Annex 2

Gas DSO regulatory regime for the fourth regulatory period 1 January 2023 – 31 December 2027

4 November 2022

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1. Introduction

This document describes the regulatory regime that applies to gas distribution system operators in Austria during the fourth regulatory period. The regime of the third period is adjusted in some respects, in particular:

- We have introduced mutable parameters because we assume that the legal framework for gas DSOs will change in the course of the regulatory period. To enable the regime to adapt to such changes, we have e.g. provided for a flexible composition of the NPI (network operator price index). In addition, there is the option to add in an expansion factor to reflect unexpected changes in the supply mandate (cf. chapter 5).
- We have designed the individual WACC to be cost neutral and symmetrical, and no efficiency floor applies to its calculation. This is intended to ensure that the individual WACC is distributed evenly. At the same time, companies that were below the efficiency floor previously get a stronger incentive to increase their efficiency (cf. chapters 6.3.1 and 6.3.2).
- We have shortened the useful life assumed for new investments in pipelines from 2023 onwards to avoid stranded investments (cf. chapter 6.3.3).
- We have updated the general productivity growth rate (X-gen, cf. chapter 7).
- In light of decarbonisation policies, we have changed the assumption of returns to scale in our benchmarking from constant to non-decreasing returns to scale (NDRS, cf. chapter 8.1.3).
- We have shortened the period for eliminating inefficiencies (realisation period) to one-and-a-half regulatory periods and have raised the efficiency floor for OPEX. The shorter realisation period is meant as an incentive for gas DSOs to actively bring their costs into line with efficiency targets. Increasing the efficiency floor will limit target realisation pressure on OPEX (cf. chapter 9).
- We have introduced a correction for the systemic t-2 time lag of the network operator price index (NPI) to take account of the current, exceptional inflation. The correction will feed into the regulatory account from 2024 onwards and will thus have an effect on tariffs from 1 January 2025 (cf. chapter 10).
- We have updated the WACC and introduced a differentiation between how existing and new assets are reflected. The idea is to enable financing (in particular in light of the evolution of interest rates on the market) and implementation of adequate and necessary infrastructure investments to secure gas supplies (section 4(1) and section 79(1) Gas Act 2011). The regime provides incentives for investment and ensures that necessary new investments are not delayed or cancelled due to a low WACC (cf. chapter 11).
- We have eliminated the operating cost factor for metering points and pipeline kilometres. This makes sure that gas customers switching to other fuels does not negatively impact the system operators’ allowed costs. It also implicitly prevents a perverse incentive for network expansions and instead supports downsizing the grid (cf. chapter 13.1).

- We have introduced a cost-plus regime for connection costs of biogas facilities, for as long as data for lump-sum compensation are not readily available (cf. chapter 13.2).
- We have introduced an innovation budget to promote the transformation of the Austrian gas system into a decarbonised system with renewable gases (cf. chapter 15).

Gas DSOs operate in a much different environment today than they did when the previous regulatory regime was set up; the above changes take this evolution into account. Having said that, we stick with incentive regulation, which has proved its worth.

Under a long-term incentive regime that applies to all companies equally and remains stable for several years, there is only limited scope for taking into account individual companies' characteristics.[1] We therefore explicitly make mention of the fact that several elements are based on average costs (in line with section 79 Gas Act 2011).[2] The regulatory regime described in this document is first applied during the cost audit conducted in 2022 (i.e. the one that serves as a basis for 2023 system charges).

We wish to point out that the contents of the present document refer to the fourth regulatory period for gas distribution system operators exclusively and do not prejudice the framework to be applied in any of the following regulatory periods. The present document is based on the currently applicable statutory provisions from the Gas Act 2011 and the E-Control Act.[3] Any amendments to these acts might entail changes to the regulatory regime, even if such amendments should occur during the regulatory period. On this issue, please refer to chapter 5, which explains the conditions under which certain regulatory parameters might be changed during the period.

The regulatory regime for the fourth period builds on insights from discussions, studies, calculations and position papers exchanged between the industry representation (FGW), individual companies, the Federal Chamber of Labour (BAK) and the Austrian Economic Chambers (WKO) on the one hand[4] and E-Control and the experts consulted on the other hand, gained during the period between October 2021 and summer 2022. Once we had consolidated the preliminary results of this process, we submitted them to the stakeholders in summer 2022 and asked for their reactions within an adequate deadline. The studies which we commissioned (appendix 1 and appendix 3) were also made available as part of the consultation procedure. The minutes of all technical and high-level meetings with the industry representation, companies and participating statutory parties and all presentations submitted during such meetings were sent to all participants before the consultation started.

The industry representation, many system operators and the statutory parties submitted their reactions to the drafts in September 2022. We analysed them and proceeded as follows: comments that referred to individual companies and general comments were addressed in the companies' individual official cost decisions. Additionally, our final position on general comments is explained in the present document. Here, we make a distinction: reactions that triggered changes to the draft regulatory regime are addressed in the relevant chapters. Reactions that did not change the draft are summarised and

[1] A regulatory model, simply by virtue of being a model, is necessarily an abstraction of reality.
[2] Gas Act 2011, FLG I no 107/2011, as amended by FLG I no 94/2022.
[3] E-Control Act, FLG I no 110/2010 as amended by FLG I no 7/2022.
[4] BAK and WKO are statutory parties to this process in line with section 69(3) Gas Act 2011.

discussed in annex II, following the same structure as the main document. We hope that this way of handling the results of the consultation improves readability and transparency.

2. Basic tenets of incentive regulation in Austria

Network infrastructures are natural monopolies in an economic sense. Regulation aims to ensure that the operators of such network infrastructures fulfil their public service obligations.

The system charges which system users pay in exchange for gas DSOs' services must cover the operators' allowed cost, which in turn is determined by applying the general principles enshrined in sections 69 et seq. and 79 et seq. Gas Act 2011:

- The regulatory authority periodically determines the allowed cost, the relevant targets and the transported quantity that form the basis for calculating the system charges.
- The charges must reflect actual costs, i.e. only costs that are caused by the operators' network business and that are necessary and adequate are allowed.
- Due consideration must be given to system security, security of supply (including quality criteria), market integration and energy efficiency.
- The allowed costs may be determined on the basis of the average costs of a comparable, rationally operated company.
- Reasonable investment costs must be allowed, taking account of both historical costs and the cost of capital. In this, adequate cost of debt and equity must be included.
- Targets and a system operator price index must be set and reflected in the allowed cost. DSOs must be incentivised to increase efficiency, but they must also be able to execute the necessary investments.

It is our task to take adequate action to ensure that the objectives stated in section 4 E-Control Act are reached. Of these objectives, the following are particularly relevant when setting the gas distribution system charges:

- promoting a competitive, secure and environmentally sustainable internal market in gas within the Union and its regions, and effective market opening for all customers and suppliers in the Union;
- ensuring appropriate conditions for the effective and reliable operation of gas networks, taking into account long-term objectives;
- helping to achieve, in the quickest and most cost-effective way, the transformation of the energy system in line with the Paris Climate Agreement of 2015;
- safeguarding the development of consumer-oriented, secure, reliable and efficient non-discriminatory systems;
- promoting system adequacy and, in line with general energy policy objectives, energy efficiency;
- integrating gas from renewable energy sources and decentralised production as well as facilitating access to the network for new generation and production capacity, in particular by removing barriers that could prevent access for new

market entrants, especially if they are renewable energy communities or producers of renewable gas;

- ensuring that system operators and system users are granted appropriate incentives, in both the short and the long term, to increase efficiencies and foster market integration;
- ensuring that customers benefit from the efficient functioning of their national market and helping to ensure consumer protection;
- helping to achieve high standards of public service in gas supply for vulnerable customers.

Section 4 Gas Act 2011 provides a number of further objectives along the same lines. With reference to setting the allowed cost, the following are especially pertinent:

1. ensuring security of supply with and efficient use of gas, including providing the infrastructure that is necessary for secure gas supply;
2. considering decarbonisation and the economical supply and efficient use of gaseous energy carriers in planning gas pipelines;
3. ensuring reasonable distribution of the network cost among network users by way of the system charges;
4. offsetting public service obligations imposed upon system operators in the general economic interest, and those relating to the safety and security – including the security of supply –, the continuity, quality and the price of supplies, as well as to environmental and climate protection;
5. laying the groundwork for increasingly exploiting the potential of biogenic gas for Austrian gas supply;
6. ensuring compliance with the infrastructure standard according to Article 5 Regulation (EU) 2017/1938;
7. contributing to achieving the goals of the Paris Climate Agreement 2015 and taking steps towards Austria’s climate neutrality in 2040, in particular when it comes to planning gas pipelines;
8. continuously increasing the share of renewable gas in the Austrian pipeline network and intensifying the use of renewable gas in Austrian gas supply;
9. realising national potentials for sector coupling in existing infrastructure.

If a company is to act in a productively efficient way, i.e. if it is to endeavour to produce goods and render services at the lowest possible inputs (costs), it must have some kind of incentive to do so. Productive efficiency must be rewarded, at least for a certain period of time. Therefore, during this period of time, we must accept an allocatively inefficient situation.[5]

On the one hand, excessive allocative inefficiency can be against consumer interests. On the other hand, any ex-post intervention in the regime for the purpose of skimming off

[5] Cf. materials relating to section 79 Gas Act 2011, explanatory notes on the government bill 1081, the annexes to the transcripts of the National Council sessions of the XXIV legislative period, 26 (27).

profits that are regarded as inappropriate contradict the goal of providing incentives for productive efficiency.

Regulation must always ensure that operators can recover costs which originate in network activities (cf. the materials mentioned above). This can conflict with the objective of productive efficiency, since it limits the most effective sanction available in a competitive economy, i.e. the possibility of a company being driven off the market.

To ensure that the regulatory regime is met with acceptance by both system users and system operators, and to enable judicial scrutiny of our decisions, we must guarantee transparency (s. Article 41(1)(a) Directive 2009/73/EC) and take objective and reasoned regulatory decisions (cf. Administrative Court findings 2012/05/0092, 2012/05/0093, and 2012/05/0094 of 18 November 2014). However, this does not mean that regulated companies' comments and wishes should be automatically accepted.

Transparency is closely connected to planning certainty: regulated companies must know the framework at the beginning of the regulatory period. Still, changes to the regime must be possible. To consolidate these two, we must continuously evaluate the regime. If we detect room for improvement, the regulatory regime should be amended, either at the beginning of a new regulatory period or during the period.

The fourth regulatory period for gas DSOs provides for annual cost audits (as previously). This imposes considerable expense on both regulated companies and the regulator. Alternatively, the time between cost audits could be stretched in favour of longer periods with stable conditions. This bears the risk of actual costs deviating too far from allowed costs. In light of the insecurities surrounding the future development of the gas market, we have decided to retain annual cost audits.

The following chapters explain each factor of the regulatory regime in detail.

3. Scope of application and length of the regulatory period

The regulatory regime described in this document applies to all gas DSOs in Austria that operate pipelines at grid levels 2 and 3. A total of 20 companies meet this condition (s. chapter 18).

There are only a few companies that operate grid level 1 lines in Austria, which is why we approximate their individual efficiency scores based on their efficiency scores for grid levels 2 and 3, with one exception: the DSO Gas Connect Austria (GCA) operates grid level 1 lines but most of its business is at transmission level. To account for this particular situation, the following caveats apply to the present document in respect of GCA: the efficiency score for its grid level 1 operations is approximated using the regulatory regime for transmission system operators; a cost-plus regulatory regime applies; only chapters 10 (network operator price index), 11 (WACC), 12 (RAB) and 14 (regulatory account) apply. The other chapters of this document are not relevant for GCA.

When setting the length of the regulatory period, we must take into account 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. 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, fairness for consumers is skewed and the regime can no longer simulate competitive pressure in the regulated sector.

Current regulatory practice usually provides for regulatory periods between three and five years. In Austria, both the regulatory authority and the regulated companies have gained extensive experience with incentive regulation. It therefore appears reasonable to maintain the 5-year period used previously.

Economic literature warns of the so-called ratchet effect;[6] to keep this to a minimum, the regime provides for ongoing benchmarking. ‘Ongoing’ in this context means that the efficiency benchmark is performed before each regulatory period, so that the resulting targets are only in effect for one regulatory period.

With such a regime, cost data must be adjusted and corrected before they can be transformed into the costs that are used in the 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 both the grounds for payment and the amount paid were reasonable.

[6] The term ‘ratchet effect’ designates the risk of exaggerated costs being stated for the audit year, resulting in excessive allowed cost at the beginning of the regulatory period (cf. Rodgarkia-Dara A., 2007, *Ratchet Effect: Theorie, Lösungsansätze und internationale Erfahrungen* (Ratchet effect: theory, solutions and international experience), E-Control Working Paper 18, 1-70).

4. Evolution of the gas sector

The gas distribution business has been subject to several developments over the past couple of years, especially in 2022, which must be taken into account in regulation.

The Russian invasion of Ukraine was followed by a reduction of gas deliveries from Russia to Europe, which in turn sent gas prices skywards and triggered uncertainty around security of gas supply. The European and national level reacted by quickly introducing a series of legislative measures to increase security of supply, diversify gas supplies and accelerate decarbonisation.

The Austrian government programme for 2020-2024 originally foresaw a ban of gas-fired heating systems in new buildings from 1 January 2025 onwards; in light of the above developments, this was moved up to 1 January 2023 in the version of the Renewable Heating Act that is currently under consultation.[7] The legal text also mandates a phase-out of heating systems that run on fossil gas by 30 June 2040; systems that use renewable gas may continue to operate.

Also the legislative package around the Renewable Energy Expansion Act carries a number of measures to boost production of renewable gas. It sets a target of 5 TWh renewable gas injection into the gas grid by 2030 and introduces an obligation for guarantees of origin and gas labelling. Power-to-gas plants that convert electricity into hydrogen or synthetic gas qualify for investment support under section 62 Renewable Energy Expansion Act. This ties in with the goal to promote renewable hydrogen as key for sector coupling and integration, enshrined in section 4(7) et seq. Gas Act 2011. Existing and new facilities for producing and processing renewable gas benefit from reduced system admission charges (section 75 Gas Act 2011). Research and demonstration projects relating to renewable gas can apply for exemptions from the system charges if they constitute a regulatory sandbox (section 78a Gas Act 2011). In addition, the government has announced that renewable gas legislation is forthcoming.

In June 2022, the government presented its hydrogen strategy.[8] Climate neutral hydrogen is meant to play an important role in achieving Austria's goal to be climate neutral by 2040, in particular in sectors that are otherwise difficult to decarbonise (such as the energy intensive industry), and in the transformation of the energy system. One target in the strategy is the development of hydrogen transport infrastructure, primarily by converting existing gas infrastructure into hydrogen infrastructure. The potential for converting existing infrastructure will be addressed in a dedicated study[9] and in the integrated network plan.

Of the objectives for gas DSOs listed in chapter 2, the following are most relevant in these circumstances:

[7] Ministerial draft of the federal act to phase out fossil heating (Renewable Heating Act), https://www.parlament.gv.at/PAKT/VHG/XXVII/ME/ME_00212/index.shtml· Last visited on 24 June 2022.

[8] Hydrogen Strategy for Austria. https://www.bmk.gv.at/themen/energie/energieversorgung/wasserstoff/strategie.html. Last visited on 24 June 2022.

[9] Public tender by the Federal Minister for Climate Action, Environment, Energy, Mobility, Innovation and Technology for a study on the role of the gas infrastructure in a climate neutral future 2040 in Austria. https://gv.vergabeportal.at/Detail/108896#tab1. Last visited on 24 June 2022.

- ensuring security of supply with and efficient use of gas, including providing the infrastructure that is necessary for secure gas supply;
- helping to achieve, in the quickest and most cost-effective way, the transformation of the energy system in line with the Paris Climate Agreement of 2015;
- contributing to achieving the goals of the Paris Climate Agreement 2015 and taking steps towards Austria's climate neutrality in 2040, in particular when it comes to planning gas pipelines;
- considering decarbonisation and the economical supply and efficient use of gaseous energy carriers in planning gas pipelines;
- integrating gas from renewable energy sources and decentralised production as well as facilitating access to the network for new generation and production capacity;
- laying the groundwork for increasingly exploiting the potential of biogenic gas for Austrian gas supply;
- continuously increasing the share or renewable gases in the Austrian pipeline network and intensifying the use of renewable gas in Austrian gas supply;
- realising national potentials for sector coupling in existing infrastructure;
- promoting system adequacy and, in line with general energy policy objectives, energy efficiency;
- ensuring that customers benefit from efficient functioning of their national market and helping to ensure consumer protection.

Against this background of general developments and recent and forthcoming legislative measures, we expect a fundamental transformation of the gas sector in the medium to longer term. Therefore, we have decided to build contingencies into the regulatory regime for the fourth regulatory period. These will enable us to quickly react to such transformations.

5. Mutable parameters

The previous chapter gave an overview of the challenges Austrian gas DSOs are facing. The current legislative framework for the regulatory regime is laid down in the Gas Act 2011, but we expect legislative changes to be forthcoming during the regulatory period and these will affect the landscape in which gas DSOs operate.

While we cannot know now how far-reaching these changes will be, we can anticipate which parameters of the regulatory regime they will have an impact on. These will most likely be parameters that try to forecast the development of system operators' supply mandate.

We have built flexibility into the regulatory system at the requisite points to make room for such changes without having to overhaul the entire regime. By singling out individual mutable parameters but keeping all other elements stable, we create contingencies while also maintaining planning security.

The basic concept of mutable parameters was repeatedly discussed with the statutory parties and the industry representation during the preparations for the fourth regulatory period. All parties considered this to be a good approach. There is consensus that conditions should be kept as stable as possible during the regulatory period, but that it must also be possible to react to changing circumstances.

If necessary,[10] the regulatory regime thus provides for flexibility with reference to the following parameters:

Expansion factors

Please note that use of the expression 'expansion' in this instance does not refer to an expansion of the pipeline network but rather to the evolution of the gas DSOs' supply mandate (cf. chapter 13). Expansion factors are mutable parameters, in particular if new legislation should directly impact the companies' supply mandate.

Also, we reserve the option to abandon the cost-plus approach for additional costs for connecting facilities for the production and processing of renewable gas in favour of a unit-cost OPEX factor. This could be done once we have sufficient data to calculate robust unit costs for connecting renewable gas facilities. Further details are provided in chapter 13.2.

In addition, we will consider integrating the roll-out of smart meters in the regulatory regime itself in the course of the fourth regulatory period. If we conclude that smart meters for gas should be built into the regime, the corresponding changes will be made. Chapter 13.3 provides further details.

Any additional tasks for gas DSOs that are not foreseen at the moment might also be reflected via expansion factors.

[10] This refers to legislative changes and the evolution of the circumstances under which gas DSOs operate. A more strict delineation of cases that could warrant adjusting the parameters is not possible at the moment. We must thus rely on case-by-case evaluation of the situation as it evolves, weighing the pros and cons of an adjustment.

