Report on Regulatory Frameworks for European Energy Networks 2024

Annex 5

Case studies of single regulatory regimes

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Annex 5.2 Case study – Austria

The present section constitutes a short case study about the regulatory practice in Austria. It describes the regime for electricity distribution system operators (DSOs) during the fifth regulatory period (RP)[1].

Grid charges[2] can be based on annual cost audits. However, this means a lot of effort for both the regulated companies and the regulator. Alternatively, regular but not annual cost audits can take place under a stable, long-term model. The Austrian National Regulatory Authority E-Control prefers the latter approach. In doing so, it minimises the direct costs of regulation. Cost audits are undertaken in intervals of several years. Between the audits, operators' costs and the derived grid charges evolve in accordance with a regulatory formula. The formula uses parameters that are known in advance.

The length of the period from one cost audit to the next constitutes a key factor in regulatory systems. To define this regulatory period, an authority should consider several effects. By temporarily decoupling allowed costs from actual costs, incentives for productive efficiency are created. The strength of the incentives rises with the length of the decoupling. Therefore, long regulatory periods seem attractive. However, any decoupling mechanism tolerates allocative inefficiency. By implication, the intervals of cost audits should be well designed: If regulatory periods are too short, the incentive for productive efficiency might not be strong enough. Too long periods, however, might induce consumers to overestimate and companies to underestimate the potential for cost reduction. This danger grows with the period's length. In Austria, a five-year period proved to balance the incentives.

A successful decoupling requires audited cost data. Strict auditing principles must apply in particular when reviewing the internal cost allocation of the regulated companies (overheads, payments for internal services). Moreover, several checks examine if costs were reasonable in both their grounds and their amount. On top of that, the audited costs are adjusted and corrected. This procedure precludes that operators strategically shift cost items (e.g., in the areas of maintenance, staff or similar). The verified costs enter a benchmarking exercise. Identified (relative) inefficiencies define the allowed costs during the regulatory period. Finally, these allowed costs are transformed into allowed revenues.

In general, the regulatory authority bases all its assessments on the most recent available figures. However, the conducted cost audits require significant time and effort, both for the regulatory authority and for the companies. In addition, regulated companies require sufficient time to submit comments on changes in the regulatory regime and on their allowed costs. Moreover, the accounts of all companies must have been approved before the benchmarking can take place. Therefore, the regulatory authority bases its assessment on the second-to-last year of financial data available.

[1] The present section is based on the document "Regulierungssystematik für die fünfte Regulierungsperiode der Stromverteilernetzbetreiber 1. Jänner 2024 - 31. Dezember 2028". For further details and all references, please see https://www.e-control.at/marktteilnehmer/strom/netzentgelte/entgeltermittlungsverfahren.
[2] This section uses the terms 'tariffs', 'charges' and 'rates' synonymously.

Example

The fifth regulatory period started in 2024. The regulatory authority did not audit the costs of the most recent full business year (2022), but rather those of the previous year (2021).

Suppose that a specific DSO's allowed cost base for 2021 (audit year) amounts to €600,000 of operational expenditure (OPEX) and €100,000 of non-controllable costs. To begin with, the regulatory authority calculates the allowed baseline OPEX[3]. In doing so, the network operator price index (NPI) and the general productivity growth rate (X_{gen}) of 0.4% p.a. are applied. The NPI reflects exogenous price changes, while the X_{gen} accounts for sector-specific productivity growth.

$$Baseline\ OPEX\ 2023 = (600{,}000 - 100{,}000) * (1 + 4.990\%) * (1 + 6.900\%) * (1 - 0.400\%)^2$$
$$= 557{,}160$$

Starting from the baseline OPEX 2023, the regulatory authority considers the company's overall efficiency target (ZV). This target consists of the general productivity growth rate (X_{gen}) and the individual efficiency target (X_{ind}). The individual efficiency target is directly obtained from each company's efficiency score (ES_{2024}), considering a realisation period of 7.5 years.

$$\mathrm{ZV} = 1 - \left(1 - X_{gen}\right) * (1 - X_{ind}) = 1 - (1 - 0.400\%) * \sqrt[7.5]{\mathrm{ES}_{2024}}$$

A company's efficiency score is derived from a benchmarking procedure. The procedure comprises two methods (data envelopment analysis DEA and modified ordinary least squares MOLS), two cost bases as inputs (financial accounting and standardised total expenditures TOTEX), a set of outputs derived from an engineering economic analysis and cost driver analysis, and an efficiency floor of 80%. The following relationship between efficiency scores and overall targets applies.

Efficiency score	Overall annual target
80%	3.320%
85%	2.535%
90%	1.789%
95%	1.079%
100%	0.400%

Efficiency scores and overall targets (Austria)

Assuming an efficiency score of 90% and inflation forecasts of 4.0% for 2024 and 2.7% for 2025, the OPEX[4] during the RP is calculated as follows:

$$OPEX\ 2024 = 569{,}080 = 557{,}160 * (1 + 4.000\%) * (1 - 1.789\%)$$
$$OPEX\ 2025 = 573{,}989 = 569{,}080 * (1 + 2.700\%) * (1 - 1.789\%)$$

Actual non-controllable costs enter the allowed costs without being subject to any efficiency targets.

[3] $Baseline\ OPEX_{2023}^{Allowed} = (OPEX_{2021} - non\text{-}controllable\ costs_{2021}) * \prod_{t=2022}^{2023}\left[(1 + \Delta NPI_t) * \left(1 - X_{gen_{5th\ period}}\right)\right]$.

[4] $OPEX_t^{Basis\ for\ charges} = OPEX_{t-1} * (1 + \Delta NPI_t) * (1 - ZV_{5th\ period})$.

The present incentive regulation system implies that the allowed OPEX is decoupled and may thereby diverge from actual OPEX. A new audit, based on which allowed OPEX is determined anew, normally only occurs before the outset of a new RP. However, the scope of the operators' mandate (number of consumers to be connected, etc.) evolves during a RP. The regulatory authority uses so-called expansion factors to account for such developments. Therefore, regulated companies can be sure that resulting OPEX will be covered. However, expansion factors are not designed to track all cost increases during a RP. After all, incentive regulation is meant to temporarily decouple allowed costs from current developments.

Capital expenditure (CAPEX) is tracked and compensated as it arises. Roughly speaking, CAPEX consists of depreciation and the cost of capital (opportunity cost) for the regulatory asset base (RAB). To incentivise efficiency, an individual weighted average cost of capital (WACC) applies.

The regulatory authority identifies the median efficiency score of all benchmarked companies, whereby the efficiency floor of 80% is not taken into account. A company with an efficiency score that corresponds to the median efficiency score of all DSOs that are part of the benchmark receives a nominal WACC of 4.16% (before taxation) on the depreciated book values of its RAB up to 2021. If a company is more/less efficient than the median, its WACC is adjusted by a maximum of ± 0.93%. To ensure that the RAB of Austrian electricity DSOs generates an average return of 4.16%, the regulatory authority offsets above-average and below-average efficiencies against each other.

Suppose that the median efficiency is 95% and the minimum efficiency score is 75%. For a grid operator with an efficiency score of 90%, the following individual WACC applies.

$$Individual\ WACC = 4.16\% - \frac{0.93\%}{(95\% - 75\%)} * (95\% - 90\%) = 3.93\%.$$

The regulatory authority then connects each company's individual WACC with the depreciated book value of its RAB activated up to 2021. A uniform WACC of 4.16% applies to all investments (minus customer prepayments) made in 2022 and 2023 ($WACC_{LegacyRAB}$). This uniform rate was chosen because there was no efficiency benchmark after the audit year. Until the next benchmark, the regulatory authority has to assume the same (average) efficiency for all investments.

In order to enable investments despite of the volatile state of the financial market, different WACCs for new investments are applied within the fifth regulatory period. While the $WACC_{LegacyRAB}$ of 4.16% for old assets was determined based on a multi-year average in accordance with the calculation method used in previous periods, the WACC for new investments is determined based on current capital market data. Thus, for the first time there is a separate consideration of old and new assets regarding the WACC to take greater account of current developments on the financial market. The WACC for new investments is updated annually (based on a 12-month average with a reporting date of August 31), whereby the update only relates to the interest rate for cost of debt and the risk-free rate in calculation of the equity interest rate. For new investments made in 2024, a WACC of 6.33% is applied.

Depreciation is passed through without any mark-downs or other changes. This system minimises the risk exposure for system operators by guaranteeing that their investments are recovered through the grid charges.

Suppose that the operator with an efficiency score of 90% reports depreciation of €250,000 in 2023. With respect to the 2023 book values, its RAB until 2021 is €5,000,000 and its investments from 2022 and 2023 amount to €375,000. By implication, the following CAPEX are included in the 2025 grid charges:

$$CAPEX\ 2025 = 462{,}100 = 250{,}000 + 5{,}000{,}000 * 3.93\% + 375{,}000 * 4.16\%.$$ [5]

Using the most recent available data (financial accounting data and technical data) creates a gap (lag of t-2). The two-year time lag could result in rates that are too low for companies whose mandates are steadily growing. Vice versa, it could cause rates that are too high for customers of companies whose mandates are steadily shrinking. To protect both sides from these effects, the regulatory authority corrects for the difference between the t-2 data and the current data once the latter becomes available.

When calculating the system charges, the regulatory authority relies on the most recent available data on capacity and the volume transported. However, the companies' revenues are calculated by multiplying these rates by the volumes actually transported in the respective year. This results in a difference between the revenue assumptions that the regulatory authority bases the ordinance on the actual revenues generated. The difference can be positive or negative. It can lead to either excessive or insufficient cost recovery for the companies. The regulatory system therefore includes a regulatory account. The regulatory account ensures that any differences are balanced in following cost decisions.

[5] $Direct\ CAPEX\ compensation_{2027} = Depreciation_{2025} + RAB^{2025}_{Assets\ up\ to\ 2021} * WACC\ individual + RAB^{2025}_{Assets\ from\ 2022} * 4.16\% + RAB^{2025}_{Assets\ from\ 2024} * 6.33\%.$
Note: WACC of 6.33% accounts only for new investments in 2024 and will be adjusted each year.

Annex 5.8 Case study – Estonia

This section describes the calculation of electricity network charges of Estonian transmission system operators (TSOs) and DSOs.

Background information

According to subsection 74 (1) of the Electricity Market Act[6] (referred to as the 'Act' in this section), the network charge established by a network operator becomes effective on the date determined by the network operator after its publication in at least one daily newspaper of national circulation, provided that at least 90 days have passed since its publication. This provision does not apply to the connection charge, the charge for the amendment of conditions and the transmission charge for the transit of electricity.

In accordance with subsection 93 (7) of the Act, the Competition Authority decides on an application for approval filed with it in accordance with the Act within 90 days following the filing of the application. When processing a particularly complex application or an application that involves a considerable amount of work, the Competition Authority may extend this time limit to 180 days. The person who filed the application must be notified of the extension of the time limit before expiry of the initial time limit.

Subsection 93 (8) of the Act provides that the running of the time limit provided in subsection 93 of this section is suspended until such time as the information that the Competition Authority has demanded, and that is necessary for deciding on the application, is presented to the Authority.

Setting of network charges

Clauses 71 (1) 3) to 6) of the Act provide that the charges payable for network services provided by a network operator are as follows:

3) a charge for ensuring the possibility to use a network connection;
4) a charge for the transmission of electricity;
5) charges for any additional services directly related to network services; and
6) charges for reactive power supplied to the network and acquired from the network.

According to subsections 71 (2) and (3) of the Act, the network operator establishes network charges in its service area in accordance with the Act and the legislation enacted under it. The criteria adopted by the network operator as the basis for establishing network charges must be transparent and comply with the principle of equal treatment.

According to subsection 71 (5) of the Act, the rate of network charges must be established in such a way that they ensure, on a consistent basis:

1) coverage of the necessary variable and operating costs;
2) the making of investments to meet operational and development obligations;
3) compliance with environmental requirements;
4) compliance with quality and safety requirements; and
5) a justified return on the capital invested by the undertaking.

Subsection 71 (5^1) of the Act specifies that the justified return mentioned in clause 71 (5) 5)

[6] Electricity Market Act 2003. Retrieved from: https://www.riigiteataja.ee/en/eli/528082014005/consolide#:~:text=This%20Act%20prescribes%20the%20principles,a%20balanced%20manner%2C%20in%20an.

of the Act is calculated based on the capital invested by the undertaking and the price of weighted average capital.

In accordance with subsection 71 (6) of the Act, the network operator sets the transmission charge in such a way that it guarantees, to market participants who have paid a connection charge and a charge for use of the network connection, the possibility of transmitting electricity throughout the entire system.

According to subsection 71 (8) of the Act, the network charges of the transmission network operator must be sufficient to allow the operator to administer and, with a view to meeting the obligations imposed by law, to develop the data exchange platform mentioned in section 42^1 of the Act.

In accordance with subsection 72 (1) of the Act, within the service area of a network operator, the transmission charge and the charge for the use of a network connection do not depend on the location of the market participant.

Subsections 72 (2) and (3) of the Act set out that network operators have the right to distinguish the network charge for a network service from other conditions for the provision of the network service. These are in relation to the level of voltage and security of supply, and to distinguish categories of market participants and apply different network charges and other conditions for the provision of network services for such categories in accordance with other provisions of the Act.

Pursuant to subsection 72 (7) of the Act, the price does not include the following expense items:

1) expenses related to claims unlikely to be paid;
2) sponsorships, gifts and donations;
3) costs that are not connected to the provision of the network service;
4) any fines or late charges imposed on the undertaking under applicable legislation;
5) financial charges as a separate cost component, which are taken into account when calculating the price of weighted average capital; and
6) other costs that are not required in order to perform the obligations imposed on the undertaking by legislation.

In accordance with subsection 72 (8) of the Act, the costs to be included in the price must be justified and reflect a cost-effectiveness-based approach and must make it possible for the undertaking to perform the obligations provided for by the legislation.

Pursuant to subsections 72 (9), (10) and (14) of the Act, only the fixed assets required for the provision of the network service are taken into account when calculating the depreciation of fixed assets to be included in the price. Calculation of the depreciation of fixed assets is based on the value of the fixed assets required for the provision of the network service and of the standard depreciation rate corresponding to the useful technical life of those assets. Fixed assets are deemed not to include:

1) long-term financial investments;
2) intangible assets, except software licences and rights of use of property;
3) fixed assets acquired in the framework of unrecoverable assistance and targeted financing;
4) fixed assets acquired for connection fees;
5) fixed assets which the undertaking does not use for the purpose of providing the network service.

The accounting of the value of fixed assets is performed on a continuous basis and continues through any change of undertaking or of asset ownership form.

Subsection 72 (13) of the Act provides that in the case of costs to be included in the price, justified investments and outlays that have been made for realising energy savings at the final customer level are taken into account. This is in the amount of up to one percent of the average sales income for the last three calendar years, provided the following conditions have been met:

1) as a result of the investments and outlays, energy savings are realised at the final consumer within the meaning of clause 21 of section 3 the Energy Sector Organisation Act;
2) such energy savings have previously been evaluated in accordance with the regulation enacted under subsection 18 (1) of the Energy Sector Organisation Act; and
3) by 1 April each year, in accordance with the regulation enacted under subsection 18 (1) of the Energy Sector Organisation Act, the undertaking assesses the energy savings realised as a result of the actions performed during the last three calendar years and presents a report regarding that assessment to the energy savings coordinator within the meaning of the Energy Sector Organisation Act.

In price proceedings, costs are divided by the Competition Authority as follows:

- Variable costs;
- Operating costs; and
- Depreciation of fixed assets.

To calculate permissible sales revenue ($R_{permissible}$), on the basis of justified costs and justified return (pursuant to subsection 71 (5^1) of the Act), the Competition Authority uses the following formula:

$$R_{permissable} = VC + OC + DFA + JR + SF$$, where:

- $R_{permissable}$ is the permissible sales revenue;
- VC is the variable costs;
- OC is the operating costs;
- DFA is the depreciation of fixed assets; and
- JR is the justified return
- $SF - supervision\ fee\ (0{,}2\%\ permissible\ sales\ revenue)$.

Price components	Unit	Regulation period
Sales quantity (SQ)	MWh	37,590
Variable costs (VC)	thousand €	100.08
Operating costs (OC)	thousand €	47.47
Depreciation of fixed assets (DFA)	thousand €	45.00
Justified return (JR)	thousand €	54.88
Allowed sales revenue	thousand €	247,43
Supervision fee	thousand €	0,49
Allowed sales revenue with SF	thousand €	247,92

Example to determination of permissible sales revenue (Estonia)

Specific costs and revenues are taken into account in the case of transmission network operators, such as the costs and revenues of the inter-transmission system operator compensation (ITC) mechanism and counter-trade cost and revenues. The accounting of such costs and revenues is consistent.

Justified return

Subsection 71 (5) of the Act sets out that the rate of network charges must be established so that they consistently ensure a justified return on the capital invested by the undertaking.

Pursuant to subsection 71 (5[1]) of the Act, the justified return mentioned in clause 71 (5) 5) of the Act is calculated based on the capital invested by the undertaking and the weighted average capital.

Pursuant to subsection 72 (11) of the Act, the justified return is calculated based on the principle according to which the value of the fixed assets required for the provision of the network service, plus the operating capital component, is multiplied by the price of weighted average capital.

Pursuant to subsection 72 (12) of the Act, the rate of the component of the operating capital referred to in subsection 72 (11) of the Act amounts to five percent of the average turnover for the last three calendar years. Where necessary, additional analysis is performed to determine the operating capital component.

Justified return is calculated on the basis of the value of regulated assets and the justified rate of return using the following formula:

$$JR = RV * WACC, \text{ where:}$$

- $JR$is the justified return;
- RV is the value of regulated assets; and
- $WACC$ is the weighted average cost of capital.

Justified return is calculated on the basis of the value of the regulated assets of the principal activity (including the value of non-depreciable fixed assets, which in the principal activity is the value of the land used) and WACC, i.e. based on the justified rate of return (RoR).

The RoR of monopoly undertakings has to be limited in line with subsection 71 (5) of the Act, i.e. network charges have to be established in such a way that they ensure a justified return on the capital invested by the undertaking. Consumers of monopoly undertakings do not have the opportunity of purchasing goods or services from competing undertakings. As a result, Europe as well as the rest of the world has established generally accepted principles of price regulation, whose purpose includes limiting the profitability of the undertakings described above. Without limitations on profitability, the undertaking that dominates the market is able to earn monopoly profit. Without the intervention of a regulator (in this case, the Competition Authority), consumers would have to pay for the potential monopoly profit of the dominating undertaking, as they would not have the choice of an alternative service provider.

The WACC is calculated as follows:

$$WACC = Ce * \left(\frac{EC}{DC+EC}\right) + Cd * \left(\frac{DC}{DC+EC}\right), \text{ where:}$$

- Ce is the price of equity capital (%);
- EC is the ratio of equity capital (%);
- DC is the ratio of debt capital (%); and
- Cd is the price of debt capital (%).

The WACC is calculated by the Competition Authority and published on its website.[7] The published document includes the WACC calculation methodology as well as WACC values of various activities during the year of validity. The values of WACC differ for transmission network operators and distribution network operators.

Justified return	Unit	Regulatory period
The residual value of fixed assets at the start of the RP (FA_0)	Thousand €	98.04
Investments (I)	Thousand €	10.00
Depreciation of fixed assets (DFA)	Thousand €	3.72
The residual value of fixed assets at the end of the RP (FA_1)	Thousand €	104.32
The arithmetic mean turnover of the regulated activity of the last three calendar years	Thousand €	100.00
Operating capital 5% of the net external turnover (OC)	Thousand €	5.00
The value of regulated assets (RV)	Thousand €	106.18
WACC[8]	%	6.27
Justified return	Thousand €	6.66

Example to calculation of justified return (Estonia)

The justified return is calculated as follows:

- $FA_1 = FA_0 + I – DFA = 98.04 + 10.00 – 1.29 =$ €104.32 thousand;
- OC = 100.00 * 0.05 = €5.00 thousand;
- RV = $(FA_0 + FA_1) / 2 + OC = (98.04 + 104.32) / 2 + 5.00 =$ €106.18 thousand; and
- Justified return = WACC * RV = 6.27% * 106.18 = €6.66 thousand.

This section describes shortly the calculation of gas network charges of Estonian transmission system operators (TSOs)

The current natural gas transmission system tariff calculation methodology for the gas TSO was implemented in 2019. The revenue cap approach is characterised by a predictable and stable tariff, business-oriented corporate governance, and greater scope for incentive-based regulatory mechanisms. The revenue cap approach is one of the most common tariff-setting approaches for system operators in Europe. Amendments to the methodology regarding the single natural gas transmission entry-exit system were an important precondition for the launch of the single entry-exit system (connecting Finland, Estonia and Latvia (FinEstLat)).

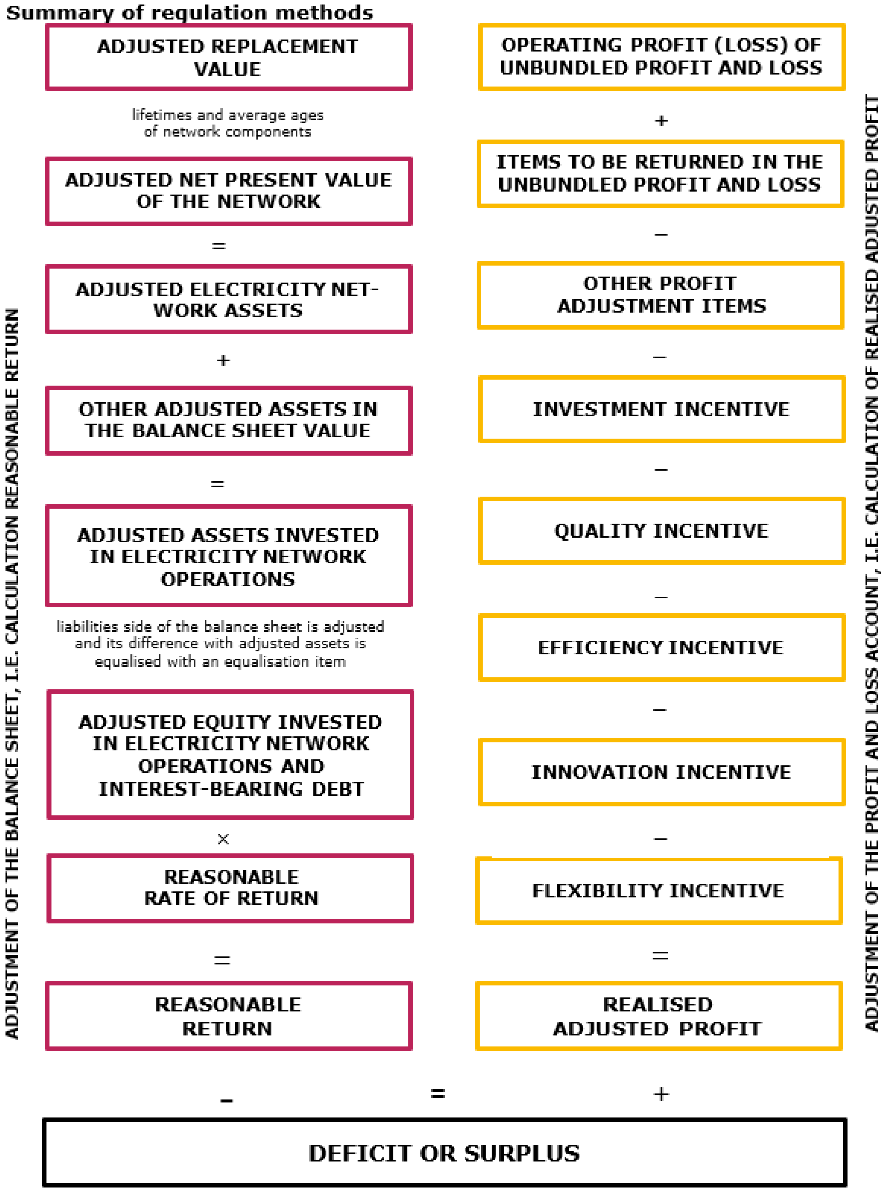
As a result of the establishment of the single natural gas transmission entry-exit system in FinEstLat, no transmission tariffs are applied to natural gas transportation between Finland, Estonia and Latvia from 2020. This means that a tariff is applied only once when the natural gas crosses the border of the single natural gas transmission entry-exit system. Furthermore, the tariff is the same at all entry points of the single natural gas transmission entry-exit system. The establishment of the single natural gas transmission entry-exit system activates the operation of the regional natural gas market, promotes competition in the natural gas market, and facilitates more efficient use of the regional natural gas infrastructure. This in turn results in more competitive natural gas prices and high-quality services, benefiting natural gas users.

