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Report on Regulatory Frameworks for European Energy Networks 2022

Incentive Regulation and Benchmarking Work Stream

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INFORMATION PAGE

Abstract

This document (Ref. C22-IRB-61-03) presents the 2022 edition of the CEER report on regulatory frameworks for European energy networks.

This report provides a general overview of the regulatory regimes applied in 2022 and the required efficiency developments. It also analyses the overall determination of capital costs of CEER members plus Northern Ireland and five Energy Community Regulatory Board (ECRB) members, four of which are also CEER observers. A major focus is placed on the calculation of an adequate rate of return (RoR), the determination of the regulatory asset base (RAB) and the depreciation of assets in the different regulatory regimes. Other important individual parameters and new incentive mechanisms presented in this study should be interpreted in the context of a whole country-specific regulatory regime. Some contents only reflect an ex ante approach for 2022, while ex post calculations are yet to be performed.

This report also serves as a background paper to CEER work on incentives, both in a quantitative as well as in a qualitative way.

Target Audience

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

Keywords

Regulatory framework, investment conditions, networks, rate-of-return regulation, regulatory asset base, cost of capital, incentive mechanisms, depreciations.

Disclaimer

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Related documents

Council of European Energy Regulators (CEER) documents

- CEER Report on Regulatory Frameworks for European Energy Networks 2021, 31 January 2022, Ref. C21-IRB-61-03
- CEER Report on Regulatory Frameworks for European Energy Networks 2020, 11 March 2021, Ref. C20-IRB-54-03.
- CEER Report on Regulatory Frameworks for European Energy Networks 2019, 28 January 2020, Ref. C19-IRB-48-03.
- CEER Report on Regulatory Frameworks for European Energy Networks 2018, 18 January 2019, Ref. C18-IRB-38-03.
- CEER Report on Investment Conditions in European Countries in 2017, 11 January 2018, Ref. C17-IRB-30-03.
- CEER Report on Investment Conditions in European Countries in 2016, 24 January 2017, Ref. C16-IRB-29-03.
- CEER Report on Investment Conditions in European Countries in 2015, 14 March 2016, Ref. C15-IRB-28-03.
- CEER Memo on regulatory aspects of energy investment conditions in European countries, 27 April 2015, Ref. C14-IRB-23-03a.
- CEER Memo on regulatory aspects of energy investment conditions in European countries, 7 March 2014, Ref. C13-IRB-17-03.
- CEER Memo on regulatory aspects of energy investment conditions in European countries, 4 July 2013, Ref. C13-EFB-09-03.

External documents

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1 Introduction

This report is the 2022 version of a series of annual reports drafted and issued by the Council of European Energy Regulators (CEER). It provides a general overview of the regulatory systems for electricity and gas networks (transmission system operators (TSO) and distribution system operators (DSO)) in CEER member countries in 2022. Due to a cooperation agreement between CEER and the Energy Community Regulatory Board (ECRB) the 2021 edition contains additional contributions from several ECRB Members. The 2022 edition still contains contributions from five ECRB Members (four of which are also CEER Observers), who opted to remain part of this report. The editors are proud to announce that the Ukrainian regulatory agency decided to be part of this year´s version again, although threatened by a violent and cruel war. As a show of solidarity with Ukrainian colleagues we have changed Ukraine's position in the report so that it comes first in the list of countries in Chapter 2.

A major focus is placed on the calculation of a classic and adequate rate of return (RoR), the determination of the regulatory asset base (RAB) and the depreciation of assets in the different regulatory regimes.

Other factors may also influence the work of the regulated network operators or the decisions of investors including, for example, the time required for permitting processes or the overall stability of the implemented regime. However, these equally important aspects go beyond the scope of this report and are therefore not covered in this analysis. With respect to this, the reader should be aware that the parameters presented in this study must be interpreted in the context of a whole country-specific regulatory regime.

CEER considers that in a system with a mature regulatory framework, the regulatory review will generally be a package of different decisions that need to form a coherent whole.

As tariff regulation schemes are highly complex, a direct comparison of certain parameters, such as capital costs, is difficult and should only be done in the context of the whole regulatory system.

CEER addressed this challenge by undertaking a survey among CEER and ECRB members, which focused on the main elements for determining allowed revenues. This data was then subject to a basic comparison, and a number of conclusions were drawn.

This report includes data submitted by the National Regulatory Authorities (NRAs) of Austria, Belgium, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Great Britain, Greece, Hungary, Iceland, Ireland, Italy, Latvia, Lithuania, Luxembourg, Netherlands, Northern Ireland, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain and Sweden (27 CEER Members plus Northern Ireland), and Albania, Georgia, Montenegro, North Macedonia and Ukraine (five ECRB Members, four of which are also CEER Observers).

The data collection, covering the current regulatory regimes in 2022, took place in the first half of 2022. In comparison to the previous report, no major content changes were found in respect of the most important parameters.

To keep the overview of the CEER and ECRB Members in the second chapter (and the equivalent tables in Annex 4), the contributions of ECRB countries have been added in alphabetic order following the contributions of CEER countries (with the exception of Ukraine as previously mentioned). In addition to the second chapter, one more country (Estonia) took the opportunity of authoring a national case study that describes its regulatory regime in a more detailed manner with tables and calculation examples (Annex 5).[1] For further details regarding differences or developments one can consult last year's report.[2]

As a further development of this report a new annex was added to this year´s version. Annex 6 deals with the so-called General Case Study (GCS). Although the main objective of this report is not to compare or rank different regulatory regimes with each other, there is always the question as to what the regulatory consequences of a national network operator faced with a foreign regulatory system would be. The GCS tries to find an answer to this question. By giving some details and answering several questions about the national regulatory system of the participating countries, an allowed revenue of a fictional electricity DSO is calculated. Because of the different treatment and influence of the regulatory instruments of the participating countries, different revenues are calculated. This enables a simplified comparison between the involved countries. It must be added that this comparison is limited in its conclusions due to the many individual national regulatory rules and instruments which are not generally, or even uniquely, used in the participating countries.

[1] Annex 5 is uploaded as a separate document on the same webpage of CEER as this report.
[2] CEER Report on Regulatory Frameworks for European Energy Networks 2021, 31 January 2022, Ref. C21-IRB-61-03.

2 Compact description of the regulatory framework

There is some variation in the number, size and structure of electricity and gas network operators across European countries, partly because of how individual European countries have developed in the past. However, network operators are universally regarded as natural monopolies requiring regulation by NRAs.

As each country decides on the type and structure of its regulatory system, it is not appropriate to compare individual systems directly. Examining the different systems does, however, make it possible to identify similarities between them. No one system is unique. Rather, each system makes use of a toolbox of regulatory instruments reflecting the current state of thinking about regulation in a country. It is often the case that several regulatory systems employ the same tools or combinations of them. However, such tools are used in accordance with their suitability in the national context.

This chapter describes most European regulatory systems. The subsections describe the regulatory framework per country without going into great detail. Any questions regarding specific features should be directed to the individual NRA that provided the description.

This chapter is intended to provide assistance to both NRAs and potential investors. It may provide supporting material/useful background information in the event of a possible change in the national regulatory system, or if key data from other regulated countries are compared. In addition, it gives investors an overview of the prevailing returns and terms for planned investments.

Each national description includes a fact sheet listing the key regulations and figures that provides an overview.

2.1 Ukraine

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	1	43	1	32
	Network length	~33,400 km	~289,600 km	24,585 km	818,782 km
	Ownership	Public ownership	Mainly public ownership, local public and private ownership	100% state property	Mostly private, the state has majority or minority stakes
General framework	**Authority**	National Energy and Utilities Regulatory Commission (NEURC, www.nerc.gov.ua)			
	System	Incentive regulation	Cost-plus	Cost-plus	Cost-plus, rate-of-return and revenue cap
	Period	Five years. Current regulatory period (RP): 2020-24	Yearly	Yearly	Cost-plus – annually; incentive-based regulation – five years (except first RP was three years)
	Base year for next period	Last year of the current RP	t-3, t-2 – fact, t-1 – estimates	t-2 – fact, t-1 – estimates	Last year of the current RP
	Transparency	The materials for regulatory decisions are published on the regulator's website for making proposals/comments and discussions with the public			
	Main elements for determining the revenue cap	Allowed revenue is composed of OPEX considering efficiency factors, CAPEX, depreciation adjusted to inflation rates	Allowed revenue is composed of OPEX, CAPEX, depreciation adjusted to inflation rates	OPEX, depreciation, network losses, costs of ancillary services, costs of performing public special obligations (PSO)	Controllable (taking into account the efficiency factor) and non-controllable operating costs, quality factor, depreciation, network losses
	Legal framework	The Laws of Ukraine "On the natural gas market", "On the natural monopolies", NEURC Resolutions of 30 September 2015 # 2517 and of 25 February 2016 # 236		Law "On the electricity market", "On natural monopolies", procedures for setting tariffs for electricity transmission and distribution services, legal acts adopted by the regulator, regulating conditions and parameters of incentive-based tariff regulation	
Rate of return	**Type of weighted average cost of capital (WACC)**	Post-tax	Not used	Not used	Post-tax
	Determination of the rate of return on equity	Calculation of marginal level of regulatory RoR is carried out (on 30 November 2018) considering leverage ratio of twin-companies and relevant leverage according to the database of Dr. Damodaran and	N/A	N/A	The RoR is set by the regulator

		without taking into account adjustment coefficient depending on the level of the company			
	Rate of return on equity before taxes	13.5% (NEURC Resolution of 24 December 2019 # 3012)	N/A	N/A	3% on the “old”[3] RAB, 16.74% on the “new”[4] RAB. The marginal RoR is set by the Ministry of Economic Development at the level of 19.11%
	Use of rate of return	The regulatory RoR is multiplied by the cost of the RAB. The regulatory RoR is set separately for the old RAB and new RAB	N/A	N/A	Applies to current RAB
Regulatory asset base	**Components of RAB**	Fixed assets	Not used	N/A	Fixed assets
	Regulatory asset value	Old RAB calculated based on the independent asset value assessment performed by State Property Fund of Ukraine	N/A	N/A	Based on revaluation of assets
	RAB adjustments	The value of the RAB is adjusted after the end of the RP	N/A	N/A	New investments net of disposals, depreciation and connection
Depreciations	**Method**	Straight line			
	Depreciation ratio	The useful lifetime depends on asset type: pipeline ~40 years, gas control equipment ~25 years, technological equipment ~16 years		Useful life of assets: buildings and structures 30-70 years; power lines 30-40 years; transformers and substations 25-35 years	
	Consideration	Based on expected useful lifetime			

Natural gas network tariff regulation

Over the past few years, Ukraine has made a number of important changes in the regulation of the gas market. One of the main achievements in this process was the adoption in 2015 of the Law of Ukraine “On the Natural Gas Market”.

The Law is a key document that establishes European standards for the Ukrainian natural gas market, as defined in the 3rd Package, particularly in Directive 2009/73/EC of the European Parliament and of the Council concerning common rules for the internal market in natural gas, and Regulation (EC) No 715/2009 of the European Parliament and of the Council on conditions for access to the natural gas transmission networks.

[3] Existing (created) before transition to incentive regulation.
[4] Created after transition to incentive regulation.

The Law stipulates that the natural gas market is based on the principles of free competition, proper protection of consumer rights and security of natural gas supply, and is capable of integration with the natural gas markets of the Energy Community member states, including by creating regional natural gas markets. The new law enshrined the EU's economically sound approaches to the organisation of the natural gas market, separated the functions of the operator from the functions of gas production and supply, clearly outlined the functions of the state and the independence of the regulator, and established the principle of regulating natural monopolies and free pricing in competitive gas market segments.

Within the framework of the implementation of the Law and in order to effectively implement the reform of the natural gas market, NEURC (the Ukrainian NRA) adopted a number of secondary legislation acts in accordance with the requirements of the 3rd Package of EU energy legislation. This was in a form adapted for the Energy Community, on the basis of which the liberalised natural gas market now operates, particularly the Natural Gas Transmission System Code, the Natural Gas Distribution System Code and methodologies of setting the tariffs in the natural gas market.

One of the main features of the new market is the increase of competition due to the entry of new players, including foreign ones, into the domestic market of natural gas of Ukraine, as well as increasing the attractiveness of the Ukrainian energy market.

Transmission of natural gas

From 1 January 2016 NEURC made a decision to apply incentive regulation in the natural gas transmission sphere. The RP is five years (except for the first RP, which was established by a separate decision of NEURC).

The calculation of the projected allowed revenue is carried out per year based particularly on reasonable operating costs (controlled/uncontrolled costs of natural gas transmission and costs associated with the purchase of natural gas to cover gas losses), depreciation, profit on the RAB, income tax, as well as adjustments in case of detection and confirmation of violations as a result of the state supervision (control).

During the RP, according to the actual data, the allowed revenue may be adjusted, taking into account, in particular:

- Actual values of the consumer price index (CPI), industrial producer price index, nominal average monthly wage growth index;
- Changes in the volume of booked capacities;
- Revenue received from the rights to use short hauls; and
- Changes in the current legislation of Ukraine.

In 2019, to implement the provisions of the EU Regulation № 2017/460, NEURC changed its approach for calculating natural gas transmission tariffs by introducing the power-weighted distance methodology. This methodology takes into account both the projected capacity of each entry/exit point or group of entry/exit points and the weighted average distance to the entry/exit point or group of entry/exit points while calculating transmission tariffs. NEURC set the transmission tariffs for the 2020-24 RP based on this methodology.

Distribution of natural gas

By 2020, payment for natural gas distribution services was based on the physical volume of natural gas distribution.

In order to implement the provisions of the Law of Ukraine “On the Natural Gas Market” from 1 January 2020, NEURC made the transition to the methodology as a fee for the booked capacity and changed the principle of determining the cost of payment for natural gas distribution services for customers. The monthly cost of the natural gas distribution service is defined as the product of 1/12 of the annual ordered capacity of the consumer's facility (facilities) at the tariff set by NEURC.

The tariff for natural gas distribution services is determined based on the DSOs’ costs, which are necessary to ensure the natural gas distribution activity, and reasonable profitability. The annual booked capacity for the estimated calendar year is determined based on the actual volume of natural gas consumption of the previous gas year.

Electricity network tariff regulation

Transmission of electricity

The electricity tariff for the TSO is set in accordance with the methodology adopted by the NEURC resolution as of 22 April 2019 № 585, which provides for incentive-based tariff regulation and the cost-plus transitional period, similarly to the DSO methodology.

During 2016-17, the necessary regulatory framework for the application of incentive-based tariff regulation for the TSO was developed and adopted. Currently, as of 2021, a cost-plus tariff is set for the TSO, while its required income consists of operating costs (material costs, depreciation and technological losses), profit (capital investments, funds to repay loans from international financial organisations, dividends to the state budget and income tax), as well as the cost of a special obligation to increase the share of renewable energy production, which is imposed on the TSO in accordance with the Law of Ukraine “On the Electricity Market”. The system operation services costs (dispatching, balancing/ancillary services, etc.) are covered through the separate dispatch service tariff, calculated using a cost-plus methodology.

Distribution of electricity

In 2013, NERC (NEURC since 2014) adopted an incentive-based tariff regulation framework for electricity DSOs.

In accordance with the requirements of the new Law of Ukraine “On Electricity Market” to replace the relevant regulation on electricity distribution tariffs, NEURC adopted a resolution as of 5 October 2018 № 1175 “On approval of the Procedure for establishing (forming) tariffs for electricity distribution services.” This defined the procedure for setting the tariff for electricity distribution services (both for incentive-based regulation and for the transitional period of application of the cost-plus methodology).

The incentive-based regulation application conditions are mandatory reinvestment of 50% of profits in construction and modernisation of the so-called “old” RAB (the RAB created before the transition to incentive-based regulation) annually. It also includes full implementation of the data reliability action plan to ensure the quality of services monitoring (including creating an outages registration system at the 6-150 kV network level).

During 2020, NEURC finalised amendments to the regulatory framework, according to which, in particular, the possibility of transition to incentive-based tariff regulation is provided for only from the beginning of the year, and the regulatory RoR is set at the level of 3% for the "old" RAB, and 16.74% for the "new" one.
-It should be noted that under the order of the Ministry of Economic Development and Trade of Ukraine as of 21 April 2016 № 729, the regulatory RoR cap for DSOs for the RP is set at 19.11%. The regulatory RoR set by the regulator cannot be higher than the cap approved by the Ministry of Economic Development and Trade of Ukraine.

NEURC's resolution also stipulates that DSOs' networks losses must be reduced by at least 1% annually at the first voltage class (above 27.5 kV) and by 3.5% in the second voltage class. The system average interruption duration index (SAIDI) should be decreased steadily over the next 13 years from 466 to 150 minutes in urban areas and from 960 to 300 minutes in rural areas. At the same time, the DSOs that use the cost-plus methodology are obliged to achieve the target level of SAIDI during the 18-year period, due to limited financial resources.

If a DSO fails to comply with the quality of services indicators, it is subject to a penalty in the form of adjustment of its required revenue, established as an incentive to improve the quality of services.

For 2021, the regulator set electricity tariffs for 25 out of 32 DSOs in Ukraine using incentive-based tariff regulation. Since 1 January 2022 one more DSO has switched to incentive-based tariff regulation. Other DSOs are still regulated based on transitional cost-plus methodology.

Transparency

Prior to submitting the issue of setting tariffs for consideration of NEURC, the licensee shall hold an open discussion (open hearing) at the place of licensed activity.

The draft decisions of the regulator on tariff setting are also subject to an open discussion on the approved procedure. All necessary information is published at the official website of NEURC.

Open discussions are held to balance the interests of consumers, licensees and the state and provide access to information on tariff setting for consumers, customers, licensees, state authorities and local governments, the media, and public organisations.

2.2 Austria

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	2	21	2	120
	Network length	2,000 km	44,500 km	7,000 km	246,100 km
	Ownership	Private and public	Private and public	Private and public	Private and public
General framework	**Authority**	E-Control (www.e-control.at/)			
	System	Incentive regulation – price cap	Incentive regulation – revenue cap	Cost-plus regulation	Incentive regulation – revenue cap
	Period	Four years. Current period: 2021-24	Five years. Current period: 2018-22	Annual	Five years. Current period: 2019-23
	Base year for next period	TBD	2020	2021	TBD
	Transparency	Methodology description	Current regulatory framework	Summary of the framework	Current regulatory framework
	Main elements for determining the revenue cap	Annual target, increase in WACC for taking full volume risk, indexed historic depreciated costs to determine RAB	Efficiency scores and general productivity offset, network price index and expansion factors, efficiency dependent WACC	Costs of t-2, annual target, network operator price index, ex ante costs according to network development plan	Efficiency scores and general productivity offset, network price index and expansion factors, efficiency dependent WACC
	Legal framework	Gas Act 2011 (GWG 2011)		Electricity Act 2010 (ElWOG 2010)	
Rate of return	**Type of WACC**	Investments from 2021 onwards: nominal pre-tax WACC, old investments mixed WACC [real cost of equity (share 40%) and nominal cost of debt (share 60%)]		Nominal WACC pre-taxes (equity share 40%, debt share 60%, beta transformation: Modigliani-Miller)	
	Determination of the rate of return on equity	r_E = (risk-free rate + levered Beta * market risk premium) / (1 - tax rate) + volume risk premium		r_E = (nominal risk-free rate + levered Beta * market risk premium) / (1 - tax rate)	
	Rate of return on equity before taxes	8.94% (real pre-tax, set in 2020, including volume risk premium of 3.5%) = (0.26% + 0.85 * 4.5%) / (1 - 0.25) + 3.5%	8.16% (nominal pre-tax, set in 2017, granted for the average efficient DSO) = (1.87% + 0.85 * 5%) / (1 - 0.25)	8.16% (nominal pre-tax, set in 2017) = (1.87% + 0.85 * 5%) / (1 - 0.25)	8.16% (nominal pre-tax, set in 2018, granted for the average efficient DSO) = (1.87% + 0.85 * 5%) / (1 - 0.25)
	Use of rate of return	Investments from 2021 onwards: nominal WACC * RAB		Nominal pre-tax WACC * RAB (book values)	
Regulatory asset base	**Components of RAB**	Intangible and fixed assets, distinction between assets up to 2020 and assets from 2021 onwards	Intangible and fixed assets, book values	Intangible and fixed assets, book values and ex ante determination of investments according to the network development plan	Intangible and fixed assets, book values
	Regulatory asset value	Historic cost approach for debt and indexed historic cost approach for equity up to 2020. For investments occurring from	Historic cost approach	Historic and planned cost approach	Historic cost approach

		2021 onwards a nominal WACC applies			
	RAB adjustments	None	RAB developments during an RP are taken into account, lead to changes of the regulated cost base	None, but yearly adjustments due to annual cost audits	RAB developments during an RP are taken into account, lead to changes of the regulated cost base
Depreciations	**Method**	Straight line			
	Depreciation ratio	Depends on asset type: lines 2-3%, transformers 4-5%, substations 4%			
	Consideration	Pass through	Pass through	Pass through	Pass through

Regulatory tasks

E-Control, the Austrian regulatory authority for the electricity and gas industry, determines the costs and volumes of two electricity TSOs, 60 electricity DSOs and 21 gas DSOs. Furthermore, the regulator has the power to approve a tariff methodology proposed by the two gas TSOs. The regulatory commission then performs the task of tariff setting based on the costs and volumes determined by E-Control. For the relevant legislation (the Electricity Act 2010, ElWOG 2010 and the Gas Act 2011, GWG 2011) please refer to E-Control's website.[5]

The relevant DSO/TSO, the Austrian Federal Economic Chamber, the Austrian Federal Chamber of Labour, the Federal Chamber of Agriculture and the Austrian Trade Union Federation are official parties in the regulatory procedure. The latter two – the Federal Chamber of Agriculture and the Austrian Trade Union Federation – are only invited to comment on the draft decisions, whereas the network operators and the two major customer representatives, may also challenge E-Control's official decision concerning costs and volumes, before the administrative courts. The customer representatives are also invited to participate in oral hearings with network operators, industry representatives, and associations on the design of various regulatory parameters such as the WACC, general productivity factors (X_{gen}), benchmarking models and the regulatory framework in general.

Current regulatory frameworks

Electricity transmission

The two Austrian electricity TSOs are regulated with an annual cost-plus methodology. Those costs and volumes are audited on an annual basis on the latest available costs (historical values). To transform the values to the year when the tariffs are in force, a network operator price index (NPI), an individual efficiency target (X_{ind}) and a general productivity offset (X_{gen}) apply for controllable costs. Currently, for one TSO the individual efficiency factor stems from CEER's international E3Grid Benchmarking procedure. For the other TSO, the efficiency target corresponds with the X_{gen} from the distribution grid.

Investments made according to the ten-year network development plan (TYNDP) need to be approved by E-Control. Resulting capital costs are recognised ex ante. To promote and facilitate investments, an equity premium of 0.8% applies, which translates into an overall

[5] See https://www.e-control.at/en/remit/rechtsgrundlagen?inheritRedirect=true.

WACC of 5.20% per annum (pa) for new assets. The WACC (including the premium) is granted for a time span in line with the third RP for gas DSOs (2018 to 2022).

Non-controllable costs consist of ancillary services, secondary control, network losses, and costs due to network expansion within the TYNDP, among others. These costs are beyond the company's control. Consequently, they are not subject to any efficiency targets.

Additional elements included in the cost-plus framework permit the companies to earn a bonus if ex ante set targets on various market relevant duties are met.

The regulatory account ensures that the companies bear no volume risk at all. Differences resulting from deviations between planned and actual volumes are considered when setting new tariffs in the subsequent years.

Gas transmission

In contrast to all other sectors, E-Control is not obliged to approve the gas TSOs' costs and volumes annually. Instead, E-Control approves a forward-looking tariff methodology that is submitted by the TSOs as a proposal. After approval, the regulatory authority sets costs and volumes according to these principles for the whole duration of the RP[6]. Tariffs remain constant during the period.

The current regulatory framework grants investments realised from 2021 onwards a nominal pre-tax WACC of 3.58%. Furthermore, no regulatory account exists for gas TSOs. Consequently, these entities bear the full volume risk. To compensate them for the assumed risk, their return on equity is raised by 350 basis points (bps). Costs for planned investments are considered ex ante and aligned with actual investments in the next RP.

Forward-looking operating costs are adjusted with an efficiency factor consisting of an individual and a general component. In total, the requirement amounts to 1.5% pa. The target results from a self-assessment by the TSOs, as well as negotiations between customer representatives and the TSOs. In addition, a symmetric bonus-malus scheme for quality and performance criteria exists.

Finally, the equity return is uplifted by 150 bps for research and development investments (pilot projects). Eligible pilot projects must enhance the efficiency of operation and should bear a positive economic surplus. If external research funds grant a subsidy, these grants are not deducted from allowed operational expenditure (OPEX).

Electricity distribution

The current fourth RP for electricity DSOs lasts until 31 December 2023 (five-year period).

The OPEX is adjusted annually by a network operator price index (NPI) (consisting of a consumer index and an index of collectively agreed wages and salaries), a general productivity offset (0.95% pa) and an individual efficiency factor. The individual efficiency factor is derived from the national relative efficiency benchmark together with a time span to eliminate inefficiencies over a period of seven and a half years (one and a half RPs). The benchmarking analysis relies on modified ordinary least squares (MOLS) and data envelopment analysis

[6] A description of the tariff methodology for the current RP 2021-24 is published in English at: https://www.e-control.at/en/marktteilnehmer/gas/netzentgelte/methodenbeschreibung.

(DEA). In comparison with the past RP, the period for eliminating individual inefficiencies was shortened to strengthen the incentive of efficiency targets. At the same time, the efficiency floor was raised. Furthermore, an operating cost factor adjusts the budget during the RP for a change in service provision. The operating cost factor reflects changes in OPEX due to changes in line lengths and metering points as well as the roll-out of smart meters.

Capital expenditure (CAPEX) is adjusted annually with an efficiency-dependent return as an incentive system. The income of occurred investments is granted based on a t-2 lag. Depreciation constitutes a pass-through. The return on investment (ROI) up to 2016 is adjusted based on the company specific efficiency value taken from the national benchmark. Returns vary within a bandwidth of ±0.5% around the pre-tax WACC of 4.88%, granted to the average efficient DSO. A calibration mechanism ensures that the system is cost neutral. Consequently, the rewards for above-average performers equal the penalties for below-average performers. Investments during the RP are treated as average-efficient until a new benchmarking analysis evaluates these. In addition, investments during the RP are encouraged by a mark-up on the WACC.

Finally, a regulatory account ensures that effects due to the t-2 lag do not translate into windfall profits or losses for the network operators.

Gas distribution

The third RP for gas DSOs started on 1 January 2018 and ended on 31 December 2022 (five-year period).[7] Compared to the previous one, several major changes applied.

The inflation-adjusted budget constraint is now limited to OPEX, while CAPEX is adjusted annually with an efficiency-dependent return as an incentive system. Both remuneration systems are based on a national benchmarking analysis and are similar to those for electricity DSOs, with two further incentives for gas DSOs to acquire new customers and to encourage the grid's density (providing services to more customers with the existing grid lengths). Initially, the efficiency-dependent ROI was not cost-neutral as the incentive for above-average DSOs exceeded the cost cut for those below average.

The Austrian Federal Economic Chamber and the Austrian Federal Chamber of Labour appealed against the official decisions of all gas DSOs. So far, a number of cases have been settled by the respective DSOs and the customer representatives. The settlement foresees to design the efficiency-dependent remuneration in a cost-neutral way and to raise the X_{gen} from 0.67% to 0.83% pa. Some cases are still pending at the Federal Administrative Court but can be expected to be settled with the same outcome.

[7] A description of the third RP for gas DSOs (only available in German) is published at: https://www.e-control.at/marktteilnehmer/gas/netzentgelte/entgeltermittlungsverfahren.

2.3 Belgium

		Gas TSO	Gas DSO		Electricity TSO	Electricity DSO	
Market structure	Network operators	1	9	1		10	1
	Network length	± 4,200 km	57,352 km	2,932 km		132,830 km	6,428 km
	Ownership	Private and public	Public		Private and public	Public	
General framework	Authority	CREG	VREG	BRUGEL	CREG	VREG	BRUGEL
	System	Incentive regulation / revenue cap	Cost + / IR on costs and KPI		Incentive regulation / revenue cap	Cost + / IR on costs and KPI	
	Period	Four years. Current RP: 2020-23	Four years. Current RP: 2021-24	Five years. Current RP: 2020-24	Four years. Current RP: 2020-23	Four years. Current RP: 2021-24	Five years. Current RP: 2020-24
	Base year for next period	Third year in current RP	Period from Y-6 to Y-2	Fourth year in current RP	Third year in current RP	Period from Y-6 to Y-2	Fourth year in current RP
	Transparency	NC TAR (network code on harmonised transmission tariff structures)	Full transparency through extensive consultation and publication	Full transparency through extensive consultation and publication		Full transparency through extensive consultation and publication	Full transparency through extensive consultation and publication
	Main elements for determining the revenue cap	Non-controllable and controllable costs, depreciation costs, taxes and fair margin	Controllable (depreciation, OPEX and WACC) and non-controllable costs, cost trend, inflation, incentives related to economies of scale, frontier shift and quality benchmark	N/A	Non-controllable and controllable costs, depreciation costs, taxes and fair margin	Controllable (depreciation, OPEX and WACC) and non-controllable costs, cost trend, inflation, incentives related to economies of scale, frontier shift and quality benchmark	N/A
	Legal framework	NC TAR, Belgian law, CREG approved tariff methodology	Regional legislation, tariff methodology	Brussels Region law, tariff methodology	Belgian law, CREG approved tariff methodology	Regional legislation, tariff methodology	Brussels Region law, tariff methodology
Rate of return	Type of WACC	No use of WACC	Nominal, pre-tax	Vanilla WACC		Nominal, pre-tax	Vanilla WACC
	Determination of the rate of return on equity	Sum of a nominal risk-free rate and a risk premium (market risk premium multiplied by a risk factor) multiplied by (1+ illiquidity premium) multiplied by a corporate tax factor	Sum of risk-free rate and risk premium	Nominal risk-free rate (ten-year Belgian bonds with a min 2.2% and max 5.5%), beta 0.7, risk premium 4.5%. 5.35% = 2.2% + 4.5%*0.7		Sum of risk-free rate and risk premium	Nominal risk-free rate (ten-year Belgian bonds with a min 2.2% and max 5.5%), beta 0.7, risk premium 4.5%. 5.35% = 2.2% + 4.5%*0.7
	Rate of return on equity before taxes	5.76% = (0.90+3.5*0.65) * (1+0.20) * 1.513	5.44%	4.39% (2020)		5.44%	4.44% (2020)

	Use of rate of return	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	RAB and net operating working capital (NOWC) (lower WACC for revaluation surpluses, green certificates and regulatory surpluses/ deficits)	Granted for existing assets to a maximum of 40% (gearing) of the employed capital. Any available equity capital in the capital structure in excess of this will be subject to another equity interest rate		RAB and NOWC (lower WACC for revaluation surpluses, green certificates and regulatory surpluses/ deficits)	Granted for existing assets to a maximum of 40% (gearing) of the employed capital. Any available equity capital in the capital structure in excess of this will be subject to another equity interest rate
Regulatory asset base	**Components of RAB**	Fixed assets, working capital, assets under construction	Intangible and tangible fixed assets (including assets under construction, excluding goodwill)	Fixed assets, assets under construction		Intangible and tangible fixed assets (including assets under construction, excluding goodwill)	Fixed assets, assets under construction
	Regulatory asset value	€2.3 billion (2016)	€4.8 billion (+ €2.1 billion revaluation surpluses)	€470 million (2020)		€3.0 billion (+ €1.2 billion revaluation surpluses)	€756 million (2020)
	RAB adjustments	Investments (+), divestments (-), depreciation (-), subsidies (-)	-	Investments (+), divestments (-), depreciation (-), subsidies (-)		-	Investments (+), divestments (-), depreciation (-), subsidies (-)
Depreciations	**Method**	Straight line	Straight line	Straight line		Straight line	Straight line
	Depreciation ratio	Depends on assets: pipes 2%, compressors 3%	Depends on asset type	Depends on assets, see tariff methodology[8]		Depends on asset type	Depends on assets, see tariff methodology[9]
	Consideration	Non controllable	-			-	

Electricity and gas distribution in Flanders

Since 2014, tariff methodologies for gas and electricity distribution have been approved by the regional regulator.

In Flanders, the Vlaamse Regulator van de Elektriciteits- en Gasmarkt (VREG) was appointed as the competent authority. There are currently ten DSOs for electricity (134,000 km, 3.5 million European Article Numbering codes (EANs)) and nine for gas (58,000 km, 2.3 million EANs). Their only shareholders are the Flemish cities and communities. The DSOs agreed a contract with operating company Fluvius System Operator, the single company in charge of operating and developing those grids in Flanders.

[8] Brugel. (2019). Méthodologie 2020 – 2024, Partie 4, Méthodologie – Gaz, p.15. Retrieved from: https://www.brugel.brussels/publication/document/notype/2019/fr/Methodologie-Methodologie-tarifaire-Gaz.pdf.
[9] Brugel. (2019). Méthodologie 2020 – 2024, Partie 4, Méthodologie – Electricité, p.15. Retrieved from: https://www.brugel.brussels/publication/document/notype/2019/fr/Methodologie-Methodologie-tarifaire-Elec.pdf.

Since 2015 VREG has used a total expenditure (TOTEX) revenue cap to set the tariffs, to promote efficiency. On the other hand, exogenous DSO costs, like for the use of the transmission grid and for the payment of green certificates (public service obligation), are passed through. An RP usually consists of four years, with 2021-24 being the latest. A nominal WACC of 3.5% on the RAB (€6 billion electricity, €4 billion gas, straight-line depreciation) was set for that period. In response to the merger of Eandis and Infrax in 2018 to become Fluvius System Operator, a cost reduction incentive was initiated to reflect the economies of scale. This will lead to a global maximum reduction of the allowed revenue for the DSOs of €109 million by 2024. The cost of capital for old revaluation surplus values on the regulated assets (€2 billion) began being gradually reduced in 2022, with the intention to fade out this simulated cost over time. The tariff methodology also contains an incentive for quality of service, mainly focused on power outages.

Electricity and gas distribution in the Brussels Capital Region

Sibelga is the single distribution grid operator in the Brussels Capital Region for both gas and electricity. The first tariff methodology established by Brugel (the energy regulator for the Brussels Capital Region) covered the years 2015-19, for both electricity and gas distribution in the Brussels Capital Region. The current tariff methodologies cover the years 2020-24 and are based on a hybrid cost-plus model. Two incentive regulation mechanisms are part of the current tariff methodologies. on costs on the one side, and on key performance indicators (KPIs) on the other side:

- Regarding costs, the operator is incentivised to maintain its actual spending under budget as it retrieves 50% of the actual-budget difference (within a limit set at 10% of the budget); and
- Regarding KPIs, the operator is incentivised to reach certain thresholds set by Brugel for a selection of parameters (SAIDI, system average interruption frequency index (SAIFI), complaint handling, etc.).

The next regulation model, for the period 2025-29, is expected to evolve from the current cost-plus regulation and will probably use a revenue or price cap.

The next tariff methodology will address the challenges facing the energy distribution sector in Brussels, including:

- The establishment of fair distribution tariffs and access to the best quality of services at the best price for all Brussels' distribution network users;
- The increased electrification and the transition towards low-carbon emissions of society; and
- The future use of the gas distribution network and the risk of stranded assets.

The full set of documents regarding the regulatory framework in Brussels is available (in French and Dutch) on Brugel's website.[10]

Electricity and gas transmission

Since 2002 for electricity and 2003 for gas, a tariff methodology has been approved by the Belgian NRA, the Belgian Federal Commission for Electricity and Gas Regulation (CREG). The methodology is applied for four years each time, meaning that the fifth edition is currently in place.[11] Each time, the methodology has been a revenue cap system, whereby the budget

[10] See https://www.brugel.brussels/themes/tarifs-de-distribution-12/methodologie-tarifaire-2020-2024-320.
[11] The full tariff methodology (in French) can be found at: https://www.creg.be/fr/publications/decision-z111011.

for four years is approved and all differences with reality are recorded in the regulatory account. The focus of the methodologies has evolved from period to period. During the first periods the focus was more on the control and decrease of OPEX, while during the more recent periods the focus was, and still is, on incentives.

When the gas transmission network was first regulated, interconnection points (IPs) were not regulated, which meant that transit activity was out of scope. In 2010, because of a change in vision, transit flows also became regulated, whereby those revenues and costs were added into the global calculation of the unique tariff.

This new vision resulted in several court cases being initiated by almost all shippers. Indeed, all of these shippers had lucrative long-term contracts with their clients (the so-called “sanctity contracts”) and did not agree that the tariffs of these contracts should become CREG-approved tariffs, However, in CREG’s opinion these tariffs needed to be non-discriminatory, meaning that the same transmission service offered at the same moment should be priced at the same tariff. Ultimately CREG won the court cases. This non-discriminatory principle was also the objective for the preparation of the EU Framework Guidelines on Tariff Structures, which later formed the basis of the Network Code on Tariff Structures. Because the non-regulated Ips in Belgium had rather low costs but high capacities (due to historical reasons), this led to a decrease in the regulated transmission tariff in 2010 of about 30%.

As explained previously, the original focus of the tariff methodology was on lowering OPEX. Different systems had been tried, such as a built-in X-factor that pushed the trajectory of OPEX down. In reality, the OPEX decrease was not significant. CREG subsequently decided, in consultation with the TSO, to put in place an efficiency-sharing mechanism whereby the TSO was allowed to retain 50% of the yearly OPEX decrease. This method proved very effective, as the TSO diminished its OPEX by around 20% over eight years. This resulted in tariff decreases of 5% in 2013, 7% in 2015 and a further 5% in 2018. Benchmarking of costs with other European TSOs did not seem efficient because it was not binding, and the efficiency score was not explainable (black box).

Another significant difference with the existing tariff methodology was the ex post calculation of the authorised margin. The ex ante approved margins, based on estimated inflation and ten-year bond rates, were recalculated ex post during the TSO’s reporting to the NRA. This led to very significant profit decreases because of the fall of the ten-year bond rates to historic low levels, even approaching zero. The very significant drops in OPEX and authorised margins has led to fill the regulatory account, mathematically. The actual level of the regulatory account is the result of the tariff methodology that stimulated the TSO to significantly decrease its OPEX and recalculate its margin according to very low ten-year bond rates. The tariff methodology in place foresees a downward trajectory of the regulatory account to a reasonable level at the end of 2023. This buffer will be needed to limit tariff increases, as from 2024 when long term contracts come to an end, shippers will book capacity much closer to their real needs.

As explained previously, the actual tariff methodology has incorporated incentive mechanisms such as lowering OPEX, lowering methane and carbon emissions, connecting biomethane installations to the grid, the availability of electronic booking platforms, and the firmness of capacity offerings.

CREG is now, together with the TSO, preparing a new tariff methodology for the period 2023-27. There are new challenges such as lower capacity bookings because of optimisation by the shippers, the energy transition towards a low carbon market, a possible merger with interconnectors, and a possible transfer of pipelines to the hydrogen network that has to be built.

2.4 Croatia

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	Network operators	1	35	1	1
	Network length	2,531 km	19,673 km	7,795 km	140,967 km
	Ownership	Public ownership	Private and local public ownership		
General framework	Authority	Croatian Energy Regulatory Agency (HERA, www.hera.hr)			
	System	Incentive regulation / Revenue cap		Cost-plus method (cost of service, rate of return)	
	Period	Five years; current RP 2017-2021		One year	
	Base year for next period	Base year is 2015 for second regulatory period 2017-2021		Base year is 2019 for regulatory period 2021	
	Transparency	For the gas TSO, information is published on its website.[12]	For the gas DSO, information about regulation and prices are published on HERA's website.[13]	Network Methodology, decision on tariff items' amounts	
	Main elements for determining the revenue cap	OPEX and CAPEX OPEX is projected for regulatory period based on 1+CPI-X formula, without ex post adjustment if realised above, but with profit-sharing mechanism if realised OPEX is below projected level. Budgeted-planned CAPEX, with an ex post adjustment based on real values (only up to the economically efficient level).		OPEX and CAPEX Operating costs TP_{pos} include the following: • Costs of network maintenance; • Costs of loss coverage in the network; • Costs of gross salaries; • Other staff costs; • Other business related costs; and • Other costs determined by the law. Costs of capital main items: RAB, WACC and allowed depreciation.	
	Legal framework	Methodology for the Determination of the Amount of Tariff Items for Gas Transmission (Official Gazette, No. 48/18,58/18, 79/20). Methodology for the Determination of the Amount of Tariff Items for Gas Distribution (Official Gazette, No. 48/18).		Meanings of the expressions used in this Tariff System are determined by the Energy Act ("Official Gazette", No. 120/12, 14/14, 102/15, 68/18), the Act on the Electricity Market ("Official Gazette", No. 22/13, 102/15, 68/18, 52/19).	
Rate of return	Type of WACC	Nominal pre-tax WACC		Pre-tax WACC	
	Determination of the rate of return on equity	The RoR on equity (r_e) is determined by applying the capital asset pricing model (CAPM), according to the formula: $r_e = r_f + \beta \times (r_m - r_f)$ where: • r_f is the risk-free RoR (%); • r_m is the RoR on the diversified market portfolio (%); • $r_m - r_f$ is the market risk premium (%); and • β is the coefficient of variability of return on the operator's shares in		The RoR on equity (r_e) is determined according to the formula: $r_e = r_f + (r_m - r_f) \cdot \beta$, where: • r_f is the risk-free RoR (%); • $(r_m - r_f)$ is the market risk premium (%); and • β is the coefficient of variability of return on the energy operator's shares in relation to average variability of return on market portfolio.	

[12] See https://www.plinacro.hr/default.aspx?id=592.
[13] See https://www.hera.hr.

		relation to the average variability of return on the market portfolio.			
	Rate of return on equity before taxes	RoR on equity: 5.34% Risk-free RoR: 2.75% Coefficient β: 0.54 Market risk premium: 4.80% RoR on diversified market portfolio: 7.55% Share of equity in total capital: 50% RoR on debt: 3.92% Share of debt in total capital: 50% RoR on profit: 18% Amount of WACC for the RP: 5.22%	RoR on equity: 6.84% Risk-free RoR: 4.25% Coefficient β: 0.54 Market risk premium: 4.80% RoR on diversified market portfolio: 9.05% Share of equity in total capital: 50% RoR on debt: 4.88% (maximum value) Share of debt in total capital: 50% RoR on profit: 20% Amount of WACC for the RP: 6.72% (maximum value)	Risk-free RoR: 2.70% Coefficient β:0.38 Market risk premium 6.45% Cost of equity: 4.85% Cost of debt: 3.36 % Share of equity in total capital: 40% Share of debt in total capital: 60% Corporate tax factor: 18% Amount of WACC for the RP: 4.03%	Risk-free RoR: 2.70% Coefficient β: 0.38 Market risk premium: 6.45% Cost of equity: 4.85% Cost of debt: 3.36% Share of equity in total capital: 40% (maximum value) Share of debt in total capital: 60% Corporate tax factor: 18% Amount of WACC for the RP: 4.03%
	Use of rate of return	The nominal WACC before tax is used as the RoR 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.		The RoR is calculated using the WACC before tax as a RoR on assets. The cost of equity is calculated using the CAPM. The share of debt and equity are defined as targeted share in the amount (debt 60% and equity 40%).	
Regulatory asset base	**Components of RAB**	RAB includes both tangible and intangible assets that are in operation and = planned investments that will be put into operation for each year of the RP.		RAB includes average value of regulated assets in the beginning of the year and at the end of the year. RAB does not include the value of assets received without charge, financed by grants.	
	Regulatory asset value	RAB is calculated as historical cost of the assets such as depreciated book value of the assets.		RAB is calculated as historical cost of the assets such as depreciated book value of the assets.	
	RAB adjustments	In the last year of the RP, revision of allowed revenues is performed. The RAB is revised in such a way that the revised value of regulated assets at the end of each regulatory year (t) is equal to the realised value determined on the basis of the balance sheet, in part that HERA considers reasonable. For the TSO, the value of pipelines is adjusted according to utilisation rate.		N/A	

Depreciations	**Method**	Linear method	Straight line method
	Depreciation ratio	2.86% for gas pipelines, measuring and regulating stations and office buildings, while for other types of assets 5-10%	Lines: 2.5%-3.3% Substations: 2.5%-3.3% Transformers: 2.5%-4% Buildings: 2%
	Consideration	Amount of annual depreciation of regulated assets is added to the allowed revenue.	Amount of allowed annual depreciation is included in CAPEX.

Regulatory framework for tariff determination for gas infrastructure activities

The Croatian NRA is the Croatian Energy Regulatory Agency (HERA). The methodologies for determining the tariffs for gas infrastructure activities in the Republic of Croatia are based on the incentive regulation method, i.e. the revenue cap method. This means projected allowed revenue should cover reasonable operating expenses generated when performing the energy activity, and ensure the return on regulated assets. The revenue cap method applied stipulates the RP as a multiannual period for which, separately for each regulatory year, the allowed revenues are defined. These consist of eligible OPEX, eligible CAPEX and the amount of tariff items. The duration of the first RP was three years (2014 - 2016), the second (2017 - 2021) and subsequent RPs are five years.

The allowed OPEX is projected for the RP on the basis of the 1+CPI-X formula (CPI = projected CPI for the regulatory year). In addition to the efficiency factor X, for OPEX, as an important incentive element for the system operator, a profit-sharing mechanism is also stipulated. This is implemented in such a manner that after expiry of the RP, the base OPEX for the following RP is defined so that the system operator retains 50% of the realised savings from the base year.

The eligible CAPEX, which includes depreciation cost and the return on regulated assets, recognises an equity capital investment into a regulated energy entity, i.e. provides sufficient funds for the required investments for the construction and reconstruction of the system and to cover the regulated return on invested capital. The regulated assets consist of tangible and intangible assets in use, that are part of a particular gas system, and investments under an approved system development plan that are taken into account for the regulatory year in which they will be in use. CAPEX i.e. depreciation and return on regulated assets, is not included in direct efficiency improvement mechanisms, but is defined by an ex ante approach as part of approving the investment plans and the amount of tariff items. This reduces the investment risk and provides more investment incentives. Namely, the risk of not covering the costs of infrastructure projects if they are eligible and economically efficient, is eliminated. Additional incentives in terms of CAPEX may lead to overinvestment and are therefore not required.

An important incentive element within the applied regulatory method is the regular audit of allowed revenues. This is performed in the last year of the RP and as part of this, the difference between the realised revenue (R) and the audited allowed revenue (AI) to be distributed the following RP is determined. Since the applied revenue cap method guarantees the system operator's level of revenue in the medium term, a significant part of the market risk is shifted to the system users. The reduction of market risk also affects the reduction of the liquidity risk and hence the reduction of the cost of financing investment activities.

An additional measure aimed at mitigating the risk to the system operator business is the option of performing an extraordinary audit of the allowed revenue during the current RP at the request of the operator, or according to estimates by HERA. The extraordinary audit of allowed revenue is performed due to unexpected changes in the market that have a significant impact on the conditions of providing the energy activity, which the system operator could not have foreseen nor prevented, eliminated or avoided. As part of the extraordinary audit, an audit may be performed of all the elements used in the calculation of the allowed revenue and in the calculation of the amount of tariff items for the current RP.

An additional measure in gas distribution is the possibility of introducing a regulatory account. This is an optional model of economic regulation that provides the system operator with the possibility of receiving , in the later years of the regulatory account, reimbursement of the revenue realised in the early years, for an amount less than the allowed revenue that would have resulted from the application of the standard regulation model.

In the case of significant investments in existing infrastructure or with entirely new infrastructure, the standard regulation model is not appropriate. This is because significant investments, which by being put into use are included in the RAB, affect the strong growth in the amount of allowed CAPEX in the first years of the project. At the same time, large investments in the initial period are often accompanied by low system usage levels. This aforementioned situation would result in uncompetitive high tariffs for using the system in the same period, which would represent a negative factor for deciding whether to invest in the project. Therefore, the regulatory account is approved in such a manner that the gas system operator cumulatively achieves the same allowed revenue as it would without the use of the regulatory account, but with a different time dynamic. The period for which a regulatory account is established may not be shorter than two RPs nor longer than the period for which the operator has concluded a concession contract. Such a mechanism also prevents discrimination against new users that use the system in the early years, since the tariff items are unified and do not fluctuate throughout the entire period for which the regulatory account is kept.

The nominal WACC before tax is used as the RoR on regulated assets. As a measure of avoiding systemic risk, the RoR on equity is calculated using the CAPM model, and the RoR 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 of 50%, which is theoretically optimal capital distribution and approximates the effect of the financial leverage to a good extent. In this respect, a pre-defined ratio of debt and equity capital in the WACC calculation significantly reduces the regulatory risk, while at the same time encouraging the system operator to consider the actual capital structure used. In addition, applying a targeted ratio provides for equal treatment and approach to WACC calculation for all energy entities in gas infrastructure activities. The decision on the actual capital structure in regular business and project financing remains with the system operator, while the target ratio defined by the methodologies for determining the amount of tariff items for gas infrastructure activities in the Republic of Croatia refers solely to the WACC calculation.

Regulatory framework for tariff determination for electricity infrastructure activities

Introduction

In Croatia there is only one TSO and one DSO which operate as monopoly companies and are subject to regulation. Electricity transmission and distribution are regulated energy activities performed as public services.

Historical development

Tariff items for electricity transmission and distribution are determined based on the Methodology for Establishing Tariff Items for Electricity Transmission and the Methodology for Establishing Tariff Items for Electricity Distribution. According to the methodologies, the postage stamp principle is used to determine the amount of tariff items. They are calculated equally for all voltage levels and all consumers on the transmission and distribution networks, regardless of the length of the transmission or distribution route.

The cost-plus method of regulation has been implemented in methodologies for electricity transmission and distribution since 2006, and there is an RP of one year.

Determining the amounts of tariff items for the future regulatory year is based on the acknowledged operating costs from the previous regulatory year and accepted planned costs for the considered future regulatory year. Revenue for the future regulatory year should cover the reasonable total costs of electricity transmission and distribution. Total costs are determined on a yearly basis i.e. for the future regulatory year and should equal the sum total of eligible OPEX and CAPEX, being depreciation and return on regulated assets. The return on regulated assets equals WACC multiplied by the average value of regulated assets. The average value of regulated assets includes the value of regulated assets at the beginning of the year (not including the value of assets received without charge and assets financed by congestion income) and the value of regulated assets at the end of the year. The regulated assets value at the end of the year equals the regulated assets value at the beginning of the year plus new assets that will be put in use, minus grants, the annual depreciation value and the misappropriated and decommissioned assets value. The method used to value assets is based on historic cost i.e. actual asset cost.

The allowed revenue for the future regulatory year should be equal to or lower than eligible total costs (OPEX+CAPEX) for the future year. The difference between the realised income by implementation of tariff items in the previous regulatory year and the acknowledged total costs from the previous regulatory year ($\Delta UTP_{pret)}$ adjusted for average inflation rate in the previous and current year, should be taken into account when calculating allowed revenue for the future regulatory year.

Transparency

Transparency data is published on the regulatory authorities' websites.