Corporate taxes in WACC

The 2022 tax reform lowered the corporate tax rate from 25% to 24% (in 2023) and 23% (from 2024 onwards).[11] Given that corporate tax is a component of the WACC, these changes directly impact the pre-tax WACC (but please note that this is only relevant for the cost of equity, not for the cost of debt). If we keep the WACC as it is, this small cost reduction would go unaccounted for and result in additional, unintended revenue for system operators. System users would be disadvantaged. Thus, we continually adjust the corporate tax rate used in WACC calculation so that it always reflects the applicable rate.

The specifics of this adjustment are detailed in the Zechner/Randl (2022a) study (attached to this document).

Network operator price index and current inflation

General inflation in Austria is measured by the consumer price index (CPI), which reflects the price of goods and services for households by way of a standardised shopping basket. The Russian invasion of Ukraine drove energy prices up and led to a consumer inflation rate of around 9.3% in August 2022 when compared with the same month in 2021.[12] At 18.9% of the basket, expenses for living, water and energy together are the largest factor in the national CPI.[13] Even before Russia invaded Ukraine, energy was 26.8% more expensive than the year before. Afterwards, prices reached unprecedented levels.[14] The Austrian Energy Agency calculates an energy price index for households (based on CPI data provided by Statistics Austria) and considers energy to be a price driver. For August 2022, the index was 40.7% higher than one year before. The Austrian Energy Agency concludes that close to 3% of inflation in Austria during August 2022 can be directly attributed to energy price increases. If we look at gas prices only, they increased 72.3% year-on-year.[15]

The incentive regulatory regime currently provides that the NPI applies to operators' controllable OPEX, to reflect external price increases that they have no control of (cf. chapter 10). The NPI has a 50% component of the CPI, which is used as a proxy for the average price evolution of the goods and services that DSOs have to purchase. (Separately, gas DSOs' energy costs are refunded as uncontrollable costs with a t-2 time lag.) Against this background, we consider it necessary to critically evaluate whether the CPI should still be used as a proxy for system operator costs during the regulatory period.

The system charges that apply in 2023 incorporate the 2021 NPI, i.e. from before the price hikes. There is thus no need to immediately address this issue. However, we will continue to evaluate the evolution of NPI and inflation and might introduce adequate adjustments. This might include an adjustment to the weighting of the factors in the NPI or use of different indices to calculate the NPI, if there are any that better reflect DSOs' costs for labour and intermediate consumption. This will mean analysing gas DSOs' OPEX cost structure in a first step, and finding out whether there are any public indices that could be

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11 Cf. https://www.parlament.gv.at/PAKT/VHG/XXVII/I/I_01293/index.shtml. Article 2, amendment of the Corporate Tax Act 1988. Last visited on 1 July 2022.

12 Cf. https://de.statista.com/statistik/daten/studie/288914/umfrage/inflationsrate-in-oesterreich-nach-monaten/ and https://www.statistik.at/statistiken/volkswirtschaft-und-oeffentliche-finanzen/preise-und-preisindizes/verbraucherpreisindex-vpi/hvpi. Last visited on 21 October 2022.

13 Cf. https://de.statista.com/statistik/daten/studie/697382/umfrage/zusammensetzung-des-warenkorbs-privater-haushalte-in-oesterreich/. Last visited on 1 July 2022.

14 Cf. https://www.oenb.at/dam/jcr:d4c6ef8c-cfdf-40fa-ad3d-1b15a2be4d5e/Inflation-aktuell_Q1-2022.pdf. Last visited on 1 July 2022.

15 Cf. https://www.energyagency.at/fakten/energiepreisindex. Last visited on 21 October 2022.

better proxies for the average DSO's costs than the CPI in a second step. Given that energy is a driver of the CPI and operators' energy costs are refunded as uncontrollable costs with a t-2 time lag, the evolution of energy costs figures in two separate elements of the regulatory regime. Changing the composition of the NPI would do away with such double counting, which in the end must be financed by system users.

Should analyses reveal that there is a fairer and more correct option for building the NPI, we will make the corresponding changes. The newly established correction that accounts for the t-2 lag would also be affected (cf. chapter 10), as any revised composition of the NPI would then be used going forward.

All parameters of the regulatory regime that are not mentioned above are considered immutable during the fourth regulatory period. This particularly applies to the X-factors.

Consultation responses relating to mutable parameters

The annual update of the cost of debt and the risk-free rate for calculating the cost of equity that are used in $WACC_{new\ investments}$ were originally part of chapter 5. The industry representation argued that they should be taken out, because this chapter contained mutable parameters and the mentioned parameters developed according to an immutable formula.

We agree with this line of thinking. The relevant section has been taken out of chapter 5, giving system operators security.

Concerning the interaction between the NPI and the current, high levels of inflation, BAK proposed that the CPI that is used in the NPI be corrected for energy costs. This would ensure that customers do not have to pay twice for these developments. The corresponding correction should be made immediately.

We concur with BAK in that factoring in the evolution of energy costs twice must be avoided. To aid discussions, the document describing the draft regulatory regime listed an example of how energy could be extracted from the CPI. This was met by much opposition from the gas industry. FGW thought that eliminating individual components from the CPI was not reasonable and increased uncertainty in the regulatory regime. They argued that CPI's value as a proxy for the operators' OPEX could only be preserved if the CPI continued to carry all components, as they formed a full picture.

We would like to underline that the example was meant to illustrate the issue at hand but was not intended as a preferred or even realistic option. So as not to create uncertainty, we have erased the example. However, we maintain our intention to further evaluate, discuss and potentially adjust the CPI composition.

6. Allowed costs

In general, we use the most recent available figures in our cost audits and in calculating the transported quantities. However, the cost audits we conduct require significant time and effort, both on our end and on the companies'. Also, regulated companies should have 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, we cannot set targets based on the most recent figures of *most* companies; rather, we need figures from *all* companies. For these reasons, we do not audit the costs of the most recent full business year (2021) but rather those of the previous year (2020).

More precisely, what counts is the balance sheet date as defined in section 201 Corporate Code: for each company, we use the data from the annual financial statement whose balance sheet date is in 2020.

There are exceptions to this rule. For some cost items (e.g. uncontrollable costs and the input parameters for calculating the expansion factors), we use the most recent figures available so as to minimise the systemic time lag. Any negative effects resulting from the remaining time lag are softened (cf. chapter 13.5).

6.1. Audited 2020 costs

In line with the above, the fourth regulatory period is based on the total costs (OPEX[16] and CAPEX[17]) for the 2020 business year (C_{2020}) as audited by us. Our decisions on whether to allow individual cost items or not follow the general principles in section 79 Gas Act 2011. To be clear: we use financial accounting data (cf. the explanatory notes on section 79(1) and (4) Gas Act 2011).[18] We also run plausibility checks of the 2020 accounts against developments in previous years and we normalise the figures accordingly. This way, we avoid looking at the figures on the balance sheet date only, we work against any strategic shifting of cost items into the 'snapshot' year and we take into account any one-off effects.[19]

In accordance with section 79(6) Gas Act 2011, the cost audit differentiates between the operational costs that are 'within the company's control' (i.e. controllable costs) and those that are 'beyond the company's control' (i.e. uncontrollable costs); added together, they make up the full OPEX for 2020 ($OPEX_{2020}$). This distinction is necessary because the controllable costs are subject to the general and individual targets specified in section 79(2) Gas Act 2011 and to the network operator price index. The uncontrollable costs, on the other hand, are not subject to any targets. They are audited based on the most recent available figures and passed through without any mark-ups or mark-downs. In other words, they are simply added in the regulatory formula (s. chapter 16). This differentiation is also relevant for dealing with the systemic time lag (s. chapter 13.5).

[16] OPEX are expenses incurred by continuous operation of the grid. This includes e.g. costs for materials, staff, and other continuous activities.
[17] CAPEX are expenses for long-term grid investment. This includes depreciation and adequate cost of equity and debt (cf. section 80 Gas Act 2011).
[18] Government bill 1081, annexes to the transcripts of the National Council sessions, XXIV legislative period, 26.
[19] Examples of one-off effects include unanticipated cost increases resulting from natural disasters (of course, normal reinvestment in grid infrastructure is not part of this category).

Section 79(6) Gas Act 2011 lists the following as uncontrollable DSO costs in a particular year (ucc_t):

- upstream network costs for using functionally connected systems in Austria and the costs of the distribution area manager;
- community levies for the use of public land;
- costs for covering system losses by way of transparent and non-discriminatory procurement; and
- costs arising from statutory rules to be followed in cases of *Ausgliederung* (a type of de-merger under Austrian law) which existed on the merits of the situation at the time of full opening of the gas market on 1 October 2002 and that are listed in the Gas SO Cost Ordinance.

Starting with the third regulatory period, we have handled OPEX and CAPEX in different ways. We stick with this differentiation for the fourth regulatory period.

6.2. Controllable OPEX

As previously, there is an OPEX budget for the regulatory period. This results from applying the overall efficiency target (i.e. X-gen and X-ind) and the network operator price index to the audited 2020 costs.

We calculate the allowed OPEX by applying the network operator price index (NPI, s. chapter 10) and the general productivity growth rate (X-gen, s. chapter 7) to the controllable 2020 OPEX,[20] thereby mapping two opposite effects: the NPI reflects exogenous price increases, while X-gen accounts for sector-specific productivity growth.

$$OPEX_{2022}^{allowed} = (OPEX_{2020} - ucc_{2020}) \times \prod_{t=2021}^{2022} \left[(1 + \Delta NPI_t) \times (1 - Xgen_{4th\,period})\right]$$

For companies whose financial year does not coincide with the calendar year, the calculation is adjusted accordingly.

The allowed OPEX upon which 2023 grid charges are based are derived from the targets described in chapter 9 and the NPI.

$$OPEX_{2023}^{basis\,charges} = OPEX_{2022}^{allowed} \times (1 + \Delta NPI_{2023}) \times (1 - overall\,efficiency\,target_{4th\,period})$$

6.3. CAPEX

For the third regulatory period, we introduced a new way of handling CAPEX. We stick to this method for the fourth regulatory period. As opposed to OPEX, for which companies are

[20] The individual target (i.e. the target identified for each company individually, s. chapter 9) is first applied when the 2022 controllable costs are translated into the grid charges for 2023, i.e. as the first year of the fourth regulatory period begins. This is presented in formal terms in chapter 16 (regulatory formula).

basically granted an overall budget to spend along the entire regulatory period, CAPEX are tracked and refunded as they arise. Roughly speaking, CAPEX consists of depreciation and the cost of capital for the regulatory asset base. The individual WACC, which we grant for assets acquired up to a certain cut-off date, incentivises efficiency.

6.3.1. Calculating the individual WACC

We use each company's efficiency score to derive its individual WACC. The efficiency scores result from the standardised TOTEX benchmarking exercise described in chapter 8.

A company with an efficiency score that corresponds to the median efficiency score of all gas distribution system operators that are part of the benchmark would receive a WACC (pre-tax, cf. chapter 11) of 3.72% for its existing regulatory asset base (cf. chapter 12)

The individual WACC diverges from this median by up to +/- 0.94 percentage points. The width of this corridor results from the minimum cost of equity, i.e. the average of unadjusted cost of equity and debt. This means that even the most inefficient system operator will yield much more than its cost of debt as long as it sticks to the normal capital structure.

The individual WACC aims to introduce an efficiency element to CAPEX and to incentivise efficient behaviour amongst regulated companies. By creating a corridor for the WACC and enabling companies to directly determine their position inside that corridor by way of their efficiency scores, they are given an incentive to improve their efficiency relative to the other companies. At the same time, inefficient companies are protected from absolute failure; their financing continues to be guaranteed.

To ensure that the RAB of Austrian gas distribution system operators generates an average return of 3.72%, we offset above-average and below-average efficiencies against each other. We use the adjustment factor ω for this purpose.

During the technical discussions that were held in preparation of the fourth regulatory period, BAK underlined the importance of having all individual WACCs balance each other out. During the third regulatory period, total above-average WACCs exceeded total below-average WACCs; the statutory parties and almost all system operators jointly applied to the Federal Administrative Court to have their individual WACCs adjusted retroactively, so as to ensure a balanced regime. The court found in favour of these applications. Following this, we applied this approach to all new cost decisions.

For the fourth regulatory period, we are setting the adjustment factor so that the total positive adjustments exactly correspond to the total negative adjustments. For the fourth regulatory period for gas distribution system operators, the above approach results in an adjustment factor of 0.24728.

Overall, the individual WACC for an above- or below-average company *i* is calculated as follows:

$$WACC_{above\ average;i}^{efficiency} = 3.72\ \% + \frac{0.94\ \% \times \omega}{(100\ \% - efficiency_{median})} \times (efficiency\ score_i - efficiency_{median})$$

$$WACC_{below\ average;i}^{efficiency} = 3.72\ \% - \frac{0.94\ \%}{(efficiency_{median} - efficiency\ score_{min})} \times (efficiency_{median} - efficiency\ score_{i})$$

Further changes to the calculation for the third regulatory period include: the elimination of the efficiency floor; the increase of the corridor width to +/- 0.94%; and the use of the median efficiency score as a starting point instead of the arithmetic mean. The reasons for these changes are explained below.

By eliminating the efficiency floor, companies receive a better incentive to increase their efficiency, as those just above the floor and those below it are no longer treated the same. We consider that an efficiency floor's main effect is to limit the effect of the targets on OPEX. The lower limit of the individual WACC (-0.94) already constitutes such a limit. An additional limitation by way of an efficiency floor is thus obsolete. In addition, we consider it both appropriate and in line with the results which competition would yield that a company with a 50% efficiency score should not receive the same return on equity as a company with an 80% efficiency score. Treating all these companies the same would not be appropriate and would eliminate the stronger incentive for companies with lower efficiency scores.

Increasing the maximum bandwidth for individual WACCs to +/- 0.94 was absolutely necessary. Incentive regulation aims to mimic competition between system operators. In a competitive situation, less efficient companies would yield much lower (or even negative) returns on equity than their more efficient competitors. Also, companies in competitive situations have no guarantee that their equity is preserved. Increasing the maximum variation from 1 percentage point (+/- 0.5 percentage points) to 1.88 percentage points (+/- 0.94 percentage points) thus increases competitive pressure and strengthens the incentive for Austrian gas distribution system operators to increase their efficiency. We would like to point out that the lower limit for the return on equity is 4.19%, which is very clearly positive, and that even the most inefficient system operator will, if it has a normal capital structure, yield an overall return on capital of 2.78%, i.e. much above cost of debt. This means that even inefficient companies will receive adequate individual returns on their regulatory asset base up to 2020.

Using the median efficiency score instead of the arithmetic mean is intended to produce a more balanced effect of the individual WACC system. It ensures that half of the system operators receive a mark-up on the average WACC, while the other half receives a mark-down. Any skewed balances (because more or fewer companies are above/below the arithmetic mean) are eliminated. Also, the median is much more robust when it comes to individual outliers, thus increasing predictability.

During the technical discussions that preceded the fourth regulatory period, system operators argued that this step would be to the detriment of smaller system operators, and that these were already disadvantaged in the benchmarking because of their small size. However, given that we have switched to non-decreasing returns to scale (NDRS), this argument no longer holds (cf. chapter 8.1.3). Participants in the discussions also doubted whether eliminating the efficiency floor was adequate, given that half of the system operators were below the efficiency floor during the third regulatory period. Again, this point loses its validity due to the elevated efficiency floor and the switch to NDRS. Empirical analysis of efficiency scores has shown that exactly five of the ten smallest companies and five of the ten largest companies received a mark-up on the average WACC.[21] This confirms that small and large companies are affected equally by the individual WACC mechanism.

We thus consider it appropriate to eliminate the efficiency floor and to use the median efficiency score as a reference in calculating the individual WACC, thereby increasing the variation of revenue and strengthening the incentive. This approach also ensures that the individual situation of system operators is better accounted for.

The resulting return on equity[22] for Austrian gas distribution system operators is 4.19%-7.13%. For a network operator with the median efficiency score, it is 6.55% before taxation.

6.3.2. Applying the individual WACC

We apply each company's individual WACC to the depreciated book value of its RAB up to 2020. Net additions to the RAB during 2021 and 2022 (i.e. additions minus final customer prepayments for installation costs) receive a uniform yield of 3.72% ($WACC_{legacy\ RAB}$). New investments from 2023 onwards are subject to a new WACC ($WACC_{new\ investments}$). It uses a shorter reference period to calculate interest, thereby better taking into account recent developments on the financial markets. The interest rate that applies to new investments is updated as of 31 August each year. Investments of 2023 receive a WACC of 4.88% ($WACC_{new\ investments}$). This is a reaction to the volatile developments of the financial markets and serves to acknowledge the increase in interest rates that has been recently observed. For more details, please refer to chapter 11.

Due to a lack of annual efficiency benchmarks, the WACC for investments from 2021 is the same for all system operators. These investments will only be included in the benchmarking exercise for the next (i.e. fifth) regulatory period. In the meantime, we are assuming that all investments have an average efficiency. Depreciation is passed through without any offsets or other changes, i.e. we minimise the risk exposure for system operators by guaranteeing that their investments are covered through the system charges.

The CAPEX part of the regulatory formula, including the individual WACC mechanism ($WACC_{ind}$), is as follows for the system charges that apply from 1 January 2023:

$$CAPEX\ compensation_{2023} = depreciation_{2021} + RAB^{2021}_{up\ to\ 2020} \times WACC_{ind} + RAB^{2021}_{from\ 2021} \times 3.72\ \%$$

For the years from 2024 onwards:

$$CAPEX\ compensation_{2024} = depreciation_{2022} + RAB^{2022}_{up\ to\ 2020} \times WACC_{ind} + RAB^{2022}_{from\ 2021} \times 3.72\ \%$$

$$\begin{aligned} CAPEX\ compensation_{2025} &= depreciation_{2023} + RAB^{2023}_{up\ to\ 2020} \times WACC_{ind} + RAB^{2023}_{from\ 2021} \times 3.72\ \% \\ &\quad + RAB^{2023}_{from\ 2023} \times 4.88\ \% \end{aligned}$$

[21] Company size was determined based on the system operators' standardised capital cost.

[22] $yield^{equity} = \frac{WACC_{ind} - debt^{rate} \times debt^{share}}{equity^{share}}$

6.3.3. Useful life

For the third regulatory period, the regulatory formula considered a useful life of gas distribution pipelines of 30 years (down from 40 years in the previous regulatory periods). The reason for this was that the future of the gas network, in particular in view of the need to attain climate goals, was uncertain. The shorter useful life aimed to avoid stranded investments.

In the document outlining the third regulatory period, we noted that we would continuously monitor and evaluate developments. We did, and have arrived at the conclusion that new investments in pipelines during the fourth regulatory period should be subject to an even shorter useful life period.

The future of the gas network continues to be uncertain. While the national and European climate goals (in particular the decarbonisation of the energy system) continue to apply, the Russian invasion of Ukraine on 24 February 2022 has triggered a renewed focus on gas security of supply (section 4 item 1 Gas Act 2011). Avoiding stranded investments which would put additional strain on the regulatory regime's financing has become even more important. In addition, the consultation of the ministerial draft of the Renewable Heating Act was launched on 14 June 2022; it mandates that no fossil gas may be used to heat buildings from 2040 onwards.