[7] See https://www.konkurentsiamet.ee/et.
[8] The WACC used is applicable to distribution network operators in 19.07.2023.

Annex 5.9 Case study – Finland

The following describes a simplified case study example regarding the regulatory regime and methodology setting allowed revenues for electricity distribution operations in Finland for the sixth regulatory period (2024-2027). The regulatory framework and principles applied are explained in more detail in the regulation methods document,[9] which can be found on the Energy Authority's webpage. The Energy Authority applies slightly divergent methodologies when setting the revenue cap for TSOs and DSOs in the natural gas and electricity sectors, however the main principles are the same in every sector.

Energy Authority implemented latest methodology in the beginning of 2024[10] and the described framework is set for regulatory periods (2024-2027 & 2028-2031) even though there are some deviations in the methods between regulatory periods.



Regulation methods for regulatory periods 2024-2027 and 2028-2031

[9] See Regulation methods in the sixth and seventh regulatory period - Electricity distribution network operations.
[10] The vast majority of the electricity DSOs appealed about the regulatory methods to the Finnish market court, hence the regulatory methods are therefore not yet legally valid.

The regulatory framework is twofold: on one hand the capital committed to network operations is reviewed and reasonable return calculated based on it, in turn, the adjusted operating profit of network operations is reviewed with the effect of incentives.

Adjustment of the balance sheet i.e. calculation of reasonable return

Adjustment of the balance sheet is the basis of the calculation of reasonable return, i.e. the revenue cap. The Energy Authority determines reasonable return for each DSO annually, which in turn is dependent on the adjusted assets and capital invested in network operations.

The electricity network forms the greatest individual part of the DSO's assets, i.e. the non-current assets in the unbundled balance sheet. The electricity network value according to the balance sheet is not, however, used when determining the revenue cap, as the value of the network assets is adjusted to correspond with their actual net present value (NPV). Hence, the revenue cap is calculated based on the adjusted NPV of the network, which in turn is determined from the adjusted replacement value of the network.

The adjusted replacement value of the network is obtained by adding together all the network components and multiplying them by component-specific unit prices (according to a pre-determined unit price catalogue). In turn, the adjusted NPV of the network is calculated from the adjusted replacement values of the components by taking into account the lifetime and average age of the components.

The correct and justified adjustment of network assets is linked to the determination of reasonable rate of return. The determination of the so-called frozen replacement value[11] is based on a principle simulating book values, in which the value of investments is determined based on the value valid during the year of acquisition using average unit prices. This is done to ensure that inflation is correctly considered, as a nominal rate of return will be used to determine a reasonable rate of return.

The adjustment of capital invested in network operations is based on the liabilities side of the DSO's unbundled balance sheet. The adjusted capital invested consists of the adjusted equity, adjusted interest-bearing debt, and adjusted non-interest-bearing-debt. An equalisation item is also added to this to balance the assets and liabilities in the adjusted balance sheet and is recorded under equity.

The DSO's revenue cap is calculated by multiplying the adjusted capital invested in the electricity network by the reasonable RoR (nominal WACC %). The DSO receives reasonable return on adjusted equity and interest-bearing debt, but there is no return obtained for non-interest-bearing debt.

Adjustment of the profit and loss account

Adjustment of the profit and loss account is made to determine the DSO's realised adjusted profit. The calculation of realised adjusted profit begins from the operating profit (loss) from the DSO's unbundled profit and loss account. In the calculation of the realised adjusted profit, certain items are returned to the operating profit, of which the most significant is planned

[11] From the beginning of 2024 in line with the new regulatory methodology, the Energy Authority modified the calculation of the network value compared to the previous methodology. So-called frozen replacement value is determined for network assets invested before year 2024 in accordance with the unit price list published as an appendix of the regulatory method document, and this network mass won't be updated or recalculated along with future unit price updates. However, unit prices will be updated every four years for investments made from 2024 onwards. The unit prices for investments made during period 2024-2027 will be determined in 2027 and for investments made during period 2028-2031 will be determined during year 2031.

depreciation in the unbundled profit and loss account. After the returnable items have been added to the operating profit, the reasonable cost of financial assets is deducted as profit adjustment items. The impact of incentives is also deducted from the operating profit. The sum total of the calculation is the realised adjusted profit.

Surplus or deficit of the financial period

Finally, the deficit or surplus of the return for the corresponding year is obtained by deducting the reasonable return from the realised adjusted profit. A positive value resulting from the subtraction means a surplus, and a negative value means a deficit.

At the end of the regulatory period, the DSO's realised adjusted profits from different years are added together and deducted from the sum of reasonable returns from the corresponding years. A surplus from the regulatory period will be compensated back to customers via lower distribution tariffs in the next regulatory period. If the realised adjusted profit during the regulatory period has exceeded the amount of reasonable return by at least 5%, interest shall be payable on the surplus. The interest rate is the average of the reasonable cost of equity for the years of the regulatory period in question.

Incentive mechanisms

Investment incentive

The investment incentive is designed to encourage DSO to make its investments cost-effectively on average and enable DSO to collect reasonable investment costs from end-users. The investment incentive consists of the incentive impact of unit prices and the straight-line depreciation calculated from the network adjusted replacement value. The incentive impact arises from the difference between investments calculated with unit prices and DSO's realised investment costs. When DSO is investing cost-effectively on average, DSO reaps benefits from the adjustment of network assets and similarly, when DSO invests ineffectively, unit prices cut off overheads in the adjustment of network assets.

The incentive impact of the straight-line depreciation arises from the fact that the method allows for the DSO an annual depreciation level based on average adjusted straight-line depreciation on the basis of the lifetimes selected by the DSO. Imputed straight-line depreciations are 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. Together with the net present value, the incentive impact of the straight-line depreciation calculated from the DSO's adjusted replacement value directs the DSO to maintain its network in accordance with the lifetimes it has selected in actual use for as long as possible. This, in turn, leads to proactive maintenance and longer component lifecycles.

When the lifetime has been correctly selected and the DSO has invested on average at a reasonable cost level in line with unit prices, the straight-line depreciation of the investment incentive covers on average all necessary component investment costs during their lifetimes. In other words, the investment incentive enables full depreciation of network components. Straight-line depreciation is permitted for components that have exceeded their lifetime in the same relation as the depreciated cost of the components that have correspondingly been demolished before reaching the end of their lifetime. Therefore, the incentive also takes into account any premature replacement investments.

In the regulatory methods implemented in 2024, the Energy Authority introduced mechanism to the incentive through which efficiency gains are also directed to the benefit of end users. The calculation considers any cost-efficiency benefits when calculating annual straight-line depreciation for end-users within the regulatory period. During the regulatory period, 15% of the cost benefit of straight-line depreciation obtained by the DSO is deducted from the sum of straight-line depreciation in relation to unit prices if the DSO has been able to make investments in that year at a cost lower than the unit prices. Therefore, 15% of the benefits brought by cost-effectiveness of the DSO are directly allocated to customers and 85% remain with the DSO.

Quality incentive

The quality incentive directs DSO to develop the quality of distribution and to minimise the number and duration of electricity distribution outages. The incentive is based on regulatory outage costs, i.e., the disadvantage caused to the end-user by the outage. Outage costs are calculated based on the number and duration of outages as well as pre-determined unit prices[12] of outages.

In the sixth regulatory period (2024-2027), the number and duration of unexpected outages, the number of high-speed autoclosers, and the number of time-delayed autoclosers are considered from medium-voltage (MV) and high-voltage (HV) distribution networks when determining the outage costs. The number and duration of planned outages is only taken into consideration in the MV distribution network. In addition, as a change to previous regulatory methods, the number and duration of planned and unexpected outages of the low-voltage (LV) distribution network are taken into account in the outage costs for the first time. DSO's average realised regulatory outage costs from the two previous RPs (years 2016-2023), are used as the reference level of regulatory outage costs.

The incentive effect arises when the costs according to the reference level for the realised regulatory outage costs are deducted from the realised regulatory outage costs. The impact of the incentive is added to the operating profit when calculating realised adjusted profit. The incentive impact (bonus or sanction) is limited to 15% of the DSO's reasonable return in the year in question.

Efficiency incentive

As the investment incentive seeks to guide DSO to invest cost-effectively, the efficiency incentive in turn encourages DSO to plan and implement operational activities in a cost-effective way. On regards to electricity distribution network operations, the cost level of efficient operational activities is assessed by using efficiency benchmarking. The efficient cost frontier is estimated based on the input and output data of all DSOs and the potential of an individual DSO to enhance its operational efficiency is identified by comparing its realised costs with those defined by the efficiency frontier.

The incentive is based on the DSO's reasonable controllable OPEX that is used as a reference level in the assessment of the DSO's effectiveness. The reference level describes the cost level at which an efficient DSO can perform operational functions with high quality, while also considering the DSO's output level and operating environment. The DSO-specific reference levels are derived from the estimated efficiency frontier using StoNED method(the Stochastic Non-Smooth Envelopment of Data). The variables in the efficiency frontier estimation and derivation of DSO-specific efficiency consist of: input variables (controllable OPEX and net present value of the network), output variables (volume of transmitted energy, total length of the network, number of metering points and regulatory outage costs) as well as an operating environment variable (the ratio of the number of connections and metering points).

The impact of the efficiency incentive is calculated so that the reasonable operational costs according to the reference level are deducted from the DSO's realised operational costs of the

[12] Unit prices of outages are based on a study commissioned by the Energy Authority in 2022.

same year. The impact of the incentive is added to the operating profit when calculating realised adjusted profit and the incentive effect is limited to 20% of the DSO's reasonable return for the year in question.

Innovation incentive

The purpose of the innovation incentive is to encourage the DSO to develop and use innovative technical and operational solutions in its network operations. The DSO's efforts in research and development (R&D) are rewarded by deducting reasonable R&D expenditure in the calculation of adjusted profit. Acceptable R&D costs must be directly related to the creation of new knowledge, technology, products, or methods of operation in the network operations. The results of the projects which costs have been accepted in the innovation incentive must be publicly available so that the results can be utilised by others as well.

The impact of the innovation incentive is calculated so that a share, corresponding to a maximum of 0,5% of the DSO's total turnover from network operations in the unbundled profit and loss accounts in the regulatory period, are treated as reasonable R&D costs. The impact of the incentive is deducted when calculating realised adjusted profit.

Flexibility incentive

In the regulatory methods implemented in 2024, the Energy Authority introduced new incentive which is intended to encourage DSOs to develop and utilise flexible solutions in distribution network operations. The purpose of the flexibility incentive is to encourage DSOs to actively undertake innovative projects to achieve a wider use of demand response in network operations.

The incentive is included for both sixth (2024-2027) and seventh (2028-2031) regulatory period though the incentive mechanism differs between periods. For the regulatory period 2024-2027 incentive aims DSOs to develop different flexibility solutions and to contribute specifically to promoting innovative demand response solutions in the early stage whose cost-benefit ratio has not yet reached maturity. While 2024-2027 regulatory period is considered as a transition period for creating market-bases flexibility, the 2028-2031 period aims to implement these flexibility solutions as an established part of the network operations.

The impact of the flexibility incentive in sixth regulatory period is calculated so that a maximum of 1% of the DSO's total turnover from network operations in the unbundled profit and loss accounts in the regulatory period are treated as reasonable flexibility incentive implementation costs. The impact of the incentive is deducted when calculating realised adjusted profit.

In the seventh regulatory period in turn the costs of flexible solutions acquired on a market basis during the regulatory period constitute a pass-through cost item for DSOs. The DSO may include up to 2% of the sum of its turnover in the unbundled profit and loss account during the regulatory period as pass-through costs.

Application example

The following presents a simplified example of the application of the regulatory framework in Finland and how the allowed revenue is determined for two fictious electricity DSOs. When determining the revenue cap, we start off with the adjusted balance sheet. All the figures presented in the tables are in thousands of euros.

Adjusted balance sheet	DSO A (thousand €)	DSO B (thousand €)
ASSETS		
Adjusted non-current assets		
NPV of the network	500,000	500,000
Adjusted current assets	0	0
Adjusted balance sheet total	**500,000**	**500,000**
LIABILITIES		
Adjusted equity		
Equity in the balance sheet value	125,000	20,000
Equalisation item of adjusted balance sheet	175,000	375,000
Adjusted debt		
Interest-bearing	175,000	20,000
Non-interest-bearing	25,000	80,000
Adjusted balance sheet total	**500,000**	**500,000**

Example of the application of the regulatory framework (Finland)

DSO A and DSO B have the same size of adjusted electricity network assets, totalling €500 million (M). However, the DSOs have a different financial structure, as DSO A has €300 M of equity, €175 M of interest-bearing debt and €25 M of non-interest-bearing debt, while DSO B has €395 M of equity, €20 M of interest-bearing and €80 M of non-interest-bearing debt.

The reasonable return i.e., revenue cap is calculated by multiplying the adjusted capital invested in network by the reasonable RoR (WACC %). We need to determine the applicable WACC % that consists of the reasonable cost of equity, reasonable cost of debt and assumed optimal capital structure. In the determination of the reasonable RoR we shall use the parameter values that the Energy Authority applies in 2024.

Parameter	Value (2024)
Risk-free rate (R_r)	2.48%
Country risk premium (*CRP*)	0.59%
Equity beta (β_{equity})	0.931
Market risk premium ($R_m - R_r$)	4.61%
Premium for lack of liquidity (*LP*)	0.6%
Debt premium (*DP*)	2.1%
Gearing	54%
Equity	46%
Rate of corporate tax (*yvk*)	20%

Parameters (Finland)

Where:

- Reasonable cost of equity is $C_E = (R_r + CRP) + \beta_{equity} * (R_m - R_r) + L$;
  - $\mathrm{C_E} = (2.48\% + 0.59\%) + 0.828 * 5.0\% + 0.6\% = 7.96\%$;
- Reasonable cost of debt is $C_D = (R_r + CRP) + DP$;
  - $\mathrm{C_D} = (2.48\% + 0.59\%) + 2.1\% = 5.17\%$;
- Reasonable RoR is $WACC_{pre-tax} = \frac{C_E * 0.46}{(1-yvk)} + C_D * 0.54$;
  - $WACC_{pre-tax} = \frac{7.96\% * 0.46}{(1-20\%)} + 5.17\% * 0.54 = 7.37\%$.

When the reasonable RoR is determined, we can then calculate the revenue cap for the DSOs.

Reasonable return	DSO A	DSO B
Adjusted equity	300,000	395,000
Interest-bearing debt	175,000	20,000
WACC $\%_{pre\text{-}tax}$	**7.37%**	**7.37%**
Reasonable return	**35,008**	**30,586**

Reasonable return (Finland)

As there is no return obtained for non-interest-bearing debt, the reasonable return is calculated by adding together adjusted equity and interest-bearing debt and multiplying by the reasonable RoR as follows:

- **DSO A**: 7.37% * (€300,000 t + €175,000 t) = **€35,008 t**; and
- **DSO B**: 7.37% * (€395,000 t + €20,000 t) = **€30,586 t**.

Once the reasonable return is determined for both DSOs, the profit and loss accounts need to be adjusted to determine the realised adjusted profit. This is done by adding the refundable items and deducting reasonable costs of financial assets and the effect of incentives from the DSOs' operating profit (loss).

Adjusted profit and loss account	DSO A	DSO B
Operating profit (loss)	40,000	30,000
Items returned into the operating profit (loss)		
Planned depreciations and value reductions from network assets	+26,000	+23,000
Other profit adjustment items		
Reasonable costs of financial assets	-600	-500
INVESTMENT INCENTIVE		
Adjusted straight-line depreciation	-27,500	-24,000
QUALITY INCENTIVE		
Realised regulatory outage costs	500	8,000
The reference level of regulatory outage costs	550	14,000
Effect of the quality incentive	-50	-4588
EFFICIENCY INCENTIVE		
Realised controllable operational costs	27,000	15,000
Reasonable controllable operational costs	25,000	16,500
Effect of efficiency incentive	+2000	-1,500
INNOVATION INCENTIVE		
Reasonable costs of research and development activities	-250	0
FLEXIBILITY INCENTIVE		
Reasonable costs of flexibility services	-350	-150
Realised adjusted profit	**39,250**	**23,262**

Adjusted profit and loss account (Finland)

Firstly, let us assume that DSO A has an operating profit of €40,000 t and DSO B has €30,000 t calculated from the unbundled profit and loss account. Returned to the operating profit are planned depreciations and value reductions of electricity network assets in non-current assets, €26,000 t for DSO A and €23,000 t for DSO B. After this, the reasonable costs of financial assets are deducted from the operating profit; €600 t for DSO A and €500 t for DSO B. Finally, the impact of incentives is added to the operating profit to get the realised adjusted profit.

Effect of investment incentive

As mentioned, the effect of the investment incentive includes two different elements. Firstly, depreciation according to DSO's accounting is changed to straight-line depreciation according to the replacement value of the network and the lifetimes set in the regulatory model for the network components. In our example it's assumed that the straight-line depreciation from the replacement value of the network for DSO A is €27,500 t and for DSO B €24,000 t. The impact of the investment incentive is calculated by deducting the adjusted straight-line depreciation of the electricity network assets from the operating profit (loss) of the unbundled profit and loss account.

As a second element of the investment incentive is the efficiency of the DSO's investment implementation. If the DSO can implement the network investments more efficiently than the unit prices set in the regulatory methods suggest, DSO benefit from the difference between the replacement value and the realised investment cost. Efficient investments are also realized in the calculation of the reasonable return, as the networks net present value is based on the unit prices. The incentive also works both ways, that is, if the actual investment costs are higher than the unit prices, the DSO will bear the loss of the inefficient investment.

The benefits resulting from the investment efficiency, nor the effect of the incentives benefit allocation between DSO and end-users is not separately presented in the example calculation.

Effect of quality incentive

Let's assume that DSO A has a history of low volume of outages in the past in which case its reference level of regulatory outage costs is low (€550 t) while DSO B has had several major supply interruptions thus also its reference level is quite high (€14,000 t). The realised regulatory outage costs in the year in question for DSO A is slightly lower than the reference level while DSO B has invested considerably to the security of supply and its realised regulatory outage costs are significantly lower than the reference value (€8,000 t). The impact of the quality incentive is calculated by deducting the reference level of outage cost from the realised regulatory outage costs. For DSO A the effect of the quality incentive, €500 t – € 550 t = -€50 t, does not exceed the DSO's 15% quality bonus threshold. However, for DSO B the difference between realised costs and reference level costs, €8,000 – €14,000 = -€6,000 t, exceeds the 15% threshold of the reasonable return and the effect of the incentive is limited to; -15% * €30,586 t = €4,588 t.

Effect of efficiency incentive

Assume that DSO A's reasonable operational cots according to efficiency frontier (benchmarking) are €25,000 and it's realised controllable operational costs are €27,000 t. Hence DSO A has inefficiencies in its operations as its realised controllable OPEX is higher than the indicative efficient reference cost level. The impact of the efficiency incentive is calculated by deducting the efficient reference costs from the DSO's realised controllable OPEX in the year in question; €27,000 t - €25,000 t = €2,000 t. As the realised costs exceeds the reference level, it leads to sanctioning effect of the incentive and the sanction is added to the realised adjusted profit.

Reasonable controllable operational costs according to efficiency frontier for DSO B are €16,500 t and realised controllable OPEX is assumed to be €15,000 t. We can observe that DSO B has operated efficiently as its realised controllable OPEX is below it's indicative efficient cost level. As the efficient reference costs are deducted from the realised controllable OPEX, the incentive effect is €15,000 t - €16,500 t = -€1,500 t. For both companies, the 20% threshold set for the incentive is not exceeded, so the difference between the realised costs and costs according to the reference level is added to the realised adjusted profit as such.

Effect of innovation incentive

Let us assume that DSO A has developed an Internet of Things-project that can be used to proactively identify the repair needs for substations and thus initiate corrective action more quickly. The project enables cost-effective monitoring and ultimately reduces repair and maintenance costs. DSO A has published the results of the project and the Energy Authority has approved the costs of the project for the innovation incentive. DSO A has used €250 t for the project, which will be deducted from the realised adjusted profit. DSO B has not published any research relating to the electricity network sector and therefore is not entitled to an innovation incentive bonus.

Effect of flexibility incentive

Let's assume that both DSOs are actively developing demand response solutions and therefore both are entitled to the flexibility incentive bonus, DSO A for €350 t and DSO B €150 t. The costs related to the flexibility incentive is deducted when calculating the realised adjusted profit.

Once all the effects of incentives have been calculated, we can then determine the realised adjusted profit for both DSOs as follows:

- **DSO A**: €40,000 t + €26,000 t - €600 t - €27,500 t - €50 t + €2,000 t - €250 t - €350 t = **€39,250 t**; and
- **DSO B**: €30,000 t + €23,000 t - €500 t - €24,000 t - €4,588 t - €500 t - €150 t = **€23,262 t**

Finally, we can calculate the surplus or deficit of the corresponding year for both DSOs by deducting the reasonable return from the realised adjusted profit.

Surplus / deficit of the financial period	DSO A	DSO B
Realised adjusted profit	39,250	23,262
Reasonable return	35,008	30,586
Surplus (+) / deficit (-)	**+ 4 242**	**- 7,324**

Surplus/deficit of the financial period (Finland)

We can see that DSO A's return is in surplus and DSO B's return is in deficit. At the end of the regulatory period the DSOs' realised adjusted profits from different years are added together and deducted from the sum of reasonable returns from the corresponding years. If the DSO has a cumulative surplus transferring to the next period, it must be equalised during the next regulatory period by lowering distribution tariffs. If the DSO in turn has a cumulative deficit transferring to the next period, the DSO can equalise it during the next period with higher tariffs.

Annex 5.11 Case study – Germany

This section provides a short case study on the determination of the revenue cap of a German electricity DSO.

Introduction

The electricity and gas network operators in Germany at the transmission and distribution network levels are identified as natural monopolies. As such they are subject to government regulation. The German regulatory system provides incentive regulation through the setting of revenue caps. For the duration of one regulatory period (RP), a revenue cap is prescribed for the network operators ex ante for each year. Based on these revenue caps and the forecasted volumes of energy supplied, the network operators then determine the network tariffs that they levy on the energy suppliers. The energy suppliers themselves pass on these network tariffs directly to the final consumers by incorporating the network tariffs into the energy sales price in the form of a fixed value.

This case study focuses on the determination of the revenue cap in general and its individual components. This description is intended to facilitate a better understanding of sub-chapter 2.11 of the 2024 Regulatory Frameworks Report (RFR). As the sub-chapter is limited to a maximum of five pages, this case study serves to illustrate the application of the regulatory system. For this purpose, diagrams will be added and elucidated as needed. Finally, the determination of the revenue cap will be illustrated based on a virtual comparison of two electricity DSOs. Depending on the design of the framework conditions, subsequent versions could also include a comparison between individual countries taking part in the RFR.