2.5 Cyprus

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	1	0	1	1
	Network length	Not developed yet	-	1362 km	27624 km
	Ownership	State ownership	-	State ownership	State ownership
General framework	**Authority**	Cyprus Energy Regulatory Authority (CERA, https://www.cera.org.cy/)			
	System	Cost-plus	Cost-plus	Revenue cap	Revenue cap
	Period	Five years, first period: 2021-2026	Five years	Five years. First period 2017-2021. Next period 2022-2026 (required revenue not approved yet for period 2022-2026)[14]	Five years. First period 2017-2021. Next period 2022-2026 (required revenue not approved yet for period 2022-2026)
	Base year for next period	Not known yet			
	Transparency	Public consultation on CAPEX for the Development Plan of Transmission System and approval by CERA, publicly available Tariff Methodology, publicly available approved regulated tariffs		Publicly available Tariff Methodology, publicly available approved regulated tariffs	
	Main elements for determining allowed revenue	Budgeted-planned CAPEX, with an ex post adjustment based on real values (only up to an economically efficient level,10%). Non-controllable and controllable OPEX	Budgeted-planned CAPEX, with an ex post adjustment based on real values (only up to an economically efficient level,10%). Non-controllable and controllable OPEX	Non controllable and controllable OPEX, RAB with annual adjustment	Non controllable and controllable OPEX, RAB with annual adjustment
	Legal framework	Laws Regulating the Natural Gas Market of 2004 to 2021[15] Regulatory Decision 1/2019 on the Methodology for the Determination of the Amount of Tariff Items for Natural Gas[16]		Law Regulating the Electricity Market of 2021[17] Regulatory Decision 1/2021 on the Statement of Regulatory Practice and Electricity Tariffs Methodology[18]	
F a	**Type of WACC**	Nominal pre-tax		Nominal	

[14] For the first regulatory period of 2017-2021, only the transmission asset owner's R.I. was calculated under the above framework. The TSO R.I. was based on a cost methodology. From 2022 the TSO will follow the same framework as above.

[15] See https://www.cera.org.cy/Templates/00001/data/nomothesia/ethniki/fysiko%20aerio/nomos/Nomos_2004-2021.pdf. (in Greek)

[16] See https://www.cera.org.cy/Templates/00001/data/nomothesia/ethniki/hlektrismos/rythmistikes_apofaseis/2019_01.pdf. (in Greek)

[17] See https://www.cera.org.cy/Templates/00001/data/nomothesia/ethniki/hlektrismos/Nomos/2021_130(I).pdf

[18] See https://www.cera.org.cy/Templates/00001/data/nomothesia/ethniki/rythmistikes_apofaseis/2021_01_en.pdf.

	Determination of the rate of return on equity	$r_e = r_f + \beta_e \times (r_m - r_f)$, where: • r_f is the risk-free RoR (%); • r_m is the RoR on the diversified market portfolio (%); • $r_m - r_f$ is the market risk premium (%); and • β is the coefficient of variability of return on the operator's shares in relation to the average variability of return on the market portfolio	Sum of a nominal risk-free rate and a risk premium (market risk premium multiplied with a beta factor)
	Rate of return on equity before taxes	$r_e = r_f + \beta_e \times (r_m - r_f)$ Not determined yet.	4.26% (WACC: 4.6%)
	Use of rate of return	As a return on RAB on regulated entity (except assets that were funded through grants).	As a return on RAB of regulated entity.
Regulatory asset base	**Components of RAB**	CAPEX of fixed assets which are in operation, depreciation and working capital.	Depreciated fixed assets, working capital
	Regulatory asset value	At historic costs less depreciation.	At historic costs less depreciation (net book value)
	RAB adjustments	There is a methodology for RAB adjustment within the RP only if the allowed revenue deviates more than 10% from real costs.	RAB is adjusted lower annually if CAPEX is lower than what was approved as part of the required income. New investments that were not included in the required income for the RP can only be included in RAB if approved by the regulator.
Depreciations	**Method**	Straight line	
	Depreciation ratio	Not defined yet.	Depending on asset type. For lines and cables 2.5%-2.8%.
	Consideration	N/A	Part of non-controllable OPEX, based on approved RAB.

Introduction

The Cyprus Energy Regulatory Authority (CERA) is the national Independent Energy Regulatory Authority of the Republic of Cyprus. CERA is entrusted with the regulatory control of the proper functioning of the internal electricity and gas market in accordance with the provisions of the European legislation and the national laws. In particular, the Law Regulating the Electricity Market of 2021 (L. 130(I)/2021) and the Laws Regulating the Natural Gas Market of 2004 to 2021 (N. 183(I)/2004). These set the framework of rules and principles for the achievement of CERA's mission, the main objective of which is to ensure the smooth operation of the energy market in Cyprus, consumer empowerment and environmental protection.

CERA is legally distinct and functionally independent from any other public or private entity. It makes autonomous decisions independently of any political organisation and has an annual revenue and expenditure budget which it implements autonomously. CERA is governed by the Top Management, consisting of three members, appointed by decision of the Council of Ministers, after consulting the Parliamentary Committee on Energy, Trade, Industry and Tourism. CERA is accountable for the performance of its duties, responsibilities and powers to the President of the Republic and, for this purpose, submits an annual activity report to the President of the Republic. The operation of CERA and its decision-making processes are regulated by Regulations that are adopted in accordance with the Law on the Establishment and Operation of the Energy Regulatory Authority of 2021 (L. 129(I)/2021).

Cyprus energy market

The energy sector in Cyprus is undergoing fundamental transformations concerning its structure and organisation, its institutional framework and the diversification of its energy mix. In an effort to open the market to new participants, CERA, following a technical support project that was carried out regarding market reorganisation, proposed the net-pool model as being the most appropriate trading arrangement approach for the Cyprus electricity market. The formulation of a net-pool is based on the European Target Model. All transactions of purchase and sale of electricity are conducted at a wholesale market level. Specifically, under the proposed net-pool design, bilateral physical forward contracts are notified, and corresponding schedules are nominated to the market operator (MO) by over the counter (OTC) market gate closure on the day ahead. Suppliers and generators provide bid curves to a day ahead market (DAM) on a half hourly basis. Orders in the DAM are unit based in the case of generators. Suppliers submit orders based on individually forecast demand. Orders in the DAM should correspond to quantities not already covered by bilateral contracts and take into account any replacement reserve of type two commitments. The DAM is centrally managed by an MO. The MO runs a process of matching bid curves to optimise dispatch of residual volumes at the day ahead. Contracts resulting from the DAM are between market participants and the MO at the DAM clearing price. An Integrated Scheduling Process with a real time Balancing Mechanism and later a continuous intra-day trading platform will be organised to further support market operations.

Due to the delays in the implementation of the competitive electricity market in Cyprus, which mainly concern the installation of two software programs, prerequisites for the operation and monitoring of the electricity market, CERA decided on a transitory regulation of the electricity market in Cyprus, prior the full implementation of the new electricity market model. The transitional arrangement permits bilateral contracts between producers and suppliers above a threshold set by CERA, with monthly clearing:

- For producers with a production license initially set above 4.5 MW and later, in order to enable a larger number of producers to participate in the transitional arrangement, above 1 MW and finally above 50 kW; and
- For suppliers with a contract for supply of energy to consumers with a total agreed power above 10 MW.

The contracts involve only the provision of energy, and a simple arrangement would require no extra software for its implementation by the TSO and DSO.
The transitory regulation of the electricity market in Cyprus started on 1 September 2017 and will be in force until the full implementation of the new electricity market model.

Main principles of tariff regulation

The overarching objectives of the tariff regulation are to maximise the long-term competitiveness of the Cypriot economy, protect the interests of consumers in the short and long term against monopoly-based prices, serve public service obligations, ensure energy

supply and promote energy efficient and quality services provided by license holders.
The tariffs are set ex ante, and in some instances, adjustments are made on an ex post basis based on the principles set out in the Tariff Methodology (Regulatory Decision 01/2021). The proposals and decisions about tariffs are evidence-based and are formulated after thorough consultation with the parties concerned.
Prior to the start of each regulatory control period, CERA conducts a periodic regulatory review to determine the allowed revenues for each activity for the regulatory control period. Each regulatory period is five years. The first regulatory period started in 2017.

The electricity market in Cyprus has been organised into separate sectors that need to be licensed by CERA, as follows:

- The electricity generation, which is a competitive activity;
- The activity of the ownership of the transmission system, which is a regulated monopoly activity;
- The activity of the operation of the transmission system, which is a regulated monopoly activity;
- The activity of the ownership of the distribution system, which is a regulated monopoly activity;
- The activity of the operation of the distribution system, which is a regulated monopoly activity; and
- The electricity supply activity, which is a competitive activity.

Before the start of each regulatory review period, CERA carries out a regulatory examination to determine the allowed revenue of each activity for that RP. CERA will determine the allowed revenue, for each of the activities of a dominant producer, the ownership of the transmission system, the operation of the transmission system, the ownership of the distribution system, the operation of the distribution system and the supply by a dominant supplier.

The authorised revenue for each activity, with the exception of supply from a supplier with a dominant position, will include a capital part and an operating part, as follows. The capital part of the allowed revenue will include the depreciation of the fixed assets included in the RAB and the allowed return on the average RAB. The allowed return on RAB shall correspond to the WACC, which will be determined in the context of the periodic regulatory review on the basis of factual data and will be a nominal rate of return.

During the periodic regulatory review, CERA may decide to index the WACC, or the data used to determine the WACC, in such a way that the WACC varies during the regulatory review period. The objective of this indexation is to protect the activity that undertakes the regulated activity from uncontrolled changes in its financing costs. The RAB for an activity is calculated at the end of each year, and there is an ex post adjustment in the capital part of the allowed revenue based on the actual CAPEX of the year included in the RAB. If the CAPEX is higher than budgeted, the difference shall be transferred to the prices, only to the extent that CERA considers the excess to be reasonable. The ex post adjustment shall be applied to the tariffs of the next year in the regulatory review period and shall adjust the projected capital part of the allowed revenue for the remaining regulatory review period.
At the end of each year, each regulated activity must submit to CERA detailed statements containing the following information:

- The actual CAPEX of the reporting year;
- A comparison of the actual CAPEX with the CAPEX included in the budgeted RAB and approved by CERA; and
- Information on the reasons for diversification, whether positive or negative.

The allowed revenue for each activity shall take into account customer contributions so that the activity is not overcompensated.

General structure of electricity tariffs

Tariffs for goods or services provided through a regulated activity are regulated. The provider of a regulated service will apply a tariff applicable to the service provided. Before the year in which the tariff is applied, the provider will propose the tariff to CERA. CERA shall examine the tariff against the targets set out in the Tariff Methodology and decide whether to approve or request an amendment to the proposal. The regulated tariffs for one year will be determined in such a way as to recover the year's allowed revenue for the regulated activity.
The tariff categories, as well as the charge for the use of the interconnection line, will be determined according to the following table.

Description	Tariffs
T-W	Wholesale electricity tariff, which is imposed on the sale of electricity produced by the regulated activity through Bilateral Contracts to any activity (regulated or unregulated)
T-NH	Tariff for the use of the Transmission System (36kV or more)
T-NM	Tariff for the Use of Distribution System (medium voltage: greater than 1kV and less than 36kV), which includes a charge component related to the DSO
T-NL	Tariff for the Use of Distribution System (low voltage: at or below 1kV), which includes a charge component related to the DSO
T-BM	Tariff for Business Management Services provided to customers (invoicing, etc.)
T-AS	Tariff for the provision of Ancillary Services
T-PSO	Tariff for the recovery of expenses of PSOs
T-TSO	Tariff for the recovery of expenses of the Transmission System Operator of Cyprus (TSOC)
T-MET	Tariff for the recovery of expenses of meter-readings incurred by the Distribution System Operator (for users connected to the Distribution System)
T-RET	Supply tariffs and electricity market charges to the end consumer
T-CS	Competitive cost tariff of regulated supply company for the supply of electricity to customers
T-ILU	Tariff for the use of the interconnection line

Cypriot categories of tariffs

2.6 Czech Republic

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	1	3 regional, 67 local	1	4 regional, 242 local
	Network length	3,974 km (2021)	62,258 km (2021, regional and local DSOs)	5,703 km (2021)	246,824 km (2021, regional DSOs)
	Ownership	Private ownership	Private and local public ownership	Public ownership	Private and local public ownership
General framework	**Authority**	Energy Regulatory Office (ERO, www.eru.cz)			
	System	Incentive regulation/ revenue cap, price cap	Incentive regulation/revenue cap		
	Period	Five years. Current RP: 2021-25			
	Base year for next period	For each regulated year the eligible cost base is determined on the basis of the actual costs of the last three completed reference years, e.g. regulated year 2022 is based on 2018-20 costs			
	Transparency	Price decisions, price control principles			
	Main elements for determining the revenue cap	Eligible costs, eligible depreciation and amortisation, RAB, WACC			
	Legal framework	Act No. 458/2000 on the Conditions of Business and State Administration in Energy Industries and on Changes to Certain Laws (the Energy Act), Public notice no. 195/2015 on price control in gas sector		Act No. 458/2000 on the Conditions of Business and State Administration in Energy Industries and on Changes to Certain Laws (the Energy Act), Public notice no. 194/2015 on price control in electricity sector	
Rate of return	**Type of WACC**	Nominal, pre-tax WACC			
	Determination of the rate of return on equity	Sum of nominal risk-free rate and a risk premium (market risk premium multiplied by beta factor)			
	Rate of return on equity before taxes	9.54% = (2.04 + 6.54 * 0.87) / (1 – 0.19)		9.78% = (2.04 + 6.54 * 0.9) / (1 – 0.19)	
	Use of rate of return	The whole RAB is multiplied by the WACC. When setting the nominal pre-tax WACC the D/E ratio of 48.89/51.11 was used		The whole RAB is multiplied by the WACC. When setting the nominal pre-tax WACC the D/E ratio of 48.92/51.08 was used	
Regulatory asset base	**Components of RAB**	Fixed assets, investments in progress, leased assets, no working capital			
	Regulatory asset value	The RAB is based on re-evaluated values of assets commissioned by 2005 (or 2006 – depends on the energy sector) and on historical values of assets commissioned in 2006 (or 2007 – depends on the energy sector) and later. These values of assets are recorded in the annual financial statements			
	RAB adjustments	The adjustment is similar to the net book value (NBV) calculation (investment - depreciation). The RAB is also annually adjusted by the individual coefficient that ensures the equalisation of the RAB and the NBV of assets in 2025			
Depreciations	**Method**	Straight line			
	Depreciation ratio	Buildings 2%, pipes 2.5%, pumps and compressors 5%	Electricity TSO calculates depreciation in accordance with national accounting standards	Buildings 2%, overhead lines and cables 2.5%, very high voltage (VHV) transformers 4%, medium voltage (MV) and low voltage (LV) transformers 3.3%, metering devices 6.6%	
	Consideration	100% of the depreciation is used to determine the allowed revenue			

Introduction

Electricity and gas distribution and transmission are so-called natural monopolies, the operation of which relies on only one network because the rollout of a parallel infrastructure is not effective in economic terms. To prevent monopolies from dictating prices uncontrollably, they have to be regulated by the state. A regulatory authority is usually authorised to do this in the case of regulation.

In the Czech Republic, Act No. 458/2000 (the Energy Act) sets up the Energy Regulatory Office (ERO) for the purpose of regulating the energy sector. Under the Energy Act, ERO is obliged to set out, in implementing legal regulations, the method of regulation in energy industries and price control procedures. To this end, public notices no. 194/2015 on price control in electricity sector and no. 195/2015 on price control in gas sector were published in August 2015. They came into effect with the beginning of the fourth RP in 2016 and are still valid. Furthermore, ERO published a document called *“Price Control Principles for the 2021-2025 Regulatory Period in the Electricity and Gas Industries and for the Market Operator’s Activities in the Electricity and Gas Industries, and for Mandatory Buyers”*, in which the price methodology for the fifth RP is described in more detail. The fifth RP is set as a five-year period (2021-25).

The purpose of the methodology for the fifth RP was to determine a reasonable level of profit for companies during the whole RP, ensure adequate quality of the services provided to customers with effective spending of costs, support future investments, provide for the resources required for network renovation, and continue to improve efficiencies from which customers also benefit.

Price control in the electricity industry

The resulting price of electricity supply for all categories of final customers is comprised of five basic components. The first component is the uncontrolled price of commodity, i.e. the electrical energy itself (in Czech called “silová elektřina”; “energy” or “electricity” in English),which is priced on market principles and in line with the various electricity suppliers’ business strategies. The other components of the price are regulated activities of a monopoly nature, which include electricity transport and distribution from the generating plant over the transmission and distribution systems to the final customer, and activities related to ensuring the stability of the electricity system from the technical point of view (the so-called provision of system services) and from the commercial point of view (primarily the electricity market operator’s activity in the area of imbalance clearing). The last component of the resulting price of electricity supply is the contribution to the support of electricity from promoted sources. The above is the approach to electricity supply pricing for all customer categories with effect as from 1 January 2006 when the Czech electricity market was completely liberalised.

Price control in the gas industry

The price of natural gas supply for final customers is comprised of four basic components. The first component is the charge for commodity, i.e. natural gas itself, which is priced on market principles and in line with the various gas suppliers’ business strategies. The other three components are the price for gas transmission, gas distribution and market operator’s activities. The prices for these three components are regulated and determined by ERO.

Regulatory methodology framework

A revenue cap methodology is used for setting allowed revenue in the Czech Republic. The length of the RP is five years.

The basic formula for determining allowed revenue is $AR = EC + D\&A + P$, where:

- AR is the value of the allowed revenue;
- EC is the value of the eligible costs;
- $D\&A$ is the value of the eligible depreciation and amortisation; and
- P is the value of the profit.

Eligible costs

The generally adopted theory of regulation assumes that the costs that enter into the subsequent RP are determined based on the analysis of values achieved in the preceding period. This theory is based on the assumption that during the RP, the companies reduce their costs under the pressure for efficiency, thereby achieving higher profits than those set for them by the regulator.

The value of the eligible costs for the fifth RP is derived from the actual values of economically justified costs, adjusted by the value of profit/loss sharing. With regard to the availability of the licence holders' relevant audited data, for every regulated year the eligible cost base is determined on the basis of the actual costs of the last three completed reference years.

The values of companies' actual economically justified costs will be adjusted by the escalation factor to the time value of the year preceding the regulated year, and by the efficiency factor. The eligible cost base for each of the regulated years of the fifth RP is calculated as the arithmetic mean of the adjusted values of actual costs for the last three known years. For example, for the first year of the fifth RP (2021), the arithmetic mean of economically justified costs in 2017-19, adjusted by the escalation factor and the efficiency factor, is used.

The difference between eligible and actual costs in the years of the fifth RP is subject to profit/loss sharing. The value of profit/loss sharing is calculated as the three-year average of the acknowledged portions of the differences between eligible costs and actual economically justified costs in the preceding years, adjusted by the escalation factor, the efficiency factor, and the profit/loss sharing coefficient, the basic value of which was set at 0.5 for the years in the fifth RP.

Escalation factor

The escalation factor for the fifth RP is composed of the annual business service price index and wage index published by the Czech Statistical Office for April of the relevant year.

Efficiency factor (X-factor)

The efficiency factor makes companies on the energy market behave more efficiently and reduce costs over the RP. At the beginning of the RP the regulator sets the value of the required efficiency, which the companies are obliged to observe.

The yearly value of the efficiency factor has been set at 0.511%. For companies that have achieved savings exceeding 15% in operating expenditure versus eligible costs for the fourth RP (2016-19), the yearly value of the efficiency factor will be set at 0.2%.

For the fifth RP, the efficiency factor is applied when calculating the eligible cost base, profit/loss sharing, and the eligible costs for the regulated year.

Eligible depreciation and amortisation

Eligible depreciation and amortisation is determined based on the planned values in individual years of the RP. The planned values of the depreciation are adjusted in the year i+2 based on the actual values using the time value of money.

Profit

The profit of the regulated entity is calculated as $P = RAB * WACC$, where:
- RAB is the value of the regulatory asset base; and
- $WACC$ is the RoR.

Regulatory asset base

The calculation of the RAB in the fifth RP uses for its input the planned values that are corrected (with a two-year lag) based on the actual values. To maintain continuity between the fourth and the fifth RP, the initial level of the RAB (RAB_0) was set at the planned value of the RAB for the year 2020.

In the subsequent years of the RP, the initial level of the RAB is increased (or decreased) by the differences between the capitalised investments and the depreciation and amortisation. Each year in the fifth RP, the RAB value will be adjusted to achieve equalisation of the RAB and NBV values by 2025.

Assets under construction are also included in the RAB. These assets are part of the RAB under certain conditions, namely that the planned acquisition period of the investments is more than two years (the time of preparation is not included), and that the planned value of individual investments under construction exceeds 500 million CZK in the relevant year.

Rate of return (WACC)

The WACC parameter (nominal, pre-tax) is used for computing profit in the Czech Republic. When determining the RoR as the key parameter for investment conditions (and decisions) in the regulated environment, ERO analysed the market environment, risk rate of individual environments as well as overall economic position of similar (peer) companies in the Czech Republic and in other EU countries. ERO set the values of the WACC parameter as fixed for the entire RP, except for cases when the income tax rate of legal entities is changed – considering the relevant specific conditions and indicators for electricity and gas industries. The RoR is set as the uniform value for the electricity industry and the uniform value for the gas industry (i.e. the same rate for the DSO as well as the TSO in the given industry).

Inflation rate – time value of money

To adjust the planned values that are included in the parameters of regulation, the standard cases are covered by an inflation rate parameter that is derived from the index of industrial producers' prices (PPI).

The inflation rate parameter is defined annually, based on the ratio of rolling averages reported by the Czech Statistical Office in the table "Industrial Producer Price Index by Section and Subsection of CZ-CPA in the Czech Republic (ratio of rolling averages)".

In specific cases the WACC value is used as the time value of money.

2.7 Denmark

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	1 (Energinet)	3 (2022)	1 (Energinet)	39 (2022)
	Network length	861 km (2017)	~18,000 km (2016)	6,913 km (2017)	~165,000 km (2016)
	Ownership	Independent public enterprise owned by the Danish Ministry of Climate, Utilities and Energy (SOV)	Public ownership	Independent public enterprise owned by SOV	Private and local public ownership
General framework	**Authority**	Danish Utility Regulator (DUR, www.forsyningstilsynet.dk)			
	System	Strict cost-plus	Revenue cap	Strict cost-plus	Revenue cap
	Period	Yearly	Four years. Current RP: 2018-21	Yearly	Five years. Current RP: 2018-22
	Base year for next period	Strict cost-plus regulation (ex post regulation)	Four previous years	Strict cost-plus regulation (ex post regulation)	Five previous years
	Transparency	Strict cost-plus regulation (ex post)	Efficiency scores, efficiency model parameters, WACC, specific cost data	Strict cost-plus regulation (ex post)	Efficiency scores, efficiency model parameters, WACC, specific cost data
	Main elements for determining the revenue cap	Danish TSO regulation doesn´t follow this scheme. For further details see regulation of transmission grid section below	Costs in previous period. Fixed interest rates; four-year period	Danish TSO regulation doesn´t follow this scheme. For further details see regulation of transmission grid section below	The revenue cap consists of three main components: a cap on costs, allowed returns and efficiency requirements. The cap on costs is based on an average of actual costs in the previous RP. The allowed returns are determined from the RAB and a specified RoR
	Legal framework	The Natural Gas Supply Act, the Energinet Act, Notice: BEK nr. 816 af 27/06/2016	The Natural Gas Supply Act, Notice: BEK nr 768 23/06/2016	The Electricity Supply Act, the Energinet Act, Notice: BEK nr. 816 27/06/2016	The Electricity Supply Act, Notice: BEK nr. 2248 29/12/2020
Rate of return	**Type of WACC**	Danish TSO regulation doesn´t follow this scheme. For further details see regulation of transmission grid section below	Nominal WACC pre-tax 4.51% (2017)	Danish TSO regulation doesn´t follow this scheme. For further details see regulation of transmission grid section below	Nominal WACC pre-tax 3.66% (2018-22)
	Determination of the rate of return on equity		Sum of a nominal risk-free rate and a risk premium (market risk premium multiplied by a beta risk factor)		Sum of a nominal risk-free rate and a risk premium (market risk premium multiplied by a beta risk factor)
	Rate of return on equity before taxes		9.00% (2018-21)		5.63% (2018-22)
	Use of rate of return		A risk-free interest rate calculated as		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		an average of the last three months available daily observations of ten-year zero coupon rates for Danish government bonds
Regulatory asset base	**Components of RAB**	Danish TSO regulation doesn´t follow this scheme. For further details see regulation of transmission grid section below	Fixed assets, working capital, assets under construction and historical debt	Danish TSO regulation doesn´t follow this scheme. For further details see regulation of transmission grid section below	All assets related to licensed activity of a DSO, working capital and assets under construction
	Regulatory asset value		Historical costs included return on capital		Historical costs included return on capital
	RAB adjustments		Investments in new assets after the base year lead to an adjustment of CAPEX		Adjusted for non-controllable costs
Depreciations	**Method**	Straight line	Straight line	Straight line	Straight line
	Depreciation ratio	Depends on asset type	Depends on asset type	Depends on asset type	Depends on asset type
	Consideration	Danish TSO regulation doesn´t follow this scheme. For further details see regulation of transmission grid section below	-	Danish TSO regulation doesn´t follow this scheme. For further details see regulation of transmission grid section below	-

Introduction

The Danish Utility Regulator (DUR) is independent of the government. The tasks of DUR are stipulated in the supply acts for electricity, natural gas and district heating.

Regulation of electricity grid companies

Danish electricity grid companies are natural monopolies. As the distribution of electricity is a monopolistic activity, the grid companies generally do not have the same incentives for financial efficiency as enterprises in a free, competitive market. The grid companies are therefore subject to financial regulation, managed by the DUR. The regulation aims to reflect the pressure on efficiency faced by enterprises subject to competition in the free market. The financial regulation primarily consists of two mechanisms: revenue caps and benchmarks.

Revenue caps set a ceiling on the operating revenues of grid companies. The revenue caps for DSOs are set for a five-year RP. The first RP is from 2018 to 2022. The revenue caps consist of three main components: a cap on costs, allowed returns and efficiency requirements. The cap on costs is based on an average of actual costs in the previous RP. The allowed returns are determined from the RAB and a specified RoR. Throughout an RP, the revenue caps are adjusted for changes in the price levels (inflation) and the specific activity level of a given DSO. The efficiency requirements are related to the overall productivity changes in the Danish economy and individual performance calculated from benchmarking.

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 DUR.

The RAB, which is used to calculate the allowed returns, is divided into two parts, a forward-looking asset base and a historical asset base. Each asset base is coupled with its own RoR and the WACC is only used as the RoR on the forward-looking asset base. The forward-looking asset base consists of regulatory assets invested from 1 January 2018 onwards.

The RoR on the historical asset base is a continuation of the previous definition of allowed RoR, which is not comparable with the WACC definitions and methods.

Regulation of gas distribution companies

Grid companies are not subject to competition and therefore DUR regulations aim to encourage these companies to be more efficient by lowering the cap on their revenues.

The revenue cap is made up of: i) operating costs (decided activity level); ii) operating costs (imposed by external factors); iii) historic debt locked (remaining from 2004 balance); iv) asset base; and v) costs to promote and realise reductions in energy consumption.

DUR sets efficiency demands on i) operating costs based on a benchmark between the DSOs, to ensure there is external pressure to lower costs continuously.

Furthermore, DUR sets a cap on i) operating costs based on historic cost levels and DSOs can achieve efficiency gains by realising operating costs that are lower than this historic level, adjusted for efficiency demands. The revenue cap is adjusted to the actual level of ii) operating costs.

Before entering an RP, DUR sets the interest rate level for the iv) asset base using a WACC framework and a CAPM methodology. The level of interest is fixed during the RP, however the asset base can vary.

The revenue cap is adjusted by v) actual costs to realise reductions in energy consumption.

Regulation of transmission grid (electricity and gas)

Energinet is the TSO for both electricity and gas in Denmark. The special provisions for Energinet were established by law on Energinet and an executive order on the economic regulation of Energinet.

Energinet is ex post regulated in accordance with a “non-profit” principle. This means 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). Energinet’s capital base on 1 January 2005 was 3,157 million DKK. In 2019 the return on capital was 41 million DKK (1.3%).

The economic regulation of Energinet does not allow explicit efficiency requirements for Energinet. However, DUR may determine that a specific cost – or an amount thereof – does not constitute a necessary cost at efficient operation and therefore may not be included (or only partially included) in Energinet tariffs.

DUR and Energinet have participated in European benchmark analyses of electricity and gas TSOs, the latest in 2018. DUR distributed the results of the benchmark analyses to the Minister of Climate, Energy and Utilities in his capacity as owner of Energinet.

In the government's utility strategy (“Regeringens forsyningsstrategi”), from September 2016 the government presented its comprehensive utility strategy to Danish households and companies. One of the proposals was a new incentive-based financial regulation of Energinet, which was approved.

2.8 Estonia

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	Network operators	1	23	1	33
	Network length	997 km	2,225 km	5,500 km	65,700 km
	Ownership	State owned	Private investors	State owned	State owned and private investors
General framework	Authority	Konkurentsiamet (www.konkurentsiamet.ee)			
	System	Rate-of-return			
	Period	There is no period			
	Base year for next period	N/A			
	Transparency	Specific cost data			
	Main elements for determining the revenue cap	Variable costs, operating costs, depreciation of RAB, justified return on RAB			
	Legal framework	Natural Gas Act		Electricity Market Act	
Rate of return	Type of WACC	Pre-tax WACC nominal			
	Determination of the rate of return on equity	Germany ten-year average bonds yield, Estonian risk premium, McKinsey market risk premium, Beta			
	Rate of return on equity before taxes	$k_e = R_f + R_c + (\beta * R_m)$ 5.84% = (1.41+0.79+ (0.728*5))	5.92% = (1.41+0.79+ (0.744*5))	5.65% = (1.41+0.79+ (0.690*5))	5.73% = (1.41+0.79+ (0.706*5))
	Use of rate of return	4.58%	4.60%	4.51%	4.61%
Regulatory asset base	Components of RAB	Fixed assets, working capital, leased assets			
	Regulatory asset value	Historical costs			
	RAB adjustments	Fixed assets do not include long-term financial investments, intangible assets (except for software licences), fixed assets acquired with grant aid (including targeted funding), fixed assets acquired with funds obtained from connection fees, or fixed assets that the undertaking does not use for the purpose of providing network services			
Depreciations	Method	For depreciation of fixed assets, a regulatory CAPEX method is used, which differs from accounting depreciation. In the regulatory CAPEX 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 an accelerated rate of depreciation is applied for them			
	Depreciation ratio	Depends on asset type. The average depreciation ratio of the TSO is 2.50% for electricity and 3.66% for gas. The average depreciation ratio of DSOs is 3.54% for electricity and 3.65% for gas			
	Consideration	Present regulation started with 2003 legal framework			

Introduction

The Estonian Competition Authority (ECA) establishes network charges for network operators. The laws provide uniform price regulation for all network operators regardless of their size. ECA has prepared uniform methods for the calculation of network charges based on the WACC. The methods are applied similarly and uniformly in analysing the activities and monitoring the prices of all the undertakings under ECA's supervision, in compliance with the principle of equal treatment and proportionality.

Variable costs

Variable costs are costs that vary in line with changes in the sales volume, i.e. are directly dependent on the sales volume. The following variable costs are included in network charges: the costs of outsourced transmission and/or distribution network services and the costs of electricity purchased for covering network losses.

ECA uses the following methods to analyse network losses:
- Monitoring the dynamics of network losses over time;
- Comparing statistical indicators with other network operators;
- Analysing technical indicators (e.g. length of lines, number of substations, etc.); and
- Analysing the impact of investments on network losses.

The cost of network electricity losses is the product of the forecast amount of network losses and the price. The forecast price of the electricity purchased for covering network losses should be justified and cost-effective. An analysis of the justification of the price is based on the weighted average price, determined on the basis of the price applicable in the Nord Pool Spot Estonian price region and the size of network losses in the 12 calendar months preceding the submission of the request, plus justified costs necessary for purchasing electricity.

The weighted average price is calculated based on the one-day forward hourly price in the electricity market during the aforementioned period and the network operator's amount of energy lost in the respective hour. If the amount of electricity purchased for compensating network losses is below 5,000 MWh a year, the electricity price may be forecast based on the electricity supply agreement. In such a case, the justification of the price, as well as the conformity of the price with the market price, should be analysed, and the organisation of a tender is expected. In the case of a transmission network operator, specific income and expenses are taken into account, including the income and expenses of the transit flow compensation mechanism between transmission network operators (inter-TSO compensation (ITC) mechanism), countertrade costs, transmission capacity auction income, etc.

Operating costs

Operating costs are all the justified costs necessary for providing network services that are not variable costs or CAPEX. Operating costs are divided into controlled operating costs and non-controlled operating costs. The following justified costs are generally considered as operating costs:
- The costs of maintenance and repairs performed by the network operator;
- The costs of outsourced works and services;
- Transport costs;
- Information technology and communication costs;
- Labour expenses (including taxes);
- The state fee payable for the activity licence for providing network services;
- Fees for tolerating technical networks or structures; and
- Other costs that must be listed and justified in the request.

ECA uses the following methods to analyse operating costs:

- Monitoring the dynamics of operating costs over time by quantity and as a special cost with regard to the sales volume;
- Comparing statistical indicators with similar network operators;
- Performing an in-depth analysis of the components of operating costs (using expert evaluations, if necessary); and
- Analysing the impact of investments on operating costs.

Monitoring the dynamics of costs in time means a change in the operating costs of a network operator across the years; in general, it must not grow more than the CPI. An in-depth analysis includes a detailed distribution of operating costs between different activities. The detailed distribution of operating costs includes data across the three calendar years preceding the submission of the request. The network operator should justify the incurrence, variation and cost-efficiency of the costs presented in the in-depth analysis. The dynamics of the special costs of various cost types may be compared in conducting an in-depth analysis.

Upon comparing the costs of a network operator and the statistical indicators determined on the basis thereof with the costs of other similar network operators, the special costs under the operating costs of similar network operators are compared (total operating costs per sales amount). If necessary, ECA may also analyse the cost types and the special costs of similar network operators (e.g. the labour expenses of network operators per sales amount).

Upon approval and verification of network charges, ECA shall not accept the following cost items:

- The cost of doubtful receivables;
- Costs related to ancillary activities;
- Costs arising from changes in the value of assets (changes in the balance of inventories, write-downs of current assets, etc.);
- Penalties and fines for delays imposed on the network operator pursuant to law (fines for administrative violations, penalty payments, compensation for damages, etc.);
- Costs not related to business activities (sponsorship, gifts, donations, etc.); and
- Other unjustified costs identified in the process of an economic analysis.

Regulated assets and capital expenditure

Determining the value of regulated assets (the fixed assets necessary for providing network services) is necessary for calculating CAPEX and justified profitability. ECA analyses the justification of both made and forecast investments for the basis of accounting for regulated assets. For the purpose of verifying the justification of investments:

- The TSO shall submit a detailed five-year investment plan and a prospective ten-year investment plan. The investment plan shall include the cost and justification of the investments, the economy and cost efficiency to be achieved, and the criteria for improving the security of supply and quality;
- A DSO with more than 100,000 consumers shall submit the same data as the TSO; and
- A DSO with fewer than 100,000 consumers shall submit a detailed five-year investment plan and a prospective ten-year investment plan upon ECA’s request.

ECA shall not accept the following costs incurred on fixed assets as regulated assets and CAPEX:

- Long-term financial investments;
- Fixed assets acquired using connection charges paid by consumers;

- Fixed assets acquired using non-refundable aid (e.g. EU external aid programmes);
- Intangible assets (excluding computer software licences and rights of use pertaining to land related to technical structures);
- Fixed assets related to ancillary activities;
- Costs arising from changes in the value of assets (impairment of the value of fixed assets, losses from sales and liquidations of property, plant and equipment and intangible assets, etc.); and
- Assets that the network operator is not actually using for the provision of network services.

CAPEX is calculated based on the value of the fixed assets (regulated assets) necessary for providing network services, and the CAPEX rate. The CAPEX rate is the reciprocal value of the useful technical life of the asset. Individual assets may have different useful lives and therefore different CAPEX rates. Upon justifying the useful life of an asset, ECA shall verify the expected period of use of the asset, the expected physical wear and tear of the asset, and the technical or moral obsolescence of the asset.

The accounting of regulated assets and CAPEX should be consistent and should also continue in the event of changes in the ownership of the undertaking or the asset.

The calculation of the net assets underlying the network fees is as follows:
- Depreciation on fixed assets is calculated using the straight-line depreciation method;
- Depreciation rates for fixed assets are not justified if they differ substantially from the depreciation rates set for similar life, same uses and similar fixed assets, or if the entity does not calculate the depreciation based on the useful (technical) life of the fixed assets;
- Depreciation is calculated based on the acquisition cost. In this case, depreciation of fixed assets to be included in the net fees is based on depreciation rate(s) set for assets acquired; and
- If necessary, differentiation of fixed assets can be used, using different depreciation rates of fixed assets.

The working capital shall be calculated based on 5% of the allowed revenue of the tariff year. If necessary, a more detailed working capital analysis may be performed. The internal turnover of undertakings belonging to a vertically integrated group should not be included in working capital accounts. If necessary, an additional working capital analysis should be performed.

Justified profitability

The justified profitability to be included in the price is calculated based on the fixed assets (both tangible and intangible assets) necessary for providing network services.

Justified profitability (JP) is determined as the product of the regulated assets (RA) and the WACC: $JP = WACC * RA$.

The WACC is calculated using a capital structure of which 50% is debt capital and 50% equity. The same proportion should also be taken as the basis in the case of all other regulated undertakings providing a similar service (i.e. a vital service provided by a dominating undertaking in the market, e.g. electricity, gas, district heating, water supply).

The risk-free RoR is the average interest rate of German ten-year bonds in the preceding ten years, plus Estonia’s state risk premium. If Estonian government bonds exist, the interest rate of the government bonds may be used as the risk-free RoR.

The cost of debt is the sum of the risk-free RoR (plus Estonia's state risk premium) and the debt risk premium of the undertaking. The cost of equity is calculated using the CAPM ($C_e = R_f + R_c + \beta * R_m$). The value of the beta coefficient is determined based on the relevant indicators of other European and/or US regulated undertakings. The market risk premium is determined based on the long-term market risk premium of other European and/or US undertakings.

Usually,[19] ECA calculates the WACC annually and publishes it on its website.[20]

[19] The period 2016-19 was an exception because the German ten-year bonds in the preceding five years decreased. Therefore, from 2020, the ECA started to use German ten-year bonds in the preceding ten years.
[20] See www.konkurentsiamet.ee/.

2.9 Finland

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	Network operators	1	17	1	77
	Network length	~1,300 km	~2,000 km	~14,000 km	~420,000 km
	Ownership	State owned	State, local public and private ownership	State and private ownership	State, local public and private ownership
General framework	Authority	Energy Authority (Energiavirasto, www.energiavirasto.fi)			
	System	Revenue cap			
	Period	Current regulatory framework is set for two RPs (2016-19 and 2020-23)			
	Base year for next period	No specific base year applied[21]			
	Transparency	Decisions, regulatory data, efficiency scores, quality of networks			
	Main elements for determining the revenue cap	Efficiency, quality, innovation and investment incentives, WACC, return on RAB	Innovation and investment incentives, WACC, return on RAB	Efficiency, quality, innovation and investment incentives, WACC, return on RAB	Efficiency, quality, innovation and investment incentives, WACC, return on RAB
	Legal framework	Electricity Market Act (588/2013), Natural Gas Market Act (587/2017) and Act on the Supervision of the electricity and natural gas market (590/2013)			
Rate of return	Type of WACC	Nominal, pre-tax			
	Determination of the rate of return on equity	Risk-free rate + beta*market risk premium + premium for lack of liquidity (+ additional risk premium for natural gas TSO and DSOs)			
	Rate of return on equity before taxes	8.16% = (0.78+0.69*5+0.6+1.7)/(1-0.2)	7.66% = (0.78+0.69*5+0.6+1.3)/(1-0.2)	6.23% = (0.78+0.72*5+0.6)/(1-0.2)	5.83% = (-0.08+0.828*5+0.6)/(1-0.2)
	Use of rate of return	Reasonable return is calculated by multiplying the adjusted capital invested in network operations by the reasonable RoR. Therefore, companies receive reasonable returns on adjusted equity and interest-bearing debt invested in network operations			
Regulatory asset base	Components of RAB	Fixed assets, working capital, leased assets			
	Regulatory asset value	The regulatory asset value is calculated from the network replacement value by applying network component-specific average age and lifetime selection			
	RAB adjustments	Book values taken to RAB annually from balance sheet			
Depreciations	Method	Straight-line depreciation on replacement value of network. Depreciation is inflation-corrected annually with CPI			
	Depreciation ratio[22]	1.6%	2.2%	1.8%	2.5%
	Consideration	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			

[21] For electricity DSOs, the average of regulatory data from the years 2015-18 was used to determine the efficiency incentive for the fifth RP (2020-23). The DSOs' efficiency figure for the fifth RP was determined by the average of reasonable controllable operational costs (SKOPEX) and the average of realised controllable operational costs (KOPEX) from the years 2015-18. The efficiency frontier determining the individual DSOs' SKOPEX was estimated by using regulatory data from the years 2012-18. For the electricity and natural gas TSOs, the efficiency reference level (SKOPEX) is based merely on the operators' own historical costs. In the first year of the RP, the average of the previous four-year RP's KOPEX is used as the benchmark for efficiency costs. In the following years, the benchmark will be the reasonable controllable costs of the previous year.

[22] Calculated as depreciation/replacement value of network.

Introduction

In the Finnish energy sector, the regulatory task is performed by the Energy Authority as an independent regulatory authority. The responsibilities of the TSOs and DSOs are set by the Finnish Electricity Market Act and Natural Gas Market Act. Guidelines for the regulatory procedures applied by the Energy Authority are provided by the Act on the supervision of the electricity and natural gas market. The main objectives of regulation are the reasonableness of pricing and high quality of network services. Therefore, the Energy Authority seeks to achieve these by using regulation methods and specific incentives on network operator's business operations. In addition to the main targets of regulation, other key targets include equality and network development, as well as the sustainability, continuity, development, and efficiency of business operations.

Historical development

Until 2005, the Energy Authority's regulation methodology was ex post regulation based on case-specific assessment. Since 2005, determining reasonableness of the network operation prices has been based on a regulation method set ex ante with pre-defined RPs. Under this regime, the allowed revenues are set for network operators before the start of the RP. The current RP is four years, but the methods are valid for two consecutive RPs since the Electricity Market Act changed in 2013.

Determining the revenue caps

The Energy Authority does not regulate the actual charges and tariffs, as TSOs and DSOs set them independently. The regulation of the electricity grid and natural gas network services is based on the assessment of the reasonableness of the pricing in network services as a whole. The method decisions are published before the start of the upcoming RP, and these method decisions determine how the allowed or target revenues are set for the period.

The supervision of the reasonableness of the pricing is directed to the accumulating entity comprised of different network service fees. Regulatory methods consider capital invested in network operations and reasonable RoR (WACC %), which constitute the reasonable return for a network operator. In turn, a comparison to reasonable return is considered to be the realised adjusted profit from network operations, which includes the effect of incentives. The impact of incentives is deducted when calculating realised adjusted profits.

The incentive elements that are applied in regulatory methods vary between TSOs and DSOs. The set of incentives used are the quality incentive, efficiency incentive, innovation incentive, and investment incentive. The Energy Authority monitors that operators' profits for the RP do not exceed the determined reasonable level. If pricing exceeds the determined reasonable level, the surplus must be returned to customers in the next RP's pricing.

Efficiency benchmarking

Efficiency means that the service required by the customer is provided at the lowest cost possible. The operation of a network operator is cost-effective when the input, or costs, used in its operations are as small as possible in relation to the output of operations. The pricing of network operations is not subject to market pressure, meaning that the operator has no incentive to improve the efficiency of its operations. In such a case, without regulation, any cost ineffectiveness could be compensated by higher prices. The purpose of the efficiency incentive is therefore to encourage network operators to operate in a cost-effective way and at an achievable cost level.

The Energy Authority applies efficiency incentives to the electricity TSO, the natural gas TSO and the electricity DSOs. Natural gas DSOs are not subject to efficiency incentives.

In the calculation of efficiency improvement potential, the network operator's realised controllable operational costs (KOPEX) are benchmarked against the operator's reasonable controllable operative costs (SKOPEX). For the electricity TSO and the natural gas TSO, the efficiency reference level (SKOPEX) is based merely on the operators' own historical costs. In the first year of the RP, the average of the previous four-year RP realised controllable operational costs is used as the benchmark for efficiency costs. In the following years, the benchmark will be the reasonable controllable costs of the previous year.

With electricity DSOs the company-specific efficiency target is also observed by comparing individual DSOs' realised controllable operative costs (KOPEX) with DSOs' reasonable controllable operative costs (SKOPEX). DSOs' reasonable controllable operational costs at an output level, according to efficient operations, are determined by using the efficiency frontier. The efficiency frontier is estimated from the combined cost and output data from all DSOs. The variables included in the measurement of a company-specific efficiency target consist of the input variables (KOPEX and the replacement value of the network), output variables (volume of transmitted energy, number of metering points, total length of the electricity network and regulatory outage costs) and operating environment variables (connections / metering points - ratio).

In the calculation of KOPEX and SKOPEX for the fourth RP (2016-19), the average of regulatory data for 2011-14 was used, and for the fifth RP (2020-23) the average of regulatory data for 2015-18 was used. The efficiency frontier was estimated for the fourth RP by using regulatory data from 2008-14 as the initial data for company specific efficiency measurement variables, and these were adjusted with the CPI to the 2014 level. The efficiency frontier was re-estimated for the fifth RP (2020-23) in 2019 using regulatory data from 2012-18. For electricity DSOs, efficiency benchmarking has been based on the Stochastic Non-Smooth Envelopment of Data (StoNED) method since 2012. In 2015, the method was developed further, into its now current form, for the RPs 2016-19 and 2020-23.

Quality incentive

The Energy Authority uses regulatory outage costs as a quality incentive. Regulatory outage costs, i.e. the disadvantage caused by outages, are calculated based on the number and duration of outages, as well as the unit prices of outages that are determined in the methodology. The DSOs' average realised regulatory outage costs for the two previous RPs, i.e. eight years, are used as the reference level of regulatory outage costs. The reference level is adjusted by the annual energy transmitted to customers, to make the reference level of regulatory outage costs comparable with the realised regulatory costs with respect to the transmitted energy. The impact of the quality incentive is deducted when calculating realised adjusted profit. The impact of the quality incentive is calculated so that the realised regulatory outage costs are deducted from the reference level of regulatory outage costs.

The maximum impact of the quality incentive in the calculation of realised adjusted profit is made reasonable. The impact of the quality incentive may not be higher than 15% of the reasonable return in the year in question for electricity DSOs, 3% for the electricity TSO, and 2% for the gas TSO. Natural gas DSOs are not subject to the quality incentive.

Innovation incentive

The purpose of the innovation incentive is to encourage the network operators to develop and use innovative technical and operational solutions in their network operations. The key objectives of research and development activities are the development and introduction of smart grids and other new technologies and methods of operation. As a result, network operators may incur research and development costs before the new technologies are in full use and utilisable. The Energy Authority encourages network operators to make active efforts in research and development by deducting reasonable research and development costs in the calculation of realised adjusted profit. Acceptable research and development costs must be recorded in the unbundled profit and loss account as expenses, as capitalised research and development costs are not accepted as being included in the calculation of the innovation incentive. Acceptable research and development costs must be directly related to the creation of new knowledge, technology, products or methods of operation in network operations for the sector.

The impact of the innovation incentive is deducted when calculating realised adjusted profit. The impact of the innovation incentive is calculated so that a share corresponding to a maximum of 1% of the DSO's total turnover from network operations in the unbundled profit and loss accounts in the RP is treated as reasonable research and development costs. The incentive is applied to all network operators.

Investment incentive

The purpose of the investment incentive is to encourage TSOs and DSOs to make investments cost-effectively and to enable replacement investments. The investment incentive consists of the incentive impact of unit prices and the straight-line depreciation calculated from the adjusted replacement value. The incentive impact of unit prices directs the network operators to invest more effectively than on average and to find more cost-effective methods of implementation than before. The incentive impact arises from the difference between investments calculated with unit prices and the cost of realised investments.

Together with the net present value (NPV), the incentive impact of the straight-line depreciation calculated from the network operator's adjusted replacement value, directs the operator to maintain its network in accordance with the lifetimes it has selected in actual use as part of the network assets and enables it to make sufficient replacement investments. The incentive impact arises from the fact that the methods allow the operator an annual depreciation level based on average adjusted straight-line depreciation, based on the lifetimes selected by the operator. Imputed straight-line depreciation is always allowed in full, as far as the component is in actual use. Therefore, imputed straight-line depreciation is calculated for the component even after the end of the lifetime if the component is still in actual use. The impact of the investment incentive is deducted when calculating realised adjusted profit and the incentive is applied to all TSOs and DSOs.

Outlook

In June 2021 Finnish Parliament approved legislation to curb rises in electricity distribution prices by amending the Electricity Market Act and the Act on the Supervision of the electricity and natural gas market and the amended Acts entered into for on 1 August 2021. The relevant changes in legislation addressed the cost-effectiveness of the design, build, and maintenance of the distribution network, which will be monitored through network development plans. In particular, DSOs will include plans for the possible use of demand response, electricity storage, energy efficiency measures and other resources as an alternative for expanding the distribution capacity. Also, the maximum amount of the annual increase in electricity transmission and distribution charges was reduced from 15% to 8%. In addition, the implementation period for security of supply requirements was extended by eight years until the end of 2036.

Due to changes in the legislation, especially in regards to extension of the implementation period of security of supply requirements, the Energy Authority reviewed and made changes to the electricity distribution system operations regulatory methodology for years 2022 and 2023. The methodology changes concerned updating standard network component values in the RAB, determination of the risk-free rate in WACC calculations and removal of the security of supply incentive from the regulatory methodology.

Currently the Energy Authority is working on the development of regulatory methods for upcoming regulatory periods 2024-27 and 2028-31. The Energy Authority intends to order studies e.g., in relation to applied incentives and WACC determination.

2.10 France

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	2	26	1	~143
	Network length	~38,000 km	~200,000 km	~106,000 km	~1,400,000 km
	Ownership	Private and public ownership	Private and public ownership (indirect and local)	Mainly public ownership (direct and indirect)	Mainly indirect public ownership
General framework	**Authority**	Commission de Régulation de l'Energie (CRE, www.cre.fr)			
	System	Incentive regulation / revenue cap			
	Period	Four years. Current RP: 2020-24	Four years. Current RP: 2020-24	Four years. Current RP: 2021-25	
	Base year for next period	Second year in current RP	Third year in current RP	Second year in current RP	
	Transparency	Cost data (detailed OPEX and CAPEX), WACC and its underlying parameters, quality of service scores, regulatory accounts			
	Main elements for determining the revenue cap	Non-controllable and controllable costs, depreciation costs, taxes, fair margin			
Rate of return	**Legal framework**	French law (code de l'énergie) and CRE tariff decisions			
	Type of WACC	Pre-tax, real		Pre-tax, nominal	N/A*
	Determination of the rate of return on equity	Sum of a nominal risk-free rate and a risk premium (market risk premium multiplied by a beta risk factor) multiplied by a corporate tax factor, and expressed in real terms		Sum of a nominal risk-free rate and a risk premium (market risk premium multiplied by a beta risk factor) multiplied by a corporate tax factor	N/A*
	Rate of return on equity before taxes	8.6% = (1.7%+5.2%*0.86) / (1-28.02%)	8.4% = (1.7%+5.2%*0.83) / (1-28.02%)	7.8% = (1.7%+5.2%*0.78) / (1-26.47%)	N/A*
	Use of rate of return	Multiplied by the whole RAB (except assets that were funded through subsidies or grants)			N/A*
Regulatory asset base	**Components of RAB**	Fixed assets			
	Regulatory asset value	Historical revaluated costs (taking into account inflation and depreciation)		NBV	
	RAB adjustments	Subsidies and grants are removed from the value of assets before entering the RAB			
Depreciations	**Method**	Straight line			
	Depreciation ratio	Depends on asset type. Ratio between 2% and 4% for network assets (lines, pipes, etc.)			
	Consideration	Integrated directly and with 100% (except assets that were funded through subsidies or grants)			

* Due to the specificities of electricity distribution in France, assets are not remunerated via a WACC

Introduction

In France, the Commission de Régulation de l'Énergie (CRE) is the independent authority responsible for the regulation of electricity and gas markets. CRE is in charge of setting up access rules and tariffs for the utilisation of electricity and gas grids. It is also responsible for approving investments of upstream electricity and gas infrastructures (electricity and gas transmission, gas storage, and liquefied natural gas (LNG) terminals).