We thus expect the number of metering points at grid level 3 to decline over the next years.[23] This means that the number of gas customers, i.e. the number of people among whom the costs of the gas network must be shared, will decline as well. We account for this development in the current regulatory framework. It is our goal to strike a balance between current and future system users in terms of costs to be borne. To achieve this, we have reduced the useful life in the regulatory formula for new pipeline investments at grid levels 1 to 3 from 2023 onwards to 20 years.[24] We are aware that shortened useful life periods for new investments have no large economic effects. Even so, they increase the portion of costs that are borne by current network users as opposed to future ones. FGW demanded that useful life at grid levels 1 and 2 be kept at 30 years or that they be exempted from the new rules. In response, we would like to point out that it is the customers that will leave the gas network in the foreseeable future who bear most of the costs for grid levels 1 and 2 (due to cost cascading). Shortening useful life for assets at grid levels 1 and 2 has a smoothing effect on future system charges. In terms of balance, we would like to underline that even with the shorter, 20-year useful life, investments from the fourth regulatory period will only be fully depreciated in 2047 (while residual book values in 2040 will be small).

We would like to underline that shortening useful life periods should not be misconstrued as a divestment strategy. Well-functioning existing pipelines can continue to be operated and used (for fossil gas, green gas or other uses) regardless of whether they are fully depreciated or not. Infrastructure is typically used longer than the regulatory useful life

[23] During the technical discussions leading up to the fourth regulatory period, both the system operators and the industry consultants Gugler/Liebensteiner explained that they expected a reduction in metering points. This is also the expectation and direction of policy makers. Cf. https://www.bmk.gv.at/themen/klima_umwelt/energiewende/waermestrategie/strategie.html and https://kesseltausch.at/. Last visited on 7 July 2022. In addition, we would like to mention that a declining total number of metering points at grid level 3 across gas distribution system operators has been observed for years. The current circumstances lead us to expect this trend to continue.

[24] Please note that useful life periods for investments that were executed before 2023 remain unaffected.

would indicate. The shorter useful life periods simply serve to prevent potentially large stranded costs in future. Given the uncertainty surrounding the future of the gas network, we consider this to be good sense.

Some system operators use even shorter depreciation periods than those that were used in the regulatory regime for the previous regulatory periods. For these, we now introduce the possibility to shorten the useful life of existing assets. While the old regulatory regime applied useful life periods of 40 years, and while this period was shortened to 30 years during the third regulatory period, some system operators used even shorter periods in their annual financial statements under the Business Code. This required us to correct depreciation periods annually, so that book values and depreciation would reflect the useful life periods foreseen in the regulatory regime from 2005. With the new regulatory regime, we introduce an option to recover capital cost from existing assets more quickly, by way of the following mechanism:

- The sum that remains after subtracting final customer prepayments for construction costs from the regulatory asset base is spread over an appropriate number of years, thus increasing the system operator’s costs. The appropriate number of years is determined depending on the period that the assets are actually operated for and the remaining sum to be recovered as compared to the overall costs.
- The system operator uses the regulatory depreciation period of 20 years in its annual financial statement from 2023 onwards.
- Correcting the useful life periods applied in the annual financial statements so that book values and depreciation are in compliance with the periods from the regulatory regime becomes obsolete.

This mechanism enables system operators to recover their existing investments from a larger group of system users than would otherwise be the case.

7. General productivity growth rate (X-gen)

In line with section 79(2) Gas Act 2011, the system operators' costs are subject to a general efficiency target that reflects productivity growth in the sector (X-gen). By way of this X-gen, system users reap the benefits of the productivity growth that is to be expected due to technological progress (i.e. the frontier shift) as the system charges (and operators' revenues) fall accordingly. This is how X-gen simulates competitive pressure.[25]

Since X-gen applies to OPEX only, this is also the reference for determining how high the general productivity growth rate should be.

When incentive regulation for gas distribution system operators was introduced in 2008, X-gen was 1.95% p.a. This was left unchanged for two regulatory periods. The third regulatory period originally provided for a drop of X-gen to 0.67% p.a. However, WKO and BAK objected against this value. Negotiations before the Federal Administrative Court were followed by joint applications by the statutory parties and the system operators; in the end, the Federal Administrative Court decided that X-gen would be 0.83% p.a.

We used historical data of Austrian gas distribution system operators to calculate X-gen for the fourth regulatory period. This approach has been tried and tested and has proven to better reflect the actual conditions under which companies operate than higher-level economic data.[26] In this, it is crucial that we can use a valid and consistent set of data. This is why we started building such a data set early on. We sent the companies economic and technical data that we had extracted from their own data submissions between 2002 to 2020 and asked them to verify and double-check.[27] Existing itemised OPEX data were corrected for items and effects that are not related to a company's productivity developments.[28] The entire process aimed to ensure a uniform basis for comparison.

In the interest of finding the factually right level for X-gen during the fourth regulatory period, we commissioned a study from WIK-Consult and DIW Berlin (WIK/DIW (2022a)).

To ensure that the data that we provided for all X-gen calculations were uniform, we asked the system operators to provide the same information to the industry consultants, Mr Gugler (Vienna University of Economics and Business) and Mr Liebensteiner (FAU Erlangen-Nürnberg), so that they could run their own analyses. The statutory parties did not submit any studies with empirical analyses of the verified data.[29]

[25] Competitive pressure forces companies to pass productivity growth on to their customers by way of low prices. Otherwise, their products would be too expensive, could not be sold on the retail market, and the companies would be priced out of the market in the long run.

[26] WIK-Consult (2018), *Ermittlung des generellen Faktorproduktivitätsfortschritts für Stromverteilernetzbetreiber in Österreich im Zuge der vierten Regulierungsperiode* (Calculating the general productivity growth for electricity Austrian distribution system operators during the fourth regulatory period), Bad Honnef.

[27] One company only had an estimate of their cost data, which is why we used a limited pool of 19 gas distribution system operators in the data basis.

[28] We corrected the following positions: metering differences, community levies, fossil gas levy, compensation payments, and the regulatory account. In addition, retroactive changes in pension reserves that resulted from interest rate changes and changes in life tables were distributed across 10 years prior to the retroactive change and 10 years following it. This should smooth out volatilities that are not related to productivity improvements.

[29] WKO submitted a slide deck they had commissioned from Swiss Economics (Swiss Economics (2022)). The slides contained X-gen analyses that supported WKO's position. For details on this position, please consult chapter 19.

The consultants (i.e. both Gugler/Liebensteiner and WIK-Consult/DIW Berlin) were invited to present their methodologies and results during the technical meetings between ourselves, FGW, the Austrian gas distribution system operators, and the statutory parties. Following these meetings, Gugler/Liebensteiner submitted their slides (Gugler/Liebensteiner (2022a)).

The results quoted by FGW during the technical meetings were based on two studies which they had commissioned and which they submitted.[30] In addition, they handed in the industry consultants' final reaction to the draft regulatory regime for the fourth regulatory period and our consultants' study.[31] Given that the results presented by the industry consultants during the technical meetings make reference to Gugler/Liebensteiner (2021a and 2021b) but carry more recent estimates, we refer to these slides in the following explanations.

Below, we first summarise and discuss the industry consultants' study. Then, we present the methodology and results produced by the study we commissioned. We continue with a discussion of the points where the studies arrived at diverging conclusions. In the end, we present our own conclusions and the final decision on X-gen.

Gugler/Liebensteiner (2022a and 2022b) – study commissioned by FGW

FGW were of the view that X-gen should be lowered considerably for the fourth regulatory period and should, in fact, take on a negative value.[32] They supported this view by way of a study conducted by consultants Gugler/Liebensteiner. Gugler/Liebensteiner (2022a) held that productivity growth in gas system operation slowed down over time and was even negative, given the circumstances under which the gas sector operated at the time (cf. chapter 4).

Empirical calculation of X-gen implies econometric estimations. The final formula[33] presented by Gugler/Liebensteiner (2022a) during the technical meetings contained the corrected and NPI-deflated OPEX of the system operators as dependent variable. Independent output variables were weighted network length, number of household and small business metering points, and peak daily gas consumption. These latter were taken from the data basis that we provided. Gugler/Liebensteiner (2022a) also integrated company-specific input prices, i.e. a price for labour($= \frac{personnel\ expenses}{number\ of\ FTEs\ in\ the\ gas\ distribution\ grid}$) and another for capital ($= individual\ WACC$). As for OPEX, they deflated the input prices with the NPI. The input prices themselves were not taken from our verified data basis but were specifically collected by the industry consultant for this purpose. Two system operators

[30] Gugler/Liebensteiner (2021a), *Gutachten zur 4. Regulierungsperiode im österreichischen Gasverteilnetz: Modul 1. Genereller X-Faktor für die 4. Regulierungsperiode im österreichischen Gasnetz* (Study on the fourth regulatory period for the Austrian gas distribution system. Module 1: X-gen). Gugler/Liebensteiner (2021b), *Gutachten zur 4. Regulierungsperiode im österreichischen Gasverteilnetz: Modul 2. Empirische Schätzung des Produktivitätswachstums im österreichischen Gasverteilnetz hinsichtlich der Festsetzung des generellen X-Faktors für die 4. Regulierungsperiode* (Study on the fourth regulatory period for the Austrian gas distribution system. Module 2: Empirical estimation of productivity growth in the Austrian gas distribution network for the purpose of calculating X-gen).

[31] Gugler/Liebensteiner (2022c), *Replik auf die vorläufige Regulierungssystematik und das WIK-Consult Gutachten vom 31.08.2022* (Reply to the draft regulatory regime and the WIK-Consult study dated 31 August 2022).

[32] Please note that this would imply that the entire gas sector experienced productivity losses.

[33] Please note that Gugler/Liebensteiner (2022a) repeatedly adjusted their formula (or rather, the parameters in their formula) during the technical meetings, which resulted in their X-gen estimates steadily rising.

could not provide these data and had to be excluded from the calculations. Also, data were only collected for the years up to and including 2019, i.e. 2020 was excluded.[34] All the variables mentioned so far were included in the analyses in logarithmic form. For the years from 2008 onwards, a dummy variable was used to control for the effects of incentive regulation.

Factor productivity growth was estimated by way of a linear and squared time trend based on the last five years.

The econometric estimation by Gugler/Liebensteiner (2022a) resulted in an X-gen range of -2.74% to -2.50% for the fourth regulatory period of gas distribution system operators. They argued that this was correct, given that: (i) efficiency potentials in gas distribution networks had already been exploited and a shrinking trend could be observed; (ii) the room for gas distribution system operators to further stretch efficiency was limited given the difficult environment in which they operated; (iii) TFP was generally overestimated as it accounted for a catch-up effect on top of the frontier shift; and (iv) TFP was also usually overestimated because there was a failure to control for the difference between gas distribution system operation and the overall economy (cf. Bernstein/Sappington (1999)).

After the technical meeting of 17 May 2022, FGW submitted a reply by the industry consultants to that meeting, which was annexed to the meeting minutes (Gugler/Liebensteiner (2022b)). It contained a revised estimate of X-gen. Instead of the price for capital used by Gugler/Liebensteiner (2022a), it used a wholesale price index as a proxy for intermediate consumption and material. The overall argument that X-gen needed to be negative was not affected. However, the revised estimate arrived at a TFP growth for 2016-2020 of -1.29%.

WIK-Consult/DIW Berlin (2022a) – study commissioned by E-Control (annex I)

WIK-Consult/DIW Berlin (2022a) state that, while it would be best for OLS estimates[35] to rely on factor prices, these are not available in the required quality. This is why NPI-deflated OPEX are used. Numerous tests to identify the basic panel structure and a quantitative cost driver analysis are conducted in preparation of the econometric calculation. This results in the total weighted network length and number of metering devices as relevant cost drivers. The time trend is included as a relevant OPEX driver both in linear and squared form. Except for the time trends, all variables are used in the parametric analyses in logarithmic form (this was the same approach the industry study took).

To verify the OLS results, WIK-Consult/DIW Berlin (2022a) conduct Malmquist DEA analyses. In contrast to averaging or OLS, Malmquist DEA enables differentiating between the frontier shift (i.e. technological advances) and catch-up effects (i.e. individual efficiency improvements of previously inefficient companies). Generally, the DEA confirms the OLS results.

Further analyses conducted by the consultants include sensitivity analyses with and without outlier analyses and a control for cost shifting between OPEX and CAPEX. In addition, an estimation using input prices is done (as was the case for Gugler/Liebensteiner). Again, the results confirm the results of the preferred specification. In the end, WIK-Consult/DIW Berlin (2022a) recommend a specification with company-specific effects, with deflated OPEX and without factor prices (because of insufficient high-

[34] The year 2020 was included in the reply submitted later (Gugler/Liebensteiner (2022b)).

[35] The ordinary least squares (OLS) method is an econometric method.

quality data), resulting in an X-gen of 0.75%-1% p.a. for the recommended reference period 2013-2020.[36]

Methodological discrepancies between the studies

FGW submitted the industry consultants' final reply to the draft regulatory regime and the WIK-Consult study dated 31 August 2022 (Gugler/Liebensteiner (2022c)). Our consultants in turn submitted their own reply to the main points of criticism presented (WIK-Consult/DIW Berlin (2022b)). Given that the industry and industry consultants' main arguments had already been presented and discussed during the technical meetings,[37] and given that we already addressed them in the document describing draft regulatory regime, we do not go into detail here but instead reference WIK-Consult/DIW Berlin (2022a) and WIK-Consult/DIW Berlin (2022b).

The following considerations thus follow the same lines as those presented in the document describing the draft regulatory regime. However, we expand on the specification of the cost function (point (i)) by adding the most recent estimation formula from Gugler/Liebensteiner (2022b), which was not referenced in the draft. We also add the results of the analysis done by Swiss Economics (2022), commissioned by WKO.

i) Specification of the cost function

The industry consultants argued that productivity growth calculations must be based on OPEX estimates which themselves use input factor prices as explanatory variables. Otherwise, TFP growth would be overestimated. Mr Liebensteiner put forward that although using input prices suffered from well-known and persistent problems, it was still preferrable to conducting an estimate without factor prices. Excluding input prices would imply that companies did not take measures to minimise their costs and would lead to a systematic overestimation of X-gen.

Swiss Economics (2022) held that there was no need to correct input prices for the purpose of estimating X-gen, neither from an empirical nor from an analytic point of view. With reference to the empirical view, they explained, for instance, that the time series of input price data were volatile and not plausible.[38] They argued that by applying an arbitrary ceiling of 120,000 EUR, the industry consultants implied that the time series were not plausible. From an analytical point of view, input prices should not be used, because X-gen could then be actively influenced e.g. by outsourcing low-skilled labour.

WIK-Consult/DIW Berlin (2022a) extensively discuss and analyse the input factor price issue. As part of this analysis, they scrutinise the data set used by the industry consultants and identify plausibility problems.[39] They also point out that the price of capital is not relevant for specifying an OPEX cost function. In addition, WIK-Consult/DIW Berlin (2022a) criticise the lack of company-specific data on intermediate consumption. This means that only half the OPEX can be explained (because there is a price for labour, but not a price for intermediate consumption). Also, the analyses without price data can use a larger sample as two companies (from a sample that is not large to begin with) could not provide price data. WIK-Consult/DIW Berlin (2022a) thus recommend proceeding without price data.

[36] Cf. WIK-Consult/DIW Berlin (2022a), specification 4-1 and table 4-3.
[37] Cf. WIK-Consult/DIW Berlin (2022b), p. 1.
[38] This conclusion was not based on recent data.
[39] Cf. WIK-Consult/DIW Berlin (2022a), p. 39 et sqq.

We concur with the arguments brought forward by WIK-Consult/DIW Berlin (2022a), in particular because we also consider the labour price data set provided by the industry to be flawed. Movements in the headcount might not result from changes in the system operators' tasks or their supply mandate, but could just as well be the result of operational decisions. For instance, many services can be outsourced instead of being provided in-house. If management decides to change its approach during the reference period, the headcount in system operation swings wildly. We do not agree with the industry consultants' statement that deflating costs without input prices necessarily leads to overestimating TFP growth. In fact, the calculations delivered by the industry consultants, using input prices, result in higher TFP growth estimations. In conclusion, as long as input price data are not robust, we share the position of WIK-Consult/DIW Berlin (2022a) that it is prudent to proceed with an estimation without price data.

In their final X-gen formula, Gugler/Liebensteiner (2022b) used a wholesale price index as a proxy for intermediate consumption and materials. They argued that this was a high-quality index. FGW criticised the authority for not using these estimates, as they believed all points of criticism to be addressed and results to be consistent.

WIK-Consult/DIW Berlin (2022b) hold that Gugler/Liebensteiner (2022b) and (2022c) commit factual errors. In their view, the wholesale price index is not an adequate proxy for the factor prices for materials and intermediate consumption. It does not yield company-specific information that would reflect cost reduction efforts by individual companies. Also, it is not a variable in the sense of OPEX and cost of labour, because as an index, it already references a base year. It is thus quite unclear how an index should be integrated into the estimations in the first place. Even so, our consultants have run estimates with the wholesale price index (both deflated and non-deflated). These yield strongly diverging X-gen values, some slightly above the results provided by WIK-Consult/DIW Berlin (2022a). WIK-Consult/DIW Berlin (2022b) consider that the wholesale price index does not constitute an adequate proxy for the material and intermediate consumption factor prices, because it does not meet the necessary criteria. They hold that information about the prices for material and intermediate consumption in a certain year *t* would be needed. The index could then deliver information about how wholesale prices in year *t* relate to the base year of the index. In addition, the index is not company specific.

We consider the arguments by WIK-Consult/DIW Berlin (2022b) to be sensible and thus do not include a wholesale price index as a proxy in the X-gen calculations.

(ii) Length of the reference period

Gugler/Liebensteiner (2022) argued that the reference period should be as short as possible. They used estimated coefficients from the time trends of the five most recent years. A longer reference period would counter the statistically significant squared time trend and the concave function of TFP growth that is implied by the non-linear trend specification.

Swiss Economics (2022) conducted their own analyses and concluded that the reference period should be 13 years (2008-2020). A cautious approach would be to use an average between the results yielded by models with 8 and 13 years. However, an 8-year reference period had a number of drawbacks. For instance, previous improvements in productivity (from 2011 and 2012) would be excluded.

The shortest reference period used by WIK-Consult/DIW Berlin (2022a) is 8 years (2013-2020). Like the industry consultants, they do not consider longer periods to be appropriate. One reason is that the entire period (2002-2020) features several years (before 2008) when incentive regulation did not yet apply. But they also argue that shorter intervals are inadequate; these would mean that the slow-down in technological progress over the years would turn into a reverse trend towards the recent end of the calculation. This might be due to the functional relation between the time trend and the corrected OPEX, which results from using a non-linear time trend. Insecurities suggest that the reference period should not be too short and that the connection should not be continued.

We agree with WIK-Consult/DIW Berlin (2022a) and consider a reference period of 8 years to be appropriate.