The determination of the revenue cap

For the determination of the revenue cap, the DSOs in principle apply the following formula:

$$RC_t = C_{pnc,t} + \left(C_{tnc,t} + (1 - D_t) * C_{c,t} + \frac{B_0}{T}\right) * \left(\frac{CPI_t}{CPI_0} - PF_t\right) + CM_t + Q_t + (VC_t - VC_0) + A_t.$$

The main component of the formula and thus of the revenue cap (RC) is the sum of the permanently non-controllable costs (C_{pnc}) as well as the (temporarily non-) controllable costs (C_{tnc} and C_c). These in turn are influenced by the consumer price index (CPI) as well as the productivity factor (PF), and which can, if applicable, be expanded by an efficiency bonus (B_0), divided into equal parts for each year of the five(T)-year RP. Controllable costs (C_c) are distributed across the individual years of an RP using a distribution parameter (D). This formula is supplemented by individual components from the capital cost mark-up (CM), the quality element (Q), the volatile costs (VC) as well as the balance (A) of the individual regulatory account.

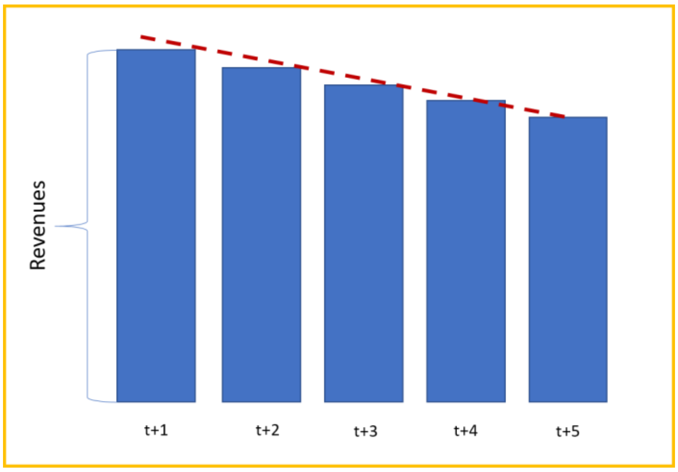
The costs incurred in the base year are requested from the network operators and reviewed. First, the permanently non-controllable costs are deducted from the reviewed overall costs. These costs are set by way of existing definitions and can be directly transferred to the revenues. These include, for example, additional non-wage staff costs, concession fees or, for TSOs, approved investment measures for investments in expansion and restructuring.

The remaining cost block is composed of current outlay costs (e.g. expenditures for material and personnel), imputed depreciations (longer depreciation periods than in the German Commercial Code), imputed returns on equity as well as imputed trade tax, minus cost-reducing revenues.

The efficiency scores determined in a national TOTEX[13]-efficiency benchmarking are then applied to this cost block. The identified proportion of inefficiencies is applied to the remaining cost block, thereby forming the controllable costs. Deducting the controllable costs from the previously remaining cost block produces the temporarily non-controllable costs.

Additionally, the reduction of CAPEX (based on depreciation and lower interest amounts) is deducted from both the temporarily non-controllable costs and the controllable costs.

Since the inefficiencies are to be removed uniformly over the course of one RP, each year an increasing reduction factor $(1 - D_t)$ is applied to the controllable costs. This gives the revenue cap a stepped trajectory, as illustrated in Figure 2:

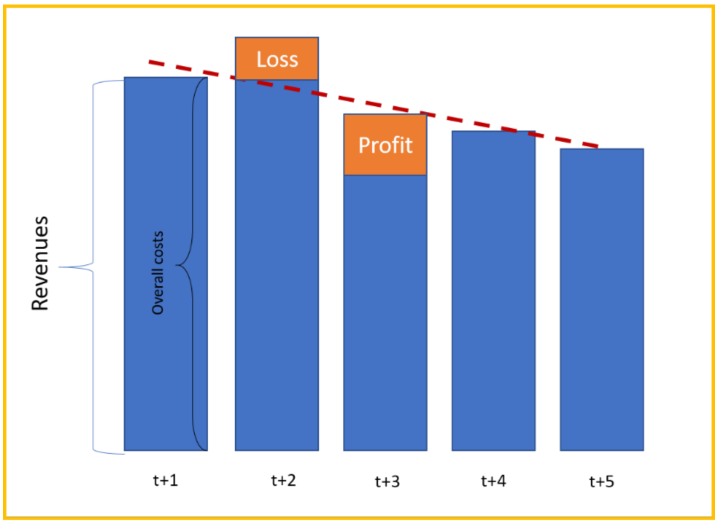


Revenue cap as stepped trajectory (Germany)

Due to the existing budgetary principle, the network operators have to decide where to reduce the inefficiencies. Neither the cost review nor the efficiency benchmarking identifies concrete inefficient cost positions, only inefficiencies in general.

In addition to the deduction of the reduced CAPEX, the determined temporarily non-controllable and controllable costs from the base year are applied to the entire RP; this is precisely where the incentive lies for network operators to reduce costs. The set revenue cap enables additional profits to be made through cost reductions within the RP, as Figure 3 illustrates:

[13] TOTEX = sum of OPEX and CAPEX.



Revenue cap enables additional profits (Germany)

If within the framework of an outlier analysis, a DSO is determined to be super-efficient (efficiency score > 100%), that DSO receives a certain efficiency bonus (limited to 5%) on their revenues, uniformly distributed over the duration of the RP.

The development of consumer prices, as well as the productivity of the network operators, is taken into account through a correction factor on the temporarily non-controllable costs, on the controllable costs and, if relevant, on an efficiency bonus.

The revenue cap is also supplemented by mark-ups for additional planned CAPEX, as well as by amounts for quality regulation, for changes in the so-called volatile costs, and for the annual balance of the individual regulation account.

For a CAPEX mark-up, network operators report in the previous year on the amount of their planned investments in necessary network assets. This CAPEX is made up of the imputed depreciations, imputed return on equity, imputed trade tax as well as the incurred interest on debt.

The quality regulation calculation returns a positive or negative amount, depending on the existing quality of security of supply.

Volatile costs are costs incurred in the technical operation of the grids, for example driving energy or flow commitments.

Deviations between amounts or cost values estimated ex ante and identified ex post are recorded in a regulatory account that exists for each network operator. The balance of the regulatory account is also factored into the revenue caps.

Application example

A simplified example of the application of the German regulatory system to calculate revenue caps/network tariffs is given below using two electricity DSOs. The framework/market conditions are shown in the following table.

Framework conditions (base year's situation)

	DSO A	DSO B
Staff costs	1,000	800
Material costs	500	200
Operating taxes	50	30
∑ OPEX	1,550	1,030
Depreciations[14]	900	870
Interest rate on equity	6.91%	6.91%
Return on equity	100	50
Cost of debt	50	40
∑ CAPEX	1,050	960
∑TOTEX (OPEX + CAPEX)	2,600	1,990
Other revenues	-100	-50
Trade taxes	50	60
CPI in the base year	100	100

Framework conditions (Germany)

For each DSO (here A and B) the revenue cap is calculated by summing up the single calculated components of the revenue formula. To this end, we take the following steps for each DSO individually:

- Review of overall costs and the different cost categories;
- Application of the efficiency score;
- Determination of other revenue components; and
- Final calculation of the revenue cap.

Step 1: Review of overall costs and the different cost categories

To calculate the reviewed overall costs, we add the DSO's material and labour costs, depreciations, return on equity and trade tax, and subtract the cost-reducing revenues from this amount. After that we have the DSO's overall costs, which we reduce by the amount of pre-determined permanently non-controllable costs.

	DSO A	DSO B
1. Material and staff costs (∑)	1,500	1,000
2. Operating taxes	50	30
3. Depreciation	900	870
4. Return on equity[15]	100	50
5. Cost of debt	50	40
6. Trade taxes	50	60
7. Other revenues	-100	-50
8. Reviewed overall costs (∑ 1. - 7.)	2,650	2,000
9. Permanently non-controllable costs[16]	1,000	800
10. ∑(Temporary non-)Controllable costs[17,18]	1,650	1,200

Review of cost categories (Germany)

[14] Based on calculated costs instead of depreciations defined by the German Commercial Code.
[15] Return on equity is calculated based on the costs of tangible assets financed by equity, multiplied by the RoR on equity of 6.91%.
[16] Defined by the cost catalogue.
[17] Separated into a controllable and temporally non-controllable part by using the determined efficiency score.
[18] Parts of positions No. 1., 2. and 7. are included at No. 9.

Step 2: Application of the efficiency score

Based on the pre-calculated efficiency score, as a result of a national efficiency benchmarking, we can determine the DSO's inefficiencies, which it has to eliminate over the RP. Therefore, we define the controllable costs and temporarily non-controllable costs.

	DSO A	DSO B
11. Efficiency score	100%	90%
12. Inefficiencies (100% – 11.)	0%	10%
13. Temporally non-controllable costs (10. * 11.)	1,650	1,080
14. Controllable costs (10. * 12.)	0	120
15. Distribution parameter[19]	20%	20%
16. Controllable costs in the first year of the RP (14. * (1 – 15.)	0	96

Application of the efficiency score (Germany)

Since DSO A has been given an efficiency score of 100%, it does not have any inefficiencies to remove over the RP. The controllable costs are therefore zero, while the temporarily non-controllable costs are 1,650 units. DSO A is not an outlier in the efficiency benchmarking and there is therefore no efficiency bonus.

Since DSO B has been given an efficiency score of 90%, it must remove inefficiencies of 10% over the RP. The controllable costs are therefore 120 in total; for the first year of the RP there are controllable costs using the distribution parameter of 80% (1-20%)*120, i.e. 96 units. The temporarily non-controllable costs are therefore 1,080 units. DSO B is not an outlier in the efficiency benchmarking and there is therefore no efficiency bonus.

Step 3: Determination of other revenue components

We have already mentioned that DSO A and DSO B are not outliers and therefore they will not get an efficiency bonus. The CPI at the base year was 100, and the index of the first year was 101. As a fictional value for the productivity factor, we assume a value of 0.5%. Due to new investments in the first year of the RP, DSO A gets a CAPEX mark-up of 100 and DSO B a mark-up of 200. As a result of the quality regulation, we assume a value of 50 for DSO A, and a value of -100 for DSO B. The volatile costs of the base year have a value of 200 for DSO A and 100 for DSO B. For the first year of the RP the volatile costs of DSO A are 300. For DSO B the volatile costs are on the same level as they are at the base year. The balances of both RPs are assumed to be zero.

	DSO A	DSO B
17. Efficiency bonus	0	0
18. CPI in the base year	100	100
19. CPI in first year of regulation	101	101
20. Development of prices (19./18.)	1.01	1.01
21. Productivity factor[20]	0.5%	0.5%
22. Correction factor for development of prices and productivity in first year of regulation (20. – ((1 + 21.^{1}) – 1)	1.005	1.005
23. CAPEX mark-up	100	200
24. Quality element	50	-100
25. Volatile costs in base year	200	100
26. Volatile costs in first year of regulation	300	100
27. Change of volatile costs (26. – 25.)	100	0
28. Regulatory account balance	0	0

Determination of other revenue components (Germany)

[19] Value at the first year of the RP.
[20] Assumed fictional value.

Step 4: Final calculation of the revenue cap

For the determination of the revenue cap, the DSOs in principle apply the following formula:

$$RC_t = C_{pnc,t} + \left(C_{tnc,t} + (1 - D_t) * C_{c,t} + \frac{B_0}{T}\right) * \left(\frac{CPI_t}{CPI_0} - PF_t\right) + CM_t + Q_t + (VC_t - VC_0) + A_t.$$

Therefore, we get a revenue cap for the first year of the RP of:

Revenue cap for the first year of the regulatory period	
DSO A	1,000 + (1,650 + (1 – 20%)*0 + $\frac{0}{5}$)*($\frac{101}{100}$ – 0.5%) + 100 + 50 + (300 – 200) + 0 = 2,908.25
	9. + (13. + (1 – 15.)*14. + $\frac{17.}{5}$)*($\frac{19.}{18.}$ – ((1 + 21.^{1}) – 1)) + 23. + 24. + (26. – 25.) + 28.
DSO B	800 +(1,080 +(1 – 20%)*120 + $\frac{0}{5}$)*($\frac{101}{100}$ – 0.5%) + 200 – 100 + (100 – 100) + 0 = 2,081.88
	9. + (13. + (1 – 15.)*14. + $\frac{17.}{5}$)*($\frac{19.}{18.}$ – ((1 + 21.^{1}) – 1)) + 23. + 24. + (26. – 25.) + 28.

Revenue cap for the first year of the regulatory period (Germany)

If the permanently non-controllable costs, CPI, CAPEX mark-up, quality element, volatile costs or balance of the regulatory account change in the course of the RP, the revenue cap is adjusted accordingly.

Assuming that all components of the formula stay constant during the other years of the RP except for the reduced (inefficient) controllable costs, we have the following calculation for the last (fifth) year of the RP:

Revenue cap for the last year of the regulatory period	
DSO A	1,000 + (1,650 + (1 – 100%)*0 + $\frac{0}{5}$)*($\frac{101}{100}$ – 2.53%) + 100 + 50 + (300 – 200) + 0 = 2,908.25
	9. + (13. + 0*14. + $\frac{17.}{5}$)*($\frac{19.}{18.}$ – ((1 + 21.^{5}) – 1)) + 23. + 24. + (26. – 25.) + 28.
DSO B	800 + (1,080 + (1 – 100%)*120 + $\frac{0}{5}$)*($\frac{101}{100}$ – 2.53%) + 200 – 100 + (100 – 100) + 0 = 1,985.4
	9. + (13. +0*14. + $\frac{17.}{5}$)*($\frac{19.}{18.}$ – ((1 + 21.^{5}) – 1)) + 23. + 24. + (26. – 25.) + 28.

Revenue cap for the last year of the regulatory period (Germany)

So, in this case DSO A could keep the revenue level, while DSO B would have to eliminate the (inefficient) controllable costs.

Annex 5.14 Case study – Greece

Methodologies regarding allowed revenue for TSOs and DSOs in the electricity and gas sectors converge on basic principles, however some differences remain, and the harmonisation process is in progress.

This section provides a short case study regarding the regulatory regime that applies to the independent power transmission system operator (ADMIE SA) during the second RP, 2018-21.[21]

The Regulatory Authority for Energy (RAE) decides on the allowed revenue (AR) and the required revenue (RR) of ADMIE for a four-year RP, based on the TSO's proposal and approved ten-year network development plan (TYNDP, investment plan).

The calculation of AR is based on reasonable and efficient costs (OPEX and CAPEX) and the return on the capital employed (RAB). Moreover, an incentive scheme for OPEX is applied, which allows the operator to earn an additional profit, if it reduces its OPEX.

The RR, which is the revenue that is recovered through the Use of System (UoS) charges, is calculated based on the AR and any required adjustments.

Below we present a short overview of the calculation of the AR and RR of ADMIE (electricity TSO) for the fourth year of the RP 2018-21.

A Allowed revenue 2021 – electricity TSO

The AR of the electricity TSO is calculated in real terms before the beginning of the RP and for each year of the RP as $AR = O + Dep + R$, where:

- O is estimated annual operating expenses;
- Dep is the annual depreciation on the tangible and intangible assets; and
- R is return on the capital employed (RAB).

A.1 Operating expenditure (OPEX)

OPEX includes the reasonable expenses of the electricity TSO, for the operation and maintenance of the national transmission system (the Greek abbreviation 'ESMIE' is used hereinafter) and divided into the following categories which are reported separately: a) payroll, b) third party payments, c) materials and consumables, and d) other expenses. Financing costs, taxes on operator's profits, and provisions (such as provisions for bad debts or for disputed legal cases) are not included.

The total approved OPEX for 2021 is €79 million, of which €66 million is payroll-related expenses.

A.1.1 Efficiency incentive

During the RP 2018-21, OPEX is not subject to any ex post adjustment or settlement within the RP. This creates an incentive for the operator to reduce its OPEX allowance and become more efficient. It should be noted that in the amended methodology, in force from 2022 onwards (495/2021), the efficiency incentive has been further improved to include a sharing mechanism for controllable OPEX (the expenditure saving will be shared between the

[21] According to the "Methodology for Calculating the Required Revenue of the Hellenic Transmission System Operator" (Decision 340/2014), which was amended by RAE Decision 495/2021 in order to be harmonised with other operators in Greece. The new methodology will be applied from 2022 onwards.

electricity TSO and network users). Moreover, under the amended methodology, OPEX is divided into controllable and uncontrollable expenses, depending on the operator's ability to control and set the values of each OPEX category. Uncontrollable expenses include taxes, fees, and levies. Controllable expenses include categories such as payroll, third-party payments, materials and consumables, and other expenses.

On controllable expenses, an incentive mechanism is applied to incentivise the electricity TSO to improve its efficiency. This mechanism is applied to savings on controllable expenses (actual), compared to forecasted controllable expenses, and the relative sharing factor ranges between 40% and 70% in favour of the operator (the value of this factor is determined in the regulatory decision for transmission).

A.2 Depreciation of assets

Depreciation is calculated for each year of the RP, based on the regulatory asset register, following a straight-line method and considering the economic, instead of accounting, life. No revaluations are taken into account. Depreciation is calculated for all assets expected to be in use during each year of the RP, while assets under construction (WIP) are remunerated only for return. Assets funded by third parties or contributions are excluded from the RAB and thus from the calculation of depreciation.

The total depreciation amount for 2021 based on the regulatory asset register is €77 million.

A.3 Return on RAB

The return on the capital employed is calculated based on:
- The estimated value of the RAB of the year; and
- The approved pre-tax RoR (r) / WACC.

A3.1 Regulatory asset base

The RAB includes the estimated capital employed for the regulated activity, estimated for each year of the RP as follows:
- (+) Undepreciated value of assets according to the regulatory asset register;
- (+) WIP[22]/new investments;
- (+) Working capital;
- (-) Disposals; and
- (-) Grants and contributions from third parties.

The RAB for 2021 was estimated to be €2 billion, of which working capital was €77 million and grants and contributions from third parties were €227 million.

From 2009 onwards no revaluation has been considered for regulatory purposes.

A.3.2 WACC

The WACC is calculated as an RoR for the RAB. For the electricity TSO, the WACC is estimated in real terms (pre-tax)[23] as $WACC_{real} = \frac{1+WACC_{nominal}}{1+i} - 1$, where:

[22] Under the amended methodology for the electricity TSO, projects of major importance during their construction period are included in the WIP, while until 2021 they are included in the RAB when they are electrified.
[23] For the electricity DSO, gas TSO and gas DSOs, a nominal, pre-tax WACC is used. The methodology for the electricity TSO was amended in order to be harmonised with the methodologies applied for the other electricity and gas operators; therefore, for the RP 2022-25 a nominal pre-tax WACC will be applied also for the electricity TSO.

- i is inflation; and
- $WACC_{nominal}$ is given by the equation below.

$WACC_{nominal} = g * r_d + (1-g) * \frac{r_e}{t-1}$, where:

- g is the gearing ratio;[24]
- r_d is the cost of debt;[25]
- $r_e = r_f + \beta_{equity} * MPR + CRP$ is the cost of equity (post-tax, nominal), where β_{equity} is equity beta, MPR is the market risk premium and CRP is the country risk premium; and
- t is the corporate tax rate.

The WACC in real terms (pre-tax) is 6.3%. The values of the parameters that are used for the calculation of WACC are presented in Table 15.

Weighted average cost of capital 2021	
Risk-free rate (r_f)	0.7%
Market risk premium (MRP)	5.0%
Gearing ratio (g)	40.30%
Beta equity (β_{equity})	0.72
Country risk premium (CRP)[26]	1.5%
Cost of equity pre-tax ($r_{e,post-tax}$)	5.8%
Tax rate (t)	29%
Cost of equity pre-tax ($r_{e,pre-tax}$)	8.2%
Cost of debt (r_d)	5.13%
WACC, pre-tax, nominal ($\mathbf{WACC_{nominal}}$)	**6.95%**
Inflation[27] (i)	0.6%
WACC, pre-tax, real ($\mathbf{WACC_{real}}$)	**6.3%**

Approved weighted cost of capital for the year 2021 (Greece)

The analytical expression of the nominal WACC is $WACC_{nominal} = g * r_d + (1-g) * \frac{r_f + \beta_{equity} * MPR * CRP}{t-1}$.

A.3.3 WACC premium

For projects of major importance that are included in the approved TYNDP, a premium RoR can be provided, in addition to the base WACC. The percentage of this premium varies between 1% and 2.5%. The WACC premium is provided as soon as the project is electrified and up to the 12th year from the planned year of electrification, according to the approved TYNDP in which the project is characterised as a project of major importance.

In the amended methodology both the range and the duration of the WACC premium have been modified. More precisely, according to the new methodology, the WACC premium varies between 0 and 2% and can be provided for a period of four to seven years, starting from the projected year of commercial operation according the approved TYNDP. In case of unjustified delays in the project's timeline, this extra WACC premium can be reduced.

[24] Until 2021, a value close to the actual gearing was considered. The new methodology introduces notional gearing as a principle.
[25] Until 2021, an estimated cost of debt was taken into account, according to actual (previous years) financing cost. According to the new methodology (Decision 495/2021), the estimated cost of debt is equal to a risk-free rate (which may differ from that used for the cost of equity) plus a debt premium.
[26] Due to specific country conditions, an extra premium (country risk premium) is added to the capital asset pricing model (CAPM).
[27] Estimated in 2018.

A.4 Allowed revenue 2021

Based on the above, the AR for 2021 is summarised in the following table.

Allowed revenue of the electricity TSO 2021	
OPEX	79,066,000
Depreciation	77,063,000
RAB	2,059,771,000
WACC (real, pre-tax)	6.3%
Return on RAB (R)	129,766,000
Allowed revenue (AR)	**285,895,000**

Allowed revenue of the electricity TSO for the year 2021 (in €) (Greece)

Required revenue 2021 – electricity TSO

The RR is recovered through the system usage charges (capacity and commodity) by all customers connected to ESMIE and to the distribution network. The RR is calculated based on the AR, considering certain adjustments (parameters) as $RR = AR \pm K \pm \Pi_1 \pm \Pi_2 - \Pi_3 \pm \Pi_4 - \Pi_5$, where:

- AR is the allowed revenue of the electricity TSO;
- K is the cost of projects of ESMIE that are funded by third parties;
- Π_1 is the settlement amount due to under/over recovery of RR in previous years;
- Π_2 is the settlement amount due to under/over investment in previous years;
- Π_3 is the revenues from interconnection rights (auctions);
- Π_4 is the expenses/revenues from participation in the ITC mechanism between TSOs; and
- Π_5 is the revenues from other, regulated or non-regulated, activities.

Based on the above, the RR of the electricity TSO for the fourth year of the RP 2018-21 is €211,596,945. The values of the parameters that constitute the RR are summarised in the following table.

Amounts in €	2021
Allowed revenue (AR)	285,895,000
Cost of projects funded by third parties (K)	0
Underinvestment (+) / overinvestment (-) (Π_1)	142,810
Clearings due to underinvestment / overinvestment in previous years (Π_2)	-6,141,261
Revenues from interconnection rights (Π_3)	-66,179,594
Revenues from participation in ITC mechanism (Π_4)	1,906,410
Income from non-regulated activities (Π_5)	-9,699,060
OPEX ARIADNI / RSC	*5,672,640*
RR ESMIE 2021	**211,596,945**

Required revenue parameters (Greece)

Annex 5.19 Case study – Latvia

The current natural gas transmission system tariff calculation methodology for the gas TSO was implemented in 2019. This introduced major changes in the tariff calculation methodology related to the regulatory regime – a move to a revenue cap approach, the introduction of efficiency incentives, and the inclusion of requirements for the entry-exit system regulations covering several Member States with several natural gas TSOs.

