when setting the regional-network tariff. Transmission customers are thus largely regional-network owners and generating companies with power stations directly connected to the national network. The point-of-connection tariff for the national transmission network comprises:

- an annual power fee, which is intended to provide about half of the revenue,
- an energy fee, to cover the transmission losses, also about half of the revenue, and
- a once-for-all connection (first connection) fee, which is only applied when connection of a new customer involves considerable costs.

The power fee is latitude dependent. This is because the prevailing power flow in the network is from north to south. Generators pay more in the north, where there is a surplus of generation, and less in the south where the load centers and export markets are located. Consumers of power will conversely pay more in the south and less in the north. The energy fee is calculated as the product of the appropriate marginal-loss coefficient for the connection point, the energy input or output at this point, and the current power price. Marginal-loss coefficients for high and low load, weekday and other times, have been calculated for each connection point in the network. These coefficients can be positive or negative. The power price indicated is currently the price paid by SvK for purchasing loss-replacement power. In future it may be decided to use the current spot price for electricity. The first connection fee will only be applied when new connections demand considerable investment. This will always be the case, for example, for new international links. The tariff contains no charges or other signals regarding possible transmission constraints. These will be dealt with when they arise using the balance service.

First Connection Charges

The first connection charges type in Sweden is characterized as “Deep” type; Generators or demand consumers connecting to the grid pay all costs related to this (lines, sub stations, etc.) system connection.

Balancing System Charges

The balance service makes it possible for SvK to continuously balance the country’s electricity generation and consumption. This is done by taking in regulating bids (volume and price) from generators willing to quickly (max 10 minutes) increase or decrease generation, or even consumers willing to increase or decrease consumption. The bids for regulation are arranged in price order to form a “staircase” for each operating hour. When manual regulation is needed the system, operator activates the most favorable bid for regulating up or down. This method for secondary regulation is combined with primary regulation based on automatic frequency control on generators in suitable power stations. SvK purchases primary regulation on long-term contracts from generating companies with suitable resources. A similar procedure applies for certain operating reserves to cope with disturbances. At the end of each hour the regulating price is fixed as the price for the most expensive measure (regulating up -balance service buys) or least expensive measure (regulating down - balance service sells) utilized during the hour. This price applies for all players having been called upon to regulate up (and/or down).

SvK distributes the costs for regulation among all the players on the electricity market who have signed a balance agreement. When the meters have been read and balances compiled, deviations from hourly balance for each balance-responsible company are calculated in SvK’s settlement system. Aggregates are debited or credited fortnightly. After settlement, all the companies will be charged or credited for their unplanned balance deviations according to the settlement curve.

Congestion Management Costs

The balance service also has a supplementary function as it provides the network coordinator with a tool with which he can manage network constraints. He has access to information regarding which regulating resources are available in various geographic locations and can for example order increased production in the area with a deficit of generation and decreased production simultaneously in the area with a surplus. This process (counter purchasing) will incur costs for SvK and can provide economic signals for network reinforcement.

An electrical high-voltage power line cannot be built or used without a permit, a so-called network concession. When holding

a network concession for an area, the grid company has the sole right to operate an electrical grid in that geographical area at the voltage levels the grid concession covers and, under the Electricity Act, is responsible for connecting parties wishing to feed electricity into or draw electricity from the grid. Regional grid companies and SvK have network concessions for lines that allow them to build a power line for a certain predetermined distance. Network concessions apply for an indefinite term unless otherwise stipulated. The Swedish Energy Markets Inspectorate makes a determination on the fairness of connection fees.

5.10.5 Portugal³¹⁷

REN operates the National Transmission Grid (RNT), which connects generators to consumption centres and ensures a balance between energy supply and demand. It is the only Electricity Transmission entity in Portugal under a concession agreement with the Portuguese state.

The transmission of extra high voltage electricity (150, 220 and 400 kV) is done in the RNT, under a concession granted by the Portuguese state in the form of a public service provided exclusively by REN. The concession includes the planning, construction, operation and maintenance of the RNT and also covers planning and overall technical management of the National Electricity System to ensure the harmonised functioning of its infrastructures, service continuity and a secure electricity supply.

The REN Group has three regulated activities in the electricity sector in Portugal:

- Global use of the System³¹⁸;
- Transmission of Electrical Power; and
- Purchase and Sale of Electrical Power from the Commercial Agent, which consists of trading in the MIBEL
- generation from two remaining power purchase agreements (CAE in Portuguese) through REN Trading.

The allowed revenues of the first two activities are recovered by the application of two regulated tariffs:

- the tariff of Overall Use of the System (UoS) and
- the tariff of Use of the Transmission Grid (URT in Portuguese).

The revenues of the third activity essentially come from the sale on the market of the generation from non-terminated CAEs. The UoS tariff reflects the positive or negative difference between the cost under CAEs added to the incentives to optimise the management of CAEs and to efficiently manage CO₂ emissions licences and the revenue from the sale on the market of energy and system services supplied by power stations.

Both tariffs are annually fixed by ERSE based on energy and economic forecasts for demand, costs, revenues and capital expenditures.

Although some costs are still considered pass through costs, such as environmental costs and other costs arising from amendments to legislation, most OPEX are subject to a revenue cap regulation.

The Total variation is mainly explained by surplus costs for the remaining Power Purchase Agreements (PPAs) ((+2.97€/MWh), Islands' tariff convergence costs (+1.95€/MWh), and Incentives related with consumption efficiency (-0.32€/MWh) on non-TSO costs. Costs for losses and system-services costs are not recovered by a regulated tariff but are recovered in the energy price.

Costs for losses and system-services costs are not recovered by a regulated tariff but are recovered in the energy price.

5.10.5.1 Connections to Networks

³¹⁷ Source: Annual Report on the Electricity and Natural Gas Markets In 2017.

³¹⁸ Tariff charged through the transmission/transportation operator, mostly composed by pass-through costs, such as energy acquisition costs related ANNUAL REPORT with the management of the two remaining PPAs (Electricity), hydro land (Electricity), positive or negative adjustments related with costs supported by the supplier of last resort (Gas) and ERSE costs.



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The regulatory framework for the commercial conditions governing connections to the electricity network is set out in the electricity Commercial Relations Code, approved by ERSE, having been modified during 2017, based on a public consultation process, to enter into force on 1 January 2018. If on the one hand the rules already in place for small facilities³¹⁹ were generally maintained, on the other important amendments were adopted for generation and for large facilities³²⁰, namely related to connection charges. Indeed, part of the network charges these requesters had to bear were set by mutual agreement between network operators and requesters. The mutual agreement approach had the main virtue of accommodating each connection's particularities raising, however, questions on transparency and equity levels concerning the treatment of requests. Additional points worth mentioning when it comes to establishing clear, balanced and sustainable cost sharing rules are the maturity level of the electrical sector, cost recovery by means of tariffs, distributed generation, network planning process and developments in the legislative framework. Therefore, the regulator tried to set a harmonised regulatory framework for generation and consumption facilities, irrespective of the voltage level. Today some regulatory procedures are still missing but the regulator's expectation is that this regulation can enter into force in 2019.

Another important amendment relates to network connection execution deadlines for the operators³²¹ that, if not observed, oblige the operators to pay requesters a financial compensation for the delay, as established under the Quality of Service Code.

Furthermore, the regulatory framework remained unchanged, namely concerning mandatory third-party access, type of charges that can be levied on requesters, rules for calculating network connection charges, construction and property of the network connection elements or provision of information.

5.10.5.2 Network Tariffs for Connection and Access

According to its Statutes, ERSE is responsible for preparing and approving the Tariffs Code, where the methodology used for calculating tariffs is established, along with the methods to regulate the allowed revenues. The approval of the Tariffs Code is preceded by a public consultation and by an opinion from the Tariffs Council. ERSE's tariff fixing process, including its time frame, is also defined in the Code. Transmission and distribution tariffs are among the tariffs approved by ERSE. The tariffs set for 2017 incorporate the rules approved following the 2014 regulatory review.³²² In May 2017, ERSE started the public consultation process to reform the Electricity Codes (Tariffs and other Codes), the results of which will take effect in 2018.

5.10.5.3 Procedures and Methodology for Calculating Electricity Network Access Tariffs

Network access tariffs are charged to all electricity consumers for the use of the public service electricity network infrastructures. In general³²³, these tariffs are paid by suppliers on behalf of their customers. The revenue generated from regulated activities is recovered through specific tariffs, each with its own tariff structure and a given set of billing variables. These tariffs are the following: Global Use of the System, Use of the Transmission Network in Extra High Voltage (EHV) and HV, and Use of the Distribution Networks in HV, MV and LV (low voltage). The billing variables are capacity, active energy, and reactive energy. Tariff prices for each activity are established so as to ensure that their structure follows the structure of the marginal costs of the activity and that the allowed revenues for the activity are recovered. The tariff design, including billing variables, is based on the principle of non-discrimination of the energy's end use, with all tariffs options available to all consumers. Access tariff prices for each billing variable are determined by adding up the corresponding tariff prices per activity. Given that the tariffs contributing to this sum are based on marginal costs, cross-subsidisation between consumers is avoided and an efficient use of resources is promoted.

In preparation for the regulatory period, 2018-2020, ERSE conducted a review of the electricity sector Codes. The public consultation was launched in May 2017 and the amendments were approved in December of that year. With respect to access tariffs, the

319 LV and MV up to 2 MVA.

320 EHV, HV and MV above 2 MVA.

321 For monitoring purposes, regulation requires network operators to send information to ERSE, on a half-yearly basis, including, among other, the number of connections established and the average execution times. In 2017, the average time required for the execution of works to connect facilities to the LV and MV networks was approximately 28 days, for a total of 9,004 connections. In 2016, the corresponding values were 23 days and 7,768 connections.

322 Source: Regulation No. 551/2014, of 15 December, available at: [http://www.erse.pt/pt/electricidade/regulamentos/tarifario/Documents/Regulamento 551-2014 \(RT SE - Dez2014\).pdf](http://www.erse.pt/pt/electricidade/regulamentos/tarifario/Documents/Regulamento 551-2014 (RT SE - Dez2014).pdf) (in Portuguese).

323 Network access tariffs can also be paid by customers who are simultaneously market agents, i.e., customers who buy energy directly from the markets and are responsible for managing any possible schedule deviations.

revised Tariffs Code establishes:

- a specific tariff for the activity of logistical operation for supplier switching;
- the introduction of seasonality in active energy prices for SpLV network access tariffs;
- further development of the provisions for pilot projects for dynamic tariffs and improvement of the tariff structure;
- the definition of specific access tariffs for operators of distribution networks exclusively in LV; and
- the change of the billing variable for supplies to public street lighting with smart metering.

Regarding the regulatory methodologies for calculating the allowed revenues of regulated companies for the 2018-2020 regulatory period, ERSE highlights the main changes:

- application of a revenue cap methodology to the operating costs of the GGS activity, with the separation of costs into controllable and non-controllable for the purpose of the application of efficiency targets;
- creation of the incentive for the economic rationalization of the costs of the investments of the transmission operator, in the place of the incentive for maintaining equipment in operation at the end of its useful life and
- application of a price cap methodology applied to TOTEX (total costs) in the Electricity Distribution activity in LV.

First Connection Charges

The connection of a facility to the electricity network causes costs that depend on the type of facility to be connected (voltage level, technical requirements), the network itself (aerial, underground, meshed, radial), the distance, route, etc. The electricity Commercial Relations Code sets the regulatory framework that applies to network connections, including charges, as described in section “Connection to Network”. One of the main issues of this framework is the cost setting that requesters have to meet, bearing in mind that the difference between total investment costs and costs met by requesters is paid by consumers through use of the network tariffs.

The first connection charges types are characterized as Super Shallow to partially Shallow in Portugal.

The grid user, either generator (G) or consumer unit (L), has to pay for the cost of the infrastructure needed to connect its installation to the transmission grid but the internal reinforcement/expansion of the grid is endorsed to TSO’s responsibility, in the case of G. The connection is made to the nearest substation where it is technically possible and where available capacity exists. For G, the available network capacities are defined in the NDP (National Development Plan) and in the annual document “Network Characterization”, according to Decree Law nº 215A and 215B/2012 from October 8th. For L, there is the obligation to connect, according to the Commercial Relationship Code and if internal grid development is needed, it is paid by L.

After built, the connection facilities (lines, cables, equipment at substations, etc.) will be integrated in TSO asset; thus TSO is in charge of their O&M costs.

Concerning the DSO reinforcement needs (there is just one in Portugal) all the costs are socialized via the tariff.

The charges are based on the actual costs and no locational differentiation is applied.

Revenue from Congestion on Interconnections

According to European legislation and regulation, congestion revenue may only be used to: 1) offset costs arising from coordinated balancing actions⁴² with a view to ensuring the interconnection capacity contracted in the daily and intraday market; 2) make investments to strengthen the interconnection capacity; or 3) reduce the use of transmission network tariff, if the revenue is not used for the two aforementioned purposes.

5.10.6 Germany

Germany is the first electricity transit country in Europe. Consequently, no other country in the EU has developed its interconnections as effectively as Germany. Interconnection lines to eight foreign transmission system operators in five countries (Netherlands (NL), Luxembourg (L), France (F), Switzerland (CH), Austria (A)) enable German transmission system operators to meet the specific transmission requirements of European power traders with utmost transmission reliability.

As different than the other European Countries, there are four German transmission system operators in Germany. These are 50Hertz, Amprion, TenneT and Trans-netBW. General information about transmission tariff applied by these transmission system operators is given in this section. For further details on transmission tariff, two biggest transmission system operators in Germany; Amprion and TenneT have been chosen as examples.

5.10.6.1 Harmonization of transmission Tariff

The four German transmission system operators; 50Hertz, Amprion, TenneT and Trans-netBW published press release to announce about charging national network fees for the first time on 27 September. As of 2019, network charges for the four German transmission system operators, are to include a nation-wide network fee component. Of this charge, 20 percent is calculated according to the cost base (revenue cap) for each transmission system operator, while the remaining 80 percent consists of the company-specific network fees charged by each transmission system operator.

The basis for this decision is the German network modernization law that took effect in July 2017 (NEMoG), as well as the regulation issued on 25 April 2018 stipulating the gradual introduction of transmission network fees based on a nation-wide standard. According to the NEMoG, the standardization of transmission network fees is to take place in stages from 2019 to 2022, so that from 2023 there will be completely uniform transmission grid fees nationwide. During this period, the share of the standardized component is to increase by 20 percent annually, while the company-specific share is to decrease accordingly.

For 2019 tariff period, transmission system operators have calculated network fees based on the company-specific revenue cap, which was approved by the Federal Network Agency, as well as the forecast of electricity drawn from their transmission system. The national network fees are to be calculated jointly by 50Hertz, Amprion, TenneT and Trans-netBW. The transmission system operators have been published their company-specific network fees as well as the national network fee for the first time for the 2019 tariff. Grid customers connected to each transmission system pay the sum of both fee components.

As of 2023, it is expected that network fees will be fully standardized. The network fees will continue to be calculated as variable and fixed prices in cents per kilowatt-hour and euros per kilowatt.

5.10.6.2 Transmission Charges

First Connection Charges

First Connection Charges borne by new grid users (producer or consumer) aiming to connect to the transmission grid, consisting of TSO's costs for the build of the transmission facility to enable the connection.

The first connection charges types are characterized as shallow/super-shallow in Germany. The first connection charging is generally based on actual costs. Grid users pay for their own connection line and substation. General reinforcements of the grid are socialized via tariffs. There is no differentiation of charges for Load, Generation and or Distribution System Operators (DSOs).

Grid Fees

The main characteristics of TSOs tariffs considered in the calculation of the Transmission Tariffs shown in this overview: share of G and L network charges in %, seasonal and locational differentiation, whether the costs of losses and system services are included in TSO tariffs and whether they are charged by TSOs. As shown in section 3, TSO tariffs applied as a charge to the users of transmission networks may allocate both TSO costs and non-TSO costs.

The grid fees 2017 compared with the grid fees 2016 are mainly increased due to the following facts:

1. Increased costs for the grid security, i.e. RES curtailment, provision of reserve capacity and increased demand of ancillary services including changes based on law amendments in this respect.

2. Increased costs for offshore and onshore investments.

RES Support (EEG Umlage)

The general RES-support mechanism (so called “EEG Umlage”) in Germany is not and has never been a part of the regulated transmission activities and thus has never been included in the transmission tariffs invoiced by German TSOs. Costs of RES-support are allocated by German TSOs through a separate charge which does not include any TSO-costs.

Regulation (StromNEV) for surcharge:

According to the Electricity Network Fee Ordinance (StromNEV), final consumers can apply for an individual network charge in accordance with StromNEV. Transmission system operators are obliged to reimburse lost revenues resulting from individual network charges to downstream operators of Electricity Distribution networks. The transmission system operators have to compensate these payments as well as their own lost revenue among themselves. The lost proceeds are allocated to all final consumers (LV) proportionally to the network charges (StromNEV surcharge).

The German transmission system operators publish on 25 October each year the forecast and the calculation of the surcharge according to StromNEV on the last consumption.

The ordinance on grid charges (StromNEV) of 25th July 2005 and recently amended by Articles 1 of the ordinance from 20th June 2018 (published in BGBl) allows final consumers to apply for individual grid charges in accordance to StromNEV. The transmission system operators are obliged to reimburse operators of Electricity Distribution networks for their lost revenues resulting from individual network charges. Furthermore, transmission system operators are obliged to compensate each other for the lost revenues. In accordance to StromNEV lost revenues are apportioned to all final consumers (LV) following KWKG (combined heat and power act).