In electricity, there is a single TSO, RTE, that operates, maintains and develops the high voltage (HV) and VHV network. With more than 100,000 km of lines between 63,000 and 400,000 volts, the network managed by RTE is the largest in Europe. There are 143 electricity DSOs in France of various sizes. Distribution is dominated by Enedis, which operates 95% of the electricity distribution network, representing 1.4 million km of lines and 35 million customers. Four to six other DSOs serve more than 100,000 customers (Gérédis, SRD, SER, GEG, URM and EDF SEI) and the remaining DSOs are local companies that serve fewer than 100,000 customers.

In the gas sector, there are two TSOs: GRTgaz and Teréga (formerly TIGF). GRTgaz operates a pipeline network of approximately 32,000 km. Teréga operates a network of about 5,000 km in South-West France. Since 1 November 2018, with the implementation of France's single market area, there is only one market area but still two balancing zones, one for each TSO, which are responsible for the balancing of their own area of operation. On the distribution side, there are 26 natural gas DSOs supplying about 11.5 million consumers. GRDF is the main DSO, distributing to more than 96% of the market. Régaz-Bordeaux and Réseau GDS each distribute to about 1.5% of the market, while the 23 other DSOs represent less than 1% of distribution in total.

TSO certification and DSO independence

On 26 January 2012, CRE certified all French TSOs under the independent transmission operator (ITO) model. Revisions were carried out for RTE and Teréga after changes in their shareholding. RTE's certification was renewed by a decision of 11 January 2018. Initially certified as an ITO, Teréga's status was changed in ownership unbundling (OU) on 3 July 2014 after a modification of the shareholding structure of the TSO.

Regarding DSOs, CRE ensures it is effectively independent of its parent company. For instance, there must be clear differentiation between companies engaged in the supply or production of gas or electricity within the vertically integrated company ("Enterprise Verticalement Intégrée" (EVI)) to which they belong. This verification is based on internal organisation and governance rules, operating autonomy, and implementation of a compliance officer in charge of independence obligations and compliance with the code of good conduct.

Electricity transmission and distribution tariffs

In electricity, the current transmission and distribution tariffs for RTE ("TURPE-6 HTB") and Enedis ("TURPE-6 HTA-BT") entered into force on 1 August 2021, for a period of approximately four years (in accordance with the CRE's deliberations of 21 January 2021).

During the elaboration process, CRE conducted in-depth analyses of the projected expenses of French operators, practices in other European countries, and the evaluation of the WACC of electricity and natural gas infrastructure in France. Operating expenditures and their comparison with those of other European network managers were also examined. At the end of the process, CRE largely kept the previous tariff structure while introducing some improvements regarding incentives relating to CAPEX, quality of service and losses.

Regarding distribution, the tariff is equalised, therefore the same applies for all DSOs. Charges are calculated based on an average distribution cost plus a management fee and determined according to the level of voltage to which consumers are connected. A specific device to ensure that the network operators have the necessary resources to meet the costs of research and development, as well as deployment of smart grids, has been introduced while encouraging operators to be efficient.

Gas transmission tariffs

The tariff for the use of the GRTgaz and Teréga natural gas transmission networks is known as the “ATRT”. The current RP (ATRT-7) entered into force on 1 April 2020 for a period of approximately four years. It took into consideration the (EU) regulation 2017/460 establishing a network code on harmonised transmission tariff structures for gas (“Tariff network code”). It was adopted after extensive stakeholder consultation conducted in 2019 and relies on several studies which were published.

The ATRT7 tariff aims at giving gas TSOs the capacity to meet the challenges of the energy transition, particularly with the development of bio-methane injection into the networks. It also provides the capacity to take into account the changes in the gas market in the coming years, especially to control the evolution of tariffs in a context marked by the expiration of certain long-term contracts and the end of major investment projects.

Gas distribution tariffs

The sixth tariff period for the use of GRDF's natural gas distribution networks, known as the "ATRD-6 tariff", entered into force on 1 July 2020 for a period of about four years. As with the previous tariff, it encourages GRDF to improve its efficiency, especially in the context of a drop in gas consumption, while maintaining the gas distribution network at a maximum-security level. It also aims at providing GRDF with the capacity to adapt to the energy transition, in particular regarding the development of smart metering, the injection of bio-methane, and research and development activities. The ATRD-6 tariff also includes the estimated expenses related to the “gas conversion” project (converting the L gas zone to an H gas zone).

2.11 Germany

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	16	~700	4	~880
	Network length	~41,000 km	~500,000 km	~37,000 km	~1,900,000 km
	Ownership	Mainly private investors, indirect public ownership	Private and local public ownership	Mainly private investors, indirect public ownership	Private and local public ownership
General framework	**Authority**	Bundesnetzagentur (BNetzA), www.bnetza.de	BNetzA and federal state authorities, depending on size and network area	BNetzA	BNetzA and federal state authorities, depending on size and network area
	System	Incentive regulation / revenue cap			
	Period	Five years. Current RP: 2018-22		Five years. Current RP: 2019-23	
	Base year for next period	Third year in current RP			
	Transparency	Efficiency scores, revenue caps, collected asset and financial data, CAPEX top-up, cost pool positions, costs of investment measures, figures on the quality of supply			
	Main elements for determining the revenue cap	Non-controllable and controllable costs, TOTEX efficiency benchmark, general inflation and sectoral productivity factor, volatile costs	Non-controllable and controllable costs, TOTEX efficiency benchmark, efficiency bonus, general inflation and sectoral productivity factor, volatile costs	Non-controllable and controllable costs, TOTEX efficiency benchmark, general inflation and sectoral productivity factor, volatile costs	Non-controllable and controllable costs, TOTEX efficiency benchmark, efficiency bonus, general inflation and sectoral productivity factor, quality element, volatile costs
	Legal framework	EnWG, ARegV, GasNEV		EnWG, ARegV, StromNEV	
Rate of return	**Type of WACC**	No use of WACC			
	Determination of the rate of return on equity	Sum of a nominal risk-free rate and a risk premium (market risk premium multiplied by a beta risk factor) multiplied by a corporate tax factor			
	Rate of return on equity before taxes	6.91% = (2.49+3.8*0.83) * 1.225			
	Use of rate of return	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			
Regulatory asset base	**Components of RAB**	Fixed assets, working capital, assets under construction			
	Regulatory asset value	Net substance preservation for business assets capitalised prior to 1 January 2006, real capital preservation for business assets as from 1 January 2006			
	RAB adjustments	By the ordinance defined investments after the base year, e.g. expansions, lead to an adjustments of the non-controllable costs and therefore of the revenue cap	Investments in new assets after the base year lead to an adjustment of CAPEX. No distinction between replacements and enhancements or expansions	By the ordinance defined investments after the base year, e.g. expansions, lead to an adjustments of the non-controllable costs and therefore of the revenue cap	Investments in new assets after the base year lead to an adjustment of CAPEX. No distinction between replacements and enhancements or expansions
Depre-ciations	**Method**	Straight line			
	Depreciation ratio	Depends on asset type. Ratio between 1.5% and 4% e.g. lines & cables ~2%, stations ~4%			
	Consideration	Part of the examined controllable costs			

Introduction

The electricity and gas networks are examples of natural monopolies, where effective competition is restricted or does not exist at all. To ensure that network operators (TSOs and DSOs) do not make any monopoly profits but still operate their networks as cost effectively as possible, the electricity and gas network operators are subject to regulation. This task is performed by the Bundesnetzagentur (BNetzA) as the regulatory authority responsible in Germany for the networks in various sectors, including electricity and gas. 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. These federal state authorities can, however, also delegate regulation to BNetzA.

Historical development

Regulation by BNetzA began in 2005 as cost-plus regulation. 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 (RP) is determined using a mathematical formula and is fixed for the period. It therefore makes sense (incentive) for network operators to lower their costs within the RP (work efficiently) so as to increase their profits within the limits of the framework (revenue (fixed) minus costs (controllable) equals profit).

Determining the revenue caps

The revenue caps for network operators are set for a five-year RP. Each cap is composed of permanently non-controllable costs, temporarily non-controllable costs, controllable costs (applying a distribution factor for reducing inefficiencies), 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 the cost of capital for investments after the base year (DSOs only), quality element (electricity DSOs only), and volatile costs. The difference between the allowed revenue and the development of actual volumes over the year is entered into a regulatory account.

Efficiency benchmarking

BNetzA carries out its efficiency benchmarking based on the cost examination (TOTEX) and structural data validation before the start of each new RP for gas and electricity network operators separately. 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.

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, for example, the number of connection points, peak load, the amount of energy delivered or injected, and transformer and compressor station data. The costs and structural data collected always relate to the base year, which is always the third year of an RP.

The costs data mainly comprises 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 data is 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 RoR on equity is determined by the regulator.

The return on equity comprises a risk-free rate (determined based on 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 based on the return on equity.

The RoR 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 RoR 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 II 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.

The costs known as the permanently non-controllable costs are deducted from this cost pool (material costs, staff costs, costs of borrowing, taxes, other costs, write-downs and return on equity, minus revenue and income with cost-reducing effects). 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.

From the third RP (2018 for gas and 2019 for electricity) there is an annual subtraction of the capital cost for the DSOs. This subtraction takes account of the fall in CAPEX for the asset base (total costs of depreciation, the return on equity and the corporate tax, each of which is imputed, plus the costs of borrowing) over the duration of the RP.

The CAPEX subtraction is also deducted from the cost pool. The remaining controllable costs data and the structural data are then used for the efficiency benchmarking model.

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 stochastic frontier analysis (SFA) methods to the defined parameter groups. Since 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 RP.

Each of the two methods used (DEA and SFA) offer 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.

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 based on a super-efficiency analysis; this bonus is limited to a maximum value of 5%. This gives operators an incentive beyond the end of an RP to improve efficiency in the long term even if they have already achieved an efficiency score of 100%.

General sectoral productivity factor and price development

Another component of the revenue cap is the general sectoral productivity factor, which is always applicable for one RP. 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.

Quality regulation

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. To counter this, the regime includes quality regulation for electricity distribution networks. This takes the form of a quality element in the formula for setting the revenue caps. Operators achieving above-average quality in past years will have an amount added to their cap, while operators with comparatively low quality will have amounts deducted (bonus/penalty system).

Adjusting the revenue caps after the reference year

A CAPEX in-period top-up for DSOs ensures that the revenue cap can be adjusted in line with the cost of capital for investments in new assets after the reference year. No distinction is made here between replacement and enhancement or expansion expenditure. Operators must apply for the top-up six months in advance.

TSOs (and, in some cases, DSOs) can refinance their necessary expansion and restructuring investments through investment measures. Proposed expansion and restructuring investments can be approved provided they are required for either 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.

From 2021 on, to set an incentive for an acceleration of the grid extension, TSOs can achieve a bonus or penalty for the development of their expected bottleneck costs.

In the event of changes in other permanently non-controllable costs of a network operator during an RP, the revenue cap and thus the network charge can be adjusted accordingly.

National specificities

Electricity (gas) DSOs with fewer than 30,000 (15,000) customers can choose to participate in what is known as the “simplified procedure” and are then not subject to efficiency benchmarking. The efficiency score applicable to these operators is the weighted average of all adjusted efficiency levels from the national benchmarking exercise in the previous RP. For companies subject to the simplified procedure, the portion allocated to permanently non-controllable costs is fixed at a flat rate of 5%.

Transparency

Data published on the regulatory authority’s website includes revenue caps and annual adjustments, efficiency scores and efficiency bonuses.

Outlook

Various changes were made to the regime in 2016. Additional changes are expected in 2024 for TSOs to introduce more incentives to support the grid extension related to the energy transition, and in 2026 for DSOs to support the decrease of grid bottlenecks and the related costs of operating with these grid bottlenecks. Due to a decision of the European Court of Justice in 2021, BNetzA must now also consider how to become a more independent authority and how the regulatory regime has to be adjusted in future.

2.12 Great Britain

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	Network operators	1	8	3	6
	Network length	~7,000 km	~265,000 km	~25,000 km	~800,000 km
	Ownership	Private ownership	Private ownership	Private ownership	Private ownership
General framework	Authority	Gas and Electricity Markets Authority (GEMA, www.ofgem.gov.uk)			
	System	Revenue cap based on rate-of-return with incentive-based regulation			
	Period	Five years. Current RP: 2021-26			Eight years. Current RP: 2015-23
	Base year for next period	N/A			
	Transparency	Full transparency through extensive consultation and publication			
	Main elements for determining the revenue/price cap	Bottom-up CAPEX and OPEX benchmarking/analysis complemented by top-down TOTEX benchmarking, efficiency considerations, RAB, WACC, retail price index (RPI), real price effects, performance against incentive schemes			
	Legal framework	Gas Act 1986, Electricity Act 1989, Utilities Act 2000, Competition Act 1998, Enterprise Act 2002 and measures set out in a number of Energy Acts			
Rate of return	Type of WACC	Vanilla real WACC			
	Determination of the rate of return on equity	Sum of risk-free rate and a market risk premium multiplied by equity beta			
	Rate of return on equity before taxes	Electricity transmission 4.30%, electricity distribution 6%, gas transmission 4.55%, gas distribution 4.55% (all in real terms)			
	Use of rate of return	Multiplied by the average period RAB			
Regulatory asset base	Components of RAB	Historical investment base (less depreciation, removals) and capitalised element of TOTEX in current control period			
	Regulatory asset value	Gas TSO £6 billion, gas DSO £20.1 billion, electricity TSO £21.1 billion, electricity DSO £28.2 billion			
	RAB adjustments	Annually updated for CPIH (Consumer Price Index including housing costs)(RPI still used for electricity distribution) and allowed additions less regulatory depreciation and cash proceeds from disposals			
Depreciations	Method	Straight line for electricity TSOs and DSOs, sum of digits for gas TSO and DSOs			
	Depreciation ratio	Generally 45 years, but some exceptions to avoid cliff edge effects			
	Consideration	N/A			

Introduction

The Office of Gas and Electricity Markets (Ofgem)[23] is a non-ministerial government department and an independent NRA. Ofgem's principal objective when carrying out its functions is to protect the interests of existing and future electricity and gas consumers. Ofgem works effectively with, but is independent of, government, the energy industry and other stakeholders within a legal framework determined by the UK government.

[23] Note: Ofgem regulates markets in Great Britain, but not in Northern Ireland.

Ofgem is governed by the Gas and Electricity Markets Authority (GEMA). The Authority determines strategy, sets policy priorities, and makes decisions on a wide range of regulatory matters, including price controls and enforcement.

Historical development

Great British (GB) gas networks were privatised in 1986 and electricity networks in 1989. The form of regulation initially chosen was “RPI-X”, whereby the regulator limits average network charges from rising by more than the rate of inflation (measured by the Retail Price Index (RPI)), less an efficiency factor (called X). Since the revenues for the regulated company are set ahead of the RP, it incentivises the company to reduce expenditure as much as possible to maximise profits. This price revelation can then be used to set allowances for the next RP, allowing consumers to benefit from the resulting lower costs.

Although costs came down significantly over the course of successive iterations of price controls, RPI-X was found to have several issues: companies sometimes compromised on quality of service to maximise profits, they had poor incentives to invest in the introduction of innovation, and the regime had a bias towards capital intensive solutions. Accordingly, in 2013 Ofgem moved to the “RIIO” price control framework, which is Revenues = Innovation + Incentives + Outputs.

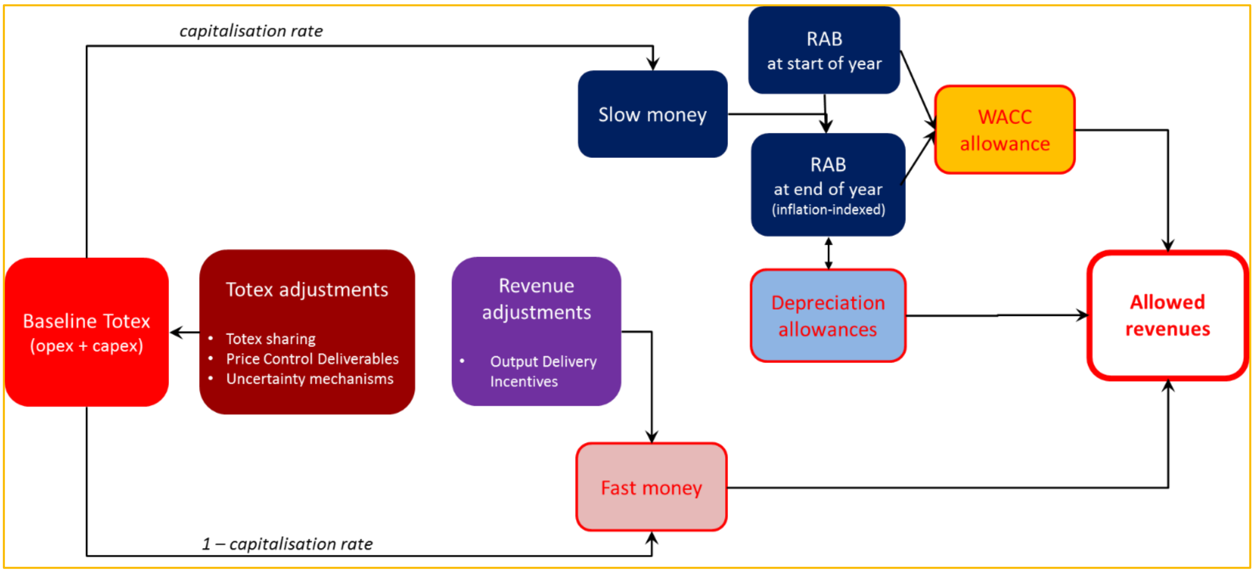
Under RIIO, companies are held accountable for delivering a high quality of service through the use of output targets, they are given financial incentives and a longer control period to encourage investment in innovation projects and the bias towards capital spending has been removed through the use of TOTEX allowances. This means that a fixed proportion of a company’s TOTEX is added to the RAB, irrespective of whether it comprises CAPEX or OPEX.

Determining the revenue caps

The revenue caps for network operators are set for either a five- or eight-year RP.[24] The current RP for gas and electricity transmission and gas distribution is April 2021 to March 2026. For electricity distribution, the period is April 2015 to March 2023.

The allowed revenues are built up as per the following diagram:

[24] The initial RIIO control period was set at eight years, with a mid-period check point after four years. However, the latest controls have been set for a five-year period, without a mid-period checkpoint.



GB allowed revenue components

Baseline TOTEX is set taking a view on justification of investment and then, if justified, making an allowance for efficient costs. Network operators are incentivised to beat these allowed costs through a sharing mechanism that allows them to keep a share of any underspend or bear a proportion of any overspend. These revealed costs then help to set benchmarks for the cost levels in the following price control period.

Efficiency requirements

Investment plans for the entire RP are approved up front, based on established needs cases and having a positive cost-benefit analysis (CBA). Operators are allowed efficient costs and incentivised to beat these through a profit/loss sharing mechanism. Where costs or timing of investment need are not clear, there are uncertainty mechanisms that allow for a revisiting of the justification at a later stage of the control period.

The efficient allowances will sometimes consider factors such as efficiency gains (to mimic the expected gains in productivity that occur in competitive markets) and real price effects (those unavoidable business costs that develop at a different rate to the CPI annual revenue indexation).

Price development

The allowed revenues are indexed to the RPI in relation to the base year and take real price effects into account. The most recent controls have moved to use CPIH as the annual price effects inflator.

Quality regulation

Network operators must meet performance outputs specified in their licences; the categories of output are common within sectors but vary between sectors. The performance targets/requirements vary from licensee to licensee. Failure to deliver outputs can be met by a variety of measures including financial penalties, claw back of revenues and, in extreme cases, enforcement action.

Adjustments after the reference year

Each year Ofgem recalculates revenue allowances due to inflation, investment, non-controllable (pass-through) operating and maintenance costs, licensee specific mechanisms and incentives. This adjustment is done on an annual basis and feeds into tariffs that come into effect two years afterwards.

Transparency

Price controls are set following extensive stakeholder consultation, typically over a two- to three-year timeframe in advance of the RP. Submissions, responses and decisions are all published on the Ofgem website (subject to commercial confidentiality restrictions). Licensees are obliged to send in annual returns and Ofgem publishes reports that monitor how the licensees are performing against the price control settlement.

2.13 Greece

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	Network operators	1	4	1	1
	Network length	1,466 km	6,849 km	12,584 circuit km	241,569 circuit km
	Ownership	Private investors and state ownership	State ownership and private investors	State ownership and private investors	State ownership and private investors
General framework	Authority	Regulatory Authority for Energy (RAE, www.rae.gr)			
	System	Cost-plus	Revenue cap	Revenue cap[25]	Revenue cap [26]
	Period	Four years. Current RP: 2019-22	Four years. Current RP: 2019-22[27]	Four years. Current RP: 2022-2025[28]	Four years. Current RP: 2021-24
	Base year for next period	Year t-2 (actual) and year t-1 (estimates)			
	Transparency	Decisions, regulatory data, specific cost data			
	Main elements for determining allowed revenue	OPEX (non-controllable and controllable costs), depreciation, RAB (assets and approved investment plans, working capital), WACC	OPEX (non-controllable and controllable costs), depreciation, RAB (assets and approved investment plans, working capital), WACC and WACC premium	OPEX (non-controllable and controllable costs), depreciation, RAB (assets and approved investment plans, working capital), WACC and WACC premium	OPEX (non-controllable and controllable costs), depreciation, RAB (assets and approved investment plans, working capital), WACC and WACC premium
	Legal framework	Law 4001/2011			
Rate of return	Type of WACC	Nominal, pre-tax	Nominal, pre-tax	Real, pre-tax[29]	Nominal, pre-tax
	Determination of the rate of return on equity	WACC: a) CAPM and additional country risk premium for cost of equity, and b) cost of debt based on operators' proposal and actual figures of base year			
	Rate of return on equity before taxes	8.12%	8.01%	8.20%[30]	8.36%[31]
	Use of rate of return	WACC is applied on RAB for each year of the RP			
Reg ulat	Components of RAB	Fixed assets, working capital, assets under construction			

[25] Since June 2021, a new methodology for allowed revenue of E-Tso is in force and will apply for the first time for the RP 2022-25. The methodology (RAE Decision 495/2021) is available at https://www.rae.gr/wp-content/uploads/2022/04/495__2021_EN.pdf.

[26] Since October 2020, a new methodology for allowed revenue of E-DSO is in force (https://rae.gr/wp-content/uploads/2021/02/%CE%9C%CE%95%CE%98%CE%9F%CE%94_%CE%91%CE%A0%CE%91%CE%99%CE%A4%CE%9F%CE%A5%CE%9C%CE%95%CE%9D%CE%9F%CE%A5_%CE%95%CE%A3%CE%9F%CE%94%CE%9F%CE%A5_%CE%95%CE%94%CE%94%CE%97%CE%95-%CE%A4%CE%95%CE%9B%CE%99%CE%9A%CE%9F_en-f.pdf).

[27] The RP for Hengas is 2021-24 (RAE Decision 615/2021 available at: https://www.rae.gr/wp-content/uploads/2022/04/timologio_2021_2024.pdf).

[28] The allowed revenue for the RP 2022-25 and the required revenue of 2022 is currently under approval.

[29] According to the new methodology for E-TSO (Decision 495/2021), WACC will be calculated as nominal, pre-tax.

[30] These figures are according to Decision 235/2018 for the RP 2018-21. The allowed revenue for the RP 2022-25 and the required revenue of 2022 is currently under approval.

[31] According to Decision 1566/2020 for the Allowed Return on RAB for E- DSO (RP 2021-24).

	Regulatory asset value	Historical costs	Historical costs since 2009 (last revaluation took place in 2004)
	RAB adjustments	No adjustments, historical values	
Depreciations	**Method**	Straight line	
	Depreciation ratio	Most assets are depreciated over a period of 25-50 years	
	Consideration	Depreciation ratio depends on asset type	

Introduction

Electricity and natural gas networks are characterised as natural monopolies, in which effective competition is limited or does not exist at all. In this context, to ensure that network operators do not abuse their dominant position i.e., provide non-discriminatory access to the network at tariffs that reflect conditions of healthy competition, and to stimulate cost effective operation of the network, TSOs and DSOs are subject to regulation.

This task is performed by the Regulatory Authority for Energy (RAE). RAE, among others, oversees and regulates the electricity and natural gas network operators in Greece. Electricity transmission and distribution in Greece is conducted by one TSO (ADMIE-IPTO) and one DSO (HEDNO) respectively. Regarding natural gas, there is one TSO (DESFA) and four DSOs (EDA Attikis, EDA Thess,[32] DEDA[33] and Hengas[34]). There is also a separate electricity DSO (privately owned) operating the network of Athens International Airport. The Athens International Airport's Electricity Grid Manager is regulated. However, only accounting obligations are applied, as it has fewer than 100,000 customers (Directive 72/2009).

Historical development

Unbundling

Following the Energy Law 4001/2011, the Public Power Corporation (PPC S.A) established a 100% subsidiary, ADMIE SA, according to the ITO model. In 2012, RAE certified ADMIE SA as the independent power transmission system operator. Since 2017 ADMIE SA has followed the model of ownership unbundling. The shareholding structure is 51% Greek State (through ADMIE HOLDINGS Inc. and DES ADMIE SA), 24% State Grid Europe Limited and 25% other institutional and private investors.

Hellenic Electricity Distribution Network Operator SA (HEDNO) was formed by the separation of the Distribution Department from PPC SA, according to Law 4001/2011 and in compliance with the 2009/72/EC EU Directive. HEDNO is a 51% subsidiary of PPC SA and 49% owned by institutional investors[35].

[32] Operator of the natural gas distribution network within the geographical areas of Thessaloniki and Thessaly Region.
[33] Operator of the natural gas distribution network in Central Greece, Central Macedonia, East Macedonia and Thrace,Pelopo¸Peloponnese and Corinthia region, West Greece, West Macedonia and Epirus.
[34] Operator of the natural gas distribution network within the geographical areas of Peloponnese, Grevena, Kilkis, Halkidiki, Pella and Central Macedonia.
[35] The privatisation of HEDNO took place in 2022.

The Hellenic Natural Gas TSO (DESFA SA) was privatised during 2018 and the company's shareholding structure is now 34% Greek State and 66% SENFLUGA SA (a consortium of the companies SNAM, ENAGAS and FLUXYS). The three natural gas DSOs (EDA Attikis, EDA Thess and DEDA) have been unbundled from supply activities since 2017. In 2021, HENGAS was also granted a licence for the natural gas distribution network (RAE Decision 423/2021).[36]

Tariff regulation

According to law,[37] RAE approves tariff setting methodologies for all non-competitive activities and sets relevant overarching principles and criteria. Explicit allowed revenue methodologies are currently in place for electricity transmission (since 2015), gas transmission (since 2012) and gas distribution (since 2016). The regulatory model is essentially a multi-year revenue cap on OPEX and cost-plus on CAPEX. Allowed revenue for electricity distribution is currently calculated by relying on the principles underpinning the electricity transmission revenue methodology, adapted to single year RPs, and applied broadly as cost-plus on both OPEX and CAPEX.

Regulatory decision process

Given the allowed revenue methodologies in place for the next period, the process starts with regulatory submissions by operators, due no later than seven months before the start of the next RP. The decision setting allowed revenue for the next period is issued two months before its start. Decisions are taken separately for each TSO and DSO in the natural gas and electricity sectors.

Main principles of tariff regulation

The regulatory period

The duration of the RP is according to the allowed revenue methodology. For all operators, a four-year RP applies. The base (reference) year is year t-2.

Determining allowed expenditures

The main building blocks of allowed revenue (OPEX and CAPEX) are determined in separate processes.

CAPEX streams are derived by approved network development plans (a ten-year plan for electricity and gas TSOs, and a five-year plan for electricity and gas DSOs) that apply for the RP under review. These can be modified on an annual basis and are approved separately from allowed revenue decisions. Modifications to approved development plans during an RP are considered in ex post treatment of CAPEX.

OPEX streams are determined in the context of the allowed revenue decision. RAE sets a reasonable OPEX allowance for the next period, scrutinising operators' expenditure proposals,

[36] RAE proceeded to the issuance to HENGAS of nine distribution licences for Deskati, Grevena, Paionia of the Regional Unit of Kilkis, Polygyros of the Regional Unit of Halkidiki, Edessa of the Regional Unit of Pella, Peloponnese Region, Corinth of the Peloponnese Region, Megalopolis of the Regional Unit of Arcadia, Skydra of the Regional Unit of Pella and Naoussa of the Region of Central Macedonia.
[37] Law 2773/1999 and Law 4001/2011.

based on past performance and forecasts and considering changes in relevant drivers, conditions, statutory and regulatory requirements, etc.

Regulatory asset base – depreciation

The RAB includes the estimated capital employed for the regulated network activity for every year of the RP, which includes the following:

- Undepreciated value of fixed assets (+);
- Assets under construction (+);
- Working capital (+); and
- Grants and contributions from third parties (-).

Depreciation is calculated for each year of the RP, for all assets that are expected to be in service during that year, excluding assets funded by third parties. Assets under construction are remunerated only for return on employed capital.

For the electricity TSO (ADMIE) and DSO (HEDNO), the historical values of 2009 have been considered (two revaluations took place before 2009, in 2000 and 2004, and the relevant surplus has been included in historical values). Since then, no revaluation has been considered. For the natural gas TSO and DSO historical values are considered.

WACC and WACC premium

A WACC is calculated as an RoR for capital employed (RAB). The WACC is estimated in real terms (pre-tax) only for the electricity TSO (since 2015 and until 2021), while for all the other operators, a nominal, pre-tax WACC is used. Due to specific country conditions, an extra premium (country risk premium) is added to CAPM.

For the electricity TSO and DSO, and for specific projects that are characterised as Projects of Major Importance in the Development Plan, a premium RoR can be provided, in addition to WACC. The percentage of this premium varies between 0% and 2% for E-TSO and 0.5% to 2% for E-DSO.

For gas DSOs, RAE can increase the allowed return (WACC) by 1.5%, according to specific objectives (defined by RAE), mainly aiming to increase natural gas consumption.

WACC calculation

$$WACC_{pre-tax,nominal} = g * r_d + (1-g) * r_e/(t-1)$$

$$r_{e,post-tax,nominal} = r_f + \beta_{equity} * MRP + CRP$$

Parameters	Electricity		Natural gas	
	Transmission (2021)	Distribution (2022)	Transmission (2022)	Distribution (2022)
Nominal risk-free rate (r_f)	0.70%	0.45%	0.35%	0.35%
Country risk premium (CRP)	1.50%	1.50%	1.50%	1.50%
Cost of debt (r_d)	5.13%	4.11%	3.91%	3.08%

Market risk premium (MRP)	5.00%	5.50%	5.30%	5.30%
Equity beta (β_{equity})	0.72	0.80	0.80	0.80
Cost of equity pre-tax ($r_{e,pre-tax}$)	8.20%	8.36%	8.12%	8.01%
Gearing - D/(D+E) (g)	40.30%	39.10%	16.10%	20.00%
Tax rate[38] (t)	29.00%	24.00%	25.00%	24.00%
Nominal pre-tax WACC	6.95%	6.69%	7.44%	7.03%

Greek WACC calculation parameters

Treatment of OPEX and CAPEX – efficiency incentives

The revealed cost of each (closing) RP is considered for the next RP (actual amounts of base year). Except for extraordinary, allowed revenue revisions, gas DSOs' OPEX allowance is not subject to ex post adjustment or settlement, either during or after the RP. This acts as an incentive for the operators to operate efficiently, reducing OPEX among RPs. For E-TSO and E-DSO a rolling and sharing mechanism applies on actual controllable OPEX to provide stable incentives for efficiency improvement. OPEX allowance of the gas TSO is fully adjusted, based on actual figures (cost-plus approach)[39].

CAPEX is treated on a cost-plus basis for both electricity and gas TSOs and DSOs, with settlements for any differences between approved and actual expenditure carried out both on annual basis.

Extraordinary revisions of allowed revenue

Extraordinary revisions of allowed revenue can be performed if a substantial change has occurred in the legal, economic or actual data that were considered when calculating the allowed revenue.

Outlook

In June 2021, RAE adopted a new regulatory regime for the electricity transmission system in Greece that will came into forcein 2022 (it applied for the first time for the RP 2022-25). The regulatory regime introduces several new provisions for the electricity TSO:

- Estimation of the allowed revenue in nominal terms, based on audited data (Certified Auditor);
- Distinction of operating expenditures into controllable and non-controllable;
- Incentive mechanism for the controllable operating expenditures (OPEX efficiency incentive mechanism), using a sharing mechanism to share the benefit of improved efficiency between the operator and network users;
- Calculation of the return on employed capital (RAB) based on a uniform return (WACC) for the entire duration of the RP, nominal/pre-tax by adopting a notional gearing and a notional cost of debt.

[38] At the end of 2019, according to Law 4646/2019, the tax rate was reduced to 24%.
[39] Tariff Regulation for G-TSO is under review.

2.14 Hungary

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	Network operators	1	11	1	6
	Network length	5,889 km	85,166 km	4,896 km	167,374 km
	Ownership	Private ownership	Two state-owned, nine private	Public	One public, five private
General framework	Authority	Hungarian Energy and Public Utility Regulatory Authority (MEKH, www.mekh.hu)			
	System	Incentive regulation			
	Period	Four years. Current RP: Oct 2021-Sept 2025		Four years. Current RP: 2021-24	
	Base year for next period	2022 (expected)	2023 (expected)	2023	
	Transparency	The methodological guidelines for determining the justified costs, and maintaining the prices during the RP, are available on MEKH's website			
	Main elements for determining the allowed revenue	Allowed revenue is composed of OPEX, CAPEX, depreciation (all adjusted to account for inflation), efficiency improvement factor for OPEX (CPI-X)	Allowed revenue is composed of OPEX, CAPEX, depreciation (all adjusted to account for inflation), efficiency improvement factor for OPEX (CPI-X)	Hybrid model	Hybrid model
	Legal framework	Act 40 of 2008 on natural gas Commission Regulation 2017/460 (NC TAR)	Act 40 of 2008 on natural gas	Act 86 of 2007 on electricity	
Rate of return	Type of WACC	Real, pre-tax			
	Determination of the rate of return on equity	Sum of the real risk-free rate and risk premium (equity beta multiplied by market risk premium)			
	Rate of return on equity before taxes	3.96% = 0.46+0.62+4.40*0.65)/(1-0.09)		4.38% = (1.08+4.40*0.66)/(1-0.09)	
	Use of rate of return	WACC is multiplied by the whole value of RAB to calculate the return on capital			
Regulatory asset base	Components of RAB	Tangible assets		Fixed assets	
	Regulatory asset value	Network assets: depreciated replacement value. Non-network assets: historical costs			
	RAB adjustments	The assets of the base year are modified yearly with modified CPI and t-1 year's investments that were approved by the Authority	The assets of the base year are modified yearly with modified CPI and t-1 year's investments that were approved by the Authority	The assets of the base year are modified yearly with CPI and t-1 year's investments minus depreciation minus connection charges	The assets of the base year are modified yearly with CPI and t-1 year's investments minus depreciation minus connection charges
Depre-ciations	Method	Straight line			
	Depreciation ratio	Depends on the useful lifetime of the asset type: pipeline 50 years, compressor station 20 years, gas delivery station 30 years		Depends on asset type. Ratio between 2.5% and 7% e.g. lines & cables ~2.5%, stations ~3.33%	
	Consideration	Based on expected useful lifetime		Based on expected useful lifetime	

Introduction

The electricity and gas networks are examples of natural monopolies, where effective competition is limited or does not exist at all. To ensure that network operators (TSOs and DSOs) do not make any monopoly profits but still operate their networks as cost effectively as possible, the electricity and gas network operators are subject to regulation.

Electricity

Historical development

Regulation began in Hungary after privatisation in 1997, with the first four-year RP. Regulation has been incentive-based from the beginning, but there have been gradual changes in each period. The development in the electricity and gas sector happened in parallel, but with some differences. In electricity, separate network tariffs have existed since 2003. The CAPM was first applied in the 2005-08 pricing period, while benchmarking was used in the 2009-12 pricing period. The last RP (2017-20) saw a move from price caps to revenue caps, as quantity changes of distributed energy were taken into account. In the current RP the same mechanism is being used.

Determining the price caps

Hungarian incentive regulation is a price-cap-like system. The price caps for network operators are set at the beginning of the four-year RP. The cap is calculated from the justified costs (operation and maintenance (O&M), depreciation, capital costs (RAB multiplied by WACC) and network loss) and the transmitted or distributed energy. The justified costs are determined through a detailed cost review. Concerning the O&M cost, there is an efficiency benchmarking; the RAB and depreciation are calculated from the indexation of the book value, and the expected lifetime of the assets.

Efficiency benchmarking

The Hungarian Energy and Public Utility Regulatory Authority (MEKH) carries out its O&M cost-efficiency benchmarking prior to the start of each new RP for gas and electricity network operators separately. 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. The benchmarking is related to the DSO's part- or sub-operations, such as O&M, metering and reading, and customer service. The partial productivity index is used.

General sectoral productivity factor and price development

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 to attract customers away from competitors.

Quality regulation

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. To counter this, the regime includes quality regulation for electricity distribution networks. This takes the form of a quality element in the formula for maintaining the price caps. Operators achieving above the required quality (SAIDI, SAIFI, outage rate) in past years will have an amount added to their price cap, while operators with comparatively poor-quality levels will have amounts deducted (bonus/penalty system). 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.

Adjusting the price caps after the reference year

The formula applied annually for maintaining the network tariffs during the RP consists of the following cost and revenue elements:

- Weighted average of the forecasted CPI and private sector gross average wages index – X (O&M), forecasted CPI (depreciation and CAPEX);
- Investments;
- Forward electricity price changes (network losses);
- The difference between the factual revenue and the forecasted revenue;
- Research and development costs;
- Quality of service; and
- Other specific costs (only in the case of the TSO).

In general the annual tariff decision is made on 1 January, but according to a Governmental Decree of 15 November 2021, in 2022 it was postponed for six months (with a new deadline of 1 July 2022). According to the decree, this postponement must be taken into account by the subsequent price decisions.

National specificities

For electricity, there are nation-wide uniform distribution tariffs, with an inter-DSO compensation tool.

Transparency

MEKH's methodological guidelines for determining the justified costs and maintaining the prices during the regulation period are available on the MEKH website.

Natural gas

Historical development

With regard to natural gas, a separate system for tariffs has existed since 2004. Before its introduction, between 1999 and 2004 regulated tariffs (containing both the costs related to system usage and commodity costs) consisted of two components – fixed and variable – and before 1999, a single component tariff (purely volume based) was in effect.

Since 2004, system tariffs have been regulated in regulatory cycles ranging between two and six years. The current RP for transmission and distribution began on 1 October 2021 and will last until 30 September 2025. In the case of storage, the RP started on 1 April 2021 and will end on 31 March 2025.

Before the start of the RP, MEKH undertook cost and asset reviews to set the tariffs for the next RP. MEKH's resolutions on the level of the initial tariffs of the RP, and their justifications, were issued at least 30 days before the annual yearly capacity auctions. These were based on the outputs of the cost and asset reviews, and in accordance with the provisions of the updated methodological guidelines. The following segments provide a methodological background for the tariffs of the current RP (2021-2025).

Determining the tariffs

Tariffs are set for four-year RPs as a default, with annual tariff reviews during the RP. MEKH carries out a cost and asset review before the beginning of each RP, during which it determines the RAB, justified operating costs, and the level of the WACC to be applied during the next RP. MEKH issues methodological guidelines detailing the applied methodologies for the cost

and asset review, for the setting of the tariffs and for the annual update of the allowed revenues during the RP.
During the cost review, mainly with regard to DSOs, MEKH benchmarks the efficiency of relevant activities among the system operators. In 2015 MEKH issued a guideline to DSOs in order to harmonise their cost accounting practices, and thus help the benchmarking process. MEKH also determines the level of metering losses considered to be justified and the cost of the lost gas. After determining the justified operating costs and the RAB, MEKH calculates the level of the costs to be recovered through the tariffs (cost base). Based on the cost base, the relevant capacities and heating-degree day normalised volumetric data, MEKH determines the applicable tariffs.
In 2021, in line with the provisions of Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas, MEKH issued a reference price methodology following a public consultation. This replaces the former methodological guideline (used until 2019) with regard to the determination of the TSO´s tariff-setting. The guidelines for the determination and annual update of the TSO´s allowed revenue are still published in a similar way as the DSO and Storage System Operator (SSO) methodologies.

A short overview of the benchmarking process used during the cost and asset review of DSOs before the current regulatory period (2021-25)

The aim of benchmarking the relevant costs is to assess the efficiency of the different operators and to determine the justified level of operating costs. For benchmarking, MEKH used partial productivity indices. MEKH divided the activity of DSOs into comparable sub-activities, allocated the relevant costs to the sub-activities, and created per unit indices based on the relevant cost drivers/outputs. These per unit, partial productivity indices form the basis of the benchmarking process.
Before the benchmarking process the following grouping of activities were used, which were further divided into two levels of sub-activities:

- Costs of procuring gas for DSO purposes (sub-activities: network and metering losses, technical gas use, odorisation costs and costs related to injecting the distributed gas to the system);
- Activities related to the operation of the infrastructure (sub-activities: operation/maintenance (further divided into pressure regulators, pipelines and other operational activities]) and disruption recovery);
- Activities related to system users (sub-activities: meter reading and customer relations (further divided into customer relationship channels, billing and settlements and activities related to customers systems));
- Support activities (sub-activity: support and management activities (further divided into: management, finance, accounting and controlling costs and other support activities)); and
- Costs related to assets (sub-activities: depreciation of DSO assets (further divided into depreciation of pressure regulators, pipelines, pressure regulators located at places of distribution and of gas meters) and the lease of assets not owned by the DSO.

Benchmarking was applied for operation/maintenance, disruption recovery, metering, customer relationship channels, billing and settlements and activities related to customer systems.
Cost drivers used during the process were determined based on the following criteria:

- The data was available from all DSOs and was determined with a sufficiently similar methodology;

- A strong correlation was found both at the level of individual DSOs and for their totality between the cost driver and the relevant cost base; and
- For activities with no sufficient cost drivers identified, composite cost drivers with a better fit were created from the combination of the relevant drivers.

To account for justified differences between the costs and operating circumstances of the DSOs, the regulator had the right to modify cost drivers. By dividing the relevant costs by the relevant cost drivers, the regulator created the partial productivity indices regarding unit costs. By dividing the sum of the relevant costs of all DSOs by the sum of the relevant cost drivers of all DSOs the regulator determined the average unit costs.
In the case of DSOs with higher-than-average unit costs, only the average unit cost level was considered to be justified. The part of the per-unit costs above the average level were not accepted as a part of the justified cost base.
To avoid unjustified under-recovery of costs due to different accounting and cost allocation practices between DSOs, an "efficiency reserve" was used for activities related to system users and infrastructure. The role of this "efficiency reserve" is to allow the efficiency increase in those sub-activities in which a DSO's efficiency is more than average, to compensate for lack of efficiency in those sub-activities in which a DSO's efficiency is less than average.

Adjusting the tariffs during the regulatory period of 2017-21

During the RP, annual tariff reviews are carried out to keep the tariffs updated. During the annual tariff review, the initial cost base is adjusted, and tariffs are recalculated based on the adjusted cost base and the updated capacities and heating-degree day normalised volumetric data. The adjustment takes into consideration the following factors:
- Inflation;
- Changes to the operating costs caused by legislative changes;
- Changes in the RAB, depreciation and cost of capital;
- Investments arising from legislative changes or regulatory obligations;
- Changes in the recognised cost of the settlement difference;
- Adjustments to be made based on the ex post examination of the system operator's profit with regards to its profit limit;
- Correction of errors, if any; and
- Changes in data expressed in volumes and quantified non-financial parameters.

National specificities
National specificities include:
- Nation-wide uniform transmission tariffs;
- Separate distribution tariffs for each DSO;[40] and
- Off-peak seasonal consumers on the DSO's system.

Transparency
The methodological guidelines for both the cost and asset review, the tariff setting and the within-period annual cost review, are published on the regulator's website. Regarding transmission tariffs, the transparency requirements of NC TAR are applied. Resolutions on the transmission system reference price methodology and resolutions on the transmission, storage and distribution tariffs and charges (and on seasonal factors, multipliers, discounts for transmission) are also published on the regulator's website (with any confidential data removed).

[40] Before 2011 uniform distribution tariffs with an inter-DSO compensation mechanism were used, however the system led to legal disputes. Since 2011 separate distribution tariffs are used.

2.15 Iceland

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	No gas TSO	No gas DSO	1	5
	Network length	-	-	~3,400 km	~22,000 km
	Ownership	-	-	Indirect public ownership	Mainly public and municipality
General framework	**Authority**	-	-	The NRA is a team within Orkustofnun National Energy Authority (www.os.is)	
	System	Incentive regulation / revenue cap			
	Period	-		Five years. Current RP: 2021-25	
	Base year for next period	Average of OPEX 2020-24, base year 2025			
	Transparency	Results published publicly. Data behind the regulation model available upon request			
	Main elements for determining the revenue cap	-	-	TOTEX: OPEX (Wage index and CPI adjusted five-year average) + CAPEX (previous year CPI adjusted book values) + non-controllable cost	TOTEX: OPEX (Wage index and CPI five-year adjusted average + non-controllable OPEX from previous year) + CAPEX (previous year CPI adjusted book values) + other non-controllable cost (e.g. network losses)
	Legal framework	-		The Electricity Act No. 65/2003	
Rate of return	**Type of WACC**	Pre-tax $WACC = (e * R_e + d * R_d(1-t))/(1-t)$, where d is debt ratio, e is equity ratio, $R_d = risk\ free\ rates + specific\ risk$ 2022 WACC for energy intensive TSO = 5.43%, TSO to DSO = 6.12%, general user (2021) = 6.18%			
	Determination of the rate of return on equity	Pre-tax $R_e = (r_f + market\ risk\ premium * \beta + specific\ risk)/(1-t)$ Sum of real risk-free rate and a risk premium (market risk premium multiplied by a beta risk factor) plus a specific risk premium multiplied by a corporate tax factor			
	Rate of return on equity before taxes	Pre-tax for 2022 energy intensive (TSO) = 8.4% = ((1.49+5.2*0.81) +1.0)/(1-0.2) TSO to DSO = 9.2% = ((2.10+5.2*0.81) +1.0)/(1-0.2) DSO to general user = 8.7% = ((2.10+5.2*0.74) +1.0)/(1-0.2)			
	Use of rate of return	The pre-tax WACC is the RoR. It is granted for operating necessary business assets			
Regulatory asset base	**Components of RAB**	Fixed operating assets			
	Regulatory asset value	Book value			
	RAB adjustments			CPI adjusted book values	
Depre-ciations	**Method**	Straight line			
	Depreciation ratio	Depends on asset type. Ratio between 2 and 20% e.g. TSO lines and cables ~2%, stations ~2.5%, DSO lines and cables ~3%-4%			
	Consideration	The regulator regularly inspects the RAB and the depreciations			

Introduction

The NRA in Iceland, Orkustofnun, is responsible for regulating natural monopolies in electricity and consists of a team of six people. Iceland has no gas networks, and the majority of space heating is conducted through the direct use of geothermal energy. Iceland has one TSO where ~75% of the energy produced is transmitted directly to energy-intensive industries. The other ~25% of the energy is transmitted to six DSOs with the number of customers ranging from ~6,500 to ~85,000. Two of the DSOs distribute both in rural and urban areas.

Historical development

The Electricity Act no. 65/2003 came into force in 2003 and implements Directives 96/92 and 2003/54. The 3rd Package has been implemented in national law. Regulation by the NRA officially began in 2005 as revenue cap regulation with a team of two people. The Electricity Act was changed in 2011. The changes in terms of regulation included, for example, a longer RP from three to five years, and the RoR changed from being based on government bonds directly to a WACC. Following the regulation change, the team was enlarged and presently consists of six people. One person is responsible for the revenue cap accounting.

Determining the revenue caps

The revenue caps for network operators are set for a five-year RP. The last cap was set in 2020 for the period 2021-25 based on data from 2015-19, where the base year is 2020. The next cap will be set in 2025 for the 2020-24 period. The cap is composed of the five-year average of controllable OPEX, non-controllable OPEX and CAPEX.

Determining the allowed revenue

The revenue cap is updated every year ex post and is referred to as allowed revenue. The allowed revenue is updated by CPI adjusting the controllable OPEX (relative to the base year) set by the revenue cap. Labour costs are updated with a wage index. Non-controllable OPEX is based on real values and includes network losses and TSO tariffs (for DSOs), which the DSOs can fully recoup as revenue. TSO network losses are not a part of their revenue cap/allowed revenue, but the tariff for network losses is monitored by the NRA.

CAPEX includes the RAB multiplied by the WACC plus depreciation for the relevant year. The RAB is based on inflation-adjusted book values on 1 January for the relevant year. Depreciations are linear and based on asset type. The difference between the allowed revenue and the actual revenue from distribution or transmission is entered into a regulatory account containing accumulated surplus or deficit balances. All changes in tariffs are based on that account. A network operator cannot have an accumulated surplus that is higher than 15% of their last allowed revenue. In this scenario the operator pays an interest cost of WACC to any surplus above 5% and should get within limits within one year. All accumulated deficits that are higher than 15% of the last allowed revenue are written off.

Split up revenue caps

The TSO and two of the five DSOs in Iceland have split up revenue caps and allowed revenue, and thus have two regulatory accounts. The TSO has a revenue cap for transmission to the DSOs and a revenue cap for transmission to energy-intensive industries. Two of the DSOs have a revenue cap for their urban areas, and a revenue cap for their rural areas. The reason for the split is that costs are substantially higher in rural areas compared to urban and the same

DSO is responsible for both. The split prevents urban users from subsidising rural users. The split also allows the government to decide on a subsidy amount to users to level their costs with urban users.

Efficiency benchmarking

Orkustofnun is legally obliged to carry out an efficiency study of the network operators before the revenue cap is set every five years. Such a study can only be carried out through independent specialists and not by the regulator. Aside from this, the efficiency legislation is open in terms of methodology and data. Following a recommendation from the specialists, the regulator can decide on an efficiency factor for the next period.

Before the last 2016-20 cap was set in 2015, independent specialists conducted an efficiency study on the TSO and the six DSOs. The TSO was evaluated independently and not benchmarked against other TSOs. The five DSOs were evaluated as seven companies, since two of them have split up revenue caps. The evaluation for the DSOs was based on DEA, controllable OPEX (input) and structural data. Structural parameters can include peak load, energy delivered, length of lines and cables, number of customers, etc.

The result was used as a recommendation for an efficiency factor for the NRA, and the NRA made an efficiency score decision based on that recommendation. That decision was, however, appealed to an independent appeal committee that revoked the NRA’s decision in this case. This was because the national Electricity Act wasn’t considered to have a sufficiently clear mandate for the NRA to impose efficiency requirements on the network operators. This means that current legislation makes it impossible to set an efficiency target in time, and hence no such study has been conducted for the period 2021-25. However, this might change depending on a new bill that has not yet been approved.