The change in the regulatory regime was related to the strategic goal in the energy sector to gradually move to tariff setting by following the revenue cap approach. Prior to the changes in the methodology, the tariff setting approach was described as a hybrid approach, primarily based on a cost-plus approach. During 2019 and 2020, the same approach was introduced in the tariff calculation methodologies for electricity TSOs and DSOs, the gas DSO and gas storage operator.

The revenue cap approach is characterised by a predictable and stable tariff, business-oriented corporate governance, and greater scope for incentive-based regulatory mechanisms. The revenue cap approach is one of the most common tariff-setting approaches for system operators in Europe.

Amendments to the methodology regarding the single natural gas transmission entry-exit system were an important precondition for the launch of the single entry-exit system (connecting Finland, Estonia and Latvia (FinEstLat)).

As a result of the establishment of the single natural gas transmission entry-exit system in FinEstLat, no transmission tariffs are applied to natural gas transportation between Finland, Estonia and Latvia from 2020. This means that a tariff is applied only once when the natural gas crosses the border of the single natural gas transmission entry-exit system. Furthermore, the tariff is the same at all entry points of the single natural gas transmission entry-exit system.

The establishment of the single natural gas transmission entry-exit system activates the operation of the regional natural gas market, strengthens Latvia's energy independence, including reducing the domination of the incumbent supplier JSC Gazprom in the region, promotes competition in the natural gas market, and facilitates more efficient use of the regional natural gas infrastructure, including the Inčukalns underground gas storage facility. This in turn results in more competitive natural gas prices and high quality services, benefiting natural gas users.

Regulatory and tariff period

The tariff calculation methodology provides for the length of the RP. The length of the regulatory period is between two and five gas years. The duration of the tariff period is one gas year. When submitting the tariff draft, the system operator submits a justification for the regulatory period used in the tariff calculation and, if necessary, for the tariff period.

If there is more than one tariff period within an RP, the allowed revenues shall remain unchanged during the RP. Where there is more than one tariff period within an RP, the planned revenue within the tariff period is changed in accordance with revenue adjustment (regulatory account).

The planned revenue for a tariff period covers the costs of capacity booking to be included in the tariff calculation. The estimated revenue over the tariff period is determined by the total cost of the capacity booking service minus the amount of the capacity booking service costs to be reduced by the system operator (by improving the efficiency of the use of assets and other resources as well as operational efficiency) and minus the balance of revenues and costs relating to the ITC mechanism.

Determining allowed/target revenues

The planned revenue for a RP covers the costs of capacity booking to be included in the tariff calculation. Planned revenue for a RP is calculated according to the formula $Ie_{PSO} = I_{PSO} - I_{PSO_{ef}} - ITC$, where:

- Ie_{PSO} is the planned revenue for a RP (€);
- I_{PSO} are the total costs of the capacity booking service (€);
- $I_{PSO_{ef}}$ is the amount of the capacity booking service costs to be reduced by the system operator by improving the efficiency of the use of assets and other resources as well as operational efficiency (€); and
- ITC is the balance of revenues and costs relating to the ITCs of TSOs of the single natural gas transmission entry-exit system that, in accordance with the ITC terms and conditions is attributed to the system operator (€).

The cost amount for providing the capacity booking service that the system operator must reduce (by improving the efficiency of the use of assets and other resources as well as operational efficiency) shall be calculated according to the formula $I_{PSO_{ef}} = \left(I_{PSO} - Ie_{kor} - ITC - I_{sist} - I_{nod(st,nac)}\right) * K_{ef}$, where:

- Ie_{kor} is revenue adjustment attributed to the cross-border and national transmission systems (€);
- I_{sist} are the costs of securing natural gas supply (€);
- $I_{nod(st,nac)}$ are taxes applicable to the cross-border and national transmission systems (€); and
- K_{ef} is a cost efficiency coefficient.

To determine the cost level that the system operator must achieve until the beginning of the next RP, and that will be used in tariff calculations for the next RP, a cost efficiency coefficient is applied to a part of the costs of the capacity booking service. The TSO determines the cost efficiency coefficient.

If the RP is longer than a year, the amount by which the system operator must reduce the costs of the capacity booking service (by improving the efficiency of the use of assets and other resources as well as operational efficiency) is equal for all tariff periods. Following a justified request from the system operator, the regulator may authorise the application of a different approach for allocating the total amount for which the system operator must reduce the costs of the capacity booking service to each tariff period within the RP.

The costs of the capacity booking service I_{PSO} included in the tariff calculation are formed of:

- The CAPEX of the cross-border and the national transmission systems;
- OPEX;
- Taxes applied to the cross-border and the national transmission systems; and
- Revenue adjustment attributed to the cross-border and the national transmission systems.

CAPEX

CAPEX consists of depreciation and return on capital, which is calculated by applying an RoR (WACC, determined by the regulator) to the value of the RAB.

Setting the RAB value

The RAB value of the transmission system consists of:

- The residual balance sheet value of the fixed assets, the intangible investments and inventories owned by the system operator at January 1 of the first year of RP (taken from the operator's financial statement); and
- The payments listed in the assets for participation in international transmission infrastructure projects, and commitments arising from decisions on the allocation of investment costs that have been taken in accordance with Regulation No. 347/2013 of the European Parliament and of the Council on guidelines for trans-European energy infrastructure and repealing Decision No. 1364/2006/EC and amending Regulations (EC) No. 713/2009, (EC) No. 714/2009 and (EC) No. 715/2009.

The revaluations of assets done by the operators after December 31, 2021, are not taken into account when calculating RAB value.

The RAB excludes financial investments, amounts receivable, securities, participating interest in capital, monetary instruments, the accumulated supplies of gas for sale as well as the value of a part of the fixed assets financed under the financial assistance or financial support of the local government, a foreign state, the EU, other international organisations and institutions.

Fixed assets acquired, financed by the users (via connection fees) are not included in the RAB value; the depreciation of these fixed assets is not covered by the tariffs and no return on capital is calculated for these assets.

Setting the WACC

The WACC is set yearly, and the system operator must apply it when calculating the new tariff proposal that is planned to come into effect in the respective year. However, the WACC stays the same during the RP.

A pre-tax real WACC is applied in electricity and natural gas sectors. 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. However, the change to nominal WACC will happen in 2025.

Depreciation

Depreciation of fixed assets and intangible investment is calculated in accordance with rules set in Methodology for Accounting and Calculation of Capital Costs. Depreciation of the gas TSO is calculated by the linear method. The typical asset life depends on the asset type: buildings 20-100 years, TSO infrastructure 40-60 years, and other assets/intangible assets three-30 years.

Taxes

The real estate tax is calculated only for assets included in the RAB in accordance with the laws and regulations. Corporate income tax is not included separately, as it is included in the return on capital, which is calculated using a pre-tax WACC.

OPEX

OPEX includes the cost of:

- Natural gas transmission losses and ensuring technological processes of the transmission system;
- Personnel;

- Repair and maintenance;
- Other economically justifiable activity of the transmission system; and
- Securing natural gas supply.

Natural gas transmission losses and ensuring technological processes.

The costs of natural gas transmission losses and ensuring technological processes of the cross-border and national transmission systems are related to the difference between the volume of natural gas supplied to the transmission system and the natural gas withdrawn from the transmission system within a particular time period, which is formed by the losses of natural gas transmission and the consumption of natural gas for technological needs.

Personnel costs

Personnel costs of the cross-border and national transmission systems are calculated in accordance with the labour market conditions, Labour Law and the laws and regulations governing the field of social insurance.

Repair and maintenance costs

The costs of the current operating repairs of the cross-border and national transmission system assets and administration assets that are leased by the system operator and are in the accounting balance sheet thereof and performed by other merchants, shall be written off and recorded in the accounting period during which they have arisen. This position also includes financing costs of accumulated natural gas supplies according to the turnover cycle and applying the incurred interest rate.

The costs of maintaining natural gas supplies are estimated taking into account the necessary volume of natural gas supply considering the continuous provision of the capacity booking service and compliance with security of supply requirements. The incurred interest rate that is applied to the financial costs of maintaining accumulated natural gas supplies cannot exceed the six-month average variable interest rate for (new) short-term loans (€) (comparable to the volume of the accumulated supplies to be maintained) for non-financial institutions published by the Bank of Latvia. Capitalised repair costs, costs concerning the development of new assets, and financing costs of maintaining related natural gas supplies, are not included here.

Other costs of economic activity

Other costs of economic activity of the cross-border and national transmission systems are the costs related to the economic activity of the system operator, that are not recorded under other balance sheet cost items.

Securing natural gas supply

The costs of securing natural gas supply relate to the obligation of the system operator stipulated in the Cabinet of Ministers Regulation No. 312 to ensure necessary natural gas withdrawal capacity from the Inčukalns underground gas storage facility (UGS) during the energy crisis. These costs shall be included in the draft tariff in accordance with the actual, justified amount. These costs are to be recovered within two storage gas years starting from the moment the costs are incurred.

The joint natural gas transmission and storage system operator (Conexus Baltic Grid), ensures that every year on March 1, the amount of active natural gas in the Inčukalnas underground gas storage is present, which is necessary to ensure the 24-hour withdrawal capacity of the Inčukalns underground gas storage, in order to supply energy users of Latvia with natural gas, including during the energy crisis.

System operator coordinates with the Ministry of Economy and Regulator the model of the fulfillment of the mentioned obligation and the amount of active natural gas stored in the Inčukalns UGS necessary for the fulfillment of the obligation. Every year until December 1, system operator can change the amount of active natural gas stored in the Inčukalns UGS, necessary for the fulfillment of the obligation, in coordination with the Ministry of Economy and Regulator.

The costs of securing natural gas supply related to the obligation of the system operator stipulated in the Regulation No.312 are one of the major cost elements of the natural gas TSO. The value of these costs is influenced by the price of natural gas, the price of future transactions, as well as the types of loss hedging available to natural gas suppliers at the time of the auction.

According to the tariff calculation methodology, the costs of securing natural gas supply are included in the operating costs of the national transmission system and are only considered when determining the charge for the use of the exit point for the supplying gas users in Latvia. Such a cost allocation principle was established in the assessment of the results of the costs of securing natural gas supply; the supply of natural gas during the energy crisis of Latvia is ensured and the required level of pressure is ensured in the natural gas transmission system. Given that the necessary pressure level in the natural gas transmission system is provided not only by the amount of natural gas stored in the Inčukalns UGS according to Regulation No. 312, but also by the amount of natural gas stored by the natural gas suppliers at the Inčukalns UGS, it can be concluded that the allocation of the costs should be based on the objective of the cost of securing natural gas supply — to provide a supply of natural gas to Latvia during the energy crisis.

Also, the economically justified costs for storing energy security reserves, associated with the system operator's obligation under Article 82.1(2) of the Energy Law to ensure the availability of the Inčukalns underground gas storage facility for energy security reserves and their storage, shall be included in the tariff project in accordance with the planned value.

ITC mechanism

In accordance with Article 10(3) of the network code on harmonised transmission tariff structures (NC TAR), to allow for the proper application of the same reference price methodology jointly, an effective ITC mechanism shall be established to prevent detrimental effects on the transmission services revenue of the TSOs involved and to avoid cross subsidisation between intra-system and cross-system network use.

The absence of internal commercial interconnection points, and the possibility of applying the flat tariff at all FinEstLat single natural gas transmission entry-exit system entry points from other transmission entry-exit systems, is one of the most significant principles of the FinEstLat single natural gas transmission entry-exit system.

To cover the reasonable costs incurred by the natural gas TSOs resulting from the provision of the natural gas transmission service in the FinEstLat single natural gas transmission entry-exit system, without any detrimental impact on the transmission service revenues of the TSOs involved, the TSOs of the FinEstLat single natural gas transmission entry-exit system entered into an agreement on ITC terms and conditions in Finland, Estonia and Latvia. According to this agreement, the Latvian natural gas TSO and the other natural gas TSOs in the FinEstLat single natural gas transmission entry-exit system will receive from, or make payments to, the other TSOs of the FinEstLat single natural gas transmission entry-exit system.

In particular, the basic principles of the ITC system of the FinEstLat single natural gas transmission entry-exit system are:

- The revenue recovered from the tariffs of all entry points of the FinEstLat single natural gas transmission entry-exit system is considered a single pool;
- The pooled revenue is shared between TSOs based on the share of natural gas delivered through the transmission system for domestic consumption in a particular country. This includes consumption for natural gas transmission losses and technological purposes in the total quantity of natural gas delivered through the natural gas transmission system for consumption in the FinEstLat single natural gas transmission entry-exit system. The distribution of pooled revenue is carried out monthly, using the previous year's corresponding national consumption shares in the total consumption of the FinEstLat single natural gas transmission entry-exit system;
- The variable costs incurred by the TSOs due to ensuring flows not dedicated for delivery to the specific market directly, is based on a regional flow scenario agreed between natural gas TSOs and estimates of compressor fuel costs incurred to facilitate the regional flow;
- For the purpose of compensation of eligible variable costs, the eligible variable costs shall be subtracted from the invoiced entry revenue of the natural gas TSO that incurred the eligible variable costs. Eligible variable costs to be compensated must be justified by appropriate invoices or calculations;
- At the end of the year, a reconciliation of the revenue recovered from the tariffs at the entry points of the FinEstLat single natural gas transmission entry-exit system is done. The reconciliation process shall result from a recalculation of the ITC entitlement shares attributable to the natural gas TSO based on actual data for the annual domestic natural gas consumption in Finland, Estonia and Latvia, and a reallocation of revenues based on the identified actual ITC entitlement share for each TSO. The estimated actual ITC entitlement share for each TSO shall be used for allocation of the following year’s pooled revenue;
- Calculation of ITC entitlement shares and annual entry revenue reconciliation shall be performed by the elected data administrator, which shall be one of the TSOs and shall rotate annually; and
- The role of the data administrator, unless agreed otherwise, shall be performed in the following order: Elering AS (Data Administrator’s obligations in 2020), Conexus Baltic Grid, the Finnish natural gas TSO.

There are the following exit points to other natural gas transmission entry-exit systems in the FinEstLat single natural gas transmission entry-exit system:

- Narva exit point (Estonia-Russia);
- Varska exit point (Estonia-Russia);
- Izborsk exit point (Estonia-Russia); and
- Kiemenai exit point (Latvia-Lithuania).

Forecasting of the entry capacity for the Latvian natural gas supply system was carried out in accordance with sub-paragraph 2.7 of the tariff calculation methodology. This set out that the estimated average daily capacity at the entry point is equal to the average daily capacity used (kWh/d) at the entry point within the three previous calendar years. The forecasted capacity at Kiemenai exit point is 4,874 MWh/day/year, i.e. 6% of the exit capacity of the transmission system in Latvia, and less than 1% of the exit capacity of the FinEstLat single natural gas transmission entry-exit system.

The forecasted booked capacity at the Korneti exit point would be attributed to Izborsk exit point and would be less than 1% of the exit capacity of the FinEstLat single natural gas transmission entry-exit system. Having assessed the natural gas flows from 2017 to 2019, it is established that natural gas flows to Russia can only be observed during repair work in the Russian north-west natural gas transmission system. The negligible amount of forecasted booked capacity towards Russia is explained by the fact that repair work in 2020-22 is not intended and consequently the natural gas flows to Russia will be minimal.

In light of the above, it can be concluded that there will in principle be no natural gas transit in the FinEstLat single natural gas transmission entry-exit system during the period 2020 to 2022, and that the whole system will operate in order to meet domestic demand for natural gas. The ITC regime is therefore based on the allocation of revenue among natural gas TSOs based on domestic natural gas consumption of the country concerned, and it is considered that this shall not allow for cross-subsidisation between intra-system and cross-system network use.

The choice of the basic principle of the ITC regime is also linked to the envisaged activities of the TSOs of the FinEstLat single natural gas transmission entry-exit system for the management of natural gas flows – TSOs do not use physical (point-to-point) delivery but use flow netting.

One of the features of the FinEstLat single natural gas transmission entry-exit system is the flat tariffs at all single natural gas transmission entry-exit system entry points, preventing discrimination of routes of supply and reducing the barriers for new market entrants. Due to the above, the changes in the natural gas suppliers' booking practice regarding the usage of the FinEstLat single natural gas transmission entry-exit system entry points are unpredictable. Taking into account the topology of the natural gas transmission systems within the FinEstLat single natural gas transmission entry-exit system, which effectively prevents circular natural gas transportation as a result of the change of the natural gas entry flows within the FinEstLat single natural gas transmission entry-exit system, a part of the currently less-used transmission system will be loaded with a view to relieving currently more-used parts of the transmission system.

It is expected that the launch of the FinEstLat single natural gas transmission entry-exit system will increase the number of natural gas trading transactions at the virtual trading point without any significant change in natural gas flows during the initial period.

Furthermore, it should be noted that the cooperation agreement between the natural gas TSOs necessary for the single Estonia-Latvia balancing zone to enter into operation, assumes that both natural gas TSOs operate as a single system operator providing network users service and technical cooperation.

If, despite the above, there is significant internal (technical) cross-border flows of natural gas in the FinEstLat single natural gas transmission entry-exit system, their provision only results in additional variable costs for the natural gas TSOs, which can be clearly identified. Accordingly, the agreement on ITC terms and conditions in Finland, Estonia and Latvia sets out the specific variable costs to be considered eligible, as well as the principles for their allocation and compensation. Such variable cost reimbursement arrangement ensures that the transmission services revenue of the TSOs involved are not detrimentally affected.

To monitor the relevance of the ITC regime of the FinEstLat single natural gas transmission entry-exit system, the TSOs are required to assess, by 1 March of each year, the results of the implementation of the ITC mechanism of the previous year and to inform the NRAs. If necessary, the relevant changes will be made to the FinEstLat ITC regime.

Regulatory account

According to the methodology, the TSO must create a regulatory account, where the difference between planned revenue and uncontrollable costs, and obtained revenue and uncontrollable costs, is attributed after the end of each tariff period, distinguishing between revenue attributed to the cross-border transmission system and the national transmission system. Planned revenues for the gas year are determined considering the forecasted weighted average entry and exit capacity of the transmission system and the corresponding approved entry or exit point tariffs on capacity products. The balance of the regulatory account is taken into account in the determination of the revenue adjustments, resulting in changes to the costs of capacity booking service for the next RP. The system operator shall submit the information regarding the regulatory account balance and its justification to the regulator within two months after the end of the gas year.

If the length of the regulatory and tariff period is the same, the revenue adjustment that is attributed to the cross-border or national transmission system is determined as follows:

- If the regulatory account balance is negative (revenue obtained is below planned (allowed) revenue), revenue adjustment is equal to regulatory account balance and it increases the costs of capacity booking service for the next RP;
- If the regulatory account balance is positive (revenues obtained surpass the planned (allowed) revenues), revenue adjustment is equal to regulatory account balance, and it reduces the costs of capacity booking service for the next RP;
- If the incurred costs of the capacity booking service (at the cost-group level) during the previous RP are lower than the approved costs of the capacity booking service (at cost-group level) (hereinafter – cost savings), the system operator shall submit justification for the said deviation. Revenue adjustment is equal to cost savings, and the planned costs of the capacity booking service attributable to the system users for the next RP shall be reduced for cost savings. If the cost savings are derived from operational efficiency, the revenue adjustment component is equal to 50% of cost savings; and
- If, due to changes in the regulatory framework or the mitigation of extraordinary event(s), there have been unforeseen justified costs during the previous RP, revenue adjustment is equal to justified unforeseen costs and it increases the costs of the capacity booking service for the next RP.

If there is more than one tariff period within the RP, the revenue adjustment that is attributed to the cross-border or national transmission system for a tariff period is determined as follows:

- If the regulatory account balance is negative, revenue adjustment is equal to the regulatory account balance and it increases the costs of the capacity booking service for the next tariff period;
- If the regulatory account balance is positive, revenue adjustment is equal to the regulatory account balance and it reduces the costs of the capacity booking service for the next tariff period; and
- If, due to changes in the regulatory framework or the mitigation of extraordinary event(s), there have been unforeseen justified costs during the previous tariff period, revenue adjustment is equal to justified unforeseen costs and it increases the costs of the capacity booking service for the next tariff period.

If there are several tariff periods within the RP, the revenue adjustment that is attributed to the cross-border or national transmission system for the next RP is determined as follows:

- If the regulatory account balance is negative, allowed revenue adjustment is equal to the regulatory account balance and it increases the costs of the capacity booking service for the next RP;
- If the regulatory account balance is positive, revenue adjustment is equal to the regulatory account balance and it decreases the costs of the capacity booking service for the next RP;
- If the incurred costs of the capacity booking service (at the cost-group level) during the previous RP are lower than the approved costs of capacity booking service (at cost-group level) (cost savings), the system operator shall submit justification for the said deviation. Revenue adjustment is equal to cost savings, and the planned costs of the capacity booking service attributable to the system users during the next RP shall be reduced for

cost savings. If the cost savings are derived from operational efficiency, the revenue adjustment component is equal to 50% of the cost savings; and
- If, due to changes in the regulatory framework or the mitigation of extraordinary event(s), there have been unforeseen justified costs during the previous RP, revenue adjustment is equal to justified unforeseen costs and it increases the costs of the capacity booking service for the next RP.

When determining the revenue adjustment, the difference between the planned and actual ITC is taken into account.

Annex 5.20 Case study – Lithuania

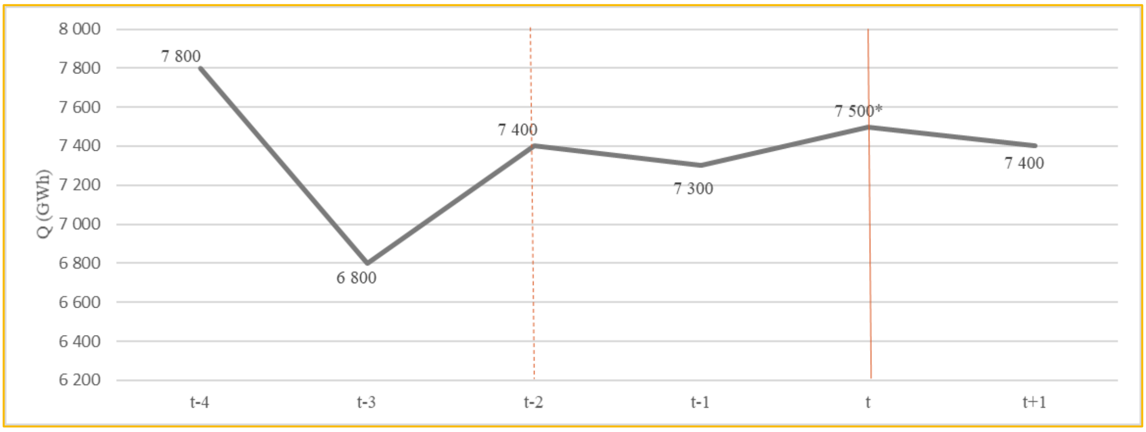
The National Energy Regulatory Council (NERC)[28] applies different methodologies for setting allowed revenues for TSOs and DSOs in the natural gas and electricity sectors, however the main principles are the same. Therefore, the case study for setting the revenue cap[29] for a natural gas DSO is provided below.

A five-year RP is being applied for the natural gas undertakings regulated by NERC. The revenue cap consists of economically justified costs (including OPEX (where personnel costs are evaluated separately), technological needs, depreciation costs and taxes) and return on investment (ROI). Moreover, an incentive scheme is in place, which allows DSOs to earn additional profit if the company reduces its OPEX.