The § 19 StromNEV levy for 2019 will be charged to end consumers as from 01st January 2019, as it is shown below table.

Table 5.20 – The StromNEV levy for 2019 to be charged to end consumers

Year	Consumption Category A' (ct/kWh)	Consumption Category B' (ct/kWh)	Consumption Category C' (ct/kWh)
2019	0,305 ct/kWh	0.050 ct/kWh	0.025 ct/kWh

The StromNEV-surcharge 2019 considers the results of the annual statement for the year 2017.

The following definitions of final consumer groups show the maximum pay rates according to the law. These contribution rates may not be exceeded. However, it is quite possible that a lower allocation for the respective year results in the context of forecasting. However, recoveries from the annual statement of previous years may Consumption categories according to StromNEV in conjunction with KWKG

Consumption Category A': End users pay for their annual consumption at one delivery point for the first 1,000,000 kWh/year the StromNEV-levy which is reported in the table above.

Consumption Category B': End users electricity consumption above 1,000,000 kWh/year of consumers that do not belong to consumer category C. Consumers of this category pay for consumption above 1,000,000 kWh/year the reduced StromNEV-levy which is reported in the table above.

Consumption Category C': End users electricity consumption above 1,000,000 kWh/year of end users belonging to the

manufacturing industry, rail-bound traffic or railway infrastructure with annual consumption leading to electricity expenses of more than 4% of the total turnover of the previous business year. Consumers of this category pay for consumption above 1,000,000 kWh/year the reduced StromNEV-levy which is reported in the table above.

5.10.6.3 Legal basis

Legal basis of the Transmission Tariff is as follows;

- The Energy Industry Act (EnWG) of 7 July 2005,
- The Energy Economy Act (EnWG) of 7 July 2005,
- The Network Fees Modernization Act (NEMoG) of 17.07.2017
- The Electricity Network Fee Regulation Ordinance (StromNEV) of 25 July 2005,
- The Electricity Network Access Ordinance (StromNZV) of 25 July 2005 and
- The Incentive Regulation Ordinance (ARegV) of 29 October 2007.

Supplemental to the EnWG, the valid legal regulations for the support of combined heat and power and of renewable energies are also implemented in each case.

5.10.6.4 TenneT TSO GmbH

As a network operator, TenneT TSO is responsible for the secure and reliable operation of the network as well as for the transmission of the electricity. Access to TenneT TSO network is based on objective, transparent and non-discriminatory criteria.

TenneT TSO operates a high-voltage network in the following states: Schleswig-Holstein, Lower Saxony, Hanseatic City of Bremen, North Rhine-Westphalia, Hesse and Bavaria.

The total fees for grid use of the electricity grid of TenneT TSO GmbH are made up of several components. The grid fees contain the following:

- Use of the grid infrastructure, for instance; lines, transformers, switching systems etc.
- Provision of the system services, for instance; maintaining the frequency, maintaining the voltage, supply recovery, and company management,
- Coverage of losses occurring during electricity transport.

Fees are understood to be inclusive of added costs for the Combined Heat and Power Act, reactive power use if applicable, license fee if applicable and VAT in the respective legal amount.

Transmission Tariff Charges

The following prices and regulations for the use of the power network of TenneT TSO GmbH are based on the current versions of the Energy Industry Act (EnWG) of 07 July 2005, the Electricity Network Fee Ordinance (StromNEV) of 25 July 2005, the Electricity Network Access Ordinance (StromNZV) of 25. July 2005 and the Incentive Regulation Ordinance (ARegV) of 29 October 2007.

In addition to the EnWG, the current legal provisions for the promotion of combined heat and power and renewable energies will

be implemented.

The following price sheets include charges for grid users (draw-off points):

- Fees for grid usage (yearly activity price system)
- Fees for grid usage (monthly activity price system)
- Fees for grid reserve capacity
- Use of reactive power
- Emergency supply
- Measurement and billing price

Transmission network usage charges

With the adoption of the Network Fees Modernization Act (NEMoG) of 17.07.2017 and the Ordinance on the gradual introduction of nationwide transmission network charges from 25.04.2018, transmission system operators (TSOs) with control area responsibility are required to gradually align the network charges for the maximum voltage grid level and the maximum voltage / high voltage interconnection level from 2019 onwards and to fully harmonize them from 2023 onwards.

The four German TSOs therefore have, for the transitional period pursuant to StromNEV, a partial payment in the transitional period and then in full as consideration nationwide

Calculate network fee share and publish. For the period from 01.01.2019 to 31.12.2022, the four TSOs additionally have to determine a company-specific network charge share in accordance with StromNEV and according to the respective calendar year Transitional period for billing total network fee from a company-specific and a nationwide network fee component composed.

The fees are also include;

- additional costs for the combined heat and power law,
- additional costs resulting from the implementation of the statutory requirements pursuant to StromNEV,
- offshore grid allocation pursuant to EnWG,
- other levies in accordance with statutory requirements, if necessary Reactive power utilization, if applicable, concession tax as well as electricity tax and value added tax in the statutory amount, as well as any other, possibly only in the future, statutory surcharges.

Fee for network usage (annual service price system)

The basis for determining the grid connection capacity used is the average ¼ h active power values determined on each delivery point agreed between the contractual partners in the grid connection contract. The maximum annual power of the network user is determined by adding the simultaneous extraction power values at all grid connection nodes.

The prices apply to the transmission network operated by TenneT TSO together with followings;

- additional costs pursuant to the Combined Heat and Power Act,
- additional costs resulting from the implementation of the statutory requirements in accordance with StromNEV,
- offshore grid allocation pursuant to EnWG,
- Further levies in accordance with legal requirements,
- possibly reactive power,
- possibly concession fee as well as electricity tax and value added tax in the respective statutory amount.

Prices include use of the network infrastructure, ancillary services and coverage of transmission losses.

Fee for network usage (monthly service price system)

For network users with a temporary high power consumption, which in the remaining time is significantly lower or no power consumption, is offered by TenneT TSO as an alternative to the annual service price system and billing on the basis of monthly power prices.

A network user with a corresponding load characteristic who decides to switch to the monthly service price system shall notify TenneT TSO of this at the latest one month before the start of a new billing period (calendar year). Monthly service price for sampling points with ¼-h power measurement

The prices include;

- additional costs pursuant to the Combined Heat and Power Act,
- additional costs resulting from the implementation of the statutory requirements in accordance with Section StromNEV,
- offshore grid allocation pursuant to EnWG,
- Further levies in accordance with legal requirements,
- possibly reactive power,
- possibly concession fee as well as electricity tax and value added tax in the respective statutory amount.

Prices also include use of the network infrastructure, ancillary services and coverage of transmission losses.

Reactive power use

When withdrawing active power from the TenneT TSO GmbH network, the network user at the network connection point has a power factor according to the grid connection rules or the connection contract to comply.

Standard range; 0.00 ct / kVARh

Extended range; 0.06 ct / kVARh

Inadmissible range; 0.87 ct / kVARh

Prices plus VAT in the respective statutory amount.

Emergency Supply

The network user ensures that his grid connection is assigned to at least one balancing group at the transmission system operator. If the grid connection is not part of an existing balancing group at the transmission system operator, for example, because there is no valid contractual relationship between the transmission system operator and the balancing group manager for handling energy deliveries or the connection is not assigned to a balancing group, the network user is supplied by the transmission system operator as part of the emergency supply.

The emergency power supply of the grid user ends when the grid connection of the grid user is effectively assigned to another balancing group at the transmission system operator.

Others

Withdrawal working price: according to balancing group accounting

Withdrawal-performance-price: according to terms of purchase for regular service after tender

Feed-in price: according to balancing group billing

The prices include;

- additional costs pursuant to the Combined Heat and Power Act,
- additional costs resulting from the implementation of the statutory requirements in accordance with StromNEV,
- offshore grid allocation pursuant to EnWG,
- Additional levies in accordance with legal requirements,
- EEG levy,
- possibly reactive power,
- possibly concession fee as well as electricity tax and value added tax in the respective statutory amount.

Prices also include use of the network infrastructure, ancillary services and coverage of transmission losses.

Fee for Metering Point Operation incl. Measurement *

Fees for regarding Metering and measurement;

- Fee metering operation including measurement (without conversion rate) per metering point
- Fee for provision Converter per metering point Prices
- plus VAT in the respective statutory amount.

* In compliance with “Metering Point Operating Act of 02/09/2016”

Interconnector Charges for Traders

In line with the ETSO CBT Agreement 2004, TenneT TSO no longer charges export or import fees for cross-border energy deliveries. This does not refer to any fees to be paid within the framework of auctions.

It is necessary to reserve grid capacity to transport electric energy via published bottlenecks in the grid.

The Energy Economy Act of 7 July 2005 applies to energy deliveries in Germany. Foreign transmission grid operators are subject to their respective national regulations. Therefore, an additional application of the described regulations and procedures to international, cross-border energy deliveries as well is not permissible.

There is currently nothing available for a standardized international procedure for handling cross-border energy transport. Due to the problems of crossing control areas, an agreement with transmission grid operators is already necessary at national and international levels now in any case.

5.10.6.5 Amprion

Amprion GmbH is responsible for the construction, operation and maintenance of its grid within its control area pursuant to the Energy Industry Act. As transmission system operator the company publishes the requirements for grid connection as well as objective criteria for power feed-in and grid usage.

With a length of around 11.000 kilometers and some 170 substations between Lower Saxony and the border to Switzerland and Austria, Amprion extra-high voltage transmission system is the largest in Germany. A population of over 29 million is supplied through Amprion grid.

Grid Connection

Amprion GmbH is responsible for the construction, operation and maintenance of its grid within its control area pursuant to the

Energy Industry Act. As transmission system operator the company must publish the requirements for grid connection as well as objective criteria for power feed-in and grid usage for Industrial Customers / Distribution System Operators, Power Plants and Minimum Technical Requirements.

Charges for the Amprion transmission grid usage since 01/01/2019

Due to regulation on incentive, a new revenue cap for Amprion GmbH is determined. The new revenue cap will be valid during the third regulation period, starting on January 1st of 2019, which will consequently lead to a recalculation of the grid charges.

Additional charges, such as KWK (Combined Heat and Power Legislation), value added tax, StromNEV-levy and concession fees, if applicable, as well as other levies (i. e. offshore grid levy or interruptible load levy) are not included in the grid charges.

Uniform TSO Grid Charges

In 2019 the successive equalization of the TSO grid charges due to StromNEV begins. The Amprion grid charge for 2019 therefore consists of an individual Amprion grid charge part and a uniform grid charge part.

Grid Charges Elements

Grid charges consist of several elements. In detail, the following services and levies are covered:

- Usage of grid infrastructure (e. g. lines, transformers, substations)
- Provision of system services (e. g. frequency control, voltage control, system operation) to ensure secure and reliable grid operation, coverage of transmission losses
- Invoicing and metering at a customer's connection point
- If applicable concession fee to the respective municipality/city
- Additional charges in accordance with the "Combined Heat and Power Legislation" (KWK-Gesetz)
- StromNEV levy
- Offshore-liability-levy
- Levy for interruptible loads

The annual demand rate system power charges cover for using the grid for an entire year whereas the monthly demand rate system power charges cover for using the grid for one month.

For calculating the overall grid charge the following data is necessary:

- Maximum Power P (metered in ¼ h time intervals) in kW (Kilowatt) for the relevant accounting year (annual demand rate system)
- Energy consumed over the year in kWh/year (Kilowatt-hours per year)
- Voltage level of the customer connection point

For the maximum power and the consumed energy, the respective values of grid users last electricity bill can be assumed as indicative values.

For customers disposing of their own generation facilities the requested additional grid capacity PR (in ¼-h time intervals) in kW must be disclosed.

The Amprion GmbH grid connection point can be attributed to the following voltage levels:

Table 5.21 – Voltage Levels for Connection Points

Extra High Voltage Level	380 kV or 220 kV
Transformer level	380 kV or 220 kV to 110 kV

From the above data the following value necessary for calculating the overall grid fee under the annual demand rate system can be derived: Yearly grid usage time T in hours / year (Ratio between yearly consumed energy and maximum power demand)

The necessary data has to be collected the same way for the monthly demand rate system.

Charges for Grid Usage

Fees for Grid Usage also include charges for the provision of necessary system services and cover expenses for the coverage of electrical losses arising from electricity transport.

The overall grid usage charge in €/year equals the sum of the two products:

1. maximum annual power P' x demand rate LP' and
2. consumed annual energy E' x energy rate AP'

The displayed demand and energy rates are calculated based on the so called “coincidence factor” representing the non-simultaneous grid usage of different customers.

Customers with a temporary high-power demand and a relatively low or no power consumption for the remaining time of the year can optimize for the monthly demand rate system as an alternative to the annual demand rate system.

The overall monthly grid usage charge in €/month equals the sum of the two products:

1. maximum monthly power PM' x monthly demand rate LPM' and
2. consumed monthly energy WM' x energy rate APM'

Charges for using grid reserves

Customers with on-site generation facilities (industrial generation, embedded generation) or grid operators with such generators feeding into their networks are entitled to request grid reserves in case of unexpected power plant shutdowns. Such grid reserves can be requested for generation outages due to maintenance or faults within the limits of the respective grid connection capacity with a predefined maximum power and for a maximal annual usage time of 600 hours per settlement year. The grid reserve capacity is limited to the maximal possible power generation of the customer generation facilities connected to a certain grid connection point.

Charges for metering and invoicing

Metering facilities at the customer connection point serve for gathering and registering consumed power and energy. Basically, metering is effectuated in ¼ hourly time intervals. Collected meter values are also used for settlement with the energy supplier. Metering facilities have to comply with calibration norms.

Charges for metering and invoicing (supply of necessary metering facilities and meter reading) has been calculated and applied by Amprion since 01.01.2013. Further details on metering equipment etc. and specific customer requirements are contractually arranged on an individual basis.

Charges for individual grid usage

According to § 19 of the German Electricity Regulation on Grid tariffs, StromNEV, in cases of special grid usage patterns individual charges can be requested for the respective customer by either the grid operator or the customer himself. According to § 27 StromNEV, these charges have to be included in the grid charge publication.

For customers with atypical grid usage individual grid charges according with StromNEV can be found here:

5.10.6.6 StromNEV Levy

According to the decision by the Federal Network Agency dated December 14th, 2011 the StromNEV levy will be charged to final customers as from January 1st of 2012. This StromNEV levy is aimed at covering revenue shortfalls arising from the provisions of StromNEV.

Additional charges in accordance with the Combined Heat and Power Law (CHP Law)

As from January 1st, 2009 the law on sustainment, modernization and extension of Combined Heat and Power generation (CHP Law) has entered into force. According to § 9 section 7 of the CHP law customers are charged a CHP surcharge depending on the consumption per connection point.

Offshore-liability-levy

On 28/12/2012 the revised German Energy Act (EnWG) has entered into force. Pursuant to § 17f section 5 EnWG the TSOs are entitled to assert their costs for provided compensations as a surcharge on the grid charges for final consumers. The offshore-liability-levy invoiced to the final consumer depends on the annual consumption at each consumption point. Further details can be found in price sheet.

Emergency Supply

The network user ensures that his grid connection is assigned to at least one balancing group at the transmission system operator. If the grid connection is not part of an existing balancing group at the transmission system operator, eg. Because no valid Contractual relationship between the transmission system operator and the balancing group manager for the settlement of Energy supply exists or the connection is not assigned to a balancing group, the network user is supplied by the transmission system operator in the context of emergency supply. The emergency power supply of the grid user ends when the grid connection of the grid user is effectively assigned to another balancing group at the transmission system operator.

Others

Withdrawal working price: according to balancing group accounting

Withdrawal-performance-price: according to terms of purchase for regular service after tender

Feed-in price: according to balancing group billing

5.11 Annex 11 – Cost-Efficiency Benchmark for Electricity Transmission System Operators

The main objective of Cost Efficiency Benchmark approach is to prepare a robust and methodological tool to estimate cost efficiency of Transmission System Operators (TSOs), under process and data quality requirements allowing use of the results to inform regulatory oversight of the operators.

The Normalized Grid or NormGrid methodological approach developed by international transmission system engineers can be used to assess performance of TSOs. This methodological approach is based on transmission cost functions, provides a TOTEX-based consideration for benchmarking of TSOs in terms of size. The Council of European Energy Regulators (CEER) is also use this approach for a stable and regular process for performance assessment of energy TSOs under the Transmission Cost Benchmarking project³²⁴. In order to test the resulting metric, the actual data is compared with the NormGrid value.

The cost impact of environmental factors is also considered and using a very detailed GIS supported data set for each TSO, the NormGrid parameter is enhanced.

The final model is formed with one input, TOTEX and three output parameters; NormGrid (corrected with environmental factors), transformer power capacity in total, and the transmission line (consider type of towers). The final model considers transmission, capacity provision and customer service as performance categories.

5.11.1 Activity Analysis and Scope

Cost-Efficiency Benchmarking depends on the structural comparability of the TSOs constituting the reference set. Due to the different duties from market facilitation to asset management of the different TSOs, direct comparison of them is not possible. Therefore, main functions of TSOs shall be identified systematically and cover all different activities to be used in an international benchmarking, as a first step. This is also very important to have different perspective from different regulatory performance evaluations point of view.

