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CEER Report on Regulatory Frameworks for European Energy Networks 2019

Annex 4

Case studies of single regulatory regimes

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Annex 4.1 Case Study – Austria

The current document describes a short case study about the regulatory regime that applies to electricity distribution system operators in Austria during the fourth regulatory period and is based on the document Electricity Distribution System Operators 1 January 2019 – 31 December 2023 Regulatory Regime for the Fourth Regulatory Period (Annex 1). For further explanations, details and all references, please refer to this document.

Regulation of grid charges[1] can be based on annual cost audits, but this means much 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. We prefer the latter approach as it minimises the direct costs of regulation. In between cost audits, operator costs and the derived grid charges evolve in accordance with a formula that uses parameters which are known in advance. To ensure that the charges do not diverge too far from the underlying cost trends, the period from one cost audit to the next should not be too long.

When setting the length of a regulatory period, the regulatory authority must consider several effects: Incentives for productive efficiency are created by temporarily decoupling the allowed costs from the actual costs (revenues). The degree to which such incentives are effective depends on how long this decoupling is maintained for, i.e. it depends on the length of the regulatory period. By decoupling, the regime intentionally tolerates a temporary situation of allocative inefficiency so as to generate incentives for productive efficiency. Choosing the length of the regulatory period is key: if it is too short, the incentive for productive efficiency might not be strong enough; if it is too long, consumers might overestimate and companies might underestimate the potential for cost reduction. This latter effect grows the longer the period lasts. In Austria, both the regulatory authority and the regulated companies have gained extensive experience with incentive-based regulation. It therefore, appears reasonable to maintain the 5-year period used previously.

With such a regime, cost data must be adjusted and corrected before they can be transformed into allowed costs and used in a benchmarking exercise, so as to avoid operators strategically shifting cost items (e.g. in the areas of maintenance, staff or similar). Particularly when reviewing the regulated companies' internal cost allocation, especially in the case of overheads and payments for internal and external services, strict cost auditing principles must apply and checks must be conducted to verify whether costs were reasonable in both their grounds and their amount.

The regulatory authority generally bases its assessment on the most recent available figures in its cost audits and in establishing the grid capacity and volumes the tariffs are based upon. However, the conducted cost audits require significant time and effort, both on the regulatory authority's end and on the companies'. Also, regulated companies must be given sufficient time to submit comments on proposed changes in the regulatory regime (including a new efficiency benchmark) and on the official decisions on their allowed costs. And finally, the accounts of *all* companies that are being benchmarked must have been approved before the benchmarking can take place. For some grid operators, therefore, the regulatory authority must base its assessment on the second-to-last annual financial data available. For the fourth regulatory period which started in 2019, the regulatory authority therefore did not audit

[1] This document uses the terms 'tariffs', 'charges' and 'rates' synonymously.

the costs of the most recent full business year (2017) but rather those of the previous year (2016).

Suppose that a specific distribution system operator's allowed cost base for 2016 amounts to 600,000 EUR of OPEX and 100,000 EUR of non-controllable costs. Furthermore, assume that this operator's depreciation in 2017 is 100,000 EUR, the 2017 book values of its regulatory asset base until 2016 1,000,0000 EUR and the 2017 book values of new investments from 2016 onwards 150,000 EUR.

The regulatory authority calculates the allowed **OPEX** by applying the network operator price index (NPI) and the general productivity growth rate (X-gen) of 0.95% p.a. to the controllable OPEX 2016, thereby mapping two opposite effects: the NPI reflects exogenous price increases, while X-gen accounts for sector-specific productivity growth.

$$504{,}908 = (600{,}000 - 100{,}000) \times (1 + 1.614\%) \times (1 + 1.293\%) \times (1 - 0.95\%)^2$$ [2]

The allowed OPEX 2018 are the basis for the 2019 grid charges (together with CAPEX). In this context, the regulatory authority considers the company's overall efficiency target which is composed of the general productivity growth rate (X-gen) and the individual efficiency target (X-ind). This efficiency target (ZV) is directly derived from each company's efficiency score and a realisation period of 7.5 years. Therefore, the formula for each company's overall efficiency target is as follows:

$$\mathrm{ZV} = 1 - (1 - 0.95\%) \times \sqrt[7{,}5]{\mathrm{ES}_{2018}}$$

where ES_{2018} designates the individual (weighted) efficiency score. This efficiency score is derived from a benchmarking procedure that comprises two methods (DEA and MOLS), two TOTEX cost bases as inputs, a set of outputs derived from a cost driver analysis and an efficiency floor of 80%. An efficient company's overall efficiency target corresponds to X-gen, i.e. there is the following relationship between efficiency scores and overall targets:

Efficiency score	Overall annual target
80%	3.854%
85%	3.073%
90%	2.332%
95%	1.625%

Assuming an efficiency score of 90%, the OPEX for 2019 are calculated as follows.

$$501{,}857 = 504{,}908 \times (1 + 1{,}769\%) \times (1 - 2.332\%)$$ [3]

CAPEX are tracked and compensated as they arise. Roughly speaking, capital cost consists of depreciation and the cost of capital (opportunity cost) for the regulatory asset base. The

[2] In English:
$OPEX_{2018}^{Allowed} = (OPEX_{2016} - NonControllableCosts_{2016}) \times \prod_{t=2017}^{2018}[(1 + \Delta NetworkOperatorPriceIndex_t) \times (1 - Xgen_{4thPeriod})]$

[3] In English:
$OPEX_{2019}^{BasisForCharges} = OPEX_{2018}^{Allowed} \times (1 + \Delta NetworkOperatorPriceIndex_{2019}) \times (1 - OverallEfficiencyTarget_{4thPeriod})$

regulatory authority introduced the concept of an individual WACC which it applied for assets acquired up to 2016; this individual WACC was designed to incentivise efficiency.

For this, the regulatory authority first calculates the average efficiency score across all companies, i.e. the arithmetic mean of all benchmarked system operators, and applies an efficiency floor of 80%. A company with an average efficiency score receives a WACC of 4.88% (before taxation) on the regulatory asset base. If a company is more/less efficient than the average, its WACC is adjusted by a maximum of +/- 0.5 percentage points. To ensure that the RAB of Austrian electricity distribution system operators generates an average return of 4.88%, the regulatory authority offsets above-average and below-average efficiencies against each other.

Suppose that the average efficiency amounts to 92%. This leads to the following individual WACC for the focal grid operator.

$$4.80\% = 4.88\% - \frac{0.5\%}{(92\% - 80\%)} \times (92\% - 90\%)$$

The regulatory authority then applies each company's individual WACC to the depreciated book value of its RAB up to 2016. A uniform 4.88% WACC applies to all investments made in 2017 and 2018 (minus customer prepayments). This uniform rate was chosen because there was no annual efficiency benchmark, i.e. until the next benchmark is carried out and can be taken into account in future regulatory periods, the regulatory authority had to assume the same (average) efficiency for all investments. For investments from 2019 forward, a mark-up raises this rate to 5.20%. This mark-up is meant to promote investments. Depreciation is passed through without any mark-downs or other changes, this system therefore minimises the risk exposure for system operators by guaranteeing that their investments are recovered through the grid charges.

Applying the individual WACC to the RAB and using the book values from year 2017 (see above), we arrive at the following calculation for the CAPEX to be included in 2019 grid charges:

$$155{,}320 = 100{,}000 + 1{,}000{,}000 \times 4.80\% + 150{,}000 \times 4{,}88\%$$ [4]

Incentive regulation means that the allowed costs are decoupled and may thereby diverge from actual costs. A new audit, based on which the allowed costs are determined anew, normally only occurs before the outset of a new regulatory period. However, the scope of the operators' mandate (number of consumers to be connected, etc.) evolves during the course of a regulatory period, and the regulatory authority uses so-called expansion factors to account for such developments. This way, regulated companies can be sure that any increase in OPEX in line with the previously set parameters will be covered. However, expansion factors are not designed to track all cost increases during a regulatory period. After all, incentive regulation is specifically meant to temporarily decouple allowed costs from current developments.