A detailed example[30] for establishing the forecasted distribution volumes, economically justified costs and ROI is provided below.

Forecasted distribution volumes of natural gas

Forecasted distribution volumes are established considering the distributed volumes during the previous RP, as well as the forecasted volumes provided by distribution system users. Illustrative figures are shown in Figure 4. As there is a visible stabilisation in distributed volumes in the years (t-2) to (t), Q is set as the average of this period: ((7,400+7,300+7,500)/3 = 7,400). Accordingly, Q for the year (t+1) is set as 7,400 GWh in this example.



Establishment of forecasted distribution volumes of natural gas (Lithuania)
*Expected Q for the year t

The calculation of economically justified costs for the first year of regulatory period

For the first year of the RP, OPEX (excluding personnel costs) is set considering costs incurred in the previous year,[31] the inflation rate (I) for years (t-1) and (t), and the efficiency coefficient (e) which is 1%. OPEX (excluding personnel costs) is calculated according to the formula:

$$OPEX_{(t+1),(excl.personnel\ costs)} = OPEX_{(t-1),(excl.personnel\ costs)} * \left(1 + \frac{I_{(t-1)}-e}{100}\right) * (1 + \frac{I_{(t)}-e}{100}).$$

[28] From 1 July 2019 according to the Law on Energy of the Republic of Lithuania, the National Commission for Energy Control and Prices of the Republic of Lithuania will be renamed to the Energy Regulatory Council (ERC).
[29] NERC used to set price caps for regulated services until 1 January 2019. However, the changes in the Law on Natural Gas of the Republic of Lithuania came into force from 1 January 2019. Therefore, NERC will be setting revenue caps for regulated services instead of price caps.
[30] Only illustrative figures are provided which do not reflect the real cost level of Lithuanian DSOs.
[31] OPEX (excluding personnel costs) set by the National Commission for Energy Control and Prices (NCC) and factual OPEX (excluding personnel costs) are compared, and the lower value is used in calculations.

The example for OPEX (excluding personnel costs) is provided in the table below.

OPEX (excluding personnel costs) in the year (t-1), thousand €	8,000
Inflation (%) in the year (t-1)[32]	3.5
Inflation (%) in the year (t)	2
OPEX (excluding personnel costs) in the year (t+1), thousand €	8,282

Calculation of OPEX (excluding personnel costs) (Lithuania)

Technological needs

Technological needs consist of fixed technological needs (natural gas consumed by the DSO as fuel in gas stations) and variable technological needs (technological losses). Technological needs for the year (t+1) are calculated according to the technological needs in the previous four years, both factually incurred and set by NERC. In the example below, fixed factual technological needs are higher than set by NERC, therefore the average between set and factual fixed technological needs is set for the year (t+1): 122 GWh. Variable technological needs are calculated considering the factual ratio to distributed volumes of natural gas (0.65%) and forecasted distribution volumes for the year (t+1) (7,400 GWh): 7,400*0.0065 = 48 GWh.

Year of the regulatory period	t-4	t-3	t-2	t-1	Average	t+1
Fixed technological needs						
Set by NCC, GWh	117	117	118	120	118	**122**
Factual, GWh	124	126	128	126	126	
Variable technological needs						
Set by NCC, GWh	85	70	62	63	70	**48**
Factual, GWh	69	47	42	34	48	
Factual losses in percentage to Q	0.88	0.69	0.57	0.47	0.65	**0.65**

Calculation of technical needs (Lithuania)

Technological costs are set by multiplying the technological needs (122+48=170) by the forecasted price of natural gas (including the transmission price) for the year (t+1). For example, if the forecasted price is €30/MWh, technological costs equal €5,100 thousand (170*30 = 5,100).

Depreciation

Depreciation is calculated using the straight-line method according to the depreciation periods for regulated long-term assets set by NERC. Changes in depreciation evaluates DSO investments which are approved by NERC.

[32] Where the inflation rate is less than one, OPEX (excluding personnel costs) is set as OPEX (excluding personnel costs) of the previous year (t-1).

Long term assets	Depreciation (gas sector)	Depreciation (electricity sector)
Buildings	25–70	15-70
Pipelines/electricity lines[33]	55–70	40-55
Meters	9–12	12-16
Other infrastructure related to pipelines/electricity lines	15–20	15-35
Machinery and equipment	5–25	5-50
Other devices	4–10	5-10
Transport means	7	7
Software	4	4
Office inventory	6–10	6-10
Other long-term assets	6–10	6-10

Depreciation of periods applied by NCC (Lithuania)

Personnel costs

Personnel costs are calculated similarly to other OPEX. OPEX (personnel costs) for the previous year[34] and the average change in personnel costs in Lithuania (ΔW) for the year (t) and (t+1) are evaluated:

$$OPEX_{(t+1),(\,personnel\ costs)} = OPEX_{(t-1),(\,personnel\ costs)} * \left(1+\frac{\Delta W_{(t)}-e}{100}\right) * \left(1+\frac{\Delta W_{(t+1)}-e}{100}\right).$$

	Calculation
OPEX (personnel costs) in the year (t-1), thousand €	10,000
ΔW (%) in the year (t)	9
ΔW (%) in the year (t+1)	7.5
OPEX (personnel costs) in the year (t+1), thousand €	11,502

Calculation of OPEX (personnel costs) (Lithuania)

Taxes

Taxes are evaluated according to the changes in legal acts. For example, in 2017, the Law on Natural Gas of the Republic of Lithuania was changed, and it was foreseen that low- and medium-pressure pipelines would no longer be considered as real estate. This legal change led to a decrease in the real estate taxes paid by DSOs and a fall in total taxes by 50% for the main DSO.

Other costs arising from factors that cannot be affected by the DSO are provided by the DSO and must be justified to be approved by NERC.

Regulatory asset base

Only those investments that are approved by NERC are included in the RAB. Moreover, there are some restrictions foreseen that prohibit inclusion in the RAB:

- The value of goodwill;
- Investment assets;
- Financial assets;
- Deferred tax assets;
- Research;
- Study and similar intangible assets;
- Leased assets;
- Assets under construction;[35]

[33] For distribution pipelines a depreciation period of 55 years is applied.
[34] OPEX (personnel costs) set by NCC and factual OPEX (personnel costs) are compared, and the lower value is used in calculations.
[35] Except for projects of common interest by the TSO.

- The value of fixed assets created by the funds of the European Union;
- Grant subsidies;
- Equivalent funds or connection fees by natural gas customers;
- The value of a fixed asset recognised as an ineffective investment by NERC;
- The residual value of an item of non-current asset that is no longer used after the investments for reconstruction of this item; and
- The value of other long-term assets not necessary to perform safe and efficient regulated activity.

Finally, only non-revalued assets are included in the RAB. For electricity transmission and distribution companies, the Long-Run Average Incremental Cost (LRAIC) method is applied for setting the RAB, depreciation costs and ROI.

Return on investment

ROI is calculated as the RAB multiplied by the WACC. In the WACC calculation, the cost of debt and equity risk premium are evaluated by $WACC = R_d * W_D * R_e * \frac{1}{1-m} * W_E$, where:

- R_d is the cap on cost of debt (interest rate, %);
- W_D is the share of debt capital (optimal capital structure);
- W_E is the share of equity capital (optimal capital structure);
- m is the tax rate;
- R_e is the return on equity (%) where $R_e = R_f + \beta * R_{erp}$;
- R_f is the equity risk premium;
- R_{erp} is 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 (last 20 years); and
- levered β is the beta coefficient.

All data used in WACC calculations, except the actual cost of debt of an individual company, is published on the NERC website.[36] Until 2019, the WACC was set for an entire RP. However, during the next RP, the WACC will be adjusted each year in accordance with changes in the DSO's cost of debt. For the main DSO, the WACC is 3.58% for 2019.

Where the RAB is €190 million and WACC is 3.58%, the ROI is calculated as €6,802 thousand (190,000*0.0358).

Calculation of revenue cap

The allowed revenue level is calculated as the sum of all economically justified costs and the ROI.

Indicator	Cell number/formula	Unit	Value
OPEX (excluding personnel costs)	1	Thousand €	8,282
Technological costs	2	Thousand €	5,100
Depreciation costs	3	Thousand €	9,202
OPEX (personnel costs)	4	Thousand €	11,502
Taxes	5	Thousand €	700
Economically justified costs	**6 = (1+2+3+4+5)**	**Thousand €**	**34,786**
ROI	7	Thousand €	6,802
Revenue cap	**8 = (6+7)**	**Thousand €**	**41,588**

Calculation of revenue cap (Lithuania)

[36] See https://www.regula.lt/en/Pages/wacc-gas.aspx.

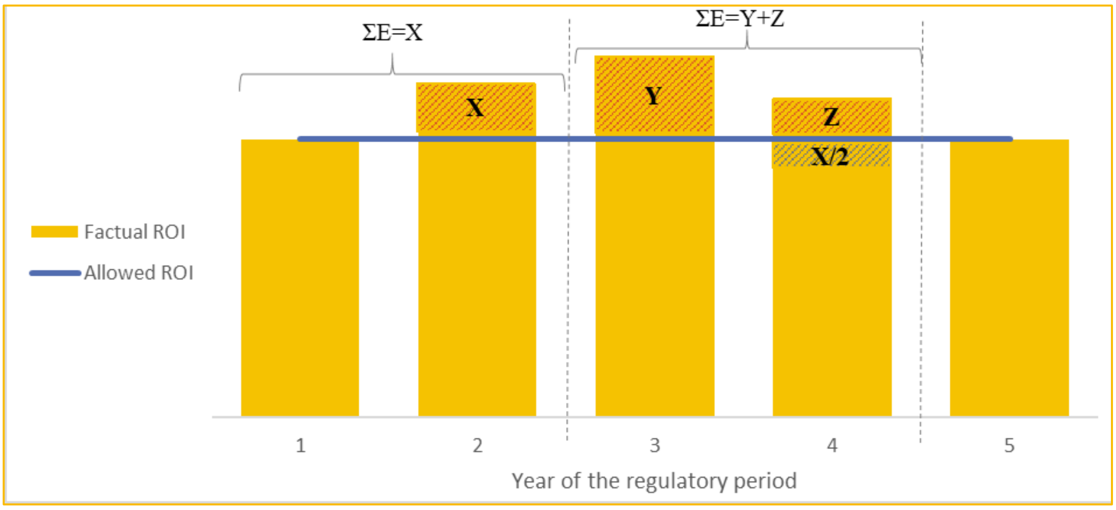
Adjustments within the regulatory period

The revenue cap may be adjusted once a year subject to a change in the inflation rate, personnel costs, volumes of distributed natural gas, investments by the DSO as agreed with NERC or deviations by the DSO from the indicators determined in the methodology (natural gas price for technological losses, changes in actual cost of debt, revenue deviations justified by the DSO, etc.).

Incentive mechanism

NERC applies an incentive scheme that allows the DSO to earn additional profit if it reduces OPEX. The evaluation of efficiency is carried out in the 2+2+1 (year of the RP) scheme. An example of the evaluation of efficiency for the RP is provided in Figure 5.

In this example, actual ROI is higher than set by NERC in the second (by value X), third (by the value Y) and fourth (by value Z) year of the RP. The assumption is made that the differences X, Y and Z are due to efficiency in OPEX (E). In this case, the ROI for the RP is increased by the value ((X+Y+Z)/2) as additional profit regarding efficiency in OPEX. The other half of the difference in ROI is derived from allowed revenue.



Evaluation of a DSO's efficiency (Lithuania)

The evaluation of efficiency in the first year of the RP is performed likewise, yet the differences of ROI in the third to fifth year of the previous RP are evaluated. Where the ROI exceeding the level set by NERC return is split over a period of more than one year, the value of the money is estimated. The value of money is subject to the cap of cost debt, as indicated on NERC's website.[37]

Transmission/distribution tariffs that do not exceed the revenue caps set by NERC are calculated by the TSO/DSOs according to their methodologies.

[37] See https://www.regula.lt/en/Pages/wacc-gas.aspx.

Annex 5.22 Case study – Netherlands

Below we present a small example of how revenue caps are set for DSOs in the Netherlands. As this is done in the same way for electricity and for gas, here we deal with gas exclusively. The example is simplified, and the data and numbers below are fictitious. Note that the length of RPs must legally be within three to five years. The exact length is determined separately for each RP, and may differ from the previous period. In each RP the allowed revenue in the base year is based on the cost average of three previous years. The years t-4, t-3, and t-2 are selected as base years, where t is the starting year of the regulatory period. For the sake of simplicity however, we assume in the example below that only t-2 is used as a base year. The current period lasts five years, from 2022 up until 2026. Our example refers to this period.

Assume that the real WACC for that period is equal to 3%. Also assume that the real WACC for the preceding period is 5%. Suppose we have a CPI of 1% for all years.

Let A, B, and C be three DSOs. For each DSO the revenue cap is calculated by comparing the DSOs through artificial yard stick competition. To this end, we take the following steps for each DSO individually:

- Calculate its realised income in the year 2021;
- Calculate its expected efficient cost level for the year 2026; and
- Set its X-factor such that its allowed revenues develop gradually from its realised income in 2021 to its expected efficient cost level in 2026. With gradually, we mean that the allowed income for year t is equal to its allowed income for year t-1 adjusted (multiplied) by its X-factor and CPI.

Note that X-factors are set individually and can also be negative (denoting a yearly rise in real allowed revenues). Also note that we do not use benchmark scores like we do for the regulation of Dutch TSOs.

Below we elaborate on each of these steps.

Step 1: Calculate realised incomes in the year 2021 for each DSO

We do this just before the RP 2022-26 starts. So, suppose we are in 2021 and have the following realised data for 2020/21 for the DSOs:

	A		B		C	
Connection category	Volume 2020	Tariff 2021 (€)	Volume 2020	Tariff 2021 (€)	Volume 2020	Tariff 2021 (€)
G4: 0-4 m3/h	1,000	100	2,000	80	5,000	80
G6: 4-6 m3/h	200	150	300	100	1,000	120
G10: 6-10 m3/h	100	200	300	110	500	140

2021 tariffs (Netherlands)

For "volume," the year 2020 is selected, as this is the most recent year for which realised volumes are known at the time of configuring the next period (which happens in 2021). Note that the output of a DSO is fully characterised by its volumes for connection categories. That means that no other types of output are considered. For electricity we also have a quality parameter, but in this example, we abstract from that.

The realised incomes are calculated as the sum of the volume*tariff products for each DSO:

	A	B	C
[1] Realised income 2021 (€)	1,000*100 + 200*150 + 100*200 = 150,000	2,000*80 + 300*100 + 300*110 = 223,000	5,000*80 + 1,000*120 + 500*140 = 590,000

Realised income 2021 (Netherlands)

Step 2: Calculate expected efficient cost for each DSO for the year 2026

In order to estimate the efficient costs for 2026, we first estimate the costs for 2021. We set this estimate equal to the costs made in 2020, indexed to the price level in 2021. We take 2020 because it is the most recent year for which we have approved annual accounts.

The realised TOTEX is calculated as follows. Suppose we have:

	A	B	C
[2] OPEX 2020 (€)	60,000	180,000	200,000
[3] RAB 2020 (€)	900,000	1,000,000	4,000,000
[4] Average asset lifetime (years)	40	39	42

Indexed costs 2020 (Netherlands)

where average asset lifetimes are based on technical lifetimes.

Then we calculate:

	Calculation	A	B	C
[5] OPEX 2020 (€)	[2]	60,000	180,000	200,000
[6] CAPEX depreciation (€)	[3]*(1/[4])	22,500	25,641	95,238
[7] CAPEX WACC (€)	[3]*3%	27,000	30,000	120,000
[8] TOTEX 2020 (€)	[5]+[6]+[7]	109,500	235,641	415,238
Cost 2021 (€)	[8]*CPI	110,595	237,997	419,390

Estimated costs 2021 (Netherlands)

So, the total cost in 2021 of the sector (A, B, and C together) is €767,982 [9]. Note that in [7] we use the WACC for the period 2022-26.

Next, we calculate the estimated output for each DSO in the year 2026. The expected output of a DSO is calculated as the weighted sum of its expected volumes of the connection categories in 2026. These expected volumes are set equal to the realised volumes in 2020, and the weight of a connection category is equal to the sector-average tariff for that connection category in 2021. For the weights – or sector-average tariffs in 2021 – we then have:

	A		B		C		Sector
Cat.	Volume 2020	Tariff 2021 (€)	Volume 2020	Tariff 2021 (€)	Volume 2020	Tariff 2021 (€)	Average tariff 2021 (weights)
G4	1,000	100	2,000	80	5,000	80	(1,000*100 + 2,000*80 + 5,000*80) / (1,000 + 2,000 + 5,000) = 82.50
G6	200	150	300	100	1,000	120	(200*150 + 300*100 + 1,000*120) / (200 + 300 + 1,000) = 120.00

G10	100	200	300	110	500	140	(100*200 + 300*110 + 500*140) / (100 + 300 + 500) = 136.67

Average tariffs 2021 (Netherlands)

By multiplying these weights with the volumes in 2020, we can calculate the DSOs' outputs:

	Weight	A	B	C
Output G4	82.50	82.50*1,000	82.50*2,000	82.50*5,000
Output G6	120.00	120.00*200	120.00*300	120.00*1,000
Output G10	136.67	136.67*100	136.67*300	136.67*500
Total output 2021		120,167	242,001	600,835
[10] Estimated output 2026		120,167	242,001	600,835

Estimated outputs 2026 (Netherlands)

Here, we set the estimated output for 2026 equal to the (estimated) output in 2021, which means that we assume that output will be stable throughout the period 2022-26. The total estimated sector output for 2026 is then the output sum of all DSOs; 963,003 units of output [11]. The efficient cost per unit of output (of the entire sector) is then [9] / [11] = €767,982 / 963,003 = €0.797 per unit of output [12].

By multiplying the output per DSO with the efficient costs per output, we can calculate the expected efficient costs for each DSO in 2026:

	Calculation	A	B	C
[13] Expected efficient cost 2026 (€)	[10]*[12]	95,773	192,874	478,865

Expected efficient costs 2026 (Netherlands)

Step 3: Setting an X-factor for each DSO

With steps 1 and 2 we finally calculate X-factors for the RP 2022-26 as:

	Calculation	A	B	C
[14] Realised income 2021 (€)	[1]	150,000	223,000	590,000
		↓	↓	↓
X-factor period 2022-26	$1-([15]/[14])^{1/5}$	8.58%	2.86%	4.09%
		↓	↓	↓
[15] Expected efficient cost 2026 (€)	[13]	95,773	192,874	478,865

X-factors for 2022-26 regulatory period (Netherlands)

So, for example, this means that A starts the RP with allowed revenues of 150,000 * (1-8.58%) = €137,130 in 2022 and ends the RP in 2026 with allowed revenues of 150,000 * $(1-8.58\%)^5$ = €95,773, i.e. its assumed efficient cost level.

Annex 5.24 Case study – Norway

Introduction

NVE-RME is the NRA in Norway and is responsible for the regulation of the DSOs and the TSO, Statnett. The DSOs operate local (240 V–22 kV) and regional (33–132 kV) distribution networks. The TSO operates the transmission grid (132–400 kV). In total, there are about 91 DSOs and one TSO.

The network operators are regulated with a combination of direct and economic revenue regulations, as well as compliance monitoring.

Direct regulations define standards, roles and procedures. Compliance monitoring is important to ensure that the operators follow these regulations. The goal of economic revenue regulation is to incentivise the network operators to provide a stable and secure service in a socially efficient manner.

Economic regulation is centred around the annual allowed revenue (AR) for each DSO/TSO. The allowed revenue covers operating costs and depreciation, and provides a reasonable ROI given efficient operation, utilisation and development of the network.

Allowed revenue

The allowed revenue is the sum of the revenue cap (RC) and some 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 current year are deducted from the allowed revenue. The CENS arrangement will be explained later.

This provides the following formula for the allowed revenue:

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

The revenue 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. NVE-RME decides an excess/deficit revenue balance every year. The balance is to be adjusted towards zero over time, through tariff changes. Excess revenues must be reimbursed to the customers, while deficit revenues may be recovered.

Revenue cap

The revenue cap is set annually, based on a formula that combines cost recovery and a cost norm resulting from benchmarking models: $RC = (1-\rho) * cost\ base + \rho * cost\ norm$.

Currently, ρ is 70%.

The DSOs and TSO annually report economic and technical data to NVE-RME through an extensive system of auditing and control mechanisms. These data provide the basis for the revenue cap calculation. Due to a time lag in the reporting scheme, there is a two-year lag in the model. For the revenue cap for 2022, data from 2020 is used as base, and for revenue cap 2023, data from 2021, etc.

Cost base

The cost base is the sum of three elements: OPEX, CAPEX and CENS.

Operation, maintenance and losses (OPEX)

The OPEX includes operation and maintenance (O&M) costs and the cost of network losses. The O&M costs are two years old and adjusted with an inflation index. The cost of network losses are the physical losses in MWh multiplied by a standardised price from the DSO's prize area for the current year.

Capital costs (CAPEX)

CAPEX is defined as the yearly depreciation plus ROI. The investments are defined as the book value per 31 December + 1% working capital. The companies are free to choose the appropriate depreciation rate, which should reflect the expected technical lifetime for the asset in their area.

The regulatory RoR is decided by a WACC model $WACC_{pre-tax} = (1-G) * \left[\frac{R_f + infl + \beta_e MP}{1-t}\right] + G * \ (Swap + P_d)$, where:

- G is the gearing rate (debt share of total capital): 0.6;
- R_f is the real risk-free rate for equity: 1.5%;
- $infl$ is the moving average of four-year inflation, observations from the previous year and the current year, and expected inflation for the next two years;
- β_e is the equity beta: 0.875, estimated from an asset beta of 0.35;
- MP is the market premium: 5%;
- $Swap$ is the nominal rate for debt: annual average of five-year swap rate;
- P_d is the debt premium: annual average of credit spread for five-year bonds for the power sector; and
- t is the tax rate: 22%.

Costs of energy not supplied (CENS)

For every outage, a CENS is calculated. The costs are defined through a set of functions depending on the duration of the outage, the customer type, time of day, week and year and whether the outage was announced in advance. The cost functions have been developed over the years and are meant to reflect the socio-economic costs of outages. Research projects have explored customers' willingness to pay to avoid outages and estimated the costs of outages.

Cost norm

The cost norm is meant to represent the averagely efficient cost level among the companies. For the TSO, there are not many similar companies to compare it to. We apply a separate model for the TSO where it is benchmarked against its own historical data. We will not describe this further in this report, but rather describe the cost norm model for the DSOs. This cost norm is calculated in three steps: a DEA model, correction for heterogeneity and a calibration of the cost norms. The calculation is done yearly.

Stage 1: DEA model

We have two DEA models, one for local distribution and one for regional distribution. In both models there is one input, TOTEX, similar to the cost base, except that network losses are not included in the regional distribution model. CENS is part of the TOTEX. Although it is not a true cost, as the DSO does not pay this to anyone, the CENS reduces the allowed revenue, and so in practice, has the same effect as a cost. When we include it in the TOTEX, the DSO must balance this cost element against other cost elements, to find the best way to keep TOTEX as low as possible.

In the local distribution model, there are three outputs: number of customers, number of kilometres with HV grid, and number of substations. In the regional distribution model there are four outputs, all weighted values of the physical components in the grid: the weighted value of overhead lines, underground cables, subsea cables and station components.

Both models are input minimising models assuming constant returns to scale (CRS). The yearly observations are compared against a dataset that consists of the average of the data for the last five years. This is to keep the frontier slightly more stable and thus avoid large variations from year to year.