Taking into consideration the existing reliable data and types of benchmarking methodologies, scope shall be concluded as a second step.

Following common core duties shall be considered;

1. Transmission (T) duty through high voltage transformers, overhead lines and cables, through high voltage transformers, overhead lines and cables with the operational control and communication by SCADA System, metering, etc., as daily activities
2. Interfaces with other entities; DSOs, generations or interconnections with neighbouring countries
3. Activities; grid operation, maintenance (M) and planning (P)
4. Indirect (I) support (partially); Central management, including CEO, Board of directors and equivalent; the residual assets for a TSO (e.g. office buildings, general infrastructure) are also explicitly included in the scope.

On the other hand, transmission of electricity through offshore (TO) assets, system operations (S) (Congestion Management, Balancing market, Ancillary Services Market, etc.) and market facilitation (X) (procurement of renewable power, capacity allocation mechanisms, capacity auctioning mechanisms, and work on coordination of feed-in tariffs) are not in the scope.

As it is shown in the following Figure, benchmarked scope is concluded as the structurally comparable core activities of TSOs, which are T, M, P, and I (partially).

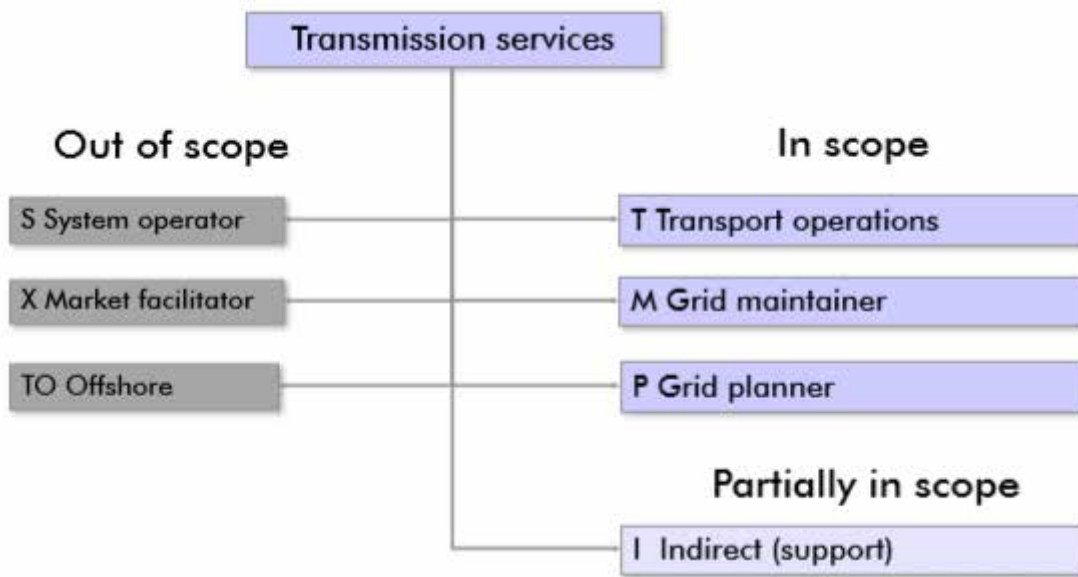


Figure 5.30 – Benchmarked activities and scope³²⁵

5.11.2 Benchmarked OPEX

The standardization of costs is extremely important for benchmarking studies. In below Figure, it is seen steps of the derivations of the benchmarked OPEX for the benchmarked functions in scope.



Figure 5.31 – Steps in deriving benchmarked OPEX³²⁶

The OPEX cost items are derived directly from the TSOs' data per activity to aggregate. TSOs use two questioners to collect the required data:

- The financial data and

325 PROJECT CEER-TCB18 Pan-European cost-efficiency benchmark for Electricity Transmission System Operators.

326 PROJECT CEER-TCB18 Pan-European cost-efficiency benchmark for Electricity Transmission System Operators.

- The asset data

A Financial accounting data report based on the audited financial statements is submitted by TSOs. This way the costs reported in the investment stream align with the costs of investments in the audited financial statements and the reported expenses align with the expenses in the profit and loss account of the audited financial statements. All reported investments and expenses shall be in scope of the benchmark defined above. The financial report is based on the International Financial Reporting Standards (IFRS).

Expense reporting

Main definitions³²⁷ are given as follows;

Personnel expenses: the non-capitalized expenses for internal and external personnel including all taxes, charges or fees related to salaries, pensions and other payroll items. This includes personnel on the payroll of the TSO, personnel on the payroll of a group company and carrying out activities for the TSO and hours of temporary personnel carrying out activities for the TSO.

Energy expenses: the non-capitalized expenses for purchasing gas and/or electricity to operate machinery and buildings, for energy losses during transport, and for congestion management and redispatch.

Expenses for landowner compensation, right-of-way and easement fees: the non-capitalized payments to third parties as a result of a legal process (e.g. expropriation or compensation agreement), procurement or negotiation, related to the damage, injury of land, and /or the right to use land, roads or waterways for the activities of the TSO. This includes the direct expenses for judicial assistance, court fees etc. for legal processes (terminated or non-terminated) related to the use, damage or injury of land for the activities of the TSO.

Expenses for taxes and levies: non-capitalized state, municipal and regional taxes, levies and public fees paid for the ownership of specific assets (e.g. property taxes, packaging), the use of specific processes (e.g. environmental levies), for investments and procurement (stamp taxes, legal fees, customs), for non-claimed value-added taxes (foreign VAT).

The total expenses reported for a given year should be equal to the expenses in the audited financial statements of the TSO for that year.

Labor cost adjustments: an adjustment for differences in national salary cost levels is applied make the operating costs comparable between countries. Otherwise TSOs would be held responsible for cost effects, e.g. high wage level, which is not controllable by them. The basis for the labor cost adjustment is the labor cost, not the data collected on FTE (full time equivalent employees) by function, since these data were less reliable.

Inflation adjustment: OPEX data is collected for a period. Hence, an indexation to a base year is necessary to make the costs comparable over the years.

Currency conversion: All national currencies are converted to EUR by the average annual exchange rate.

5.11.3 Benchmarked CAPEX

As accounting procedures, depreciation patterns, asset ages and capital cost calculations differ between countries and sometimes even between operators depending on their ownership structure, the CAPEX needs to be completely rebuilt from the initial investment stream and up. In addition, a real annuity must be used since the application of nominal depreciations (even standardized) would immediately introduce a bias towards late investments. The steps involved in the calculation of benchmarked CAPEX are given in Figure below.

327 CEER's definitions are used.

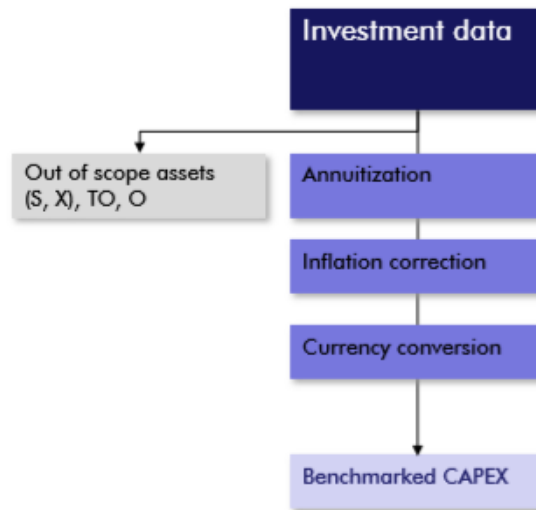


Figure 5.32 – Steps in deriving benchmarked CAPEX³²⁸

The full investment stream is reported by the operators from beginning to current year. The investment stream assets, excluding out of scope (S, X, TO, O) activities assets, is divided by type of asset as:

1. Overhead lines,
2. Cables,
3. Switchgear,
4. Transformers,
5. Series and shunt compensation,
6. Control centers,

The investment stream assets are subject to different techno-economic lifetimes. Standard lifetimes for new individual assets are considered to make the investment costs comparable between countries.

Table 5.22 – standard techno-economic lifetime³²⁹

Asset class	Lifetime (yrs)
Overhead lines	60
Cables	50
Circuit ends	45
Transformers	40
Series and Shunt compensations	40
Control centers	20

Assets acquired as used of any asset class are collected with original commissioning year or the expected remaining lifetime. The reported residual life is taken into account for the annuity calculation for used assets.

328 PROJECT CEER-TCB18 Pan-European cost-efficiency benchmark for Electricity Transmission System Operators.

329 PROJECT CEER-TCB18 Pan-European cost-efficiency benchmark for Electricity Transmission System Operators.

Investment reporting

Investments are expenditures for assets or components of assets (including fences, security cameras, etc.) that are recognized in the audited financial statements as tangible fixed assets.

Expenditures for in used assets (second-hand assets previously owned by a different company) is also an investment, but, contrary to investments in new assets the acquisition year will differ from the commissioning year.

Significant rehabilitation investments defined as at least 25% of the initial investment are large incremental investments into an existing asset without change of any characteristics (i.e. its dimensions and properties). In this case, the rehabilitation year also needs to be provided

Upgrades of existing assets changing the characteristics are reported as investments. Investments changing the characteristics are considered as “upgrades” and not as rehabilitation. Investments linked to upgrading assets that change asset class are counted as new investments. Thus, the original asset is replaced in the asset data with the new asset

If major spare parts, stand-by equipment and servicing equipment recognized as tangible fixed assets in the audited financial statements of the TSO, these expenditures are included in the investment stream, given Figure in below.

The following items are used for the correction of the investment stream prior to the calculation of the annuities:

- Capitalized costs for out-of-scope assets
- Capitalized costs for financial costs (construction interest)
- Capitalized taxes, fees and levies

Direct subsidies, exceptional direct depreciation and internal labor as direct expense.

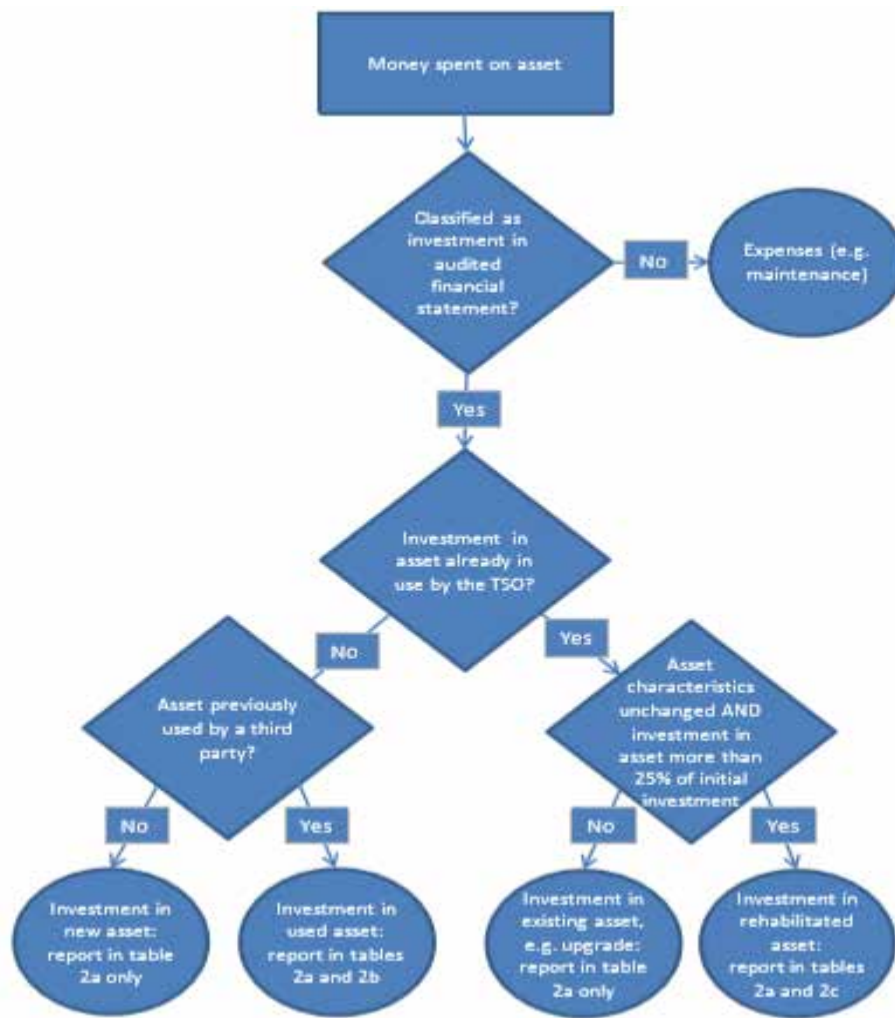


Figure 5.33 – Flowchart for treating investments³³⁰

Capitalized cost for out-of-scope assets, financial costs and taxes etc. are deducted from the gross investment stream.

Direct subsidies and exceptional depreciation are added to the gross investment stream.

Main definitions³³¹ are given as follows;

Real annuities: CAPEX consists of depreciation and a return on capital. The actual investment streams are annuitized using a standard annuity factor $\alpha (r, T)$, where r stands for a real interest rate; and T stands for the average life-time of the investments in the respective year. The annual investments from the investment stream data are multiplied with the annual standard annuity factor $\alpha (r, T)$.

Real interest rate: The real interest rate is set for the base run. The sensitivity with respect to this parameter is subject to an analysis.

Inflation adjustment: The current value of the past investments relative to the reference year is calculated using inflation indexes. Ideally, a sector-relevant index would capture both differences in the cost development of capital goods and services, but also

330 PROJECT CEER-TCB18 Pan-European cost-efficiency benchmark for Electricity Transmission System Operators; APPENDIX.

331 CEER's definitions are used.

the possible quality differences in standard investments. Several indexes can be collected from EUROSTAT and OECD. The index is specifically developed for international comparisons, which is not the case with conventional indexes such as CPI and PPI. This provision is ensured by selecting comparable services and goods for the index, rather than those potentially only being used domestically.

Currency conversion: As for OPEX, all amounts are converted to EUR values using the average exchange rates. The exchange rates (annual averages of daily rates) used are provided among the public parameter files.

Old CAPEX: Investment stream data prior to reference year are not required and by default are excluded, since they do not always exist or being of lower quality. However, without any correction this would create a bias towards operators with later opening investments, since these also include earlier assets. Thus, the calculation of the comparable CAPEX includes a residual element in current year corresponding to the pre-reference year assets still in the asset base.

The calculation is equivalent to a CAPEX Break for reference year, that is the CAPEX unit cost from reference year to current year is assumed prevail also up until reference year. In this manner, the inclusion of pre-reference year assets do not change the CAPEX-efficiency, but assures comparability. The calculated value, CAPEX Old, is capped by the sum of incumbent investments if known and validated.

3.8.1 Benchmarked TOTEX

The benchmarked TOTEX is the sum of OPEX and CAPEX where C_{ft} is the total OPEX for firm f and time t after currency correction, I_{fs} is the investment stream for firm f and time s after inflation and currency correction, and $a(r, T)$ is the annuity factor for asset with life time T and real interest rate r .



Figure 5.34 – Benchmarked TOTEX = OPEX + CAPEX³³²

5.11.4 Benchmarked TOTEX

In order to assess transmission system performance, quantifying of the network is required and should be detailed enough to address the relevant scope of different asset types per energy.

NormGrid is based on relative ratios for CAPEX and OPEX per asset type including the cost impact of environmental factors.

Technically, the relevant scope (already described above) is provided by an asset base consisting of:

- 1) Overhead lines,
- 2) Cables,
- 3) Switchgear,
- 4) Transformers,
- 5) Series and Shunt compensation,
- 6) Control centers.

A very detailed dataset was collected for the six asset categories above. Due to different dimensions, material choices and capacities of the different asset, it does not make sense just to sum together the different asset. And taking into account the geographical

nature of the power system, it is also necessary to consider following environmental factors;

1. Land use
2. Subsurface features
3. Topography

Based on the data specification, a cost-norm for the cost of construction of the standard assets recognized above is developed, including the cost impact of the environmental factors above. The result is an asset aggregate that is called the Norm Grid. It is noted that this detailed cost norm is independent from the actual costs and investments of the individual TSO; it provides average costs rather than best practice estimates. However, it is more general than a simple cost catalogue since it provides a complete system of complexity factors that explain the ratio of cost between any two type of assets, irrespective of which year, currency or context it is applied to (within reasonable bounds of course).

The Norm Grid OPEX: the weighted sum of assets in use at a given time, irrespective of their age:

$$NormGrid_{OPEX} = \sum_t \sum_a N_{at} w_a$$

Where

- N_{at} Number of assets of type a in use, acquired at time t
- w_a OPEX weight for assets of type a

The Norm Grid CAPEX: assets that are within their techno-economic life (=their annuity depreciation period) and the weights are multiplied with the same annuity factors as for the corresponding investments:

$$NormGrid_{CAPEX} = \sum_t \sum_a n_{at} v_a \alpha(r, T_a)$$

Where

- n_{at} Number of assets of type a in use, acquired at time t and in prime age
- v_a CAPEX weight for assets of type a
- r Real interest rate
- T_a Techno-economic standard life for assets of type a
- $\alpha()$ Real annuity function

The Norm Grid can be seen as a sum of equivalent assets, e.g. if $v = 1$ for 1 circuit km overhead line of 300 kV at 500 mm² cross-section, then $v = 1.44$ for 1 circuit km overhead line of 300 kV at 900 mm² would mean that 144 circuit km of (300 kV, 500 mm²) would correspond to an asset base equivalent to 100 circuit km of (300 kV, 900 mm²).