Rate of return

According to the Electricity Act, the WACC is the RoR on book values of all assets in the RAB. Both the TSO and two of the DSOs have two RABs on account of their split revenue cap. The WACC is the weighted average of the cost of debt and cost of equity calculated by the CAPM. Corporate tax is accounted for through a factor applied to the WACC formula. Inflation is, however, not accounted for in the WACC formula since the RAB is adjusted in terms of inflation every year.

All parameters in the WACC model are fixed in regulation no. 192/2016, except the risk-free rate. The risk-free rate is a moving average of ten-year inflation-indexed US Treasury Inflation-Protected Securities (TIPS) plus ten-year credit default swap (CDS) spread for energy-intensive industries, and ten-year inflation-indexed Icelandic government bonds for the general user and DSOs. The NRA calculates a new WACC every year based on the change in the risk-free rate.

For example, in May 2021, the NRA at Orkustofnun published new WACC for 2022, based on the average of the risk-free rate from 1 January 2011 to 31 December 2020. The 2022 WACC is the RoR for the RAB, while the allowed revenue for 2022 will be calculated in 2023. The WACC regulation mentioned above has a revision clause and is revised upon request. The revision and recommendation for the parameters of the WACC formula is performed by an independent group of specialists, the WACC committee appointed by the NRA. The regulation was last revised in April 2020.

Quality regulation

The Icelandic regulatory regime provides incentives to cut costs and to invest. There is still a risk that operators will refrain from undertaking the necessary investments or measures to achieve the required or potential savings. To counter this, data on quality of the network is collected and monitored by the NRA. The quality element is not a part of the revenue cap/allowed revenue formula, although it has been considered and was included in the draft of the Electricity Act.

Investments

The DSOs are not legally obligated to report their investment plans to the NRA. The NRA can, however, request such information. This is especially the case when it comes to potential changes in tariffs, where DSOs are obligated to provide a forecast for the allowed revenue to account for the effect on the regulatory account.

The TSO is obligated by law to deliver a three-year exact investment plan and TYNDP to the NRA. The NRA approves or disapproves the investment plan. The three-year plan is equivalent to an investment authorisation. This plan includes all investments of the TSO.

Transparency

The NRA publishes data on the regulatory website that includes revenue caps and annual adjustments, WACC, etc. All data related to the regulation can be made available upon request.

Outlook

The NRA aims to increase cost benchmarking and incentives to improve efficiency.

2.16 Ireland

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	1	1	1	1
	Network length	~2,477 km	~11,913 km	~6,711 km	~172,000 km
	Ownership	Gas Networks Ireland (GNI)	GNI	EirGrid operates the System and ESB Networks owns the system	ESB Networks
General framework	**Authority**	Commission for Regulation of Utilities (CRU, www.cru.ie)			
	System	Incentive regulation / revenue cap		Incentive regulation / revenue cap	
	Period	Five years. Current RP: 2017-22		Five years. Current RP: 2016-20	
	Base year for next period	Fourth year of current RP		Fifth year of current RP	
	Transparency	GNI publishes performance reports (customer performance and system performance) annually. An innovation reporting framework has been established and GNI publishes an annual report. CRU publishes its five-year price control decisions following public consultation. CRU also publishes an annual tariff information paper		Network companies publish performance reports annually. CAPEX monitoring and reporting is in place, and CAPEX reports are published on an annual basis. ESBN and EirGrid publish innovation reports annually. Furthermore, CRU publishes a report on stakeholder engagement annually. CRU publishes its five-year price control decisions following public consultation. CRU also publishes an annual tariff information paper	
	Main elements for determining the revenue cap	Review of historic and forecast OPEX, review of historic and forecast CAPEX, value of assets in TSO's RAB, RoR, inflation, depreciation, reporting and incentives	Review of historic and forecast OPEX, review of historic and forecast CAPEX, value of assets in DSO's RAB, RoR, inflation, depreciation, reporting and incentives	Review of historic and forecast OPEX, review of historic and forecast CAPEX, value of assets in TSO's RAB, RoR, inflation, depreciation, reporting and incentives	Review of historic and forecast OPEX, review of historic and forecast CAPEX, value of assets in DSO's RAB, RoR, inflation, depreciation, reporting and incentives
	Legal framework	The Department of Communications, Climate Action and Environment (DCCAE) is the lead government department (or ministry) with responsibility for energy policy. In the natural gas sector, the Department determines policy in relation to security of energy supply and the functioning of the market. The Department is responsible for transposing EU gas directives into national law and is responsible for financial oversight and corporate governance of state-owned energy companies. CRU is the independent economic regulator for the natural gas, electricity and water sectors in Ireland. Under Section 10A of the Gas Act 1976 as amended CRU sets the tariffs and the allowed revenue for the TSO. The Competition and Consumer Protection Commission is the government body responsible for enforcing Irish and European competition law in Ireland. Generally, it looks to CRU (there is a Memorandum of Understanding between		The DCCAE is the lead government department (or ministry) with responsibility for energy policy. The Department must ensure that Irish energy policy and legislation are in line with European law. It is within its remit to formulate and implement policy and legislation on the liberalisation and regulation of the electricity markets. CRU is the independent economic regulator for the natural gas, electricity and water sectors in Ireland. CRU's legislative basis for setting charges – under Section 35 of the Electricity Regulation Act 1999 ("the Act"), CRU approves charges for the use of the electricity transmission / distribution system in Ireland. In accordance with Section 35 of the Act, CRU's Price Review decisions outline the revenue that the TSO, TAO (transmission asset owner) and DSO will be allowed to recover from customers during a Price Review Period. Section 36 of the Act states that the TSO/DSO's statement of charges, prepared in accordance with Section 35, must be	

		the two) for matters relating to the electricity and natural gas sectors		submitted to CRU for approval and will not take effect until approved by CRU. The Competition and Consumer Protection Commission is the government body responsible for enforcing Irish and European competition law in Ireland. Generally, it looks to CRU (there is a Memorandum of Understanding between the two) for matters relating to the electricity and natural gas sectors
Rate of return	**Type of WACC**	The pre-tax real WACC for the period 2017-22 is 4.63%. CRU decided that a further aiming up allowance was not required		The WACC for the period 2016-20 is made up of a baseline WACC plus an aiming up allowance. The real pre-tax WACC for the TSO, TAO and DSO is set at 4.95%
	Determination of the rate of return on equity	The CAPM methodology is used to calculate the cost of equity using the formula $k_e = r_f + \beta * (r_m - r_f)$, where: • k_e is the expected RoR for the risky asset; • r_f is the RoR on a risk-free asset (the "risk-free rate"); • 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 • r_m is the expected RoR on a market value-weighted portfolio of all assets (the "market portfolio"). The term $r_m - r_f$ in the CAPM is referred to as the market risk premium.		
	Rate of return on equity before taxes	Cost of equity (pre-tax) 7.22%		Cost of equity (pre-tax) – high 7.99%, low 5.62%, point estimate 6.63%
	Use of rate of return	The RAB is the base to which the RoR is applied when determining the return on capital		The RAB is the base to which the RoR is applied when determining the return on capital
Regulatory asset base	**Components of RAB**	Fixed assets, assets under construction		Fixed assets, assets under construction
	Regulatory asset value	Replacement cost approach – historic cost indexed to present value using inflation		
	RAB adjustments	RAB adjusted for disposals	RAB adjusted for disposals	Assets are added to the RABs as costs are incurred, not on the date of commissioning. The network companies receive a return on the assets from the middle of the year in which the costs are incurred, rather than when the asset is commissioned. Assets that have been added to the RAB, but have not been energised within five years (except in the case where the programme of work was scheduled to be longer than five years or where the system operator 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 used
Depre-ciations	**Method**	Straight line		
	Depreciation ratio	Depends on asset category		
	Consideration	Part of the examined controllable costs		

Introduction

The Commission for Regulation of Utilities (CRU) is the independent body responsible for regulating the natural gas and electricity sectors in Ireland. Part of its responsibilities involves regulating the level of revenue which the monopoly system operators can recover from their customers to cover their costs.

The electricity and gas networks in Ireland are described as natural monopolies, as the nature of it is that it would be inefficient to develop duplicate sets of wires and pipes to service customers. Given the relatively small size of Ireland it would also be inefficient to break the current geographical area of the networks into smaller sections managed by individual TSOs and DSOs, although this is possible in larger jurisdictions/networks.

Gas

Gas Networks Ireland (GNI) is the gas system owner and operator in Ireland. GNI owns and operates both the transmission network and distribution network. Companies must hold a licence issued by CRU to distribute electricity or gas through the energy network. CRU is responsible for ensuring that customers and network users receive value for money while the network companies earn a fair return on their activities to make the necessary network investments. Those investments go towards the efficient operation, development and maintenance of the networks. There are almost 700,000 natural gas customers in Ireland.

Electricity

The transmission business consists of EirGrid, licensed by CRU as the TSO, and ESB, acting through its ESB Networks business unit, as the licensed Transmission Asset Owner (TAO). EirGrid is responsible for the operation and setting the maintenance and development policies of the transmission system, while ESB Networks is responsible for maintaining the system and carrying out construction work for its development. ESB Networks Ltd., a wholly owned subsidiary of ESB, is licensed by CRU as the DSO, and is responsible for building, maintaining and operating the distribution system. ESB, acting through its ESB Networks business unit, is the licensed distribution asset owner (DAO) and owns the distribution and transmission networks.

Determining the revenue cap

CRU uses a revenue-cap regulatory regime to determine the appropriate level of revenue required to allow the system operators to operate the networks in Ireland. CRU sets revenues ex ante for an RP of five years. There are a number of key components required to estimate the level of revenue that will be sufficient to finance the system operators. The building blocks of the regime are as follows:

Operational expenditure

The overall revenue figure for OPEX that is put in place by CRU is the result of both rigorous scrutiny of the system operator's proposals and benchmarking. CRU applies both a top-down and bottom-up benchmarking approach to OPEX. The objective of the bottom-up assessment is to develop a base year or stable run rate of normalised OPEX that represents the core historic 'business as usual' OPEX (which can then be revised as to reflect additional items of core OPEX), forecast to be incurred in future years of the RP. There are two components to the top-down benchmarking assessment. Firstly, the system operators are benchmarked to comparable utility businesses to determine how expenditure compares to an efficiency benchmark for the relevant sector. Secondly, CRU considers the degree of ongoing efficiency improvement or frontier shift that might be possible for the system operator over the RP.

Capital expenditure

In reviewing the system operator's CAPEX proposals, CRU analyses the proposals to determine whether they are appropriate, fully justified, whether they would deliver benefits to the customer, and whether the estimated costs are realistic.

Determining the appropriate rate of return

CRU sets the RoR that the system operator can earn on the efficiently incurred capital investments in its RAB. This is known as the WACC. This is essentially a weighted average of the cost of debt and the cost of equity. CRU sets a WACC that is used to derive a fair return on the capital investments made by the utility while also endeavouring to ensure that the system operators sit comfortably within an investment grade credit rating. The CAPM is used to assess the cost of equity which is used to aid the determination of an appropriate WACC.

Uncertain costs

Uncertain costs are defined as those that could not reasonably be foreseen by the system operators. CRU decided that such costs should be dealt with on a case-by-case basis. In each case, the system operator would be expected to ensure that changes in OPEX or new CAPEX would take place in an efficient manner and this would be reflected in the allowance provided – that is, there would not be an automatic pass-through of such costs.

Pass-through items

The price control model contains a provision for the pass-through of certain types of costs, such as business rates, that are deemed to lie outside the business's control. In some cases pass-through items are subject to incentive mechanisms, which share savings between the system operators and the network customers, for example, in areas such as rates and safety.

K-factor adjustments

CRU regulates the system operators through a form of revenue cap regulation which allows adjustments relating to one revenue control period to feed through into subsequent periods. This adjustment mechanism is generally referred to as a k-factor mechanism. The k-factor methodology is an adjustment used to allow for the fact that while CRU approves a level of revenue to allow the system operator to cover its costs over an RP, this level depends on assumptions about what happens over the course of that period, but it may not necessarily reflect events as they occur. The adjustment essentially corrects for these events by applying a correction to the annual revenue to be collected in subsequent periods.

Indexation

The model used by CRU uses a base allowable revenue which is indexed to take account of price inflation. The index used should be the best reflection of the increases in prices faced by the utility, such as wage inflation or materials inflation etc. Also, the index needs to be practical to implement, robust and transparent. In the recent review of allowable revenues for the system operators, CRU used the Harmonised Index of Consumer Prices. CRU accepts that no one index can precisely mirror the utility's input costs. It is also accepted that the majority of the annual revenue which the utility receives, covers depreciation and return on its asset base, rather than operating costs.

Valuation of the RAB

The system operators' RAB is valued using a replacement cost approach. The use of this approach has continued during the prevailing price control periods. While it is recognised that there are advantages and disadvantages associated with each methodology, the replacement cost approach was taken as it is more likely to result in the correct level of network investment. CRU notes that there are a number of variations of replacement cost that could be used. The version used by CRU uses the acquisition cost, indexed with inflation, as a proxy for the replacement cost.

Depreciation method

CRU used the straight-line depreciation methodology in its recent price control decisions and for the prevailing price control decisions.

Determining the allowed revenue

Combining all the component parts, CRU generates an overall revenue allowance for the system operators. This revenue feeds through into setting the transmission and distribution tariffs for each tariff period i.e. 1 October to 30 September.

Outlook

With regard to the gas price control, CRU is beginning work for the PC5 period, keeping in mind issues such as movement towards a decarbonised economy and incentive mechanisms.

With regard to the electricity price review, in May 2018 CRU published its decision on reporting and incentives under PR4. CRU introduced what it considers to be improvements to the existing incentives and reporting regime through the decisions in that paper. The aim is to provide the customer with better value for money and improve quality of services provided to the customer.

2.17 Italy

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	9	~194	11 (1 system operator)	~126
	Network length	~35,100 km	~266,000 km	~73,600 km	~1,276,000 km
	Ownership	Mainly private investors, indirect public ownership	Mainly private and local public ownership	Mainly private investors, indirect public ownership	Mainly private and local public ownership
General framework	**Authority**	Italian Regulatory Authority for Energy, Networks and Environment (ARERA, www.arera.it)			
	System	Cost-plus for CAPEX. Price cap for OPEX	Cost-plus for CAPEX. Price cap for OPEX. Standard cost approach for centralised costs	Cost-plus for CAPEX. Price cap for OPEX	Cost-plus for CAPEX. Price cap for OPEX. Standard cost approach for smaller DSOs
	Period	Four years. Current RP: 2020-23	Six years. Current RP: 2020-25	Four years. Current RP: 2020-23	Four years. Current RP: 2020-23
	Base year for next period	-			
	Transparency	All data pursuant to Commission Regulation (EU) 2017/460	Aggregated data at sectoral level published at beginning of RP	Aggregated data at sectoral level published at beginning of RP	Aggregated data at sectoral level published at beginning of RP
	Main elements for determining the revenue cap	OPEX (updated with price cap), return on net RAB, additional return for incentives, depreciation, fuel gas, losses, unaccounted for gas	OPEX (updated with price cap), return on net RAB and depreciation	OPEX (updated with price cap), return on net RAB, additional return for incentives, depreciation, regulatory account, ITC costs/revenues	OPEX (updated with price cap), return on net RAB, additional return for incentives, depreciation
	Legal framework	ARERA Res. 114/2019/R/gas	ARERA Res. 570/2019/R/gas	ARERA Res. 568/2019/R/eel	ARERA Res. 568/2019/R/eel
		For WACC: ARERA Res. 583/2015/R/com			
Rate of return	**Type of WACC**	Pre-tax, real			
	Determination of the rate of return on equity	Sum of real risk-free rate (with a floor of 0.5%), a country risk premium, and a beta risk factor multiplied by an equity risk premium (determined as the difference between total market return and the risk-free rate) $Ke_{p,s}^{real} = max(\frac{RF_p^{nominal} - isr_p}{1 + isr_p}; 0.005) + \beta_s^{asset} * \left[1 + (1 - tc_p) * \frac{g_{p,s}}{1 - g_{p,s}}\right] * \left(TMR - max(\frac{RF_p^{nominal} - isr_p}{1 + isr_p}; 0.005)\right) + CRP_p$			
	Rate of return on equity before taxes[41]	8.12%	8.36%	7.91%	8.34%
	Use of rate of return	Applied to the net value of RAB			
Regulatory asset base	**Components of RAB**	Fixed assets, working capital, assets under construction			
	Regulatory asset value	Historical cost re-valued for inflation, net of depreciation and grants	Both historical cost and standard unit cost (sectoral average) depending	Historical cost re-valued for inflation, net of depreciation and grants.	Historical cost for bigger companies. Standard unit cost (sectoral average)

[41] Values in real terms. As the methodology delivers a post-tax return on equity value, the pre-tax value has been computed taking into account the values of tax rate and tax shield. Compared to previous editions, it also internalises the effects of the correction factor (F).

			on type (central vs local assets). Both are revalued for inflation and are net of depreciation and grants	Investments prior to 2004 are considered as lump-sum with standard net value evolution and depreciation	for smaller companies. Both are revalued for inflation and are net of depreciation and grants
	RAB adjustments	New investments, depreciation, grants	New investments, depreciation, grants. For standard costs, changes in the driver	New investments, depreciation, grants. For investment prior to 2004, standard evolution	New investments, depreciation, grants. For standard costs, changes in the driver
Depreciations	**Method**	Straight line			
	Depreciation ratio	Buildings 3%, pipelines 2%, stations 5%, metering 5%-7%, other 10%-20%	Buildings 2%-3%, pipelines 2%, city gates 5%, metering 5%-7%, other 14%	Buildings 3%, lines 2%, stations 3%, metering 7%, other 5%-20%	
	Consideration	Deducted from gross RAB to form net RAB			

For 2022, the NRA was not able to author the descriptive part of this subchapter.

2.18 Latvia

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	1 (JSC Conexus Baltic Grid)	1 (JSC Gaso)	1 (JSC Augstsprieguma tīkls)	10
	Network length	1,190 km	5,381 km	5,509 km	92,430 km
	Ownership	Public ownership	Mainly private	Public ownership	Public and private ownership
General framework	**Authority**	Public Utilities Commission (PUC, www.sprk.gov.lv)			
	System	Revenue cap			
	Period	Three years[42]	Two to five years	Two to five years	Two to five years
	Base year for next period	Tariffs are based on justified historical costs (some of the costs are justified based on historical three-year average costs) and forecast of any other future costs (taking into account official forecast of inflation)			
	Transparency	When submitting a new tariff proposal, an overview with key indicators and figures is published on the regulator's website. As a part of the evaluation process, a public hearing takes place. All stakeholders are welcome to submit comments, questions and proposals			
	Main elements for determining the revenue cap	OPEX and CAPEX			
	Legal framework	Energy Law, Law on Regulators of Public Utilities, Methodology for the Calculation of the Tariffs on the Natural Gas Transmission System Services, Methodology for the Calculation of the Tariffs on the Natural Gas Distribution System Service		Electricity Market Law, Law on Regulators of Public Utilities, Methodology for the Calculation of the Tariffs on the Electricity Transmission System Services, Methodology for the Calculation of the Tariffs on the Electricity Distribution System Services	
Rate of return	**Type of WACC**	Pre-tax, real			
	Determination of the rate of return on equity	Return on equity: sum of a nominal risk-free rate,[43] country risk premium, market risk premium multiplied by a beta risk factor and a size premium (which is applied only to small and micro-sized entities)			
	Rate of return on equity before taxes	6.33%		6.33%	
	Use of rate of return	The WACC is applied to the value of the RAB to calculate the return on capital, which is a part of capital costs in tariff			
Regulatory asset base	**Components of RAB**	Fixed assets, intangible investment. Does not include inventories and assets under construction			
	Regulatory asset value	Book value as per financial reports (taking into account asset revaluations carried out by the operator at replacement cost value)			
	RAB adjustments	The RAB is adjusted and set when the operator submits the tariff proposal. During the period the tariff is in force no RAB adjustment takes place			
Depre-ciations	**Method**	According to International Accounting Standards (IAS) and operators accounting policy (straight line is mostly applicable)			
	Depreciation ratio	According to the asset type. Ratio between 1% and 20%, e.g. gas pipelines 1.7-2.5%, electricity lines 2-5%, electricity transformation substations 2.5-12.5%			
	Consideration	Depreciation is a part of capital costs in the tariff			

[42] According to the methodology, the NRA can decide on a different length of regulatory and tariff period.
[43] To calculate the real WACC, the inflation rate is applied to the calculated nominal pre-tax WACC as a whole.

Introduction

The unified multi-sector regulator in Latvia was established on 1 September 2001. The Public Utilities Commission (PUC), in accordance with the law "On Regulators of Public Utilities", is an institutionally and functionally independent, fully fledged, autonomous body governed by public law and independent in the implementation of its budget approved by law. The regulator independently performs functions determined in law and, within its competence, independently adopts decisions and issues administrative acts which are binding for specific public utilities providers and users.

In accordance with the law "On Regulators of Public Utilities", one of the regulator's main functions is to determine tariffs and the methodology for calculation of tariffs. Tariff calculation methodologies of the different sectors are developed in accordance with the law "On Regulators of Public Utilities", sectoral laws and other normative acts which are in force in the EU and Latvia. All methodologies are regularly updated and renewed according to changes in the normative environment.

Corresponding with market opening (in 2015 for electricity and 2017 for gas), former vertically integrated energy supply monopolies have been unbundled. The task of the regulator is to ensure the availability of public services, the availability of infrastructure to public service providers in all regulated sectors, the correspondence of public service tariffs/prices to their economic value, as well as to promote competition, transparency, and availability of information. Therefore, tariffs are set by PUC.

Although there are some differences in methodologies applied in tariff calculation between TSOs and DSOs, and between the electricity and gas sectors, the common goal remains.

In 2021 all energy tariff setting methodologies stipulate a revenue cap principle in tariff calculation.

When setting tariffs using a revenue cap approach, the RP may vary. The gas TSO methodology defines it as a three-year period while the DSO methodology defines it as a two- to five-year period. For electricity, the TSO and DSO methodologies define it as a two- to five-year period. PUC has legal rights to request new tariff proposals from system operators in case of significant deviations from the tariffs set. The system operator has similar rights to submit new tariff proposals if there is a legal, technical or economical reason for significant changes.

Determining the allowed/target revenues

The allowed revenues are calculated using the building-block approach. The two main parts of the allowed revenues are OPEX and CAPEX. Capital costs consist of depreciation and return on capital, which is calculated by applying a RoR (WACC, determined by the regulator) to the value of the RAB.

The WACC is set yearly and the system operators must apply it when calculating the new tariff proposals that are planned to come into effect in the respective year. From 1 January 2020, a pre-tax real WACC is applied in electricity and natural gas sectors.

The general RAB definition, used in all energy sector tariff calculation methodologies, states that the RAB consists of assets or part thereof used for providing the regulated service by the system operator. The electricity transmission and distribution sectors, as well as gas distribution sector, exclude inventories and assets under construction from RAB. Instead, they include the financing costs of maintaining the necessary inventory levels in OPEX. For projects of common interest, the costs of assets under construction can be included in the RAB only if such incentive is granted to the project according to Article 13 of the Regulation (EU) No 347/2013.

Transparency

When approving new tariffs, an overview with key indicators and figures is published on PUC’s website and public hearings are organised.

2.19 Lithuania

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	Network operators	1 (AB Amber Grid)	5	1 (LITGRID AB)	5
	Network length	2,285 km	9,986 km	6,986 km	126,814 km
	Ownership	State owned	State owned, private investors	State owned	State owned, private investors
General framework	Authority	National Energy Regulatory Council (NERC, www.vert.lt)			
	System	Revenue cap		Price cap	
	Period	Five years. Current RP: 2019-23	Five years. Current RP: 2019-23 for the main DSO	Five years. Current RP: 2022-26	For the main DSO, five years. Current RP: 2022-26. For small DSOs, five years. Current RP: 2020-24
	Base year for next period	2024	2024 for the main DSO	2027	2027 (for the main DSO), 2025 (for small DSOs)
	Transparency	Decisions			
	Main elements for determining the revenue cap	TOTEX, RAB, WACC, technical losses, efficiency benchmark		TOTEX, RAB, WACC, technical losses	
	Legal framework	The Law on Natural Gas of the Republic of Lithuania		The Law on Electricity of the Republic of Lithuania	
Rate of return	Type of WACC	Nominal, pre-tax			
	Determination of rate of return on equity	Sum of a nominal risk-free rate and market risk premium multiplied by a beta risk factor			
	Rate of return on equity before taxes	RoR on equity = 5.47%	For the main DSO, RoR on equity = 5.51%	RoR on equity = 5.185%	For the main DSO: RoR on equity = 5.315%
	Use of rate of return	WACC is used to calculate ROI. WACC is a multiplied by the whole RAB			
Regulatory asset base	Components of RAB	Fixed assets			
	Regulatory asset value	Historical values. €282 million (2021)	Historical values. €248 million (2021)	Mixed current value (for the main network elements (lines, cables, transformers) selected by the LRAIC model) and historical value (for the rest of asset) – €330,323 million (2021)	Historical value for five small DSOs. For the main DSO, mixed current value (for the main network elements (lines, cables, transformers) selected by the LRAIC model) and historical value (for the rest of asset) – €1096,92 million (2021)
	RAB adjustments	New investments and depreciation		New investments and depreciation	
Depre-ciations	Method	Straight line			
	Depreciation ratio	1.33%-25%	1.43%-25%	1.43%-25%	
	Consideration	Depreciation ratio depends on asset type. All depreciation of regulated assets is integrated into revenues			

Introduction

Natural gas, electricity transmission and distribution are regulated activities under the Law on Energy of the Republic of Lithuania, Law on Electricity of the Republic of Lithuania and Law on Natural Gas of the Republic of Lithuania. The performance of TSOs and DSOs are licensed and regulated by the National Energy Regulatory Council (NERC). NERC approves the requirements for keeping records of regulated activities, approves methodologies for the setting of state-regulated prices, sets state-regulated prices and price caps, and controls the application of state-regulated prices and rates. Moreover, NERC sets requirements for reliable transport of energy and quality of services, controls compliance therewith and performs other functions laid down by legal acts.

TSOs and DSOs are responsible for the stability and reliability of the transmission and distribution systems. They are also responsible for the provision of system services in the territory of the Republic of Lithuania, and the operation, maintenance, management and development of interconnectors to other systems. TSOs and DSOs must ensure objective and non-discriminatory conditions for access to the system by network users.

DSOs provide electricity and natural gas distribution, connection and disconnection of customers and guaranteed[44] natural gas supply (only gas DSO) services. TSOs provide electricity and natural gas distribution, transit and balancing services. Moreover, the natural gas TSO also performs the LNG terminal funds administrator function.

Main principles of tariff regulation

The main methodologies on which tariffs for natural gas and electricity transmission and distribution are calculated have been approved by NERC. These are:

- Methodology of Electricity Transmission, Distribution and Public Supply Services and Public Price Cap Calculation;
- Methodology of Setting State-Regulated Prices for Natural Gas Sector;
- Methodology for Determining Income and Prices of State Regulated Natural Gas Activities; and
- Methodology on Rate of Return on Investments.

A five-year RP applies for the natural gas and electricity transmission and distribution prices regulated by NERC. The allowable income levels are calculated as the sum of economically-based costs consisting of CAPEX (cost of depreciation – using the straight-line method – and ROI), OPEX (repair and maintenance, administrative cost, wages, etc.), taxes and technical losses.

The WACC of the natural gas and electricity TSOs and DSOs is calculated in accordance with the Methodology on Rate of Return on Investments, where cost of debt (the entity's actual long-term borrowing costs limited by the market average) and equity risk premium (the sum of the equity risk premium of the country with the developed capital market (the US) and the additional market risk premium of Lithuania; for regulated entities with new RP which starts in 2022 equity risk premium is equal to 5%) are evaluated. The equity risk premium is set for the entire RP and the cost of debt must be adjusted annually. NERC uses the WACC to calculate ROI as well as the discount rate in approving capital investments of TSOs and DSOs.

[44] Guaranteed natural gas supply means the supply of natural gas is guaranteed to customers through the provision of services of public interest.

Making adjustments during a regulatory period

In the natural gas sector, a NERC decision allows regulated price caps to be adjusted once a year. These are subject to the change in the inflation rate, prices of imported natural gas, taxes, amount of natural gas or the requirements of legal acts regulating activities of natural gas network operators, investments by natural gas undertakings as agreed with NERC, or deviation by natural gas network operators from the indicators determined in methodologies for the calculation of price caps approved by NERC.

In the electricity sector, the regulated price caps are adjusted each year following a change of the inflation rate (OPEX), new investments, depreciation and change of WACC (CAPEX), the electricity price (technical losses) and the ROI adjustment from previous periods.

The actual ROI in the natural gas and electricity sectors is estimated after the first two years of the RP and after the entire RP, taking into account the income earned, costs incurred and effectiveness of regulated activities. The ROI may be increased due to the decisions of regulated companies related to the reorganisation or other factors decreasing OPEX, accordingly 50% or 100% of the proved savings. This procedure applies in the electricity sector for RPs that started before 2021.

For RPs beginning after 2021, the actual ROI in the electricity sector is estimated after the first two years of the RP, and thereafter after four years of the RP and then after the entire RP (including the extension of the RP). The ROI may be increased due to the decisions of regulated companies related to the reorganisation or other factors decreasing OPEX, accordingly 50% of the proved savings.

Regulatory decision process

The process of setting transmission and distribution prices starts with the provision of data for establishing price caps. NERC evaluates the data provided by TSOs and DSOs, sets or corrects the price caps, and approves them by NERC resolutions. TSOs and DSOs provide NERC with an application to approve specific transmission and distribution prices. Having verified and determined that the prices calculated do not breach the requirements for setting prices laid down in methodologies and do not discriminate against customers and/or are not false, NERC gives instructions to natural gas network operators in relation to the calculation of specific prices and tariffs. Specific prices approved by NERC resolution are published by the TSO or DSO and NERC no later than one month before the prices enter into force.

Investments

Each year, each TSO provides NERC with the TYNDP – the strategic document that covers main investment projects for the following ten years. Where a TSO does not execute an investment, NERC shall require the TSO to execute the investments or oblige the TSO to accept a capital increase to finance the necessary investments and allow independent investors to participate in the capital. NERC determines whether the national TYNDP is consistent with the non-binding TYNDP of the European Networks of Transmission System Operators for gas and electricity (ENTSOG and ENTSO-E). From 2018, DSOs also have an obligation to prepare a ten-year network development, renovation, upgrading and investment plan.

Concerning the RAB, TSOs and DSOs can only include those investments that are already implemented[45] and approved by NERC. NERC's approval of the TYNDP does not mean the approval of the concrete projects, thus, projects must also be approved individually. An investment project is considered as an investment if it exceeds a certain value (€3.5 million for the TSO or €1.5 million for a DSO in the electricity sector and €2 million or 5% of the company's yearly investments (but not lower than €0.15 million) in the natural gas sector). Otherwise, investments are provided in the simplified manner, as part of a yearly investment plan.

Investment projects are based on technical, financial, and economic justification, e.g. CBA, NPV, cost-benefit ratio and impact on regulated prices. However, there are some exemptions in the evaluation process. For example, for all investment projects, the impact on regulated prices is taken into account. However, financial analysis is only necessary for projects related to security of supply and diversification and to the development of the system due to a change in the amount of transport of the energy. Economic justification is made only for projects where there is a need to ensure the functioning and efficient operation of the company's assets and for projects related to security of supply and diversification.

The yearly investment plan is composed of the list of investments with a value lower than that of an investment project. NERC can oblige a company to exclude particular investments from the yearly plan and present them as an investment project. All investments included in the yearly investment plan must be reasoned and have technical justification. Moreover, a report of the previous yearly investment plan must be provided and all changes to the values of each investment must be justified compared to the approved plan.

Quality regulation

NERC sets the minimum levels of the reliability indicators for electricity and natural gas (Momentary Average Interruption Frequency Index (MAIFI) and average interruption time (AIT) for TSOs, and SAIDI and SAIFI for DSOs) for the RP. These levels are estimated taking into account the average of actual numbers of the previous RP (not worse than set for the last RP), the improving task of the reliability indicators level (which is determined by assessing the impact of the planned investments during the RP on the transmission reliability) in the electricity sector, and the average of actual numbers of the last three years in the natural gas sector.

The actual ROI of electricity transmission and distribution services must be reduced by 1% (for each reliability indicator between 5-10% worse than the level set by NERC) or 2% (for each reliability indicator more than 10% worse than the level set by NERC).

The WACC of natural gas transmission and distribution services must be increased/reduced by 0.005% (for each reliability indicator between 10-15% better/worse than set by NERC) or 0.010% (for each reliability indicator more than 15% better/worse than set by NERC).

[45] An exception is applied to projects of common interest (PCIs), as assets under construction of PCIs are also included in the RAB.

2.20 Luxembourg

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	Network operators	1	3	1	5
	Network length	284 km	3,120 km	161 km	11,028 km
	Ownership	Mainly direct and indirect public ownership			
General framework	Authority	Institut Luxembourgeois de Régulation (ILR, www.web.ilr.lu)			
	System	Revenue cap / incentive regulation			
	Period	Four years. Current RP: 2021-24		Four years. Current RP: 2021-24	
	Base year for next period	2023			
	Transparency	Public consultation before the tariff methodology can be adopted. Methodology published in official journal and on NRA website. Possibility to contest NRA decisions			
	Main elements for determining the revenue cap	Remuneration on RAB, depreciation, controllable OPEX, non-controllable OPEX	Remuneration on RAB, depreciation, controllable OPEX, non-controllable OPEX	Remuneration on RAB, depreciation, controllable OPEX, non-controllable OPEX, ancillary services	Remuneration on RAB, depreciation, controllable OPEX, non-controllable OPEX
	Legal framework	Law modified 1 August 2007 relative to the organisation of the natural gas market, ILR/G20/21		Law modified 1 August 2007 relative to the organisation of the electricity market, ILR/E20/22	
Rate of return	Type of WACC	Nominal pre-tax WACC			
	Determination of the rate of return on equity	Sum of cost of debt and cost of equity. For more details see explanations			
	Rate of return on equity before taxes	For natural gas and electricity: 4.81% = 0.5 * 2.18% + (1 – 0.5) * 7.44%			
	Use of rate of return	Granted for self-financed assets in the RAB and for work in progress according to the dispositions of ILR/E20/22 and ILR/G20/21			
Regulatory asset base	Components of RAB	Fixed assets containing production costs, work in progress			
	Regulatory asset value	For assets since 2010: historical costs Before, and if re-evaluation was used at the time: assets financed by own funds (max 50%), historical costs re-evaluated with published indexes Remaining part: historical costs			
	RAB adjustments	Adjustments not foreseen in the method. After activation, new assets also enter the RAB			
Depre-ciations	Method	Linear			
	Depreciation ratio	Depends on the asset type. Useful lifetime 25-50 years for technical assets and constructions, and 3-20 years for IT related fixed assets			
	Consideration	Depreciation is fully included in the allowed revenues			

Introduction

The Luxembourgish electricity market has about 320,000 consumers and had a total consumption of 6.3 TWh in 2020. The natural gas sector accounts for some 90,000 consumers with a total consumption of 8.1 TWh in 2020.

The NRA is the Institut Luxembourgeois de Régulation (ILR). ILR has the role of supervising the market functioning in both electricity and gas sectors, as well as ensuring universal service in the interest of all consumers. As part of these tasks, ILR has the power to determine a tariff calculation methodology, and to take decisions in matters for which the national law explicitly entitles the ILR to. The tariff calculation methodology, as well as changes to the methodology, can only be decided after a public consultation process.

Network tariffs in electricity are identical for all the network operators in Luxembourg. This helps the consumer to better understand the tariffs and makes it easier for suppliers to manage clients in different networks.

For natural gas, the network tariffs remain different for each DSO.

Determining revenue caps

The tariff calculation methodology is set for four-year periods, with the current RP being from 2021-24. In principle, the methodologies for natural gas and for electricity are alike. The current method is a revenue cap method.

On a yearly basis, the network operators submit their tariff proposals for the following year, along with the final regulatory accounts of the previous year. ILR evaluates the submitted documents and approves the tariffs when no objections remain. The yearly review of the closed accounts allows adjustments to the maximum allowed revenue according to the real costs observed. Differences are transferred to the regulatory account.

The main categories of costs forming the maximum allowed revenue are RAB remuneration, depreciation, controllable OPEX, specific pass-through, quality factor and the regulatory account term.

Investments and depreciation

The current tariff methodology distinguishes between two categories of investments:
- Ordinary investments as defined in the respective electricity and gas tariff methodologies are counted among the “lots” (batch investments); and
- Individual investment projects, that are non-ordinary investments.

For assets in the “lots” category, the administrative burdens are considerably lower than for individual investment projects. They must be classified according to the voltage level (for natural gas, according to the level of pressure) and pre-defined asset categories. The operator also must note whether the costs are replacement costs or new investments. In addition, the network operator must submit to ILR its procedures for standard investments. This allows ILR to verify the efficiency of the procedure. Costs under this category enter the RAB in the year they occurred.

For individual investment projects, the system operator informs ILR annually about the progress of each project and informs ILR about projects for which it foresees the start of works before the end of the following year. Documentation to be submitted for new projects includes a justification, an analysis of alternatives and other options for the project, a CBA, the detailed costs, an analysis of events that could delay the project or have an influence on the total costs of the project, and an operational plan.

The tariff methodology provides the possibility to adjust individual investment projects during the realisation phase in case of unforeseen events that cannot be influenced by the network operator. The date of activation as well as the total costs of the project can be adjusted upon approval by ILR, provided that the system operator immediately notifies ILR of such deviations.

Upon completion of individual investment projects, real costs are compared to planned costs and 30% of the difference is allocated to the regulatory account term. To support digitalisation efforts by network operators, individual investment projects in IT apply the 30% allocation to the regulatory account term only if real costs are not between 83% and 120% of planned costs.

The work in progress, from the start of the project until the planned activation date communicated in the operational plan, is remunerated by the WACC. In case of delays of the project remuneration, the tariff methodology allows a reduction or the annulation of the remuneration for the years in question.

A project enters the RAB based on historical costs and is depreciated on a straight-line basis over the useful lifetime, as defined in the tariff methodology. Parts of an asset subsidised by public funds or financed by third parties are not included in the RAB.

Remuneration – WACC

The WACC used for the current RP is a nominal pre-tax remuneration. The final rate of 4.81% is a combination of the cost of equity and the cost of debt, with a weight of 50% each. This gearing represents an efficient capital structure, protecting the interests of the consumer as well as allowing the system operator to access capital markets at reasonable costs. The nominal cost of debt is set to 2.18%, and the nominal pre-tax cost of equity is set to 7.44%.

Controllable costs

Controllable costs are set at the beginning of the RP, based on the profit and loss account of the reference year. These costs are adjusted for price or salary indexes and network expansion (length of the network and consumers connected to it). For subsequent years, the set costs are carried forward taking into account the previously mentioned adjustment factors. Among controllable costs are mainly salaries, administrative costs, and other operating costs for which no specific pass-through is foreseen.

Specific pass-through

Costs and revenues eligible under this category are subject to the annual review of the maximum allowed revenues in the year X+1. During this review, the costs estimated during the calculation of tariffs are adjusted for real costs.

The non-controllable costs can be subdivided into operating costs and additional remunerations (financial incentives). The first part of these costs contains human resource costs such as training costs and commitments concerning supplementary pensions. The second part of non-controllable costs is for taxes, contributions and notary fees. Costs eligible under technical operation include network losses, the use of third-party infrastructure, ancillary services, preparatory studies, revenues from other transmission or distribution services not accounted separately, and revenues from participations of third parties in investment costs. Costs linked to cooperation between network operators can be accepted for transnational cooperation projects with the aim of increasing market integration, as well as costs linked to common projects of network operators aiming at enhancing market functioning or increasing the efficiency of the management of distribution networks. Finally, research and development costs can be submitted for projects supporting digitalisation, energy transition, smart grids, decarbonisation, or a more efficient market functioning.

Quality

In the current methodology for electricity the maximum allowed revenue has a specific component for quality. The quality factor covers availability of the network as well as quality of service. Availability is measured by means of the SAIDI. Quality of service takes into account how quickly the network operator handles network connection demands by users, as well as the transmission ratio of data from smart meters to suppliers the following day.

For natural gas, no quality factor is applicable for the current RP.

Regulatory account

The annual review of the maximum allowed revenue (MAR) allows the adjustment of some of the cost elements to account for real costs. RAB remuneration, work in progress remuneration, depreciation, quantity factor and indexes for controllable costs and specific pass-through items will be adjusted. The reviewed MAR will then be compared to the revenues from approved tariffs for the year concerned. For a given year, differences between the reviewed MAR and realised revenues are allocated to the regulatory account.

2.21 Netherlands

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	Network operators	1 (GTS)	6	1 (TenneT)	6
	Network length	12,000 km	125,000 km	23,000 km	262,000 km
	Ownership	State owned (public by law)	Local public ownership (public by law)	State owned (public by law)	Local public ownership (public by law)
General framework	Authority	Authority for Consumers and Markets (ACM, www.acm.nl)			
	System	Incentive regulation / revenue cap	Incentive regulation / price cap	Incentive regulation / revenue cap	Incentive regulation / price cap
	Period	Three to five years. Current RP: 2022-26	Three to five years. Current RP: 2022-26	Three to five years. Current RP: 2022-26	Three to five years. Current RP: 2022-26
	Base year for next period	TBD	TBD	TBD	TBD
	Transparency	Method and tariff decisions, regulatory data, efficiency scores, quality of networks			
	Main elements for determining the revenue cap	TOTEX, CPI, cost efficiency benchmark, productivity change, WACC, RAB	TOTEX, CPI, yardstick, productivity change, WACC, RAB	TOTEX, CPI, cost efficiency benchmark, productivity change, WACC, RAB	TOTEX, CPI, yardstick, productivity change, WACC, RAB, quality incentive
	Legal framework	Gaswet (Gas Act)		Electriciteitswet 1998 (Electricity Act)	
Rate of return	Type of WACC	Nominal, pre-tax		A "real-plus", pre-tax WACC is used. This "real-plus" WACC is defined as the nominal WACC adjusted for half of the inflation (CPI).	
	Determination of the rate of return on equity	Sum of risk-free rate and equity risk premium * beta. Equity risk premium is based on data in individual Eurozone countries over the period 1900-2019 (Dimson, Marsh and Staunton database). An average of both the geometric and arithmetic average is taken. Multiplied by beta based on comparator group			
	Rate of return on equity before taxes	4.20%			
	Use of rate of return	Nominal WACC is currently based on a 50% debt and 50% equity capital structure. Nominal WACC is multiplied by the RAB	Nominal WACC is currently based on a 45.25% equity capital structure. Nominal WACC is multiplied by the RAB	The "real-plus" WACC is currently based on a 45.25% equity capital structure. The "real-plus" WACC is multiplied by the indexed RAB to determine the ROI	
Regulatory asset base	Components of RAB	Fixed assets and certain intangible assets (such as software) are included, no working capital			
	Regulatory asset value	Indexed historical costs			
	RAB adjustments	Adjustment for certain specific (expansionary) investments	Adjustment for certain specific (expansionary) investments	Annual indexation (in the current RP: with half of the CPI). Also adjustment for certain specific (expansionary) investments	Annual indexation (in the current RP: with half of the CPI). Adjustment for certain specific (expansionary) investments

Depreciations	**Method**	Accelerated depreciation. Determined by the variable decline balance method. The acceleration factor is 1.3	Accelerated depreciation. Determined by the variable decline balance method. The acceleration factor is 1.2	Straight-line depreciation (in the current RP: corrected for half of the inflation (CPI) each year)
	Depreciation ratio	Most assets are depreciated over a period of 35-55 years		
	Consideration	Depreciation is part of the total costs, which are subject to an X-factor over the course of the RP		

Introduction

TSOs and DSOs in electricity and gas are neutral market facilitators. The Dutch Electricity Act and Gas Act specify the responsibilities of TSOs and DSOs. These responsibilities are linked to two domains. First, TSOs and DSOs are tasked with the transport and distribution of electricity and natural gas in an efficient, safe, and secure manner. Second, they are responsible for creating and maintaining connection points with other networks and consumers. TSOs are also responsible for system operations. Furthermore, TSOs and DSOs have a responsibility to share all relevant information to enable consumers and producers to make efficient decisions. And finally, they have the task of ensuring the safety of the networks.

The electricity grids and gas networks are natural monopolies, where effective competition is restricted or does not exist at all. They are also legal monopolies. To ensure that network tariffs reflect what is normal in competitive circumstances, and to stimulate operators to operate their networks as cost effectively as possible, electricity and gas network operators are subject to regulation. This regulatory task is performed by the Authority for Consumers and Markets (ACM).

Historical development

Regulation by (the predecessor of) ACM began in 2002 with an incentive-based regulatory regime, which is still in place to date. Under this regime, the revenues that network operators are allowed to earn within a certain period (RP) is determined using a mathematical formula and fixed for the period. This incentivises network operators to lower their costs to maintain or increase profits.

Regulatory decision process

The process of setting allowed revenues starts with the publication of a method decision (valid for a period between three and five years) before the start of that RP. Method decisions are taken separately for GTS (the gas TSO) and TenneT (the electricity TSO), but are combined for gas DSOs and for electricity DSOs.

In these decisions, ACM determines how the allowed or target revenue is calculated. Soon after this, ACM publishes the so-called X-factor decisions. In these decisions, the base level of revenue for the RP and the annual tariff cut (the X-factor) are set. Also, for the electricity DSO a quality incentive is set (the q-factor, see below). X-factor decisions are made for each TSO and DSO individually.

Finally, during the RP, ACM publishes tariff decisions annually and individually for each TSO and DSO. Tariff decisions take the relevant X-factor decision as a starting point and account for further tariff corrections due to changes during an RP, additions for certain specific (expansionary) investments, court decisions, etc.

Main principles of the tariff regulation

The most important principle is a revenue/price cap based on an exogenous efficient cost level. ACM incentivises TSOs and DSOs to operate efficiently by setting the operators' revenue before the start of the RP (i.e. an ex ante revenue cap or price cap). The allowed or target revenue is set equal to the expected efficient costs. If a system operator operates more efficiently than the cap, it may keep the resulting profits. On the other hand, if it operates less efficiently, it must also take the resulting losses. Because the efficient cost level is not only based on the network operator's own costs, the regulation also gives incentives for efficiency. That is, because the efficient cost level is based on mostly exogenous data, the network operator knows that, in future periods, it can profit from efficient choices made today. This gives the system operator an incentive to be efficient both in the short term and the long term.

For each RP, ACM renews the revenue or price cap to the actual efficient cost level. If cost reductions lead to a lower efficient cost level, consumers will benefit from these cost reductions in the period following these cost reductions. In this way, network operators earn a bonus for efficient operation, and consumers profit from lower cost levels in the long run. Hence, the Dutch incentive regulation also ensures affordability of energy network services.

To ensure the safety and security of the network, TSOs and DSOs must invest in their networks, and this requires capital. The incentive scheme parameters (like the WACC) are set such that network operators receive an appropriate return on their investment so that they can compensate their investors. This return should match the return a company would get in a competitive market (reasonable return). However, whether or not a network operator actually receives this return will depend on the decisions the network operator makes. The regulation is technology-neutral, i.e. it facilitates efficient investments, regardless of their nature.

Quality of transport

By way of a so-called q-factor, ACM gives an incentive to the electricity DSOs to maintain an optimal quality standard. If a DSO has fewer or shorter outages than the norm, it will gain extra revenue through a positive q-factor. If it has more or longer outages than the norm, it will lose a share of its revenues through a negative q-factor. For the gas DSOs, there is no q-factor as no informative indicator for quality has been identified so far. By law, q-factors are not implemented for TSOs. Quality maintenance for the TSOs and gas DSOs is therefore safeguarded by minimum requirements embedded in the Electricity Act, the Gas Act, and technical conditions, which are also set by ACM through separate procedures. Q-factors are added to X-factors when setting allowed revenues, so they have a cumulative effect.

The regulatory period

The law allows for a RP of three to five years. The current RP started on 1 January 2022 and runs until 31 December 2026. In the past, periods of three years were often implemented. The advantages of a shorter period are the flexibility to actualise the method more frequently, and the fact that the gap between ex ante estimates and ex post realisations is lower. The main advantage of a longer period is more stability and certainty for network operators and customers. In addition, a longer period creates stronger efficiency incentives, because the network operators will have a longer period in which they are able to profit from efficient operations.

X-factor mechanism

The mechanism of the X-factor works as follows. ACM determines the base revenue based on the realised costs and static efficiency parameters. Then, using parameters that estimate future cost trends, ACM determines the level of the revenue at the end of the period. The annual revenue then gradually evolves from the base level to the level at the end of the period, i.e. the X-factor is equal to the annual change in revenue. This means that the X-factor is a price differential, rather than an efficiency target.

Determining the regulatory cost base

The costs of a network operator include operational costs and capital costs. Operational costs are determined based on data from the network operators. Capital costs include the ROI and depreciation. These are calculated by ACM based on investment data from network operators.

For all types of investments regulated, depreciation periods are set out in the regulation. Periods vary between classes of assets, ranging from five to 55 years.

The tariffs include an appropriate return, which is based on a WACC method. This WACC gives an allowance for both the cost of debt and the cost of equity. When setting the WACC, ACM looks at the market return instead of the actual costs the network operators face. By looking at the market return, it ensures that the return is no higher than what would be appropriate in a competitive environment.

For the electricity TSO and DSOs, in the current RP, a “real-plus” pre-tax WACC is used. This “real-plus” WACC is defined as the nominal WACC adjusted for half of the inflation. The use of the “real-plus” WACC allows part of the compensation demanded for inflation by investors to be recovered immediately. This immediate compensation enables the network operators to finance the investments necessary due to the energy transition more easily. Since a “real-plus” WACC is used, the RAB is adjusted only by the remaining half of the inflation.

For the Gas TSO and DSOs, in the current RP, a nominal pre-tax WACC is used. The nominal 2022 WACC for the gas TSO is set at 3.1% and for 2026 at 3.0%. The method takes into account embedded debt. This is not necessary for expansion investments, so for new capital, the WACC is set at 3.0% for all years in the current RP. Since the method for the gas TSO is set earlier in time than the method for the gas DSOs, the nominal pre-tax WACC differs. The nominal pre-tax 2022 WACC for gas DSOs is set at 2.94%.

The WACC (nominal, pre-tax) is the same for TenneT and the DSOs (with the exception of the operator of the offshore grid) because the reference group used to set the WACC is representative for all network operators. For 2022 it is set at 2.94% and for 2026 at 2.77%. The method takes into account embedded debt. This is not necessary for expansion investments, so for new capital, the WACC is set at 2.76% for all years in the current RP.

Based on this nominal pre-tax WACC, for the electricity TSO and DSOs, the “real-plus” pre-tax WACC for 2022 is set at 2.04%, and for 2026 at 1.87% for existing capital. For new capital, the “real-plus” pre-tax WACC is set at 1.86%.

A separate WACC is set for the operator of the offshore grid to take into account the additional systemic risk due to the major investments task faced by this operator. For 2022 the “real-plus” WACC for the operator of the offshore grid is set at 2.44%, and for 2026 at 2.42% for existing capital. For new capital, the “real-plus” pre-tax WACC for the operator of the offshore grid is set at 2.42%.

For TSOs, the operational costs attributable to the expansion (or contraction) of the grid are estimated at 1% of the change in the combined historical costs of all assets in use. For each year, the change in combined total historical costs of all assets in use is determined using the historical costs of all assets that have not been fully depreciated in 2020, an estimation of the historical costs of new investments based on the level of investment in the period 2018-20, and the disinvestments as reported by the TSO.