Stage 2: Correcting for heterogeneity/Z-variables compared to the peer

We use regression analysis to identify and correct for the impact of heterogeneity on the DEA scores from stage 1. We have defined a number of Z-variables based on the geographical location of the grid. We can define for example, how much of the grid goes through forest or how far the grid is from the coastline. We also have structural variables, like the share of underground or subsea cables, for example.

There are five Z-variables in the local distribution model and one in the regional distribution. Some of the Z-variables are composite variables that we have calculated, using principal component analysis:

Local distribution
Share of network components located in forest
Comp variable 1: mountain environments: slope around grid, coniferous forest, snow accumulating on trees and local production
Comp variable 2: coastal environments: share of grid near coast, strong wind, salting
Comp variable 3: cold environments: days of deep snow, number of frost hours, days with snow and strong wind, strong wind

Z-variables for DEA model (Norway)

In stage 2, we calculate the Z values for the peers for each of the DSOs. The DEA score from stage 1 can be corrected up or down, depending on whether a DSO has “worse” conditions than its peer or not. If the peer has more of the grid through forest than the DSO we evaluate, the DEA score will be lowered in stage 2.[38]

Stage 3: Calibrating the level of the cost norms

After stage 2, all the DSOs have a DEA score that is adjusted for heterogeneity. This is multiplied by the cost base to find the cost norm. For most DSOs, the cost norm will be lower than the cost base. The cost base includes RoR on the capital, which means only the most efficient DSOs would be able to achieve the WACC in return on their investments if we used the cost norm from stage 2. In stage 3, however, the cost norms are adjusted so the sum of them equals the sum of the cost base for all DSOs. Thus, the industry as a whole has all of its costs covered and receives the WACC on its investments, although the return for each

[38] Stage 2 is more thoroughly described in Recent Developments in Data Envelopment Analysis and its Applications, pp. 334-342. Retrieved from: http://www.deazone.com/proceedings/DEA2014-Proceedings.pdf..

DSO will differ. The averagely efficient DSO can achieve the WACC on its investments. A DSO that is more (less) efficient than the average can achieve a higher (lower) return on its capital. This gives strong incentives for the DSOs to improve their efficiency. It also gives incentives for the most efficient DSOs to maintain their efficiency, since the model is calculated every year.

Annex 5.26 Case study – Portugal

Framework

This section describes the Portuguese case study of the application of the TOTEX regulatory methodology to network operation activities in Portugal (transmission and distribution). Since the beginning of ERSE's regulation, the Incentive Regulation Model has been applied to distribution activities. It focuses on CAPEX and OPEX, both at high and medium voltage (HV/MV) and at low voltage (LV). From the 2012-2014 regulatory period, an accepted cost methodology was applied to CAPEX, while a price cap type methodology was maintained for OPEX at both voltage levels. During 2018, a TOTEX incentive methodology has been implemented at the LV level, while maintaining the separate OPEX/CAPEX methodology at the HV/MV level. In the case of transmission activity, a methodology of regulation by incentives, both for CAPEX and OPEX, have only been applied since 2009, with the aim of leading the transmission system operator to better performance by giving it more freedom and, at the same time, more responsibility to act; previously, a methodology of accepted costs was applied.

For the 2022-2025 regulatory period, ERSE decided to apply the method of regulation by incentives, applied to the total controllable costs of TOTEX, to electricity transmission and distribution activities. Thus, for the current regulation period, the same regulation methodology is applied to all network operation activities, transmission and distribution, regardless of the voltage level. This decision by ERSE, which could be considered as disruptive, has been the subject of considerable discussion and reflection with the various stakeholders in the sector, namely the network operators, consumer associations and the ERSE Tariff Board, in the context of a public consultation. It should be noted that the comments received included a number of positive and supportive aspects, but also a number of unfavourable comments and resistance to change. Thus, in the final decision, following the public consultation, several proposals were accepted which addressed the main concerns of the sector's agents. These issues are discussed in more detail in this case study.

Motivation

The move towards this new methodology was based on several factors, including stability in the face of future challenges, the promotion of innovation and ensuring the economic and financial balance of regulated activities. The regulatory methods to be applied to network activities need to be defined and applied in such a way to respond to the current and future challenges and objectives of the power sector, in particular those arising from the transformation process of the European power sector, driven by the "clean energies" package.

In this way, transport and distribution activities have all the resources they need to play a decisive and indispensable role in the decarbonisation of the economy. By not favouring a distinction between CAPEX and OPEX, this type of methodology allows companies to make investment decisions in a more efficient and flexible way. Incentive regulation applied to TOTEX does not guarantee full cost recovery either, but allows the company to retain profits (in part or in full) against the targets set by the regulator. The situation is close to a, low risk market environment, in which ERSE use its powers to ensure that the economic and financial equilibrium is never jeopardised. In short, the main purpose of the application of regulation by TOTEX is to ensure that the company carrying out the regulated activity makes the most economically efficient choices in the management of its resources in order to meet the new challenges that the electricity sector will face.

Looking ahead, it is expected that similar regulatory methodologies for the more capital-intensive network activities and a regulatory approach focused on the electricity system as a whole will strengthen cooperation between the respective operators, promote a reduction in the overall costs of the networks in the medium and long term and increase the overall benefits to consumers. Moreover, some of the common challenges faced by transmission and distribution system operators in the energy transition process underway in Europe, such as the integration of renewable generation or the management of demand flexibility, suggest the need for greater convergence of the strategies of the two operators, which can be signalled by regulatory methodologies that send the same economic signals.

TOTEX Methodology

a. General aspects

The application of a methodology and regulation by incentives in TOTEX will be supported by the definition of a total cost base that integrates both controllable operating costs and capital costs associated with existing assets and planned investments. This cost base will evolve according to the selected drivers and efficiency targets, while ensuring that these targets are not retroactive to past investments. However, some costs, such as those considered uncontrollable by the company and those related to pilot projects, will be recognised outside the total cost base through a case-by-case assessment by ERSE.

Some inconveniences may arise from this methodology, such as the appearance of excessive profits, i.e. higher than desired profitability, resulting from a reduction in the level of investment compared to what was initially expected, or a possible reduction in the quality of service. To overcome these risks, it is necessary for ERSE to ensure adequate monitoring of the performance of the network, the monitoring of investments and the economic and financial performance of the company. In our specific case, this methodology is complemented by a profit and loss sharing mechanism that aims to mitigate the main risks of TOTEX by reducing the differences between the actual revenues and the allowable revenues defined by ERSE.

In general terms, and without taking into account the sharing mechanism and other costs not included in the efficiency targets, the following formulation can be considered for the TOTEX methodology, according to the ERSE Tariff Regulation.

$$\tilde{R}^{D}_{URD,t} = \underbrace{FC_{URD,t}}_{\text{Fixed Component}} + \sum_{i} \underbrace{\left(VC_{iURD,t} \times \tilde{D}C_{iURD,t}\right)}_{\text{Variable Component}}$$

- FC is a fixed component that varies with inflation and the efficiency factor;
- VC is a price component that evolves with inflation and the efficiency factor;
- DC is a quantity representing part of the evolution of the activity (cost drivers).

b. Cost Base

As mentioned above, the cost base is the amount of costs to be recovered through tariffs, defined at the beginning of the regulatory period, which evolves during the period according to the cost drivers, the defined efficiency targets and the inflation rate. Its definition implies the construction of the underlying OPEX and CAPEX components, with TOTEX being the sum of these two parts. The OPEX component is calculated using a retrospective method, while the CAPEX component is based on a prospective calculation.

Thus, in order to define the OPEX component, we proceeded as follows:

- For each operator (TSO and DSO), the starting cost base was the average between the real audited operational costs of the previous 2 years (2019 and 2020);

- Then, this real cost base was compared with the corresponding OPEX allowed revenues that had been set in the previous regulatory period for those same years. Part of the cost savings/losses was then passed on to the operator, by adding it to initial average real costs. This step was required by a general principle in the Tariff Code, which establishes that any savings/losses obtained through incentive regulation during a regulatory period must be shared between operators and consumers through the new cost base set for the subsequent regulatory period.
- In parallel, setting this new cost base involved several decisions regarding the acceptance of certain specific cost items
- The resulting new cost base was implemented in 2022 by applying $RPI - X$, where RPI is the GDP deflator and X is the efficiency target set for the previous regulatory period.

As for the CAPEX component, ERSE estimated the annual CAPEX (depreciation + RAB remuneration) for the 4 years of the new regulatory period (e.g. 2022 to 2025), based on ERSE's analysis of the operators' business plans and ERSE's opinion on their NDPs. These annual revenues were turned into an equivalent constant payment, using the new WACC as the discount rate.

c. Cost Drivers

Implementing this methodology entailed reconfiguring the cost drivers to reflect the specificities of TOTEX.

Two important constraints have been applied in defining the fixed and variable parts of TOTEX's revenues and the cost drivers related to the CAPEX components:

- No efficiency factors are applied to CAPEX for investments made before 2022. This restriction was introduced in the new tariff code (August 2021) and was raised by operators in the public consultation due to concerns about earlier financial commitments.

This restriction stipulates that CAPEX before 2022 (depreciation and RAB remuneration) must evolve with a cost factor that replicates the inverse of the RPI-X accumulated throughout the regulatory period, i.e., an efficiency adjustment.

- The evolution of the TOTEX should reflect the evolution of the financial conditions during the regulatory period in order to neutralise this evolution in the operator's investment decisions during the regulatory period.

This constraint determines that the RAB remuneration for new and past investments should evolve with a cost factor that replicates the evolution of the WACC (similar to indexation) throughout the regulatory period.

In order to meet the above constraints, two types of cost factors have been analysed and adopted for the implementation of the TOTEX methodology:

- Drivers of an economic and financial nature

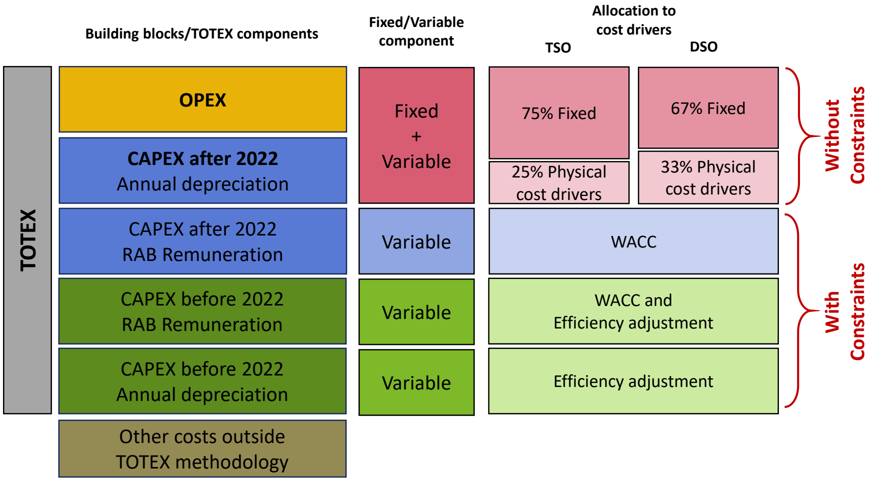
These drivers are indicators reflecting changes in financial conditions are intended to ensure that the change in the WACC is reflected in the allowed revenue of network activities, that the efficiency targets in the CAPEX components relating to investments before 2022 are offset, and that the indicators don't reflect changes in prices (e.g. equipment prices, labour costs) due to the diversity of indices and the complexity of defining their weight in network investment costs.

- Drivers based on physical quantities

This type of driver should be representative of the pace of evolution of the company's activity and reflect the corresponding evolution of the level of costs. Since the drivers must be measurable variables, they generally correspond to the outputs of the production functions. Thus, these drivers are intended to be a mix of drivers associated with (i) the evolution of network size and capacity and (ii) the results of network activities, excluding those already included in other incentives (e.g. quality of service or network losses). In addition, technologically neutral inducements were sought and preference given to those reflecting the results of network activities, so as not to induce operators to adopt pre-defined solutions.

The following figure summarises the relationship between the TOTEX methodology and its allocation to cost drivers, by fixed and variable components as well as by OPEX and CAPEX components.

Figure 1 – Building blocks and TOTEX components



Profit/loss sharing mechanism

As mentioned above, this methodology may involve some risks and challenges, mainly due to the fact that it is being applied for the first time. For this reason, the TOTEX methodology has been complemented with a profit and loss sharing mechanism. The purpose of this mechanism is to assess, for each year of the regulatory period, the deviations of the profitability of the activity in relation to the return on assets defined by ERSE. The aim of the mechanism is to minimise the risk of excessive deviations from a baseline return, thereby protecting companies and consumers from a possible unbalanced calibration and/or parameterisation in this first regulatory period of wider application of the TOTEX methodology. As the sharing mechanism is applied over the horizon of a regulatory period, its activation will result from the comparison of the average of the regulatory operating profitability verified in the years of that regulatory period with the average of the tariffs in the same period. Thus, a mechanism, defined *ex ante*, is proposed which will be applied after the end of the regulatory period. Its impact on tariffs can, therefore, only be felt two years after the end of each regulatory period, at the time of the final adjustments for that last year.

In short, this mechanism is designed to be progressive and to encourage companies to improve their efficiency. Hence, there are three bands corresponding to different levels of excess or shortfall in profitability in relation to the return on assets, characterised as follows

- normal band - profitability in relation to the rate of return is within normal limits (the mechanism is not activated)

- moderate band - profitability deviates moderately from the rate of return (above a spread called δ^{MOD}but below the spread that defines the beginning of the extreme band), with a fair sharing of gains or losses between firms and consumers, i.e. with a sharing factor equal to 0.5;
- extreme band - profitability is critically different from the rate of return (above a spread called δ^{EXT}), with full replacement of profits or losses above the threshold of the band, i.e. the sharing factor within this band is equal to 1.

In order to apply this mechanism, it is necessary to define the parameters that delimit the three bands, in particular the extreme and moderate band spread.

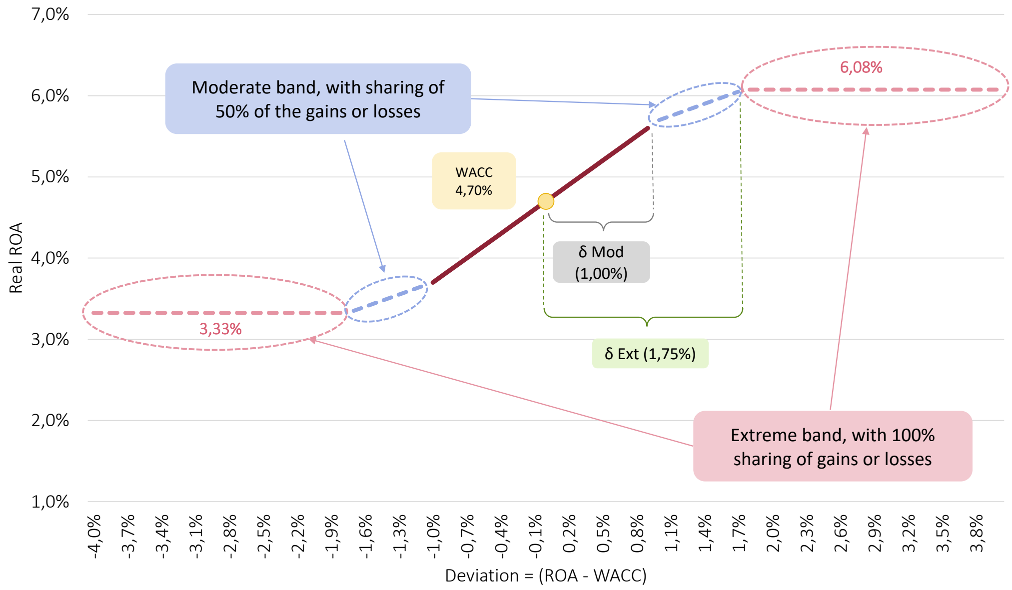
A simulation of the application of this mechanism and its parameters for TSO and DSO is shown in the following figures. For the TSO, the parameters defined are presented below:

Table 1 – Parameters of the Profit/loss sharing mechanism for the Transmission and Distribution activity

	TSO	DSO
WACC	4,40%	4,70%
δ^{MOD}	0,625p.p.	1,000p.p.
δ^{EXT}	1,50p.p.	1,750p.p.

It should be noted that the bands for transmission and distribution activities are not the same, due to the greater weight of revenues subject to efficiency targets in distribution, where the OPEX component is more significant. Differentiating the bands ensures that the same regulatory approach applies to both activities, with equivalent treatment in different situations. In short, although paradoxical, treating distribution and transmission in the same way requires the application of differentiated bands to these activities. The following figure illustrates the mechanism for the DSO:

Figure 2 – Profit/loss sharing mechanism for the Distribution activity



Challenging Points

The process of implementation of the TOTEX methodology presented several challenges and uncertainties for the regulator, namely how to deal with unpredictable events, such as the limitation of inflated business plans and the introduction of new investments approved in NDPs.

Dealing with unforeseeable events

A key concern expressed by operators during the consultation was the treatment of costs and investments incurred as a result of extreme and unforeseen circumstances caused by changes in legislation, energy policy decisions or other unforeseen circumstances, which were properly justified by the company. The TOTEX methodology mitigates this risk partially, but not completely, through the profit/loss sharing mechanism.

There are two approaches to solving this problem. On the one hand, a general revision of the regulatory parameters, such as the TOTEX cost base, may be justified if the level of additional and unforeseen costs is so high that it could jeopardise the economic sustainability of operators. This hypothesis is in line with the provisions of the Tariff Regulation. On the other hand, if the unforeseen event has a minor but still justifiable impact on the operators' costs, then these costs can be included in the annual allowed revenues, albeit separately from the TOTEX revenues. However, after almost three years under TOTEX, ERSE has not received any such request.

How to limit inflated business plans

As mentioned above, this methodology carries the risk that operators will submit unrealistic business plans. It is necessary to encourage operators to be truthful in their business plans and to disclose their real cost reduction opportunities, thereby reducing information asymmetries and incentives to artificially inflate cost forecasts. In order to address and mitigate these risks, it will be necessary for ERSE to closely monitor the implementation of the business plans that underpin the cost base of TOTEX, and to act to review the regulatory parameters if there is significant underinvestment without adequate justification. Furthermore, the sharing mechanism described above mitigates, through its bands, the revenues generated by overstated business plans.

Inclusion of new investments approved in NDPs

Another concern raised by operators in the public consultation was the investments that would be included in the CAPEX component of the new TOTEX initial cost base, as in some cases their business plans included investments that had not yet been approved through the NDP process. This concern was taken into account in the design of the methodology and ERSE agreed to include all investments involved in existing NDPs that had already received ERSE's opinion, even if they had not yet been approved by the government. Regarding the treatment of additional investments approved under new NDPs during the regulatory period, ERSE's TOTEX methodology does not include a specific provision to adjust the annual allowable revenue to the new NDP, which is in line with the reasons for choosing TOTEX outlined at the beginning of this case study. However, if investments in new NDP have a significant impact on operators' costs and are considered unavoidable or legally binding, they will be assessed by the regulator.

Annex 5.30 Case study – Spain

Introduction

This case study describes the regulatory regime that applies to an electricity transmission company in Spain, in order to set its remuneration. It is based on the methodology established by Circular 5/2019, of 5 December, of Comisión Nacional de los Mercados y la Competencia (CNMC, the Spanish NRA). Further details can be found in Circular 5/2019[39] and its justifying report.[40]

The annual remuneration received by the transmission company i is calculated by summing up the components of the following formula for year n: $R_n^i = RI_n^i + ROM_n^i + REVU_n^i + ID_n^i$, where:

- RI is investment remuneration;
- ROM is O&M remuneration;
- $REVU$ is remuneration for the extended regulatory lifetime of assets; and
- ID is the grid availability incentive.

Once the annual remuneration has been calculated, if assets and other regulated resources have been used in other activities, an adjustment will be made. There is also a penalty that is applied if the recommended values of several economic and financial ratios are not met.

This annual remuneration and the adjustments, if any, determine the allowed revenue for the electricity transmission company.

Assets commissioned in year n start receiving revenues in year n+2. This means that, if the calculation is made for year 2020, the last year considered is 2018. There are factors that compensate for this delay.

Application example

A simplified fictional example of the application of the Spanish remuneration regime for an electricity transmission company is given.

For the sake of simplicity and given that both the investment and the O&M remuneration are based on the cost of individual assets, only six different asset types have been considered in this example. They are shown in the table below.

[39] See https://www.boe.es/buscar/act.php?id=BOE-A-2019-18260.
[40] See https://www.cnmc.es/sites/default/files/2782083_19.pdf.

Asset nº	Technical characteristics	Commissioning	Location	Regulatory lifetime	Audited cost (€)	Other characteristics
1	Overhead single duplex transmission line of 10 km, 400 kV and 1,000 MVA	1 January 2018	Iberian Peninsula	40 years	3,100,000	20% was financed and transferred by a third party
2	Conventional substation bay, 400 kV, 50 kA, all configurations	1 January 2018	Iberian Peninsula	40 years	900,000	-
3	Single-phase transformer (400/220 kV), 200 MVA	1 January 2019	Iberian Peninsula	40 years	1,800,000	-
4	Overhead single duplex transmission line of 8 km, 220 kV and 200 MVA	1 January 2019	Tenerife	40 years	4,200,000	EU subsidy of €2,000,000
5	Overhead single duplex transmission line of 10 km, 400 kV and 1,000 MVA	1 January 1978	Iberian Peninsula	40 years	Not necessary because its regulatory lifetime expires 31 December 2017	-
6	Underwater cable, 8 km, 132 kV, 100 MW	1 January 2018	Balearic Islands	40 years	4,500,000	Considered as a unique facility

Asset types (Spain)

The remuneration is calculated for the RP that ranges from 1 January 2020 to 31 December 2025, the first in which the new methodology is used.

Step 1: Determination of the investment remuneration (RI)

To calculate the investment remuneration (RI), we add the depreciation and the financial retribution terms for the assets that have not exceeded their regulatory lifetime. In this example, all assets receive investment remuneration except asset number 5 because it reached its regulatory lifetime (40 years) on 31 December 2017.

The magnitude of both terms, depreciation and financial retribution depends on the recognised value of the investments. To determine the recognised value of the investments, there are two different approaches, depending on whether the assets are considered as unique facilities or not.

For those assets not considered as unique facilities, the recognised value of investments can be calculated in three ways depending on the date of commissioning:

- For facilities commissioned prior to 1 January 1998: the recognised value of investment is considered as a whole, not asset by asset. It was set in 2016 by the Directorate General for Energy Policy and Mines;
- For facilities commissioned from 1 January 1998 to 31 December 2017: there is a recognised investment value for each asset, whose calculation is based on the methodology established by Royal Decree 1047/2013.[41] For those assets commissioned

[41] See https://www.boe.es/buscar/act.php?id=BOE-A-2013-13766.

from 1 January 2015 onwards, the investment value is calculated as the average of the reference values and the audited cost of the asset; and

- For facilities commissioned from 1 January 2018 to year n-2 (the case of our fictional example): there is an investment value for each asset, also calculated as the average of the reference values and the audited cost of the asset, but a new limitation is introduced if the audited cost is higher than the reference value divided by 0.85. Circular 7/2019[42] of CNMC has established that the investment reference values for the RP 2020-25 are those established in the catalogue of Order IET/2659/2015,[43] shown below for the assets in the example.

Electricity transmission assets	$VI^{reference\ value}$	
Power lines	*Variable term (€/km)*	*Fixed term (€)*
Asset nº 1: 10 km, in Peninsula	298,437	-
Asset nº4: < 10 km, in Tenerife	404,937	824,267
Substation bays	*Term in €/bay*	
Asset nº2	1,043,909	
Transformers	*Variable term (€/MVA)*	
Asset nº3	9,835	

Electricity transmission assets (Spain)

The reference values for mainland assets are determined according to the average values considered as representative for the cost of each asset, whose technical design and operating conditions fit to the standards used in the Spanish mainland electricity system. The reference values for the assets located in non-mainland electricity systems can differ according to the particularities derived from their geographical location and isolation. In any case, the reference values will be calculated based on regulatory information on costs.