5.11.6 Benchmarking Model Specification

Any efficiency comparison shall consider differences in the outputs and the structural environment of the TSOs.

Conceptually, it is useful to think of the benchmarking model as in Figure below. A TSO transforms resources X into services Y. This

transformation is affected by the environment Z. The aim of the benchmarking is to evaluate the efficiency of this transformation. The more efficient TSOs can provide more services using less resources and in environments that are more difficult.

Conceptually, it is useful to think of the benchmarking model as in Figure below. A TSO transforms resources X into services Y. This transformation is affected by the environment Z. The aim of the benchmarking is to evaluate the efficiency of this transformation. The more efficient TSOs can provide more services using less resources and in environments that are more difficult.

The inputs X are typically OPEX, CAPEX or TOTEX. In any benchmarking and in an international benchmarking study, it requires a considerable effort to make costs comparable. Cost reporting guide is also important to make sure that out-of-scope is interpreted uniformly, and that differences in depreciation practices, taxes, land prices, labor prices etc. are neutralized.

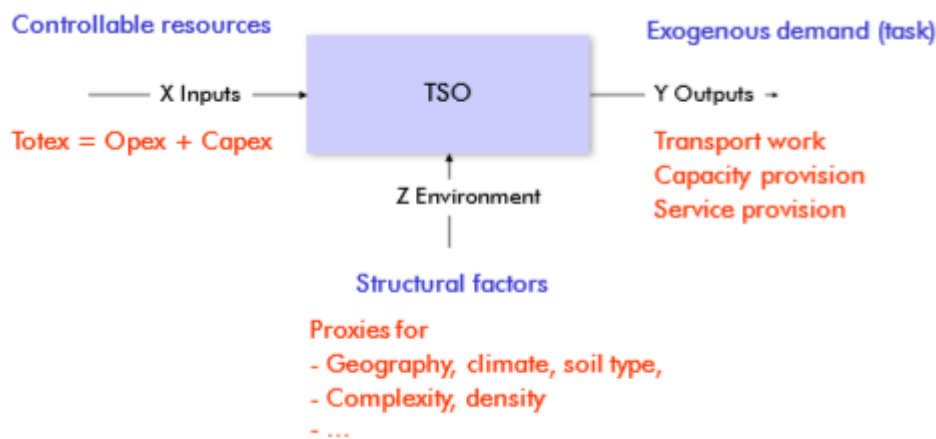


Figure 5.35 – Conceptual benchmarking model

The outputs Y are made of exogenous indicators for the results of the regulated task, such as typically variables related to the transmission duty (energy delivered etc.), capacity provision (peak load etc.) and service provision (number of connections, customers, etc.).

The class of structural variables Z contains environmental cost impact parameters which have a non-controllable influence on OPEX or CAPEX without being differentiated as a client output. These are indicators of geography (topology, obstacles), climate (temperature, humidity, salinity), soil (type, slope, zoning) and density (sprawl, imposed feed-in locations).

5.11.7 Benchmarking methods

Econometrics has provided a portfolio of techniques to estimate the cost models for networks, given in Table below. Depending on the assumption regarding the data generating process, the techniques are divided in deterministic and stochastic, and further depending on the functional form into parametric and non - parametric techniques. These techniques are usually considered state of the art and are advocated in regulatory applications provided enough data is available.



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Table 5.23 – Model taxonomy

	Deterministic	Stochastic
Parametric	Corrected Ordinary Least Square (COLS) Greene (1997), Lovell (1993), Aigner and Chu (1968)	Stochastic Frontier Analysis (SFA) Aigner, Lovell and Schmidt (1977), Battese and Coelli (1992), Coelli, Rao and Battese (1998)
Non-Parametric	Data Envelopment Analysis (DEA) Charnes, Cooper and Rhodes (1978), Deprins, Simar and Tulkens (1984)	Stochastic Data Envelopment Analysis (SDEA) Land, Lovell and Thore (1993), Olesen and Petersen (1995)

In a study of European electricity TSOs, the number of observations is too small for a full-scale application of SFA as main instrument. Therefore, DEA is used as a base estimation approach, in line with regulatory best practice and earlier studies such as E3GRID. The DEA method is by now well established in the scientific literature as well as in regulatory applications.

So far measures of output quality have not been widely used in TSO cost efficiency studies. Wherever measures of output quality have been considered and/or used, studies focused on measures for energy losses or reliability. Although the energy not supplied asked, but, did not correlate very well to cost within E3grid studies. Still, CEER remains open to add the aspect of quality to future benchmarks. For that, however, it is required to define the concept of quality, to find ways to measure it, and to be able to relate such measure(s) to benchmarked cost.

5.12 Annex 12 – Commercial quality indicators for Natural Gas Distribution

Commercial quality indicators are indicated in Table 5.24. In the table countries that monitor or apply a requirement for the different commercial quality aspects are shown. The most common indicators among the NRAs are the ones concerning customer information and metering issues. In total 13 of the responding countries apply some types of indicator regarding the time for response to customer request and/or complaints and the number of customer requests and/or complaints; and 9 countries monitor a minimum period for reading the meter.

Table 5.24 – Commercial quality indicators³³³

		AT	BE	CZ	EE	ES	FR	HR	HU	IE	IT	LT	LV	NL	PL	PT	SE	SI
I. Customer information	I.1 Time for response to the customer request and/or complaints	X	X	X	X		X	X	X	X		X	X	X	X	X		
	I.2 Number of customer requests and/or complaints	X	X	X			X	X	X	X		X	X	X	X	X		X
	I.3 Percentage of responses to customer complaints and/or requests in written form within a given time period				X		X	X			X	X	X			X		
	I.4 Percentage of market participants who display the gas emergency number on invoices, homepage, etc.	X	X	X		X	X	X					X					
	I.5 Number of market participants who display the quality of supply standards on invoices, homepage, etc.	X					X	X										
	I.6 Time of availability of a market participant's call centre		X				X						X			X		
	I.7 Time of availability of a network operator's website accessible to providers						X		X				X					
	I.8 Average response time to customer request and/or complaints															X		
II. Customer care	II.1 Punctuality of market participants regarding appointments with customers	X					X	X	X		X					X		
	II.2 Punctuality of customers regarding appointments with market participants								X							X		
	II.3 Time limit for market participants / for clients to cancel an appointment						X											
	II.4 Time limit for waiting in customer centers								X									
	II.5 Percentage of customers attended within the waiting time limit in customer centers								X									
	II.6 Time limit for waiting in call centers								X							X		
	II.7 Target call answer time in call centers								X									
	II.8 Percentage of dropped calls in the call centers								X				X					
	II.9 Other performance indicators or targets for different customer issues in call centers (telephone contact)		X				X		X			X						
	II.10 Obligation for DSO regarding response time for emergency situations							X	X				X			X		
	II.11 Percentage of customers with a waiting time below the limit in call centres															X		



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		AT	BE	CZ	EE	ES	FR	HR	HU	IE	IT	LT	LV	NL	PL	PT	SE	SI
III. Grid access	III.1 Number of customer requests for technical grid access	X	X	X				X				X					X	
	III.2 Average response time of a DSO to customer requests for technical grid access	X						X	X			X					X	
	III.3 Number of customer requests for cost estimations for connecting customers to the network	X	X								X	X					X	
	III.4 Time for providing a cost estimation of connecting customers to the network	X					X				X	X	X					
	III.5 Time for execution of connecting customers to the network						X				X	X	X					
IV. Activation, deactivation, reactivation of supply	IV.1 Number of activations of supply / deactivations of supply due to late payment/reactivations of supply after payment (for bad payer previously disconnected) carried out						X	X	X		X	X	X					
	IV.2 Time of response to customer request for activation	X							X									
	IV.3 Time for activation of supply following a request			X			X		X		X		X			X		
	IV.4 Time for deactivation of supply following a request		X	X			X		X		X							
	IV.5 Success rate for deactivation of supply on the first request			X					X									
	IV.6 Number of calls required to successfully deactivate a customer																	
	IV.7 Time of reactivation of supply after payment (for bad payers previously disconnected)	X		X				X	X		X		X			X		
	IV.8 Time for disconnection of a customer following deactivation for non-payment		X						X						X			
V. Meters	V.1 Number of installed gas meters	X	X	X				X				X	X		X			
	V.2 Number of gas meters not installed in due time	X		X														
	V.3 Time for meter verification			X			X	X	X		X	X	X					X
	V.4 Time for replacement of the meter (when found out of order after verification)			X			X		X		X							
	V.5 Number of network customers who were informed about meter readings in absentia	X							X									
	V.6 Number of market participants who offer the possibility of online meter data announcement (self service)	X					X		X				X					
	V.7 Number of customers receiving real time meter data		X					X	X									
	V.8 Percentage of meter reading successfully transmitted by customers through a dedicated IVR call centre number															X		
	V.9 Times a year the meter is read by type of customers (Industrial / Commercial / Household)		X	X			X	X	X			X	X				X	
	V.10 Minimum period for reading the meter	X	X	X				X	X			X	X			X	X	
	V.11 Regulation value of the readings made by the customers and by DSO or suppliers	X	X	X				X	X				X				X	
	V.12 Percentage of meter readings made within a certain amount of time after the last one																	X

		AT	BE	CZ	EE	ES	FR	HR	HU	IE	IT	LT	LV	NL	PL	PT	SE	SI
VI. Invoices	VI.1 Percentage of invoices submitted in due time	X	X						X				X					
	VI.2 Percentage of corrected invoices submitted in due time	X						X	X				X					
	VI.3 Number of customers who have requested settlement data	X																
	VI.4 Number of settlement data not transmitted in due time X 1	X																
	VI.5 Number of DSOs who are offering the possibility of cash payment	X											X		X			
	VI.6 Number of DSOs who are providing settlement data online to their network customers	X							X				X					
	VI.7 Time for changing provider on customer request			X			X	X	X						X			

5.13 Annex 13 – Applied Natural Gas Transmission Tariff Structures in Turkey and the EU

5.13.1 Overview of the Existing Natural Gas Transmission Tariff Structures in Turkey

The regulatory authority EMRA is responsible for the preparation of tariff legislation and approving the proposed tariffs by the operators. EMRA published the Natural Gas Tariff Regulation, first in 2002. The methodologies for preparing the tariffs have been published through EMRA Board Decisions.

The Tariff for the Natural Gas Transmission is referred as “Transmission and Shipping Control Tariff” (the Tariff) in the secondary legislation. The related legislative documents in effect are:

- Natural Gas Tariff Regulation, dated 13/10/2016 (herein after may be shortly referred as the NGTR);
- Principles and Procedures for Determining the Revenue Caps to be taken as basis to the Tariffs of Natural Gas Transmission License Holding Companies, EMRA Board Decision dated 03/10/2010 with the number 4638-1 (to be shortly referred as PPRC); and
- EMRA Board Decision dated 29/12/2016 with the number 6821 specifying the methodology for the second implementation period for the transmission and shipping tariffs of BOTAS during the term 01/01/2017-31/12/2019 (to be shortly referred as SIP)

The Transmission System Operating Regulation specifies the Entry/Exit model for Natural Gas Transmission activities and so does the Tariff Regulation.

The essential features of the Tariff can be summarized as follows:

- Entry/Exit model,
- Transmission System Operator may propose different tariffs for firm, interruptible and reverse flows,
- Capacity and Commodity split,
- Revenue Cap regulation,
- Capital Asset Pricing Model, Weighted Average Cost of Capital (WACC, pre-tax) methodology in determining the Internal Rate of Return,
- The depreciation period is typically 22 years,
- 3 years of implementation periods, to be determined through EMRA Board Decisions (may go up to 10 years),
- Reconciliation of the determined revenue requirements are handled in accordance with inflation effect, investment adjustments, realized flows and/or capacity bookings and unforeseen expenses. The transmission system operator submits relevant data 6 months prior to the beginning of tariff year (calendar year),
- Transmission System Operators are required to submit their proposed methodologies for the definition of transmission and shipping control services latest 8 months prior to the commencement of each tariff implementation period. EMRA publishes the applicable Tariff within 2 months upon receipt of the submittal,

- The Regulatory Asset Base (the RAB) for BOTAS Transmission Network is determined each year in accordance with new investments and realized depreciations. The RAB figure specified for the 2011 - 2013 implementation period has been taken as the reference.

5.13.1.1 Determining the Revenue Requirement and the Revenue Cap

The basic data relating to Natural Gas Transmission tariff are stated in the PPRC as follows:

- The investments already realized and the planned new investments on annual basis detailed in the format specified by the Regulatory Authority,
- Balance Sheets, Revenues, Cost of Services and other financial tables
- Operating Costs pertaining to previous years and the estimated operating costs for the current and following years of the Tariff Application Period; in the format specified by EMRA,
- Accrued incomes out of services carried out during the past year.

As it is detailed in the PPRC, the Revenue Requirement of the transmission system operator is determined according to below stated formula.

$$GG_t = [(ODVT_t + SHDVT_t) * RMGO_{net}] + IST_t * RMGO_{net} + I_t + IG_t + YFDB$$

In this formula:

t : Each year of the Tariff Application Period

GG_t : Annual Revenue Requirement pertaining to the t Tariff Year,

$ODVT_t$: The Regulatory Asset Base pertaining to t Tariff Year,

$SHDVT_t$: The Regulatory Asset Base excluding the transmission grid at t Tariff Year,

$RMGO_{net}$: The Real Reasonable Rate of Return levelised with the ODVT for the Tariff Application Period (%),

IST_t : The cost of linepack for the t Tariff Year,

IG_t : Operating Costs for the t Tariff Year,

$YFDB$: Adjustment factor for the investment deviation

The PPR defines the Revenue Cap applicable for certain year according to the formula:

$$GT_t = GGG_t * (1 - X_t) + GFDB_t$$

Where;

t : Each year of the Tariff Application Period,

GT_t : The Revenue Cap for the t Tariff Year,

GGG_t : The updated Revenue Requirement for the t tariff Year,

X_t : The **Efficiency Parameter** for the t Tariff Year; specified prior to the commencement of the Tariff Application Period,

$GFDB_t$: The correction factor for the revenue deviation for the t Tariff Year.

5.13.1.2 BOTAS Natural Gas Transmission Network Code

BOTAS operates the National Natural Gas Transmission System and no other TSO exists in the gas market yet. The NGTR and other transmission tariff related legislation make reference to the BOTAS Natural Gas Transmission Network Code (shortly the GTNC) terms for the Tariffs.

BOTAS is responsible for the operation of nationwide Natural Gas Transmission grid whose total length has already exceeded 14,000 km. Natural Gas is supplied to the main transmission network through 4 interconnected (foreign) transmission networks, 4 LNG terminals (2 of which are the FSRU's), 2 underground storage facilities and 2 domestic production sites. Gas is handed over to the Distribution Companies at the inlet of the Pressure Reduction and Metering Stations directly connected to the high-pressure grid. There are totally 9 compressor stations in operation.

The GTNC is in force since 1st September 2004. Shippers adhere the provisions of the GTNC and enter into a Standard Transportation Contract with the Transporter specifying the booked capacities by the Shipper at certain Entry and Exit Points. The requirements of the Natural Gas Market Law in terms of unbundling BOTAS has not been achieved yet. Accordingly, the GTNC has a provision to envisage that the trading departments of BOTAS will be treated as any other Shipper by the BOTAS Transporter. The Code is structured to base on daily settlements in terms of nominations, allocations and balancing. Entry/Exit System is applied for capacity reservation. The duration of the capacity reservation is maximum one year and minimum one month, in Standard Cubic Meters per Day (based on GCV of 9155kcal/m³, 15°C temperature and 1,01325 barg pressure) terms.

The Capacity reservation at the interconnections with other (foreign) transmission systems are unidirectional, terms for bidirectional flow arrangements is not in place yet.

Nomination processes and other interactions with the Shippers are carried out through a commercial operating system named "Electronic Bulletin Board (EBT)" which is accessible via web site of BOTAS. Virtual Points are defined to allow title transfers between the Shippers. The "National Balancing Point" is defined for the whole network to allow for title transfers among the Shippers for trading and balancing purposes. The National Balancing Point concept is the main tool to provide the Over the Counter trading platform for the Shippers as structured in the Organized Wholesale Market Regulation, which is in force since 1st September 2018. The Transporter has a Residual Balancer role in this market. With the commencement of the Organized Wholesale Market operations, many processes of the Transporter such as the procurement of its own utilization gas, management of nomination process etc. have become coordinated actions together with the Organized Wholesale Market Operator (EPIAS).

In accordance with the Entry/Exit capacity booking methodology of the GTNC, the transmission and shipping control fees are specified as follows.

- **Entry Capacity Fee:** Separately defined for each Entry Point
- **Exit Capacity Fee:** Uniformly applied for all Exit Points (excluding the Exit Points utilized for reexport to foreign interconnections)
- **Transmission Service Fee:** Unit rate for the transported amount of gas to the Exit Points

The upper limits for those fees stated above is determined by EMRA each year.

The GTNC defines transmission services only on firm basis and capacity booking on interruptible basis has not been applied so far. The capacities can be booked annually as maximum and monthly as minimum. Daily capacity booking may be applicable for only the interconnection points with the underground gas storage facilities. Utilization of those storage facilities is incentivized also by applying lower service fees for such points as compared to other Entry and Exit Points.