(iii) Catch-up effect

Econometric OPEX estimations cannot distinguish between the frontier shift and the (company-specific) catch-up effect. Gugler/Liebensteiner (2022) assumed that the catch-up effect was included in the time trend and that thus, TFP growth was overestimated and must be corrected. WIK-Consult/DIW Berlin (2022a) run a regression analysis based on a parametric OLS method, i.e. they cannot distinguish between the two effects either. However, they point out that this might just as well lead to underestimating X-gen. They also underline that separating the frontier shift from the catch-up effect becomes less and less relevant the longer incentive regulation has been in place. Even so, they verify the OLS results via a Malmquist DEA, which can distinguish between the two.

Swiss Economics (2022) stated that from a methodological point of view, it would be prudent not to account for the catch-up effect separately if the results of a Malmquist DEA with a 20 DSO sample were not significant enough.

The Malmquist DEA largely corroborates the OLS results. We therefore do not see a need to adjust X-gen.

(vi) Bernstein-Sappington formula

In the interpretation by Gugler/Liebensteiner (2022), the Bernstein-Sappington formula (1999) for X-gen represented the difference between the input prices and productivity as they evolve in the regulated sector and their evolution in the rest of the economy. This led them to the conclusion that the OLS productivity calculation tended to overestimate X-gen, i.e. it needed to be corrected downwards. WIK-Consult/DIW Berlin (2022a) explain that there is no need to apply the Bernstein-Sappington formula in the Austrian regulatory context. They quote a footnote in Bernstein/Sappington (1999), which points out that the relative development of a specific sector and the overall economy is only relevant if the regulated sector's costs are indexed with an overall economic output price index. However, in the Austrian regulatory regime, the gas DSOs' OPEX cost basis is subject to the network operator price index. This is a sectoral input price index (cf. chapter 10), i.e. there is no need to apply the Bernstein-Sappington formula. X-gen exclusively represents technological progress in the sector in Austria.

We concur with the arguments presented by our consultants and do not see a need to apply the Bernstein-Sappington formula or to otherwise correct X-gen.

Conclusions

We believe the reasoning presented by WIK-Consult/DIW Berlin (2022a) to be factually correct. Analysing the reactions that have been submitted, WIK-Consult/DIW Berlin (2022b) do not identify a need to adjust their statements from WIK-Consult/DIW Berlin (2022a). We concur and continue to hold that the methodology applied by WIK-Consult/DIW Berlin (2022a) is conclusive and should be pursued. However, the industry consultants' arguments must also be acknowledged. Following a prudent approach, we account for the discussions about input factor prices and any potential catch-up effects by choosing an X-gen at the lower end of the bandwidth resulting from the WIK-Consult/DIW Berlin (2022a) calculations. Leaving X-gen unchanged from the third regulatory period, when the Federal Administrative court determined it to be 0.83% in response to joint applications by the system operators and the statutory parties, would thus seem appropriate.

In chapter 4, we referenced the difficult circumstances under which the gas industry currently operates. The upheaval we are currently witnessing results in uncertainty around the gas network's future, and we wish to take this uncertainty into account through X-gen. We have sympathy with the Gugler/Liebensteiner (2022a) argument that energy policy goals and the pressure resulting from Russia's invasion of Ukraine are making additional productivity improvements difficult. The entire situation seems to act as a limitation on the possibilities of gas distribution system operators. We are thus proposing a cautious approach,[40] deviating from the lower end of the bandwidth proposed by the consultants and setting an X-gen of 0.4%.

This is the average between 0% (no productivity growth), and the arithmetic mean between 0.75% (the lower end of the bandwidth recommended by our consultant) and 0.83% (the X-gen from the third regulatory period).[41] Integrating 0% in the calculation takes account of the slowdown in productivity growth over time, which was pointed out by the system operators and could (partially) be detected in the data. WKO had requested that the 0.83% X-gen from the third period be kept, while our consultant calculated a range that starts at 0.75%; both these values are also taken into account. Applying a negative X-gen would imply that the entire industry was regressing on their technological path; we do not think this is appropriate.

[40] Erring on the side of caution usually means acting in accordance with the arguments brought forward by the regulated companies. This prevents overly ambitious regulatory goals that might squeeze regulated companies too much, causing economic disadvantages that outweigh the advantage of lower allowed costs.

[41] $Xgen_{4th\ period} = \frac{0\ \% + \frac{(0.75\ \% + 0.83\ \%)}{2}}{2} = 0.4\ \%$

8. Individual efficiency targets (X-ind) – benchmarking

Section 79(2) Gas Act 2011 states that the authority may set individual targets based on the efficiency of each system operator. State-of-the-art methods must be applied to calculate the targets. When setting the individual targets, both an overall company assessment and, where factual comparability is given, an assessment of individual processes is admissible. The targets must incentivise distribution system operators to increase efficiency and execute the necessary investments in an appropriate manner. If no individual targets were set, companies would hardly have an incentive to increase their efficiency beyond the general efficiency target. Also, if there is an option to determine individual efficiency scores, it would be inadequate not to take them into consideration. Instead, it is our goal to apply a balanced regulatory regime: preferential treatment of some companies or excessively burdening others must both be avoided. Productive efficiency must be promoted.

It is appropriate to use individual targets during the fourth regulatory period for Austrian gas distribution system operators. Together with the general efficiency target, this ensures that system operators are incentivised to increase efficiencies in system performance, thus fulfilling the requirement of section 4(6) E-Control Act. The individual efficiency targets are based on an efficiency benchmarking analysis. In order to determine each regulated company's individual efficiency target, the calculated inefficiencies are spread out over a certain period of time. This reflects that companies can control their own efficiency and at the same time provides them with attractive incentives for productive behaviour. Whether an efficiency floor must be set and how long the realisation period should be crucially depends on the distribution of efficiency scores. This subject is discussed in chapter 9 below. The following paragraphs describe the benchmarking methodology.

Benchmarking serves to calculate a relative efficiency score for each system operator. The actual costs of individual companies are compared against the costs of their peers.

The benchmarking analysis can be broken down into three steps:

(1) Select the benchmarking method(s).

(2) Select the variables on the cost side (inputs) and on the service or structure side (outputs).

(3) Perform the efficiency benchmarking analysis.

Based on the selected methods and variables, the efficiency of a company and any potential for increasing efficiency are calculated. Please note that the analysis reveals only the relative efficiency of the companies that are compared with each other. Companies with high scores are not necessarily efficient in absolute terms, i.e. efficiency potentials could exist for them as well.

By the same token, the inefficiencies identified should not be mistaken for absolute efficiency potentials. Instead, the efficiency score may change if a company's position in a renewed benchmarking exercise changes. Benchmarking delivers static snapshot results that may well change in future. Also, they do not necessarily converge over time. Benchmarking is meant to simulate competition, i.e. it makes sense if the efficiency targets themselves also evolve. This mimics the saying 'competition never sleeps'.

As a general principle, all methods and parameters that we use to set targets must correspond to the state of the art (section 79(2) Gas Act 2011). We are basing the benchmarking exercise for the fourth incentive regulatory period on the considerations and lessons learnt during the previous editions, i.e. in 2007 and 2017, when we conducted benchmarking exercises for the first and third regulatory periods. We believe the main parameters from the previous benchmarkings (allowed cost, output parameter specification, cost driver analysis methodology, outlier analysis) to be valid and adequate, which is why we keep them as they were. Each of the main parameters is explained in detail below.

As previously, we benchmark only grid levels 2 and 3. Level 1 is excluded because there are only a few companies that operate at this level. Instead, the individual (weighted) efficiency score for grid levels 2 and 3 is also applied to level 1. In our view, the efficiency score for levels 2 and 3 adequately represents the overall efficiency of a company.

Please note that the company GCA, which operates at grid level 1 only, is not part of the efficiency benchmark. This makes for a sample of 20 out of the 21 regulated gas distribution system operators. We use an appropriate definition of the structure and service parameters (outputs) and the allowed cost (inputs), an ex-ante cost driver analysis and a relevant model specification to account for heterogeneity across the companies.

8.1. Benchmarking methodology

When benchmarking to set targets, we can choose from a range of methodologies. Generally, we differentiate between non-parametric methods such as data envelopment analysis (DEA) and parametric methods such as modified ordinary least squares (MOLS). In an expert study we commissioned, Gugler et al. (2012) evaluate alternative stochastic methods for measuring efficiency in terms of their theoretical foundations and suitability for practical use in the Austrian regulatory context. Such methods include SFA (stochastic frontier analysis) as well as hybrid models such as SDEA (stochastic data envelopment analysis) and StoNED (stochastic non-parametric envelopment of data).[42] In SFA, the residual (error term) is divided into two components: one representing inefficiency and another representing data noise. This distinction is made using statistical methods and requires observations for a sufficient number of companies. The German regulatory authority Bundesnetzagentur, for example, draws on a data set with well over 100 companies to calculate the efficiency of electricity and gas distribution system operators. Gugler et al. (2012) conclude that the data available in Austria are not sufficient for SFA. Given that the number of Austrian gas DSOs has not changed, this conclusion still holds.

With regard to hybrid models (including SDEA and StoNED), Gugler et al. 2012 find it difficult to compare the advantages and disadvantages of these methods. Unlike methods such as DEA and MOLS, which are well established and have been sufficiently evaluated, hybrid methods have not yet been adequately appraised and are hardly applied in practice. As of 2022, we do not know of hybrid models that are clearly superior to the tried and tested methods.

[42] Gugler, K., Klien, M., Schmitt S. (2012), *Wirtschaftswissenschaftliches Gutachten zu Benchmarkingmethoden für die österreichischen Energienetze* (Economics expert study of benchmarking methods for Austrian energy networks), study commissioned by E-Control.

Based on the above arguments, we see no reason for using methods other than the ones that have proven reliable in the past (DEA and MOLS). They continue to reflect the state of the art. We consider them both to be equally suitable to our task.[43]

8.1.1. Data envelopment analysis (DEA)

DEA is a non-parametric method, i.e. it constructs the efficiency frontier solely based on observed best-practice companies (instead of referencing a production context that would be described using econometric estimations). This also means that there is no need for an underlying cost function.[44]

DEA is by far the most widely applied non-parametric benchmarking method. Not only is it easily understood, it also allows for a heterogeneous sample of companies to be modelled relatively easily. It requires making an assumption on the returns to scale, the choices being constant, increasing, non-decreasing or variable returns to scale (for more details on the different types, please see below).

Data quality is crucial as any deviation from the efficiency frontier is interpreted as inefficiency (i.e. we can speak of a 'deterministic' method).

A major disadvantage of DEA is that efficiency values are biased upwards in cases where few observations occur in conjunction with a large number of outputs ('curse of dimensionality'). DEA is also highly sensitive to outliers. The more dimensions, the greater the risk of a separate dimension for each company – where each company would seem to be absolutely efficient. A large number of outputs would mean that the DEA loses validity and the efficiency scores would tend towards 1.

Best-in-class companies are assigned a score of 1 (perfect efficiency) and thus represent the efficiency frontier, while the efficiency of the remaining companies is relative to that frontier. Consequently, outliers can strongly impact the efficiency scores of the 'enveloped' companies.

In view of the aspects mentioned above, we put great emphasis on verifying that input data are complete and correct (using plausibility and validity checks) and on analysing outliers. In addition, the advantages and disadvantages of the second method that we apply, MOLS, are almost exactly the opposite of those associated with DEA (cf. the next chapter).

8.1.2. Modified ordinary least squares (MOLS)

In contrast to DEA, MOLS is a parametric method and requires a cost function that specifies the relationship between inputs and outputs.[45] This functional relationship is modelled by means of an OLS estimation, which represents the basic (average) relationship between inputs and outputs. To model the efficiency frontier, the OLS line is shifted by the standard error of the regression. This standard error is an indicator of the validity of the OLS estimation; it measures by how much, on average, the estimated regression line deviates from the actual data. It also reflects the variance of residuals (insecurity of the estimation). OLS also requires making assumptions on the distribution of inefficiencies. Under the

[43] The features as well as the advantages and disadvantages of the two methods are described in the explanatory notes on the 2006 Electricity and the 2008 Gas System Charges Ordinance and in the Frontier-Economics/Consentec study (2004). A further discussion is available in Gugler et al. 2012.

[44] Cf. in general the explanatory notes on the 2006 Electricity System Charges Ordinance, pp. 35 et seq.

[45] Cf. in general the explanatory notes on the 2006 Electricity System Charges Ordinance, pp. 38 et sqq.

assumption that the inefficiency term is exponentially distributed, the shift is by the root mean square error (RMSE), i.e. by the standard error of regression; assuming a half-normal distribution of the inefficiency term, the shift is by $RMSE \times \frac{\sqrt{2}}{\sqrt{\pi}}$.

The outward shift increases with the variance of the residuals and consequently with the estimator for the average inefficiency, i.e. the extent to which the companies deviate from the efficiency frontier. This ensures that most data points, but not all of them, are enveloped. It is this characteristic that renders MOLS less sensitive to outliers than DEA.

We assume a half-normal distribution for the inefficiency term. Alternatively, an exponential distribution could also be assumed for the error term. The former does not shift the efficiency frontier as strongly as the latter, generally resulting in higher efficiency scores. Employing a function that takes a log-linear form (i.e. Cobb-Douglas or translog), efficiency scores are calculated as follows:

$$efficiency\ score_{MOLS} = \min\left(1\ ;\ \frac{1}{e^{\left(residual+RMSE\times\frac{\sqrt{2}}{\sqrt{\pi}}\right)}}\right)$$

8.1.3. Returns to scale

The term ‘returns to scale’ refers to economies of scale achieved by varying company size. While a doubling of input factors results in a doubling of outputs under conditions of constant returns to scale (CRS), changes in inputs and outputs are not proportionate where variable returns to scale (VRS) apply. VRS may present as increasing returns to scale (IRS) where a doubling of inputs results in more than a doubling of outputs, or as decreasing returns to scale (DRS) where the opposite is the case. Non-decreasing returns to scale (NDRS) is a variant of VRS that assumes smaller companies to benefit from increasing returns to scale but larger companies to have constant returns to scale.

MOLS can account for different assumptions on returns to scale but can also be run without them; DEA needs at least one such assumption. While parametric methods allow testing for returns to scale, an a priori decision might be preferable from the standpoint of regulatory policy. This holds all the more where regulated companies can choose their company size themselves.

For the first and third regulatory periods, we assumed constant returns to scale for both benchmarking methods (MOLS and DEA). This means that company size did not impact the efficiency scores. The benchmarking compared all companies in the sample with each other, regardless of their size. We argued that this assumption acted as an incentive for companies to eliminate any inefficiencies that were tied to a less-than-optimal company size. This argument still holds: system users are not responsible for their operator’s company size and should not bear the cost of any inefficiencies of scale. System operators, on the other hand, are absolutely able to take business decisions to eliminate any such inefficiencies. This might include cooperation and mergers, for instance.

We have always underlined that previous decisions do not pre-empt future regulatory decisions. After all, both scientific progress and the conditions under which companies operate are subject to change. As detailed in chapter 4, conditions for gas distribution system operators have indeed massively changed. We thus re-evaluate the issue of returns to scale.

The above considerations lead us to change the assumption for DEA and MOLS from CRS to NDRS. The main argument for this change is the political goal to phase out fossil fuels, i.e. the political rejection of any further gas expansion. The possibilities for gas distribution system operators are thus limited and small companies could not reap scale effects to a great extent. The notion that system operators should be incentivised to eliminate their size-related inefficiencies is no longer as important as it was.

Please note that this decision does not in any way pre-empt the decisions for the regulatory regime of electricity DSOs. For them, we consider the CRS assumption to be as adequate, factual and relevant as before and we are not envisaging a change to this direction.

8.2. Specification of benchmarking parameters

A benchmark basically compares the ratio of outputs to inputs among companies to arrive at an efficiency score. This can be approached from either the input or the output side. The idea of the former approach is that an externally given number of outputs (services) is to be produced with the least possible inputs (costs), while with the second approach we take the inputs as fixed and look for the maximum output. In energy distribution, most of the outputs relevant for system operators are not within their control: load is driven by consumption behaviour and the number of metering points depends on the customers. Thus, the input-oriented approach seems to be more appropriate.

In terms of parameters, cost is often considered the only relevant input (i.e. the efficiency score is a measure of cost efficiency). Choosing outputs is more complex and relies on a variety of procedures, e.g. expert opinions (cost-driving effects inferred intuitively), approaches based on engineering science (engineering economic analysis) and empirical analysis using statistical significance tests (econometric cost driver analysis). These selection methods are often combined with each other.

The following chapters discuss how we choose and specify the input and output parameters for our benchmarking exercise and explain the underlying premises.

8.2.1. Variable selection: input parameters

Either operating expenditure (OPEX) or total expenditure (OPEX+CAPEX=TOTEX) can be used as the input variable. Using total expenditure has the advantage that the benchmarking results are not distorted by companies' decisions with regard to the capital intensity of their production processes. Using OPEX only could create incentives for them to shift items (e.g. certain maintenance operations) from OPEX into CAPEX or even to opt for capital investment over OPEX-intensive solutions simply to improve the benchmarking result.

In line with the requirement for the grid charges to reflect actual costs, we hold the view that the benchmarking analysis should not be limited to operating expenses (including maintenance costs) but also include capital expenditure (CAPEX). This view is still valid. It provides an incentive for companies to make efficient investments and optimise the use of resources in their operations.

The benchmark generally uses the audited costs for network levels 2 and 3 (cf. chapter 6.1). The total amount of a company's OPEX is understood to exclude metering differences, community levies, and upstream network costs. We use the historical costs for the companies' fixed assets to derive normalised, standardised CAPEX, thereby enabling comparability even though the age and useful life of the assets differ (cf. chapter 8.2.1.1).

8.2.1.1. Standardising CAPEX

The concept of using annuities to standardise capital cost for benchmarking was introduced for the third regulatory period. We maintain and update this approach for the fourth period.

The historical costs incurred in acquiring or producing the items in the individual asset categories are indexed by first year of operation, enabling us to calculate their current replacement values. We combine this data with standardised useful life periods and a real interest rate to derive annuities (i.e. constant payments over the entire useful life, whose total present value corresponds to the replacement value). This involves the following steps:

- Recording the investment time series for all asset categories (using the asset category data for the gas sector polled by the authority);
- Determining a suitable index for the average changes in fixed asset prices;
- Determining the term of the annuity ('depreciation period' or 'useful life');
- Determining the interest rate for the annuity ('real WACC').

By applying a price index to the historical costs, we can derive indexed historical costs and the assets' replacement value. No specific inflation rates are available for the various asset categories during the required period (50 years in many cases); all asset categories are therefore indexed using the consumer price index (CPI).[46] After calculating the indexed costs for each asset category, the annuities (with present value corresponding to the standardised CAPEX) are determined using a uniform real interest rate[47] and a uniform useful life for each asset category. We use the classic form of the annuity formula:

$$annuity_i = \sum historical\ costs_i^{indexed} \times \frac{(1+rR)^{ul,i} \times rR}{(1+rR)^{ul,i}-1},$$

where $\sum historical\ costs_i^{indexed}$ is the sum of the indexed historical costs (replacement value) for asset category *i* *rR* is the real interest rate[48], and *ul,i* is the useful life of asset category *i*. The standardised (but not yet normalised) CAPEX are the total annuities of all relevant asset categories.[49]

The standardised useful life for each asset category relies on actual company data. We use the 75% quantiles of the data submitted by the regulated companies for each asset

[46] Neither industry representatives nor the industry consultant (Consentec) raised objections against using the consumer price index or proposed better suited methods.