For the assets considered as unique facilities, the investment reference values are not used, as these assets do not fit in the catalogue. Unique facilities are those whose design, operative and technical characteristics differ from the standards, namely underwater laying, direct current transmission lines, AC/DC converter stations, as well as remote control stations. Additionally, investments in pilot projects could be considered as unique ones.

Circular 2/2019[44] sets the RoR of investments based on a WACC methodology. For electricity transmission in the RP 2020-25, the RoR takes a value of 5.58% (nominal pre-tax). There is an exception for the year 2020, when RoR takes a value of 6.0033% according to the fourth Additional Provision of Circular 5/2019.

The formulas to calculate the investment remuneration for our fictional electricity transmission company, and the results obtained, are shown below.

[42] See https://www.boe.es/buscar/act.php?id=BOE-A-2019-18262.
[43] See https://www.boe.es/buscar/act.php?id=BOE-A-2015-13487.
[44] See https://www.boe.es/buscar/act.php?id=BOE-A-2019-16639.

Investment remuneration for assets in service from 1st January 2018 to year n-2

$$\mathrm{RI}_n^i = \sum_{\forall j \text{ of } i} \mathrm{RI}_n^j$$

$$\mathrm{RI}_n^j = \mathrm{A}_n^j + \mathrm{RF}_n^j$$

$$\mathrm{A}_n^j = \frac{\mathrm{VI}^j}{\mathrm{VU}^j} \qquad \mathrm{RF}_n^j = \mathrm{VN}_n^j \cdot \mathrm{TRF}_p$$

$$\mathrm{VN}_n^j = \mathrm{VI}^j - (k-2) \cdot \frac{\mathrm{VI}^j}{\mathrm{VU}^j}$$

$$\mathrm{VI}^j = \left[\left(\mathrm{VI}_{n-2}^{j,\text{audited}} + \frac{\mathrm{VI}_{n-2,p}^{j,\text{reference value}} - \mathrm{VI}_{n-2}^{j,\text{audited}}}{2}\right) \cdot \delta_j - \mathrm{AY}^j\right] \cdot \mathrm{FRRI}_{n-2}^j$$

$$\mathrm{FRRI}_{n-2}^j = (1 + \mathrm{TRF}_{APS})^{tr^j}$$

For unique facilities, this parameter is the investment value considered in the uniqueness request: $\mathrm{VI}_{n-2}^{j,\text{uniqueness request}}$

j	asset
i	transmission company
n	year
p	regulatory period
A	depreciation
RF	financial remuneration
VI	investment value
VU	regulatory lifetime
VN	net investment value
TRF	rate-of-return
k	number of years from commissioning
$VI^{audited}$	audited investment cost
$VI^{reference\ value}$	reference investment value
δ	1 less the proportion financed or transferred by third parties
AY	public subsidies received
FRRI	remuneration delay factor
TRF_{APS}	rate-of-return of the year of the operating licence
tr	time remuneration delay: number of years between the date of the operating licence and the start of revenues

Calculating investment remuneration (Spain)

For each non-unique asset, if there is a big difference between its audited cost and its reference value, the limits established in Articles 7.3 and 7.4 of Circular 5/2019 will be applied to the recognised investment value.

In particular, if the transmission company is able to build an asset at an audited cost below its reference value, half of the difference between the reference value and the audited cost will be limited up to 12.5% of the audited cost. On the other hand, for assets built from 1 January 2018 onwards, if the audited cost is higher than the reference value divided by 0.85, the transmission company has to submit a technical audit justifying the high costs, and the recognised investment value is calculated using the reference value plus the 12.5% of the reference value.

For unique assets, according to Article 9 of Circular 5/2019, the recognised investment value cannot be higher than 25% of the investment value established in the uniqueness request. In this example, none of these limits are exceeded.

Asset	$VI^{audited}$ (€)	$VI^{reference\ value}$ (€)	δ	AY (€)	TRF_{APS}	tr[45]	FRRI	VI^j
Assets that start to receive remuneration in 2020								
1	3,100,000	2,984,370	0.8	0	6.503%	2.00	1.1	2,760,573
2	900,000	1,043,909	1.0	0	6.503%	2.00	1.1	1,102,477
6	4,500,000	5,000,000[46]	1.0	0	6.503%	2.00	1.1	5,387,872
Assets that start to receive remuneration in 2021								
3	1,800,000	1,967,000	1.0	0	6.503%	2.00	1.1	2,136,433
4	4,200,000	4,063,763	1.0	1,800,000[47]	6.503%	2.00	1.1	2,645,027
5	As the asset has exceeded its regulatory lifetime (40 years), it does not receive any investment remuneration							

Investment values (Spain)

[45] We assume that the date when it obtains the operating licence and the commissioning date are the same.
[46] There are no reference values for unique facilities; this is the investment value of the uniqueness request ($\mathrm{VI}_{n-2}^{j,\text{uniqueness request}}$).
[47] As the asset receives a subsidy from the EU, this value is 90% of the subsidy received, as established in Article 7.2 of Circular 5/2019.

				2020	2021	2022	2023	2024	2025
			TRF_P	6.0033%[48]	5.58%	5.58%	5.58%	5.58%	5.58%
Assets commissioned in 2018			k	2	3	4	5	6	7
1	VI_1	2,760,573	VN_1	2,760,573	2,691,559	2,622,545	2,553,530	2,484,516	2,415,502
	A_1	69,014	RF_1	165,725	150,189	146,338	142,487	138,636	134,785
	VU_1	40 years	RI_1	234,740	219,203	215,352	211,501	207,650	203,799
2	VI_2	1,102,477	VN_2	1,102,477	1,074,915	1,047,353	1,019,791	992,229	964,668
	A_2	27,562	RF_2	66,185	59,980	58,442	56,904	55,366	53,828
	VU_2	40 years	RI_2	93,747	87,542	86,004	84,466	82,928	81,390
6[49]	VI_6	5,387,872	VN_6	5,387,872	5,253,175	5,118,479	4,983,782	4,849,085	4,714,388
	A_6	134,697	RF_6	323,450	293,127	285,611	278,095	270,579	263,063
	VU_6	40 years	RI_6	458,147	427,824	420,308	412,792	405,276	397,760
Assets commissioned in 2019			k		2	3	4	5	6
3	VI_3	2,136,433	VN_3		2,136,433	2,083,022	2,029,611	1,976,201	1,922,790
	A_3	53,411	RF_3		119,213	116,233	113,252	110,272	107,292
	VU_3	40 years	RI_3		172,624	169,643	166,663	163,683	160,703
4	VI_4	2,645,027	VN_4		2,645,027	2,578,902	2,512,776	2,446,650	2,380,525
	A_4	66,126	RF_4		147,593	143,903	140,213	136,523	132,833
	VU_4	40 years	RI_4		213,718	210,028	206,339	202,649	198,959
Investment remuneration (€), RI				**786,634**	**1,120,912**	**1,101,336**	**1,081,761**	**1,062,186**	**1,042,611**

Investment remuneration (Spain)

Step 2: Determination of the operation and maintenance remuneration (ROM)

To calculate the O&M remuneration (ROM) for a transmission company, we add the O&M remuneration for each of its assets in service.

For assets not considered as unique facilities, the O&M remuneration is based on reference values, multiplied by an efficiency factor. In this example, all assets receive O&M remuneration because all of them are in service as of 31 December 2018. The reference values for O&M are established by Circular 7/2019 and are shown in the table below for the asset types of the example.

Electricity transmission assets	VOM
Power lines	*Variable term (€/km and circuit)*
Assets nº 1,5: 10 km, in Peninsula	3,056
Asset nº4: < 10 km, in Tenerife	3,255
Substation bays	*Variable term (€/bay)*
Asset nº2	47,339
Transformers	*Variable term (€/MVA)*
Asset nº3	131

O&M reference values (Spain)

The calculation is made gathering the assets in families of electricity transmission assets, which are defined in the annex of Circular 5/2019. For each family of assets, there is an O&M reference value. In this fictional example, we have four different families of assets:

- Overhead lines at 400 kV;
- Overhead lines at 220 kV;
- Conventional substation bay at 400 kV; and
- Transformer with primary at 400 kV.

[48] According to the fourth Additional Provision of Circular 5/2019, for 2020 the RoR has been established as 6.0033% for the first year of the first RP in which this methodology applies (2020).
[49] Asset considered as unique facility.

For assets considered as unique facilities, O&M remuneration is based on the value of operation and maintenance established in the uniqueness request and a beta factor that allows its adjustment to the actual cost. This parameter takes a value of one in the first year and can be adjusted from the second year onwards, according to the information provided by the transmission agent to CNMC. In no case can the O&M remuneration for unique assets be higher than 25% of the value of O&M established in the uniqueness request.

The formulas to calculate the O&M remuneration for our fictional transmission agent, and the results obtained, are shown below.

O&M remuneration for assets in service

$$\mathbf{ROM_n^i} = \sum_{\forall \text{F of i}} \mathrm{ROM}^{\mathrm{F,i}}_{\mathrm{n,ccuu}} \cdot (1 + \theta^{\mathrm{i}})$$

$$\mathrm{ROM}^{\mathrm{F,i}}_{\mathrm{n,ccuu}} = \sum_{\forall \text{j of F}} \mathrm{ROM}_{\mathrm{n}}^{\mathrm{j}} \qquad \theta^{\mathrm{i}} = \alpha \cdot \frac{\mathrm{ROM}^{\mathrm{i}}_{\mathrm{k-1,ccuua}} - \mathrm{ROM}^{\mathrm{i}}_{\mathrm{k-1,ccuu}}}{\mathrm{ROM}^{\mathrm{i}}_{\mathrm{k-1,ccuu}}}$$

$$\mathrm{ROM}_{\mathrm{n}}^{\mathrm{j}} = \mathrm{VOM}_{\mathrm{p}}^{\mathrm{j}} \cdot \mathrm{UF_i} \cdot \mathrm{FRROM}_{\mathrm{p}}^{\mathrm{j}}$$

$$\mathrm{FRROM}_{\mathrm{p}}^{\mathrm{j}} = (1 + \mathrm{TRF_p})^{\mathrm{tr\_om_j}}$$

For **unique facilities**, the O&M remuneration is determined as:

$$\mathrm{ROM}_{\mathrm{n}}^{\mathrm{j}} = \mathrm{ROM}^{\mathrm{j}}_{\text{uniqueness request}} \cdot \mathrm{FRROM}_{\mathrm{p}}^{\mathrm{j}} \cdot \beta$$

j	asset
i	transmission company
F	family of assets
n	year
p	regulatory period
k	first year of the regulatory period
n,ccuu	reference values of the year n
k-1, ccuu	reference values of the year k
k-1, ccuua	reference values of the year k-1
ROM	O&M remuneration
θ	O&M efficiency factor
α	parameter that allows companies to retain a percentage of the drop of reference values (incentive to promote cost efficiency)
VOM	O&M reference value
UF	number of assets
FRROM	O&M remuneration delay factor
tr_om_j	number of years O&M remuneration delay
$ROM_{uniqueness}$	O&M remuneration established in the uniqueness request
β	parameter to adjust the O&M cost established in the uniqueness request to the actual cost

Calculating O&M remuneration (Spain)

The aim of the efficiency factor (θ) is to adapt the O&M remuneration of transmission companies, calculated with the reference values of the previous RP, to the remuneration calculated according to the reference values of the current RP. If the companies are able to lower their O&M costs during an RP, the O&M reference values of the next RP can be set lower, to allow customers to benefit from this cost reduction. Nonetheless, the efficiency factor (θ) contains a parameter (alpha) that allows companies to retain a percentage of the drop in reference values, which serves as an incentive to promote cost efficiency.

In this example, the calculation of the efficiency factor is based on the O&M remuneration of year 2019 (year k-1, where k is the first year of the RP 2020-25), calculated according to the reference values set in Order IET/2659/2015, and the O&M remuneration of year 2019 calculated according to the new reference values defined by Circular 7/2019. Notice that, for this fictional example, we use the only asset that was in service in 2017 (as to calculate 2019's remuneration we take into account assets in service up to 2017). This is asset number 5, which corresponds to an electricity transmission line.

The O&M reference value established by Order IET/2659/2015 for a transmission line of 10 km located in the Iberian Peninsula is €3,106 per km and circuit. Taking into account that alpha takes a value of 0.5, as established in the second Additional Provision of Circular 5/2019, and that the O&M reference value for the current RP is €3,056 per km and circuit, the efficiency factor takes a value of 0.8%, as shown below:

$$\theta = 0.5 * \frac{3{,}106\frac{€}{km*circuit}*10\ km*1\ circuit - 3{,}056\frac{€}{km*circuit}*10\ km*1\ circuit}{3{,}056\frac{€}{km*circuit}*10\ km*1\ circuit} = 0.008.$$

				2020	2021	2022	2023	2024	2025
Family	Asset	TRF_P		6.0033%[50]	5.58%	5.58%	5.58%	5.58%	5.58%
Family I	1	tr_om=1 UF=1 VOM=30,560	$FRROM_{I,1}$	1.060	1.056	1.056	1.056	1.056	1.056
			$ROM_{I,1}$	32,395	32,265	32,265	32,265	32,265	32,265
	5	tr_om=0 FRROM=1 UF=1 VOM=30,560	$ROM_{I,5}$	30,560	30,560	30,560	30,560	30,560	30,560
Family II	4	tr_om=1 FRROM=1.056 UF=1 VOM=26,040	ROM_{II}		27,493	27,493	27,493	27,493	27,493
Family III	2	tr_om=1 UF=1 VOM=47,339	$FRROM_{III}$	1.060	1.056	1.056	1.056	1.056	1.056
			ROM_{III}	50,181	49,981	49,981	49,981	49,981	49,981
Family IV	3	tr_om=1 FRROM=1.056 UF=1 VOM=26,200	ROM_{IV}		27,662	27,662	27,662	27,662	27,662
ROM_{ccuu}				**113,136**	**167,961**	**167,961**	**167,961**	**167,961**	**167,961**
Θ				**0.8%**					
O&M remuneration for non-unique facilities (€)				**114,061**	**169,335**	**169,335**	**169,335**	**169,335**	**169,335**
Unique facility	6	ROM=55,000 tr_om=1	$FRROM_{unique}$	1.060	1.056	1.056	1.056	1.056	1.056
			β[51]	1	0.98	0.98	0.98	0.98	0.98
			ROM_{unique}	58,302	56,908	56,908	56,908	56,908	56,908
O&M remuneration (€), ROM				**172,363**	**226,242**	**226,242**	**226,242**	**226,242**	**226,242**

O&M remuneration (Spain)

Step 3: Determination of the remuneration for extending the regulatory lifetime (REVU)

There is only one asset that receives remuneration for extending its regulatory lifetime, asset number 5, which is an electricity transmission line commissioned on 1 January 1978. Consequently, its regulatory lifetime (40 years) ended on 31 December 2017, and, in 2018, as it is still in service, it only receives O&M remuneration and this complement.

Remuneration for extending the regulatory lifetime of assets

$$\mathbf{REVU}_n^i = \sum_{\forall j \text{ of } i} \mathrm{REVU}_n^j$$

$$\mathrm{REVU}_n^j = \mu_n^j \cdot \mathrm{ROM}_n^j$$

$x \leq 5$ years	$\mu_n^j = 0.30$
$6 \leq x \leq 10$ years	$\mu_n^j = 0.30 + 0.01 \cdot (x-5)$
$11 \leq x \leq 15$ years	$\mu_n^j = 0.35 + 0.02 \cdot (x-10)$
$x > 15$ years	$\mu_n^j = 0.45 + 0.03 \cdot (x-15)$

j	asset
i	transmission company
n	year
x	years exceeding the regulatory lifetime
μ	exceeding regulatory lifetime coefficient
ROM	O&M remuneration

Extending the regulatory lifetime of assets (Spain)

[50] According to the fourth Additional Provision of Circular 5/2019, for 2020 the RoR has been established as 6.0033% for the first year of the first RP in which this methodology applies (2020).
[51] We assume that from 2021 on, the actual O&M costs of this unique facility are lower than the ones established in the uniqueness request.

Asset		2020	2021	2022	2023	2024	2025
1	$REVU_1$	It has not exceeded its regulatory lifetime					
2	$REVU_2$	It has not exceeded its regulatory lifetime					
3	$REVU_3$	It has not exceeded its regulatory lifetime					
4	$REVU_4$	It has not exceeded its regulatory lifetime					
5	ROM_5	30,560	30,560	30,560	30,560	30,560	30,560
	μ_5	0.30	0.30	0.30	0.30	0.30	0.31
	$REVU_5$	9,168	9,168	9,168	9,168	9,168	9,474
6	$REVU_6$	It has not exceeded its regulatory lifetime					
Remuneration for the extension of the regulatory lifetime (€), REVU		**9,168**	**9,168**	**9,168**	**9,168**	**9,168**	**9,474**

Remuneration for the extension of regulatory lifetime (Spain)

Step 4: Determination of the grid availability incentive (ID)

The grid availability incentive applies to the families of electricity transmission assets. These families of assets have a homogeneous treatment regarding the grid availability incentive because, given their functions and technical characteristics, they have a similar failure rate.

These families of electricity transmission assets are established in the annex of Circular 5/2019. In this fictional example, we have three different types of families of assets:

- Overhead lines at 400 kV;
- Overhead lines at 220 kV; and
- Transformer with primary at 400 kV.

Substation bays and assets considered as unique facilities are not taken into account in the calculation of the grid availability incentive.

The grid availability incentive for an electricity transmission company can range between a minimum of -3.5% and a maximum of +2.5% of its O&M remuneration for that year.

Grid availability incentive

$$\mathbf{ID_{i,n}} = (CMax_{i,n} \text{ or } CMin_{i,n}) \cdot \frac{D^{i}_{n-2} - D^{min-i}_{n-2}}{D_{period\ target} - D^{min-i}_{n-2}}$$

$$CMax_{i,n} \quad \text{if} \quad (D^{i}_{n-2} - D^{min-i}_{n-2}) > 0$$

$$CMin_{i,n} \quad \text{if} \quad (D^{i}_{n-2} - D^{min-i}_{n-2}) < 0$$

$$D^{i}_{n-2} = \sum_{\forall F} IDF^{i}_{n-2} \cdot k_{F,n-2}$$

$$CMax_{i,n} = +2.5\% \cdot ROM^{i}_{n}$$

$$CMin_{i,n} = -3.5\% \cdot ROM^{i}_{n}$$

$$IDF^{i}_{n-2} = 100 - IIF^{i}_{n-2}$$

$$IIF^{i}_{n-2} = \frac{\sum_{\forall j \text{ of } i \in F} t_j \cdot PN_j}{\sum_{\forall j \text{ of } i \in F} T_j \cdot PN_j} \qquad k_{F,n-2} = \frac{\sum_{\forall j \text{ of } i \in F} VOM_{F,j} \cdot UF_j}{\sum_{\forall j \text{ of } i} VOM_j \cdot UF_j}$$

j	asset
i	transmission company
F	family of assets
n	year
VOM	O&M reference value
UF	number of assets
t	number of hours of interruption
T	yearly hours
PN	nominal power
ROM	O&M remuneration
D^{min-i}	minimum availability required to the company in order to not to be penalised
$D_{period\ target}$	availability target for the period

Calculating the grid availability incentive (Spain)

				2020	2021	2022	2023	2024	2025
Tj (h)				8,760	8,760	8,784	8,760	8,760	8,760
Family I (assets 1, 5)	UF_I	2	$t_{I,1}$ (h)	160	170	200	240	155	145
	$PN_{I,1}$	1000 MVA	$t_{I,5}$ (h)	200	190	300	260	145	135
	$PN_{I,5}$	1000 MVA	IIF_I	2.05%	2.05%	2.85%	2.85%	1.71%	1.60%
	VOM_I	30.560 €	k_I	70%	54%	54%	54%	54%	54%
			IDF_I	97.95%	97.95%	97.15%	97.15%	98.29%	98.40%
Family II (asset 4)	UF_{II}	1	t_{II} (h)		90	200	90	120	100
	PN_{II}	200 MVA	IIF_{II}		1.03%	2.28%	1.03%	1.37%	1.14%
	VOM_{II}	26.040 €	k_{II}		23%	23%	23%	23%	23%
			IDF_{II}		98.97%	97.72%	98.97%	98.63%	98.86%
Family III (asset 3)	UF_{III}	1	t_{III} (h)	150	100	200	120	120	150
	PN_{III}	200 MVA	IIF_{III}	1.71%	1.14%	2.28%	1.37%	1.37%	1.71%
	VOM_{III}	26.200 €	k_{III}	30%	23%	23%	23%	23%	23%
			IDF_{III}	98.29%	98.86%	97.72%	98.63%	98.63%	98.29%
D				98.05%	98.39%	97.42%	97.91%	98.45%	98.48%
D_{min}[52]				97.50%	97.60%	97.80%	97.95%	97.91%	97.92%
$D_{period\ target}$				98.50%	98.50%	98.50%	98.50%	98.50%	98.50%
$D_{period\ target} - D_{min}$[53]				1.00%	0.90%	0.70%	0.55%	0.59%	0.58%
CMax				4,309	5,656			5,656	5,656
CMin						-7,918	-7,918		
Grid availability incentive, ID (€)				**2,361**	**4,979**	**-4,341**	**-629**	**5,137**	**5,463**

Grid availability incentive (Spain)

Step 5: Determination of the financial prudence penalty

A penalty on the remuneration is established for those companies that do not meet the recommended values of several economic and financial ratios. These ratios, and their recommended values, are defined in the Communication 1/2019[54] of the CNMC. The maximum penalty is 1% of the remuneration.

Nevertheless, as established in the third Additional Provision of Circular 5/2019, this penalty would not be applied until 2023, to let the companies adapt to the recommended values.

Financial prudence penalty

$$\mathbf{PPF_n} = -0.01 \cdot RA_n \cdot (1 - IGR_n) \qquad \text{if} \quad IGR_n < 0.90$$

$$IGR = 0.1 \cdot R1 + 0.05 \cdot R2 + 0.3 \cdot R3 + 0.2 \cdot R4 + 0.35 \cdot R5$$

Ratios	Recommended values	R value for the IGR
$\text{Ratio 1} = \frac{\text{Net debt}}{\text{Net debt + Equity}}$	≤70%	R1 = 0 if Ratio 1 > 70% R1 = 1 if Ratio 1 ≤70%
$\text{Ratio 2} = \frac{\text{Funds arising from operations + Interest expenses}}{\text{Interest expenses}}$	≥5.0	R2 = 0 if Ratio 2 < 5.0 R2 = 1 if Ratio 2 ≥ 5.0
$\text{Ratio 3} = \frac{\text{Net debt}}{\text{RAB + Assets under construction}}$	≤70%	R3 = 0 if Ratio 3 > 70% R3 = 1 if Ratio 3 ≤70%
$\text{Ratio 4} = \frac{\text{Net debt}}{\text{EBITDA}}$	≤6.0	R4 = 0 if Ratio 4 > 6.0 R4 = 1 if Ratio 4 ≤ 6.0
$\text{Ratio 5} = \frac{\text{Net debt}}{\text{Funds arising from operation}}$	≤7.3	R5 = 0 if Ratio 5 > 7.3 R5 = 1 if Ratio 5 ≤ 7.3

PPF penalty value
n each year of the regulatory period
RA annual remuneration of the transmission agent
IGR general ratios index
R1 ratio 1
R2 ratio 2
R3 ratio 3
R4 ratio 4
R5 ratio 5

Net debt = Long-term debts + Long-term debts payable to group companies and associates + Short-term debts + Short-term debts payable to group companies and associates – Cash and cash equivalents
Funds arising from operations = Cash flow from operating activities – Changes in working capital – Capitalized expenses
EBITDA = Operating result + Depreciation + Impairments and gains/losses on disposal of non-current assets

Calculating the financial prudence penalty (Spain)

[52] The minimum availability index required for the company to not be penalised is determined as the average of the availability index in the three years prior to year n-2. In consequence, for years 2023-25 the minimum availability indexes have been calculated for the fictional example, but for years 2020-22, we have assumed their values.
[53] According to Article 15.7 of Circular 5/2019, ($D_{period\ target} - D_{min}$) cannot take a value lower than 0.1.
[54] See https://www.boe.es/diario_boe/txt.php?id=BOE-A-2019-15789.