There are 15 Entry Points to the transmission system (6 interconnections with foreign transmission systems, 2 interconnections with underground facilities, 4 interconnections with LNG terminals and 3 domestic production sites). It is aimed by the regulatory authority that there should not be divergent figures among the capacity charges for different entry points. The split between capacity fees and service fees as part of the specified Revenue Cap is also specified. The Article 2 of the SIP states that:

“Transmission charges are classified as capacity and service (commodity) payments and in order to reduce the differences among the capacity charges a socialization methodology is applied for those” ...

“It is an essential principle that the 45 % of the approved revenue requirement shall be met through the capacity charges. The part of this amount belonging to the CAPEX of the Export Exit Point should be set as the Revenue cap for that Point; the remainder is allocated to all other points. When allocating this amount for the capacity charges pertaining to the Points specified in Part 2.1, each point’s fixed asset value and the relevant line pack cost is taken into consideration. A socialization is applied for such amounts in relation with the Entry Points”

There is also a fixed service fee called as **“Standard Service Fee”** equally payable by all Shippers accessing the transmission system in that year. This fee totally amounts to 0.03 % of the total revenue out of Transmission Service payments by all Shippers (i.e. 55% of the Revenue Cap).

The tariff applied by BOTAS for Natural Gas Transmission have been referred as the “Turkish Entry Postalised Exit (TEPE) Methodology”. There are also elements of the Tariff classified under “Shipping Control Charges” namely as:

- **“System Balancing Participation Fee”** which refers to the payments between the Transporters and the Shippers for the imbalance position of the Shipper (positive or negative).
- **“Interruption Balancing Charges”** which refer to a special compensation payment from a defaulting Shipper (excessively negative imbalanced) to a non-defaulting Shipper (who submitted gas at the Entry Point as per its nomination) whose deliveries to the Exit Points was partially or wholly curtailed.
- **“Service Interruption Fee”** which refers to the payment by The Transporter to the Shipper(s) for under deliveries to the Exit Points which are attributable to the Transporter’s default.

5.13.1.3 Efficiency Requirements in the Existing Legislation Related to Natural Gas Transmission

The NGTR defines the “Efficiency Target” in the definitions part referring only to the Distribution System Operators.

“Efficiency target: The target specified for the purpose of increasing the efficiency of the Distribution Companies by benchmarking similar applications in or out of Turkey”

The Article 7 of the Regulation states that the Authority may require any infrastructure operator to submit the documentation relating to the quality of service.

The PPRC introduces the concept of “Efficiency Parameter” for the transmission services in the definitions part.

“Efficiency parameter: The parameters specified for each company to promote efficiency increases in the investment and operating costs by taking into account the other performances in similar works”

The concept is further detailed in the Part III, Section I and Article 16 of the PPRC as follows:

“Efficiency Parameter

Article 16- (1) *The Transmission Company is responsible for the efficient and economical operation of the transmission system. When it is considered necessary, the EMRA Board may specify efficiency parameter in order to provide efficient operation and reduction in costs.*

(2) The efficiency ratios targets shall be separately specified for the investment costs and operating costs and the efficiency parameter to be used in Revenue Cap calculation shall take into account such allocation.

(3) The performance data from other companies both in land and out of Turkey with similar work scope can be used for benchmarking in determining efficiency ratio targets. The realized data of the same company for the previous years can also be used for the same purpose”

Although the formula for the Revenue Cap includes the concept of the “**efficiency parameter**”, as it is set out above, it is left to the discretion of the authority to apply such parameter or not. Involvement of the efficiency parameter in determining the Revenue Cap has not been practiced yet and there is no methodology developed for the determination of that parameter.

3.8.2 The European Union (EU) Case and ENTSOG Tariff Network Code

The main legislative documents related with the Natural Gas Transmission applications in the EU can be stated as follows:

- The 3rd Gas Directive; “Directive 2009/73/EC of the European parliament and of the council of 13 July 2009 concerning common rules for the internal market in natural gas”
- The Regulation 715; “Regulation (EC) No 715/2009 of the European parliament and of the council of 13 July 2009 on conditions for access to the Natural Gas Transmission networks”
- ENTSOG Capacity Allocations Methodologies (CAM) Network Code; “Commission Regulation (EU) 2017/459 of 16 March 2017 establishing a network code on capacity allocation mechanisms in Natural Gas Transmission systems”
- ENTSOG Balancing Network Code; “Commission Regulation (EU) No 312/2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Networks”
- ENTSOG Tariff Network Code.

5.13.2.1 The Third Gas Directive

The Third Gas Directive is the principal legislative document defining the requirements for natural gas markets within the Third Energy Package of the EU. The Introduction part, Item 59 requires the regulatory authorities provide information (among others) related with efficiency improvements in Natural Gas Transmission and Distribution Systems.

“The regulatory authorities should also provide information on the market to permit the Commission to exercise its role of observing and monitoring the internal market in natural gas and its short, medium and long-term evolution, including aspects such as supply and demand, transmission and distribution infrastructure, quality of service, cross-border trade, congestion management, investments, wholesale and consumer prices, market liquidity and environmental and efficiency improvements. National regulatory authorities should report to the competition authorities and the Commission those Member States in which prices impair competition and proper functioning of the market.”

The technical adequacy of the transmission system in terms of capacity utilization and efficiently functioning commercial arrangements between the Transporters and the Shippers and also other gas infrastructure system operators have crucial role in establishing a properly functioning gas market. In that sense, the transmission system operators are required develop their network development plans with 10 (ten) years projections (Ten Year Network Development Plans-TYNDPs). As per the Article 22 of the 3rd Gas Directive, the regulatory authorities should monitor the realization of the investments for the TYNDPs.

“7. In circumstances where the transmission system operator, other than for overriding reasons beyond its control, does not execute an investment, which, under the ten-year network development plan, was to be executed in the following three years, Member States shall ensure that the regulatory authority is required to take at least one of the following measures to ensure that the investment in question is made if such investment is still relevant on the basis of the most recent ten-year network development plan:

(a) to require the transmission system operator to execute the investments in question;

(b) to organize a tender procedure, open to any investors for the investment in question; or

(c) to oblige the transmission system operator to accept a capital increase to finance the necessary investments and allow independent investors to participate in the capital.

Where the regulatory authority has made use of its powers under point (b) of the first subparagraph, it may oblige the transmission system operator to agree to one or more of the following:

(a) financing by any third party;

(b) construction by any third party;

(c) building the new assets concerned itself;

(d) operating the new asset concerned itself.

The transmission system operator shall provide the investors with all information needed to realize the investment, shall connect new assets to the transmission network and shall generally make its best efforts to facilitate the implementation of the investment project.

The relevant financial arrangements shall be subject to approval by the regulatory authority.

8.*Where the regulatory authority has made use of its power under the first subparagraph of paragraph 7, the relevant tariff regulations shall cover the costs of the investments in question."*

The Article 41 of the Directive sets out the duties and powers of the regulatory authorities. The sub Article 8 specifically refers to appropriate incentives to be granted to the transmission and distribution system operators to increase their efficiencies.

"In fixing or approving the tariffs or methodologies and the balancing services, the regulatory authorities shall ensure that transmission and distribution system operators are granted appropriate incentive, over both the short and long term, to increase efficiencies, foster market integration and security of supply and support the related research activities."

5.13.2.2 The Regulation 715/2009

The Regulation sets out the principles for access to Natural Gas Transmission Systems and defines the obligations of the transmission system operators. One of the main principles is the use of Entry-Exit methodology in defining the tariffs for transmission, as stated in the Item 19 of the Introductory section.

"To enhance competition through liquid wholesale markets for gas, it is vital that gas can be traded independently of its location in the system. The only way to do this is to give network users the freedom to book entry and exit capacity independently, thereby creating gas transport through zones instead of along contractual path."

As per (sub) Article 17-5 of the Regulation, the transmission system operator should assess market demand and determine its investment plans accordingly.

"Transmission system operators shall regularly assess market demand for new investment. When planning new investments, transmission system operators shall assess market demand and take into account security of supply."

The Article 13 of the Regulation details the requirements for transmission tariffs. The article reads:

“1.Tariffs, or the methodologies used to calculate them, applied by the transmission system operators and approved by the regulatory authorities pursuant to Article 41(6) of Directive 2009/73/EC, as well as tariffs published pursuant to Article 32(1) of that Directive, shall be transparent, take into account the need for system integrity and its improvement and reflect the actual costs incurred, in so far as such costs correspond to those of an efficient and structurally comparable network operator and are transparent, whilst including an appropriate return on investments, and, where appropriate, taking account of the benchmarking of tariffs by the regulatory authorities. Tariffs, or the methodologies used to calculate them, shall be applied in a non-discriminatory manner.

Member States may decide that tariffs may also be determined through market-based arrangements, such as auctions, provided that such arrangements and the revenues arising therefrom are approved by the regulatory authority.

Tariffs, or the methodologies used to calculate them, shall facilitate efficient gas trade and competition, while at the same time avoiding cross-subsidies between network users and providing incentives for investment and maintaining or creating interoperability for transmission networks.

Tariffs for network users shall be non-discriminatory and set separately for every entry point into or exit point out of the transmission system. Cost-allocation mechanisms and rate setting methodology regarding entry points and exit points shall be approved by the national regulatory authorities. By 3 September 2011, the Member States shall ensure that, after a transitional period, network charges shall not be calculated on the basis of contract paths.

2.Tariffs for network access shall neither restrict market liquidity nor distort trade across borders of different transmission systems. Where differences in tariff structures or balancing mechanisms would hamper trade across transmission systems, and notwithstanding Article 41(6) of Directive 2009/73/EC, transmission system operators shall, in close cooperation with the relevant national authorities, actively pursue convergence of tariff structures and charging principles, including in relation to balancing.”

The Regulation initiated the Establishment of the European Network of Transmission System Operators for Gas (ENTSOG) and defined a road map for developing network codes for cross border Natural Gas Transmission networks within the EU. The Item 16 of the Introductory section states that:

“In order to ensure optimal management of the Natural Gas Transmission network in the Community a European Network of Transmission System Operators for Gas (the ENTSO for Gas), should be established. The tasks of the ENTSO for Gas should be carried out in compliance with Community competition rules which remain applicable to the decisions of the ENTSO for Gas. The tasks of the ENTSO for Gas should be well-defined and its working method should ensure efficiency, transparency and the representative nature of the ENTSO for Gas. ...”

ENTSOG was established in 2009 and started to develop the network codes for all aspects of Natural Gas Transmission activities within the EU. Development of such codes have been realized through a consultation process involving market stakeholders and at a later stage regulatory review by the ACER (Agency for the Cooperation of Energy Regulators) on the drafts developed by the ENTSOG.

5.13.2.3 ENTSOG CAM Network Code

Payments by the Shippers for the booked capacities in the systems constitute the major part of the revenues of the Transporters. The capacity reservation requirements from the Shippers for existing and new Entry and Exit Points are the basis of the network investment plans regarding capacity extensions. The optimal use of the existing capacities and avoiding unnecessary investments for capacity extensions is very much related with the involvement of the various capacity products (short, mid and long terms, firm/interruptible etc.) and the rules stated in the network codes in terms of capacity utilization.

The CAM Network Code mainly focuses onto the above-mentioned issues and union wise optimization and/or efficiency is aimed

at by bringing detailed rules dealing with definitions, utilizations and extensions of the capacity products.

“Bringing about effective competition between suppliers from inside and outside the Union requires that they are able to flexibly use the existing transmission systems to ship their gas according to price signals. Only a well- functioning network of interconnected transmission grids, offering equal access conditions to all, allows gas to flow freely across the Union. That in turn attracts more suppliers, increasing liquidity at the trading hubs and contributing to efficient price discovery mechanisms and consequently fair gas prices that are based on the principle of demand and supply” (Introductory Items, 4)

The capacity expansion projections for Natural Gas Transmission systems are often linked with increase of the capacities at the interconnections with the other Natural Gas Transmission systems (exports or imports). Such investments may cause significant costs to the Transporters since they are usually linked to the construction and/or capacity expansion of compressor stations installation of loop lines. The CAM Network Code focuses onto the issue in an extensive manner since the subject matter is closely related with the security of supply and optimizations of the investments where more than one member state is involved. The capacity expansions at the interconnections between the Natural Gas Transmission systems are referred as **“incremental capacity”** whose definition is given below:

*‘**incremental capacity**’ means a possible future increase via market-based procedures in technical capacity or possible new capacity created where none currently exists that may be offered based on investment in physical infrastructure or long-term capacity optimization and subsequently allocated subject to the positive outcome of an economic test, in the following cases: (a) at existing interconnection points; (b) by establishing a new interconnection point or points; (c) as physical reverse flow capacity at an interconnection point or points, which has not been offered before;*

The Transporters are required to carry out an “auction” process for the incremental capacity where at the end binding capacity bookings should be in place.

*‘**incremental capacity process**’ means a process to assess the market demand for incremental capacity that includes a non-binding phase, in which network users express and quantify their demand for incremental capacity, and a binding phase, in which binding commitments for contracting capacity are requested from network users by one or more transmission system operators;*

When the “incremental capacity process” is successfully completed, an economic test should be carried out by the transmission system operator(s) or by the national regulatory authority, as decided by the national regulatory authority, for each offer level of an incremental capacity project after binding commitments of network users for contracting capacity have been obtained by the involved transmission system operators.

Design Phase begins upon seeing the positive outcomes of the Economic Test at both side of the interconnection. Following the consultation and finalization of the design phase for an incremental capacity project, the involved transmission system operators submit the project proposal for an incremental capacity project to the relevant national regulatory authorities for coordinated approvals.

5.13.2.4 **ENTSOG Tariff Network Code**

The transmission tariffs throughout the EU should comply with the Tariff Network Code developed by the ENTSOG. The related EC Regulation has been published as “Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonized transmission tariff structures for gas”. The network code (TAR NC) aims at harmonizing transmission tariff structures for gas and setting out the Union-wide rules which have the objectives of contributing to market integration, enhancing security of supply and promoting the interconnection between gas networks. The code set outs terms related with harmonized transmission tariff structures for gas, including rules on the application of a reference price methodology, the associated consultation and publication requirements as well as the calculation of reserve prices for standard capacity products. The Transmission System Operators are required to comply fully with the Tariff Network Code latest 31 December 2019.

Under Entry/Exit capacity booking regime, the TAR NC introduces some provisions applicable for all entry and exit points and some

provisions applicable for only the interconnection points between the transmission systems. For example, the TAR NC introduces the concept **‘reference price’** which means the price for a capacity product for firm capacity with a duration of one year, which is applicable at entry and exit points. The same **“reference price methodology”** (which means the methodology applied to the part of the transmission services revenue to be recovered from capacity-based transmission tariffs with the aim of deriving reference prices) should be applicable at all the interconnection points between the member states and/or transmission systems.

Relating to the reference price methodology, the Article of the TAR NC reads:

“The reference price methodology shall comply with Article 13 of Regulation (EC) No 715/2009 and with the following requirements. It shall aim at:

- (a) enabling network users to reproduce the calculation of reference prices and their accurate forecast;*
- (b) taking into account the actual costs incurred for the provision of transmission services considering the level of complexity of the transmission network;*
- (c) ensuring non-discrimination and prevent undue cross-subsidisation including by taking into account the cost allocation assessments set out in Article 5;*
- (d) ensuring that significant volume risk related particularly to transports across an entry-exit system is not assigned to final customers within that entry-exit system;*
- (e) ensuring that the resulting reference prices do not distort cross-border trade.”*

The TAR NC does not require the regulators to adopt certain regulatory regime from the alternatives as price cap and non-price cap regimes (revenue cap, rate of return and cost plus). The definition of the “allowed revenue” for the non-price cap regimes is stated as follows.

‘Allowed revenue’ means the sum of transmission services revenue and non-transmission services revenue for the provision of services by the transmission system operator for a specific time period within a given regulatory period which such transmission system operator is entitled to obtain under a non-price cap regime and which is set in accordance with Article 41(6)(a) of Directive 2009/73/EC;

On the other side, the Code refers to the price cap regimes defining the “target revenue” as follows.

‘target revenue’ means the sum of expected transmission services revenue calculated in accordance with the principles set out in Article 13(1) of Regulation (EC) No 715/2009 and expected non-transmission services revenue for the provision of services by the transmission system operator for a specific time period within a given regulatory period under a price cap regime;

As of date, the majority of the EU countries apply incentive based Revenue Cap Regulation. However, the TAR NC does not define a methodology to be commonly adopted by the member states for setting up the incentive mechanisms and efficiency targets.

For non-price cap regimes, the transmission system operators are required to keep a certain account recording the differences with respect to the allowed revenues.

‘regulatory account’ means the account aggregating at least under- and over-recovery of the transmission services revenue under a non-price cap regime;

The Code also brings a classification for the revenues of the TSO’s out of services directly related with the Natural Gas Transmission activities and those out of non-transmission related activities.

‘transmission services’ means the regulated services that are provided by the transmission system operator within the entry-exit system for the purpose of transmission;

‘non-transmission services’ means the regulated services other than transmission services and other than services regulated by Regulation (EU) No 312/2014 that are provided by the transmission system operator;

An important obligation for the National Regulatory Authorities is that the transmission revenues shall be recoverable out of the capacity-based tariffs.

Article 4.3 *The transmission services revenue shall be recovered by capacity-based transmission tariffs.*

Exceptions for the application of commodity-based tariff which would provide minor part of the transmission revenue are allowed under specific conditions defined in the Article 4.3 of the Code, subject to the approval of the national regulatory authorities.