[4] In English:
$DirectCAPEXCompensation_{2019} = Depreciation_{2017} + RAB^{2017}_{AssetsUpTo2016} \times WACCIndividual + RAB^{2017}_{AssetsFrom2017} \times 4.88\%$

Using the most recent available data (financial accounting data and technical data) creates a gap as the actual costs in the year when the new rates apply are likely to have changed in the meantime (t-2 lag). For instance, both the 2019 expansion factor and regulatory asset base rely on data from 2017 (see above), but it can be safely assumed that OPEX and CAPEX are not the same in 2019 as they were two years earlier. The same is true for the non-controllable costs. This systemic time lag could detain companies from investing because they only recover their costs two years later, when new investments are included as part of direct CAPEX compensation and the parameters for the operating cost factor are updated. This means that companies would have to pre-finance these investments, meaning they are exposed to a certain interest rate and liquidity risk. Vice versa, savings are not passed on immediately either, creating elevated charges for customers (at least for some time). The two-year time lag could result in rates that are too low for companies whose mandates are steadily growing or 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 these latter become 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 (because these are derived from the most recent available data, not the actual, current data) and the actual revenues generated. This difference can be positive or negative, i.e. it can lead to either excessive or insufficient cost recovery for the companies. The system for cost regulation therefore includes a regulatory account where these differences are accounted for and recovered in the following cost decisions.

Annex 4.9 Case Study – Germany

Determination of the revenue cap of a German electricity distribution system operator

Introduction

The electricity and gas network operators in Germany at 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, 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 2.9 of the 2019 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 distribution system operators. 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:

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

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), which are in turn 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 regulatory period. Controllable costs (C_C) are distributed across the individual years of a regulatory period 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[5]-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 capital costs (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 regulatory period, each year an increasing reduction factor ($1\text{-}D_t$) is applied to the controllable costs. This gives the revenue cap a stepped trajectory, as illustrated in Diagram 1:

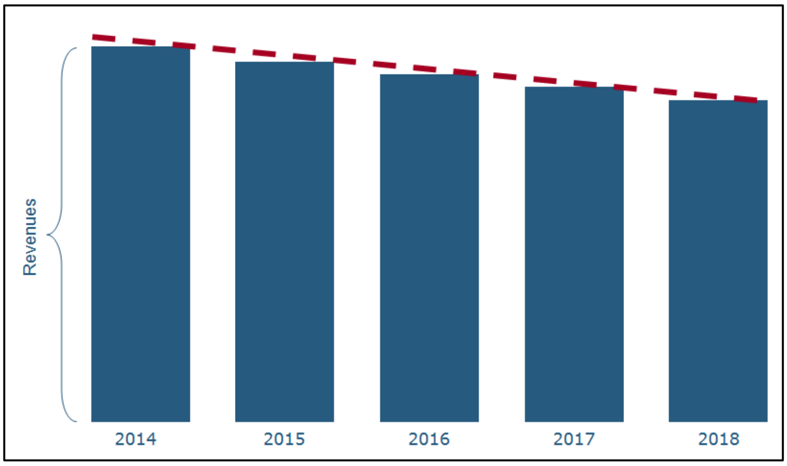


Diagram 1

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 identify concrete inefficient cost positions, only inefficiencies in general.

In addition to the deduction of the reduced capital costs, the determined temporarily non-controllable and controllable costs from the base year are applied to the entire regulatory period; 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 regulatory period, as Diagram 2 illustrates:

[5] TOTEX = Total expenditures = Sum of operational costs (OPEX) and capital costs (CAPEX).

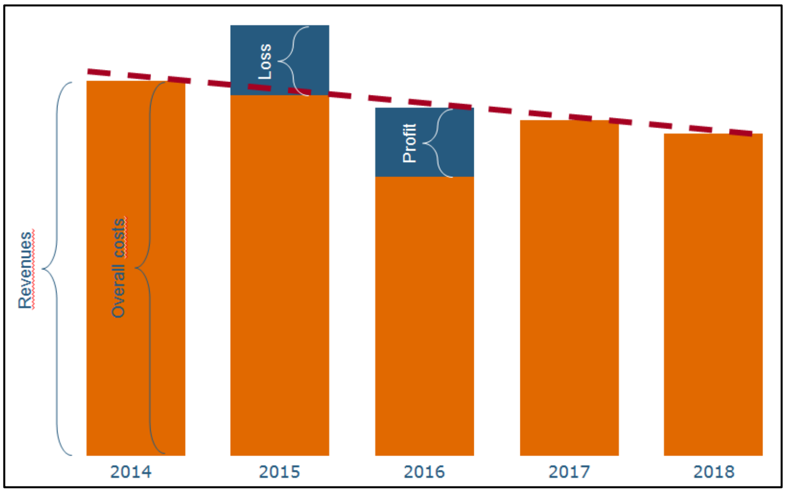


Diagram 2

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 the revenues, uniformly distributed over the duration of the regulatory period.