European directives stipulate that tariffs should reflect the actual costs incurred, insofar as they correspond to those of an efficient and structurally comparable network operator. Since there is only one gas TSO and one electricity TSO in the Netherlands, ACM determines the efficient costs for the TSOs by comparing them with other European TSOs in a cost efficiency benchmark. When setting the efficient cost level for TSOs, ACM also takes into account dynamic efficiency. This is the expected scope for improving cost efficiency resulting from technological and economic trends. Lower costs due to dynamic efficiency are passed on to consumers during the RP in the form of lower tariffs. Effectively, the result of cost efficiency studies is used when historic actual costs are translated to allowed revenues for a future period.

For DSOs, so-called yardstick competition is used to determine static efficiency. Two yardsticks are determined, one for electricity DSOs and one for gas DSOs. ACM sets yardsticks equal to the average cost per unit of output, based on the actual cost of the DSOs. Each service that is billed separately by a DSO adds to the output, where the national tariff code prescribes what can be billed and what cannot. For incomparable types of costs (so-called objectified regional differences) a correction is made on an individual basis. For DSOs, dynamic efficiency is equal to the geometric mean of the annual difference in the costs/output ratio. This figure is used to adjust the yardstick. The so-determined efficient cost levels constitute the basis for the cost estimates used to set the allowed revenues for the upcoming period.

Making adjustments during a regulatory period

For some cost estimates, ACM is obliged to correct estimates annually and correct the allowed revenue accordingly. There can also be other circumstances that may call for intermediate corrections: (a) by court ruling, (b) if it turns out that the decision was based on incomplete or incorrect data, (c) if deviations between estimates and realisations are disproportional, or (d) if the revenue is based on services that a network operator no longer provides. For circumstances (b)-(d) it is at the discretion of ACM to decide if and how corrections will be made.

2.22 Northern Ireland

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	3	3	2	1
	Network length	~430 km	~6,000 km	~ 2,200 km	~45,000 km
	Ownership	Public	Private	Public	Public
General framework	**Authority**	Northern Ireland Authority for Utility Regulation (known as Utility Regulator, www.uregni.gov.uk]			
	System	Mixture	Incentive regulation – revenue and price cap	Incentive regulation – revenue cap	Incentive regulation – revenue cap
	Period	Five years. Current RP: 2022-27	Six years. Current RP: 2017-23	Five years. Current RP: 2020-25	Six and a half years. Current RP: 2017-24
	Base year for next period	TBD	TBD	TBD	TBD
	Transparency	Regulatory reporting in place for all TSOs and DSOs. Cost and performance reports published intermittently during the price control period			
	Main elements for determining the revenue/price cap	Review of historic and forecast OPEX, productivity, WACC, inflation	Review of historic and forecast OPEX and CAPEX, efficiency scores, productivity, WACC, inflation, future growth	Review of historic and forecast OPEX and CAPEX, productivity, WACC, inflation	Review of historic and forecast OPEX and CAPEX, efficiency scores, productivity, WACC, inflation
	Legal framework	Gas (NI) Order 1996		Electricity (NI) Order 1992	
Rate of return	**Type of WACC**	For GNI (UK) only, pre-tax real WACC	Pre-tax as well as post-tax real WACC	Pre-tax real WACC	Post-tax real WACC
	Determination of the rate of return on equity	The CAPM is used to calculate the cost of equity. This method relates the cost of equity (R_e) to the risk-free rate (R_f), the expected return on the market portfolio (R_m) and a business specific measure of investors' exposure to systematic risk (beta or β) using the formula $R_e = R_f + (R_m - R_f) * \beta$			
	Rate of return on equity before taxes	6.08% (real pre-tax)	6.6% (real pre-tax)	6.21% (real pre-tax)	5.50% (real pre-tax)
	Use of rate of return	The RAB is the base to which the RoR is applied when determining return on capital			
Regulatory asset base	**Components of RAB**	Fixed assets only	Fixed assets plus profile adjustment	Fixed assets and pre-construction work for investments according to the TYNDP	Fixed assets and assets under construction
	Regulatory asset value	Historic cost indexed to present value using inflation			
	RAB adjustments	None	RAB developments during an RP taken into account subject to uncertainty mechanism and actual outputs	Transfer of cost to the TAO upon construction	RAB developments during an RP are taken into account and lead to changes of the RAB

Depreciations	**Method**	Straight line (with electricity DSO kinked line)
	Depreciation ratio	Depends on asset type
	Consideration	Part of the examined costs

Introduction

The Northern Ireland Authority for Utility Regulation (otherwise known as the Utility Regulator) is the independent non-ministerial government department responsible for regulating Northern Ireland's electricity, gas, water and sewerage industries, to promote the short- and long-term interests of consumers.
The Utility Regulator's statutory objectives are to:

- Protect the short- and long-term interests of electricity and gas consumers with regard to price and quality of service;
- Promote competition, where appropriate, in the generation, transmission and supply of electricity; and
- Promote the development and maintenance of an economic and co-ordinated natural gas industry.

The Utility Regulator's work involves:

- Issuing and maintaining licences for gas and electricity companies to operate in Northern Ireland;
- Making sure that these companies meet relevant legislation and licence obligations;
- Challenging these companies to keep the prices they charge as low as they can be;
- Encouraging regulated companies to be more efficient and responsive to customers;
- Working to encourage competition in the gas and electricity markets;
- Setting the service standards which regulated companies provide to customers; and
- Acting as an adjudicator on certain customer complaints, disputes and appeals.

In carrying out its work, the Utility Regulator also takes account of the needs of vulnerable consumers. It also aims to contribute to the promotion of sustainable development in exercising its duties.

Historical development

The electricity industry in Northern Ireland was privatised in 1992-93. The industry is split into wholesale, network (transmission and distribution) and supply. The regulator ensures that each licensed activity is ring-fenced from other activities in the same group of companies. All consumers have metered supply, but more sophisticated meters and tariffs are used for industrial consumers than for households.
There are three electricity transmission licences, a distribution licence, and a market operator licence. System Operator for Northern Ireland Limited (SONI) holds the TSO licence for Northern Ireland. SONI also holds the market operator licence for Northern Ireland, in conjunction with EirGrid.
A transmission licence is held by NIE Networks Limited in respect of ownership of the main transmission system. A second is held by Moyle Interconnector Limited, a subsidiary of Mutual Energy Limited (MEL) that owns the Moyle Interconnector assets linking the network to the GB system in Scotland.
NIE Networks also holds a distribution licence for its distribution system. The Utility Regulator sets price limits for the monopolistic components of the electricity industry and ensures that end prices for consumers reflect efficient costs and reasonable levels of profitability.

The gas sector is split into three main areas: transmission, distribution and supply. Gas transmission deals with the large high-pressure pipelines that convey gas to the distribution systems. There are four transmission pipelines in Northern Ireland:

- The Scotland to Northern Ireland Pipeline (SNIP) is 135 km long and runs from Twynholm in Scotland to Ballylumford in Northern Ireland. The SNIP is owned by Premier Transmission Limited, which is part of the Mutual Energy Ltd. group of companies;
- The Belfast Gas Transmission pipeline (BGTP) is 26 km long and is connected to the SNIP and the North West Pipeline (NWP). It also supplies gas to the Belfast distribution network. The BGTP is owned by Belfast Gas Transmission Limited (BGTL), which is part of the Mutual Energy Ltd. group of companies;
- The NWP is 112 km long and runs from Carrickfergus to Coolkeeragh power station. It is owned by GNI (UK); and
- The South North Pipeline is 156 km long and runs from Gormanstown in Co. Meath to Carrickfergus where it links into the NWP. It is also owned by GNI (UK).

Gas distribution covers the medium- and low-pressure gas mains that convey gas to licensed areas within Northern Ireland. There are three gas distribution licensed areas within Northern Ireland:

- Greater Belfast and Larne area – operated by Phoenix Natural Gas Limited;
- Ten Towns distribution area – operated by Firmus Energy (Distribution) Limited; and
- West distribution licensed area – operated by SGN Natural Gas Limited.

The legislative framework that governs the energy industry in Northern Ireland includes the Energy (NI) Order 2003,[46] Electricity (NI) Order 1992,[47] and Gas (NI) Order 1996.[48]

Current regulatory frameworks

Electricity transmission

In Northern Ireland the transmission system is owned by NIE Networks (the TAO) and operated by SONI (the TSO) who is certified under Article 9(9) arrangements of Directive 2009/72/EC.[49] Both NIE Networks and SONI are part of wider corporate structures under the ownership of the Irish state government. Moyle Interconnector Limited is also a certified TSO but this asset is operated and administered by SONI.

SONI is regulated under a revenue cap framework. The final determination for the 2020-25 period was published in December 2020,[50] with licence changes becoming effective in January 2022. Controllable costs are set on an ex ante basis with a WACC return for capital projects.

A cost sharing mechanism exists for over-/underspend on controllable costs, whereby customers fund 75% of any overspend but retain the same proportion of any savings against the allowance.

A new mechanism has been introduced for conditional cost sharing for some costs, whereby either the TSO or the customer can retain all over-/underspend depending on the service delivered and if costs are justified or not. A new evaluative performance framework has also been introduced. Furthermore, SONI earns a margin for performing a revenue collection

[46] See http://www.legislation.gov.uk/nisi/2003/419/contents.
[47] See http://www.legislation.gov.uk/nisi/1992/231/contents.
[48] See http://www.legislation.gov.uk/nisi/1996/275/contents.
[49] European Parliament and Council of the European Union. (2013). Commission decision of 12.4.2013 pursuant to Article 3(1) of Regulation (EC) No 714/2009 and Article 10(6) of Directive 2009/72/EC – United Kingdom (Northern Ireland) – SONI / NIE. Retrieved from: https://ec.europa.eu/energy/sites/ener/files/documents/2013_059_uk_en.pdf.
[50] Utility Regulator. (2020). Final Determination for SONI Price Control 2020-2025. Retrieved from: https://www.uregni.gov.uk/publications/final-determination-soni-price-control-2020-2025.

function.
Certain non-controllable costs such as ancillary services are provided on a pass-through basis. Mechanisms are also in place to provide additional revenue within period for unforeseen projects or pre-construction work associated with investments prescribed by the TYNDP.
Typically speaking, no catch-up efficiency target is applied to the TSO. Rather, a general productivity challenge is applied alongside an assessment of real price effects. As the company bears no volume risk, tariffs are adjusted via a correction (K-factor) adjustment on a t-2 basis to account for any over/under-recovery of revenue. The evaluative framework will also provide a bonus or penalty following a review of the TSO's annual delivery by an independent panel of experts and the Utility Regulator.[51]
For the TAO (NIE Networks), the Utility Regulator's methodology for setting an efficient transmission allowance follows a traditional RPI ± X regulatory approach. NIE Networks' transmission allowance is set alongside its distribution price control. This is discussed further in the distribution section below. The regulated electricity revenue entitlements for network and market costs for 2021-22 can be found on Utility Regulator's website.[52]

Gas transmission

The regulatory framework for gas transmission is different depending on the TSO. All TSOs are certified under the full ownership unbundled arrangements. Premier Transmission Limited (PTL) and BGTL are part of the MEL group. These companies are all subject to a mutualised model.
In this model, Northern Irish gas consumers absorb deviations between forecast and actual operating costs in return for an absence of equity funding/returns from the business. These TSOs have a "shadow" price control which sets out expectations. While they carry no cost risk, the licence holders have a reputational incentive to manage costs effectively in line with the "shadow" allowance.
GNI (UK) is a subsidiary of Gas Networks Ireland, which is part of Ervia, a utility infrastructure company owned by the government of the Republic of Ireland. GNI (UK) is subject to a traditional revenue cap framework. In the case of GNI (UK), the allowance for controllable OPEX represents a fixed amount the licence holder will recover from consumers.
Any variation between this allowance and actual controllable OPEX is absorbed (or retained) by the licence holder. In this instance the consumer is exposed to no operating cost risk. Instead, this risk is borne entirely by the shareholders of the licence holder and is reflected in the RoR. This provides the licence holder with a very clear incentive to effectively manage costs.
For all three TSOs the only spend they incur is OPEX. Any maintenance or replacement costs are treated as operational spend. GNI (UK) earns a WACC return on its initial pipeline construction costs. PTL and BGTL networks are entirely debt-financed by way of bond cost repayments.
Revenue decisions for the current price control period 2022-27 for gas TSOs are published on Utility Regulator's website.[53]

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[51] For more detail on the evaluative performance framework, see: https://www.uregni.gov.uk/sites/uregni/files/mediafiles/Annex%202%20Service%20and%20outcomes.pdf.
[52] Utility Regulator. (2020). Regulated Entitlement Values 2021/22 Tariff Year. Retrieved from: https://www.uregni.gov.uk/files/uregni/documents/2021-09/201-09-24-regulated-entitlement-values-information-note.pdf.
[53] Utility Regulator. (2022). Final Determination for Gas Transmission Networks GT22. Retrieved from: https://www.uregni.gov.uk/news-centre/price-control-decisions-northern-irelands-gas-transmission-networks-gt22-published.

Electricity distribution

The current sixth RP for the electricity DSO has been effective since 1 October 2017 and lasts until 2024 (a six-and-a-half-year period). The regulatory framework that was adopted for this period follows a traditional RPI ± X revenue cap approach.
OPEX costs are subject to efficiency challenge via yardstick benchmark modelling against GB comparators. This modelling takes account of local circumstances in the form of special factors and regional price adjustments for labour costs. Revenues are inflated by RPI inflation but subject to real price effect considerations and a general productivity challenge.
Capital costs are treated in three ways:

- Investment for which an ex ante allowance is included in the determination;
- Investment carried out under the re-opener mechanism, where costs will be determined at a later date when the need for the project has been confirmed; and
- Investment that is subject to a volume driver.

Capital costs earn a WACC return of 3.18% (real), although this is subject to adjustment following refinancing. There are various uncertainty mechanisms in place and a variety of incentives based on delivery of key outputs aligned with cost control. A reliability incentive was introduced with annual financial incentives and penalties around performance on customer minutes lost. The final determination can be found on Utility Regulator's website.[54]
Work has begun on the next price control known as RP7. An approach document[55] has been consulted upon which looks at the key issues around delivery and the approach to tackling energy transition issues.

Gas distribution

The current price control for the three gas DSOs in Northern Ireland began on 1 January 2017 for a period of six years. Phoenix and Firmus both have a revenue cap, while SGN has a price cap to incentivise it to outperform on volumes as it develops its distribution network.
The focus of the price control is to grow and develop the network, to maximise the number of connections possible. Incentives are in place to achieve this.
The price control is based on a standard RPI-X framework. Efficient operational costs are set by virtue of top-down benchmarking, a bottom-up build-up of costs, and application of real price effects and productivity challenge. Capital costs are challenged on a similar basis. An innovation fund is available if DSOs can make an economic case and justify why the cost should be funded by customers. Various uncertainty mechanisms are also available to reflect the actual outcomes of performance and provide flexibility on workload priorities.
The description of this RP for gas DSOs is published on Utility Regulator's website.[56] Work is ongoing on setting revenues for the next price control period known as GD23. A draft determination was consulted upon in March 2022[57] with a final decision expected later this year.

[54] Utility Regulator. (2017). RP6 Final Determination. Retrieved from: https://www.uregni.gov.uk/rp6-final-determination.
[55] Utility Regulator. (2022). RP7 Approach Document. Retrieved from: https://www.uregni.gov.uk/files/uregni/documents/2022-03/rp7-approach-document.pdf.
[56] Utility Regulator. (2016). GD17 Final Determination. Retrieved from: https://www.uregni.gov.uk/publications/gd17-final-determination-final.
[57] Utility Regulator. (2022). GD23 Draft Determination. Retrieved from: https://www.uregni.gov.uk/consultations/consultation-launched-next-gas-distribution-price-control-gd23.

2.23 Norway

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	N/A	2	1	114
	Network length	N/A	740 km	~12,800 km	~105,000 km HV, ~220,000 km LV (≤ 1 kV)
	Ownership	N/A	Public and private ownership	State ownership	Mainly municipality/ local public ownership
General framework	**Authority**	N/A	Norwegian Water Resources and Energy Directorate (NVE-RME, www.nve.no/reguleringsmyndigheten)		
	System	Under development		Incentive regulation / revenue cap	
	Period	Under development		Data is updated every year, important factors (i.e. WACC model) fixed for five years	
	Base year for next period	Under development		Annual regulation, based on cost data from two years ago	
	Transparency	Under development		Full transparency – revenue caps, efficiency scores, all data, script for calculation in R	
	Main elements for determining the revenue cap	N/A	Under development	Controllable and pass-through cost, TOTEX efficiency benchmark. Averagely efficient company receives rate of return	
	Legal framework	Act on common rules for the internal market for gas with underlying regulations.		Energy Act with underlying regulations, accounting legislation	
Rate of return	**Type of WACC**	Under development		Nominal, pre-tax	
	Determination of the rate of return on equity	Under development		CAPM	
	Rate of return on equity before taxes	Under development		$\frac{(R_f+Infl+\beta e*MP)}{(1-t)}$ = (1.5 + 2.2 + 0.875*5.00)/(1-0.22) = 10.35%[58]	
	Use of rate of return	-		WACC is multiplied by RAB	
Regulatory asset base	**Components of RAB**	-		Book values from financial statement adjusted by 1% working capital premium, assets under construction and grants-funded assets are excluded	
	Regulatory asset value	-		Book values from financial statements	
	RAB adjustments	-	-	Book value + 1% working capital premium	
Depreciations	**Method**	Linear depreciations from financial statements			
	Depreciation ratio	Depends on asset type, must be approved by accountant			
	Consideration	Part of examined controllable costs			

[58] R_f is the risk-free rate, Infl is inflation, βe is equity beta, MP is the market premium, and t is the tax rate.

Introduction

The present Norwegian Energy Act came into force on 1 January 1991. The Act unbundled the activities of generation and supply, which can operate in competitive markets, from transmission and distribution of electricity. To achieve a competitive and efficient electricity market, the Norwegian Water Resources and Energy Directorate (NVE-RME) regulates TSOs and DSOs with a combination of direct regulation and incentive-based economic revenue cap regulation. The goal of the regulation is to promote efficient transmission and distribution of energy.

Norway has 106 electricity DSOs. Statnett is the only TSO. The electricity system operators set their tariffs based on the allowed revenue (AR).

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

AR is the sum of the revenue cap (RC), pass-through costs related to property tax (PT) and tariff costs to other regulated networks (TC). Approved research and development costs ($R\&D$) are also included. To remove the time lag (TL) 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 ago is included.

Further, any costs of energy not supplied ($CENS$) during the year are deducted from the allowed revenue. CENS is a measure of the calculated value of lost load for the customers. The CENS arrangement acts as a quality regulation, and an incentive for network operators to maintain their assets properly and to ensure necessary investments to avoid power outages at a socioeconomically efficient level.

Revenue compliance is subject to regulatory control. Excess or deficit revenue for a given year is calculated as the difference between actual collected revenues and allowed revenues in a year. Actual collected revenues include tariff revenues from customers, congestion revenue and revenue from system operations.

NVE-RME decides an excess/deficit revenue balance each year. The decision is made approximately one year after the RC is set, when the companies have reported their actual costs in the RC-year. The balance is to be adjusted towards zero over time through tariff changes. Excess revenues must be reimbursed to customers, while deficit revenues may be recovered.

According to the economic regulation of network companies, transactions within a vertically integrated company, and transactions between the network company and other companies in the same group, need to be based on competitive market conditions. Further, the national regulator may impose a specific method for cost allocation between areas of operation in vertically integrated companies. NVE-RME audits a selection of the companies annually to reveal any cross-subsidies.

Historical development

In the first RP (1993-96), NVE-RME used a rate-of-return regulation for the industry. During this period, NVE-RME prepared to implement a framework for revenue cap regulation that would give better incentives for cost efficiency than those possible under rate-of-return regulation. NVE-RME developed systems to collect data from the DSOs, and a revenue cap model that included the use of DEA to set general, as well as company-specific, efficiency targets.

In the second RP (1997-2001), NVE-RME introduced a revenue cap model with a cost base that was based on the DSOs' own historical costs. The regulatory RoR was fixed at 8.3%. The cost base was adjusted yearly to calculate revenue caps; the cost base was increased by CPI, and reduced by an efficiency target X. The general efficiency target was 1.5%, and individual efficiency targets were between 0 and 3%. The revenue caps were also adjusted for new investments with a factor deducted from growth in distributed electricity. In this period, the incentives for cost efficiency increased from the first RP. To avoid incentives designed to reduce costs resulting in low quality of service, NVE-RME introduced an incentive mechanism for quality of service in 2001.[59] CENS was calculated based on price per MWh for energy that was not delivered due to outages. An expected value of CENS was added to the revenue caps, and the actual value of CENS was deducted from allowed revenue when this was settled.

The regulatory model in the third RP (2002-06) was similar to the second period. The cost base was updated and based on data from 1996 to 1999, and minor changes were introduced in the benchmarking models. The CENS model was expanded to differ between more customer groups (from two to six) and adapted to implicitly take into account heterogeneity among DSOs. Similar to the second RP, the decoupling of the DSOs' costs and revenues due to the use of up to ten-year-old data gave strong incentives for efficiency. At the same time, the time delay between costs and revenues created weak incentives for investments. It also took time before efficiency improvements resulted in lower tariffs for end users.

In the fourth RP (2007-12), NVE-RME introduced major changes to the model. To address the weaknesses described above, the CPI-X model was abandoned. It 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. This cost norm was estimated through benchmarking methods based on the costs of other comparable DSOs (yardstick competition). The cost base in the model was no longer fixed for the period but updated yearly. This contributed to increase incentives for investments.
After two RPs with strong incentives for cost efficiency, the change was partly motivated to strengthen the incentives for investment. Around 2005, greater investments were expected in the industry. A large part of the asset base had become rather old, and there was a need for reinvestment. Reducing the lag of the cost base increased the incentives to invest. During this period, the incentives for quality were strengthened through expansion of the CENS arrangement. The incentives for cost efficiency were still strong, but these incentives were applied differently than in traditional CPI-X regulation. The cost norms were calibrated so that on industry level, the sum of cost norms was equal to the sum of cost bases. With this mechanism, the industry as a whole received the regulatory RoR, and also DSOs with average efficiency. DSOs that were more efficient than the average earned a higher return, and the opposite for those that were less efficient. Since this model was applied yearly, the implication was that the DSOs "competed" for their share of the total revenue cap. In the model, DSOs that lagged behind the average performance of DSOs would experience a lower RoR.
This mechanism incentivised efficiency, and at the same time reduced the time lag between costs and revenues. Another feature of this period was the incorporation of environmental variables (Z-factors) into the cost norm. This was important to increase the credibility of the model. These Z-factors were included as outputs in the model. In 2007, the DEA model had one input (total costs) and nine output variables. Five of these were related to network structure and four were Z-factors.
The fifth RP started in 2013. The main model framework from 2007 was maintained, but several elements in the model were improved. Disincentives for mergers and acquisitions were

[59] Langset, T. (2002). Quality Dependent Revenues – Incentive Regulation of Quality of Supply. *Energy & Environment*, Volume 13(4), pp. 749-61.

removed, and incentives for participation in research, development and pilot projects were strengthened. The number of outputs in DEA was reduced and the method for adjusting Z-factors was revised.[60] In 2010, the Z-factors had been moved to a second stage regression, but in 2013 further changes were applied to address some of the criticism of this approach. The model for calculating the regulatory RoR (based on a WACC model) was also updated to ensure the DSOs' ability to be able to earn a reasonable RoR on their assets.[61]

Determining the revenue caps

NVE-RME regulates the network companies using an incentive-based RC model. The RC is set annually, based on a formula of 40% cost recovery and 60% cost norm resulting from benchmarking models. To strengthen incentives, this will change to 30% and 70% respectively from 2023. There is a two-year lag in the cost data. The model covers operators of all electricity networks. Statnett is benchmarked against its own historical cost level, while the other network operators are benchmarked in models based on DEA. There are separate models for local and regional distribution. NVE-RME announces the RC for the coming year in November and the network companies set the tariffs accordingly. In principle, the only difference between the announced and the final RC for a year are the actual prices, inflation and WACC that must be estimated in the notification. In addition to this, any errors in the companies' cost or technical data discovered after the notification are corrected in the final RC.
Any changes in the rules and regulations will be subject to a public consultation, implemented before the RC-year begins. Changes in the methodologies not stated in the regulation are also subject to a consultation with affected parties. The RCs are calculated based on expected total costs using inflation adjusted cost data from two years ago. The deviation between the expected total costs and the actual total costs of all companies in a year is included in the RC calculation two years later (e.g. the deviation between expected and actual costs for 2017 will be corrected in the RC for 2019). The total cost deviation is distributed among the companies using their share of the sector's total RAB. This mechanism does not apply to the regulation of Statnett.

Efficiency benchmarking

NVE-RME implements two different efficiency assessment models for determining the revenue caps for DSOs in the local and regional distribution grids. Both models follow the same three stage procedure:

- DEA – compares efficiency solving specific tasks;
- Z-factor correction – adjusts the DEA scores from the first stage for differences in environmental factors. Efficiency may increase or decrease, depending on target units Z-factors; and
- Calibration – addition to cost norm such that the total industry cost base equals the cost norm. This ensures that averagely efficient companies receive a return equal to the NVE-RME-interest.

The inputs in the first and second stage of the calculation are essentially what differ in the two models. The differences are depicted in the table below.

[60] Amundsveen, R., Kordahl, O., Kvile, H., and Langset, T. (2014). Second Stage Adjustment for Firm Heterogeneity In DEA: A Novel Approach Used in Regulation of Norwegian Electricity DSOs. Retrieved from: https://www.deazone.com/proceedings/DEA2014-Proceedings.pdf.
[61] Langset, T. and Syvertsen, S. (2015). The WACC Model in the Regulation of the Norwegian Electricity Network Operators. Retrieved from http://icer-regulators.net/download/icer-chronicle-edition-4/.

	Local distribution		Regional distribution	
	Input	Outputs	Input	Outputs
Stage 1 – DEA	1) TOTEX = OPEX + depreciations*[62] + return on BV* + cost of network losses + CENS	1) Number of customers 2) Length of HV network km 3) Number of substations	1) TOTEX = OPEX + depreciations * + return on BV* + CENS	1) Overhead 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 and slope environments**	
	Coastal environments**			
	Cold environments**			
	City (share of grid laid as underground cables)			
	Forest environments (share of overhead lines in coniferous forest)			

Norwegian efficiency assessment model inputs and outputs

TOTEX is used as input in a single input cost-minimising DEA, assuming constant returns to scale. The weighted values used as outputs in the regional distribution grid also capture a lot of the differences between companies. This is one of the important reasons the second stage analysis includes more variables in the second stage analysis of the local distribution compared to the regional distribution. For calculation specifics, see NVE-RME's script (in R).[63]

General sectoral productivity factor and price development

NVE-RME does not implement any productivity factor for the DSOs. As described above, the total revenue cap for the industry is given. Since the model is updated annually, there are strong incentives for each DSO to reduce costs. To maintain a given level of RoR a DSO has to keep up with the development of the "average DSO". The large number of DSOs limits the effects of cartelisation.
For the TSO, Statnett, NVE-RME has introduced a general productivity factor in addition to the benchmarking against its own history. The level is 2% of total cost, and Statnett can realise this over six years, which translates into an annual factor of around 0.3%.

National specificities

Some smaller DSOs are exempted from the regular RC-model described above. These companies' costs are compared to their own historical average cost.

Outlook

NVE-RME has decided that the share relationship between actual costs and cost norm that is currently 40:60 will change to 30:70 from 2023. This will increase the incentives for cost efficiency.

[62] * Including depreciations on grants funded assets, ** Estimated using principal component analysis.
[63] See https://github.com/NVE/IriR.

2.24 Poland

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	1 entity	1 main entity and 52 local DSOs	1 entity	185 local DSOs
	Network length	~12,078 km[64]	~147,031 km[65]	~15,000 km	~815,000 km
	Ownership	State-owned	Indirect state-owned, public and private	State-owned	Public, partly public and private
General framework	**Authority**	The President of the Energy Regulatory Office (URE, www.ure.gov.pl)			
	System	Revenue cap	Cost of service with elements of revenue cap	Cost of service with elements of revenue cap	Mixed (revenue cap with elements of incentive-based regulation and elements of quality regulation)
	Period	Calendar year	12 months	Calendar year	Calendar year[66]
	Base year for next period	Mainly a year preceding the year of tariff submission for approval, for which an audited financial statement is available		Mainly a year preceding the year of tariff submission for approval, for which an audited financial statement is available	The base will be set when developing the assumptions for the next RP
	Transparency	The approved tariffs and guidelines on WACC issued by the President of URE. For TSO also publication of information according to articles 29 and 30 of NC TAR[67]		The approved tariffs and guidelines on WACC issued by the President of URE	Tariffs, assumptions on benchmarking models and WACC guidelines
	Main elements for determining the revenue cap	Justified operating expenditures, depreciation, local taxes and other fees, cost of gas losses and return on capital employed	Justified operating expenditures, depreciation, local taxes and other fees, cost of gas losses, pass-through costs and return on capital employed	Return on capital and OPEX, depreciation, property taxes, losses, costs of maintaining the system-related standards of quality and reliability of current electricity supplies	Return on capital (determined also by quality regulation factors) and OPEX, depreciation, property taxes, losses and pass-through costs
	Legal framework	Energy Law Act and regulations of the Minister of Energy			
		EU law	-	-	
Rate of return	**Type of WACC**	Pre-tax nominal		Pre-tax nominal	
	Determination of the rate of return on equity	$C_{equity\ pre-tax} = \frac{(\text{Risk-free rate} + \beta_{equity} * \text{equity risk prei}}{(1 - \text{corporate tax rate})}$		$\frac{(\text{Risk-free rate} + \beta_{equity} * \text{equity risk premi}}{(1 - \text{corporate tax rate})}$	
	Rate of return on equity before taxes	6.644%[68] = (2.340%+0.676*4.50%)/(1-19%)		6.415%=(1.938%+0.724*4.5%)/(1-19%)	
	Use of rate of return	In allowed revenue, URE includes RoC = WACC * RAB			

[64] High-methane and low-methane natural gas transmission network (including SGT transit pipeline).
[65] For main entity high-methane and low-methane natural gas network (not including customer's connections).
[66] Temporary solution. Work on the next RP is underway.
[67] Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas (OJ L 72 of 17 March 2017 p. 29).
[68] Value included in the calculation of the gas TSO tariff for 2022.

Regulatory asset base	**Components of RAB**	Tangible fixed assets in use and intangible assets, with assets financed by subsidy deducted		Fixed assets, assets under construction, intangible assets	
	Regulatory asset value	Set for every tariff		Re-evaluated assets	
	RAB adjustments	Adjustments of return of capital included in allowed revenue are possible during tariff calculation		Annually	Annually
Depreciations	**Method**	Straight line	-	Straight line	
	Depreciation ratio	Economic useful life (EUL) is set according to requirements of accountancy law for adequate groups of fixed assets. Approximate EUL for compressors equals five years, measuring stations 15 years, pipelines and buildings 40 years		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) equal to 4% is allowed	
	Consideration	A component of allowed revenue			

Regulatory framework

The President of URE[69] is the head of a central body of governmental administration accountable for the regulation of fuels and the energy economy. His competence, referred to in article 23 of the Energy Law Act of 10 April 1997, embraces inter alia granting and revoking licences, approving tariffs and controlling their application and the promotion of competition as well. The President of URE regulates activities of energy enterprises with the aim of balancing the interests of these companies and customers.
The legal framework for the regulation of transmission and distribution of gaseous fuels and electricity is constituted by the Energy Law Act and regulations of the Minister of the Economy/Energy on detailed terms for the structuring and calculation of tariffs and on detailed terms of the transmission system operation.

Network tariffs – allowed revenue components

Energy enterprises dealing with transmission and distribution (both of gas and electricity) are obliged to hold a licence, and bill based on tariffs approved by the President of URE. According to article 47 of the Energy Law Act, tariffs are set by energy enterprises and submitted for approval by the President of URE, who approves the tariff or refuses to do so if he assesses that the tariff has not been set in line with the provisions of articles 44-46 of the Energy Law Act. Generally, gas transmission and distribution tariffs must cover the justified costs of conducting the licensed activity (set ex ante) and a justified return on capital employed. Moreover, the protection of the customer’s interest against unjustified level of prices and charges must be taken into account.
Allowed or target revenue in the case of gas network tariffs consists of planned reasonable OPEX, depreciation, local taxes and other fees, cost of gas losses and return on capital employed. In the WACC calculation for 2017 and 2018 the notional gearing of 25/75 and 30/70 was applied respectively, whereas before 2017 the actual WACC, derived from the latest audited financial statement of the regulated entity, was used. According to the WACC methodology for gas system operators for the years 2019-23, the share of debt increases annually by four percentage points starting from the level of 34% in 2019.
For electricity network companies, allowed revenue consists of planned reasonable OPEX, depreciation, local taxes and other fees, cost of losses, return on capital employed and costs

[69] URE – Urząd Regulacji Energetyki (in English: Energy Regulatory Office).

of maintaining the system-related standards of quality and reliability of current electricity supplies. In the WACC calculation for electricity an equal ratio of debt to equity (50/50) is applied.
The risk-free rate applied in the calculation of the WACC for a specific quarter of the year is published by the President of URE at the beginning of each quarter. It corresponds to the average profitability of the fixed rate ten-year treasury bonds with the longest maturity, listed on Treasury BondSpot Poland over 36 months, both for gas and electricity system operators. All data necessary for the WACC calculation is published. Guidelines on the WACC calculation for gas network companies are included in *“The methodology for a calculation of cost of capital employed by gas network companies for years 2019-2023,”* published on URE’s website.[70]

The main components of the RAB for gas assets are tangible fixed assets in use and intangible assets from which depreciation is deducted i.e. net value, revealed in the latest audited financial statement of the gas network company, from which assets financed by subsidy are deducted. Remunerated assets include the average value (from the tariff period and the previous period) of planned CAPEX from network development plans accepted by the President of URE. Planned connection fees are deducted from this, and in some cases planned CAPEX is corrected by a coefficient indicating the average underperformance of planned CAPEX in previous years. An average planned depreciation for the tariff year and previous year is also subtracted.
Guidelines on the WACC calculation for electricity network companies are included in *“The methodology for a calculation of cost of capital employed by electricity network companies for years 2016-2020,”*published on URE’s website.[71] The RAB is based on re-evaluated assets. The re-evaluation of the RAB was done on 31 December 2008. In subsequent years, the RAB was mostly adjusted due to investments, depreciation and connection fees. Work is underway on a possible change/amendment in the approach to the WACC.
The compliance of a proposed tariff with the specific provisions of law is verified under an administrative procedure that concludes with the decision of the President of URE (either approving a tariff or refusing to approve it). In the proceedings for tariff approval, the President of URE carries out a detailed analysis of the costs that constitute the basis for the calculation of transmission and distribution charges, making sure that there are no cross-subsidies between licensed and unlicensed activities, or between different types of licensed activities. Justified costs used for calculating tariffs are set according to articles 44 and 45 of the Energy Law Act and rules of cost recording stipulated in the Accountancy Act. The basis of verifying these costs is the audited financial statement from the previous year, referred to in article 44, paragraph 2 of the Energy Law Act. Energy enterprises are also obliged to deliver quarterly reports on their activity (including inter alia amounts of gas sold, revenue, costs and investment expenditures) according to URE’s template.
The tariff decision of the President of URE together with the tariff itself (the document containing transmission charges and conditions of its application) are published in the Bulletin of URE, available on URE’s website, within 14 days from the approval date. Energy enterprises apply tariffs no earlier than 14 days and no later than 45 days after the publication date, with the exception of gas transmission tariffs, which are applied in the period specified in the decision approving the tariff but no earlier than 14 days after the publication.

If a concerned energy enterprise is not satisfied with the President of URE’s decision approving or denying approval of the tariff, it can appeal against it within a 14-day period to the Court of Competition and Consumer Protection. The appealed tariff is not applied.

[70] See https://www.ure.gov.pl/pl/biznes/taryfy-zalozenia/zalozenia-dla-kalkulacj-2/7834,Pismo-Prezesa-Urzedu-Regulacji-Energetyki-do-przedsiebiorstw-energetycznych.html.
[71] See https://www.ure.gov.pl/pl/biznes/taryfy-zalozenia/zalozenia-dla-kalkulacj/7828,Zalozenia-do-kalkulacji-taryf-OSD-na-rok-2016.html.

Tariffs for the gas TSO

There is one gas TSO in Poland, OGP GAZ-SYSTEM SA (100% state-owned). It operates its own transmission network and the network owned by SGT EuRoPol GAZ SA (Yamal pipeline) under the ISO formula. The tariff methodology is compliant with European and domestic law, supplemented by guidelines issued by the President of URE. The postage stamp cost allocation methodology is applied. There is no distinction between domestic and cross-border transmission tariffs, i.e. the same tariff applies both for domestic and cross-border network users. For gas storage facilities and LNG facilities connected to the transmission system, an 80% and 100% discount is applied respectively. The transmission tariff is calculated and approved for a yearly period, based on calendar years. The RP therefore equals one year. The details of tariff calculation are included in the President of URE's decision on the reference price methodology for 2020-22 issued pursuant to article 27(4) of the NC TAR.[72]

The tariff calculation for gaseous fuels transmission services also includes the communiqué of the President of URE on multipliers, seasonal factors and discounts, referred to in Article 28(1)(a) to (c) of the NC TAR, that is issued on a yearly basis (starting from 2020).[73]

Since the 2019 tariff year, an under- or over-recovery of the transmission services revenue is set and registered using a regulatory account. The regulatory account is reconciled with the aim of reimbursing the TSO for any under-recovery or returning any over-recovery to the network users, taking into account principles set out in Article 17 of the NC TAR. The reconciliation of the regulatory account is carried out in accordance with the applied reference price methodology, so no charge referred to in Article 4(3)(b) is applied.

Tariffs for gas DSOs

As of 31 December 2020, only one DSO was operating in Poland that was undergoing legal and functional unbundling requirements – Polska Spółka Gazownictwa Sp. Z o. o. (Polish Gas Company Ltd), whose main shareholder was PGNiG SA. This company carries out its business activity involving the distribution of gaseous fuels using low-, medium- and high-pressure distribution networks for customers located throughout Poland. In addition, 52 local DSOs were operating in Poland that were not obliged to unbundle their distribution and trading activities. Very often, the share of gas supplying revenues for these companies made up a marginal amount of total revenues.

The methodology of setting justified costs and calculating return on capital employed is much the same as for the TSO's tariffs but instead of entry/exit tariffs, a group tariffs approach is applied. For companies conducting an integrated activity (distribution and supply of gas), the tariff incudes prices of gas for households, because the obligation to apply regulated prices of gas will remain in force until 31 December 2023 (according to Energy Law Act, Article 62b).

Regulation of electricity grid operators

There is one electricity TSO in Poland – a state-owned company, PSE SA. It runs its business activity under a licence for electricity transmission granted by the President of URE, which is valid until 31 December 2030.

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[72] See http://bip.ure.gov.pl/bip/taryfy-i-inne-decyzje-b/inne-decyzje-informacj/3777,Inne-decyzje-informacje-sprawozdania-opublikowane-w-2019-r.html.

[73] See https://www.ure.gov.pl/en/markets/gas/nc-tar-consultation-mul/298,Consultation-on-discounts-multipliers-and-seasonal-factors-for-2022-gas-transmis.html.

DSOs operating within vertically integrated companies and serving more than 100,000 customers connected to their grids are obliged to be independent in terms of legal form, organisational structure and decision-making (Article 9d of the Energy Law Act). There are 185 DSOs authorised by the President of URE, including five entities legally separated from former integrated distribution companies and 180 DSOs not obliged to be legally unbundled. Almost all DSOs not obliged to be legally unbundled perform their functions in systems not connected directly to the transmission grid, but to the distribution networks of the five legally unbundled operators.

Tariffs for electricity grid operators

The electricity TSO's tariff is set as a one-year tariff and is approved by the President of URE, although it is derived from long-term (multi-year) regulation of the TSO. Cost of service and revenue cap methods are used in tariff setting. A WACC determining method was adopted for the years 2016-20 (both for the electricity TSO and DSOs) and was extended to 2021.
The RP for the five biggest DSOs is five years (the current one being 2016-20). Nevertheless, the tariffs are approved annually by the President of URE. A mixed type of regulation, i.e. a revenue cap with elements of incentive-based regulation and quality regulation, is used. Models for OPEX and grid losses were established for the aforementioned RP. The X-coefficients were included in the charges for the first year of the RP, and were set for the next years. A quality charge (for maintaining power system standards) is also included in TSO and DSO tariffs. For 2022, the assumptions were developed exclusively for a one-year period. Work is being conducted on the model to be used for the future RP.
For DSOs, elements of quality regulation were introduced for the 2016-20 RP. The regulation assumes the use of a quality factor, Qt, which influences return on capital. The Qt factor depends on DSOs' performance in the field of supply quality, measured inter alia by SAIDI and SAIFI indicators.

TSOs' and DSOs' network development plans (electricity and gas)

The network development plan should ensure a long-term maximisation of the efficiency of CAPEX and costs incurred by energy enterprises, so that in particular years the CAPEX and costs do not cause an excessive increase in prices and charges for the supply of electricity and gas, while ensuring continuity, reliability and quality of supply. CAPEX, which influences the return on capital employed and depreciation included in tariff calculations, is agreed by energy enterprises with the President of URE in the network development plans.
The energy enterprises involved in the transmission or distribution of electricity prepare network development plans for their area of operation in terms of satisfying current and future demand for electricity, for a period not shorter than three years. This excludes the TSO that must prepare the plan for a ten-year period, and DSOs that must prepare plans for at least five years. The plans are updated every three years.

The energy enterprises involved in the transmission or distribution of gaseous fuels must draft network development plans for their area of operation in terms of satisfying current and future demand for gas. In the case of the TSO, the plan is drafted for a ten-year period while in the case of DSOs it is for a five-year period. The TSO's and DSOs' plans are updated every two years, other than plans of the TSO pertaining to entrusted transmission networks, which are updated at yearly intervals. Currently this only applies to the Yamal Transmission Network, which is entrusted by SGT EuRoPol GAZ SA (the owner) to OGP Gas-System SA (TSO) under the ISO unbundling model. It should be noted that development plans are elaborated where distribution and transmission systems pertain not only to natural gas, but also to other gaseous fuels.

2.25 Portugal

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	Network operators	1 (REN)	11	1 (REN)	1 (EDP)[74]
	Network length	1,375 km	19,573 km	9,659 km	230,979 km
	Ownership	Private ownership	Private ownership	Private ownership	Private ownership
General framework	Authority	Entidade Reguladora dos Serviços Energéticos (ERSE, www.erse.pt/inicio)			
	System	Price-cap (OPEX) and rate-of-return (CAPEX)	Price-cap (OPEX) and rate-of-return (CAPEX)	Revenue-cap (TOTEX: OPEX+CAPEX) + profit/loss sharing mechanism	Revenue-cap (TOTEX: OPEX+CAPEX) + profit/loss sharing mechanism)
	Period	Four years (current period 2020-23)		Four years (current period 2022-25)	
	Base year for next period	Last real year	Last real year	Average of last two real years	Average of last two real years
	Transparency	Tariff code, tariff board and tariff documents. Efficiency scores, specific cost data			
	Main elements for determining the revenue cap	Non-controllable and controllable costs, RAB, WACC, efficiency benchmark, inflation mechanism for attenuation of tariff adjustments	Non-controllable and controllable costs, RAB, WACC, efficiency benchmark, inflation	Non-controllable and controllable costs, RAB, WACC, efficiency benchmark, inflation, incentives, general economic interest costs	Non-controllable and controllable costs, RAB, WACC, efficiency benchmark, inflation, incentives, general economic interest costs
	Legal framework	Decree-Law No. 62/2020 of 28 August		Decree-Law No. 15/2022 of 14 January	
Rate of return	Type of WACC	Nominal, pre-tax			
		The WACC (pre-tax) is indexed to the Portuguese ten-year bond benchmark and depends, in each year, on its evolution, with a cap and a floor			
		Tax rate = 31.5%		Tax rate = 31.5%	
	Determination of the rate of return on equity	CAPM: $Market\ risk\ premium\ =\ risk\ premium\ for\ mature\ market\ +\ country\ risk\ spread,$ • Where: The risk premium for mature market is the average between the spread between S&P500 and USA ten-year treasury bond yields since 1961 and the average of the risk premia applied by CEER members;[75]and • The country risk spread is the spread between Portuguese ten-year bond yields and ten-year bond yields of Germany and Netherlands.			
	Rate of return on equity before taxes	6.7%	7.1%	5.5%	6.1%
		Initial values for the RP (January 2020)		Initial values for the RP (January 2022)	
	Use of rate of return	WACC is currently based on 50% debt and 50% equity applied to RAB		WACC is currently based on 50% debt and 50% equity applied to RAB	
Regulatory asset base	Components of RAB	Fixed assets deducted from third parties' contributions			
	Regulatory asset value	RAB is based on historical and re-evaluated costs	RAB is based on historical and re-evaluated costs	RAB is based on historical costs and standard costs	RAB is based on historical costs

[74] Due to the volume of information, the table only includes data about the regulated distribution network operator of mainland Portugal.

[75] From the Regulatory Frameworks Report.

	RAB adjustments	Each year the RAB is adjusted to consider new investments, write-offs and depreciation		RAB does not adjust automatically every year due to the revenue cap on TOTEX. However, the profit/loss sharing mechanism calculated after the end of the regulatory period considers the annual real RAB adjusted for new investments, write-offs and depreciation	
Depreciations	**Method**	Straight line depreciation			
	Depreciation ratio	5-45 years	5-40 years	10-30 years	5-40 years
	Consideration	Part of CAPEX		Considered for TOTEX initial cost base and profit/loss sharing mechanism	

Introduction

In Portugal, regarding allowed revenues, regulation of the electricity sector focuses on the transmission, system management, supplier switching, distribution, last resort supplier and energy purchase and sale activities. In the Autonomous Regions of the Azores and Madeira, in addition to those activities, the Portuguese NRA, ERSE, also defines allowed regulation for energy acquisition and global system management activity.[76]

In addition to transmission, system management, supplier switching, distribution, last resort supplier and energy purchase and sale activities in the gas sector (mainland Portugal only), the regulation also focuses on the global system management activity, underground storage activity and reception, storage and regasification of LNG activity. Beyond these activities, ERSE is also responsible for monitoring the markets and infrastructures and annual tariff fixing.

Historical development

Regulation of the electricity sector began in 1999, with a major change in 2007 with the liberalisation of the markets, which required the separation of the figure of the "last resort supplier" from the distribution network operator. In the natural gas sector, regulation began in gas year 2007-08 for high-pressure activities and in gas year 2008-09 for the remaining activities.

In both sectors, the main methodology to define the allowed revenues of regulated activities has been incentive regulation (price-cap and revenue-cap) for OPEX and on the application of the RoR to investments in CAPEX. However, since 2022, a TOTEX approach has been applied in electricity distribution and transmission activities.

Throughout the RPs, it was necessary to keep adapting the regulatory methodologies. Therefore, in the electricity sector there are also other incentives, such as incentives for quality of service, losses reduction and smart grids, as outlined below.

The main features of the regulatory methodologies followed by ERSE in the electricity sector have been:

- The application of reference costs in the electricity transmission activity from the 2009-11 RP up to 2021. This mechanism ended in the new RP 2022-25 with the change to a TOTEX methodology, which already incorporates an implicit incentive for efficient investment costs;
- The modification in 2012 of the price cap methodology applied to TOTEX in the distribution activity to a price cap methodology applied to OPEX and RoR to CAPEX;

[76] The electricity generation activity in the Autonomous Regions of the Azores and Madeira is regulated and is not liberalised because these regions benefit from a derogation from the application of Directive 2003/54 / EC.

- The change to a revenue cap methodology applied to TOTEX in the distribution and transmission activities in the new RP 2022-25[77], combined with an ex post profit/loss sharing mechanism; and
- In the Autonomous Regions, the definition of reference costs for fossil fuels consumed in electricity generation in energy acquisition and global system management activity, as well as the application of an incentive regulation to the three activities of the Autonomous Regions from the 2009-11 RP. [78]

As for the gas sector, at the beginning of the RP 2016-17 to 2018-19, ERSE introduced a mechanism in the transmission and distribution activities that sought to mitigate the effects of demand volatility on the amount of allowed revenues recovered through tariffs. In the same period, for the LNG reception, storage and regasification activities, and natural gas subterranean storage activity, the regulatory methodology was changed to include a mechanism to mitigate tariff adjustments, recognising the positive externalities this activity brings to the whole natural gas national system. In the global system management activity, regulation changed from an accepted cost model to an incentive regulation model (revenue cap). In the gas sector a new RP started in 2020 and will end in 2023. This was the first time that ERSE defined a four-year RP. In addition, the RP now coincides with the calendar year instead of the gas year (from June of one year to July of the following year).The main changes in the new RP that began in 2020 were:

- Differentiation in the treatment of investments, with costs recovered though tariffs according to their nature and to the degree to which they are fulfilling their initial objectives;
- Sharing of the results of efficiency targets between companies and consumers;
- The possibility to delay the recovery of capacity auctions' revenues to ensure tariff stability, since in some years these revenues can be higher than the total costs of the activity;
- Improvements in the reporting of audited information for regulatory purposes; and
- The cessation of the mechanism applied to distribution activity to mitigate the effects associated with the volatility of demand.

More recently, there have been changes to the gas sector legal framework. This new legal framework will lead to new regulatory challenges, for instance due to the creation of the activity of renewable gases and gases with low carbon production.

Regulatory process (allowed revenues perspectives)

ERSE is responsible for preparing and approving Tariff Codes, for both the electricity and gas sectors. These codes establish the methodologies for defining allowed revenues and calculating tariffs. The approval of the Tariff Code is preceded by a public consultation and an opinion from ERSE's Tariff Board. The codes also define ERSE's tariff-setting process, including its timeframe.

The allowed revenues for each regulated activity are recovered through specific tariffs, each with its own tariff structure and a given set of billing variables. The methodologies and parameters for the tariff calculation are evaluated and fixed at the beginning of each RP to be applied during that period.

Allowed revenues

[77] The TOTEX approach was applied to distribution activity between 1999 and 2011.

[78] In energy acquisition and global system management, incentive regulation only started in 2012.

ERSE calculates the allowed revenues based on information sent annually by the regulated companies, including real audited data and estimated data. This information comprises financial data, such as operating costs and depreciation, investments and subsidies, as well as technical data, such as quantities. At the beginning of each RP the companies send their cost forecasts for the entire new RP.

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 certain costs are allowed outside the "cost base", that are therefore not subject to efficiency. This is the case, for example, for concession rents and actuarial gains and losses.

The definition of efficiency targets, which aim to reduce 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.

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 (only for HV/MV in the electricity sector). In this case, ERSE must also carry out a public consultation and, in accordance with the results, issue its opinion for subsequent approval by the Government.

In addition to defining accepted costs, incentives are also defined. For electricity distribution activity, these consist of incentives for quality of service, losses reduction and for investments in smart grids. Recently ERSE has defined a new, output-based incentive, which aims to lead the DSO to deliver value-added services enabled by smart grids to consumers. The amount of this incentive is based on sharing the benefits generated by such services between the DSO and consumers. To access it, the DSO must demonstrate that it provides a package of "key smart-grid services".

For electricity transmission activity, in the new RP that started in 2022, ERSE introduced a new incentive to improve the technical performance of the network. Since this new RP, the regulatory methodology has changed to a revenue cap applied to TOTEX. All other previous incentives ended in 2021 (i.e., the incentive for efficient investment in the transmission network, through the use of reference prices in the valuation of the new equipment to be integrated into the network, and the incentive for the economic rationalisation of costs).

Asset base remuneration

The remuneration of the asset base (including in the definition of the TOTEX cost base for the activities regulated through a revenue cap on TOTEX) 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.Due to some remaining uncertainty and the financially volatile environment, the RoR is updated ex post each year in order to reflect the evolution of financial market conditions. Activities regulated through a revenue cap on TOTEX also benefit from this update, through a specific cost driver. The WACC (pre-tax) applied in the RP is indexed to the Portuguese ten-year bond benchmark and depends, each year, on its evolution, with a cap and a floor.