The Article 13 of the Regulation 715 states that the Tariffs for network users shall be non-discriminatory and set separately for every entry point into or exit point out of the transmission system. Cost-allocation mechanisms and rate setting methodology regarding entry points and exit points shall be approved by the national regulatory authorities. Pursuing this requirement, the TAR NC introduces the concept of the “capacity weighted distance” under the Article 8 and the reference price methodology associated with it. Currently the defined methodology is a kind of suggested application by the ENTSOG and not obligatory for the member states. According to the methodology, entry points and exit points can be combined in a relevant flow scenario, the shortest distance of the pipeline routes between an entry point or a cluster of entry points and an exit point or a cluster of exit points can be taken as reference and in conjunction with the allocated capital expenditures pertaining to the segment, the unit capacity price for each entry and exit point (or cluster of entry and exit points) is determined. There is a specific requirement for the allocation of the revenues referred as the “entry-exit split” meaning the breakdown between the revenue from capacity-based transmission tariffs at all entry points and the revenue from capacity-based transmission tariffs at all exit points. Such split is required as to be 50/50.

Reconciliation requirements under non-price cap regimes have been addressed in the Articles 17 and 20.

Article 17 - Reconciliation of Revenue

1. Where and to the extent that the transmission system operator functions under a non-price cap regime, the following principles shall apply:

(a) the under- or over-recovery of the transmission services revenue shall be minimized having due regard to necessary investments;

(b) the level of transmission tariffs shall ensure that the transmission services revenue is recovered by the transmission system operator in a timely manner;

(c) significant differences between the levels of transmission tariffs applicable for two consecutive tariff periods shall be avoided to the extent possible.

Article 20 - Reconciliation of regulatory account

The regulatory account shall be reconciled with the aim of reimbursing to the transmission system operator the under-recovery and of returning to the network users the over-recovery.

The Article 26 of the TAR NC brings an obligation for the NRAs (or the TSOs as decided by the NRA) to carry out consultations for the tariff application prior to the beginning of each Tariff Application Period. Among others, some information to be published in the consultation document is stated as follows.

The description of the proposed reference price methodology as well as the following items:

(i) the indicative information including:

- (1) the justification of the parameters used that are related to the technical characteristics of the system;*
- (2) the corresponding information on the respective values of such parameters and the assumptions applied.*

(ii) the value of the proposed adjustments for capacity-based transmission tariffs;

(iii) the indicative reference prices subject to consultation;

(iv) the assessment of the proposed reference price methodology; and

(v) where the proposed reference price methodology is other than the capacity weighted distance reference price methodology detailed in Article 8, its comparison against the latter accompanied by the information set out in point (iii).

There is a specific requirement that the consultation document should be published also in the **English** language.

The TAR NC does not require the regulators to adopt certain regulatory regime from the alternatives as price cap and non-price cap regimes (revenue cap, rate of return and cost plus). As of date, the majority of the EU countries apply incentive based Revenue Cap Regulation. However, the TAR NC does not define a methodology for setting up the incentive mechanisms and efficiency targets.

5.14 Annex 14 – Cost-Efficiency Benchmarking for Natural Gas Transmission System Operators

5.14.1 Activity Analysis and Scope

This Annex will be giving information about the employment of efficiency factors and performance metrics (rewards and penalties) in the EU countries' Natural Gas Transmission tariffs and certain applications related with efficiency benchmarking among the gas TSOs.

Incentive regulation can be defined as “the use of rewards and penalties to induce the utility to achieve desired goals where the utility is afforded some discretion of the manner of achieving goals”. Incentive regulation can be introduced through a variety of regulatory tools, including price setting regimes with inbuilt incentives; efficiency reviews focused on controllable costs; benchmarking; and the setting of performance targets associated with both rewards and penalties. Under incentive-based price regulation (also referred to as RPI-X) the regulated entity is allowed to increase its tariffs annually by the level of the Retail Price Index (RPI) minus a target efficiency factor (X). A key part of the tariff application is that the X factor is based not only on the operator's past performance, but also on the performance of other operators.

Benchmarking quantifies the relative historical performance of the network operators. The first step in benchmarking is to search the information that is available. Such information might include system operations, network capacity, financial flows, and outputs. Then with purposes and possibilities in mind, the regulator can choose the metrics to use in benchmarking and how they will be used to provide incentives for improved performance.

Benchmarking is not widely established and applied for Natural Gas Transmission by EU NRAs.

*“A key question then (given the current heavy reliance on bottom-up assessments) is whether the increased regulatory burden of employing benchmarking or other related tools can be justified. The answer depends on the current level of inefficiency in the EU TSO sector. Some inefficiency is likely to exist (it does even in highly competitive markets), but **the critical point is whether the inefficiency is sufficiently large to necessitate closer scrutiny of TSO costs and the use of more rigorous cost assessment methods**. The question is somewhat circular, as benchmarking and statistical analysis would be needed in the first instance to provide empirical evidence for the presence or absence of large inefficiencies. However, a priori, there are grounds for believing that inefficiencies are likely to be material:*

- *by virtue of their monopoly status, TSOs are shielded from competition (and the absence of competition is generally associated with reduced efficiency)*
- *many of the EU TSOs are state-owned businesses and cannot be acquired by or merged with other companies (the threat of hostile takeovers can act as a discipline for operating efficiently)*
- *TSOs cannot be allowed to become insolvent – regulators generally have a legal obligation to ensure the financial viability of the TSOs and in any case TSO bankruptcy would not be tolerated (politically and socially) given the large disruption costs and security of supply concerns*
- *whatever evidence does exist (notwithstanding data and sampling size deficiencies) from cost benchmarking studies of network industries (such as Electricity Transmission and Distribution where benchmarking is more prevalent) suggests that there are very large divergences between the most and least efficient businesses.”³³⁴*

5.14.2 Employment of Efficiency Factors

Related with the topic, the references will be done to the Report “**Methodologies and parameters used to determine the allowed or target revenue of transmission system operators**” (ECA Study) has been prepared by Economic Consulting Associates (ECA) for the Agency for the Cooperation of Energy Regulators (ACER) under the assignment Tariff Network Code, Article 30(1)(b)(iii).

Under the ECA Study, the NRAs were requested to indicate whether cost forecasts or allowed expenditures include efficiency or productivity improvements, whether embedded within the cost forecasts/allowances themselves (eg where these are based on

³³⁴ Source: Methodologies and parameters used to determine the allowed or target revenue of Natural Gas Transmission System Operators (TSOs) Final report September 2018 Submitted to ACER by: Economic Consulting Associates

cost benchmarks) or are set over and above the 'base' cost allowances after assessing the reasonableness of TSO cost submissions (as opposed to applying an efficiency or productivity factor at the level of the overall price or revenue control). **In the case of capital expenditures, the use of efficiency factors was not found to be common; it is generally limited to those NRAs applying a TOTEX approach** and therefore efficiencies are embodied in the analysis itself (ie in Germany, the Netherlands and Great Britain). Beyond these, efficiency considerations for capital expenditure are reflected in Spain, where allowances are partly based on 'reference unit costs' determined under a recent benchmarking/costing study.

In the case of OPEX, the majority of NRAs (19 out of 27) are seen applying efficiency factors. The countries that employ efficiency factors for operating expenditure versus those that do not are shown in the below Table.

Table 5.25 – Employment of efficiency factors when setting OPEX allowances³³⁵

NRAs that employ efficiency factors	NRAs that do not employ efficiency factors
1. Austria	1. Belgium
2. Bulgaria	2. Denmark
3. Czech Republic	3. Estonia
4. Germany	4. Greece
5. Finland	5. Spain
6. France	6. Latvia
7. Croatia	7. Poland
8. Hungary	8. Sweden
9. Ireland	9. Slovakia (not applicable)
10. Italy	
11. Lithuania	
12. Luxembourg	
13. Portugal	
14. Netherlands	
15. Romania	
16. Sweden	
17. Slovenia	
18. Great Britain	
19. Northern Ireland	

The corresponding efficiency factors adopted in the NRA decisions appear in Figure 5.36 below.

³³⁵ Source: Methodologies and parameters used to determine the allowed or target revenue of Natural Gas Transmission System Operators (TSOs) Final report September 2018 Submitted to ACER by: Economic Consulting Associates.

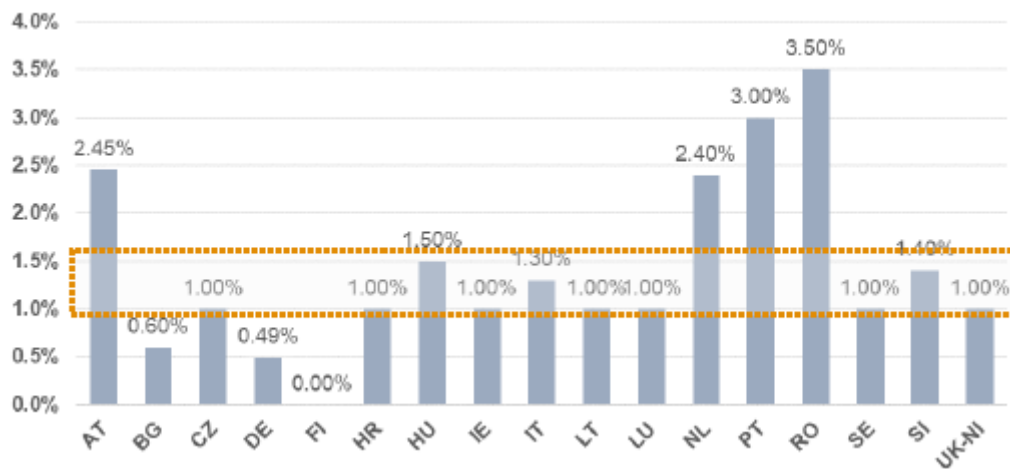


Figure 5.36 – OPEX Efficiency Factors (%)³³⁶

As shown in Figure above, **most OPEX efficiency factors are in the 1%-1.5% range**. Four countries have higher efficiency factors of 2%-3.5%, while Bulgaria employs a lower factor of 0.6%⁴⁴. In the case of Finland, the efficiency factor was 0% for the latest revenue control because of additional tasks undertaken by the TSO (but was previously 1% per year).

For all countries (except the Netherlands) the factors used are effectively for ‘relative efficiency’ (or what is termed ‘static efficiency’ in the Netherlands) - this represents the improvement needed to close the gap between a TSO’s current level of efficiency and that represented by the most efficient firms currently (defined as those firms lying on the ‘efficiency frontier’). **In the case of the Netherlands (and for Germany and Great Britain), this ‘catch-up efficiency’ is embedded in the cost allowances or allowed revenues.** The Netherlands uses a static efficiency factor from two benchmarks and applies a margin of 5%, since some of the data is relatively dated. The TSO is benchmarked against the German TSOs: $78.9 + 5 = 83.9\%$ and against 21 other European TSOs, which has a score of $81.6 + 5 = 86.6\%$.

In Germany, the efficiency factor is TSO-specific, and each TSO must eliminate any inefficiencies compared to the industry benchmark within a regulatory period. However, **in the Netherlands, productivity growth (or what is termed ‘dynamic efficiency’) is also considered** (over and above static efficiency) **and the 0.6% factor refers to this element, representing the expected movement of the efficiency frontier over time**, as new technologies and work practices become available (*Note that, the NRA decision was under challenge when the report is published*). Germany also applies a productivity factor, currently set at 0.49% per year.

5.14.3 Rewards and Penalties

Another area explored with the NRAs through the ECA Study, which is important for incentive-based regimes, is the extent to which there are additional ‘revenues at risk’ (ie further rewards or penalties) associated with a performance regime that sets quality and performance targets and standards.

The results of the survey show that there is limited use of performance regimes or other similar incentive mechanisms, with only the following four NRAs specifying that such incentives are used:

- **Austria** - TSOs are measured on the following performance metrics (with weighting in brackets): customer satisfaction (25%), unplanned availability time (25%), transparency obligations and quality of data (25%), environmental aspects (15%), and agency cooperation (10%). This is a reward-only incentive regime, with up to 5% of OPEX (excluding the cost of fuel gas) ‘at risk’.
- **Finland** – rewards are paid when energy not supplied (ENS) is in the top quartile when compared to the reference years

³³⁶ Source: Methodologies and parameters used to determine the allowed or target revenue of Natural Gas Transmission System Operators (TSOs) Final report September 2018 Submitted to ACER by: Economic Consulting Associates.

(2008-2015). Penalties apply when ENS is in the bottom quartile, and there is a dead band in the middle. The scheme applies symmetrically: +/-2% of 'reasonable return' for the year.

- **France** – there is a quality of supply regime entailing 16 different metrics and other schemes, including additional rewards for implementing large investment projects (>€20m) significantly below budgeted costs (and corresponding penalties for significant cost overruns), and an R&D funding scheme.
- **UK** – there are various schemes in place that cover financial, statutory and reputational incentives. *(Note that the details of UK case are provided in the main body of the Activity 1.1 report, Section 4.2.5)*

5.14.4 Benchmarking of EU Gas TSOs

In general, benchmarking procedures are carried out by means of specially developed mathematic models which relate the quantities of output and input of specific companies to each other and – using the resulting index of productivity – estimate the efficiency of certain companies compared to other companies. Essentially, benchmarking is a relative performance evaluation. The performance of a TSO is compared against the actual performance of other TSOs rather than against what is theoretically possible.

Comparison of information and data on expenditures is difficult to compare across the countries. An initiative by a group of national regulatory authorities (NRAs) in the Council of European Energy Regulators (CEER) was established and a study³³⁷ (the European efficiency benchmarking for Natural Gas Transmission System Operators (E2GAS)) was completed in 2016, following a feasibility study in 2014.

The consultant (Sumicsid SPRL – Belgium) had developed a technical measure called the **Normalized Grid** that basically is a weighted sum of the grid assets that serve the in-scope activities. The weights for the normalized grids correspond to the relative costs of components, transportation, installation and operation for the different assets, based on engineering expertise. It also included the cost factors resulting from environmental complexities (land use, topography, soil structure, humidity). The normalized grid was not derived from the accounting data from the operator, it was calculated directly from the technical asset data. Thus, the desired investment efficiency could be obtained by simply observing the ratio of benchmarked (standardized) capital costs to the normalized grid.

The primary benchmarking model was a DEA model under increasing returns to scale, meaning that operators that are below best-practice scale are not penalized for their size but larger operators are always compared to best-practice. The dataset consisting of 22 operators in a cross section for two reference years (2010 and 2014) was reduced to 21 operators by identifying one extreme outlier using standard techniques. The results have given an average cost efficiency of 79% in the sample, where two operators were classified as frontier outliers and six operators constituted the best-practice peers. This means that on average there was a 21% efficiency difference in terms of total expenditure, corrected for inflation and labor cost differences.

The benchmarking model of E2GAS was as shown in Figure 5.37 below. A gas TSO transforms resources X into services Y. This transformation is affected by the environment Z. The aim of the benchmarking is to evaluate the efficiency of this transformation. The more efficient TSOs are able to provide more services using less resources and in environments that are more difficult.

The inputs X were set typically thought of as OPEX, CAPEX, or TOTEX. Differences in depreciation practices, that taxes, land prices, labor prices etc. were neutralized and it was also found that it was useful to do process-oriented models of OPEX and CAPEX efficiency in addition to the theoretical ideal of TOTEX benchmarking.

The outputs Y were made of exogenous indicators for the results of the regulated task, such as typically variables related to the transportation work (volume of gas delivered etc.), capacity provision (storage volume, peak load, coverage in area etc.) and

service provision (number of connections, customers etc. Outputs were often substituted by proxies constructed as functions of the assets base, like km of pipes, number of meters, number of compressors etc.

The class of structural variables Z contained parameters that may have a non-controllable influence on operating or capital costs without being differentiated as a client output. In this class, it was often found indicators of geography (topology, obstacles), climate (temperature, humidity, salinity), soil (type, slope, zoning) and density (sprawl, imposed feed-in locations).

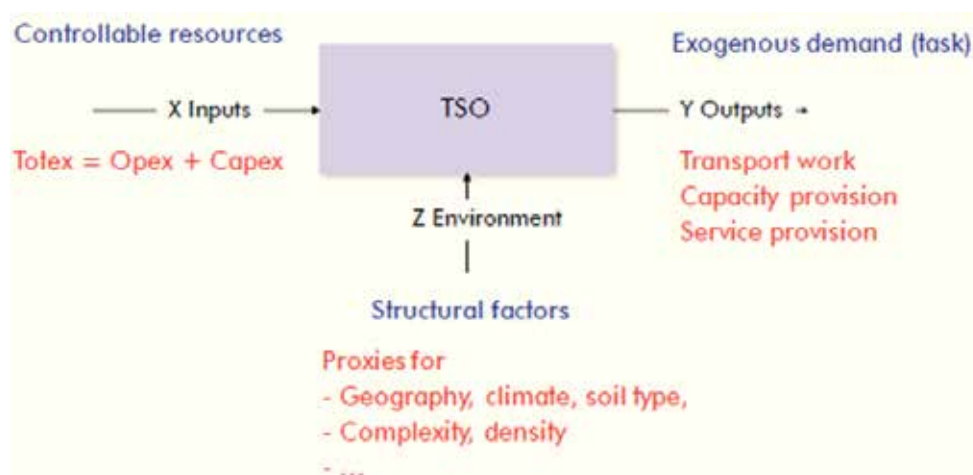


Figure 5.37 – Conceptual Benchmarking Model³³⁸

The final model specification in the e2GAS project included three cost drivers as shown in Table 5.38 below.