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 capital costs, 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 capital cost mark-up, network operators report in the previous year on the amount of their planned investments in necessary network assets. These capital costs are made up of the imputed depreciations, the imputed return on equity, the imputed trade tax as well as the incurred interest on debt.

The quality regulation calculates 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 booked onto 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 distribution system operators. The framework/market conditions are shown in the following table:

Framework conditions (base year´s situation):

	DSO A	DSO B
Staff costs	1000	800
Material costs	500	200
Operating taxes	50	30
∑ OPEX	1550	1030
Depreciations[6]	900	870
Interest rate on equity	6.91%	6.91%
Return on equity	100	50
Cost of debt	50	40
∑ CAPEX	1050	960
∑TOTEX (OPEX + CAPEX)	2600	1990
Other revenues	-100	-50
Trade taxes	50	60
Consumer price index in the base year	100	100

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:

1. **Review of overall costs and the different cost categories**
2. **Application of the efficiency score**
3. **Determination of other revenue components**
4. **Final calculation of the revenue cap**

<u>Step 1: Review of overall costs and the different cost categories</u>

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

[6] Based on calculated costs instead of depreciations defined by German Commercial Code.

	DSO A	DSO B
1. Material and staff costs (∑)	1500	1000
2. Operating taxes	50	30
3. Depreciation	900	870
4. Return on equity[7]	100	50
5. Cost of debt	50	40
6. Trade taxes	50	60
7. Other revenues	-100	-50
8. Reviewed overall costs (∑ 1. - 7.)	2650	2000
9. Permanently non-controllable costs[8]	1000	800
10. ∑(Temporary non-)Controllable costs[9][10]	1650	1200

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 regulatory period. 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.)	1650	1080
14. Controllable costs (10. * 12.)	0	120
15. Distribution parameter[11]	20%	20%
16. Controllable costs in the first year of the regulatory period (14. * (1 – 15.)	0	96

Since DSO A has been given an efficiency score of 100%, it does not have any inefficiencies to remove over the regulatory period. The controllable costs are therefore 0, while the temporarily non-controllable costs are 1650 units. DSO A is not an outlier at 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 regulatory period. The controllable costs are therefore 120 in total; for the first

[7] The return on equity is calculated on the basis of the costs of the tangible assets financed by equity multiplied by the rate of return on equity of 6.91%.
[8] Defined by cost catalogue.
[9] Separated into a controllable and temporally non-controllable part by using the determined efficiency score.
[10] Parts of positions No. 1., 2. and 7. are included at No. 9.
[11] Value at the first year of the regulatory period.

year of the regulatory period there are controllable costs using the distribution parameter of 80% (1-20%)*120, i.e. 96 units. The temporarily non-controllable costs are therefore 1080 units. DSO B is not an outlier at 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 consumer price index at the base year was 100, 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 at the first year of the regulatory period, DSO A gets a capital cost mark-up of 100, DSO B of 200. As a result of the quality regulation we assume for DSO A a value of 50 and for DSO B a value of -100. The volatile costs of the base year have a value of 200 for DSO A and 100 for DSO B. At the first year of the regulatory period 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 regulatory periods are assumed with 0.