The floor is 3.70% for the electricity TSO and 4.00% for the electricity DSO. The cap is 7.00% for the electricity TSO and 7.30% for the electricity DSO. The floor is 4.50% for the gas TSO and 4.70% for the gas DSO. The cap is 8.80% for the gas TSO and 9.00% for the gas DSO. For investments added to the RAB between 2009 and 2021, where the cost was considered efficient[79], a 0.75pp (percentage points) premium is added to the electricity TSO WACC.

[79] Using a methodology where real and standard costs for those investments were compared.

	Gas		Electricity	
	TSO	DSO	TSO	DSO
Risk-free rate (nominal)	0.57%	0.57%	0.06%	0.06%
Tax rate	31.50%	31.50%	31.50%	31.50%
Equity risk premium	6.50%	6.50%	5.94%	5.94%
Equity beta	0.62	0.66	0.62	0.69
Cost of equity (before taxes)	**6.68%**	**7.08%**	**5.50%**	**6.10%**

Portuguese ROE parameters

Allowed revenue adjustments

The allowed revenues from each activity are adjusted after two years based on real, audited values. For price-cap and revenue-cap methodologies, the adjustments made result from changes in the level of cost drivers. In energy purchase and sale activities, given their more volatile nature, the adjustments are made after one year based on estimated values. Costs accepted outside the cost base are also recalculated taking into account actual values. For the gas sector, all activities undergo adjustments at the end of one year (estimated adjustment) and at the end of two years (actual adjustment).

In activities regulated through an RoR on CAPEX, investments and amortisations are updated, in a first stage, based on revised estimated values and, after two years, based on actual and audited values.

The values of the estimated adjustments are deducted when determining the actual adjustment 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.

For activities where revenue cap is applied on TOTEX (electricity transmission and distribution), on top of the actual adjustment after two years, there is another adjustment related to a profit/loss sharing mechanism. This is calculated after the end of the RP to reflect real values that occurred throughout that period. This mechanism ensures that extra losses or gains obtained by the companies in the previous RP are recovered or paid during the new RP.

National specificities

In the electricity sector, there are regulated activities in mainland Portugal and the Autonomous Regions, while in the gas sector they operate only in mainland Portugal. In addition to the electricity distribution network operator in HV/MV and LV, there are ten LV distribution network operators that operate locally.

In Portugal, the concession of electricity distribution activity at the LV level is awarded by municipalities that entered into concession contracts with the national distribution network operator in exchange for rent. Although most of the municipal concession contracts are about to expire, government approval of the public tenders necessary to award new concessions is in progress.

In the gas sector, the distribution activity is licensed by different geographic areas, but is subject to the same regulatory methodologies. As mentioned, in the gas sector, at the high-pressure level, mechanisms have been created to mitigate extreme volatility of demand, when it occurs.

The allowed revenues for transmission and distribution network operators relating to the overall management of the system, the purchase and sale of electricity from and to the commercial agent, and the purchase and sale of access to the transmission network, includes costs arising essentially from legal decisions, the so-called general economic interest costs (CIEGs).

2.26 Romania

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	1	31	1	8 (concessionaires), 46 (non-concessionaries)
	Network length	13,925 km	54,209 km	8,891 km	327,687 km (+168,545 km – final connections)
	Ownership	Private and public ownership	Private and public ownership	Mainly public ownership	Mainly private investors, indirect public ownership
General framework	**Authority**	National Regulatory Authority for Energy (ANRE, www.anre.ro)			
	System	Incentive regulation – revenue cap	Incentive regulation – revenue cap	Incentive regulation – revenue cap	Incentive regulation – price cap/cost-plus
	Period	Generally five years. Current RP (DSO): 2019-23. Current RP (TSO): Oct 2019-Sept 2024		Five years. Current RP: 2020-24	Five years. Current RP: 2019-23
	Base year for next period	Last year of current RP Fifth year in current RP		-	
	Transparency	Tariffs methodologies, approved revenues and tariffs, general rules for efficiency, Articles 29 and 30 requirements of Reg (EU) 460/2017		Tariffs methodologies, approved tariffs, general rules for efficiency	
	Main elements for determining the revenue/price cap	Non-controllable (pass-through) and controllable costs, efficiency factor, general inflation rentability of RAB (RAB * RoR), depreciation, technological consumption	Non-controllable (pass-through) and controllable costs, efficiency factor, general inflation rentability of RAB (RAB * RoR), depreciation, technological consumption	Non-controllable and controllable OPEX, variable costs, RAB depreciation, rentability of RAB (RAB * WACC)	Non-controllable and controllable OPEX, variable costs, RAB depreciation, rentability of RAB (RAB * WACC)
	Legal framework	Energy and Gas Law 123/2012, ANRE Order 217/2018 for distribution activity and Order 41/2019 for transmission activity		Energy and Gas Law 123/2012, ANRE Order 171/2019 and Order 75/2020	Energy and Gas Law 123/2012, ANRE Order 169/2018 and Order 75/2020
Rate of return	**Type of WACC**	Real, pre-tax WACC determined using CAPM method		Real, pre-tax	
	Determination of the rate of return on equity	$WACC(\%) = CCP * \frac{K_p}{(1-T)} + CCI * K_i$, where: • CCP is the cost of equity in real terms, calculated after tax, recognised by ANRE (%); • CCI is the cost of the borrowed capital in real terms, calculated before tax, recognised by ANRE (%); • K_i is $(1 - K_p)$ and is the share of the borrowed capital in total equity, recognised by ANRE; • K_p is the equity share in the total capital, recognised by ANRE; and • T is the rate of profit tax.		Sum of risk-free rate and a market risk premium multiplied by beta	
	Rate of return on equity before taxes	April 2019-29, April 2020 6.9% (approved by the government)	April 2019-29, April 2020 6.9% (approved by the government)	From April 2019 6.9% (approved by the government)	January-March 2019 5.66% (approved by ANRE)

		30 April-12 May 2020 5.66% (approved by ANRE). From 13 May 2020-Sept 2024 (end of RP) 6.39% (approved by ANRE)	30 April-12 May 2020 5.66% (approved by ANRE). From 13 May 2020-Dec 2023 (end of RP) 6.39% (approved by ANRE)	From 13 May 2020, 6.39% (approved by ANRE)	From April 2019 6.9% (approved by the government). From 13 May 2020 6.39% (approved by ANRE)
	Use of rate of return	Granted for initial RAB (privatisation value), existing assets and new assets: • RAB value at the beginning of each RP (remaining value of initial privatisation RAB and the other existing assets) is multiplied by RoR and included in the regulated revenue • Beginning with the second year of the RP, each year new entries are multiplied by RoR and included in the regulated revenue		Granted for initial RAB (privatisation value), for existing assets and for new assets. RoR is multiplied by whole RAB. Debt and equity percentages are 40/60%.	
Regulatory asset base	**Components of RAB**	Fixed assets		Fixed assets, except contributions from third parties	
	Regulatory asset value	The RAB value consists of the value of historical assets and the value of new investments (the latter is considered to be the accounting value). For each year of the RP, the RAB value increases with investment in new assets and decreases with depreciation and the value of assets that exit before complete depreciation		The assets of the base year are used as the initial RAB. For each year of the RP, the RAB value increases with investment in new assets and decreases with depreciation and the value of assets that exit before complete depreciation. For the RAB existing on 1 January 2005 or the privatisation date, it was a fair value of the assets	
	RAB adjustments	Investments in new assets after the base year and assets that exit before complete depreciation lead to CAPEX adjustment	Investments in new assets after the base year and assets that exit before complete depreciation lead to CAPEX adjustment	The plus value that resulted from the revaluation of assets, but limited to RAB adjusted by CPI	RAB adjusted by CPI, but limited by the current value of the assets
Depreciations	**Method**	Straight line			
	Depreciation ratio	Depends on asset type: buildings 50 years, pipes and technical installations 40 years, others between seven and 20 years, land not included		Depends on asset type. Ratio between 2% and 16.6% e.g. lines and cables 2.5-10%, stations 2%	
	Consideration	Part of regulated revenue. Depreciation calculated for the previous year's asset entries is directly and 100% integrated into regulated revenues. Afterwards, when the tariff adjustments are made, depreciation already included in regulated revenues is adjusted by the inflation rate		Part of regulated revenue. Depreciation is included directly and 100% in revenue, before the linearisation	

Introduction

The Romanian Energy Regulatory Authority (ANRE) is the regulatory authority responsible in Romania for approving methodologies and tariffs for electricity and gas networks.

For electricity, ANRE is responsible for regulating the Romanian TSO (there is only one), eight operators holding the concession of distribution service (ODCs) and other distribution operators (ODs).

For gas, ANRE is responsible for regulating the Romanian TSO (there is only one) and 31 operators holding the concession of the distribution service (DSOs).

Historical development

An incentive-based regulatory regime was introduced in 2005 for the TSO (for setting transmission tariffs) and ODCs.

The methodology for setting electricity transmission tariffs uses a revenue cap regulatory system. ANRE uses a price cap methodology (tariffs basket cap) for setting electricity distribution tariffs applied to ODCs. For ODs (electricity distribution operators other than concessionaires), a cost-plus methodology is in force.

For setting regulated gas tariffs, ANRE has used a revenue cap methodology since 2019 for both distribution and transmission activities.

Determining the revenue/price caps

For electricity, the revenue/price caps for electricity network operators (the TSO and ODCs) are set for a five-year RP. The current RP is 2020-24 for transmission and 2019-23 for distribution.

Each revenue cap is composed of the non-controllable operating and maintenance costs, controllable operating and maintenance costs (OPEX, applying an efficiency factor for reducing inefficiencies), costs of electricity losses, costs of RAB depreciation and rentability of the RAB (the RAB multiplied by the WACC). There are efficiency requirements for controllable OPEX and for costs of electricity losses.

The WACC is set in the reference year for the next RP and can be updated during the RP to reflect the evolution of financial market conditions.

The following assets are eliminated from evaluating the RAB:
- Grants, fees received from new customer connections;
- Assets that are conserved and assets that are still under construction; and
- Inefficient investments and others that do not follow the prudence criteria provided by regulations.

For gas, revenue caps for the TSO and DSOs are set for a five-year RP. Each revenue cap is composed of controllable costs (applying an efficiency factor for reducing inefficiencies) and non-controllable (pass-through) costs, technological consumption costs, costs of the RAB depreciation, rentability of RAB (the RAB multiplied by the RoR) and general inflation.

Efficiency requirements

Electricity

The level of controllable OPEX for the first year of the RP is set by ANRE based on an efficiency benchmarking. An efficiency requirement (X-factor) is applied to controllable OPEX during the RP. In the current RP an X-factor equal to 2% is applied annually to controllable OPEX for transmission, and for distribution (ODCs) the X-factor is 2% for the RP 2019-23.

For the level of electricity losses recognised in tariffs, ANRE imposed targets at the beginning of the RP that have a declining trend during the RP. For the electricity price recognised for acquiring the energy required to cover electricity losses, ANRE considers a limit equal to the average of the prices recorded by ODCs.

The investment plan for the entire RP is verified in terms of necessity, opportunity, efficiency, and cost of investments. The structure of the plan is also verified, and the plan is approved ex ante by ANRE. The estimated benefits that justify the efficiency of every investment in the electricity network are evaluated ex ante and also ex post by the network operator and reported to ANRE. ANRE removes the investments that prove ex post to be inefficient from the RAB, because the expected benefits are not realised.

Gas

The level of controllable and pass-through costs for the first year of the RP is set by ANRE based on the analysis performed of the costs submitted by the TSO and DSOs. An efficiency factor (X-factor) is applied to controllable OPEX during the RP. For DSOs, the X-factor was set to 1% for each year of the RP 2020-23. For the TSO, the efficiency was set to 1.5% for each year of the fourth RP (1 October 2019 to 30 September 2024).

Price development

The revenue/tariffs basket caps 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.

Regulated tariffs for gas are adjusted yearly within each RP and reflected in the regulated prices.

Quality regulation

ANRE sets quality indicators for service quality and reliability for electricity and gas.

For electricity distribution, there are also set minimum levels for individual indicators like the number and duration of interruptions to power supply. The distribution operator must pay compensation to the users of the grid when the minimum levels imposed are exceeded. Compensation paid by the operator is not a justified cost recognised in regulated tariffs.

Adjustments after the reference year

Each year, ANRE calculates revenue corrections due to inflation, investment, non-controllable (pass-through) operating and maintenance costs, changes in energy volumes and losses (quantity and price of losses). The value of the revenue correction is included in the revenue used to determinate tariffs for the next year for both electricity and gas.

For electricity, if the accomplished value of annual investments is less than 80% of the predicted value taken into consideration, an annual revenue adjustment is made. In this way ANRE ensures that unused revenues are recovered as quickly as possible. These annual adjustments are considered at the end of the RP for the final corrections.

For gas, ANRE calculates revenue and tariff corrections due to differences in total revenue generated by volumes variations, inflation, investment, pass-through costs, and technological consumption.

Transparency

The data published on the ANRE website includes the tariffs and an informative note with details on the analysis used for calculating the revenue caps and annual adjustments.

For gas, ANRE publishes the tariffs for each operator (TSO and DSOs) on its website.

Outlook

For all regulated activities (electricity and gas distribution and transmission), ANRE approved new methodologies starting from the fourth RP. The aim is to harmonise the provisions of the four methodologies.

For gas distribution activity, the methodology has been changed from price cap to revenue cap, and for gas transmission activity the methodology was modified in order to comply with article 26 requirements of Reg. (EU) 2017/460.

2.27 Slovakia

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	1	1	1	3
	Network length	2,332 km	33,300 km	3,008 km	94,790 km
	Ownership	Private and public	Private and public	Public	Private and public
General framework	**Authority**	Regulatory Office for Network Industries (ÚRSO, www.urso.gov.sk)			
	System	Benchmarking	Price cap		
	Period	Five years. Current RP: 2017-21, extended until 2022			
	Base year for next period	2023			
	Transparency	Price decrees determining the tariff methodology, price decisions published			
	Main elements for determining the revenue/price cap	Analysis of entry-exit tariffs in other Member States of the EU	Allowed costs, allowed depreciation, RAB, WACC		
	Legal framework	Act No. 250/2012 Coll. On Regulation in Network Industries, Act No. 251/2012 Coll. On Energy Industry, URSO Decree No. 223/2016 Coll. (gas), URSO Decree No. 18/2017 Coll. (electricity)			
Rate of return	**Type of WACC**	N/A	Nominal, pre-tax WACC		
	Determination of the rate of return on equity	N/A	Sum of nominal risk-free rate and a risk premium (market risk premium multiplied by beta factor)		
	Rate of return on equity before taxes	N/A	10.82% = (0.76 + 7.56 * 1.03) / (1 – 0.21)		
	Use of rate of return	N/A	When setting the nominal pre-tax WACC the D/E ratio of 60/40 was used. The whole RAB is multiplied by the WACC.		
Regulatory asset base	**Components of RAB**	N/A	Fixed assets, no working capital		
	Regulatory asset value	N/A	Expertly appraised value of assets used for regulated activities as at 31 Dec 2015	Expertly appraised value of assets used for regulated activities as at 1 Jan 2011	
	RAB adjustments	N/A	No RAB adjustment takes place during the RP		
Depreciations	**Method**	N/A	Regulatory depreciation (technical life cycle of assets)		
	Depreciation ratio	N/A	Ratio between 1.25% and 20%		
	Consideration	N/A	A component of target revenue		

Introduction

The Regulatory Office for Network Industries (URSO), as an independent public authority, was established on 1 August 2001 and performs regulation in the sectors of electricity, gas, district heating and water. In September 2012, new acts on regulation in network industries (No. 250/2012 Coll.) and the Energy Act (No. 251/2012 Coll.) came into effect, governing the position and powers of URSO. The two acts also brought a significant shift in the protection of market participants as well as in the reinforcing of URSO's independence and competences.

Currently, URSO is in the fifth RP (2017-22), which was originally set at five years. However, in order to harmonise amendments to the primary legislation by the transposition of the Clean Energy Package with the new regulatory policy for the next RP (2023-27), the current RP has been extended by one year.

URSO's dominant activity is tariff (price) regulation. The scope and manner of its implementation is set out in the implementing regulations in the form of price decrees, and the terms and conditions of tariff application are set out in individual price decisions.

Historical development

In 2001, Slovakia's electricity TSO (SEPS) was unbundled and, as a result, three vertically integrated undertakings providing electricity distribution, electricity supply and services were established. In 2013, SEPS was certified based on the ownership unbundling model.

Eustream, the sole gas TSO, was certified as an ITO in 2013. Gas transmission assets were not transferred to the TSO, but remained the property of the parent company, SPP a.s. SPP-distribúcia, the only gas DSO, which was unbundled from SPP in 2006.

The electricity and gas markets were fully liberalised as of July 2007. From the start of the third RP (2009-11), URSO ceased to apply the original revenue cap method and established an incentive regulation principle based on a price cap methodology. Since 2012, the three-year RP has been replaced by a more stable regulatory framework with a five-year period.

Main principles of price regulation

The basic principle of the regulation of prices (tariffs) approved or set by URSO for the five-year RP applies a price cap as a method, which guarantees profit only under real efficient business operation and incentivises network operators to reduce their own losses.

Since 2009, URSO has also regulated the quality of services, which focuses primarily on consumer protection. Network operators and suppliers must comply with the quality standards set by a URSO decree in order for consumers to receive adequate quality for the price they pay for electricity, gas and heat. In the event of non-compliance with the quality of supply and services standards, the regulated entity is obliged to pay a compensatory payment to the consumer.

Additional adjustments during the regulatory period

The price decision is valid for the entire RP. In the event of a significant change in the economic parameters on which URSO approved or set the price, the regulated entity may request a change in the price decision. URSO may also initiate a change in the price decision on its own initiative.

Basic formula for setting the price cap (electricity)

Price cap = [OPEX allowance * (1 + core inflation – efficiency factor) + (RAB * WACC) + depreciation (from RAB + from planned CAPEX for next year) – revenues from connections] / forecasted volume.

In electricity distribution, the price cap is set for each voltage level separately (with EHV being 110 kV, HV 22 kV and LV 0.4 kV).

Basic formula for setting the price cap (gas)

Price cap = [OPEX allowance * (1 + core inflation – efficiency factor) + (RAB * WACC) + depreciation (from RAB) + costs to cover losses and own consumption – revenues from connections] / forecasted volume.

Gas distribution tariffs are categorised based on a contractually agreed annual volume of distributed gas for each offtake (supply) point and the postage stamp principle is applied.

Eligible costs (electricity)

Operating costs are optimised through the JPI – X-factor, where JPI is the core inflation set by the Statistical Office and X is the efficiency factor of 3.5%. If $JPI < X$, then $JPI - X = 0$ and overheads up to the amount of overheads in year t-1 are included in the eligible costs in year t.

Allowed depreciation

The price proceeding for each year of the RP will also assess the use of the declared costs for new investments in the form of depreciation.

Profit

A reasonable profit within the price proceeding is calculated by multiplying the RAB and WACC values. It shall take into account the scope of the investments required to ensure a long-term, reliable, safe and efficient system operation, an adequate return on operating assets, and the stimulation of stable long-term business.

Regulatory asset base

The value of the property is referred to as the RAB. The RAB for electricity was determined on 1 January 2011 and its value is equal to the general value of assets determined based on an expert opinion. The RAB for gas was determined as of 31 December 2015.

WACC

The WACC value (before tax, nominal) is set at a maximum of 6.47% and is applied constantly throughout the whole RP. However, if the difference of input parameters entering the WACC calculation exceeds 10%, a new WACC value is determined for the relevant year and published on the URSO website by 30 June of the calendar year.

WACC pre-tax, nominal $= \frac{E}{E+D} + \frac{R_e}{1-T} + \frac{D}{E+D} * R_d$, where:

- T is the income tax rate for year t;
- E is equity;
- D is liabilities;
- R_d is the real price of liabilities for the RP set at 3.73% (average rate of loans provided to non-financial corporations for a period of five years or more with a loan amount over €1 million); and
- R_e is the real price of equity.

$R_e = R_f + \beta_{lev} * (R_m - R_f)$, where:

- R_f is the return on risk-free assets for the RP set at 3.03%;
- β_{lev} is a weighted beta coefficient, which defines the sensitivity of the company's share to market risk, taking into account the income tax rate and the share of liabilities; and
- $(R_m - R_f)$ is the total risk premium set at 4.54%.

$\beta_{lev} = \beta_{unlev} * \left[1 + (1-T) * \frac{D}{E}\right]$, where:

- β_{unlev} is an unweighted coefficient without the influence of the income tax rate and the share of liabilities set at 0.53; and
- $\frac{D}{E}$ is the ratio of liabilities to equity set at 60% in favour of liabilities.

Methodology for setting gas transmission tariffs

The regulatory framework for gas transmission differs from gas distribution in that it consists of a method of comparing tariffs in EU Member States (international benchmarking). According to the Act on Regulation, if there is effective pipeline-to-pipeline competition, URSO shall, by direct comparison, approve or determine comparable prices for access to the transmission network and gas transmission, which take the form of tariffs.

Tariffs are set for individual entry and exit points of the transmission network (entry-exit system) and apply for domestic and foreign users of the transmission network. The submitted analysis compares the total average prices for gas transmission, including conversion to length units, taking into account the relevant distance of entry and exit points of the transmission network, costs, depreciation and revenues for the provision of services in the transmission networks.

The method allows TSOs to cover all costs while generating a reasonable profit, which enables the company to make new investments required by the gas market, develop sufficient flexibility in offering new products and services and adopt measures under EU legislation.

Tariffs are set for the entire RP; their final amount is subject to an annual increase equivalent to the inflation rate.

2.28 Slovenia

<table>
<tr><th></th><th></th><th>Gas TSO</th><th>Gas DSO</th><th>Electricity TSO</th><th>Electricity DSO</th></tr>
<tr><td rowspan="3">Market structure</td><td>Network operators</td><td>1</td><td>13</td><td>1</td><td>1</td></tr>
<tr><td>Network length</td><td>~1,196 km</td><td>~5,030 km</td><td>~2,925 km</td><td>~64,261 km</td></tr>
<tr><td>Ownership</td><td>Public</td><td>Private and public</td><td>Public</td><td>Private and public</td></tr>
<tr><td rowspan="7">General framework</td><td>Authority</td><td colspan="4">Energy Agency (www.agen-rs.si)</td></tr>
<tr><td>System</td><td colspan="4">Incentive regulation/revenue cap</td></tr>
<tr><td>Period</td><td colspan="2">Three years. Current RP: 2022-2024</td><td colspan="2">One year. Current RP: 2022</td></tr>
<tr><td>Base year for next period</td><td colspan="2">TBD</td><td colspan="2">TBD</td></tr>
<tr><td>Transparency</td><td colspan="4">Full transparency through extensive consultation and publication</td></tr>
<tr><td>Main elements for determining the revenue/price cap</td><td>Controllable OPEX (general productivity), uncontrollable OPEX, CAPEX (depreciation, regulated return on assets), consumption, incentives</td><td>Controllable OPEX (efficiency score, general productivity), uncontrollable OPEX, CAPEX (depreciation, regulated return on assets), incentives</td><td>Controllable OPEX (general productivity), uncontrollable OPEX, CAPEX (depreciation, regulated return on assets), losses, ancillary services, consumption, incentives</td><td>Controllable OPEX (efficiency score, general productivity), uncontrollable OPEX, CAPEX (depreciation, regulated return on assets), losses, consumption, incentives</td></tr>
<tr><td>Legal framework</td><td colspan="2">Act on the methodology for determining the regulatory framework for the natural gas system operators</td><td colspan="2">Act on the methodology determining the regulatory framework and the methodology determining the network charge for the electricity system operators</td></tr>
<tr><td rowspan="4">Rate of return</td><td>Type of WACC</td><td colspan="2">Pre-tax WACC nominal (equity share 60%, debt share 40%)
WACC 2022 - 2024 = 5.15%</td><td colspan="2">Pre-tax WACC nominal (equity share 60%, debt share 40%)
WACC 2022 = 5.15%</td></tr>
<tr><td>Determination of the rate of return on equity</td><td colspan="4">The cost of equity is determined on the “risk premium model” (cost of equity = cost of debt + 3%). The cost of debt is the eight-year average (2012-19) for interest rate to non-financial companies in Slovenia. The premium of 3% is the difference between return on equity and cost of debt for the Slovenian market</td></tr>
<tr><td>Rate of return on equity before taxes</td><td colspan="4">Cost of equity = cost of debt + premium (2.95% + 3% = 5.95%)</td></tr>
<tr><td>Use of rate of return</td><td colspan="4">For each year of the RP, the WACC is applied to the value of the RAB</td></tr>
<tr><td rowspan="3">Regulatory asset base</td><td>Components of RAB</td><td colspan="4">Book values of tangible and intangible assets after RAB adjustment, ex ante investments according to development plan, no working capital, no assets under construction</td></tr>
<tr><td>Regulatory asset value</td><td colspan="4">Book value for existing assets, investment value according to development plan for new assets</td></tr>
<tr><td>RAB adjustments</td><td colspan="4">RAB adjustments are:
• Value of assets acquired with subsidies and grants;
• Assets under construction;
• Value of assets acquired with disproportionate costs for connection to the network; and
• Value of assets acquired with congestion income.</td></tr>
<tr><td rowspan="3">Depreciations</td><td>Method</td><td colspan="4">Straight line</td></tr>
<tr><td>Depreciation ratio</td><td colspan="2">For existing assets and new investments, the actual rate of depreciation is taken into account</td><td colspan="2">• For existing assets, the actual rate of depreciation depends on the asset type;
• For planned new investments in energy infrastructure, 3,33%; and
• For other planned assets, 8,33%.</td></tr>
<tr><td>Consideration</td><td colspan="4">100% of depreciation is integrated into revenues</td></tr>
</table>

Regulation of electricity transmission and distribution operators

The Energy Agency is carrying out regulation in the RP from 1 January 2022 to 31 December 2022 on the basis of the Act on the methodology determining the regulatory framework and the methodology determining the network charge for the electricity network operators. The methodology for setting the network charge determines the principles of economic regulation for electricity services of general economic interest. It also sets the eligible costs of the electricity network operators. The methodology is based on the regulated network charge, with the aim that by setting the network charge and other revenues, and taking into account identified deviations from previous years, the system operator should be able to cover all eligible costs in the RP.

In establishing the regulatory framework for 2022, the Energy Agency considered electricity consumption, planned development of the infrastructure, quality of supply level, eligible costs of the system operators and network charge tariffs for each consumer group.

Eligible costs of the electricity system operators consist of controlled operation and maintenance costs, uncontrolled operation and maintenance costs, costs of electricity losses, depreciation costs, and a regulated return on assets. The basic controlled operational and maintenance costs are calculated in accordance with requested yearly productivity improvement. The yearly productivity improvement consists of planned general productivity and individual productivity. For the TSO only, the planned general productivity is used. The individual productivity of each DSO is determined by benchmark analysis.

Eligible costs are covered by the network charge and other revenues. When determining the resources to cover eligible costs, due consideration is given to deviations from the regulatory framework in previous years, and the planned settlement for the current RP.

The methodology for the network charge determines the procedures and elements to set the network charge, and to divide consumers into various consumer groups. To calculate the network charge, the non-transaction postage stamp method is used. This means using a system of uniform tariffs for calculating the network charge in the territory of Slovenia within the individual consumer group. To allocate costs for different voltage levels, a gross approach to calculating the network charge for the transmission and distribution networks is used.

The methodology for the regulated network charge is also based on incentives, which depend on incurred eligible costs, achieved quality of supply level, the provision of free ancillary services, the acquisition of non-refundable European funds, savings in the purchase of smart electricity meters with communications modules, realised investments in smart grids projects, realised pilot projects, and special incentives for innovation.

If the system operator achieves higher or lower eligible costs than actually incurred eligible costs, this difference is reflected in its income statement. Incentives concerning the achieved quality of supply level are determined according to the achieved level of supply continuity from the reference level, and are reflected in increased or decreased eligible costs. If the system operator provides one or more ancillary services free of charge, which are not the result of legislation, the system operator will get an incentive of 10% of the saving that equals the amount paid for the ancillary service. If the system operator obtains non-refundable European funds, it will get an incentive of 0.5% of the current value of the asset, in the year when the asset was put into service. An incentive mechanism has been set up to provide operators with a financial incentive to achieve a lower price than the reference price set by the Energy Agency when purchasing electricity to cover losses.

The incentive scheme for smart grid investments and an incentive scheme to promote research and innovation for system operators are summarised in the following table:

Incentive scheme	Promotion of research and innovation	Smart grid investments
Project value	Low	High - 100.000 EUR minimum
Incentive amount	Sum of the incentives of all research and innovation projects capped at 0,5% of the recognised resources for covering the eligible costs of the undertaking in the regulatory period	Sum of incentives capped at 10% of the demonstrated net benefits of the whole project.
Different incentives	• Coverage of the system operator research and innovation costs • Performance incentives aimed at eliminating regulatory barriers to the implementation of innovative measures that are not possible under the existing regulatory framework and involve the active participation of consumers.	• A time-limited financial incentive of 2% of the carrying amount of the asset at 31 December for a period of three years from the date of activation • In addition, an incentive of 3% of the carrying amount of the asset as at 31 December is granted to the system operator for a period of three years from the date of activation if it proves it applied the whole system approach in the design and implementation of the solution • In addition, a one-off project performance incentive of 5% of the cost of the assets needed exclusively to achieve the key performance indicators is granted to the system operator

Slovenian incentive schemes

The electricity system operator must identify deviations from the regulatory framework after each year of the regulatory framework. Deviations are established as the difference between planned and actual eligible costs of the system operator and the difference between planned and actual revenue sources, which include the identified surplus or deficit of the network charge from previous years. The Energy Agency issues a separate decision if it concludes that deviations were not calculated in accordance with the methodology. The Energy Agency keeps the implementation of the regulatory framework under review during the RP by monitoring the monthly realisation of the network charge, analysing the criteria of the costs, and calculating deviations from the regulatory framework.

Regulation of gas transmission and distribution operators

The Energy Agency is carrying out regulation in the RP 1 January 2022 to 31 December 2024 on the basis of the Act on the methodology for determining regulatory framework of the natural gas system operator, the Act on the methodology for determining the network charge for the natural gas transmission operator and the Act on the methodology for determining the network charge for the natural gas distribution operator. The methodology for setting the network charge determines the principles of economic regulation. It also sets the eligible costs of the gas operators. The methodology is based on the regulated network charge, with the aim that by setting the network charge and other revenues, and taking into account identified deviations from previous years, the system operator should be able to cover all eligible costs in the RP.

The regulation methodology is based on regulated annual income and regulated network charges of the TSO or DSO arising from the determination of eligible costs. In addition to the network charge, the methodology takes into account:

- All other revenues as sources of the system operator to cover eligible costs;
- The obligation of the TSO or DSO to transfer the surplus of the network charge and its dedicated use for covering eligible costs in the next RP; and
- The right of the TSO or DSO to take into account the coverage of the network charge deficit when determining the regulatory framework for the following years.

Eligible costs of the gas system operators consist of controlled operating and maintenance costs, uncontrolled operating and maintenance costs, depreciation costs and a regulated return on assets. Resources for covering eligible costs are the network charge and other revenues. In determining the resources for covering eligible costs, deviations from the regulatory framework of the previous years are duly taken into account.

By using the method of regulated annual income and regulated network charges, the TSO or DSO determines the regulatory framework in such a way that the planned annual income, surplus of network charges from the previous years, and planned network charge deficit (maximum up to the amount of depreciation charge) cover their costs up to the amount of eligible costs for the RP and the corresponding deficit of previous years. The TSO or DSO submits the request for granting consent to the regulatory framework, network tariff items, and tariff items for other services for the relevant RP, to the Energy Agency. In the process of issuing its approval, the Energy Agency assesses compliance of the proposed eligible costs, network charge and other network charge items, with the applicable methodologies.

At the end of each RP the TSO must determine deviations from the regulatory framework. Deviations are determined as the difference between actual eligible costs and existing sources for covering eligible costs, which include recorded income or a network charge deficit from previous years. The Energy Agency issues a special decision if it finds that deviations are not calculated in accordance with the methodology. The Energy Agency monitors the implementation of the regulatory framework during the RP.

Three investment incentives are available for gas. If the system operator obtains non-refundable European funds, it is granted an incentive of 0.5% of the current value of the asset in the year when the asset was put into service. For a customer who consumes biomethane or synthetic biomethane, the network charge for both the TSO and DSOs is reduced by up to 20%, depending on the proportion of biogas in gas consumed. The network charge is set to 50% for a filling station for compressed gas for vehicles.

2.29 Spain

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	Network operators	1 large TSO (ENAGAS), 1 small TSO, and 8 transport companies	20 DSOs that are part of 7 groups	1 TSO (REE)	5 large DSOs (>90% system revenues), 328 small DSOs (<100,000 clients)
Market structure	Network length	13,361 km (2020)	80,983 km (2020)	44,553 km (2020)	787,310 km (2020)
Market structure	Ownership	Private, except for 5% stake of the State in ENAGAS	Private: utilities and investment funds	Private, except for 20% stake of the State in REE	Private: 5 large DSO are part of integrated utilities
General framework	Authority	Comisión Nacional de los Mercados y la Competencia (CNMC, www.cnmc.es) sets revenues (from 2020 onwards) and methodologies (from 2020/2021 for electricity/gas)			
General framework	System	Incentive regulation			
General framework	Period	Six years. Current RP: 2021-26 (gas years, i.e. from 1 Oct-30 Sept, except gas year 2021: 1 Jan-30 Sept 2021)		Six years. Current RP: 2020-25 (calendar years)	
General framework	Base year for next period	For RP (n to n+5) the review is made with n-1 available data, so n-2 data			
General framework	Transparency	CNMC publishes its proposals and final decisions on its website. There is a period for a hearing process. Final decisions (circulars) are published in the official state gazette			
General framework	Main elements for determining the revenue cap	Investment and OPEX reference values, RAB, RoR, regulatory lifetime of assets, incentives	Base revenues, changes in the number of clients and in the volume of gas distributed, incentives	Investment and OPEX reference values, RAB, RoR, regulatory lifetime of assets, incentives	Investment values, OPEX values, other regulated tasks reference values, RAB, RoR, regulatory lifetime of assets, number of clients, incentives
General framework	Legal framework	Law 34/1998 of the Hydrocarbons sector, circulars 2/2019, 9/2019, 4/2020 and 8/2020		Law 24/2013 of the Electricity sector, circulars 2/2019, 5/2019, 6/2019 and 7/2019	
Rate of return	Type of WACC	Nominal, post-tax WACC (except for gas DSO where RoR not WACC-based)			
Rate of return	Determination of the rate of return on equity	• Electricity transmission and distribution. RoR calculated by CNMC using WACC formula (nominal, pre-tax). 6.003% in 2020, 5.58% over 2021-25; • Gas transmission. RoR calculated by CNMC using WACC formula (nominal, pre-tax). 5.44% for the RP 2021-26; and • Gas distribution. A RoR of ten-year bond plus a spread of 150 bps was set in 2002. From then on, a parametric remuneration formula applies.			
Rate of return	Rate of return on equity before taxes	Electricity TSO and DSOs: after taxes 6.40% = 2.97 + 0.72 * 4.75, before taxes 8.53% Gas TSO: after taxes 6.48% = 3.03% + 0.74 * 4.64%, before taxes 8.64%			
Rate of return	Use of rate of return	RoR is applied (nominal pre-tax) on RAB in gas TSO, electricity TSO and electricity DSO. A RoR was set for gas distribution in 2002 and from then on, a parametric remuneration formula applies			
Regulatory asset base	Components of RAB	Fixed assets (no working capital, no assets under construction)			
Regulatory asset base	Regulatory asset value	• Electricity. Depends on commissioning year: replacement cost, average of audited costs and investment reference values or audited costs with some limitations. For TSO unique facilities and TSO or DSO pilot projects: audited costs; • Gas transmission. Average of audited costs and investment reference values. Audited costs for unique facilities; and • Gas distribution. RAB based on the inflated gross investment value of assets in 2000. Since then, the parametric formula applies.			
Regulatory asset base	RAB adjustments	Assets built year n-1 are added year n	RAB defined in 2002 and then parametric formula	Assets built year n-2 are added year n	Assets built year n-2 are added year n

Depreciations	**Method**	Straight line
	Depreciation ratio	Generally 2.5% (lines, cables, substations, transformers, transmission pipelines). For gas distribution assets, a 5% depreciation ratio was set in 2002 and since then, the parametric remuneration formula applies
	Consideration	100% of depreciation is integrated into the revenues

Introduction

Six-year RPs are established for both electricity and gas activities. Regulatory parameters are not updated by price indexes within the RP.
Royal Decree Law 1/2019 gives CNMC (the Spanish NRA) powers to set revenues and tariffs, which was previously done by the Ministry. Consequently, CNMC has published a new regulation to set revenues for the gas and electricity TSO and DSO for the 2020-25 electricity RP and 2021-26 gas RP.
To coordinate remuneration with gas transmission tolls and charge periods, determined according to Commission Regulation (EU) 2017/460, the RP for gas transmission and distribution is set according to gas years instead of calendar years. A gas year ranges from 1 October in year n-1 to 30 September in year n, except for gas year 2021 which ranges from 1 January 2021 to 30 September 2021.

Electricity TSO and DSO frameworks

The electricity DSO and TSO receive remuneration for investment (CAPEX), O&M (OPEX), remuneration for the extended regulatory lifetime of assets, incentives/penalties, and other regulatory tasks (only DSO).

Investment remuneration (CAPEX)

Regulatory asset base
RAB is updated every year, by adding new investments and subtracting depreciation. Assets under construction and working capital are not included in the RAB. Subsidies and assets built or financed by third parties are also excluded. When assets end their regulatory lifetime, they are taken out of the RAB, and stop receiving revenues for investment.
Assets commissioned in year n start receiving revenues in year n+2. To take this into account, RAB is increased by (1 + RoR) ^ (remuneration delay factor). This factor is calculated for each asset for TSOs, while it is equal to 1.5 for DSOs.
For information on how the electricity TSO and DSO RAB is calculated, please refer to the CEER Report on Regulatory Frameworks for European Energy Networks 2020.

Depreciation
The RAB is recovered by a straight line depreciation value. The regulatory asset lifetime is set at 40 years for most assets (lines, transformers, etc.) and 12 years for control centres.

Rate of Return
The net RAB pending to recover is multiplied by the RoR. The RoR has been calculated using the WACC formula for RP 2020-25, resulting in a rate of 5.58%. It was exceptionally set at 6.003% in 2020 so that the decrease from the previous year's RoR (6.503%) was lower than 50 bps
The CAPM model is used for the RoR on equity, where:
- The risk-free rate is the ten-year Spanish government bond;

- The beta coefficient is obtained as the average beta from a peer group of utilities;
- The market risk premium is obtained from the Dimson, Marsh and Staunton report's data for European countries;
- The cost of debt is calculated as the average of interest rate swaps (IRS) ten-year + CDS ten-year of the utilities in the peer group. In cases where there are no CDS for a company, its debt bonds (8-12 years) are used instead of IRS + CDS, and;
- The proportion between debt and equity is set as the optimal regulatory gearing ratio (50%) but also taking into account the values of the peer group.

Operation & Maintenance remuneration (OPEX)
TSOs receive an allowance for OPEX that is calculated by multiplying the number of physical assets of each type by the OPEX reference values plus an efficiency term. This allows TSOs to retain part of the efficiencies gained in the previous RP. During the RP, TSOs have an incentive to operate and maintain the grid below reference values.
For TSOs' unique assets only, unique OPEX values may apply. There are also specific OPEX reference values for TSO assets in the isolated energy systems of the Islands.
DSOs receive an allowance for O&M (OPEX) included into a term named 'COMGES', which comprises OPEX and also a small part of investments not included in the electric assets that have reference values. It is updated within the RP with a factor that establishes a proportion between this term and the investments in electric assets that have reference values. An efficiency factor also adjusts COMGES to reflect the company's capacity to manage 'COMGES' costs.

Remuneration for the extended regulatory lifetime of assets
Assets, where their regulatory lifetime has expired, receive increased OPEX reference values to incentivise that they are kept in operation. The increasing factor is 30% in the first five years, 30%- 35% from five to 10 years, and 35%-45% from 10 to 15 years. After 15 years, the factor keeps rising by 3% per year until it reaches 100%.

Remuneration for other regulated tasks (DSO only)
DSOs receive the following revenues to perform other regulated tasks: (a) metering; (b) help with clients contracting electricity i.e. revenues to support invoicing and to reduce client non-payments; (c) attend telephone calls from clients; (d) grid planning; and (e) revenues to cover overhead costs.
Each type of revenue for other regulated tasks is calculated as a reference value multiplied by the number of clients. There are different reference values for each defined range of number of clients. DSOs are incentivised to perform these tasks at lower costs than those established as reference values per client, as they retain the difference. There is also a bonus term that takes into account the performance of the company in the previous RP compared with an efficient company.

Incentives/penalties
TSOs have an incentive to maximise grid availability. DSO have incentives to reduce grid losses and to improve quality of supply. An incentive to detect fraud was applied for electricity DSOs in 2020 and 2021 and then integrated into the incentive to reduce grid losses.

Gas TSO framework

The remuneration formula for the primary transmission network includes: investment remuneration, O&M remuneration, remuneration adjustments for productivity and efficiency gains, remuneration for facilities under a special administrative situation and remuneration for investments with transboundary impacts resulting from the application of Article 12 of Regulation (EU) nº 347/2013.

Investment remuneration
The investment remuneration formula includes depreciation, financial remuneration (calculated by applying the RoR to the annual net value of investment), a remuneration investment term for new facilities that do not belong to the backbone network (regional gas pipelines and new LNG plants) based on the gas processed, and another term for the acquisition of minimum reserve gas.

Regulatory asset base
The RAB is updated every year, by adding new investments and subtracting write-offs and depreciation. Assets under construction and working capital are not included in the RAB. Subsidies and assets built or financed by third parties are also excluded, as well as 90% of the proceeds for the sale of decommissioned assets for building new ones, or equivalent measures. When assets end their regulatory lifetime, they are taken out of the RAB, and stop receiving revenues for investment. Assets commissioned in year n start receiving revenues in year n+1.
For information on how the gas TSO RAB is calculated, please refer to the CEER Report on Regulatory Frameworks for European Energy Networks 2021.

Depreciation
RAB is recovered by a straight-line depreciation value. The regulatory lifetime is set at 40 years for all pipelines and between 10-50 years for other transmission and regasification assets.

Rate of return
The net RAB pending to recover is multiplied by the RoR. The RoR has been calculated by using the WACC formula for this RP (2021-26), resulting in a rate of 5.44%.
Likewise, the CAPM model is used for the RoR in electricity, but with a different risk-free rate. For gas transmission and regasification, this is the ten-year Spanish government bond including an adjustment of 80 bps in the 2021-26 RP due to the quantitative easing program.

Remuneration for operation and maintenance
Remuneration is based on technical characteristics by using reference O&M values, except for variable costs over which the transmission agent has limited managerial capacity (for which remuneration is based on audited costs). The O&M cost of unique assets is also valued according to their audited cost.

Remuneration adjustments for productivity and efficiency gains (ARPE)
This term includes remuneration for the extended regulatory lifetime of assets, to incentivise assets whose regulatory lifetime has expired to be kept under operation, receiving increased OPEX reference values. It also includes remuneration for continuity of supply (only for the RP 2021-26), remuneration for productivity gains (companies retain 50% of year-on-year productivity variation in the RP 2021-26), an incentive for gas losses settlement, and a remuneration incentive for using lower-polluting transport fuels (vehicular natural gas and LNG as marine fuel).

Gas DSO framework

Annual revenues are calculated by adding the following items:

- Base revenue. The remuneration for the distribution activity corresponding to the existing market as of 31 December 2020. Its value is set for each company for the RP 2021-26. It is the result of calculating remuneration in accordance with the methodology set out in Annex X of Law 18/2014, for the facilities and supply points existing in 2020 ("RD"), and then deducting a remuneration adjustment of the distribution activity ("AAD"). This AAD is an adjustment in relation to the remuneration corresponding to the distribution activity carried out during the year 2000;
- Revenue for market development. This is associated with new supply points commissioned from 2021 onwards. It depends on the yearly change in the number of clients, and in the volume of gas distributed. To incentivise the connection of industrial consumers to the distribution network, which will probably lead to the substitution of other more polluting fuels, an additional remuneration for supply points between four bar and 60 bar during the first five years is established. An additional reference value for supplying natural gas to petrol stations to be sold as vehicular gas is also established, which aims to promote it and contribute to fighting climate change. To incentivise network expansion to non-gasified zones, different reference values are used during the five years depending on whether or not customers are in recently-gasified municipalities. However, Circular 4/2020 also establishes that, in recently gasified municipalities, the maximum possible remuneration due to the development of the gas market should equal the income from distribution tolls in that municipality during the gas year. This is an implicit incentive to only make investments that are justified by demand;
- Transitional distribution revenue (RTD). This remuneration concept aims to carry out a gradual application of the AAD over the 2021-26 RP. The RTD is calculated as a percentage of the AAD for each gas year, which will be gradually reduced over 2021-25 to reach zero in 2026;
- Loss settlement incentive. The positive or negative incentive for the settlement of gas losses for each year and company; and
- Financial prudence penalty. This operates on the same terms as for the gas TSO.

Additional regulated income (such as regulated inspections, activation rights, regulated services lines, supply renewal revenues, meter rents, etc.) is also received by the DSO.

Electricity and Gas TSO and DSO

Adjustment for related products and services
For both electricity and gas TSOs and DSOs, there is an adjustment for related products and services, that companies might procure to third parties employing regulated assets or resources, such as, for example, leasing of optic fibre.

Financial prudence incentive
For both electricity and gas TSOs and DSOs (electricity DSOs with more than 100,000 clients), there is a financial prudence penalty if the company's economic and financial ratios do not meet the recommended values of Communication 1/2019. This is limited to 1% of total revenues. In electricity, the penalty applies from 2023 onwards and in gas, from 2024 onwards. For more information on the financial prudence incentive, please refer to the CEER Report on Regulatory Frameworks for European Energy Networks 2021.

2.30 Sweden

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	1	6	2	168
	Network length	601 km	3,350 km	~16,000 km	~568,000 km
	Ownership	Foreign ownership	Municipality and foreign ownership	State owned (SVK) and private (Baltic Cable)	State, municipality, private, and foreign ownership
General framework	**Authority**	Swedish energy markets inspectorate, Ei (www.ei.se)			
	System	Revenue cap			
	Period	Four years. Current RP: 2019-22		Four years. Current RP: 2020-23	
	Base year for next period	2021		2022	
	Transparency	Information related to decisions are public on the NRA's webpage, including cost and production data, efficiency scores, different incentives, and calculations of the revenue caps and the WACC, amongst other available data			
	Main elements for determining the revenue cap	TOTEX (divided into CAPEX, non-controllable OPEX and controllable OPEX). General efficiency target of reducing 1% of controllable OPEX annually	TOTEX (divided into CAPEX, non-controllable OPEX and controllable OPEX). General efficiency target of reducing 1% of controllable OPEX annually	TOTEX (divided into CAPEX, non-controllable OPEX and controllable OPEX). Incentives for good quality of supply. General efficiency target of reducing 1% of controllable OPEX annually	TOTEX (divided into CAPEX, non-controllable OPEX and controllable OPEX). Incentives for efficient grid utilisation. Individual efficiency benchmark (reduction of controllable OPEX)
	Legal framework	Naturgaslagen (Gas Act)		Ellagen (Electricity Act)	
Rate of return	**Type of WACC**	Real WACC pre-tax			
	Determination of the rate of return on equity	CAPM: $r_e = r_f + \beta * (r_m - r_f) + extra\ risk\ premium$			
	Rate of return on equity before taxes	For gas: 11.37% = (4 + 0.697 * 5 + 1.5) / (1 – 0.21) For electricity: 5.52% = (0.9 + 0.52 * 6.68) / (1 – 0.208)			
	Use of rate of return	The WACC is applied to the RAB. The debt share is derived from market values of European comparison companies that are publicly traded (44% debt 56% equity for both electricity and gas)			
Regulatory asset base	**Components of RAB**	Fixed assets divided into meters, pipelines, stations, storage, and regasification assets (not assets under construction)		Fixed assets divided into lines, cables, buildings, shunt reactors, transformers, switchgear, stations, cable cabinet, control-equipment, meters and IT-system (not assets under construction)	
	Regulatory asset value	Replacement values (after age-adjustment) 2021 SEK ~6.9 billion	Replacement values (after age-adjustment) 2021 SEK ~3.5 billion	Replacement values (after age-adjustment) 2021 in SEK ~39 billion	Replacement values (after age-adjustment) 2021 in SEK ~226 billion
	RAB adjustments	Adjusted for inflation, adjustments ex post for new investments and disposals			
Depreciations	**Method**	Real linear (straight line) depreciation			
	Depreciation ratio	Meters: 25 years Pipelines: 90 years Stations:40 years (Storage: 50 years)	Meters: 12 years Pipelines: 90 years Stations: 40 years (Regasification assets: 25 years)	In total 17 asset categories and six different depreciation times. Typically, 60 years for lines and 40 for cables	In total 17 asset categories and six different depreciation times. Typically, 40 years for lines and 50 for cables
	Consideration	The depreciation is fully integrated into the revenue cap			

Introduction

The electricity and gas networks are examples of natural monopolies, as it would be both economically and environmentally unreasonable to have competing infrastructure available for each customer. This means that the network operators (TSOs and DSOs) have limited or no competition. To be the only seller in a price-inelastic market entails a possibility for the operator to increase prices and thereby increase profits. To ensure that the network operators do not make unreasonably high profits, regulation needs to be in place. The Swedish energy markets inspectorate, Ei, is the NRA responsible for designing the regulation in a way that minimises the welfare losses from monopoly power. The main objective of 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 a high quality and fair prices will be ensured for customers.
Ei regulates both the gas and electricity sectors. The size of the regulated operators spans from around ten connections for the smallest operators, to about 900,000 customers for the largest operators.
There are currently 168 E-DSOs and two E-TSOs in Sweden. The Swedish E-TSOs are Svenska Kraftnät (SVK) and Baltic Cable (BC). With a few exceptions SVK owns and operates all parts of the transmission system. BC owns one line of transmission connecting the electricity grid between Sweden and Germany.

All other entities that operate power systems in Sweden are defined as DSOs. The 168 E-DSOs are of varying sizes and ownership structures (state, municipal, private and other), and they each have a so-called concession (permission) for the distribution of electricity, either for a defined geographical area or for specific lines. The concession means a privilege, but also entails several obligations, which are governed by laws and a regulation. Ei monitors that the network operators follow the existing rules. Ei's role as the NRA is, for example, to ensure that customers have access to a power distribution system, and to provide incentives for cost efficient operation with acceptable reliability and with objective, reasonable and non-discriminatory tariffs.

The gas market is relatively small in Sweden and consists of one TSO, Swedegas, one storage facility owned by Swedegas and six DSOs. There is no distribution system for gas in the northern parts of Sweden.

Historical development

The Swedish electricity market was deregulated in 1996. Since then, generation and trading of electricity have been exposed to competition. The network operators in their capacity as natural monopolies are subject to regulation. Since deregulation, multiple regulation methods have been implemented. One example is that in 2003, a performance-based tariff regulation was introduced where fictive reference networks were used. Until 2012 Sweden used ex post regulation, where each year was treated as an RP. From 2012 an ex ante revenue cap regulation has been used. In the regulation, the regulator decides on a revenue cap for each network operator. The revenue cap shall cover reasonable operational costs and a reasonable return on the assets used for distribution and transmission.
A trend in Sweden amongst the DSOs is that the operators seem to merge into fewer and larger companies. At the end of the 1950s, there were more than 1,500 companies, but in the early 1980s the number had dropped to 380 companies. Today there are fewer than 200 network operators under Ei's regulation. For the gas network operators an ex ante regulation has been used since 2015.