Table 5.26 – Model specification: Base model³³⁹

Variables	Comment
INPUT	
dxTotex_noenergy_invadj	Totex excl energy, adj for labor in opex AND investments
OUTPUT	
yNGTotex_adj_ver2	Normalized Grid calibrated to reflect opex-capex relation in sample
yConnections_tot	Total number on connections
yCapacity_max	Maximum of injection and delivery peak capacity

Input in the base model was total expenditure (TOTEX). It was calculated as standardized capital costs using real annuities and after correcting for inflation and currency differences plus standardized operating costs OPEX excluding cost of energy, out-of-scope activities and possible Z-deductions Labor cost expenditures in OPEX were adjusted to average European costs by the EUROSTAT labor cost index. CAPEX also included a labor cost adjustment for 30% of the investment amount that is estimated to be activated labor cost.

The base model used three outputs: normalized grid, total number of connection points, and the peak capacity (maximum of injection and delivery peak capacity)

338 Source: PROJECT E2GAS Benchmarking European Natural Gas Transmission System Operators, 02 June, 2016.

339 Source: PROJECT E2GAS Benchmarking European Natural Gas Transmission System Operators, 02 June, 2016.

In addition to three-cost driver model specification, Unit Cost analysis was also done where TOTEX is explained solely by the Normalized Grid. The full distribution of the efficiencies is shown as a bar chart in Figure 5.39 below. Notably, it is seen that the large number of TSOs have very low efficiencies.

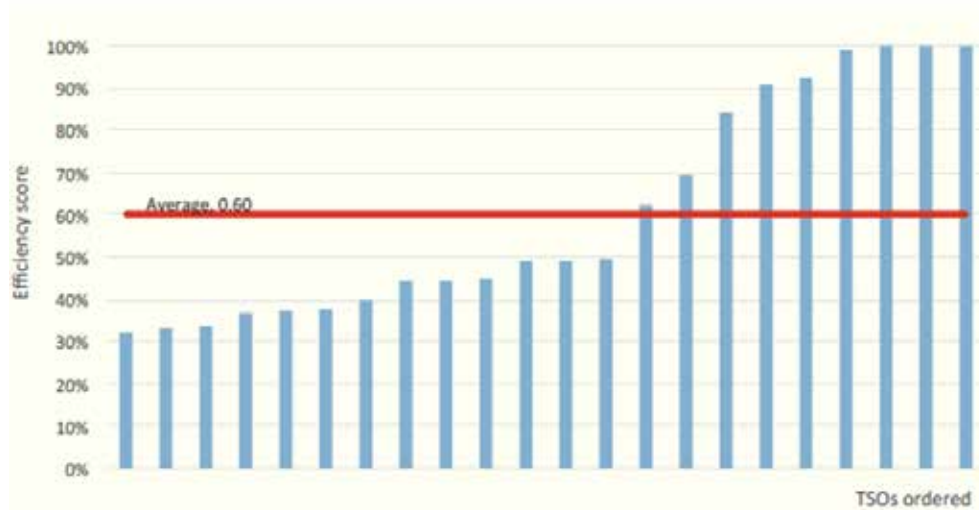


Figure 5.38 – Distribution of Unit Cost Scores³⁴⁰

Most recent CEER study related with Natural Gas Transmission benchmarking is the “The Transmission Cost Benchmarking project 2018 (TCB18)”. It is an initiative by the Council of European Energy Regulators (CEER) to initiate a stable and regular process for performance assessment of energy transmission system operators. The project covered both electricity and Natural Gas Transmission and involved in total 46 operators from 16 countries in Europe.³⁴¹

The benchmarking was performed on NRA collected data, subject to a multi-stage data quality assurance process and using state-of-the-art benchmarking methods such as Data Envelopment Analysis (DEA). The reliability and replicability of DEA results are immediate, since the method does not depend on any ad hoc parameters but relies on the input data and linear programming. The environmental, economic and technical parameters and indices used have been collected from public sources based on clear techno-economic arguments.

The project handled the data quality (i) by issuing and validating data collection guides and templates to avoid the use of incomparable data sources at an early stage, (ii) by defining a clear NRA validating procedure, (iii) by organizing a cross validation process for both technical and economic data through the consultant, (iv) by fully disclosing all processed data to each respective operator for control and confirmation to avoid misinterpretations and error, (v) by organizing interactive workshops to enable questions, and (vi) by providing online support on the project platform for submitting operators and NRAs.

The common core task for the gas TSOs can be defined as providing and operating the assets for transport and transit of energy. More specifically, the study focused on (i) services: transport to downstream exit and transit to a cross-border point, (ii) assets: a pipeline network with its control system and (iii) activities: grid planning, grid financing/ownership, grid construction, grid maintenance, and grid metering. Other elements, notably storage and LNG services/assets and system operations and market facilitation, were kept out of scope in TCB18.

³⁴⁰ Source: PROJECT E2GAS Benchmarking European Natural Gas Transmission System Operators, 02 June, 2016.

³⁴¹ PROJECT CEER-TCB18 Pan-European cost-efficiency benchmark for Natural Gas Transmission System Operators, 17/07/2019

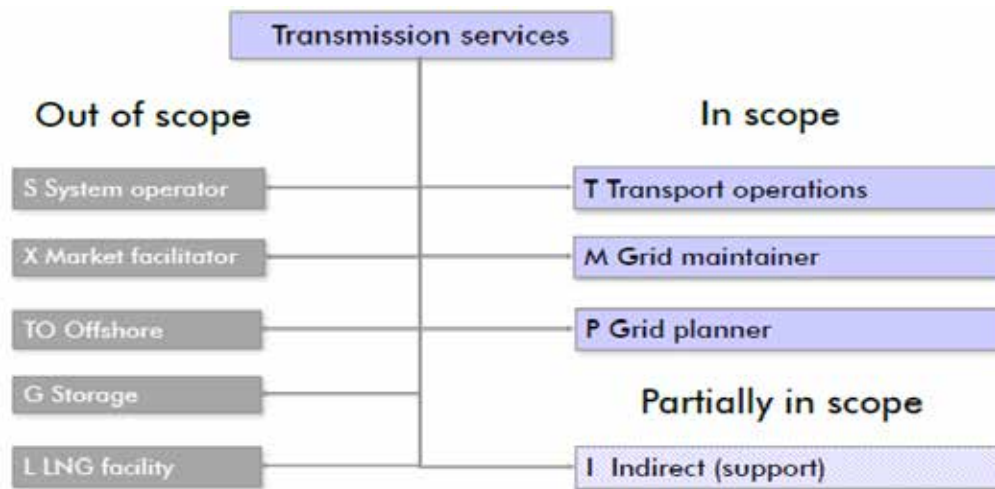


Figure 5.39 – Benchmarked activities and scope³⁴²

Conceptually, the benchmarking model of the TCB18 can be shown as in Figure 5.41 below. A gas TSO transforms resources X into services Y. This transformation is affected by the environment Z. The aim of the benchmarking is to evaluate the efficiency of this transformation. The more efficient TSOs are able to provide more services using less resources and in environments that are more difficult.

The inputs X are typically thought of as OPEX, CAPEX, or TOTEX. It was found in previous studies that a careful cost reporting guide is important to make sure that out-of-scope is interpreted uniformly, and that differences in depreciation practices, that taxes, land prices, labor prices etc. are neutralized.

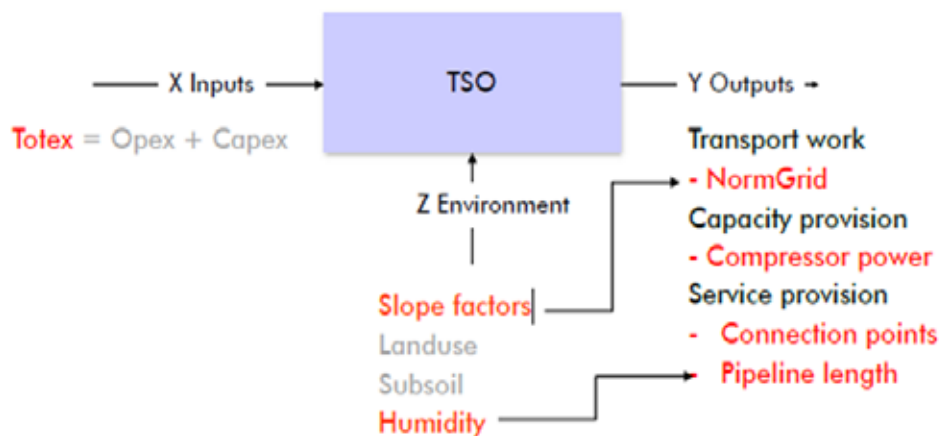


Figure 5.40 – Final Gas Model of the TCB18³⁴³

The outputs Y are made of exogenous indicators for the results of the regulated task, such as typically variables related to the transportation work (energy delivered etc.), capacity provision (storage volume, peak load, coverage in area etc.) and service provision (number of connections, customers etc.). Ideally, the output measures the

services directly. In practice, however, outputs are often substituted by proxies constructed as functions of the assets base, like km of pipelines, number of connections, installed power of compressors etc.

342 Source: PROJECT CEER-TCB18 Pan-European cost-efficiency benchmark for Natural Gas Transmission System Operators, 17/07/2019.

343 Source: PROJECT CEER-TCB18 Pan-European cost-efficiency benchmark for Natural Gas Transmission System Operators, 17/07/2019.

The class of structural variables Z contains parameters that may have a non-controllable influence on operating or capital costs without being differentiated as a client output. In this class, there are indicators of geography (topology, obstacles), climate (temperature, humidity, salinity), soil (type, slope, zoning) and density (sprawl, imposed feed-in locations). Elaborate engineering weight systems of the grid assets have been used to reflect the

investment and operating conditions. In this way, Z factors could to a large extent be captured by the traditional Y factors.

Main findings

The TCB18 project has established a comprehensive platform for cost efficiency assessments in Natural Gas Transmission through a set of detailed data specifications for assets, activities, costs and environmental conditions. The specifications have been reviewed in several rounds by NRAs, TSOs and external experts to be as relevant and clear as possible

The collected data have been processed in order to derive a benchmarking model capturing the three main service dimensions (grid provision, capacity provision and customer service) considering heterogeneous economic and environmental conditions and technical specifications. Using the normalized grid metric, the multiple assets of the power system have been included to form a TOTEX-relevant proxy for grid size, more predictive to cost than using conventional measures such as pipeline length or gas volumes transported. Using statistical methods to derive the most informative models, a final model with four outputs and one input, TOTEX, has been developed.

The cost efficiency results from the model present a mean cost efficiency for 2017 corresponding to 79% of relevant TOTEX. This result indicated an efficiency improvement potential that is on average about 21%.

Benchmarking for gas TSOs, Germany Case

Germany may be regarded as unique case with 16 gas TSOs and applying efficiency benchmarking among the TSOs. The NRA, Bundesnetzagentur, carries out its national efficiency benchmarking on the basis of the assessed costs before the start of each new regulatory period. Total cost benchmarking approach is adopted that takes both capital and operating costs equally into account.

A network operator's efficiency is not determined solely on the basis of the absolute level of the operator's costs. Rather, the costs recognised as necessary for network operation are assessed in relation to the operator's supply obligations (an operator may well be operating extremely efficiently even though the operator's network charges are higher than others' – it is simply that the operator's circumstances are different). Efficiency benchmarking determines each operator's relative cost efficiency compared to other operators, taking into account the individual supply tasks. The network operators are compared only with each other. The benchmark is always an existing energy network operator and not a company operating in an actual competitive sector such as the automobile industry.

The benchmarking does not take into account any costs that a network operator cannot control, such as costs for the use of the upstream network. The Incentive Regulation Ordinance (ARegV) lists the costs that are deemed to be non-controllable.

In Germany, the efficiency factor is TSO-specific, and each TSO must eliminate any inefficiencies compared to the industry benchmark within a regulatory period. Germany also applies an efficiency factor, currently set at 0.49% per year. A network operator's efficiency is not determined solely on the basis of the absolute level of the operator's costs. Rather, the costs recognized as necessary for network operation are assessed in relation to the operator's supply obligations. The efficiency benchmarking determines each operator's relative cost efficiency compared to other operators, taking into account the individual supply tasks. The network operators are compared only with each other.

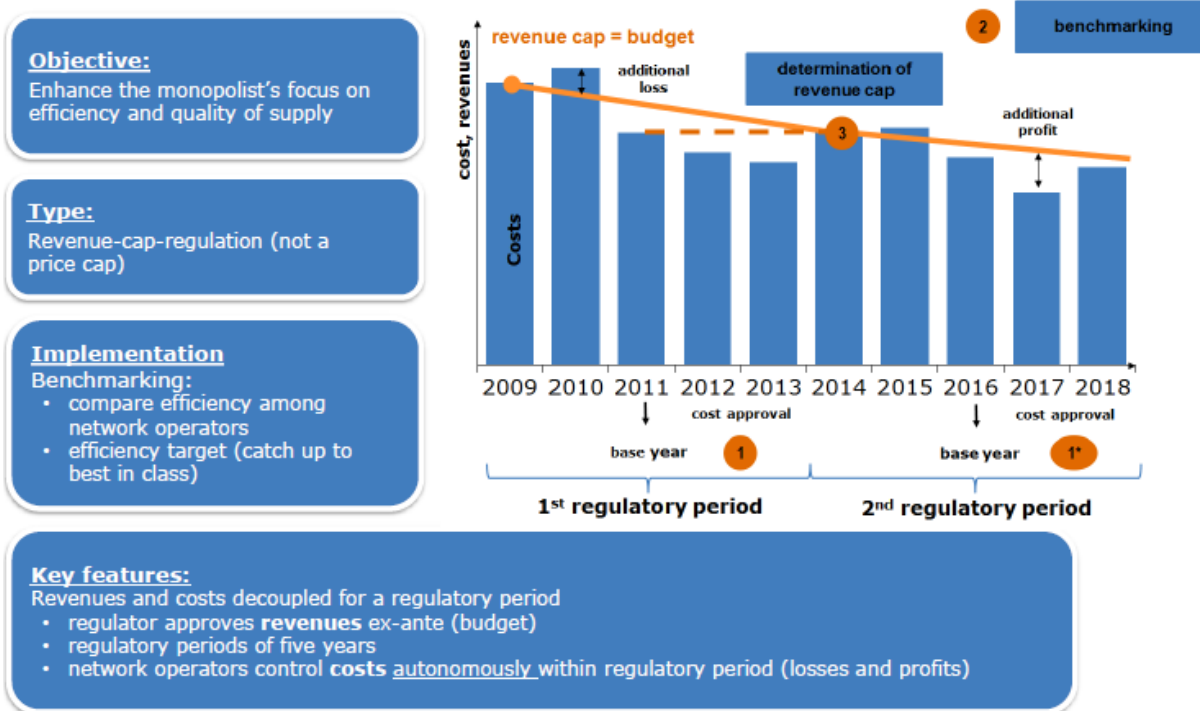


Figure 5.41 – Overview on the German Incentive Regulation³⁴⁴

Benchmarking among the network operators is carried out to determine individual efficient costs. General efficiency targets are individually defined for each TSO (X-gen) by individual efficient costs (X-ind). TSOs are obliged to cut inefficient costs over the regulatory period.

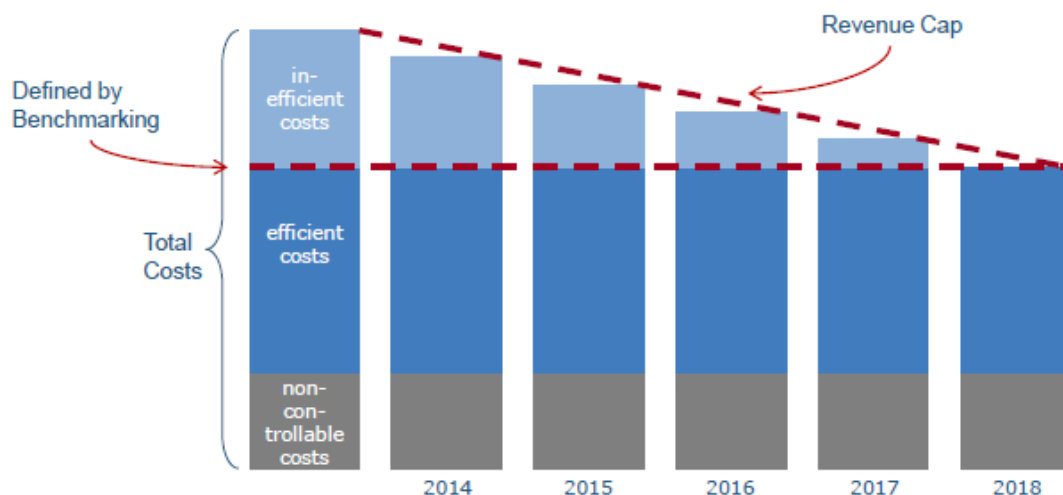


Figure 5.42 – Incentive Regulation Procedure

BNetzA published an evaluation report of the German incentive regulation in 2015³⁴⁵ where one of the main findings was that the

344 Source: Dr. Annegret Groebel, BNetzA's role in energy infrastructure regulation and planning/permitting.

345 Bundesnetzagentur-Evaluation report pursuant to section 33 of the Incentive Regulation Ordinance, 26 February 2015

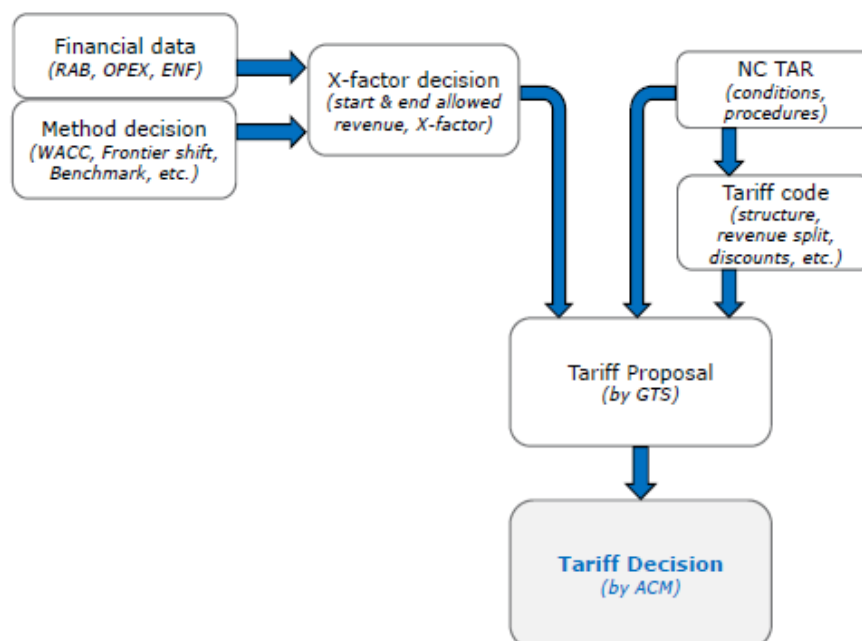
incentive regulation provides network operators with incentives to operate the network efficiently.