Financial statements	Items (in thousand €)	2020	2021	2022	2023	2024	2025
Balance sheet	Long-term debts	3,000	2,800	2,500	1,100	1,000	1,000
	Long-term debts payable to group companies and associates	2,200	2,100	2,100	2,000	2,000	2,000
	Short-term debts	1,500	700	500	500	500	200
	Short-term debts payable to group companies and associates	1,000	800	800	700	700	500
	Cash and cash equivalents	500	500	100	500	1,000	1,000
	Equity	2,500	2,000	2,200	2,200	2,100	2,100
	Assets under construction	4,781	0	0	0	0	0
Profit & loss account	Capitalised expenses	0	0	0	0	0	0
	Operating result	1,200	1,200	1,100	1,000	1,000	1,100
	Depreciation[55]	200	300	300	300	300	300
	Impairments and gains/ losses on disposal of non-current assets[55]	30	35	40	45	50	40
Cash flow statement	Cash flow from operating activities	800	900	900	900	1,000	1,100
	Changes in working capital	-50	-45	-40	-40	-35	-35
	Interest expenditures[55]	300	250	200	110	100	80
RAB		9,251	13,801	13,450	13,099	12,749	12,398
Calculated magnitudes	Net debt	7,200	5,900	5,800	3,800	3,200	2,700
	Funds arising from operations	850	945	940	940	1,035	1,135
	Earnings before interest, taxes, depreciation and amortisation (EBITDA)	1,430	1,535	1,440	1,345	1,350	1,440
Ratio 1	Result	74%	75%	73%	63%	60%	56%
	Recommended value	Maximum of 70%					
	Value for IGR	0	0	0	1	1	1
Ratio 2	Result	3.8	4.8	5.7	9.5	11.4	15.2
	Recommended value	Minimum of 5.0					
	Value for IGR	0	0	1	1	1	1
Ratio 3	Result	51%	43%	43%	29%	25%	22%
	Recommended value	Maximum of 70%					
	Value for IGR	1	1	1	1	1	1
Ratio 4	Result	5.0	3.8	4.0	2.8	2.4	1.9
	Recommended value	Maximum of 6.0					
	Value for IGR	1	1	1	1	1	1
Ratio 5	Result	8.5	6.2	6.2	4.0	3.1	2.4
	Recommended value	Maximum of 7.3					
	Value for IGR	0	1	1	1	1	1
IGR_n		0.50	0.85	0.90	1.00	1.00	1.00
RA_n (€)		970,526	1,361,301	1,332,406	1,316,543	1,302,734	1,283,790
Penalty, PPF_n (€)		**-4,853**[56]	**-2,042**[56]	**0**[56]	**0**	**0**	**0**

Financial prudence penalties (Spain)

Step 6: Final calculation of the total remuneration

To determine the total remuneration of a transmission company we add the terms of investment and O&M remuneration, the remuneration for the extended regulatory lifetime of assets, and the grid availability incentive. Then the remuneration adjustment is applied if some assets and resources have been used in other activities, and the financial prudence penalty is applied.

[55] To make the calculation, these items change their sign.
[56] The penalty does not apply until 2023, according to the third Additional Provision of Circular 5/2019.

	2020	2021	2022	2023	2024	2025
Investment remuneration	786,634	1,120,912	1,101,336	1,081,761	1,062,186	1,042,611
O&M remuneration	172,363	226,242	226,242	226,242	226,242	226,242
Remuneration for exceeding assets regulatory lifetime	9,168	9,168	9,168	9,168	9,168	9,474
Grid availability incentive	2,361	4,979	-4,341	-629	5,137	5,463
Adjustment due to the use of assets and resources in other activities	In this example we assume that all the assets are only used in the electricity transmission activity, so we do not have to make any adjustment.					
Financial prudence penalty	N/A	N/A	N/A	0	0	0
Total remuneration (€)	**970,526**	**1,361,301**	**1,332,406**	**1,316,543**	**1,302,734**	**1,283,790**

N/A: non applicable

Total remuneration (Spain)

Annex 5.31 Case study – Sweden

Electricity network regulation, regulatory period 2024-27

General information

Before the RP, the NRA, Ei, determines the allowed revenues for the network operators, partly based on forecasts, for every electricity network operator, normally for a four-year period, which is presented as a total for the entire customer collective of that operator. For details see formula 1. After the RP, Ei updates the revenue caps and replaces the forecasts with the actual outcomes. After the RP, an adjustment of the revenue caps is also made by an annual bonus or malus. This takes quality into account based on the way the network companies have been operating and to what extent the operation is compatible with or contributing to an efficient utilisation of the network. Formula 2 describes the calculation of the revenue caps after the RP.

Formula 1 = capital costs based on opening RAB and <u>projected</u> investments and disposals + controllable costs, normally based on four-year historical costs, deducted for efficiency requirements + <u>forecasted</u> costs for flexibility services + non-controllable costs based on <u>forecasted</u> data + <u>forecasted</u> costs for interruption compensation.

Formula 2 = capital costs based on opening RAB and <u>actual</u> investment and disposals + controllable costs, normally based on four-year historical costs, deducted for efficiency requirements + <u>actual</u> costs for flexibility services + non-controllable costs based on <u>actual</u> data + bonus or malus according to quality in the way the network companies have been operating and to what extent the operation is compatible with or contributing to an efficient utilisation of the network + costs for interruption compensation based on actual outcome.

Differences in the price level are also adjusted after the period. The revenue cap that is set before the RP is determined by an amount for the whole RP of four years. In the decision before the RP it is clarified that the revenue cap after the RP must be adjusted for every year with different indexes. The use of the indexes for cost and revenues should be limited to being used where it is directly stated in the legislation. The legislation states that the "factor price index for buildings" is to be used for the RAB, and "factor price index for electricity network companies, sub-index operation and maintenance costs, controllable" shall be used to index the controllable costs. The non-controllable costs will be determined based on the actual data for each year at each year's price level.

The bonus or malus according to quality in the way the network companies have been operating and to what extent the operation is compatible with or contributing to an efficient utilisation of the network, is given in each year's price level. The price level management is only required in the part that refers to quality in the way the network companies conduct network operations, as it is based on an established interruption cost estimate. This valuation is calculated for each year's price level with the CPI.

Regulatory asset base and cost of capital

Capital cost calculation method and valuation methods

The method that is used to calculate capital costs for electricity network companies' assets is a real linear depreciation method. To calculate the capital cost based on this method, the network assets must be given a replacement value that reflects what the cost to acquire and commission an entirely new asset would be today. This includes project planning, materials, certain labour and material costs, preparation, etc., reported in accordance with generally accepted accounting principles.

There are four valuation methods that companies can use to give an electricity network asset a replacement value. These methods are ranked, which means that the first method should be used, but if the first cannot be used, the second method should be used and so on. The methods according to the ranking are as follows: 1) catalogue cost, 2) initial acquisition value, 3) book value and 4) other reasonable value. Note that, depending on the method, remuneration is done in real terms according to the factor price index for buildings, the construction cost trend mentioned in the above section. Below follows an example of assets that will be used to illustrate the calculation of the revenue cap. In the example we do not consider any loans from government or any costs for interruptions, that are handled a bit differently from the described methodology below. All monetary figures are presented in SEK in 2022 year price level.

Asset category	Asset_ type	Technical spec	Quantity (km, pcs)	Catalogue nr	Voltage	Catalogue cost (for Q=1)	Replacement value	Year_ from
Other lines, area concession	Underground cable, city	N1XV(E) 4x150 mm²	0.0051	NG1 4435	0.4	1 331 550	6,791	2013
Other lines, area concession	Underground cable, populated area	PEX 3x150 mm²	1.0113	NG1 4523	12	1 106 925	1,119,433	1963
Meter	Meter	Meter category 1	304	NG1 5951	0.4	2,494	758,176	2020 H2
Network station	Station	Network station 315 kVA	26	NG1 5224	12/0.4	222,660	5,789,160	2009
Transformer	Transformer	500 kVA	6	NG1 5922	12/0.4	156 126	936,756	1985
Total cost for replacement							8,610,316	

Example of reported assets with catalogue costs[57] (Sweden)

The DSOs only report quantity, investment year (year_from), and the catalogue nr. The other data is generated in the system. The assets in the table above are used to illustrate how the cost of capital is calculated. Since 2011 CAPEX has been calculated semi-annually and the notation of H2 means the asset has been taken into operation in the second half of the year.

Depreciation ratio

Depreciation ratios that electricity network assets have for the RP 2024-27 are given in the table below (Regulatory depreciation ratios for electricity assets). Where economical depreciation is the normal depreciation time, if an asset is fully functional after that time it might get an extended lifetime and be included in the RAB up to the maximal depreciation time. The maximal depreciation time is a 25% extension compared to the economical depreciation time.

[57] No planned investments or disposals.

Categories for electricity network assets	Economical depreciation (years)	Maximal depreciation (years)
Other groundworks and buildings, line concession	50	62
Other lines, line concession	50	62
Other lines, area concession	50	62
Other overhead lines, line concession	50	62
IT-system	10	12
Cable box	30	37
Lines with voltage from 220 kV or more, with exception for overhead lines, line concession	40	50
Overhead lines with voltage from 220 kV or more, line concession	60	75
Overhead lines, area concession	40	50
Groundworks and buildings with connection to a network with HV from 220 kV or more, line concession	40	50
Groundworks and buildings, area concession	50	62
Meter	10	12
Network station	40	50
Shunt reactor	40	50
Steering and control equipment	15	18
Switchgear without secondary appliances	40	50
Transformer	50	62

Regulatory depreciation ratios for electricity assets (Sweden)

When putting an age to the assets introduced in the table above (Example of reported assets with catalogue costs), we can see that all except one are within the economical depreciation time. The asset *Underground cable, populated area* (Asset 2) is within the maximal depreciation time until the end of 2026. The age of the assets for each half year in the RP is shown in the table below (Age of the assets).

		Age							
	Assets	2024 H1	2024 H2	2025 H1	2025 H2	2026 H1	2026 H2	2027 H1	2027 H2
1	Underground cable, city	10	10	11	11	12	12	13	13
2	Underground cable, populated area	60	60	61	61	62	62	63	63
3	Meter	3	3	4	4	5	5	6	6
4	Station	14	14	15	15	16	16	17	17
5	Transformer	38	38	39	39	40	40	41	41

Age of the assets (Sweden)

Calculation formulas for the cost of capital (CAPEX)

CAPEX is calculated as the sum of depreciation and return on capital. If a fixed asset is younger than the economic depreciation time, the calculation is done as $Depreciation\ per\ half\ year\ = 0.5 * \frac{Replacement\ value}{Economic\ Depreciation\ Time}$, and $Return, half\ year = 0.5 * Replacement\ value * \frac{(Economic\ depreciation\ time - age\ of\ the\ asset)}{Economic\ depreciation\ time} * Real\ WACC\ before\ tax.$

If an electricity grid installation is older than the economic depreciation period but younger than the maximum depreciation period (i.e. asset 2), the calculation is done as $Depreciation\ per\ half\ year\ = 0.5 * \frac{Replacement\ value}{Age\ of\ the\ asset}$, and $Return, half\ year = 0.5 * Replacement\ value * \frac{1}{Age\ of\ the\ asset} * Real\ WACC\ before\ tax.$

Also note the following:

- The cost of capital is calculated semi-annually (H1 and H2), which explains the multiplication by 0.5 in the formulas above. If a change is made in the RAB (investment or disposals) at some point during the first half of the year, this change will first affect the RAB in the next six months. For example, if an investment is made in 2024 H1, it will be added to the RAB in 2024 H2.
- During first year the age of the electricity network asset is zero, not one. For example, when the economic depreciation period is 30 years, the asset will generate full capital cost during the years zero to 29, which is then 30 years.

For the assets introduced in the tables above the cost of capital (depreciation in SEK) would be:

	Depreciation							
Assets	2024 H1	2024 H2	2025 H1	2025 H2	2026 H1	2026 H2	2027 H1	2027 H2
Underground cable, city	68	68	68	68	68	68	68	68
Underground cable, populated area	9,329	9,329	9,176	9,176	9,028	9,028	0	0
Meter	37,909	37,909	37,909	37,909	37,909	37,909	37,909	37,909
Station	72,365	72,365	72,365	72,365	72,365	72,365	72,365	72,365
Transformer	9,368	9,368	9,368	9,368	9,368	9,368	9,368	9,368
Sum	**129,037**	**129,037**	**128,884**	**128,884**	**128,736**	**128,736**	**119,709**	**119,709**

Depreciation of the assets (Sweden)

Each cell is calculated as the replacement cost divided by the depreciation time, except for asset two, where the actual age is used instead of depreciation time until it reaches its maximal depreciation time.

To calculate the return, we must first adjust for the age of the asset (i.e. deduct already depreciated capital). Below, we can see the age adjusted RAB for the example assets.

	Age adjusted RAB							
Assets	2024 H1	2024 H2	2025 H1	2025 H2	2026 H1	2026 H2	2027 H1	2027 H2
Underground cable, city	5,433	5,433	5,297	5,297	5,161	5,161	5,025	5,025
Underground cable, populated area	18,657	18,657	18,351	18,351	18,055	18,055	0	0
Meter	530,723	530,723	454,906	454,906	379,088	379,088	303,270	303,270
Station	3,762,954	3,762,954	3,618,225	3,618,225	3,473,496	3,473,496	3,328,767	3,328,767
Transformer	224,821	224,821	206,086	206,086	187,351	187,351	168,616	168,616

Age adjusted value of the RAB (Sweden)

From the age adjusted RAB, we multiply by the WACC to get the return on capital.

	Return on capital							
WACC = 4.53%	2024 H1	2024 H2	2025 H1	2025 H2	2026 H1	2026 H2	2027 H1	2027 H2
Underground cable, city	123	123	120	120	117	117	114	114
Underground cable, populated area	423	423	416	416	409	409	0	0
Meter	12,021	12,021	10,304	10,304	8,586	8,586	6,869	6,869
Station	85,231	85,231	81,953	81,953	78,675	78,675	75,397	75,397
Transformer	5,092	5,092	4,668	4,668	4,244	4,244	3,819	3,819
Sum	**102,890**	**102,890**	**97,460**	**97,460**	**92,030**	**92,030**	**86,199**	**86,199**

Return on capital[58] (Sweden)

CAPEX for each year is presented below.

CAPEX	2024	2025	2026	2027
SEK	**463,854**	**452,688**	**441,532**	**411,816**

CAPEX, SEK (Sweden)

After the RP, the cost of capital is corrected for actual investments and disposals, as well as indexed to the price level for each year.

Calculation of controllable costs and efficiency requirements

The controllable costs are calculated based on an average of four years of historical data two years before the start of the RP. For the RP 2024-27, the controllable costs correspond to the companies' historical costs for the years 2018-21. In cases where a company is newly established, or its O&M costs during the RP are assumed to deviate significantly from the historical data, the company's forecasts for this cost item can be used instead, which are then replaced with actual data after the period.

An example of controllable costs is shown in the table below (Calculation of controllable OPEX). First, all components of OPEX are added into one post for the historical costs. The combined post is adjusted for some specific cost elements, including (among others) the non-controllable costs. In some cases, prior to the RP, the DSOs have the possibility of correcting historical values.

[58] Per half year = (age adjusted RAB*WACC)/2.

			2018	2019	2020	2021
Costs related to transit and purchase of energy			83,000	84,660	86,353	88,080
Material			1,500	1,530	1,561	1,592
Other external costs			65,000	66,300	67,626	68,979
Labour cost			42,000	42,840	43,697	44,571
Other operating expenditure			0	0	0	0
Sum	(A1)		**191,500**	**195,330**	**199,237**	**203,221**
Adjustments						
Changes in inventory			0	0	0	0
Activated work for own account			0	0	-5,000	-7,000
Non-controllable costs (see next chapter)			-61,060	-62,480	-63,900	-65,320
Compensation for interruptions			-1,225	-750	-1,100	-560
Leasing costs for assets included in the RAB			-350	-524	-487	-431
Adjusted controllable costs	B1(=A1-adjustments)		**128,865**	**131,576**	**128,750**	**129,910**
Adjustment for tangible assets not included in the RAB						
		2017	**2018**	**2019**	**2020**	**2021**
Book value		88,000	140,000	130,000	118,000	
Depreciations			10,000	12,000	12,000	12,000
r =	*6.64%*					
Cost for tangible assets not in the RAB	(B2)		15,843	21,296	20,632	19,835
Total controllable costs	C1(=B1+B2)		**144,708**	**152,872**	**149,382**	**149,745**
Indexation to base year (2022)						
Index to 2022			1.1083	1.0813	1.0813	1.0556
Total controllable costs, price level 2022			160,380	165,300	161,527	158,071
Average controllable costs 2018-21			**161,320**			

Calculation of controllable OPEX (Sweden)

From the average cost for 2018-21, an annual deduction due to efficiency requirements is made to all companies' considerable O&M costs.

For local DSOs, the annual efficiency requirements are individually calculated and mean that companies that conduct their operations less efficiently than other comparable electricity network companies are assigned a higher efficiency requirement. The minimum level the claim can amount to is 1%, and the highest level of the claim means an annual reduction of 1.82% of the controllable costs.

Ei uses the DEA method to determine the efficiency requirement for local DSOs, which is based on comparisons between the local DSOs performances. Each network company receives an individual requirement based on how their performance relates to the other grid companies. By comparing the companies to each other, a competitive pressure is simulated where the companies are given incentives to reduce their costs in relation to their competitors. The most efficient companies are assigned a requirement that reflects the industry's average productivity growth, which means that they must reduce their controllable OPEX annually by 1%. The less efficient companies have a higher individual requirement to catch up with the efficient companies. If a company can increase productivity more than the set requirement, they may retain the difference in full.

The model consists of two input variables that constitute the resource consumption, controllable costs (OPEX) and capital costs (CAPEX), and five production variables: delivered energy distributed on HV and LV networks, the number of subscriptions, the number of network stations and the highest value of subscribed and withdrawn power to overlying networks.

In the calculation, outliers are identified as non-comparable DSOs according to set criteria for super-efficiency: $Effi > q\ (75) + 2 * [q\ (75) - q\ (25)]$, where:

- $Effi$ is the measure of efficiency for companies, which is obtained by driving with super efficiency;
- q (75) is the efficiency of the third quartile for all companies; and
- q (25) is the efficiency of the first quartile for all companies.

An observation should thus be regarded as not comparable with the others if the measure of efficiency exceeds the sum of the third quartile and the difference between the first and third quartiles multiplied by two.

As we move from potential to efficiency requirements, we have also built in several restrictions. These restrictions are as follows:

- The time to realise the full potential is set at eight years, that is, two RPs;
- The realisation is shared with customers, i.e. 50-50;
- The highest level of efficiency potential is limited to 30%; and
- The lowest level of efficiency requirements is 1% per year.

No benchmarking is used for the regional DSOs or the TSO; these receive the lowest annual requirement of 1%.

The requirements described above are applied only to the companies' current controllable costs, as we consider that current legislation prevents us from applying it on the additional cost items.

With an annual efficiency requirement at 1% (the lowest possible), the example above would generate the following controllable costs for the RP 2024-27.

Price level 2022	2018	2019	2020	2021
Controllable costs	160,380	165,300	161,527	158,071
Average controllable costs 2018-21 per year	161,320			
	2024	2025	2026	2027
Yearly controllable costs	161,320	161,320	161,320	161,320
Efficiency requirement, 1% yearly accumulated	1,613	3,243	4,888	6,550
Controllable costs, after deduction for efficiency requirement	159,706	158,077	156,431	154,769
Controllable costs for 2024-27	**628,983**			

Controllable costs for 2024-27 (Sweden)

After the period the controllable costs are indexed to the price level for each year.

Costs for flexibility services

The DSOs also report yearly expected costs for flexibility services during the regulatory period. These costs will be updated with the actual outcome after the regulatory period and are treated as a pass-through cost.

For this example, let's assume the company predicted a cost of 10,000 SEK.

Non-controllable costs

The DSOs report projections of non-controllable costs prior to the RP. These are treated as a pass-through cost and updated with the actual outcome at the end of the period (for TSOs there are different cost elements than the ones presented below). The two largest components are subscription fees to other networks, and costs for network losses (purchase). In the table below the different non-controllable costs are presented, as well as how they can be projected before an RP.

	2024	2025	2026	2027
Cost for network losses (purchase)	15,000	16,000	17,000	18,000
Subscription fee to other network(s)	50,000	50,000	51,000	51,000
Connection fees to other network(s)	0	0	0	0
Compensation to producers for production	4,000	5,000	5,000	6,000
Government fees	2,000	2,000	2,000	2,000
Capacity reserve	0	0	0	0
Total estimate for the period	**296,000**			

Non controllable costs for 2024-27 (Sweden)

Costs for interruption compensation

If a company pays interruption compensation for interruptions between 12-24 hours due to network interruptions to customers, this cost is taken into account in the revenue cap. Ei handles this cost separate in the revenue cap and applies a method where the cost might not be fully accounted for, only the efficient cost is included in the cap. This cost is predicted by the company before the regulatory period for each year and is updated with the actual outcome after the regulatory period.

For this example, let’s assume the company predicted a cost of 0 SEK.

Supplementary decisions for the next regulatory period due to deviation between final revenue caps after the period and revenues

If it turns out that the companies’ total revenues from network operations during the RP 2024-27 deviate from the established revenue cap for the same period, the revenue cap for the next period 2028-31 shall decrease or increase by the differing amount. In addition, if a company's total revenue from network operations during the RP 2024-27 exceeds the established revenue cap with more than 5% for the same period, an overcharging supplement will be added. A new rule from 2021 makes it possible for the DSOs to apply for an extension of non-utilised revenues in order to increase investments.

The total revenue cap for 2024-27 (ex ante)

The numbers presented in the previous sections add up to the revenue cap presented below. No extra amount from previous periods is assumed in this case. Note that these are fictive numbers. The numbers in the revenue cap are presented in 2022 year price level.

		2022 price level
CAPEX		1,769,890
OPEX		
	Controllable costs (excl. costs for flexibility services)	628,983
	Costs for flexibility services	10,000
	Non-controllable costs	296,000
Costs for interruption compensation		0
Revenue cap 2024-27		**2,704,873**

Final revenue cap (Sweden)

After the RP, CAPEX will be updated based on actual investments and disposals, and the return on capital will be adjusted based on the incentives for quality of supply and efficient network utilisation. The non-controllable costs, costs for flexibility services as well as compensation for interruptions will be updated with the actual outcome.

The total revenue caps decided for 2024-27, CAPEX constitute ~43%, non-controllable costs ~37%, controllable costs (excl. costs for flexibility services) ~20%, costs for flexibility services ~0.4% and Costs for interruption compensation less than 0.001% of the total revenue caps decided.