Determining the revenue caps

Sweden's regulatory model is based on different cost items. First the division between CAPEX and OPEX. The latter cost is in turn divided into controllable and non-controllable OPEX. Controllable OPEX is based on data reported by the network operators on historical costs. The costs are reduced yearly by an efficiency target (see further on efficiency benchmarking). This requirement to increase productivity is not applied to non-controllable OPEX. Non-controllable OPEX is based on estimates provided by the network operators prior to the period, that are corrected for actual outcome ex post.

For CAPEX, the assessment of the RAB is the first (and possibly the most important) part. The RAB is valued based on replacement values for the existing assets, set by Ei. When calculating CAPEX, the replacement values are adjusted for age (depreciation). Investments and disposals of assets under the RP are estimated prior to the period and corrected for the actual outcome ex post. Investments and disposals are reported for every six-month period. The RoR is decided by the WACC method and applied on the age-adjusted RAB. The different costs are adjusted for inflation to have the same price level. Any deviations from the revenue cap will be added to the cap in the next RP.

For electricity network operators, there are incentives to provide a good security of supply and for an efficient network utilisation. The security of supply incentive is set as a norm for the period based on historic data on interruptions (average interruption time (AIT), average interruption frequency (AIF), and customers experiencing multiple interruptions (CEMI)) in combination with benchmarking between DSOs. The data on interruptions after the RP is compared to the historical norm, and the return on capital is adjusted in relation to the change of quality. The incentive for efficient use of the network has the same outline as the other incentive, with a norm set prior to the period that is compared with the actual outcome after the period. As indicators for efficient use of the network, the average load factor and network losses are used. The norm for losses is based on benchmarking between DSOs, while the average load is compared to historical values. Together the two incentives can affect the yearly return for the network operators by ±33%. For the gas network operators, no such incentives exist.

According to Section 5,1-2§§ of the Electricity Act, revenues will be fixed in advance for each RP consisting of four calendar years, unless there are special reasons to use another period. The data and methodology used when determining the revenue cap should be described in the decision for the revenue cap (3§).

The Electricity Act states that the cap should cover the reasonable costs of conducting grid activities during the supervisory period and provide a reasonable return on capital (equity) needed to carry out the activity. Regarding the design of the tariffs the legislation says that: "grid tariffs should be objective, non-discriminatory, and promote efficient use of the network" (Section 4, 1§ law 2009:892).

Quality regulation

For electricity, as mentioned above, there are incentives for efficient use of the network and good security of supply. For the gas market there is currently no quality regulation in place.

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 to achieve the required or potential savings. To counter this in the electricity market, quality norms are integrated in the cap. If norm values for delivery are exceeded (fewer outages than the norm indicates) during the RP, the operator will get an increased revenue cap for the coming RP. The purpose is to provide incentives for future improvements in quality. Operators achieving above-average quality in past years will have an amount added to their cap, while operators with comparatively poor-quality levels will have amounts deducted. Like the security of supply incentive, the

regulation includes incentives to reduce network losses and to have a stable average load factor. Prior to the period, reference values are set for losses and the average load factor. If a company can outperform the reference value, they will get an increase in the cap, if they preform worse, they will get a deduction of the cap.
The adjustments based on the incentives are calculated annually and are limited to ±33% of the operators' return on the RAB. Beyond this, the network operators will need to economically compensate customers for outages longer than 12 hours. Outages longer than 24 hours are illegal and if they happen the operators must come up with a plan for it not to happen in the future.
Every DSO should, on a yearly basis, submit data to Ei on a customer level. For the reliability incentive scheme, data about outages between three minutes and 12 hours are used (both longer and shorter outages are also reported). Outages above 12 hours are excluded, so as not to punish DSOs twice.

Efficiency benchmarking

The gas network operators have a general efficiency requirement to annually reduce 1% of their controllable OPEX. The reason for a general requirement rather than firm-specific efficiency targets is 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. We also see a lot of heterogeneity amongst the Swedish gas network operators making it difficult to compare them to each other. The same target is set for the electricity TSOs, also due to a lack of comparable operators.
For the electricity DSOs, an efficiency benchmarking model is used to estimate firm-specific potential for efficiency improvements. The benchmarking involves assessing the operators' individual costs against the services they provide and determining each DSO's cost efficiency compared to the other DSOs. In the benchmarking process Ei uses a DEA model to compare the inputs (controllable OPEX and CAPEX) to the outputs (number of customers, high and low voltage electricity delivered, the highest effect against overhead grid, and number of network stations) for the DSOs. By the choice of variables some structural differences are accounted for to some extent, for example, the number of network stations and customers work as a proxy for customer density.
The calculations are based on the average of four years' historical data for outputs and controllable OPEX. For CAPEX the first year of the RP is used. The efficiency requirement is applied on the controllable OPEX. The maximal improvement potential has been set to 30% with a realisation time of eight years (two RPs) and the DSOs get to keep 50% of their realised improvements. This results in a maximal requirement (lowering of the revenue cap) of 7.5% of a DSO's controllable OPEX. To also incentivise the relative efficient operators to improve, a minimum level has been set to 1% annually of controllable OPEX.

Deciding the regulatory asset base and reasonable return

For electricity, the RAB is determined by catalogue costs (norm values) as a way to estimate the replacement value for all assets. In total there are 17 asset categories in the asset base with six different depreciation times for which the asset base is adjusted before calculating the operators' allowed return. In Sweden a real linear depreciation method is used to estimate depreciation costs. The depreciation times are currently set between ten to 60 years (with the possibility of an additional 25% extra lifespan if the assets are functional after their regulatory lifespan). For the gas network operators, indexed acquisition values are used as the primary method to determine the value of the asset base. The depreciation times for gas assets are stated in the table above.

To determine the RoR for the network operators, a WACC method is used, both for electricity and gas. The WACC gives allowance for the cost of debt and the cost of equity. To calculate an efficient debt ratio, European network operators that are publicly traded are observed, since they should have incentives to minimise their costs to maximise shareholders' utility. The debt part of the WACC is based on the risk-free RoR and a credit risk premium based on the ratings for the publicly traded comparison networks. To determine the cost of equity the CAPM is used. The same European comparison network operators as earlier are used for estimating the beta value, while the market risk premium and the risk-free RoR are based on Swedish market data. Apart from this, the gas network operators also receive an extra risk premium due to differences in risk structure than the European comparison network operators. No such risk premium exists on the electricity side.

Court proceedings and new legislation to determine reasonable return

Since the implementation of the ex ante regulation with revenue caps, the question of how to determinate a reasonable RoR for network operators has been widely discussed in Sweden. The network operators have appealed Ei's decisions multiple times and argued for a higher RoR. The court proceedings have resulted in higher return for the network operators for the first two RPs.
For the electricity RP 2020-23, the government decided on new secondary legislation for how to determine a reasonable RoR and added more differentiated depreciation time for network assets. This has lowered the real WACC pre-tax to 2.35% from the previous 5.85%. The companies appealed the decision and the validity of the government legislation.. Their main argument was that the secondary legislation impedes on the NRA's ability to make independent decisions.
Due to an ongoing case in the Supreme Administrative Court, collectively appealed by the electricity network companies and referred to the judgement in the Court of Appeal in Jönköping on 16 June 2022, case number 1103-21, the legal situation regarding some issues in the appeal is still uncertain. Even if the final judgement is not yet delivered, there are some certain outcomes from the appealed case, for example the Court of Appeal came to the conclusion that Directive (EU) 2009/72 (and Directive 2009/73) of the European Parliament and of the Council has a direct effect. It has also clarified that Ei is not sufficiently independent in relation to public and private organisations, including in the legislature.
For the gas network operators, where no secondary legislation exists, Ei has decided on a real WACC before tax of 6.52% for the RP 2019-22 based on previous rulings in court.

Developments in the regulation

Ei is currently working on the implementation of the fourth energy package, as well as ongoing projects to develop the methodology for efficiency benchmarking. During spring 2022, Ei has designed secondary legislation on how the network operators should design their tariffs for efficient use of the electricity grid. The legislation can be applied from 1 July 2022 and shall begin to be applied no later than 1 January 2027. Ei has also started work on the upcoming package for gas.

Transparency

Information, guides for reporting, and how to calculate the revenue cap are published on the webpage of the NRA.[80]

[80] See www.ei.se (in Swedish).

2.31 Albania

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	1	1	1	1
	Network length	~271 km	N/A	~2,585 km	~29,790,097 km
	Ownership	State ownership			
General framework	**Authority**	Ministry of Infrastructure and Energy		Ministry of Finance and Economy	Ministry of Infrastructure and Energy
	System	Price cap			
	Period	Yearly. Current RP: 1 January-31 December 2022			
	Base year for next period	2020		2020	
	Transparency	Efficiency scores, efficiency model parameters, specific cost data			
	Main elements for determining the revenue cap	OPEX and CAPEX, general inflation (only for electricity), revenue requirement adjustment			
	Legal framework	Law on Natural Gas Sector		Law on Power Sector	
Rate of return	**Type of WACC**	$WACC = \left[ES * \frac{AroE}{(1-T)}\right] + (DS * CoD)$, where: • ES is the target for its capital in the RAB; • T is the corporate tax rate; • $AroE$ is the permitted rate of return on capital after tax; • DS is the target for debt ratio of the RAB; and • CoD is the cost of debt			
	Determination of the rate of return on equity	Sum of a nominal risk-free rate and a risk premium (market risk premium multiplied by a beta risk factor) multiplied by a corporate tax factor • Gas: the allowed return on equity after tax consists of a base interest rate and a premium for grid operation specific risks. The base interest rate corresponds to the five-year average value of the weighted average of bond coupons of Albanian government bonds published by the Bank of Albania; • Electricity TSO: the allowable RoR on capital is set by the regulator based on the TSO's need to obtain cash flow for CAPEX and servicing debt judged from the statement of the sources and use of funds in the base year; and • Electricity DSO: to calculate the RoR on its own capital, the CAPM or other methodologies shall be used, where a number of factors shall be taken into consideration, including comparisons with other companies that have the same risk, attraction of the capital, current financial and economic conditions, capital cost, enterprise risk, the financial policy and capital structure of the company, management competence, and the financial history of the company.			
	Rate of return on equity before taxes	For gas: 7.972% = (2.18%+0%+54.28%*7%)/1-15% For electricity: 15.29% = (2.18%+0+88.56%*12.21%)/1-15% In all methodologies it is predicted that the $AroE$ is after tax			
	Use of rate of return	• For gas, setting of grid tariffs according to the methodology is based on rate-of-return regulation. The network operator is allowed to recover justified grid operation costs and a regulated ROI; • For the electricity TSO, the allowable RoR on capital is set by the regulator based on the TSO's need to obtain cash flow for CAPEX and servicing debt judged from the statement of the sources and use of funds in the base year. All profits shall be used to support the TSO's CAPEX programme and increase the accounted value of the capital; and • For the electricity DSO, the methodology does not determine the use of the RoR, but it is usually considered for supporting the CAPEX program. All profits are used for investment and to decrease accumulated losses.			

Regulatory asset base	**Components of RAB**	• Gas: fixed assets, working capital, assets under construction (all the specification is predicted in Article 10 of the TSO/DSO methodology); • Electricity DSO: the recognised value of used and useful assets at the beginning of the RP, investment – foreseen average cumulative nominal amount for the middle of the year approved by the regulator that shall be invested during the RP, working capital (all the specifications are predicted in Article 8 of the DSO methodology); and • Electricity TSO: the value of the RAB shall be equal to the historic cost of the fixed assets used to ensure the transmission service, minus depreciation and an adjustment for economic obsolesce. None of the TSO assets shall be considered as a “stranded” asset (with a registered value higher than the market value). Only investments at prudent levels approved by the regulator may be included in the RAB. The TSO shall submit to the regulator, in written form, the program to allocate the proposed investments for the RP in conformity with the Regulation on the procedures of submitting and approving the investment plan. The regulator shall review the realised investments against the planned/approved ones by the end of each year, and shall correct the tariffs if the TSO fails to implement the investment plan (all the specifications are predicted in Article 4.2 8 of the TSO methodology).			
	Regulatory asset value	• Gas: historical cost + assets that enter operation each year + the value of investment foreseen as an average cumulative nominal amount for the middle of the year depending on the investment plan approved by the regulator + prepayments and assets under construction in the base year; and • Electricity TSO and DSO: historical cost + assets that enter operation each year + the value of investment foreseen as an average cumulative nominal amount for the middle of the year depending on the investment plan approved by the regulator.			
	RAB adjustments	There are no RAB adjustments, but in each case, it shall be considered the average value of the start-of-year and end-of-year data	There are no RAB adjustments, but in each case, it shall be considered the average value of the start-of-year and end-of-year data	The value of the RAB shall be equal to the historic cost of the fixed assets used to ensure the transmission service, minus depreciation and an adjustment for economic obsolesce. The regulator reviews the realised investments against the planned/ approved ones by the end of each year	RAB takes the recognised value of used and useful assets at the beginning of the RP. The regulator reviews the realised investments against the planned/approved ones each year
Depreciations	**Method**	Straight line			
	Depreciation ratio	Depends on asset type			
	Consideration	Part of the examined controllable costs			

Introduction

The electricity and gas networks are examples of natural monopolies, where effective competition is restricted or does not exist at all. To ensure that network operators (TSOs and DSOs) do not make any monopoly profits but still operate their networks as cost effectively as possible, the electricity and gas network operators are subject to regulation. The Albanian Regulatory Entity (ERE) is the regulatory authority responsible in Albania for the networks in various sectors, including electricity and gas.

Historical development

ERE was established in 1995 and operates based on Law no. 43/2015 of 30 April 2015 "On power sector" and Law no.102/2015 "On natural gas sector". Regulation by ERE is established as a cost-plus regulation. Under this regime, the revenue that network operators are allowed within a certain period (RP) is determined by their predictable costs within that period.

Determining electricity network tariffs

Allowed revenues and prices for the use of electricity transmission and distribution systems are determined by a hybrid regulatory method that basically considers the price cap principles. The implemented methodology limits the allowed revenue by providing a price cap, and therefore provides incentives for improving efficiency. The methodology is also based on principles intended to improve transparency and non-discriminatory access, facilitate trading and competition, create favourable investment conditions, avoid cross-subsidies, reduce costs and encourage improvements in efficiency.

This regulation is applied to the average revenues permitted of the electricity TSO and DSO. The regulator approves the average transmission and distribution tariff, and the tariffs of each voltage level of the DSO, in accordance with the output of the methodology. There is one TSO and one DSO. At the DSO level, an average tariff is approved. This tariff is then allocated into different levels of voltage such as 35 kV, 20/10/6 kV and 0.4 kV. The tariffs depend only on the level of voltage that the users are connected to.

The price caps for network operators in theory consider the RP to be for three years, but until now the tariffs have been set for one-year RPs. Each cap is composed of costs that the operator predicts it will incur during the RP (applying a distribution factor for reducing inefficiencies), general inflation relative to the base year, a CAPEX component to take account of the cost of capital for investments, a quality element (for electricity DSOs only), and volatile costs. Each cap consists of the sum of each single component divided by the energy delivered at that voltage level. The difference between the allowed revenue and the development of actual volumes over the year is adjusted at the end of the RP.

If the average distribution tariff ceiling for any voltage level, defined according to the historic data for one of the years in the tariff review cycle, exceeds the average permitted distribution tariff ceiling set by ERE for each voltage level, the DSO shall reduce the average distribution tariff in the next year for that voltage level. This is so that the customers and distribution system users in a defined voltage level receive a refund of the amount of excess revenues collected (over-repayment amount).

Revenue requirements for the base year are calculated as $RR = C + (RAB * WACC)$, where:

- RR are the annual revenue requirements;
- C is the allowed annual costs of operation for the licensed activity, with the following components: personnel costs, maintenance, fines and penalties, corporate services, marketing and communications, rental expenses, postal services, IT related, law and legal, consultancy, and other;
- RAB is the regulatory asset base; and
- $WACC$ is the weighted average cost of capital before taxes.

Each component of the tariff for the base year is multiplied by the annual adjustment/correction factor, i.e. $A = (1 + RPI - X)$, where:

- A is the annual adjustment/correction factor;

- RPI is the rate of customer price inflation for year two according to the National Bank of Albania, or INSTAT publications; and
- X is the efficiency improvement factor set by ERE, which shall include at least four categories of expenses: direct and indirect work, work productivity, procurement and technology. Technology shall include the implementation of management systems and the reduction of the technical losses.

According to this methodology, both the TSO and DSO are incentivised to improve the efficiency of their activities and reduce their operational costs.

At the end of the RP, ERE calculates the real cost of this RP, before starting to forecast the revenue of the new RP for the gas and electricity network operators separately. This benchmark involves assessing the operators' individual costs against the services they provide and determining each operator's cost efficiency for each RP.

Determining gas network tariffs

Setting grid tariffs according to the methodology is based on rate-of-return regulation, where the network operator is allowed to recover justified grid operation costs and a regulated ROI, since the natural gas market is not yet fully developed.

The RP is 12 months and is equivalent to the calendar year and business year of the operator of the gas transmission and gas distribution grid. In Albania the same company is licensed in transmission, distribution, and as an LNG and/or storehouse plant operator, and acts as a combined network operator.

The grid costs are identified and compiled in accordance with the methodology. The costs and grid tariffs are calculated based on data derived from the previous business year of the network operator. Reliable information regarding the planning year may be also taken into account.

The grid costs are calculated as $GC_t = C_{t-2} + D_{t-2} + ROC_{t-2} - CRI_{t-2} + OCP_t$, where:
- GC_t is the annual grid cost for the planning year t;
- C_{t-2} is the current outlay cost items for the year $t-2$;
- D_{t-2} is imputed depreciations for the year $t-2$;
- ROC_{t-2} is imputed return on capital for the year $t-2$;
- CRI_{t-2} is cost-reducing revenue and income for the year $t-2$; and
- OCP_t is offsetting across calculation periods for the planning year t.

The methodology foresees a short-term calculation period instead of a long-term RP. The calculation period enables network operators to adapt grid tariffs annually, to ensure that high and volatile costs that are necessary for the establishment of grid infrastructure in Albania can be included in the grid cost calculation.

If, and to the extent, the TSO and DSO tariffs calculated based on the methodology exceed the average amounts of grid tariffs in neighbouring countries, and do not allow for end consumers to have gas prices that are competitive with other sources of energy, grid tariffs can be calculated based on a comparative analysis of grid tariffs in neighbouring countries. The network operator can only make use of this exemption for five years after the methodology came into force. The network operator shall provide a survey of average amounts of grid tariffs in neighbouring countries, including an estimate regarding competitiveness of end consumer gas prices in Albania, with written evidence justifying such an estimate.

The regulator has currently only approved a transmission tariff of 28 Albanian Lek(ALL)/m^3 or 2.6457 ALL/kWh.

2.32 Georgia

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	1	25	1	2
	Network length	~2,000 km	~32,000 km	~4,338 km	~65,372 km
	Ownership	State ownership	Private/local public ownership	State ownership	Private ownership
General framework	**Authority**	Georgian national energy and water supply regulatory commission (GNERC, www.gnerc.org)			
	System	Cost-plus / incentive-based regulation			
	Period	Three years. Current RP: 2020-22		Five years. Current RP: 2021-25	
	Base year for next period	Third tariff year of the RP		Fifth tariff year of the RP	
	Transparency	Regulatory framework, including tariff methodology, explanatory notes on tariff calculations, etc.			
	Main elements for determining the revenue cap	CAPEX, OPEX, cost of normative losses, correction component and service quality component			
	Legal framework	Georgian law on energy, tariff calculation methodologies and investment appraisal rules approved by GNERC			
Rate of return	**Type of WACC**	$WACC_{pre-tax} = R_d * g + R_e * \frac{(1-g)}{(1-T)}$, where: • R_d is the cost of debt; • R_e is the cost of equity; • g is the gearing ratio (60%); and • T is the corporate tax rate			
	Determination of the rate of return on equity	$R_e = \frac{(risk\text{-}free\ rate + \beta * market\ risk\ premium)}{(1-T)}$			
	Rate of return on equity before taxes	18.70% - pre-tax cost of equity in nominal terms (in local currency)		16.93% - pre-tax cost of equity in nominal terms (in local currency)	
	Use of rate of return	The value of RAB for the specific tariff year is multiplied by the WACC			
Regulatory asset base	**Components of RAB**	RAB includes fixed tangible and intangible assets (excluding goodwill) in operation and planned investments agreed with GNERC based on investment appraisal rules			
	Regulatory asset value	Historical cost model (NBV)			
	RAB adjustments	Since RAB includes planned investments, it is adjusted according to the actual figures			
Depreciations	**Method**	Straight line			
	Depreciation ratio	2-2.5%	2.5-3.3%	3.3%	2.5-3%
	Consideration	Annual depreciation of RAB is included in the allowed revenue			

Current regulatory frameworks

Georgia signed the association agreement with the EU in 2014 which, along with other topics, implies the harmonisation of Georgia's energy legislation with the EU laws. Furthermore, in 2016 Georgia signed Europe's Energy Community Accession Agreement, which established specific terms and conditions relating to the introduction of the Energy Community's legislation in Georgia. By signing the aforementioned agreement, Georgia took the responsibility of transposing the legislation of the Energy Community into national legislation.

Adoption of the Law of Georgia on Energy and Water Supply by the Parliament of Georgia on 20 December 2019 encouraged unprecedented reformation of the Georgian energy sector. This increased the role of the Georgian National Energy and Water Supply Regulatory Commission (referred to in this section as the Commission) and its functions that arose out of necessity due to the elaboration of several normative acts by the Commission.

In terms of the structural reorganisation of the energy market, 2020 was a crucial year, as the legislative basis of the reformation was established due to the requirements envisaged by the Law of Georgia on Energy and Water Supply.

In 2021, the Government of Georgia approved a new electricity market concept model, in accordance with the Law of Georgia on Energy and Water Supply. The new electricity market concept model establishes a manual for the organisation and functioning of the wholesale electricity market, for the purpose of launching the electricity market model. This is intended to ensure the formation of an attractive environment for investors and free choice for customers, both at a wholesale and retail level. It also defines means that need to be implemented for moving to the target model.

In 2021, the Government of Georgia also approved the concept of the natural gas market model. This concept identifies natural gas wholesale market segments and lays down the guidelines for the organisation and functioning of the natural gas market in Georgia. The natural gas market rules, that will be based on the main principles grounded in the natural gas market concept design, are in the process of development.

Tariff regulation methodology

The gas and electricity TSOs create ten-year action plans for the development of the transmission network, whereas DSOs create five-year plans for the development of the distribution network. Based on the aforementioned plans, the companies produce investment plans for the tariff period (three to five years), which are presented to the Commission along with tariff applications for the next RP (three to five years). The appropriate investments will be agreed with the Commission and reflected in advance of the next tariff RP.

The Law of Georgia on Energy and Water Supply, and tariff methodologies elaborated by the Commission and approved by the normative acts (in accordance with this law) are the basis of the tariff calculation for licensees.

Based on the tariff methodology, incentive-based regulation (revenue cap) and cost-plus regulation principles are applied for the tariff calculation, which aim to ensure financial stability and cost effectiveness of licensees.

According to the tariff methodologies and regulations approved by the Commission, the electricity sector tariffs are set for given RPs individually for specific enterprises:

- A five-year RP for TSOs and DSOs;
- A three-year period for hydropower plants; and
- For thermal power plants, a guaranteed capacity fee is set annually for a one-year period, and the electricity generation tariff of the guaranteed capacity source is set monthly based on the actual data.

Under the Law of Georgia on Energy and Water Supply, the Commission adopted the relevant decisions in relation to the revocation of tariff regulation of electricity import. In particular, amendments were made to the tariff methodology, as well as to the Resolution on Electricity Tariffs, according to which the calculation rule and principles of electricity import tariff were revoked.

Pursuant to the Law of Georgia on Energy and Water Supply, electricity supply (electricity sold to final customers) is defined as a separate activity, and from 1 July 2021 does not represent a part of distribution activity. A supply service, with the exception of universal service, that is available for household customers and small enterprises, shall be carried out based on a market price in the framework of public service envisaged by the same Law. The public service obligation is imposed by the Government of Georgia. Based on the approved methodology, the Commission is authorised to set the electricity supply tariff for final customers served by the universal service provider.

By the Resolution #68 of 15 December 2020 on Approving of Methodologies for Calculating Tariffs and Fees of Activities Rendered as a Public Service in the Electricity Sector, the Commission approved the tariff calculation methodology for the universal service supply. The methodology ensures protection of customers during a market opening transition period, by supporting continuous and reliable functioning of the universal service provider. It also supports the determination of a stable price, within which the tariff RP is defined as one calendar year.

Natural gas transportation and distribution activities are natural monopolies and are subject to tariff regulation by the Commission. Pursuant to the natural gas tariff calculation methodology, the tariff RP is defined as three calendar years.

According to the tariff methodologies in both the electricity and natural gas sectors, the calculation of CAPEX and non-controllable OPEX is determined based on information from the base year and forecasted expenses of the RP (adjusted by the cost-plus principle). Non-controllable OPEX includes all those expenses that are caused by external factors and that cannot be influenced by the licensee, namely taxes, fees, Commission adjustment fees, market operator service fees, etc.

Incentive regulation mechanisms are applied to controllable OPEX, which establish certain incentives to promote cost efficiency. Controllable OPEX includes all expenses that a company has influence over.

In accordance with the requirements of the tariff methodology, licensees provide financial and technical data for the base year, which is information from the previous calendar year of the tariff calculation year. For regulatory purposes, base data, CAPEX and OPEX (controllable and noncontrollable) are audited and analysed. Audited controllable OPEX for the base year is calculated taking into account an efficiency factor (X-factor) and forecasted inflation (CPI).

2.33 Montenegro

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	-	-	1	1
	Network length	-	-	1,627.8 km	19,997.63 km
	Ownership	-	-	Ownership structure: 55.00% the state of Montenegro, 22.09% Terna Rete Nazionale S.p.a.,15.00% Elektromreza Srbije AD Beograd,6.69% natural persons and the rest joint venture funds and joint custody accounts	100% in the ownership of Elektroprivreda Crne Gore AD Niksic, in which the State owns ~88%
General framework	**Authority**	-	-	Energy and Water Regulatory Agency of Montenegro (REGAGEN, www.regagen.co.me)	
	System	-		Hybrid regulatory model	
	Period	-		At least one calendar year. Current RP: 2020-22 (three years) Next RP:2023-2025.	
	Base year for next period	-		Last year of current RP (2022)	
	Transparency	-		All decisions are published in the official gazette and on the website of the regulator. Decisions are also published on the suppliers' and REGAGEN's websites[81]	
	Main elements for determining the revenue cap	-	-	Controllable, partially controllable and non-controllable costs, depreciation and return on assets	Controllable, partially controllable and non-controllable costs, depreciation and return on assets
	Legal framework	-		Energy Law[82]	
Rate of return	**Type of WACC**	-		For RP 2020-22 WACC (real, pre-tax). For RP 2023-2025 WACC (nominal, post-tax)	
	Determination of the rate of return on equity	-		The RoR on equity (r_e) is determined by applying the CAPM, according to the formula $SPVK = r_f + \beta * PRRT + PRZ$, where r_f is the risk-free rate (%), β is beta, $PRRT$ is the market risk premium (%), and PRZ is the country risk premium (%)	
	Rate of return on equity before taxes	-		For RP 2020-22 WACC: $SPVK$ 12.4% r_f 0.40%, β 0.96, $PRRT$ 5.96%, PRZ 6.25%	
	Use of rate of return	-		The RoR is calculated using the WACC formula. The WACC reflects two main sources of funding – debt and equity. WACC is multiplied by the RAB	
Regulatory asset base	**Components of RAB**	-		RAB = net value of asset + investments + working capital	
	Regulatory asset value	-		The first part of RAB (net value of assets) is determined based on re-evaluation of assets. The TSO and DSO have the right to conduct re-evaluation of assets, and REGAGEN has the right to hire an independent appraiser to conduct re-evaluation for regulatory purposes The second part of RAB (investments) is determined based on the value of work in progress and investments contained in the approved investment plans. Working capital is determined as 1/12 of approved OPEX	
	RAB adjustments	-	-	The RAB is determined for the three-year RP in advance. As a rule, the RAB is not adjusted during the RP, unless the condition prescribed by energy law is fulfilled, i.e. if the real costs and revenues (non-controllable costs, cost of losses, network	

[81] See https://www.epcg.com/.
[82] See http://regagen.co.me/site_cg/public/index.php/index/artikli?id=21.

				revenues, other revenues, return on assets and depreciation related to deviation of working capital and realisation of planned investments) deviate more than 10% from the previously set values
Depreciations	**Method**			Straight line
	Depreciation ratio			TSO: buildings 1.25%, network lines 2%, equipment 2.78%, other 10-20% DSO: buildings 1.67%, network lines 2%-4%, equipment 2.78%, other 5%-33.33%
	Consideration			Amount of annual depreciation of regulated assets is added to the allowed revenue

Introduction

The electricity sector of Montenegro was vertically integrated until 2009. The electricity distribution and transmission networks were legally unbundled from electricity generation and supply in 2009 and 2016 respectively. The electricity market was opened for eligible customers on 1 January 2009 and for all customers on 1 January 2015, meaning that all customers now have the right to choose their electricity supplier.

The transmission network of Montenegro is characterised by a radial structure on three voltage levels. CGES is the sole TSO in Montenegro, providing services through the grid on 400 kV, 220 kV and 110 kV voltage levels. Montenegro has one DSO, CEDIS, which operates the network at 35 kV, 10 kV and 0.4 kV voltage levels.

Montenegro's Energy and Water Regulatory Agency (REGAGEN) is an independent regulatory body with responsibilities in the field of energy (including electricity, natural gas and oil/petroleum products). REGAGEN also has responsibility for regulating public utilities managing water supply and municipal wastewater.

The legal basis for the regulation of the TSO and DSO is the Law on Energy, which is harmonised with the relevant EU acquis and was adopted in 2016, with changes in 2017 and 2020. The law stipulates that tariffs for end-users should reflect actual costs, including operational costs, depreciation and return on assets of the TSO and DSO.

According to the Law on Energy, REGAGEN is responsible for developing and implementing the methodologies for determining the allowed revenue for the TSO, DSO and the market operator. The market operator means an energy undertaking responsible for the organisation and management of the electricity market, electricity purchase from privileged producers, and resale to suppliers and self-supplying customers. In particular the market operator shall carry out the following activities:

- Organise and manage the electricity market, except for the stock exchange electricity market;
- Keep records on all the contracts signed in the electricity market in accordance with the market rules;
- Account volume imbalance of electricity intake and delivery relative to operating schedules, and account and control for a financial settlement of imbalance;
- Publish on its webpage all the information required for undisturbed market operation and for carrying out of energy activities pursuant to Energy Law;
- Maintain records on suppliers and final customers;
- Regulate in the Market Rules the rules and procedures on electricity purchase and sale; and

- Define standard contracts (contracts on: participation in the electricity market, financial settlement of balancing account, balance responsibility, electricity purchase from privileged customers, purchase and sale of a mandatory proportional share of electricity purchased from privileged producers, and membership in the balancing market), etc.

Historical development

REGAGEN was established in 2004 according to Energy Law from 2003, as an autonomous, non-profit organisation, legally and functionally independent from the state authorities and energy undertakings. In 2007 REGAGEN started to regulate electricity prices. At the beginning of regulation, generation, transmission, distribution and supply were regulated activities. The first methodologies were based on the cost-plus method. The duration of the RP was one year. Since all regulated activities were carried out by one vertically integrated entity – Elektroprivreda Crne Gore AD Niksic (EPCG) – the costs of energy activities were not separated, and it was not possible to identify separate prices for transmission and distribution in such conditions. Therefore, in the first years of regulation, REGAGEN undertook measures within its competence to create the conditions for future unbundling and setting separate prices for each regulated activity.

In 2009 the electricity market opened for eligible (large) customers, and final electricity prices for all consumers were divided into explicit price components such as generation, supply, transmission, distribution, and taxes and levies. The unbundling of the TSO was carried out in 2009 when CGES was established. CGES is also certified in accordance with Energy Community acquis in 2018.

In accordance with the Energy Law of 2010, regulation of generation ended. The decisions on the approval of regulatory allowed revenues and prices from March 2011 completely abolished the cross-subsidisation that existed before between customer categories connected to the low-voltage network. All customers in Montenegro began to pay electricity prices that reflected the real costs of transmission and distribution that different customer categories caused to the system. The Energy Law of 2010 and new regulatory framework that was implemented in 2012 introduced an incentive-based method of regulation and a three-year RP. In 2012 allowed revenues of the TSO and DSO were determined based on a revenue cap methodology. Investment incentives and efficiency incentives for the TSO and DSO were introduced for the first time. In the same year the market operator was established as a separate entity and its fee was separated from TSO charges. REGAGEN has the competence to determine fees for the operation of the market operator.

To support and encourage production from renewable energy sources, a “RES and cogeneration” fee was included in energy bills in 2014 as a separate tariff component. The legal framework changed in 2016 and, in accordance with the Energy Law of 2016, REGAGEN started to determine allowed revenues and prices for transmission and distribution, as well as the market operator fee. The regulatory framework for the TSO and DSO was changed and a hybrid regulatory method was introduced. This aimed to limit allowed revenue, provide efficiency improvement and investment incentives, and allow risk-sharing between operators and users of the system (risks related to changes in deployed capacity). The same method was applied in 2019 for the current RP (2020-22).

The incentive-based regulatory framework that has been applied since 2012 has encouraged the TSO and DSO to invest in the development of the systems they operate, to ensure the long-term ability of the system to meet the requirements for electricity transmission and distribution in a secure and quality manner. Since the introduction of investment incentives in

2012 until the end of 2021, the value of realised investments in the transmission and distribution systems has amounted to approximately €423 million, while the value of the fixed assets of the TSO and DSO prior to the introduction of investment incentives was approximately €319 million.

The applied regulatory framework has provided sustainability of regulated undertakings, improved efficiency, and led to the realisation of significant investments in the system and the stability of system usage prices. Future development of the regulatory framework will focus on quality improvement. As previously noted, since 1 January 2015 all customers have the right to choose their electricity supplier, and electricity supply has ceased to be a regulated activity. From 1 January 2017, the supplier that had the status of a public supplier shall be in a position to change prices for households and small-sized non-household customers, in line with changes of prices on the market, under certain restrictions prescribed by Energy Law. These restrictions refer only to the supplier that has the dominant position in the market, and can only be applied in a transitional period, which ended in 2022.

Current regulatory frameworks

The most recent RP for the electricity TSO and DSO has been effective since 1 January 2020 and lasted until 31 December 2022 (a three-year period). Allowed revenues and prices for the use of electricity transmission and distribution systems are determined by a hybrid regulatory method. The hybrid regulatory method is implemented as a type of economic regulation that aims to limit allowed revenue, provide efficiency improvement incentives, and allow risk-sharing between operators and users of the system (risks related to changes in deployed capacity). The methodologies are also based on principles intended to improve transparency and non-discriminatory access, facilitate trading and competition, create favourable investment conditions and avoid cross-subsidies, reduce costs and encourage improvements in efficiency.

The formula for calculation of allowed revenues is $AR = AC + D + RR$, where:
- AR is allowed revenue;
- AC is allowed costs;
- D is deprecation; and
- RR is the RoR.

Allowed revenues consist of allowed OPEX (controllable, partially controllable (cost of losses) and non-controllable costs), depreciation and return on assets. Controllable costs are salary costs and other personal expenses, material costs, production service costs, intangible costs except tax costs, contributions and representation costs, and other costs. Partially controllable costs (cost of losses) include the cost of purchasing electricity to cover justified losses in the transmission and distribution system. Non-controllable costs are costs related to property taxes, fees and charges in accordance with the law, costs incurred on the basis of international treaties, environmental protection costs, costs related to the fee for the market operator and other costs according to the law.

Methodologies for the TSO and DSO include an efficiency factor (X), which is calculated as a sum of the following sub-factors:
- X_1 – an inefficiency sub-factor which is calculated as a correlation of actual and approved costs for the previous RPs; and
- X_2 – an efficiency sub-factor that includes application of new technologies (constant value of 0.005).

X_1 (the inefficiency sub-factor) is calculated as $X_1 = \frac{TPu^{os}}{TPu^{ut}} * \frac{1}{100}$, where:

- TPu^{os} is the average realised operating costs that can be affected in the last year of the previous RP and all years of the RP in which the application is submitted for which there are final data; and
- TPu^{ut} is the average approved operating costs that may be affected in the last year of the previous RP and all years of the RP in which the application is submitted for which there are final data.

According to the methodologies, both the TSO and DSO were incentivised to improve the efficiency of their activities and reduce their operational costs.

Depreciation is calculated according to the straight-line method. The amount of annual depreciation of regulated assets is added to the allowed revenue.

The return on assets is calculated according to the formula $RA = WACC * RAB$.

The RoR on assets is calculated using the real (pre-tax) WACC. The WACC reflects two main sources of funding – debt and equity. It is multiplied by the RAB to calculate return on assets. The RAB is determined for the next three-year RP in advance. It reflects net assets, work in progress and planned investments. As a rule, the RAB is not adjusted during the RP, except if the condition prescribed by Energy Law is fulfilled, which is that the real costs and revenues deviate more than 10% from the set values.

The regulatory framework related to WACC was changed during 2022 for the next RP (2023-25). Instead of the real pre-tax WACC, the nominal post-tax WACC is applied. The aforementioned change was introduced to avoid the impact of high inflation (partly caused by the energy crisis, i.e. the rise in energy prices in Europe), as well as to ensure sustainability and a safe business environment for network operators who are obliged to meet the needs of the system users and to ensure its development. In addition to the above, the change of regulatory framework also includes the transition from the pre-tax rate to the post-tax rate, to enable the adjustments of costs arising from corporate income tax.

Transparency

REGAGEN publishes regulatory laws, bylaws and all decisions in the official gazette and on its website.[83] The TSO[84] and DSO[85] also publish documents on their websites, as well as the supplier EPCG.[86] Moreover, the TSO publishes documents on the ENTSO-E transparency platform.

[83] See http://regagen.co.me/site_cg/public/index.php/index/kategorija?id_kategorija=1.
[84] See http://www.cedis.me/.
[85] See https://www.cges.me/.
[86] See https://www.epcg.com/.

2.34 North Macedonia

		Gas TSO	Gas DSO	Electricity TSO	Electricity DSO
Market structure	**Network operators**	1	3	1	2
	Network length	210 km	70 km	2,122 km	29,360 km
	Ownership	Public and private ownership	Public and local ownership	Public ownership	Larger DSO: 90% of shares are privately owned and 10% is in public ownership, Second DSO: 100% public ownership
General framework	**Authority**	Energy and Water Services Regulatory Commission of Republic of North Macedonia (ERC, www.erc.org.mk)			
	System	Revenue cap			
	Period	Five years. Current RP: 2022-26		Three years. Current RP: 2021-23	Three years. Current RP:2021-23)
	Base year for next period	2022 (t-2)			Last year of the RP (2020)
	Transparency	Network codes natural gas[87]	Network distribution rules on natural gas[88].All bylaws and decisions are published on the regulator's website.[89]	All bylaws and decisions are published on the regulator's website. Decisions are published on the TSO's website.[90]	All bylaws and decisions are published on the regulator's website. Decisions are published on the DSO's website.[91]
	Main elements for determining the revenue cap	OPEX and CAPEX	OPEX and CAPEX	Operational costs, depreciation, return on assets and losses	Operational costs, depreciation, return on assets and losses
	Legal framework	-			Law on Energy and regulatory acts
Rate of return	**Type of WACC**	WACC (real,(pre-tax)			
	Determination of the rate of return on equity	The rate of return on equity (r_e) is determined by applying the • CAPM, according to the formula: $WACC\left\{\frac{((1-Debt)*K_e)}{(1-T_p)}\right\}+Debt*K_d$, where:Debt is the ratio between equity and long-term debt for the RP; • K_e is the cost of equity = risk-free rate + β* market risk premiums • Market risk premiums = debt premiums – risk-free rates; • T_p is the profit tax rate; • β is beta; and • K_d is the real cost of debt.			
	Rate of return on equity before taxes	Equity = 98.75% Long-term debt = 1.25% K_d – real cost of debt = 0%	N/A	Equity = 60% Long -erm debt = 40% K_d– real cost of debt = 3.93% Risk-free rates = 1.68%	

[87] See Network codes natural gas.
[88] See https://www.strumicagas.mk/images/mrezni_pravila.pdf.
[89] See https://erc.org.mk/default.aspx.
[90] See https://www.mepso.com.mk/index.php/mk/component/content/article/69-mk-kategorii/doma/vesti-i-aktuelnosti/436-tarif-2020?Itemid=614.
[91] See https://www.elektrodistribucija.mk/Services/Products-and-prices/Distribution-of-electricity.aspx?lang=en-us.

		Debt premiums = 6.11% Risk-free rates = 2.72% Market risk premiums = 3.39% β = 1 Cost of equity = 6.11% T_p - profit tax rate = 10% WACC = 6.7%		Market risk premiums = 3.80% β = 1 Cost of equity = 5.48% T_p - profit tax rate = 10% WACC = 5.2253%	
	Use of rate of return	The RoR is calculated using the WACC formula. The WACC reflects two types of finance used to fund investments, debt and equity respectively. The WACC is multiplied by the RAB			
Regulatory asset base	**Components of RAB**	RAB = value of asset + investments – grant financed investments + depreciation			
	Regulatory asset value	Financial accounts			
	RAB adjustments	The RAB is not adjusted during the RP			
Depreciations	**Method**	Straight line			
	Depreciation ratio	Pipelines: 40 years, 2.5%, Buildings, Metering stations, Compressors: 20 years, 5%	Pipelines: 40 years, 2.5%, Buildings, Metering stations, Compressors: 20 years, 5%	Lines: 2.5%, 40 years Transformers: 5%, 20 years"	Lines: 2.5%, 40 years Buildings: 5%, 20 years Metering devices: 5%, 20 years Transformers: 5%, 20 years
	Consideration	Depreciation of regulated fixed assets is calculated in accordance with the prescribed annual depreciation rates, which includes:depreciation of own regulated fixed assets, and depreciation of assets financed by grants			

Introduction

The Energy and Water Services Regulatory Commission of the Republic of North Macedonia (ERC) was established in accordance with the Law on Energy in 2003, as an independent regulatory body in the field of electricity, natural gas, oil/petroleum products and heat. The legal basis for the regulation of the DSOs and the TSO is the Energy Law, which is harmonised with the relevant EU acquis and was adopted in 2018. ERC is responsible for developing and implementing the methodologies for determining the maximum allowed revenue for the DSOs, TSO, and the market operator. The electricity market operator (MEMO) is a company that was established in 2018 by the TSO that performs activities related to the organisation, efficient operation, and development of markets with bilateral agreements. The first tariff and prices set by ERC were adopted in 2006. Since then, ERC has implemented revenue cap-based methodologies for setting maximum approved revenue for both electricity and gas transmission and distribution.

Electricity transmission and distribution companies

In 2005, in the Republic of North Macedonia conditions were created for the restructuring of the vertically integrated company for the production, transmission and distribution of electricity, AD "Elektrostopanstvo na Makedonija", into three newly established companies: JSC MEPSO (company for transmission and organisation of the electricity market), JSC ELEM (company for production of electricity and distribution, which was renamed ESM in 2019) and JSC ESM (company for distribution and supply of electricity, which was privatized and rebranded as EVN Macedonia in 2006, while in 2016 distribution and supply were unbundled). The step wise approach was implemented for the opening of the electricity market that started in 2007 and was gradually finalised by 2018. As of 1 January 2019 all consumers including households have the right to choose their electricity suppliers. In electricity, there is a single TSO, JSC MEPSO, which operates, maintains and develops the high voltage network with a total length of 2,122 km of lines on 110 kV and 400 kV. The TSO was certified in accordance with the 3rd Package in July 2019.

In North Macedonia there are two electricity DSOs. The dominant DSO is Elektrodistribucija, which operates the electricity distribution network representing 29,190 km of lines and 888,825 customers. Elektrodistribucija was established as a separate legal entity by EVN Macedonia, which is also a supplier and DSO. The rest of the electricity distribution network is operated by ESM Energetika, representing 170 km of lines and 158 customers.

Regulation of electricity transmission and distribution companies

From the very beginning to the present day, ERC has been applying the revenue cap method for determining the regulated maximum income of the TSO and DSOs, except for the first RP when a hybrid method was applied when determining the DSOs' tariffs. The revenue caps for the TSO and DSOs are set for a three-year RP (current RP 2021-23). By no later than 30 June in the first year of the RP, ERC sets the base revenue for all three years of the RP and the maximum revenue for the first year of the RP. In the second and third year of the RP, ERC sets the maximum revenue for the current year by 30 June at the latest. The base year is the year before the first year of the RP. Data from the base year are used in the calculation of the components contained in the base revenue. The revenue caps consist of the following main components: basic revenue, specified pass-through costs and losses. The basic revenue (BA), which consists of operational costs, depreciation and return on assets, is set at the beginning of the RP for each year and is not adjusted during the RP.The return on assets is calculated as $RA = WACC * RAB$. The RAB is determined for the three-year RP in advance for each year. It reflects assets with which the regulated activity is performed and planned investments. Assets acquired from capital contributions such as grants are not taken into consideration in the calculations. The RAB is not adjusted during the RP.

The RoR is calculated using the WACC formula. The WACC, on a real basis before taxation for each regulated activity, is calculated for the regulated company with the application of the following formula $WACC \left\{ \frac{((1-Debt)*K_e)}{(1-T_p)} \right\} + Debt * K_d$, where:

- Debt is the ratio between equity and long-term debt, determined to be 60/40;
- The cost of equity (K_e) is determined by applying the CAPM, based on the income of non-risky investments and systematic risks expressed with the coefficient β. For the RP 2021-23, coefficient β is equal to one. The new methodology does not determine the beta value in the methodology itself, as was the case in the previous one; and
- The cost of debt (K_d) is calculated based on the average interest rates of the used loans by the regulated company for performing the regulated activity. The control is carried out based on the loan terms and interest rates, published by the National Bank of the Republic of North Macedonia.

Depreciation is calculated according to straight line method. The amount of annual depreciation of regulated assets is part of the base revenue. Unlike operational costs, depreciation and return on assets - which are determined in the first year of the RP for all three years of the RP - the cost of purchasing electricity for covering allowed technical losses in the transmission and distribution grid and specified pass-through costs, are non-controllable costs and are calculated for every year of the RP.

Specified pass-through costs (SPT_t) for the TSO = regulatory fee, cost of concession fees, environmental tax and property taxes + cost of ancillary services + payment made under the ITC mechanism - revenues received under the ITC mechanism - revenues earned by the allocation of interconnection capacity - revenues from the sale of surplus electricity to the organised electricity market to optimise the supply of electricity to cover losses in the transmission network - connection charges aimed at recovering the cost of connection assets maintenance and operation and other revenues from sources other than the transmission grid use. Specified pass-through costs (SPT_t) for the DSO = regulatory fee, cost of concession fees, environmental tax and property taxes - revenues from the sale of surplus electricity to the organised electricity market to optimise the supply of electricity to cover losses in the distribution network - connection charges aimed at recovering the cost of connection assets maintenance and operation and other revenues from sources other than the distribution grid use.

Electricity transmission and distribution tariffs

Electricity transmission and distribution tariffs are mainly commodity based (kWh) and are adjusted annually. Tariffs can be adjusted more often during the year. This happens if there are changes in the circumstances that existed at the time of the approval of the regulated maximum revenue and regulated average tariff. These circumstances indicate a change in the elements on the basis of which the regulated maximum revenue and regulated average tariff were determined. Electricity transmission and distribution tariffs are adjusted concerning the costs for procuring electricity for covering the losses in the transmission and distribution grids, by a percentage approved by ERC. This percentage refers to the input of the electricity in the system from generators, imports, and transit.

Transparency

ERC publishes the tariff methodologies and decisions on tariffs on its website and in the official gazette. ERC publishes notes on the operators' requests for tariff setting in newspapers. The draft decisions with explanations on how tariffs are calculated are published on the ERC website. The TSO and DSOs are obliged to publish the tariffs set by ERC on their websites.

Gas transmission and distribution companies

ERC is responsible for setting tariffs for natural gas on an annual basis (for the TSO, market operator and DSOs' services). Methodologies provide full cost-reflectiveness of the regulated tariffs. The current tariffs were set on 30 December 2021. During 2021, the total number of connected customers of natural gas were approximately 550, with a transmission network length of about 210 km, a distribution network of about 70 km and total distributed quantities of about 426 million m^3. Since 1 January 2015, the natural gas market in the Republic of North Macedonia has been fully liberalised. As of the end of 2020, five years have passed since the full liberalisation of the natural gas market, without any disturbances noticed in the status among the participants of the market. In the Republic of North Macedonia, the following natural gas distribution systems have been built:

- Located in the Technology and Industry Development Zones (TIRZ) Skopje 1 and Skopje 2,
- Located in the village Bunardzik with 6.09 km length of the distribution grid;
- The Municipality of Kumanovo with 20 km length of the distribution grid; and
- The Municipality of Strumica, with 43 km length of the built distribution grid.

The nominal capacity of the transmission grid is 800 million nm^3 on an annual basis. Considering the difference in the dynamics of the natural gas consumption between the winter and summer months, the exploitation of the system varies during the year. The lowest exploitation of the system is typically in the months of April and May, escalating from 5% to 15%, while in the winter months, the season of high natural gas consumption, the escalation is significantly higher, and on a daily basis the exploitation of the natural gas transmission system is in the range of 50% to 80%.

The average tariff and tariffs are regulated through determining the upper revenue limit that the regulated company can achieve during one calendar year (the maximum allowable revenue). Unlike the electricity sector, in the natural gas sector different methodologies for determining the price of natural gas have been implemented over the years. The average tariff for performing a regulated natural gas transmission activity is determined based on the regulated revenue of transmission network operator.

The joint stock company GA-MA Skopje (TSO) was established based on a Government Decision of 14 June 2006 on the transformation of the Public Enterprise GA-MA. In the ownership structure of AD GA-MA Skopje, the Government participates with 50% of the total capital, and 50% of the total capital is owned by AD Makpetrol Skopje. By the end of 2020, the Assembly of the Republic of North Macedonia adopted the Law on Dispute Resolution between the Government of the Republic of North Macedonia and Makpetrol joint-stock company Skopje via agreement[92]. On 27 August 2021, with mediation from the Center on Dispute Solution and Negotiation of the Energy Community, the Treaty was performed and signed between the joint stock company Makpetrol Skopje and the Republic of North Macedonia. This concerned solving the dispute related to the determination of the participation of all parties regarding the realisation of the gas line system in the Republic of North Macedonia.

In the next period, the Ministry of Economy will become the full owner of the natural gas TSO, after which ERC shall issue a licence for the execution of natural gas transmission to the newly formed natural gas transmission operator. ERC will also certify the TSO with the 3rd Package of the EU internal market legislation. The new natural gas transmission operator shall continue with the preparation and adoption of the remaining legislation from the field of natural gas, provided in the Law on Energy, which will be published after being approved by ERC.

Natural gas distribution systems are established as private companies. Regulated revenue for the service of the natural gas transmission company should cover the justified costs of natural gas transmission and provide adequate return on capital.

The base year is the year that is two years before the first year of the regulated period. Data from the base year are used in the calculation of the components contained in the base revenue (operational costs, depreciation and return on assets). Operational costs mean costs for the operation and maintenance of the company's regulated activity, in accordance with the technical standards applicable in the Republic of North Macedonia and which reflect standardised costs for providing the regulated activity.