The third regulatory period for Natural Gas Distribution and Transmission System Operators began on 1 January 2018 and will last until 2022. To determine the efficiency scores for the 16 German TSOs, the structural and cost data were first subjected to an intensive examination and plausibility check. The efficiency model identified and applied included the structural parameters of pipeline volume, corrected number of entry and exit points, surrounding surface and corrected compressor capacity. This was primarily a continuation of the model from the second regulatory period, with the addition of the compressor capacity. The average efficiency score of all TSOs was 98.06%, with 13 of the 16 achieving 100%. All revenue caps except one had been completed by the end of the year.³⁴⁶

Benchmarking for gas TSOs, Netherland Case

The regulator, the ACM, sets the permitted revenues for the national TSO, Natural Gas Transmission Services (GTS) and thus the maximum tariffs, based on the method decision. The method decision describes the method by which GTS can recoup its efficient costs during a regulatory period, and the rules and parameters that apply. The current regulatory period runs from 2017 to 2021. At the beginning of 2019, the ACM adopted a revised method decision in which the amount of the permitted returns (WACC) and the annual productivity improvement were adjusted, as a result of a successful appeal by GTS to the Dutch Trade and Industry Appeals Tribunal (CBB) against the original amount of these parameters. The ACM has now started to prepare for the method decision for the next regulatory period, which starts in 2022. These preparations include a study of the utilisation of the gas transport network and the development of GTS transport tariffs in the coming decades. The results of this study will be included in the next method decision. Aside from this, it is also expected that in future method decisions, the ACM will also compare GTS' cost efficiency with that of other European gas transport companies (cost benchmarking).³⁴⁷

As a result of two decisions issued by the CBB in 2019, the ACM released an amended version of the GTS 2017-2021 method decision and a second amended version of the GTS 2017-2021 x-factor decision. The outcome of these decisions produces an overall upward adjustment to the permitted revenues over the 2017-2021 period. This one-time adjustment is reflected in the regulated tariffs for 2020 (and probably also 2021). It is expected that the ACM will publish the draft method decision for the new regulatory period in September 2020. The ACM's final method decision for the new regulatory period will follow in the first quarter of 2021.



³⁴⁶ Bundesnetzagentur Annual Report 2018.

³⁴⁷ GTS Annual Report 2019

Figure 5.43 – Context of the Tariff Decision³⁴⁸

Prior to the commencement of the regulatory period 2017 – 2021, ACM had decided to use the German gas TSO benchmark commissioned by BNetzA to determine the static efficiency of GTS. ACM had commissioned Frontier Economics and Consentec to undertake a static efficiency analysis for GTS. The aim of the benchmark study was to determine the static efficiency of the costs for GTS based on the data from all gas TSO's (totally 13 TSOs) participating in the German benchmark undertaken in 2012 and used for the regulatory period 2013-2017. The analysis had been based on data from the year 2010 with the steps illustrated in the figure given below ³⁴⁹

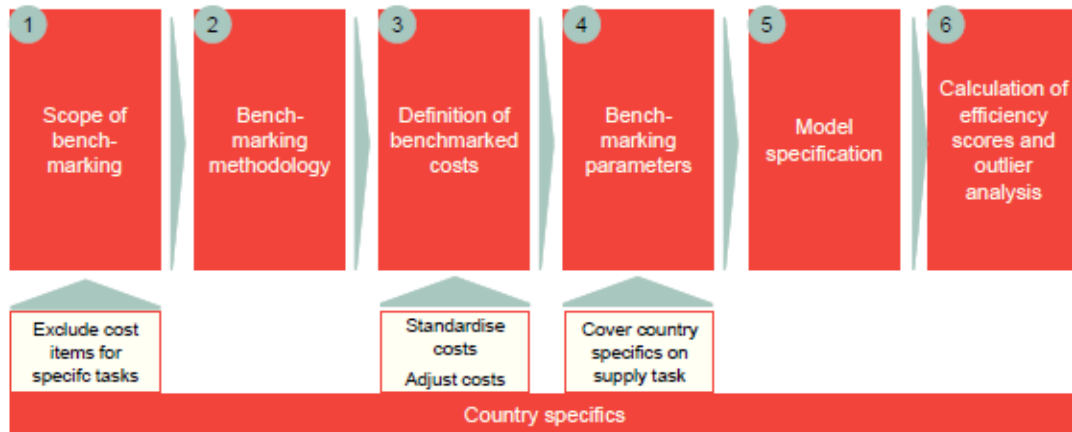


Figure 5.44 – Steps in Benchmarking Analysis

By applying DEA in the study, the relatively simple approach of comparison of partial indicators of efficiency (e.g. employees per kWh, length of transmission line per kWh etc.) was generalized, in order to compare companies with multiple inputs and outputs. The approach consisted of enveloping the recorded input and output data of the companies by an optimal frontier. The frontier was described by those companies which realize the most favourable output-input combination. Formally, this frontier was calculated by a linear optimization program. The relative efficiency of those companies which do not meet the frontier was calculated as relative distance to the frontier. DEA determines – from the multidimensional input-output area – a one-dimensional summary measure of efficiency relative to the best-performing companies.

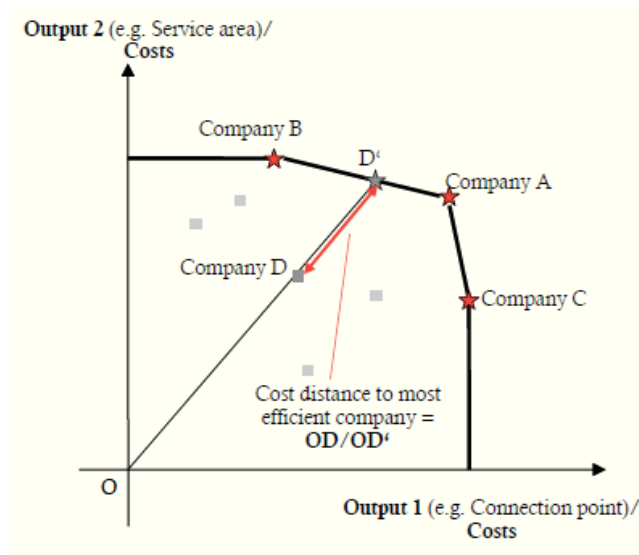


Figure 5.45 – DEA Functional Diagram

348 Explanation Tariff Decision, GTS 2020 15 May, 2020.

349 Source: (Frontier/Consentec) "Gas TSO efficiency analysis for the Dutch transmission system operator", January 2016

A long-run service model was adopted in the study, in which the efficiency of the operator is judged-based on the total cost (TOTEX) incurred relative to the outputs produced, which in this case would be represented by the services provided by the operator. The OPEX part of the total costs was classified as:

1. Energy costs;
2. Labour costs;
3. Expenses for external services;
4. Other expenses;
5. Capitalised assets and (non-tariff) Revenue

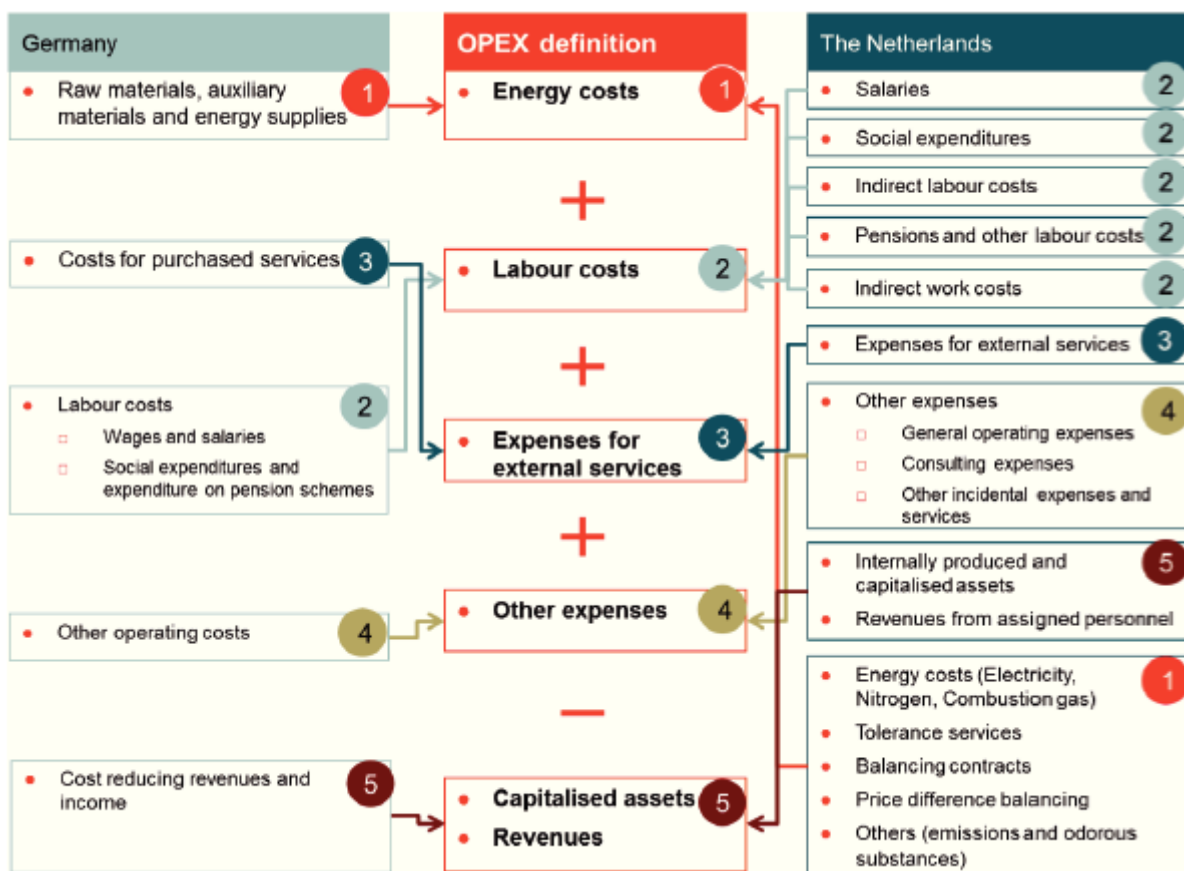


Figure 5.46 – Grouping of GTS and German Gas TSOs OPEX³⁵⁰

Given the differences in the calculation of capital costs between the involved German TSOs and GTS a separate calculation of capital costs for the study was necessary. In order to make CAPEX comparable we apply the approach used by ACM for calculating CAPEX which was based on

- indexed historic costs;
- standardised depreciation periods; and
- WACC approach to calculate the cost of capital.

The detailed data on investment streams for GTS and the German gas TSOs allowed to apply the excel file used by ACM when calculating the capital costs. The approach allowed an alignment of the capital costs used in the benchmarking analysis and in the allowed regulatory revenues.

Possible model candidates were formed based on the following three principles:

- Modelling of the supply task
- Identifying inefficiencies
- Practicability

The process of model specification in had led to three possible model candidates. Two of which have also been considered in the German TSO benchmarking.

Model A included pipeline volume to reflect the dimension of capacity provision. Pipeline volume can be classified as non-exogenous parameter because network companies can control this parameter by companies' decisions. Hence, the model (partly) was considered as comparing how efficient network companies have constructed and operated (part) of their physical assets (i.e. pipelines).

Model B included pipeline volume and transport momentum (as part of SQRT (TM*area). On the one hand the model considered as comparing how efficient network companies have constructed and operated (part) of their physical assets. On the other hand, also comparing how efficient network companies fulfil their supply task reflected by the exogenous parameter transport momentum.

Model C included only exogenous parameters. The model was considered as comparing how efficient network companies fulfil their exogenous supply task and neglects companies' physical assets as output.

As illustrated in the figure given below the three models differed with respect to the number of outliers, the average and minimum efficiency:

	Model A	Model B	Model C
Output 1 <i>Granularity</i>	Connection points		
Output 2 <i>Capacity provision</i>	Pipeline volume		Transport momentum
Output 3 <i>Network expansion</i>	Supply area	SQRT (TM*area)	Supply area
Average efficiency*)	95.7%	88.2%	96.2%
Number of outlier	2	1	2
Minimum efficiency*)	75.3%	59.5%	85.1%
Efficiency GTS*)	75.3%	79.2%	90.5%

Source: Frontier / Consentec

*) based on DEA (NDRS) excluding outlier

Figure 5.47 – Final efficiency scores



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Special Note – Benchmarking Fuel Gas Efficiency

Fuel gas burned in compressor stations driven by gas turbines is among the main cost elements in OPEX, especially for the countries consuming significant amount of gas, like Turkey. The typical amount in many cases would be around 1 % of the throughput. A quick evaluation is given below about the efficiency benchmarking related with fuel gas cost (in terms of amount).

Benchmarking with other TSOs and Networks: Although the figures indicating the percentage of fuel gas with respect to throughputs may provide certain idea, such benchmarking would not be realistic and reliable. The geography, length of the pipelines, transported amounts and the amount of LNG in the mix and the efficiency of the compressor facilities themselves are important elements effecting the consumed amounts. Many other factors like the delivery pressures at the entry interconnections are also beyond the control of the TSOs. What is aimed by fuel gas incentive is basically the improvement of TSO efficiency in operating the compressor stations. Benchmarking with other networks can not provide direct base to assess the said incentive.

Benchmarking Using Historical Data of the TSO: What is important here is to define the reference conditions for benchmarking. The usage of the historical data of the network is essential tool together with a specific methodology to be applied. Such methodology in assessing efficiency performance of the TSO regarding fuel gas consumption needs to be developed by the TSO itself. Apart from incentives that can be defined by the Regulatory Authority, Energy Efficiency is among the obligations of the TSOs and such methodology is expected to be developed by the TSO in any case.

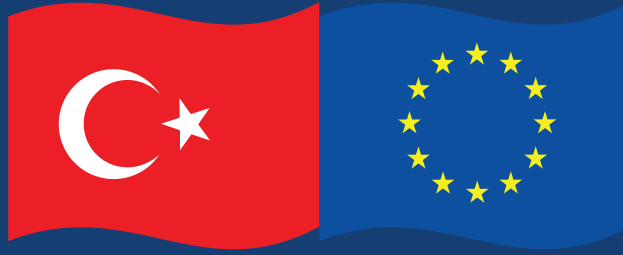
There are certain critical issues to consider when using the historical data and defining reference conditions. The amount of LNG in the mix is an important detail. LNG regasification terminals provide enough compression to inject natural gas into the transmission grid and there is usually no compressor station located at such LNG Terminal entry points. On the other side, in most cases there are compressor stations located at the entry points with interconnected upstream pipeline networks. So, referenced throughput volumes should take into account such distinction.

The Network configuration changes is another important element. Benchmarking using historical data needs to be done with similar network configurations. *(The case of BOTAS Kırklareli Compressor Station is a good example for this. Formerly, an important portion of fuel gas had been utilised in the station. Upon the commencement of deliveries through the Turk Stream Pipeline, the station is no more in operation as before.)*

There are many other factors that must be taken into consideration together with the overall throughput (like the changing amounts for each entry and exit point since the locations of such points effect the fuel gas consumption) affecting the fuel gas consumption. So, evaluation of performance might be considered individual compressor station basis also.

Line pack levels also effect the fuel gas consumption of the compressor stations. Maintaining ideal levels of line packs in different segments may become an important element. This may be associated with allowance of the TSO to keep account in underground storage facilities.

Evaluation criteria needs to be updated every year and the TSO should submit annual reports in performing fuel gas incentive. This is the applied methodology in the UK where the NGGT has a regression model for fuel gas performance, using historic data. The regression model is updated on an annual rolling basis.



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