[47] Indexing the investment time series requires a real interest rate. This is derived from the nominal interest rate and an inflation rate. For the latter, we use the arithmetic mean of the inflation rate from 2016 to 2020. This corresponds to the same period that is used for the risk-free rate in calculating the WACC (5 years).

[48] $rR = \frac{(1+WACC)}{(1+\Delta CPI)} - 1$

[49] This does not include assets at grid level 1, prepayments made and facilities under construction at grid levels 2 and 3, customer prepayments for construction costs at grid levels 2 and 3 that are recorded as liabilities, goodwill or any securities, stocks and bonds.

category over the entire period of time (data as of 2020). This leads to the following standardised useful life periods:

Asset category	Standardised useful life	Asset category	Standardised useful life
IT equipment	3	PVC pipelines at grid level 3	40
Pressure regulator stations at grid level 2	25	Gate valves at grid level 2	20
Pressure regulator stations at grid level 3	25	Gate valves at grid level 3	20
Customer prepayments for construction costs collected at grid level 2	40	Software	4
Customer prepayments for construction costs collected at grid level 3	40	Remaining assets	10
Low-value assets	1	Compressors at grid level 2	5
Communication equipment	10	Compressors at grid level 3	30
Pipelines at grid level 2	40	Metering devices	14
Non-PVC pipelines at grid level 3	40	Smart meters	14

Figure 1: Standardised useful life periods used to calculate annuities (in years)

For some asset categories, the useful life periods we use now are shorter than those from the third regulatory period. This is because we now refer to the 75% quantile[50] instead of the maximum values. We believe the former to be more adequate than the latter, which might be distorted even by a single outlier.

We keep the idea of normalising the annuities so as to preserve the original CAPEX/OPEX ratio for the industry (which was derived from cost accounting data).

As part of this normalising process, we calculate each company's ratio of standardised capital cost (annuities) to capital cost as shown in cost accounting data.[51] The median of these ratios across all companies is the overall normalisation factor. We divide all annuities by this general normalisation factor to render normalised standardised CAPEX. In formal terms:

$$normalised\ standardised\ CAPEX\ = \frac{\sum annuities\ across\ asset\ categories}{normalisation\ factor}$$

Our normalisation factor for the fourth regulatory period, i.e. the median of the companies' individual normalisation factors, is 2.1592.

For the input cost basis that is used in the efficiency benchmark (for grid levels 2 and 3), this means:

[50] This is the same approach chosen for the fourth regulatory period of electricity DSOs.

[51] The normalisation factor for an individual company j is defined as $individual\ normalisation\ factor_j = \frac{annuity_j}{cost\ accounting\ CAPEX_j}$.

$$standardised\ TOTEX = normalised\ standardised\ CAPEX + OPEX = \frac{\sum annuities\ across\ asset\ categories}{normalisation\ factor} + OPEX$$

Using the two benchmarking methods (MOLS and DEA), individual efficiency scores are calculated from standardised TOTEX.

8.2.2. Variable selection: output parameters (structure and service variables)

Efficiency analyses must encompass service and structure data that reflect exogenous structural environmental conditions beyond the companies' control. In order to guarantee a high level of discriminatory capacity, as few parameters as is possible should be used. The parameters must also be cost drivers and it should be possible to derive them from available data.

The below analysis builds on the experience gained in previous benchmarking exercises.

Analysis of cost drivers

We conduct an econometric cost driver analysis to identify the relevant output parameters for the benchmarking analysis. The following output parameters are relevant: weighted network length,[52] load billed to industry and large businesses (load in bands A-F at grid levels 2 and 3, including load to further distribution points and gas fuelling stations), and number of household and small business metering points (metering points in bands 1-4 at grid level 3, including gas fuelling stations). The industry representation agreed that these parameters are cost drivers and that they reflect the main tasks of gas DSOs (making available of pipelines, capacity and customer services). With a view to section 79(2) Gas Act 2011, these cost drivers implicitly also reflect each company's market position inside their network area and integrate this aspect into the benchmarking exercise.

The load for customers with daily load metering (section 10(6a) and (6c) Gas System Charges Ordinance 2013) is converted into hypothetical monthly peak load averaged over 12 months (section 10(5) Gas System Charges Ordinance 2013) to address the homogeneity of the load output parameter between industry and large businesses. The few companies where load is billed in line with section 10(6a) and (6c) Gas System Charges Ordinance 2013 calculated this hypothetical peak load (i.e. the annual average of the 12 monthly peak loads) themselves. To verify the calculations, we asked the companies to provide information for each metering point separately and to always state the metering point reference number.

For the cost driver analysis, we use a simple linear regression, as follows:

$$\log(TOTEX_{stand}) = \beta_0 + \beta_1 * \log\left(NL_{weighted}\right) + \beta_2 * \log\left(load_{industry+large\ business}\right) + \beta_3 * \log(MP_{households+small\ business}) + \varepsilon$$

Where ε is the error term.

[52] The weighting factors are the same as in the first efficiency benchmark (cf. the explanatory notes on the 2008 Gas System Charges Ordinance). In preparation for the fourth regulatory period, we re-evaluated the weighting factors, to see whether they were still valid. The results confirm that the factors do not need to be changed. FGW confirmed that the weighting continues to reflect the differences between the different types of pipelines and that it can be kept as it was.

The coefficients are estimated via an OLS based on verified 2020 data. All of them are statistically significant different from 0, i.e. the output parameters are indeed cost drivers. The result of the regression analysis[53] that also delivers the values for the AIC (Akaike information criterion), BIC (Bayesian information criterion) and R^2 is presented below.[54] The coefficients of the explanatory variables are in rows, the corresponding standard errors in brackets.

	Dependent variable:
	log($TOTEX_{stand}$)
log($NL_{weighted}$)	0.211** (0.092)
log($load_{industry+large\ business}$))	0.155** (0.055)
log($MP_{households+small\ business}$)	0.524*** (0.068)
Constant	0.604 (0.331)
Observations	20
AIC	-7.21648
BIC	-2.237818
R^2	0.990
Adjusted R^2	0.988
Standard error of residuals	0.176 (df = 16)
F-statistic	540.856*** (df = 3; 16)
Notes:	*p<0.1; **p<0.05; ***p<0.01

As an alternative to billed load, we also discussed and analysed the possibility to use hourly or daily peak consumption by industry and large businesses. We needed detailed, transparent and verified data for these variables to ensure a high-quality output. We conducted a comprehensive data collection exercise to get hourly and daily peak loads for 2018-2020.

This data basis was then used to analyse a variety of model specifications. For instance, we tried a specification that used hourly peak load (maximum of the fifth highest hourly load between 2018 and 2020) instead of the billed load, and the total number of metering points across grid levels 2 and 3 instead of the number of household and small business metering points. We identified a number of issues with this approach. One, the estimated coefficient of the peak hourly load was not statistically significant. Two, the quality indicators (AIC and BIC) were worse. Three, this specification represented a higher multicollinearity than the basic specification, i.e. two or more output variables highly correlated with each other, increasing the calculation's uncertainty. We used the variance inflation factor (VIF) to check this. Other model specifications which we tested as part of the cost driver analysis were rejected for the same reasons.

[53] The regression results were calculated using the package stargazer: Well-Formatted Regression and Summary Statistics Tables in R (Hlavac, 2018); details: https://CRAN.R-project.org/package=stargazer.

[54] The AIC and BIC values have decreased compared with those from the regression analysis in the draft approach. This means that the model quality has improved.

Based on significance, model quality and multicollinearity, we decided to apply the same model specification as in the third regulatory period. This also confirms that the model chosen is stable. Another advantage is that there is no need to choose a particular percentile for the daily or hourly peak load, which would have been necessary to minimise the impact of random spikes of this output variable.

8.3. MOLS specification

Based on the above, the model specification for the MOLS benchmarking exercise is as follows:

- Functional form: log-linear
- Returns to scale: non-decreasing
- Inputs: standardised TOTEX ($TOTEX_{stand}$)
- Outputs
  - $NL_{weighted}$ = weighted real network length at grid levels 2 and 3
  - $load_{industry+large\ business}$ = billed load for industry and large businesses (bands A-F at grid levels 2 and 3, including load delivered to further distribution points and gas fuelling stations)
  - $MP_{households+small\ business}$ = household and small business metering points (bands 1-4 at grid levels 2 and 3, including gas fuelling stations)
- Assumed distribution of inefficiencies: half-normal distribution

The fourth regulatory period is the first time we are assuming non-decreasing returns to scale in MOLS. This is meant to account for the changing political framework which limits gas DSOs' expansion options extrinsically (cf. chapter 8.1.3). To apply an NDRS specification, the MOLS must first be run separately under the assumption of CRS and VRS. This is necessary because the production function that is estimated in MOLS can only be either concave or convex. The degree of homogeneity delivers assumptions on the curve of the cost function, which in turn yields assumptions on the returns to scale.

Based on the sum of the coefficients that result from the OLS with VRS assumption, we can see that there are increasing return to scale. This means that the gas DSOs' costs increase less steeply than their output.

The specification for the log-linear cost function with CRS is the same as in the third regulatory period, namely:[55]

$$\begin{aligned}\ln(TOTEX_{stand} - MP_{households+small\ business}) &\\ = \beta_0 + \beta_1 * \ln\left(NL_{weighted} - MP_{households+small\ business}\right) + \beta_2 &\\ * \ln\left(load_{industry+large\ business} - MP_{households+small\ business}\right) + \varepsilon &\end{aligned}$$

With VRS, the cost function is specified as follows:

[55] The curve of the cost function results from the restriction implied by constant returns to scale, formally expressed as $\sum_{i=1}^{3} \beta_i = 1$. The transformation of the formula is explained in the document detailing the regulatory framework for the third regulatory period.

$$\ln(TOTEX_{stand}) = \beta_0 + \beta_1 * \ln(NL_{weighted}) + \beta_2 * \ln(load_{industry+large\ business}) + \beta_3 * \ln(MP_{households+small\ business}) + \varepsilon$$

Running the analyses yields two efficiency scores for each system operator: one for CRS and one for VRS/IRS. The efficiency scores are calculated in the same way as in the previous regulatory periods, following the formula from chapter 8.1.2. The NDRS efficiency score from MOLS then corresponds to the higher of these two.

8.4. DEA specification

The specification of DEA is as follows:

- Input-oriented analysis
- Returns to scale: non-decreasing
- Inputs: standardised TOTEX ($TOTEX_{stand}$)
- Outputs
  - $NL_{weighted}$ = weighted real network length at grid levels 2 and 3
  - $load_{industry+large\ business}$ = billed load for industry and large businesses (bands A-F at grid levels 2 and 3, including load delivered to further distribution points and gas fuelling stations)
  - $MP_{households+small\ business}$ = household and small business metering points (bands 1-4 at grid levels 2 and 3, including gas fuelling stations)

Like MOLS, DEA also requires two calculations to account for the NDRS assumption. The difference between MOLS and DEA is that the latter can handle IRS directly, so there is no need to check whether IRS present or not. Once the DEA has been run separately for CRS and IRS, a company's efficiency score again is the higher of the two.

Like in the third regulatory period, we do not apply weight restrictions. This does not create precedent; we reserve the right to analyse such weight restrictions in detail for future regulatory periods and, should they turn out to be appropriate, to apply them in DEA.

8.5. Analyses of outliers

The general aim of analyses of outliers is to exclude individual system operators that could strongly sway most other system operators' scores. Outlier classification works differently for DEA and for MOLS.

Parametric method (MOLS)

In parametric methods (MOLS), a company is considered an outlier if it moves the calculated regression line to a considerable extent, biasing it in its own direction. In this regression, influenceability is independent of the efficiency of the outlier. Therefore, statistical tests aim at generally identifying influential data points.

Cook's distance measures the effect of deleting individual observations from the regression analysis. Data points with high absolute residuals and/or unusually high or low values in independent output parameters can distort the result of the regression; they can be identified using Cook's distance. If an observation's Cook's distance exceeds a previously defined threshold, that company is treated as an outlier and its data are excluded from further analysis. Our threshold is $\left(\frac{4}{n-k-1}\right)$, where *n* is the number of observations and *k* the number of parameters.

Using Cook's distance to identify outliers in parametric methods has proven its worth. It is intuitive (cf. the explanations above), and has been used in regulation in Europe (cf. Annex 3 of the German Incentive Regulation Ordinance, German FLG I p. 2529). While the outlier analysis was subject to a number of objections during the third regulatory period for electricity system operators, the Federal Administrative Court found that Cook's distance corresponds to the state of the art (cf. e.g. Federal Administrative Court finding W157 2006170-1 of 27 September 2018). A further appeal against this finding to the Supreme Administrative Court was not filed.

Regulatory practice has not produced an alternative method that could match Cook's distance in terms of ability to identify outliers, neither in concrete nor in abstract terms. We follow this line of thinking and do not see a need to apply a different method. Like for the third regulatory period, we use Cook's distance for the outlier analysis in MOLS.

Unlike DEA, MOLS enables us to identify 'positive' and 'negative' outliers. All 'positive' outliers are assigned an efficiency score of 100% (i.e. the highest score from the sample without outliers); the 'negative' ones get the lowest efficiency score found in the sample (after eliminating the outliers). We believe this to be a fair approach; applying the lowest efficiency score from the entire sample (i.e. including the other outliers) would expose the results to the influence of the other outliers; using a score above the lowest one identified (e.g. the efficiency floor) would unduly overestimate the outlier's efficiency.

<u>*Non-parametric method (DEA)*</u>

In DEA, we refer to the concept of 'super-efficiencies' for identifying outliers. It enables us to identify companies with extremely high efficiency scores (in this case, there is no restriction to 100%). By looking at the distribution of 'super-efficiencies', we can draw conclusions regarding any outliers which could draw the efficiency frontier excessively far away from the remaining companies. Annex 3 of the German Incentive Regulation Ordinance stipulates that companies whose super-efficiency score exceeds the upper quartile value by more than 1.5 times the interquartile range (i.e. the range between the 75% and the 25% quantiles) are classified as outliers. The formula for identifying outliers is as follows: $\text{critical value} = \text{Q75} + 1.5 * (\text{Q75} - \text{Q25})$, where $Q75$, for instance, indicates the 75% quantile of the distribution of DEA efficiency scores before the outlier analysis has been performed. This is the same methodology as is applied by Sumicsid (2019) in the pan-European TSO efficiency benchmark (TCB18) commissioned by CEER.[56]

We used the same approach during the third regulatory period and maintain it for the fourth period.

As a result, any outliers in DEA are assigned an efficiency score of 100%. The efficiency scores of the remaining companies are calculated without taking into consideration the outliers.

[56] Cf. https://www.ceer.eu/documents/104400/-/-/90707d6c-6da8-0da2-bce9-0fbbc55bea8c. Last visited on 14 July 2022.

Summary

We conduct outlier analyses along the above lines for both MOLS and DEA and then eliminate the outlier data from our sample. This way, outliers do not set the efficiency frontier and there are no detrimental effects for the other companies in the same benchmarking sample.

Our outlier analyses yield the following results:

Analyses of outliers		
Benchmarking methodology	**MOLS**	**DEA**
Statistical method applied	Cook's distance	Distribution of super-efficiencies
CRS assumption		
Critical threshold value	$0.25 = \frac{4}{(20-3-1)}$	$144.4\,\% = Q(75\,\%) + 1.5x(Q(75\,\%) - Q(25\,\%))$
Number of outliers	0	0
IRS assumption		
Critical threshold value	$0.267 = \frac{4}{(20-4-1)}$	$154.3\,\% = Q(75\,\%) + 1.5x(Q(75\,\%) - Q(25\,\%))$
Number of outliers	1	1

Figure 2: Outlier analyses for each benchmarking methodology

The industry consultants Consentec asked us to consider the masking effect when conducting the super-efficiency analysis. This refers to a situation where two companies are not identified as outliers because they mask the effect of each other's scores. If each company was analysed separately, they would both be identified as outliers and thus excluded from the sample. We analysed this masking effect in detail. However, after considering all arguments, we conclude that it is not relevant in the current context. In a small sample it is particularly important that all companies be included in the calculation of thresholds for the outlier analysis. Excluding similar companies would not do justice to their factual existence and would not reflect reality. It is thus not necessary to look for any masking, eliminate the relevant companies and re-calculate the super-efficiencies.

The industry consultants Consentec also suggested that the interquartile distance in the formula to calculate the critical value in the DEA outlier analysis should be adjusted by subtracting the maximum between the 25% quantile and the efficiency floor from the 75% quantile. They reasoned that if the 25% quantile was too low, it increased the interquartile distance and shifted the critical value towards excessive values. We investigated this suggestion but maintain that it would not be adequate. In our view, efficiency scores that are used to identify outliers should never be changed ex ante. This would constitute an asymmetrical distortion of the results in one direction. It also confuses two separate concepts: while the outlier analysis relies on the empirical efficiency distribution to identify influential data points, the efficiency floor serves to limit the targets for the OPEX. Mixing these two would not be logical. Finally, applying an efficiency floor ex ante would imply feeding expected results of the outlier analysis into the analysis at the beginning, thus creating a circular argument.

8.6. Individual (weighted) efficiency score – X-ind

The final efficiency score is a weighted 50/50 combination of the scores rendered by MOLS and DEA. It takes into account each method's advantages and disadvantages (cf. chapter

8.1). They basically outweigh each other and make for equally suited and complementary methods. Efficient companies should get good scores in both analyses.

The models described above result in the following distribution of efficiency scores:

Model	MOLS	DEA
Specification	log-linear NDRS	NDRS
Input	standardised TOTEX	standardised TOTEX
Outputs	- weighted system length - billed load for industry and large businesses, including load delivered to further distribution points and gas fuelling stations - household and small business metering points, including gas fuelling stations	- weighted system length - billed load for industry and large businesses, including load delivered to further distribution points and gas fuelling stations - household and small business metering points, including gas fuelling stations
Average efficiency score	89.06%	85.90%
Lowest efficiency score	57.53%	45.08%
Number of companies with a score of 100% (incl. outliers)	4	8

Figure 3: Overview of the preliminary distribution of efficiency scores by model

Figure 4 illustrates the distribution of the efficiency scores based on the weighting of the methods described above. The blue bars show the individual system operators' efficiency scores, sorted from highest to lowest. The grey horizontal line marks the 80% efficiency floor (cf. chapter 9).

We use the efficiency scores from the benchmarking exercise to set targets (cf. chapter 9) for controllable OPEX (cf. chapter 6.2) and we use them to determine each company's individual WACC (cf. chapters 6.3.1 and 6.3.2).