	DSO A	**DSO B**
17. Efficiency bonus	0	0
18. Consumer price index in the base year	100	100
19. Consumer price index in first year of regulation	101	101
20. Development of prices (19./18.)	1.01	1.01
21. Productivity factor[12]	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.Capital cost 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

[12] 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:

$RC_t = C_{pnc,t} + (C_{tnc,t} + (1 – D_t) * C_{c,t} + \frac{B_0}{T}) * (\frac{CPI_t}{CPI_0} – PF_t) + CCT_t + Q_t + (VC_t – VC_0) + S_t$

Therefore we get a revenue cap for the first year of the regulatory period of

	Revenue cap for the first year of the regulatory period
DSO A	1000 +(1650 +(1 – 20%)*0 + $\frac{0}{5}$)*($\frac{101}{100}$ – 0.5%)+ 100 + 50 +(300 – 200)+ 0=2908.25
	9. +(13. +(1 – 15.)*14. + $\frac{17.}{5}$)*($\frac{19.}{18.}$ – ((1 + 21.^{1}) – 1))+ 23. + 24. +(26. – 25.)+ 28.
DSO B	800+(1080+(1 – 20%)*120 + $\frac{0}{5}$)*($\frac{101}{100}$ – 0.5%)+ 200 – 100 +(100 – 100)+0=2081.88
	9. +(13. +(1 – 15.)*14. + $\frac{17.}{5}$)*($\frac{19.}{18.}$ – ((1 + 21.^{1}) – 1))+ 23. + 24. +(26. – 25.)+ 28.

If the permanently non-controllable costs, the consumer price index, the capital cost mark-up, the quality element, the volatile costs or the balance of the regulatory account change in the course of the regulatory period, the revenue cap is adjusted accordingly.

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

	Revenue cap for the last year of the regulatory period
DSO A	1000 +(1650 +(1 – 100%)*0 + $\frac{0}{5}$)*($\frac{101}{100}$ – 2.53%)+ 100 + 50 +(300 – 200)+ 0=2908.25
	9. +(13. + 0*14. + $\frac{17.}{5}$)*($\frac{19.}{18.}$ – ((1 + 21.^{5}) – 1))+ 23. + 24. +(26. – 25.) + 28.
DSO B	800 +(1080 +(1 – 100%)*120 + $\frac{0}{5}$)*($\frac{101}{100}$ – 2.53%)+ 200 – 100 +(100 – 100)+ 0 =1985.4
	9. +(13. +0*14. + $\frac{17.}{5}$)*($\frac{19.}{18.}$ – ((1 + 21.^{5}) – 1))+ 23. + 24. +(26. – 25.) + 28.

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

Annex 4.17 Case Study – Lithuania

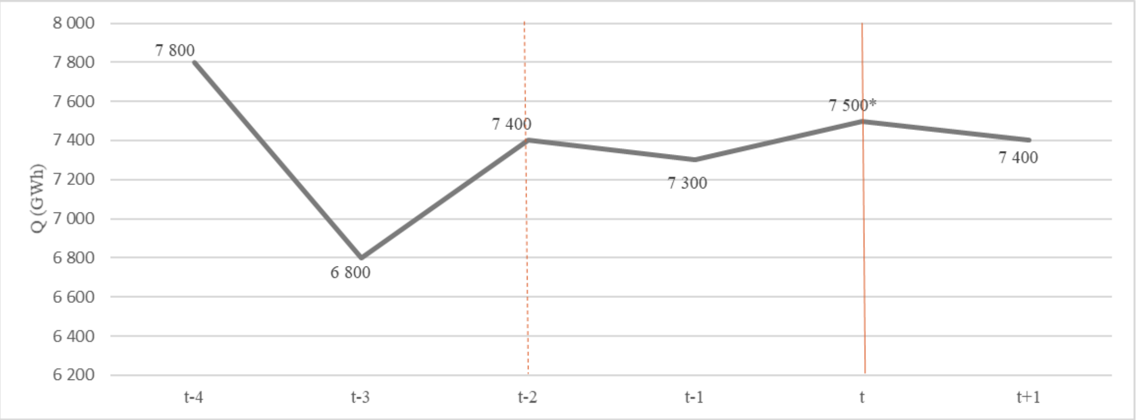
The National Energy Regulatory Council (hereinafter – NERC) applies different methodologies for setting allowed revenues for transmission system operators and distribution system operators (hereinafter – DSO) in natural gas sector and electricity sector, however, the main principles are the same. Therefore, the case study for setting the revenue cap[13] for natural gas DSOs is provided below.

A five-year regulatory period 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 ROI. Moreover, incentive scheme is in place, which allows to earn additional profit, if company reduces its operational expenditures.