The level of standardised costs is determined under the following guidelines:

1. Costs for materials, energy, spare parts and small inventory on the basis of consumption and the average market price norms in the period of the supply;
2. Costs for regular maintenance, repair and asset maintenance services up to 20% of the calculated annual depreciation;
3. Costs for construction facility and equipment insurance shall be acknowledged pursuant to the insurance premium level paid by the company;
4. Gross salaries per employee up to the level of average gross salary per employee realised in the economy of the Republic of North Macedonia in the current year, increased by 40% as a reflection of the employees' qualification structure and the regulated activity complexity;
5. Management salaries and rewards, in standardised amounts appropriate to the efficiency increase, and according to company management bodies' decisions;
6. Other services, up to the level of the average three-year share (%) in the costs for materials, energy, small inventory (item 1);
7. Other and excessive costs, up to 10% from the total costs referred to in items 1,2, 3, 4 and 6; and
8. Specified pass-through costs (taxes, contributions and other fees not subordinate to the performance) shall be acknowledged in accordance with the legal regulations.

Depreciation is calculated according to the straight-line method. The amount of annual depreciation of regulated assets is part of to the base revenue. The return on assets, WACC and RAB are calculated in the same manner as for electricity. The RAB is determined for the five-year RP in advance for each year. The RAB is not adjusted during the RP.

[92] Official Gazette of the Republic of North Macedonia no. 317/20

3 Economic theory and the regulatory system

In the past, cost-based regulation approaches (rate-of-return regulation or cost-plus regulation) were widely used for tariff regulation purposes. The rate-of-return model guarantees the regulated company a certain pre-defined RoR on its RAB. Another approach is cost-plus regulation, in which a pre-defined profit margin is added to the costs of the company. Evidently, the regulated company has no incentive to minimise its costs under a cost-based regulation framework, because it can increase its profits by simply expanding the asset or cost base. Under cost-plus regulation a company may have an incentive to signal incorrect costs to the regulator or to even opt for wasting resources in order to increase the cost base ("gold-plating").

As a response to the major drawbacks of cost-based regulation, incentive-based approaches to tariff regulation were first developed in Great Britain and are currently applied in many other countries.

Incentive-based regulation can be characterised by the use of financial rewards and penalties to induce the regulated company to achieve the desired goals (generally in the form of an efficient cost base) while the company is allowed some discretion in how to achieve them. Rewards and penalties replace a command and control form of regulation and provide incentives to the company to achieve the goals by allowing it to share the extra profit in case it over-fulfils the targets set by the regulator. In general, incentive-based regulation aims at cost control – so that grid users could later benefit from lower costs in a quantitative way through lower tariffs in the future.

All the installed characteristics of regulation can be used in parallel or somehow merged together. There is, for example, no contradiction to have an incentive-based regulation with an RoR.

3.1 Regulatory system in place

Most European countries use incentive-based regulation in the form of a revenue cap. The tables in Annex 4 accompanying this report,[93] which contains the NRAs' answers to the questionnaires, underline the usage of this regulatory instrument. In general, most countries use a mixture of a cap regulation (revenue or price) and a guaranteed RoR. Revenue cap regulation can thereby be seen as an indirect form of price cap regulation, where the revenue is the result of price multiplied by the quantity. Nowadays, cost-plus regulation is an exception and is only used in a few countries.

Electricity transmission is regulated by incentive methods in 18 out of 33 countries. Revenue caps are set by 15 NRAs.

In electricity distribution, 23 NRAs apply incentive regulation. Price caps are used by five NRAs and 18 NRAs use revenue caps.

Gas transmission is regulated by incentive methods in 18 countries, including a limitation by caps. In two countries, an RoR is implemented.

In gas distribution, incentive-based methods are applied by 19 countries. In 16 countries, a revenue cap is used.

[93] Annex 4 is uploaded as a separate document on the same webpage as this report.

3.2 Efficiency requirements

Efficiency requirements stimulate the network operators to reduce costs and to work more efficiently. One way of implementing these requirements is to reduce the allowed revenues year by year. The tables in Annex 4 show whether the NRAs set efficiency requirements (X-factors) on OPEX and CAPEX.

The survey revealed that a majority of CEER regulators in electricity and gas focus on cost saving on the OPEX side. On the CAPEX side, about 20% of respondents apply efficiency requirements. More than 50% have an X-factor for OPEX. These results are independent of the type of energy (gas or electricity) and the market player (TSO or DSO). In some cases, an efficiency requirement is applied to TOTEX (CAPEX + OPEX). One country (Belgium) uses different efficiency requirements depending on the region of the country.

There are only a few countries that set a minimum efficiency score, which is granted at least to every network operator. For electricity TSOs it is only Germany, which applies a minimum efficiency score of 60%. For electricity DSOs, Austria, Germany and Sweden set minimum efficiency scores from 30%-80%. For the gas sector, only Germany and Spain apply a minimum efficiency score at TSO level and Austria and Germany at DSO level. It should be noted that only Germany sets minimum efficiency scores for both sectors and levels. The length of the time span granted to the operators for eliminating individual inefficiencies, and the way of eliminating these inefficiencies, varies a lot between the respective countries.

3.3 General overview of system operators

Some regulatory regimes distinguish between the TSO functions of transport and of system operation. For electricity, the tasks of a system operator cover the complete area of activities for operating electric power systems, including security, control and quality in terms of fixed technical standards, principles and procedures, but also the synchronous operation of interconnected power systems.[94] This activity includes balancing services, primary and secondary reserves, capacity management, ancillary services (disturbance reserves, voltage support) and the purchase of energy for congestion management and redispatching. This activity excludes day-to-day management of the network functionality.

For gas, system operation includes ancillary services and congestion management. It also includes the maintenance of security of supply in the natural gas system, by the coordination of entry and exit agents and the balancing of the natural gas system. This activity also excludes day-to-day management of the network functionality.

In almost all countries, all functions are within one company and there is no separation of transport and system operation. In eight countries, there is no separation but separated financial accounts per function. Therefore, there is no different regulatory treatment at this point. Only Spain separates the transport and system operation functions in both sectors.

3.3.1 Regulatory system in place and efficiency requirements

Most CEER and ECRB members use a common methodology for setting the revenues for both functions. In the case that there are separated market functions, a separate X-factor (efficiency requirement) is applied to OPEX or even TOTEX.

[94] Definition used by the Agency for the Cooperation of Energy Regulators (ACER).

3.3.2 Operational expenditure (OPEX)

The OPEX of the system operators consists of the components of personnel and operating costs. Sometimes, additional components are included and there is also OPEX of the system operator that is excluded from the allowed revenue (e.g. costs of capitalised property and equipment or subsidies). To obtain the items that comprise OPEX, financial as well as regulatory accounts are used.

3.3.3 Capital expenditure (CAPEX)

To calculate the RoR for system operator investments, in most countries the same methodological components (CAPM and WACC) are used, and the same rate is used as for transmission investments.

3.3.4 Incentives and penalties

In most cases, there are no incentives or penalties included in the methodology derived from the fulfilment of the system operator functions and, therefore, in most cases there is no related cap for incentives or penalties. In some countries there are incentives or penalties included in the methodology derived from the fulfilment of the system operator functions, like a bonus/malus system for the procurement of balancing and loss energy in Germany or incentives for solving technical restrictions in Spain.

For the gas sector, North Macedonia applies the return on regulated assets. The return on capital is calculated as follows:

- For transmitted natural gas quantities to 250,000,000 m^3 per year, 30% of the calculated return on regulated assets shall be approved;
- For transmitted natural gas quantities from 250,000,000 m^3 to 400,000,000 m^3 per year, 50% of the calculated return on regulated assets shall be approved; and
- For transmitted natural gas quantities over 400,000,000 m^3 per year, 100% of the calculated return on regulated assets shall be approved.

3.3.5 Tariffs

In most cases regulators that have a separated treatment of system operators do not have a special tariff for the revenues of the system operators. For these NRAs, the general tariffs are used. In other cases, there is a special third-party access tariff (e.g. in Portugal). In Spain, the remuneration of the electricity system operator is satisfied 50% by electricity producers, according to their available capacity, and 50% by retailers and direct consumers. For the Spanish gas system operator, the revenues are collected as a percentage of the tolls and fees collected. Georgia have specific tariffs for the revenues of the system operator.

3.3.6 Allowed revenue

If there are deviations between the system operator’s collected revenues and the system operator’s allowed revenues, most countries make an adjustment, at the latest, two years later, after which the difference is settled or incorporated when setting new tariffs. In the Czech Republic, a correction factor is applied. In Georgia and North Macedonia a correction factor is applied in the electricity sector.

4 Calculating the rate of return

Most regulatory systems allow for an RoR on investments. In this chapter we discuss how such returns are set.

4.1 Methods used to calculate the rate of return

There are different possible methods to calculate the RoR. Mostly a WACC factor is used.

In general, WACC can be expressed in a simplified manner by the following formula:

$$WACC = \underbrace{\frac{equity}{(equity+debt)}}_{\text{Weighting factors}} * \ cost\ of\ equity + \underbrace{\frac{debt}{(equity+debt)}}_{\text{Weighting factors}} * cost\ of\ debt$$

NRAs can distinguish between *nominal* or *real* and *before* and *after* taxation as well as a “vanilla” WACC.[95]

For electricity network regulation, the most popular approach is to use nominal WACC before taxation (as can be seen in the tables of Annex 4 accompanying this report). Otherwise, the most commonly used method for calculation of the RoR is the real WACC before taxation, which is used by about 25-30% of the NRAs. In the gas sector, the nominal WACC before taxation approach is popular as well, however, the real WACC before taxation is also frequently used (WACC nominal 50%, WACC real 30%). In addition, it should be noted that three NRAs do not use the WACC in the regulation of electricity and gas TSOs, and Germany also does not use the WACC in the regulation of electricity and gas DSOs.

4.2 Year of rate of return estimation and length of regulatory period

To obtain information about the length of RPs and the different tariff years in the individual regulatory systems, a time series from 2010 to 2022 was considered. In general, the majority of NRAs evaluate (or adjust) the RoR parameters in the year before the RP starts. The year before the RP starts is used as a “photo” or base year in which the RoR parameters are evaluated or adjusted for TSOs as well as for DSOs. Most NRAs make no distinction between gas and electricity. There are only a few countries that evaluate or adjust the parameters two or three years before the start of the RP.

The typical RP is between four and five years, regardless of whether it is a CEER or an ECRB member, a TSO or DSO, or the electricity or gas sector. Just a few countries use a yearly RP or a period that is longer than five years. One country (Estonia) uses an undefined RP, so the operator can submit data at any time.

4.3 Rate of interest

The WACC is a factor applied to an asset volume to calculate an RoR. However, as a company's capital generally consists of both equity and debt capital, rates of interest for both of these must be calculated when determining a suitable return.

[95] This is the WACC using a pre-tax cost of debt and a post-tax cost of equity.

4.3.1 Risk-free rate

The risk-free rate is the expected return on an asset, which bears in theory no risk at all, i.e. whose expected returns are certain.[96] In other words, the risk-free rate is the minimum return an investor should expect for any investment, as any amount of risk would not be tolerated unless the expected RoR was greater than the risk-free rate.

The risk-free rate can be described as either "nominal" or "real". The nominal interest rate is the amount, in money terms, of interest payable. The real risk-free rate excludes inflation and reflects the pure time value of money to an investor.

The relationship between nominal and real risk-free rates and inflation can be expressed as follows:[97]

$$(1 + nominal\, risk - free\, rate) = (1 + real\, risk - free\, rate) * (1 + inflation)$$

In practice, it is not possible to find an investment that is free of all risks. However, freely traded investment-grade government bonds can generally be regarded as having close to zero default risk and zero liquidity risk.

4.3.1.1 Evaluating risk-free rates

There are only marginal differences in the individual regulatory systems concerning evaluating the risk-free rate. Most NRAs (CEER and ECRB) evaluate the risk-free rate based on government bond interest rates. The risk-free rates are usually evaluated based on their own national government bond interest rates. Some regulators, however, use interest rates based on the government bonds of selected foreign countries (AA or higher rated) or OECD averages.

In most cases, they use the same methodology for all network operators, but in some countries, there are differences in approaches between the electricity and gas sector, and/or between transmission and distribution. The main reason for such differences is that the risk-free rates have not been evaluated at the same time.

The most frequently used bonds have maturities of ten years, but lower year bonds also appear. In addition, it should be noted that Germany uses maturities of one, two, five, ten, 20 and 30 years. Most CEER and ECRB members use historical averages, but in relation to the years of historical analysis there is no uniform usage. The majority of NRAs apply one, five or ten years of historical analysis independent of the electricity or gas sector and TSO or DSO regulation.

4.3.1.2 Values of nominal and real risk-free rates

Regulators use different values of nominal and real risk-free rates. To compare the value of risk-free rates, the countries were also asked if the risk-free rate used is nominal or real.

[96] IRG/ERG Regulatory Accounting. (2017). Public consultation summary: Principles of Implementation and Best Practice for WACC calculation. Retrieved from: https://berec.europa.eu/doc/publications/consult_principles_best_implem/erg_07_04_pibs_on_wacc_public_cons_summary_mar2007_final.pdf.

[97] Ross, S., Westerfield, R. and Jordan, B. (2016). Essentials of Corporate Finance. Irwin/McGraw-Hill.

The conclusions could be drawn that most of the NRAs (CEER and ECRB) use nominal risk-free rates (only a few countries use real risk-free rates) and the average value of the nominal risk-free rate of CEER members is 1.38%. The average value of the nominal risk-free rate of ECRB members is 4.77%. This average is highly influenced by the value of Georgia (10.24% for electricity and 9.17% for gas). The single values of the ECRB members range between 0.4% and 10.24%. Nevertheless, the values of the risk-free rates also depend on the year of assessment.

4.3.2 Debt premiums

In corporate debt finance, the debt risk premium is the expected RoR above a (determined) risk-free interest rate. The risk premium is determined as the margin between the risk-free rate and the corporate bond rate. It expresses the incentive for an investor to invest in the corporation instead of investing in, for example, secure government bonds.

4.3.2.1 Evaluating debt premiums

The tables in Annex 4 show the approach towards debt premiums (where applied), their value, the applicable year and a short description of the evaluation. The evaluation of the values of debt premiums differs from NRA to NRA. They are usually estimated based on market analysis provided by external experts and internal comparative analysis conducted by the NRAs, but some of them also use country ratings. The values reflect the borrowing conditions for network operators which are seen as companies with good ratings.

The average value of debt premiums used by the CEER regulators is 1.39%. Portugal uses a debt premium of 3.25% for electricity and 2.75% for gas. The values of the debt premium differ marginally from electricity to gas regulation and TSOs to DSOs. Only a few CEER members do not use debt premiums in their regulatory system.

The average of the debt premium used by the ECRB members ranges from 2.04% and 2.95%, with an average of 2.64%.

4.3.2.2 Real cost of debt in tariff calculation

The tables in Annex 4 show the value of the real cost of debt. To make the cost of debt applied by the NRAs more comparable, the debt premium was (in most cases) added to the real risk-free rates. The survey shows that for the majority of the analysed countries (CEER and ECRB), the real cost of debt is in a range between 1.5% and 4.0%. Concerning the year of evaluating the real cost of debt, most NRAs apply years between 2016 and 2022.

4.3.3 Market risk premiums

Market risk premium can be defined as the excess return that the overall stock market provides above an investment at the risk-free rate. This is determined by comparing the returns on equity and the returns on risk-free investments. This excess return compensates investors for taking on the relatively higher risk of the equity market. The size of the premium will vary as the risk changes (in the stock market as a whole); high-risk investments are compensated with a higher premium.

4.3.3.1 Evaluating market risk premiums

The surveyed countries gave information about the value of the market risk premium, the year of evaluation and the NRA's approach for evaluating it. The average value of the market risk premium over both sectors and levels is 5.28% (CEER members). It is noteworthy that Great Britain uses the highest value for the TSO and DSO gas and TSO electricity market (8%). Ireland uses the highest value for the electricity DSO market (range of 6.9% to 7.55%). Concerning the year of evaluation of the market risk premium, CEER and ECRB members apply years between 2015 and 2022.

For ECRB members the average of the market risk premium is 5%. Montenegro has the highest market risk premium with 5.96% in the electricity sector.

As in the case of debt premiums, the values of market risk premiums are also based on a market analysis. NRAs also use reports prepared by the expert group Dimson, Marsh and Staunton[98] and analysis provided by Damodaran.

4.3.4 Capital gearing

Gearing can be defined as the proportion of assets that were funded from borrowed funds. It is necessary for calculating the WACC, when the weighting factors have to be determined. As shown in subchapter 4.1, the formula $\frac{debt}{equity+debt}$ defines the gearing.

4.3.4.1 Evaluating the gearing ratio

The questionnaire for this report included the values of gearing for the year of evaluation and a short description of the evaluation by the NRAs. Almost all of the countries (CEER and ECRB) use a gearing between 40% and 60%. In general, the same value is used for all sectors, be they TSOs or DSOs. Only a few countries make use of different values, and if they do so, the value changes only minimally. Concerning the year of evaluation of the gearing, CEER members apply years between 2015 and 2022. Most NRAs base the gearing ratio on experts' reports or market analysis.

4.3.5 Taxes

The tax value can be defined as the rate of income tax paid by the network operators.

4.3.5.1 Evaluating the tax value

The tables in Annex 4 show the value of the tax rates used by the NRAs. Additionally, the year of evaluation and a short description of the evaluation is included.

[98] Dimson, E., Marsh, P., and Staunton, M. (2002). Long-Run Global Capital Market Returns and Risk Premia. Retrieved from: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=299335.

The NRAs provided the value of the corporate tax or the corporate income tax (depending on the name that is used) that applies to the network companies. The value of corporate tax depends on the national tax system. In general, the same value is used for all sectors, be they TSOs or DSOs. Only a few countries use different values; if this is the case, the value only changes slightly. The average corporate tax rate over both sectors and levels is around 21% for CEER members. It is noteworthy that the average corporate tax rate for electricity TSOs is the highest (around 33%) and the value for electricity DSOs is the lowest (around 9%). Concerning the year of the gearing ratio evaluation, countries apply years between 2015 and 2022. In many regulatory systems the tax value is defined by law.

The average value of the ECRB members is 13.89%.

4.3.6 Beta

An asset beta can be described as a quantitative measure of the volatility of a given stock, mutual fund, or portfolio, relative to the overall market. The asset beta therefore reflects the business risk in the specific market where the company operates. A beta of one corresponds to the expectations of the market as a whole, a beta above one is more volatile than the overall market, while a beta below one is less volatile. The beta of a company is calculated after subtracting its debt obligations, thus measuring the non-diversifiable risk.

An asset (unlevered) beta removes the effects of leverage on the capital structure of a firm, since the use of debt can result in tax rate adjustments that benefit a company. Removing the debt component allows an investor to compare the base level of risk between various companies.

An equity beta can be defined as an indication of the systematic risk attached to the returns on ordinary stocks. Equity beta accounts for the combined effects of market and financial risks that the stockholders of a company must face. It equates to the asset beta for an ungeared firm, or is adjusted upwards to reflect the extra riskiness of stocks in a geared firm.

The dependence between the asset and equity beta is usually represented by the formula $e\beta = a\beta * \left[1 + (1 - t) * \left(\frac{D}{E}\right)\right]$, where:

- $e\beta$ is the equity beta;
- $a\beta$ is the asset beta;
- t is the tax rate;
- D is debt;
- E is equity; and
- $\frac{D}{E}$ is the gearing ratio.

Sometimes in the calculation of the equity beta, the influence of taxes is not taken into account. In this case the formula for calculating equity beta is as follows:

$$e\beta = a\beta * \left[1 + \left(\frac{D}{E}\right)\right]$$

4.3.6.1 Evaluating the asset and equity beta

The questionnaire asked about the NRAs' approach to asset and equity beta evaluation.

The majority of NRAs evaluate beta values by using both external and internal market analyses. The most frequently applied approach in the calculation of equity beta is to use the formula which includes tax. Some regulators use a formula that does not include tax, and Belgium, Great Britain and Hungary use direct equity beta without a calculation of asset beta.

Due to the different gearing ratios, a comparison of equity betas could be misleading. To make the values comparable, the asset beta was calculated. The calculation was based on the value of equity betas and gearing ratios used by the regulators. The formulas presented above were used in this calculation.

4.3.6.2 Betas in the regulation

The tables in Annex 4 show asset beta $a\beta = \frac{e\beta}{\left[1+(1-t)*\left(\frac{D}{E}\right)\right]}$ and/or $a\beta = \frac{e\beta}{\left[1+\left(\frac{D}{E}\right)\right]}$ is used in tariff calculations for the electricity and gas TSOs and DSOs.

The values of asset beta calculated with $a\beta = \frac{e\beta}{\left[1+(1-t)*\left(\frac{D}{E}\right)\right]}$ are typically in the range of 0.3 to 0.5 in the electricity sector as well as in the gas sector. The values of asset betas calculated with $a\beta = \frac{e\beta}{\left[1+\left(\frac{D}{E}\right)\right]}$ are generally a little bit lower for CEER members.

5 Regulatory asset base

In general, the RAB serves as an important parameter in utility regulation to determine the allowed profit. The structure of individual components included in the RAB and their valuation differ significantly among countries (CEER and ECRB) and even among the regulated sectors. The RAB value is usually also linked with depreciation, depending on an individual NRA's approach.

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. The RAB 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 are, on the contrary, usually excluded.

The RAB may be valued according to different methods (e.g. historical costs, indexed historical costs or actual re-purchasing costs), which will have an influence on the determination of CAPEX. A RAB based on indexed historical costs would, therefore, require the use of a "real" instead of a "nominal" WACC. As a result, it is important to understand the relationship between the RAB definition and the WACC structure.

5.1 Components of the RAB

The following subchapter analyses the approaches taken by NRAs towards fixed assets, working capital, assets under construction, contributions from third parties and leased assets with respect to their inclusion/exclusion from the RAB.

5.1.1 Tariff calculation

In general, the role of the RAB is very important for the tariff calculation. Most of the countries use the RAB as one component (multiplied by the WACC) for calculating allowed revenue. With a determined revenue, the necessary tariffs can also be calculated.

Concerning the question of whether 100% of the RAB is used in tariff calculation, almost all of the surveyed countries answered "yes" for both sectors at the TSO and DSO levels. Only Denmark uses a different approach at the TSO level and Slovakia for the gas TSO.

5.1.2 Fixed assets

Fixed assets, also known as non-current assets, 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 pipes, land and buildings, motor vehicles, furniture, office equipment, computers, fixtures and fittings, and plants and machinery.

According to the survey data submitted, almost all countries count fixed assets in the RAB. In Poland, gas network assets are included in the RAB at the NPV.

5.1.3 Working capital

Working capital represents operating liquidity available to a company. Working capital is considered as a part of operating capital. Net working capital is calculated as current assets minus current liabilities:

$$\text{Working capital} = \text{current assets}$$
$$\text{Net working capital} = \text{current assets} - \text{current liabilities}$$

The answers to the survey showed that approximately a third of the countries include working capital in the RAB, therefore, the majority of countries do not count working capital in the RAB. It should be noted that only in parts of Belgium is working capital included in the RAB in electricity and gas DSO regulation. For the Flemish region, they calculate working capital in the RAB, whereas in the Walloon and Brussels regions they do not include working capital in the RAB. In Finland, accounts receivables and inventories are allowed in the RAB in book values, however, excluding cash equivalents or other receivables. In Germany, only working capital necessary for operations is included, and in Luxembourg the working capital is approved if duly justified.

5.1.4 Assets under construction

Assets under construction are a special form of tangible assets. They are usually displayed as a separate balance sheet item and therefore require a separate account determination in their asset classes.

Costs include all expenditure incurred for construction projects, capitalised borrowing costs incurred on a specific borrowing for the construction of a fixed asset incurred before it has reached the working condition for its intended use, and other related expenses. A fixed asset under construction is transferred to a fixed asset once it has reached the working condition for its intended use.

Ordinary depreciation is not allowed for assets under construction in most countries. Even if, from the accounting point of view, these assets are not included in the fixed assets, the NRAs, from a regulatory perspective, do sometimes include such costs in the RAB for remuneration, as shown in the survey.

About half of CEER countries responded that electricity transmission and distribution assets under construction are included in the RAB.

In gas transmission and distribution, a few NRAs responded that assets under construction are included in the RAB. Some countries have certain conditions for assets under construction to be included in the RAB, e.g. for certain categories of investments, as a transition before phase-out or a length of construction of more than two years. In Luxembourg, financing costs of assets under construction may also be considered under working capital.

For ECRB members, Montenegro and North Macedonia include assets under construction in the RAB at the electricity TSO and DSO level. Concerning the gas TSO and DSO level, only North Macedonia includes assets under construction in the RAB.

5.1.5 Contributions from third parties

Contributions from third parties such as connection fees, contributions from public institutions, EU funding under cohesion/structural funds, or EU grants under Decision No. 1364/2006/EC, which lays down guidelines for trans-European energy networks, are often deducted by the NRAs from the RAB ("ringfencing").

This approach is based on the reasoning that to the extent the asset (partly or in total) was not financed by the regulated entity, it should not be included in the RAB and remunerated.

The survey shows that the vast majority of the countries deduct such contributions from the RAB in the electricity and gas sector, both for TSO and DSO regulation. Only a few countries include contributions from third parties in the RAB in their regulation.

5.1.6 Leased assets

According to International Financial Reporting Standards (IFRS),[99] finance lease assets must be shown on the balance sheet of the lessee, with the amounts due on the lease also shown on the balance sheet as liabilities. This is intended to prevent the use of lease finance to keep the lease liabilities off-balance sheet.

According to a number of national accounting standards, however, it is possible to consider these assets as OPEX and keep them off-balance sheet.

The attached tables (in Annex 4) show that around 40% of the surveyed CEER countries include leased assets in the RAB. For DSO regulation, Belgium includes leased assets only for the Flemish Region and not for the Walloon or Brussels Regions. Most countries which do not include leased assets consider them as OPEX. Some countries have certain conditions for leased assets to be included in the RAB, e.g. for certain types of leases, or do not always base them on IFRS.

Concerning the ECRB countries, only Georgia and North Macedonia at the electricity and gas TSO level, and also Albania at the electricity DSO level, include leased assets in the RAB.

5.2 Determination of initial regulatory asset value

The value of the RAB on which the companies earn a return in accordance with the regulatory cost of capital (i.e. the WACC where applicable) is crucial for the calculation of the regulatory revenue.

The value of the assets included in the RAB can be expressed either in terms of historical costs or re-evaluated values. Whilst the historical cost approach values the RAB with reference to the costs that were actually incurred by the company to build or acquire the network, the re-evaluated values represent the costs that would hypothetically be incurred at the time of re-evaluation of the assets.

5.2.1 Historical costs

The method of valuation of the RAB using historical costs is applied in regulatory regimes where the assets of regulated companies were not re-evaluated, or in regimes where NRAs keep a regulatory database of the historical values of the assets. As the historical costs do not reflect a decrease in the real value of the assets caused by inflation, some NRAs use the indexed historical cost method.

In electricity and gas TSO and DSO regulation, about half of the surveyed countries do not base the RAB exclusively on the historical value of assets.

[99] See https://www.ifrs.org/.

5.2.2 Re-evaluation of assets

The re-evaluation of fixed assets is a technique that may be required to accurately describe the true value of the capital goods a business owns. The purpose of a re-evaluation is to bring into the books the fair market value of fixed assets. This may be helpful for a company to decide on selling one of its assets or inserting part of the company into a new company. Re-evaluation of assets was conducted in many countries following the unbundling of vertically integrated companies where separate network companies were established.

Other reasons for re-evaluation mentioned in the survey were very high inflation rates, and the consolidation processes of regulated companies. In some regulatory regimes, a re-evaluation of distribution assets is conducted annually according to the IFRS accounting standards. Even though the most frequently applied method was depreciated replacement costs, for the sake of comparison it is crucial to know when the last re-evaluation was performed. This is the major difference among countries surveyed. The re-evaluation can be done in two ways, either once or on a frequent basis.

One of the main advantages of the annual re-evaluation is that an NRA works with the real asset values and does not need to deal with the significant increase of RAB due to market circumstances.

The surveyed countries answered the question of whether the RAB is exclusively based on re-evaluated assets and if yes, how they influence the level of RAB. Overall, it should be noted that only a few CEER member countries (around 25%) base the RAB on re-evaluated assets. Some of them index RAB annually by using different indexes e.g. RPI or construction industry index, or they evaluate assets on the basis of historical costs.

In electricity transmission, the RAB is exclusively based on the re-evaluated assets in seven countries: Great Britain, Italy, Latvia, Poland, Romania, Slovakia and Sweden. In electricity distribution, the situation is the same, but with Iceland instead of Great Britain.

For gas transmission only France, Hungary, Ireland, Latvia, and Sweden do not exclusively base RAB on re-evaluated assets. In gas distribution, the situation is almost the same plus Slovakia.

In the case of ECRB countries it should be noted that only Ukraine at the electricity DSO level bases the RAB on re-evaluated assets.

5.2.3 Mix of historical and re-evaluated assets

Several CEER countries apply a mix of historical values and re-evaluated assets.

In Germany, the equity-financed share of old assets is indexed at replacement values for the cost determination. The debt-financed share of old assets is valued at historical values. New assets are always valued at historical values.

In Luxembourg, assets are valued at historical costs. Old assets (capitalised before 1 January 2010) may, as an option, be evaluated as follows: a fraction of old assets is valued at historical costs (up to the debt ratio, 50% of all old assets) and at indexed historical costs (up to the equity ratio, 50%).

For ECRB countries, the methodology varies from, for example, (indexed) purchasing costs used in North Macedonia to an independent appraiser who decides which methodology to apply in Montenegro. For the gas sector, North Macedonia also uses purchasing costs.

5.3 Difference between the RAB defined on the net book values and the RAB based on re-evaluated asset base

CEER member countries were asked for the difference (in percentage terms) between the RAB defined on NBVs according to national general accepted accounting principles (or IFRS), and the RAB based on a re-evaluated asset base. The purpose of this question was to find out if there is any difference between the NBV and the RAB. Regulated companies may have re-evaluated the assets but the NRA, for regulation purposes, could approve only part of those assets.

The survey shows that in the electricity as well as the gas sector, for almost all countries, there is no difference between the NBV and the RAB. If there is a difference between the NBV and the RAB, the percentages vary greatly, from 40% to over 140%.

5.4 Monetary value of regulated assets on historical cost basis and monetary value of re-evaluated regulated assets

The survey included the question of the monetary value of regulated assets on a historical cost basis and the monetary value of re-evaluated regulated assets (in both cases aggregated for all companies).

Nearly half of the surveyed CEER members were unable to make a statement concerning this, and some were not permitted to because of confidential information considerations.

Half of the ECRB members were also unable to make a statement concerning this for the electricity sector and almost all NRAs were unable to make a statement for the gas sector.

The monetary values of regulated assets and re-evaluated regulated assets are very different and vary from country to country. It cannot be said that the amount of the values depends on a specific sector.

5.5 RAB adjustments

The RAB is ordinarily adjusted annually within the RP when the value of new investments is taken into consideration and the value of depreciation is deducted.

According to the survey responses, almost three quarters of CEER NRAs adjust the RAB during the RP. The annual recalculation of the NBV (new investment depreciation) is the most common approach. Concerning the question of whether the adjustment affects NBVs by accounting for new investments and/or depreciation, most countries confirm this. Usually, the book value is calculated by adding investments and subtracting depreciations.

The survey also enquired whether NRAs adjusted the RAB within the RP to correspond the real values of the RAB with some kind of progression index. In Great Britain, the RAB is indexed for inflation using CPI and in Italy, an inflation index measured by the National Institute of Statistics is used.

5.6 RAB conclusions

From a balance sheet perspective, fixed assets are the most significant items in the energy industry. Also, according to the responses of CEER and ECRB energy regulators, fixed assets were without exception indicated as a component of the RAB. One third of CEER regulators also include working capital in the RAB, albeit with specific rules for its determination and inclusion. Concerning ECRB members, only a few include working capital in the RAB, therefore, the majority of countries do not include working capital in the RAB.

Fewer than half of the CEER regulators in the gas and electricity distribution sectors and the gas transmission sector include investment in progress in the RAB. For electricity transmission, on the other hand, the ratio is inversed and investment in progress is more often than not included in the RAB. Almost half of the ECRB regulators do not include investments in progress in the RAB. Contributions by third parties are deducted from the RAB by nearly all NRAs, with only a few exceptions on the CEER side.

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 a mixture of these two methods applied only rarely. In all countries surveyed, other adjustments were not mentioned.

6 Depreciation

Depreciation decreases the asset value through use and the shortening of theoretical asset life, and should also allow a firm to cover replacement investment costs during the economic lifetime of an asset. Concerning the duration of depreciation, the economic lifetime of the asset should be taken into account in a forward looking, long-run approach.

The two most common approaches towards depreciation are straight line and accelerated depreciation. The straight-line depreciation method spreads the cost evenly over the life of an asset. On the other hand, a method of accelerated depreciation such as the double declining balance, allows the company to deduct a much higher share in the first years after purchase.

6.1 Overview

Almost all countries use the straight-line approach towards depreciation. Once the NRA has decided on a depreciation method (straight line or accelerated depreciation), this method is applied for both gas and electricity system operators in the country.

For both electricity and gas regulation, most NRAs have the same depreciation rate for typical TSO and DSO network assets. Even when this is not the case, there is usually only a marginal difference.

One question to the NRAs was: *"Which values of depreciation are allowed into the regulation?"* The regulators predominantly use the same value of depreciation for TSOs and DSOs. There may be some minor differences between the two. Additionally, the NRAs use different depreciation values, with the majority using historical values in different variations.

The lifetime of a typical network asset ranges from 20 to 50 years and the majority of NRAs use the individual depreciation rate for each type of asset. However, in some regulatory frameworks the average rate for all companies and all assets is applied.

As with RAB valuation, the depreciation of assets can be based on historic values, re-evaluated values, or on a mixture of these two methods. The vast majority of regulators allow depreciation of tangible and intangible assets valued on the same basis as the RAB in their regulation, hence, clear correlation between these values can be observed.

7 Incentives and improvements

Incentives are one of the central elements of the regulatory regimes in European countries. Due to the absence of a competitive environment for network operators, regulation has been introduced. Instead of defining all the working processes of the regulated network operators, most regulatory regimes only constitute a certain framework that aims to give incentives to network operators in a certain direction. The next subchapter and the corresponding tables in Annex 4 give an overview of the established incentives.

At the end of this chapter, the trending topics and regulatory improvements that are currently planned or implemented are highlighted.

7.1 Description of the incentives established

Generally speaking, the installation of incentive elements in the national regulatory regimes are assessed as one main element. The questionnaire reveals various installed incentives. For ECRB members, enhancing cost efficiency in operational costs is the most common objective. This might be the most important reason to integrate an incentive element in the regulatory regime, independent of the network level or energy sector.

For CEER members, different objectives besides the enhancement of cost efficiency in operational costs lead to the installation of incentives. At the electricity TSO level, incentives that improve the interconnection between separate countries play an important role.

Furthermore, for both TSO sectors incentives for a better quality and security of supply are installed. Finland, as an example for electricity TSO incentive regulation, has established a quality incentive. The quality incentive is based on a quality bonus method in which rewards and sanctions are defined on fixed steps, and where undelivered energy is used as a quality indicator. Annual undelivered energy is benchmarked against the TSO’s reference level, which is determined by undelivered energy over eight years. The target level and upper and lower quarters determining rewards and/or sanctions are derived from the reference level.

At the electricity DSO level, there are some incentives established for the integration of renewable distributed generation and for the installation and operation of smart grids and smart meters.

Some countries also have individual incentives established in their regulatory regimes. For example, the Spanish regulatory regime at the electricity TSO level includes incentives to not exceed investments eligible for remuneration, incentives to promote adequate economic and financial capacity, suitable capitalisation and a sustainable debt structure, and incentives to extend the useful remuneration lifetime of assets in order to avoid incurring unnecessary investment costs in the electricity system.

At the electricity DSO level, again Spain is one of the countries that has implemented several additional incentives such as an investment control incentive, a financial prudence incentive, an asset lifetime extension incentive and innovation support.

At the gas DSO level, the integration of smart metering and the enhancement of cost efficiency for operational costs and investments seem to be important. The pace of technological change has intensified in recent years. Therefore, these changes are taken into account at this network level.

Finally, Ireland can be mentioned as a country with individual incentives at the gas DSO level. It has established incentives for building new connections, better customer performance, reducing shrinkage against target values and incentives for controllable OPEX and CAPEX.

Concerning examples of ECRB members, the Albanian and Georgian regulatory regimes can be mentioned. Both regimes include incentives for network stability and market liquidity at the electricity TSO level, and for research and development at the electricity DSO level.

In the gas sector, Albania and Georgia include incentives for the availability of capacity, security of supply and environmental aspects at the TSO level, and incentives for density of customer connections at the DSO level.

7.2 If there are no incentives established

Several NRAs are planning to implement different incentives in their regulatory regime to react to the changes occurring in energy markets.

In the gas TSO sector, Croatia will review the overall tariff setting regulation framework for its third RP (2022-26). Other countries are considering introducing new incentives, however none of them mentioned concrete contents.

7.3 Trending topics and regulatory improvements

The current trending topics that the network operators and the NRAs must deal with are a mixture of general tasks and new tasks and strategies, caused by changes in energy markets and climate change.

Many CEER members at the electricity and gas TSO level mention new interconnection points as current topics. Another important role for the future might be the installation and operation of data hubs in some cases, related to the increasing usage of smart meter and smart grids.

Due to the energy transition, NRAs have to deal with new tasks such as the integration of renewable energies e. g. wind, solar and biogas, and the necessary investments in new lines, pipes and new technology. Here, the right adjustments and the implementation of incentives are needed to prepare the networks for their new and/or changed tasks.

There are also different trending topics for ECRB members. For the electricity sector, the security of supply and the integration of renewable energy seem to be important. In the gas sector, the development of interconnections between countries and of distribution networks were mentioned as upcoming projects.

8 Conclusions

This CEER report analysed different regulatory systems of electricity and gas networks of CEER members and five ECRB members. It provides a general overview of the regulatory practices in place, the calculation of an RoR, the determination of the RAB and the depreciation of assets in different regulatory systems. All these components give an impression of the conditions for possible investments in electricity and gas networks in Europe.

It is not the intention of this report to paint a complete picture of the existing regulatory framework. For example, the costs of OPEX and their treatment within the regulatory systems are not considered in this report. Furthermore, other important factors that are difficult to measure (such as the stability of the regulatory framework or regulatory processes) are not addressed in this report, although they play a key role in the decisions of investors.

When interpreting the figures that are used as the background for the report's content and that are presented in the tables of Annex 4 accompanying this report, the regulatory framework must be considered as a whole, as singling out selected parameters would distort the overall picture. Nevertheless, this report provides detailed information about the regulatory framework and indirect information about the investment conditions in each country, offering helpful insights.

The report shows that different countries have different characteristics in their respective regulatory systems. But there are also many parallels between the regulatory regimes that can be identified (as seen in chapter 2).

For the method of asset valuation, the WACC is the preferred method by many NRAs. Whereas the real WACC is used for profitability calculations for re-evaluated assets, the nominal WACC is used for calculating historical values of assets.

The RAB can be comprised of several components, including fixed assets, working capital or construction in progress. There is thus some variation amongst NRAs. According to the survey data, almost all NRAs include fixed assets in the RAB. In contrast, with respect to working capital, more than half of NRAs do not include working capital in the RAB, or use a derived notion of that working capital, depending on whether the electricity or gas system operator is considered. The "construction in progress" component gives the same result as working capital. Fewer than half of the NRAs surveyed include assets under construction in the RAB.

The RAB value is usually linked with depreciation, depending on the NRA. In gas and electricity regulation, straight-line depreciation is applied by most NRAs. The surveyed NRAs use different depreciation values, with the majority using the historical values in different variations. The lifetime of the typical network asset ranges from 20 to 50 years and the majority of the NRAs use an individual depreciation ratio for each type of asset.

For a deeper analysis of investment conditions, it would be useful to take a closer look at other parameters such as costs per unit, share of CAPEX, TOTEX or the consideration of total costs.

Finally, the developments of the energy networks in Europe should regularly be closely analysed in the future due to changes caused by the energy transition. The switch from conventional to renewable energy sources, a growing cooperation between (and inside) European energy networks, and the integration of smart elements into the networks can be seen as the next challenges for network operators, but also for the national authorities.

Annex 1 – Lists of abbreviations

General abbreviations

Term	Definition
ACM	Authority for Consumers and Markets (Netherlands)
ANRE	Agency for Energy Regulation (Moldova)
ANRE	National Regulatory Authority for Energy (Romania)
ARERA	Italian Regulatory Authority for Energy, Networks and Environment
BNetzA	Bundesnetzagentur (Germany)
bp	Basis point
CEER	Council of European Energy Regulators
CAPEX	Capital expenditure
CAPM	Capital asset pricing model
CBA	Cost-benefit analysis
CDS	Credit default swaps
CNMC	Comision Nacional de los Mercados y la Competencia (Spain)
CPI	Consumer price index
CRE	Commission de Régulation de l'Énergie (France)
CREG	Belgian Federal Commission for Electricity and Gas Regulation
CRU	Commission for Regulation of Utilities (Ireland)
DEA	Data envelopment analysis
DSO	Distribution system operator
DUR	Danish Utility Regulator
ECA	Estonian Competition Authority
ECRB	Energy Community Regulatory Board
Ei	Swedish Energy Markets Inspectorate
ERC	Energy and Water Services Regulatory Commission of Republic of North Macedonia
ERE	Albanian Energy Regulatory Authority
ERO	Energy Regulatory Office (Kosovo)
ERSE	Entidade Reguladora dos Serviços Energéticos (Portugal)
ERÚ	Energy Regulatory Office (Czech Republic)
GNERC	Georgian National Energy and Water Supply Regulatory Commission
HERA	Croatian Energy Regulatory Agency
HV	High voltage
IFRS	International Financial Reporting Standards
ILR	Institut Luxembourgeois de Régulation (Luxembourg)
IRS	Interest rate swaps
ISO	Independent system operator
ITC	Inter-TSO compensation (mechanism)
ITO	Independent transmission operator

Term	Definition
KOPEX	Realised controllable operational costs
LNG	Liquefied natural gas
LV	Low voltage
MEKH	Hungarian Energy and Public Utility Regulatory Authority
MV	Medium voltage
NRA	National regulatory authority
NBV	Net book value
NC TAR	Network code on harmonised transmission tariff structures
NERC	National Energy Regulatory Council (Lithuania)
NEURC	National Energy and Utilities Regulatory Commission (Ukraine)
NOWC	Net operating working capital
NPV	Net present value
NVE-RME	Norwegian Water Resources and Energy Directorate
OPEX	Operational expenditure
pa	Per annum
PSO	Public special obligation
PUC	Public Utilities Commission (Latvia)
RAB	Regulated asset base
RAE	Regulatory Authority for Energy (Greece)
REGAGEN	Energy and Water Regulatory Agency (Montenegro)
ROI	Return on investment
RoR	Rate of return
RP	Regulatory period
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SFA	Stochastic frontier analysis
SKOPEX	Reasonable controllable operative costs
TAO	Transmission asset owner
TOTEX	Total expenditure
TSO	Transmission system operator
TYNDP	Ten-year network development plan
URE	Urząd Regulacji Energetyki (Poland)
URSO	Regulatory Office for Network Industries (Slovakia)
VHV	Very high voltage
WACC	Weighted average cost of capital

Annex 2 – List of questions

3.1 Regulatory system in place

What regulatory system is in place?

3.2 Effiency requirements

Is an X-factor/efficiency requirement applied on the CAPEX?
Is an X-factor/efficiency requirement applied on the OPEX?
Is there a minimum efficiency score, which is granted at least to every network operator? If yes, where is this limit?
How long is the time span granted to the operators for eliminating individual inefficiencies?
How is the way of eliminaton of inefficiencies determined? Please give the used formula or a description.

3.3 General overview of system operators

Is there only one System Operator (SO) in the country or are there more than one? (Please, name them)
How is the function of system operation implemented at your TSOs? (Please, select from the list)
Which unbundling model for system operation do you have? (Please, select from the list)
Which are the duties of the SO? (Please, choose the correct ones from the list and, if applicable, add other duties not included)

3.3.1 Regulatory system in place and efficiency requirements

Does the system operation activity have a different remuneration framework from the transmission activity?
What regulatory system is in place for SO?
Is the cost of any function of the SO recovered apart from the general recovery framework, through specific regulated prices? (meaning that, if it was not excluded from the general recovery framework, it would be recovered twice)
Is an X-factor/efficiency requirement applied on the CAPEX? (If yes, please describe your approach)
Is an X-factor/efficiency requirement applied on the OPEX? (If yes, please describe your approach)
Is an X-factor/efficiency requirement applied on the TOTEX? (If yes, please describe your approach)
Is there an annual remuneration revision methodology implemented? (If yes, please give details about it)
Since when has this regulatory system been applied?
What is the length of the SO regulatory period?
As SO is a continuous evolving activity: Can revenues for new tasks be recognized within the regulatory period?

3.3.2 Operational expenses (OPEX)

Which items are included in the operational expenses?
Are there any operational expenses of the SO excluded from the allowed revenue?
What source is used to obtain the items that integrate the OPEX? (e.g. financial accounts, regulatory accounts, etc.)
As the SO is an "asset light utility", does this have any particular consideration in the revenues framework? Like, for example, to allow a margin over allowed OPEX? (If yes, please give details about its quantity and if it is pre-tax or post-tax)
Are revenues reviewed based on inflation or any price index?

3.3.3 Capital expenses (CAPEX)

Which is the rate-of-return for SO capex investments? Is it the same as the one used for the transmission activity? (In case it is different, please explain the differences)
Which methodology is used to calculate the rate-of-return?
Are there any investment controls, like ex ante approval of investment plans?
How are the investments remunerated? In case there is a RAB in place, which components are included in it and how often is it updated?

3.3.4 Incentives and penalties

Are there any incentives/penalties included in the methodology derived from the fulfilment of the SO functions? (If yes, please detail them and especify to which SO function they are related)

Is there any cap established for the incentives/penalties? (e.g. maximum of 5% and minimum of -5% of the total revenue) (If yes, please give details about it)

3.3.5 Tariffs

How are the allowed revenues for the SO collected? (e.g. through an specific term of the tariff, third-party access tariffs, etc.)

3.3.6 Allowed revenue

What happens if there are deviations between the SO collected revenues and the SO allowed revenue?

4.1 Method used for Calculation of the Rate of Return

WACC nominal or real (pre-tax, post-tax, Vanilla)?

4.2 Year of rate of return estimation and length of regulatory period

4.3.1.1 Evaluating risk free rates

Years to maturity

4.3.1.2 Values of nominal and real risk free rates

Risk free rate (nominal or real)?

4.3.2.1 Evaluating debt premiums

Debt premium (value, year)
Short description of evaluation

4.3.2.2 Real cost of debt in tariff calculation

Real risk free rate (value, year)
Debt premium (value, year)
Real cost of debt (value, year)

4.3.3.1 Evaluating market risk premiums

Market risk premiums (value, year)
Short description of evaluation

4.3.4.1 Evaluating the gearing ratio

Gearing ratio (value, year, formula)
Short description of evaluation

4.3.5.1 Evaluating the tax value

Corporate Taxes (value, year)
Short description of evaluation

4.3.6.1 Evaluating the asset and equity beta

Evaluation of asset and equity beta
Short description of evaluation

4.3.6.2 Betas in the regulation

Equity beta (value, year)
Asset beta aß = eß/[1+(1-t)*(D/E)] and aß = eß/[1+D/E]

5.1 Components of the RAB

5.1.1 Tariff calculation (is 100% of RAB used in tariff calculation?)
5.1.2 Fixed assets (are fixed assets taken into RAB?)
5.1.3 Working capital (is working capital taken into RAB?)

5.1.4 Assets under construction

Are assets under construction taken into RAB?

5.1.5 Contributions from third parties

Are contributions from the third parties taken into the RAB? If yes, which ones and what is the approach?

5.1.6 Leased assets

Are leased assets included into the RAB? (according to the IFRS)

5.2.1 Historical costs

Is the RAB exclusively based on historical value of assets?

5.2.2 Re-evaluation of assets

Is the RAB exclusively based on re-evaluated assets? (If previous answer was 'yes' please describe in detail how the re-evaluation of assets influenced the level of RAB)

5.2.3 Mix of historical and re-evaluated assets

Which methodology was applied?
If Regulated Asset Base (RAB) is evaluated ac-cording to market value or replacement cost, which sources are used? (e.g.cost
When was the re-evaluation done (year)**?**
Was the re-evaluation done for all companies in the same manner and at the same time?

5.3 Difference between the RAB defined on net book values and the RAB based on re-evaluated asset base

What's the difference (in %) between the RAB defined on net book values according to national GAAP (or IFRS) and the RAB based on re-evaluated asset base? (Please use net book values as the basis for your calculation).

5.4 Monetary value of regulated assets on historical cost basis and monetary value of re-evaluated assets

If possible, please provide the monetary value of regulated assets (aggregated for all companies) on historical cost basis.
If possible, please provide the monetary value of re-evaluated regulated assets (aggregated for all companies).

5.5 RAB adjustment

Is the RAB adjusted during the regulatory period?
IF RAB is adjusted during the regulatory period please indicate how often (e.g. annually).
Does the adjustment affect net book values by accounting for new investements and/or depreciation? Please explain your approach.
Is the RAB adjusted within regulatory period by any kind of escalation index?

6.1 Depreciations

How is the depreciation calculated?
What is the depreciation ratio for typical network assets?
Which values of the depreciation are allowed into the regulation?

7.1 Description of the incentives established

For which challenges are the incentives established? (Please, select them from the list and, if necessary, add others not included)
Does the remuneration for the incentives have a cap and a floor? (e.g. maximum of 5% and minimum of -5% of the total revenue)
What remuneration mechanism is it used for integrating each incentive? (Please, give details about it)
Have any drawback been detected in the methodology implemented? (If yes, please give details about the problem and the suggested solutions, if any)

7.2 If there are no incentives established

Are you planning to incorporate any incentive? (if yes, please describe the type of incentive, when it is expected to be implemented and give some details about it)

7.3 Trending topics and regulation improvements

Please, outline which are the trending topics in your country (e.g. integration of DER, smart grids, security of supply, etc.)
How are they implemented within the regulatory framework? (e.g. specific incentive, WACC adder, legislative change, non-technological neutral framework, capacity markets, etc.)
Stage (e.g. under review, under discussion, public consultation, in force, etc.)

Annex 3 – About CEER

The Council of European Energy Regulators (CEER) is the voice of Europe's national energy regulators. CEER's Members and Observers comprise 39 national energy regulatory authorities (NRAs) from across Europe.

CEER is legally established as a not-for-profit association under Belgian law, with a small Secretariat based in Brussels to assist the organisation.

CEER supports its NRA members/observers in their responsibilities, sharing experience and developing regulatory capacity and best practices. It does so by facilitating expert working group meetings, hosting workshops and events, supporting the development and publication of regulatory papers, and through an in-house Training Academy. Through CEER, European NRAs cooperate and develop common position papers, advice and forward-thinking recommendations to improve the electricity and gas markets for the benefit of consumers and businesses.

In terms of policy, CEER actively promotes an investment friendly, harmonised regulatory environment and the consistent application of existing EU legislation. A key objective of CEER is to facilitate the creation of a single, competitive, efficient and sustainable Internal Energy Market in Europe that works in the consumer interest.

Specifically, CEER deals with a range of energy regulatory issues including wholesale and retail markets, consumer issues, distribution networks, smart grids, flexibility, sustainability, and international cooperation.

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More information is available at www.ceer.eu.