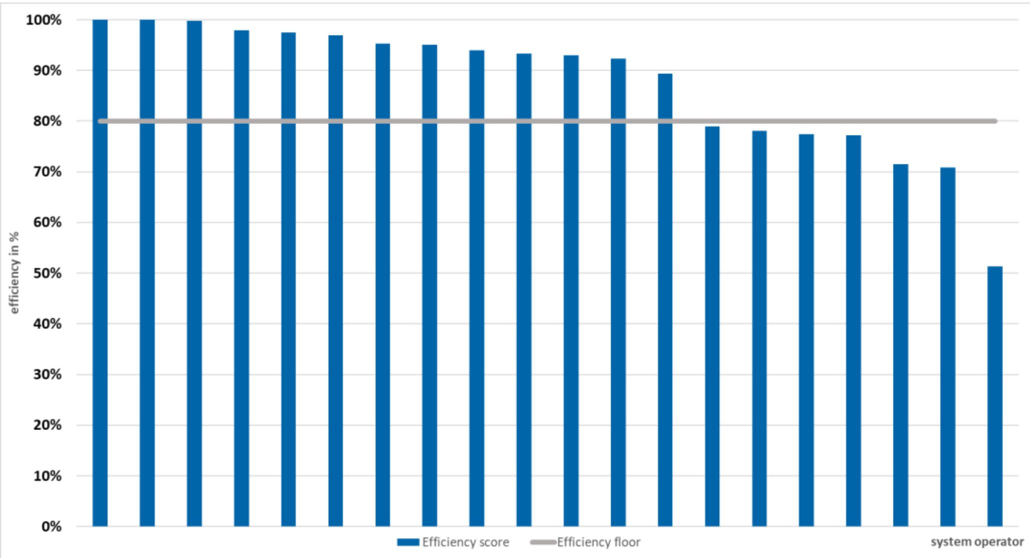

Figure 4: Distribution of final efficiency scores

9. Targets

A company's overall efficiency target is composed of the general productivity growth rate (X-gen) and the individual efficiency target (X-ind). As in previous regulatory periods, this efficiency target is directly derived from each company's efficiency score and a certain realisation period. In accordance with section 79(3) Gas Act 2011, we may divide the time given to attain the targets set (realisation period) into several regulatory periods of one or more years. It is crucial to base this decision (which in turn determines the companies' annual efficiency targets) on the benchmark conducted and on the general goals of incentive regulation (productive efficiency versus allocative inefficiency). For the fourth regulatory period, we can rely on a new benchmarking exercise to determine the individual efficiency targets. Also, in order to ensure system stability, we set an efficiency floor and choose an appropriate period for realising efficiency potentials. Regardless of how long a realisation period we set, a new benchmarking exercise must again be conducted ahead of the next regulatory period. It will enable us to update each company's efficiency target. The realisation period, the efficiency floor and the duration of a regulatory period – all of these are elements that must to be defined for each regulatory period anew.

To reduce pressure on the system operators from the overall efficiency target, and taking into account the above considerations, we set an efficiency floor of 80% for the fourth regulatory period. This is an increase of 5.94 percentage points from the third period. Even so, fewer companies than previously are below the efficiency floor. The main reason for this is our transition to an NDRS assumption for the relative efficiency benchmarking exercise.

The realisation period for eliminating inefficiencies is set to one-and-a-half regulatory periods, i.e. 7.5 years. During the third period, it was 10 years, which means we shorten the time by 2.5 years. Both the increase of the efficiency floor and the shorter realisation periods mirror the changes that have been introduced for electricity DSOs. The shorter realisation period is meant to increase the pressure of the efficiency targets for gas distribution system operators and to avoid inflated allowed costs at the beginning of a regulatory period. If efficiency targets were spread over two entire regulatory periods, the pressure to improve would be too weak.

Following the above considerations, the formula for each company's overall efficiency target is as follows:

$$Overall\ efficiency\ target = 1 - (1 - X_{gen}) \times \sqrt[7.5]{ES_{2022}},$$

where ES_{2022} designates the individual (weighted) efficiency score.

With an efficiency floor of 80% and a realisation period of one-and-a-half regulatory periods (i.e. 7.5 years), the maximum annual individual efficiency potential is 2.931%. Together with the general productivity growth rate, this results in a maximum overall efficiency target of 3.320% p.a.; this is below the maximum targets that were in place previously. An efficient company's overall efficiency target corresponds to X-gen.

Consequently, there is a linear relationship between the efficiency scores and the corresponding overall targets:

Efficiency score	Overall annual target

80.00%	3.320%
85.00%	2.535%
90.00%	1.789%
95.00%	1.079%
100.00%	0.400%

Figure 5: Relation between the efficiency score and the overall annual target

Please note that these targets apply to the controllable operational costs only (cf. chapter 6.2); capital cost is indexed with each company's individual WACC (cf. chapters 6.3.1 and 6.3.2).

The annual target does not change during the fourth regulatory period. For subsequent periods, an entirely new regulatory system may be established; therefore, the efficiency scores of the fourth regulatory period do not pre-empt how gas and electricity DSOs' compensation will be handled in the future.

10. Network operator price index (NPI)

In the interest of cost reflectiveness, costs must be indexed with an inflation factor over the course of the regulatory period. This way, we account for external cost increases (i.e. cost increases beyond the companies' control). OPEX and CAPEX are handled separately; the NPI applies to OPEX only.

Section 79(5) Gas Act 2011 stipulates that the system operator inflation rate must be derived from a network operator price index combining public indices that reflect the gas DSOs' average cost structure.

The cost increases of system operators are accounted for by the change in the network operator price index (ΔNPI), which comprises the following indices (unchanged from the previous regulatory period):

- the index of agreed minimum wages and salaries (WSI), a general index which is compiled and published by Statistics Austria. The change in this index is a proxy for the average changes in personnel costs (weighting: 50 percent).
- the consumer price index (CPI), published by Statistics Austria. The change in the CPI is a proxy for the average changes in other costs (weighting: 50 percent).

To calculate the annual change in the NPI (ΔNPI_t), we stick to the approach taken previously by using the most recent available figures (instead of forecasts). The consumer price index is published each month, with final numbers available about one month later (after any data corrections have taken place); the same is true for the index of agreed minimum wages and salaries, with a 3.5-month revision period. Considering the deadlines in the tariff review process and the delays inherent in the indices (in particular the WSI), the most recent numbers we can use to calculate ΔNPI_t are those of last December.

In line with the above, the changes in CPI and WSI are calculated as follows:

$$\Delta CPI_t = \frac{CPI_{01.t-2} + \ldots + CPI_{12.t-2}}{CPI_{01.t-3} + \ldots + CPI_{12.t-3}} - 1$$

$$\Delta WSI_t = \frac{WSI_{01.t-2} + \ldots + WSI_{12.t-2}}{WSI_{01.t-3} + \ldots + WSI_{12.t-3}} - 1$$

We then weigh and combine them:

$$\Delta NPI_t = 0.50 \times \Delta WSI_t + 0.50 \times \Delta CPI_t$$

As indicated in chapter 5, we will take some time during the regulatory period to re-evaluate the NPI in terms of the suitability of the CPI as a proxy for the DSOs' exogenous price increases. While increased energy costs are one of the main inflation drivers, they are already addressed as uncontrollable costs.

The system charges that apply in 2023 incorporate the 2021 NPI, i.e. from before the price hikes. There is thus no need to immediately address this issue. The 2022 inflation rate will only become relevant for 2024 system charges. We will pick this topic up again as part of the cost review V KOS G 2023.

Reactions relating to the network operator price index

FGW conceded that using the most recent available values to calculate the NPI was reasonable in previous years, when the NPI was always more or less 2%. However, the exceptional inflation developments after the snapshot year 2020 (i.e. the spikes seen in 2022 and 2023) made the t-2 time lag of the NPI a problem; it was essential that the systemic time lag in the NPI be eliminated by established methods to avoid massive financial difficulties on part of the system operators. Otherwise, the extraordinary inflation of 2022 and 2023 could not be recovered by the end of the fourth regulatory period. Only by correcting for the NPI time lag and by swiftly integrating the corresponding amounts into the regulatory account for each year could the statutory principle of cost recovery from section 79 Gas Act 2011 be honoured.

Section 79(5) Gas Act 2011 states that the system operator inflation rate must be derived from a network operator price index. This must combine public indices that reflect the system operators' average cost structure. To calculate the annual change in the NPI (ΔNPI_t), we stick to the approach taken previously by using the most recent available figures (instead of forecasts). This means there is a systemic t-2 time lag in the NPI's ability to account for inflation.

We understand the system operators' concerns about the time lag in light of the inflation spikes in 2022 (cf. chapter 5) and, likely, also 2023. During the fourth technical discussion ahead of the fourth regulatory period, the companies also explained that planning security and cost recovery inside the same regulatory period were of utmost importance for their accounting. This could only be addressed by accounting for the NPI's systemic time lag through the regulatory account. In addition, this handling of the time lag absolutely had to be fixed in writing in the document on the regulatory framework for the fourth period, so that auditors could already take it into account.

We concur with the arguments brought forward and thus account for the t-2 time lag. This is to create planning security for the companies, but it is without prejudice to decisions relating to any future regulatory periods.

Please also note that there will be no corrections for the third regulatory period. As for the fourth regulatory period, we consider that the correction of the systemic time lag that is introduced now adequately accounts for the inflation during the entire regulatory period. The method is transparent and predictable, and resolves the issues that presented during 2022.

The correction will feed into the regulatory account from 2024 onwards and will thus have an effect on system charges from 1 January 2025. In a first instance, the controllable 2020 OPEX will be projected with ΔNPI_{2021} and ΔNPI_{2022} and then indexed with ΔNPI_{2023}. Similarly, the controllable 2020 OPEX are also projected with $NPI_{actual_{2021}}$ (the 2021 NPI) and $\Delta NPI_{actual_{2022}}$ (the 2022 NPI) and indexed with $\Delta NPI_{actual_{2023}}$ (the 2023 NPI). The difference between the two results then feeds into the 2024 cost review and manifests in the 2025 system charges.[57]

[57] Please note that we have simplified the formula $Correction_{NPI_{2025}}$, omitting the effects of X-gen and the individual efficiency target$_{\text{4th period}}$. Of course, they are taken into account in the actual calculation (cf. the cost review for 2023 system charges in chapter 16).

$$
\begin{aligned}
Correction_{NPI_{2025}} &= (OPEX_{2020} - ucc_{2020}) \times (1 + \Delta NPI_{2021}) \times (1 + \Delta NPI_{2022}) \times (1 + \Delta NPI_{2023}) \\
&- (OPEX_{2020} - ucc_{2020}) \times \left(1 + \Delta NPI_{actual_{2021}}\right) \times \left(1 + \Delta NPI_{actual_{2022}}\right) \times (1 \\
&+ \Delta NPI_{actual_{2023}})
\end{aligned}
$$

For system operators whose financial year does not coincide with the calendar year, we must of course account for this difference by multiplying by $(1 + \Delta NPI_{2020})$ and $\left(1 + \Delta NPI_{actual_{2020}}\right)$.

The same method is applied throughout the fourth regulatory period. For further details on how we correct for the systemic time lag, please see chapter 13.5.

11. Weighted average cost of capital (WACC)

Section 80(1) Gas Act 2011 stipulates that the cost of capital must comprise the reasonable cost of interest on debt and equity, taking capital market conditions into account. As during previous regulatory periods, we apply a WACC approach to comply with this requirement. Ideally, the WACC ensures that it does not make a difference whether a company invests in the market or in regulated infrastructure. Setting the WACC too high offers incentives for over-investing in the network (known in academic literature as the Averch-Johnson effect). This leads to excessive costs for system users. Too low a WACC entails the risk that necessary investments in the regulated infrastructure are not carried out. Either way, there is a danger of misallocations. Our main concern is to ensure that the Austrian network is viable in the long term and can continue to provide high-quality network services.

The WACC set ex ante can be different from the companies' actual yield. This is intended under incentive regulation, where system operators are incentivised to efficiently provide infrastructure. For instance, companies should refinance themselves as cost-effectively as possible (and inefficient refinancing should not be at the expense of network users).

We are assuming a normal capital structure of 40% equity and 60% debt. If a system operator deviates from this structure (more specifically, if it has less than 36% equity), section 80(3) Gas Act 2011 stipulates that we use the company's actual capital structure and its equity and debt shares to calculate the WACC. By contrast, a higher equity ratio does not change the WACC calculation; we would still be assuming a normal capital structure.

Both in the method for gas TSOs for the period from 1 January 2017 (in line with section 82 Gas Act 2011)[58] and the third period of incentive regulation for gas DSOs, the WACC (pre-tax) for companies with a normal capital structure was 4.88% p.a. This was based on a study conducted by Frontier Economics in 2016.

For the fourth regulatory period of gas DSOs, we commissioned a new study from Zechner and Randl (*Gutachten zur Ermittlung von angemessenen Finanzierungskosten für Gas-Verteilernetzbetreiber für die Regulierungsperiode 2023 bis 2027* (Study on calculating the appropriate WACC for gas DSOs during the 2023-2027 regulatory period), 2022, annex 3). They recommend ranges for the individual components of the WACC and for the overall

[58] https://www.e-control.at/marktteilnehmer/gas/netzentgelte/methodenbeschreibung

WACC. Within these ranges, and in well-reasoned individual cases even going beyond, we take discretionary decisions on how to set each component.

In the interest of counteracting insecurity and limiting risk premiums, we prefer a stable approach for WACC calculation. Consistency with previous proceedings and decisions is a key principle. This ensures that advantages and disadvantages of individual decisions, e.g. about the length of the periods included when calculating averages, offset each other.

We have extensively explained the current situation above. For instance, the Russian invasion of Ukraine has triggered insecurity and large gas price increases since February 2022. This in turn has led to very dynamic developments and increasing inflation rates over the last months. Even though inflation is not an element in WACC calculations, inflation expectations figure in interest rates and thus have an impact on cost of capital. We believe this should feed into the WACC, in particular since section 80(1) Gas Act 2011 prescribes that capital market conditions must be taken into account.

We must strike a balance between consistency on the one hand and consideration of the current interest rate volatility on the other. Underinvestment in the energy grid to the detriment of the Austrian infrastructure would have considerable negative impacts on the economy. Current volatilities on the capital market must thus be adequately reflected in our WACC calculation.

We have decided to calculate two separate WACCs for the fourth regulatory period:[59] the first WACC applies to the RAB for each year up to and including 2022 ($WACC_{legacy\ RAB}$). The second WACC applies to investments from 2023 onwards, i.e. is multiplied by the RAB from 2023 ($WACC_{new\ investments}$). This $WACC_{new\ investments}$ applies to all new investments, i.e. including replacements and expansions. There is no need to differentiate. To best reflect the current situation on the financial market, we use the most recent numbers (the average of the interest rates over six months from March to August 2022) to calculate $WACC_{new\ investments}$. This is meant to incentivise investment and prevent necessary investments from being postponed or not carried out at all.

Having separate WACCs for these two periods ensures that adequate and necessary infrastructure investments can be carried out (section 4(1) and section 79(1) Gas Act 2011), while customers are shielded from excessive cost of capital for legacy RAB.

We will update the interest rate for new investments annually and apply it to the cost of debt and the risk-free rate for the cost of equity in $WACC_{new\ investments}$. We leave the market risk premium and the beta factor unchanged, because we consider that both the general market risk premium and the general risk of operating a gas grid are stable. Annually adjusting $WACC_{new\ investments}$ in accordance with a consistent formula ensures adequate treatment in line with section 80(1) Gas Act 2011. An annual update is also in the network users' interests, given that the adjustment might be downwards just as well as upwards.

The cost of debt and the risk-free rate for the cost of equity for $WACC_{new\ investments}$ for investments in 2023, which will apply for the entire fourth regulatory period, is based on data from March to August 2022 (i.e. a six-month average). Starting on 31 August 2023, $WACC_{new\ investments}$ for the following year will be calculated annually, based on a 12-month average. The results will be published each year in November.

[59] This is without prejudice to future regulatory periods.

Aside from the fact that $WACC_{new\ investments}$ relies on recent average yields, we use the same parameters and methodology as previously to calculate the WACCs. This ensures regulatory stability and predictability. If we were to abandon the established practice of using historical data in favour of applying forecasts, this would contradict the concept of setting a WACC that is balanced in the long term as required by section 80 Gas Act 2011.

In the draft regulatory framework for the fourth regulatory period, we also considered updating $WACC_{legacy\ RAB}$. Given the volatility over the last months and the dynamic situation currently, and to ensure that our decisions are based on the most recent available data (up to August 2022), we have decided to revise not only $WACC_{new\ investments}$ but also $WACC_{legacy\ RAB}$. We asked our consultants to update both WACCs (or rather, the cost of debt and the risk-free rate for both WACCs) as of 31 August 2022. For further details, please consult Randl/Zechner (2022b), in annex 4 to this document (*Aktualisierung zum Gutachten zur Ermittlung von angemessenen Finanzierungskosten für Gasverteilernetzbetreiber für die Regulierungsperiode 2023 bis 2027* (Updated study on calculating the appropriate WACC for gas DSOs during the 2023-2027 regulatory period)).

The figure below illustrates the composition of both WACCs and a comparison with the WACC that applied during the third regulatory period.

	third period	$WACC_{legacy\ RAB}$	$WACC_{new\ investments}$
risk-free cost of equity	1,87%	0.66%	1.63%
cost of debt	2.70%	1.64%	2.71%
cost of issuing debt	0.00%	0.20%	0.20%
market risk premium	5.00%	5.00%	5.00%
ungeared beta	0.400	0.400	0.400
geared beta	0.850	0.850	0.850
debt share	60.00%	60.00%	60.00%
equity share	40.00%	40.00%	40.00%
tax rate	25.00%	25.00%	25.00%
cost of equity pre-tax	8.16%	6.55%	7.84%
cost of equity post-tax	6.12%	4.91%	5.88%
cost of debt pre-tax	2.70%	1.84%	2.91%
WACC pre-tax	**4.88%**	**3.72%**	**4.88%**
WACC post-tax	3.66%	2.79%	3.66%

Figure 6: Components of the WACC in accordance with section 80 Gas Act 2011

The 3.72% WACC for the legacy RAB ($WACC_{legacy\ RAB}$ pre-tax) is the baseline for the individual WACC. A company whose efficiency score corresponds to the median score of all benchmarked gas DSOs receives this exact WACC (cf. chapters 6.3.1 and 8.6).

Below, we explain how each WACC parameter is calculated. For more detail, please consult Rand/Zechner (2022a and 2022b, also in annexes 3 and 4 to this document).

Cost of equity

Risk-free rate: We use interest rates for zero-coupon bonds from Finland, the Netherlands and Austria (as also used by Randl/Zechner (2019)). The interest rates referenced have maturities of 10, 15 or 20 years. This is in line with the Dimson, Marsh and Staunton (DMS) database for calculating the market risk premium and represents a plausible range of bonds for the risk-free rate. First, we calculate the arithmetic mean of the daily interest rates from Austria, the Netherlands and Finland. These are then averaged over a five-year period, from September 2017 to August 2022. Zechner/Randl (2022a) recommend choosing a risk-free rate at the upper end of the calculated range. We follow this recommendation and set a risk-free rate of 0.66% (representing the average of the equally weighted interest rates from Austria, the Netherlands and Finland for bonds with 20-year maturities). In light of the current, high interest rates, the risk-free rate for the cost of equity for new investments is 1.63%.