The detailed example[14] 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 regulatory period as well as the forecasted volumes provided by distribution system users. Illustrative figures are shown in Figure 1. As there is a visible stabilisation in distributed volumes in the year (t-2) – (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.



*Expected Q for the year t.
Figure 1. Establishment of forecasted distribution volumes of natural gas

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

[13] NERC used to set price caps for regulated services until the 1 January 2019. However, the changes in the Law on Natural Gas of the Republic of Lithuania came into force from the 1 January 2019. Therefore, NERC will be setting revenue caps for regulated services instead of price caps.
[14] Only illustrative figures are provided which do not reflect the real cost level of Lithuanian DSO.

For the first year of regulatory period ***OPEX (excluding personnel costs)*** is set considering costs incurred in previous year[15], inflation rate (I) for years (t-1) and (t) and efficiency coefficient (e) which is 1%. OPEX (excluding personnel costs) is calculated according to the formula:

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

The example for OPEX (excluding personnel costs) is provided in Table 1.

OPEX (excluding personnel costs) in the year (t-1),	8,000
Inflation (%) in the year (t-1)[16]	3,5
Inflation (%) in the year (t)	2
OPEX (excluding personnel costs) in the year (t+1),	8,282

Table 1. Calculation of OPEX (excluding personnel costs)

Technological needs consist of fixed technological needs (natural gas consumed by DSOs 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 previous 4 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 are 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 NERC, GWh	117	117	118	120	118	**122**
Factual, GWh	124	126	128	126	126	
Variable technological needs						
Set by NERC, 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**

Table 2. Calculation of technological needs

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

[15] OPEX (excluding personnel costs) set by NERC and factual OPEX (excluding personnel costs) is compared and the lower value is used in calculations.
[16] Where inflation rate is less than 1, OPEX (excluding personnel costs) is set as OPEX (excluding personnel costs) of previous year (t-1).

Depreciation is calculated using 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.

Long term assets	Depreciation (Gas sector)	Depreciation (Electricity sector)
Buildings	25–70	15-70
Pipelines/electricity lines*	55–75	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

*For distribution pipelines the depreciation period of 55 years is applied.

Table 3. Depreciation periods applied by NERC

Personnel costs are calculated similarly to the other OPEX, yet the OPEX (personnel costs) for previous year[17]and average change in personnel costs in Lithuania (ΔW) for the year (t) and (t+1) are evaluated:

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

OPEX (personnel costs) in the year (t-1), TEUR	10 000
ΔW (%) in the year (t)	9
ΔW (%) in the year (t+1)	7,5
OPEX (personnel costs) in the year (t+1), TEUR	11 502

Table 4. Calculation of OPEX (personnel costs)

Taxes are evaluated accordingly 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 small and medium pressure pipelines are no longer considered as real estate. This legal change led to decrease in real estate taxes paid by DSOs and a fall in total taxes by 50% for the main DSO.

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

RAB. Only those investments which are approved by NERC are included into the RAB. Moreover, there are some restrictions foreseen which prohibit inclusion into the RAB the value of goodwill, investment assets, financial assets, deferred tax asset, research, study

[17] OPEX (personnel costs) set by NERC and factual OPEX (personnel costs) is compared and the lower value is used in calculations.

and similar intangible assets, the leased assets, assets under construction[18], 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 ineffective investment by NERC, the residual value of an item of a non-current asset that is no longer used after the investments for reconstruction of this item, the value of other long term assets not necessary to perform safe and efficient regulated activity. Finally, only non-revalued assets are included into 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.

ROI is calculated as RAB multiplied by WACC. In WACC calculation cost of debt and equity risk premium are evaluated:

$$WACC = R_d \times W_D + R_e \times \frac{1}{1-m} \times W_E$$

R_d - cap of cost of debt (interest rate), percent; W_D - share of debt capital (optimal capital structure); W_E – share of equity capital (optimal capital structure); m - tax rate;

Return on equity, percent: $R_e = R_f + \beta \times R_{erp}$;

R_f - equity risk premium; R_{erp}- 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); levered β - Beta coefficient.

All data used in WACC calculation except actual cost of debt of individual company is published in NERC website[19]. Until 2019 WACC was used to be set for entire regulatory period, however, during the next regulatory period WACC is adjusted each year in accordance with changes in DSO's cost of debt. For the main DSO WACC is 3.58% for 2019.

Where RAB is 190 MEUR and WACC is 3.58% the ROI equal to 6,802 TEUR (190,000×0.0358) is calculated.

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

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

[18] Except projects of common interest by transmission system operator.
[19] https://www.regula.lt/en/Pages/wacc-gas.aspx.

Table 5. Calculation of revenue cap.

Adjustments within regulatory period

Revenue cap may be adjusted once a year subject to the 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 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 which allows DSO to earn additional profit, if it reduces operational expenditures. The evaluation of efficiency is carried out in 2+2+1 (year of regulatory period) scheme. The example of the evaluation of efficiency for the regulatory period is provided in Figure 2.

In this example actual ROI is higher than set by NERC in the 2nd (by value X) and the 3rd (by the value Y) and 4th (by value Z) year of regulatory period. 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 regulatory period is increased by the value ((X+Y+Z)/2) as additional profit regarding efficiency in OPEX. The other half of difference in ROI is derived from allowed revenue.

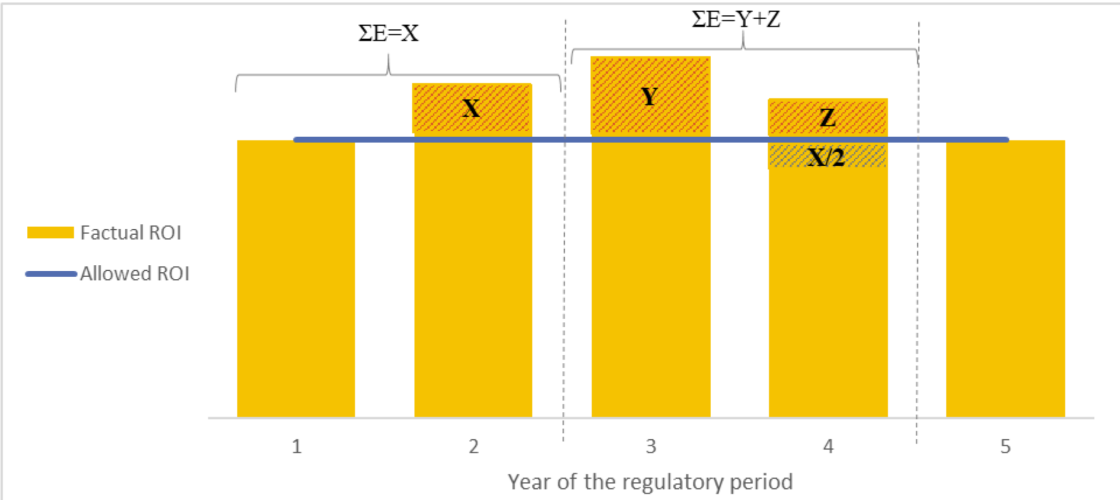


Figure 2. Evaluation of DSO's eficiency.

The evaluation of efficienty in the 1st year of regulatory period is performed likewise, yet the differences of ROI in the 3rd–5th year of the previous regulatory period are evalued.

Where the ROI exceeding the level set by NERC return is splited 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 NERC's website[20].

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

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

Annex 4.19 Case Study – the Netherlands

Below we present a small example of how revenue caps are set for DSOs in the Netherlands. As this is done the same way for electricity and for gas, we deal with gas exclusively. The example is simplified and data and numbers below are fictitious. Note that Dutch regulatory periods legally have a length of three to five years. The exact length of a specific period is set each time again and each time the base year lies two years before the first year of a period. The current period started in 2017 and lasts five years, i.e. it ends 31 December 2021. Our example refers to this period.

We assume that the real WACC for that period is set to 3% and that for the preceding period this 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 bringing the DSOs in a situation of yard stick competition. To this end, we take the following steps for each DSO individually:

1. Calculate its realised income in the year 2016.
2. Calculate its expected efficient cost level for the year 2021.
3. Set its x-factor such that its allowed revenues develop gradually from its realised income in 2016 to its expected efficient cost level in 2021. 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 be negative as well (denoting a yearly rise in real allowed revenues). Also note that we do not use benchmark scores like for the regulation of our TSOs.

Below we elaborate on each of these steps.