Market risk premium: Zechner/Randl (2022a) base their calculation on historical data, analysing past market risk premiums as reflected in the DMS data set from a very long reference period (1900-2021). They calculate an MRP range from 3.2% to 4.4% (MRP bonds, global, geometric and arithmetic mean) and undertake a number of sensitivity analyses, which corroborate the result.

While we generally concur with our consultant and their calculation (cf. annex 3), we also acknowledge that this parameter is particularly prone to insecurities in relation to the calculation method. In a number of consultations and hearings, alternative calculations were presented along with reasons why the MRP should be higher. The arguments always boil down to the question whether MRP calculation should be based on historical data (as done by our consultants) or on projections and expectations for the future.

Even if the same methodology is applied, it can yield very different results. We have thus conducted our own calculations, based on historical data. We compared 10-year investments in the market portfolio with 10-year risk-free investments. To approximate the market portfolio, we used the MSCI World Index (based on data from 1970 onwards). For instance, the historical market yield for 1970 results from the average annual yield for investors that bought global shares at the beginning of 1970 and held them until the end of 1979. As a proxy for risk-free investments, we used German government bonds with a 10-year maturity. Based on these public data, the MRP is the arithmetic mean of the annual difference between the yield from the shares and from the bonds from 1970 until 2011. The result is 1.43%.

The below figure illustrates the results of our analysis:[60]

[60] Data from MSCI World: https://www.dividendenadel.de/wp-content/uploads/2021/01/MSCI-World-Renditedreieck-2022.pdf Last visited on 18 July 2022.
Data for the risk-free investment (Germany): https://data.oecd.org/interest/long-term-interest-rates.htm. Last visited on 18 July 2022.

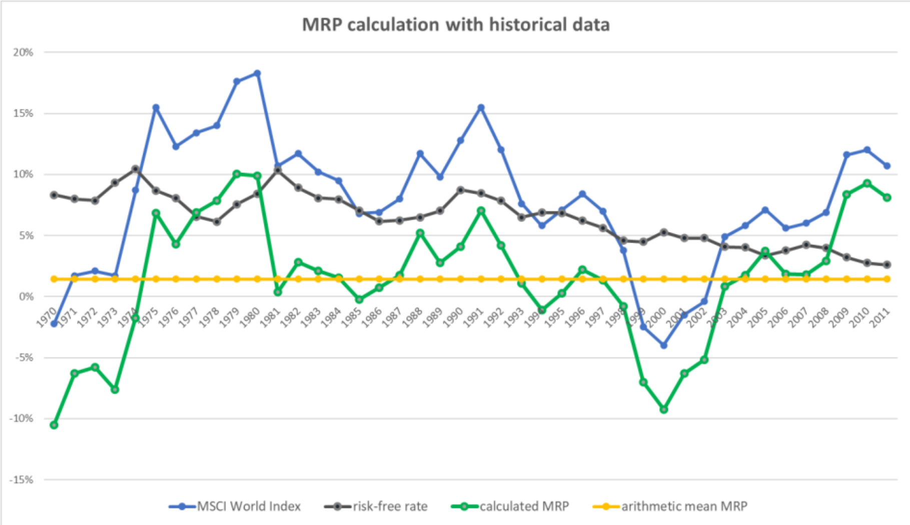

Figure 7: MRP calculation based on historical data, 10-year maturity (own calculations)

As part of the technical discussion on 21 April 2021 with FGW, the Austrian gas DSOs and the statutory parties, we invited FGW consultants KPMG Alpen-Treuhand und Bogner (2022) to present their results regarding the WACC and their calculation methodology. Their approach is similar to our own, as explained above, one main difference being that their reference period starts in 1975 and assumes a 20-year investment cycle. They also chose a different type of averaging. The result was 7.57%.

Even though the applied methodology is similar, the results from our own calculations and those from the industry consultants differ widely. This illustrates that the MRP hinges strongly on the parameters, such as the reference period or the type of averaging. It also serves to show that there is no one truth when it comes to the MRP.

In the interest of stable decisions and the considerable insecurity around interest rate developments that we are witnessing, we leave the MRP at 5.0%. This is the same value as during the third regulatory period, even though the upper end of the consultants' recommendation at that time was 4.4%. As pointed out previously, we will evaluate whether the reduction suggested in the study turns out to be stable in the longer term.

Beta factor: Zechner/Randl (2022a) isolate an adequate peer group (short list) of undertakings for calculating the beta factor. They define a number of criteria that are then applied to the short list to ensure that the peer group's risk profile is as similar as possible to the gas DSOs'. Further details on these criteria, on the reference indices, the methodology for adjusting the raw beta and the adjustment of the capital structure are available in Zechner/Randl (2022a, also in annex 3).

The consultants calculate the betas over 3 and 5 years, using weekly data granularity. The methodology is based on a linear regression approach, which calculates the linear relation between the historical yield of a share and the market yield. Using three peer groups from the study results in a range of Vasiced-adjusted, ungeared betas of 0.31 to 0.40. The gearing factor (a combination of the Austrian corporate tax rate and the target capital structure of the Austrian gas DSOs) is 2.125. The resulting range for the geared beta is 0.66 to 0.85. Both in the interest of stability and following the recommendation by Zechner/Randl (2022a) to choose a value at the upper end of the range to account for current insecurities, we again set the ungeared and geared beta to 0.40 and 0.85, respectively.

Equity issue: FGW argued that cost for issuing equity should also figure into the calculations. Zechner/Randl recommend reviewing the actual individual costs if and when a company indeed issues equity on the capital market, and then taking the adequate costs in to account. We concur with this line of thinking.

Cost of equity: The resulting cost of equity (pre-tax) is:

$$Cost\ of\ equity_{legacy\ RAB} = \frac{0.66\ \% + 0.85 * 5\ \%}{(1 - 0.25\ \%)} = 6.55\ \%$$

$$Cost\ of\ equity_{new\ investments} = \frac{1.63\ \% + 0.85 * 5\ \%}{(1 - 0.25\ \%)} = 7.84\ \%$$

Cost of debt

Cost of debt consists of three components: a risk-free base rate, a credit risk mark-up, and annualised cost of issue. Zechner/Randl (2022a) do not distinguish between the risk-free rate and the credit risk mark-up but instead calculate these two components as one. This is possible because there are adequate indices for company bonds. Zechner/Randl (2022a) use indices of renowned sources. For further details, please consult annexes 3 and 4.

Cost of debt: We aim to set a rate that adequately reflects the costs that comparable companies face when acquiring capital on the market. The first step in determining the cost of debt is again isolating a peer group with a risk structure that is as similar as possible to that of gas DSOs. Even though ratings by international agencies show that Austrian energy suppliers enjoy A ratings, Zechner/Randl (2022a) use a peer group with mainly BBB ratings to estimate cost of equity. They argue that this is adequate against the current energy crisis, which means an increased risk for the entire sector.

Consistency is key in setting the parameters; this ensures that the advantages and disadvantages for the providers and users of infrastructure from choosing a particular reference period for averaging largely offset each other. This line of thinking leads Zechner/Randl (2022a) to choose a five-year reference period. This corresponds both to the risk-free rate that is used in determining the cost of equity and to the approach chosen by Zechner/Randl (2019). Based on this five-year reference period, the cost of debt ranges from 1.16% to 1.64%. We concur and set the cost of debt at the upper end of this range, at 1.64% (pre-tax) for legacy RAB.

For new investments, the average yield from relevant bond indices over six months (from March to August 2022) results in a range for the cost of debt (pre-tax) of 2.71% to 3.03%. The cost of debt for new investments will continuously be adjusted to reflect actual market conditions, which is why we choose a value at the lower end of the range. Also, we would like to point out that the reference bonds used have a BBB rating, while all energy companies in Austria enjoy at least an A rating. We can thus safely assume that the risk premium chosen is easily high enough to cover Austrian gas DSOs' costs.

Please also note that the European Investment Bank (EIB) has been offering loans to Austrian system operators. They have hardly been used in the last years. This could indicate that there was no incentive to do so.[61] One reason might be that 65% of the preferential treatment from such loans must flow towards system users (in line with a finding of the Federal Administrative Court). The reference interest rate has always been the pre-tax cost of debt from the previous regulatory period. At 2.70%, this interest rate was considerably above market rates, which means these loans would actually have been a disadvantage to DSOs. Now, the interest rate is continuously revised to reflect market conditions, which should create a sufficient incentive for Austrian gas DSOs to use this type of financing.

Issuing cost: Zechner/Randl (2022a) consider issuing cost of 0.2% p.a. to be adequate. This is in line with Zechner/Randl (2019) and we again follow their argument.

Cost of debt: The resulting cost of debt (pre-tax) is:

$$Cost\ of\ debt_{legacy\ RAB} = 1.64\ \% + 0.20\ \% = 1.84\ \%$$

$$Cost\ of\ debt_{new\ investments} = 2.71\ \% + 0.20\ \% = 2.91\ \%$$

Reactions on the WACC

BAK appreciated the split of the WACC for legacy and new investments.[62]

Based on a study they submitted and with reference to the pluralistic approach, FGW argued that the range for the WACC (pre-tax) should be 4.07%-5.39%. They concede that the use of two separate WACCs satisfies both the industry consultants' pluralistic approach and their own position.

Both our consultants, Zechner/Randl, and we ourselves have extensively analysed the different approaches, even before the document describing the draft regulatory framework was issued. The reactions and the industry studies were provided to our consultants. Randl/Zechner analyse them and do not see any reason to change their approach. They stick with their method from Randl/Zechner (2022a).[63]

We agree with this line of thinking. Therefore, the individual components of the WACC remain unchanged from the document describing the draft regulatory regime.[64] The only exception is the acknowledgement of the insecurity attached to the calculation of the MRP. To account for this, we set the MRP above the range recommended by our consultants, instead moving closer to the results produced by the industry consultants. In the interest of stability, we continue to apply the same value as in the previous regulatory periods.

Bogner/KPMG (2022), whose study *Gutachten zur Angemessenheit des Finanzierungskostensatzes (WACC) für Gasnetzbetreiber in Österreich für die 4. Regulierungsperiode 2023 bis 2027* (Study on the adequacy of the WACC for gas DSOs in Austria for the fourth regulatory period, from 2023 to 2027) was attached to the industry reaction, referred to the above analysis of the MRP calculation based on historical data. They argued that the data on yields for the MSCI World Index were consistent, but the one-

[61] There is a revision under way that should make it easier to use EIB loans also from a legal point of view.

[62] Please note that replacements and expansions will be categorised as new investments in this context, and that we will make no distinction here. This would be very difficult in practice and would go against the basic tenet of $WACC_{new\ investments}$, i.e. enabling the financing and execution of adequate and necessary infrastructure investments in the interest of securing gas supply (section 4(1) and section 79(1) Gas Act 2011). This is why we apply $WACC_{new\ investments}$ to all new investments, including replacements and expansions.

[63] Cf. Zechner/Randl (2022b), p. 3.

[64] The deviations from the draft regulatory regime result from updated data.

year yields were not. They believed that a fee should be subtracted. Even if our calculations could be confirmed, the data basis was not suitable and the methodology not correct. Bogner/KPMG used the same data and calculated an MRP of 3.92%.

In response, we point out that we have indeed accounted for the 0.2% fee by adding it to the yields from shares. As we see it, the main difference between the two methodologies is whether values are first averaged and then annualised or the other way around. This leads to lower MRPs (in our case) or higher ones (in the case of Bogner/KPMG). The widely diverging results just due to a change of averaging (1.43% vs. 3.92%) in fact corroborate our intended message: MRP results are very sensitive to the methodology chosen. We do not agree that the methodology applied by Bogner/KPMG is the only correct option. However, please note that our intention was not to actually estimate and derive a new MRP. Instead, the calculations were illustrative and were meant to show how strongly the results could be swayed by changing individual parameters (such as the reference period, the market index, or the averaging method chosen).

12. Regulatory asset base (RAB)

According to section 80(4) Gas Act 2011, the regulatory asset base consists of the sum of intangible assets and tangible assets minus the system admission and provision charges collected (customer prepayments for construction costs) that are recorded as liabilities and any goodwill, all of which as shown on the balance sheet.

RAB composition
Total intangible assets
Total tangible assets
Total leased assets
minus customer prepayments for construction costs (no interest)
minus goodwill
other corrections
RAB

Figure 8: Regulatory asset base

Calculating the regulatory asset base as shown above has proven appropriate during the previous regulatory periods, which is why we maintain it for the fourth period. Facilities under construction are taken into account as tangible assets. Please note that under the title ‘other corrections’, we adjust for subsidised loans, which are included at their actual subsidised cost of capital (cf. section 80(1) Gas Act 2011). Further examples of ‘other corrections’ are those concerning fixed assets, e.g. as a result of unbundling.

13. Expansion factors

Incentive regulation implies that the allowed costs, i.e. the costs as projected based on the regulatory path, are decoupled from actual costs. A new audit, based on which the allowed costs are freshly determined, normally only occurs before the outset of a new regulatory period.

The DSOs' supply mandate depends on the needs of the system users, i.e. the related costs can change considerably during the regulatory period. If this happens, it should be adequately accounted for through expansion factors. This ensures that companies are financially secure, while also reflecting the actual costs of operating a system (section 79(1) Gas Act 2011). However, the expansion factors are not meant to capture any and all cost increases during a regulatory period. In fact, the entire idea behind incentive regulation is to temporarily break the link between the allowed cost and real-time developments.

The insecurity around the medium and longer-term use of the gas grid is a particular challenge during the fourth regulatory period. To account for this, the expansion factors are not fixed for the entire period but instead continuously re-evaluated to enable us to flexibly react to changes in the overall situation (cf. chapter 5).

Below, we explain the expansion factors as they stand at the outset of the fourth regulatory period, but please note that they are potentially subject to change.

13.1. OPEX factor

Operating cost factors were already applied during the second and third regulatory periods for gas DSOs. They reflect changes in the system operators' supply mandate during the period.

With the start of the fourth regulatory period, we introduce a fundamental change in the operating cost factor. Previously, the factor reflected the number of metering points and system length. This is deleted completely, i.e. eliminated from the regulatory formula.

The deletion creates two types of incentive. First, the construction of new pipelines does not increase the allowed OPEX. This should stop further network expansion. Second, decommissioning lines is incentivised. Changes to the length of the network no longer trigger changes to the allowed OPEX.[65] The companies continue to recover them, even though their actual OPEX might shrink. Decommissioning lines can thus increase the DSOs' revenue.

FGW argued that there should be an operating cost factor for system length that reflects the system operators' supply mandate for connecting new business customers. In light of the sustainability goals at European and national level, we do not agree with this argument. To reach the goal of climate neutrality, transforming heating is a crucial element.[66] In Austria, the Renewable Heating Act (currently in consultation) reduces fossil fuels in

[65] Replacements, in particular where they are necessary to ensure the secure operation of the grid, are not affected by this. Instead, they are explicitly included in the costs and integrated into the RAB.

[66] Vgl. European Commission, Directorate-General for Energy, Bacquet, A., Galindo Fernández, M., Oger, A., et al., District heating and cooling in the European Union: overview of markets and regulatory frameworks under the revised Renewable Energy Directive, Publications Office, 2022. https://data.europa.eu/doi/10.2833/962525. Last visited on 28 June 2022.

heating. We thus expect the number of household gas connections to stagnate or even retract and we already provide the adequate regulatory framework. This reflects the insecurity that surrounds the future use of the gas infrastructure. Concerning the connection of renewable gas (e.g. from biogas facilities), please consult the next chapter.

We also eliminate the acquisition bonus that was part of the regulatory regime during the third period (this was a one-off refund of marketing costs per new metering point). We no longer wish to incentivise the creation of new metering points for households. System operators are also rather expecting this number to decline. Eliminating this bonus is one step towards bringing the regulatory regime in line with the political goals.[67]

13.2. Connecting biogas facilities

We agree with FGW that more and more facilities to generate and process renewable gas (biogas facilities) will be connected during the coming years. New biogas connections increase a system operator's OPEX. These are not accounted for in the allowed costs at the beginning of the regulatory period, but must be included to ensure that companies remain operational.

FGW argued that there was a need to refund system operators during the fourth regulatory period for the increased costs resulting from new biogas connections and the necessary compressor stations, as follows: CAPEX were to be included in the annual CAPEX compensation. OPEX could be broken down into two categories. One, the assets necessary to connect biogas facilities must continuously be maintained, which created OPEX.[68] Two, any need for compression caused additional energy consumption.

We are sympathetic with the need to get increased OPEX due to new biogas connections integrated into the allowed cost during the regulatory period. To achieve this, we introduce an annual cost-plus mechanism[69] for these additional OPEX. This naturally means accepting a systemic t-2 time lag. Additional energy costs must be handled separately. They are treated as uncontrollable costs and are refunded together with the costs for covering grid losses, as was done in previous regulatory periods.

FGW would prefer a lump-sum compensation via a new OPEX factor for new biogas connections. We are not against such an approach in general. However, defining the amount of such a compensation must rely on a large data basis. At the moment, there are insufficient data to derive robust costs. We reserve the option to change from a cost-plus mechanism to a new OPEX factor during the regulatory period. We will continuously evaluate the available cost data and, if appropriate, introduce a lump-sum OPEX factor via the mechanism of mutable parameters (cf. chapter 5).

[67] Cf. the plan to phase out fossil fuels as stated in the government programme 2020-2024. https://www.bmk.gv.at/themen/klima_umwelt/energiewende/waermestrategie/strategie.html. Last visited on 8 June 2022. Also, cf. https://www.parlament.gv.at/PAKT/VHG/XXVII/ME/ME_00212/index.shtml. Last visited on 20 June 2022.
[68] Examples given include odourisation facilities and calorific value metering equipment.
[69] This means that the costs incurred are reviewed on an ongoing basis and taken into account in an appropriate manner in the charges. Opportunity cost considerations are not an option.

13.3. Smart meter investments

Preparations for the fourth regulatory period included discussions about smart metering for gas. In particular, we debated whether there should be incentives for smart meter investments, either as a standalone mechanism or through an OPEX factor.

Due to the pandemic and the Russian invasion of Ukraine, which has triggered considerable insecurity, the gas sector currently suffers from extreme price hikes and volatilities. Smart meters for gas could deliver a number of advantages in such circumstances. They increase transparency for system users and can increase energy efficiency if promptly delivered consumption information coincides with high energy prices and efficiency potentials.

Smart meters for electricity have been accounted for in the regulatory regime for electricity DSOs since the third regulatory period, first through a cost-plus regime, then through an OPEX factor with uniform unit costs. This was introduced to ensure that the additional OPEX caused by smart meter rollout would be recovered.

While the rollout of smart meters for electricity crucially rests on European and national legislation, there is no obligation to roll out smart meters for gas. It is at the discretion of each system operator whether to install smart gas meters or not.