<u>Step 1: Calculate realised incomes in the year 2016 for each DSO</u>

We do this just before the regulation period 2017-2021 starts. So suppose we are in 2016 and that we have the following realised data for 2015/2016 for the DSOs:

	A		**B**		**C**	
Connection category	**Volume 2015**	**Tariff 2016 (EUR)**	**Volume 2015**	**Tariff 2016 (EUR)**	**Volume 2015**	**Tariff 2016 (EUR)**
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

For "Volume" the year 2015 is selected as this is the most recent year for which realised volumes are known just before the start of the period (the period is configured in 2016). Note that the output of a DSO is fully characterised by its volumes for connection categories. That is, no other types of output are considered, give or take that for electricity we also have a quality parameter, but in this example we abstract from that.

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

	A	B	C
[1] Realized income 2016 (EUR)	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

Step 2: Calculate expected efficient cost for each DSO for the year 2021

In order to estimate the efficient costs for 2021, we first estimate the costs for 2016. We estimate this as the (indexed) cost made in 2015 as this is the most recent year for which we have approved annual accounts.

The realized totex is calculated as follows. Suppose we have:

	A	B	C
[2] Opex 2015 (EUR)	60,000	180,000	200,000
[3] RAB 2015 (EUR)	900,000	1,000,000	4,000,000
[4] Average lifetimes (years)	40	39	42

where average lifetimes are based on technical lifetimes.

Then we calculate:

	Calculation	A	B	C
[5] Opex 2015 (EUR)	[2]	60,000	180,000	200,000
[6] Capex depreciation (EUR)	[3]*(1/[4])	22,500	25,641	95,238
[7] Capex WACC (EUR)	[3]*3%	45,000	30,000	200,000
[8] Cost 2015 (EUR)	[5]+[6]+[7]	127,500	235,641	495,238
Cost 2016 (EUR)	[8]*CPI	128,775	237,997	500,190

So the total cost 2016 of the sector (A, B, and C together) is 866,962 EUR [9]. Note that in [7] we use the WACC for the period 2017-2021.

Next, we calculate the estimated output for each DSO in the year 2021. The expected output of a DSO is calculated as the weighted sum of its expected volumes of the connection categories in 2021, where these expected volumes are set equal to the realised volumes in 2015, and the weights are equal to the sector average tariff 2016 for the connection category. For this sector average tariff 2016 we have:

	A		**B**		**C**		**Sector**
Cat.	**Volume 2015**	**Tariff 2016 (EUR)**	**Volume 2015**	**Tariff 2016 (EUR)**	**Volume 2015**	**Tariff 2016 (EUR)**	**Average tariff 2016 (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

With this we calculate the DSO's 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 2016		120,167	242,001	600,835
[10] Estimated output 2021		120,167	242,001	600,835

So what we do here, is to set the estimated output for 2021 equal to the (partly estimated) output in 2016, i.e. to estimate the efficient cost level in 2021 we simply assume that output will be stable throughout the period 2017-2021. The total estimated sector output for 2021 then is the sum of this: 963,003 units of output [11]. The efficient cost (sectorial) is than [9] / [11] = 886,962 / 963,003 = 0.921 EUR per unit of output [12].

With this the expected efficient cost DSO's make in 2021 reads:

	Calculation	**A**	**B**	**C**
[13] Exp. Eff. Cost 2021 (EUR)	[10]*[12]	110,674	222,883	553,369

Step 3: Setting an x-factor for each DSO

With Steps 1 and 2 we finally calculate x-factors for the regulatory period 2017-2021 as:

	Calculation	**A**	**B**	**C**
[14] Realized income 2016 (EUR)	[1]	150,000	223,000	590,000
		↓	↓	↓
x-factor period 2017-2021	$1-([15]/[14])^{1/5}$	5.90%	0.01%	1.27%
		↓	↓	↓
[15] Exp. Eff. Cost 2021 (EUR)	[13]	110,674	222,883	553,369

So, for example, this means for A that they start the regulatory period with allowed revenues of 150,000 * (1-5.90%) = 141,150 EUR in 2017 and end the period in 2021 with allowed revenues of 150,000 * $(1\text{-}5.90\%)^5$ = 110,674 EUR, i.e. its assumed efficient cost level.