Whether it is adequate for the regulatory regime to interfere with these business decisions is an open question. We will continue to evaluate the issue and potentially commission an external study to gain a full view. Based on an extensive cost-benefit analysis, such a study would mainly serve to answer the question whether including smart meters for gas in the regulatory regime for gas DSOs would be compatible with the main goals of incentive regulation (cf. chapter 2).

Depending on the results of such a study, we reserve the possibility to include smart meters via the mechanism for mutable parameters (s. chapter 5) during the regulatory period.

13.4. Targets for changes in the supply mandate

System operators may recover any increases in OPEX due to new biogas facilities being connected or in CAPEX due to new investments.[70] These sums are not subject to any efficiency targets or the network operator price index.[71] For the duration of the regulatory period, we assume that these costs have an average efficiency. This is without prejudice to future regulatory periods. All costs can be assessed within the next efficiency benchmark, and can then be subject to the company's individual WACC. We are thus working with a sliding delimitation between ‘old’ and ‘new’ investments and relative changes in costs (OPEX and CAPEX) will affect the efficiency score in the next regulatory period. This is meant to incentivise efficient investments and efficient operation of the infrastructure connecting biogas facilities.

[70] CAPEX are subject to the average WACC, i.e. without the individual WACC.

[71] Targets as defined in section 79(2) Gas Act 2011 refer to the general productivity factor as well as individual company efficiency targets.

13.5. Systemic time lag

Using the most recent available data (financial accounting and technical) 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, the CAPEX compensation for 2023 is calculated using the historical values from the 2021 business year. It can be assumed that the actual 2023 values deviate from the 2021 values taken as the basis. The same is true for the uncontrollable costs under section 79(6) Gas Act 2011.[72] Companies only recover their costs two years later, which means they advance the money and are exposed to interest rate risks and liquidity risks during this time. Vice versa, savings are not passed on immediately either, creating elevated charges for system users (at least for some time).

The two-year time lag could mean rates that are too low for companies whose mandates are steadily growing or it could mean rates that are too high for customers of companies whose mandates are steadily shrinking.[73] To protect both of them, we correct for the difference between the t-2 data and the current data once these latter become available.

We introduced this as part of the regulatory regime for the second period and continue with the same idea. The correction for the 2023 and 2024 rates relies on the specification applied for the operating cost factor from the third regulatory period.

$$\begin{aligned} Correction_{2023} &= OPEX\ factor_{2023}^{3rd\ period} - OPEX\ factor_{2021}^{3rd\ period} \\ &+ CAPEX\ compensation_{2023} - CAPEX\ compensation_{2021} + ucc^{74}{}_{2021} \\ &- ucc_{2019} \end{aligned}$$

From 2025 onwards, the methodology for the correction is maintained, but the OPEX factor is eliminated. The CAPEX compensation continues to be part of the correction. The correction for the systemic time lag of the NPI (cf. chapter 10) will feature in the 2025 rates (i.e. calculated in 2024) for the first time.

The formula for the corrections from that year onwards thus goes:

$$\begin{aligned} Correction_t = {} & biogas\ cost\ plus_t^{new} - biogas\ cost\ plus_{t-2}^{new} + CAPEX\ compensation_t \\ & - CAPEX\ compensation_{t-2} + ucc^{75}{}_{t-2} \\ & - ucc_{t-4} \pm correction_{NPI_t} \end{aligned}$$

[72] We would like to explicitly point out that the two-year correction discussed in this chapter does not extend to controllable costs, which are already accounted for in the regulatory formula.
[73] This does not apply to metering points and system length kilometres, where the regulatory regime is meant to incentivise system operators by creating a targeted over-financing situation.
[74] Metering deviations and own consumption are already accounted for via price expectations for the relevant year (in the above case, 2019 quantities and expected 2021 prices are compared to 2021 quantities and actual 2021 prices).
[75] Metering deviations and own consumption are already accounted for via price expectations for the relevant year (i.e. the correction always includes a t-2 time lag).

14. Regulatory account

When calculating the system charges, we rely on the most recent available data on the quantities transported (cf. section 81 Gas Act 2011). However, the companies' revenues result from multiplying these rates by the quantities actually transported in the respective year. This results in a difference between the assumed revenues that we base our 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.

To deal with this issue, section 71(1) Gas Act 2011 specifies that any differences between the actual revenues collected and the assumed revenues in the gas system charges ordinance must be taken into account when establishing the allowed costs for the next charges ordinances.

During the second regulatory period, we introduced the regulatory account to enable us to account for these differences, which we maintain for the fourth regulatory period.

15. Innovation budget

During the fourth regulatory period, we grant gas DSOs a lump sum for innovation of 0.5% of the annual controllable OPEX (total OPEX 2020, excluding uncontrollable costs according to section 79(6) Gas Act 2011). We hope to strengthen innovation among Austrian DSOs. The innovation budget is meant to provide companies with the necessary financial resources to transform the Austrian gas grid in the interest of long-term security of supply (cf. section 79(1) Gas Act 2011). The grid will need to be transformed for the use of renewable gas in line with the European and national decarbonisation targets.

The innovation budget is meant to enable R&D in the following areas: security of supply, hydrogen compatibility, alternative system uses, digitalisation, reduction of methane emissions, re-dimensioning (rentability), energy efficiency. In using this budget, we must differentiate. The costs that are necessary for system operators to fulfil their statutory duties as gas DSOs under section 58(1) Gas Act 2011 are recovered through the allowed cost and cannot be double counted as innovation. Borrowing from section 2(20) Public Procurement Act 2018, we define innovation as the introduction or realisation of new or radically improved processes and methods for operating gas networks. Research, in this context, must focus on making the Austrian gas grid fit for the future, i.e. for decarbonisation and the energy transition.[76] There must also be a realistic expectation that the results will be useful in practice.

In the interest of handling financing efficiently, all claims to the innovation budget must be handed in to the Austrian Association for Gas and Water (OVGW). They must ensure that there is no double financing, neither inside the same company nor between companies and external research bodies.

If any innovation budget is left over after the end of the regulatory period, the system operators' allowed costs for the next regulatory period will be reduced accordingly. This returns these sums to the system users. The principle of recovering actual costs (section 79(1) Gas Act 2011) is complied with and we ensure that the budget is only used for the defined purposes. We have decided against refunding unused budget annually, because innovation projects often have multi-year lifespans. This also enables system operators to save up or use the budget flexibly along the regulatory period.[77] Of course, there must be a mechanism to ensure that CAPEX are not double-counted, i.e. are not refunded both through the innovation budget and through the CAPEX compensation.

Each system operator must annually report on how the innovation budget has been used. They can also issue joint reports. In addition, and without prejudice to any and all further rights to information and inspection on part of the regulatory authority, the companies must inform us about the process for selecting the projects and all economic and technical parameters of these projects, if so requested.

Should we find that a project is not useful or does not constitute an innovation as defined above, or if it cannot be categorised into one of the areas mentioned above, the funds for such project cannot be recovered from the innovation budget. Instead, the corresponding portion of the innovation budget will be returned to the system users. System operators must also clearly demonstrate in their reports that each innovation project supports the

[76] Cf. the legislative materials on public procurement reform (explanatory notes on the government bill 69 in the annexes, legislative period XXVI, p. 11).
[77] Please note that the innovation budget that is not used during a year is not inflated by any index.

transformation towards renewable gas and goes beyond the core tasks of system operators as listed in section 58(1) Gas Act 2011.

We would also like to emphasise that the innovations funded through the innovation budget must be made available to the entire industry, to attain the largest possible usefulness. The results cannot be hoarded by the company that has created the innovation. This is meant to ensure that smaller companies, which have a smaller innovation budget, are not disadvantaged.

16. Regulatory formula

In this section, we summarise the contents of this document in formal terms.[78] The formula for the allowed costs (which form the basis for the system charges) are shown for 2023. Pursuant to section 79(1) and (7) Gas Act 2011, allowed costs must be calculated for each network level separately. Please note that the below equations do not differentiate between network levels; this is purely for the sake of clarity. The representation below is simplified in this regard, but the calculations work the same way if applied to the individual network levels or to the years after 2023. The formula serves to illustrate the previous chapters. Concrete calculations will then be executed as part of the allowed cost decisions issued to system operators.

[78] In the event that any inaccuracies or errors are found in the formulas of this document, we reserve the right to adjust such in accordance with the principles presented here.

2023 allowed costs

$$C_{2023}^{basis\ for\ charges} = OPEX_{2022}^{allowed} \times (1 + \Delta NPI_{2023}) \times \left(1 - overall\ efficiency\ target_{4th\ periode}\right) + CAPEX\ compensation_{2023} + ucc_{2021} \pm regulatory\ account_{2023} \pm correction_{2023} - prepayments\ for\ installation\ costs_{2021} - metering\ charges_{2021} - supplementary\ service\ charges_{2021} + biogas\ cost\ plus_{2023} + innovation\ budget_{2023}$$

<u>For companies with 31 December as their balance sheet date, this means:</u>

$$OPEX_{2022}^{allowed} = (OPEX_{2020} - ucc_{2020}) \times \prod_{t=2021}^{2022} \left[(1 + \Delta NPI_t) \times (1 - Xgen_{4th\ period})\right]$$

$$CAPEX\ compensation_{2023} = depreciation_{2021} + RAB_{up\ to\ 2020}^{2021} \times WACC_{individual} + RAB_{from\ 2021}^{2021} \times 3.72\ \%$$

$$\Delta NPI_{2023} = 0.50 \times \Delta WSI_{2023} + 0.50 \times \Delta CPI_{2023}$$

<u>Where:</u>

$$\Delta CPI_{2023} = \frac{CPI_{01.2021} + \ldots + CPI_{12.2021}}{CPI_{01.2020} + \ldots + CPI_{12.2020}} - 1$$

$$\Delta WSI_{2023} = \frac{WSI_{01.2021} + \ldots + WSI_{12.2021}}{WSI_{01.2020} + \ldots + WSI_{12.2020}} - 1$$

$$Overall\ efficiency\ target = 1 - \sqrt[7.5]{\frac{C_{2027}}{C_{2022}}} = 1 - \sqrt[7.5]{\frac{C_{2022} \times (1 - Xgen)^{7.5} \times ES_{2022}}{C_{2022}}} = 1 - (1 - Xgen) \times \sqrt[7.5]{ES_{2022}}$$

Where:

$$C_{2027} = C_{2022} \times (1 - overall\ effieicncy\ target)^{7.5}$$

$$\begin{aligned} Correction_{2023} \\ &= OPEX\ factor_{2023}^{3rd\ period} - OPEX\ factor_{2021}^{3rd\ period} \\ &+ CAPEX\ compensation_{2023} - CAPEX\ compensation_{2021} \\ &+ ucc_{2021} - ucc_{\ 2019} \end{aligned}$$

Where:

$$\begin{aligned} OPEX\ factor_{2023}^{3rd\ period} &= OPEX\ factor\ from\ 3\text{rd}\ period\ for\ 2023 \\ &= (metering\ points_{2021} - metering\ points_{2015}) \times 103.32 \\ &+ \left(line\ length_{weighted_{2021}} - line\ length_{weighted_{2015}}\right) \times 1035.23 \\ &+ density\ incentive + acquisitions \end{aligned}$$

$$ucc_{2021} = uncontrollable\ costs\ from\ 2021$$

$$regulatory\ account_{2023} = deviations\ recorded\ in\ the\ regulatory\ account$$

$$correction_{2023} = correction\ for\ systemic\ time\ lag$$

$$prepayments\ for\ installation\ costs_{2021} = returning\ prepayments\ for\ installation\ costs\ from\ 2021$$

$$metering\ charges_{2021} = \ metering\ charges\ from\ 2021$$

$$supplementary\ service\ charges_{2021} = supplementary\ service\ charges\ in\ line\ with\ section\ 18\ Gas\ System\ Charges\ Ordinance\ 2013$$

$$biogas\ cost\ plus_{2023} = additional\ OPEX\ from\ connecting\ biogas\ facilities\ by\ way\ of\ a\ cost\ plus\ mechanism$$

$$innovation\ budget_{2023} = lump\ sum\ for\ innovation\ corresponding\ to\ 0.5\%\ of\ annual\ controllable\ OPEX$$

The 2024 allowed costs are established in the same way.

From 2025 onwards, there are changes to the CAPEX compensation (cf. chapter 6.3.2) and the corrections (s. chapters 10 and 13.5).

17. References

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growth for Austrian gas distribution system operators during the fourth regulatory period - reply to main points of criticism by the industry), study commissioned by E-Control, 10 October 2022. Annex 2.

18. Annex I

List of regulated companies

001 Netz Burgenland GmbH
002 Wiener Netze GmbH
004 Netz Oberösterreich GmbH
005 LINZ NETZ GmbH
006 eww ag
007 Energie Ried Gesellschaft m.b.H.
010 Salzburg Netz GmbH
011 Energie Graz GmbH & Co KG
013 TIGAS-Erdgas Tirol GmbH
014 Netz Niederösterreich GmbH
016 KNG-Kärnten Netz GmbH
017 Energie Klagenfurt GmbH
023 Stadtwerke Kapfenberg GmbH
032 Energienetze Steiermark GmbH
033 Vorarlberger Energienetze GmbH
034 Stadtwerke Bregenz GmbH
035 Stadtwerke Leoben e.U.
036 Gas Connect Austria GmbH *(limited applicability, s. chapter 3)*
039 Elektrizitätswerke Reutte AG
043 Stadtbetriebe Steyr GmbH
045 Marktgemeinde St. Barbara im Mürztal

19. Annex II

Below, we present reactions to the draft regulatory regime that were handed in but did not lead to immediate changes for the fourth regulatory period.

Statements on the future of the gas grid

FGW pointed out that the Russian invasion of Ukraine had caused price spikes with constituted a formidable challenge for the entire energy sector, including gas system operators. Security of supply gained new prominence. In addition, gas infrastructure was also crucial for the energy transition. By 2040 it would transport renewable gas exclusively. Such a fundamental re-orientation of the gas network towards carbon neutrality and diversification were important tasks and should be adequately reflected in the regulatory regime. It should create both the framework and the incentives that enabled companies to maintain stable system operation and security of supply, and to invest into network development and support the transformation and decarbonisation process. The regulatory regime should be flexible enough to adapt to changing circumstances and it should be possible to implement innovative solutions for distribution systems.

BAK stated that the decarbonisation of the energy system was both an overarching policy goal and a statutory requirement, and that the regulatory regime should support the gas DSOs in this endeavour. Given the limited domestic potential for renewable gas and its high import costs, using them for heating was not realistic. They thus assumed that the number of gas connections and the overall gas consumption would decline. This was accelerated by legal requirements such as those in the Renewable Heating Act (currently in consultation) and by the current geopolitical developments. The importance of the fossil gas network for heating was receding. This must be reflected in re-dimensioning. Otherwise, fewer and fewer metering points would have to bear the costs for the same-sized infrastructure. This would mean increasing costs for each individual household, business and industrial facility. The grid should be adapted as soon as possible to avoid lock-in effects (to fossil infrastructure) and sunk costs. New and replacement investments should thus be scrutinised particularly carefully. However, new investment would be needed to achieve the transformation. Biomethane facilities must be integrated into the grid. Industry and power plant must be able to rely on hydrogen infrastructure.

WKO held that gas would continue to be crucial for the economy for many years to come. Though consumption for heating would decline, use in industrial facilities would go sideways as there were no alternatives. At the same time, the existing gas infrastructure constituted valuable assets that should be used. Gas would not necessarily be fossil in future; increasing hydrogen production would go hand in hand with progressive hydrogen integration in the gas network. Gas investments could be investments into the future if they were planned and built to be suitable for hydrogen transportation. The regulatory regime should take into consideration all these elements.

Reactions to chapter 5: mutable parameters

FGW listed examples of potential system operator tasks that had an immediate bearing on the supply mandate and that had already manifested (e.g. the OPEX building on the actual calorific value from 1 October 2024, based on the 2022 amendment to the Gas Market Model Ordinance 2020). The document describing the regulatory regime should include examples of such new, additional tasks.

Chapter 5 explains that the expansion factors are subject to change in the course of the regulatory period if new legislation immediately affects the operators' supply mandate. We understand that system operators would like to recover additional OPEX right away if they arise from new tasks, i.e. if they were not included in the allowed cost in the first place. However, please note that the X-gen chosen explicitly acknowledges the challenges for system operators in connection with their changing mandate under the current and future circumstances. Also, increasing the allowed cost every time there is any change to the system operators' tasks would run counter to the purpose of incentive regulation to increase efficiencies (section 79(2) Gas Act 2011).

Against this background, we do not consider it useful to have a non-exhaustive, merely illustrative enumeration of potential tasks in the document on the regulatory regime. If additional expansion factors turn out to be necessary in the course of the regulatory period, this will be taken care of. At the moment, it is sufficient to have an option for changes to the expansion factors built into the regulatory regime.

BAK welcomed the introduction of mutable parameters, which enabled us to react more quickly to directives from climate policy while maintaining planning security for companies. Should existing incentives turn out to be insufficient, they suggested introducing a bonus/malus system for reaching decarbonisation targets.

We are of the view that sustainable gas system operation and climate policy are already taken account of in the regulatory regime. Several new elements, such as the mechanism of mutable parameters, give us flexibility during the regulatory period if new political or legislative developments apply. The newly introduced innovation budget enables system operators to transform their grids in line with decarbonisation targets, and the elimination of the OPEX factor for metering points and system length incentivises decommissioning and avoids further network expansion. These considerable changes to the regulatory regime are sufficient and an additional bonus/malus mechanism in chapter 5 is not necessary to incentivise system operators to reach decarbonisation targets.

Reactions to chapter 6.3.1: individual WACC

Several companies and the industry representation were critical about the increased bandwidth of the individual WACC of up to +/- 0.95 percentage points around the mean WACC.[79] FKW suggested taking into consideration that the average WACC was already much lower than during the previous regulatory period. The downward pressure on sunk CAPEX was too strong for inefficient companies. The mechanism of the individual WACC was introduced during the previous regulatory period to ensure that average companies would receive the average WACC. Changing from the arithmetic mean to the median would mean that this intention was no longer fulfilled. The industry representation stated that deviating from the previous system was inconsistent and led to a skewed, inappropriate calculation of the individual WACC. We should return to the arithmetic mean.

Concerning the pressure on inefficient system operators, we would like to point out that the individual WACC does not curtail costs for system operation. It did so in previous regulatory periods, but in the fourth period there are no effects on depreciation or recovery of OPEX. Inefficient system operators are simply not able to yield as much return for their owners.

[79] Please note that the maximum bandwidth of +/-0.95 percentage points was reduced to +/-0.94 percentage points after the calculation of the individual WACC was concluded.

We hold that our evolution of the methodology for the individual WACC is indeed adequate. The incentive for companies is strengthened, following the line of thinking presented in chapter 6.3.1.

WKO's consultants indeed found that the incentive previously provided by the individual WACC was not strong enough, barely nudging companies to increase their CAPEX efficiency.

BAK underlined that a balanced and symmetric mechanism for the individual WACC corresponded to what the statutory parties and almost all system operators applied for with the Federal Administrative Court and to the finding of the court. The shift towards non-decreasing returns to scale meant a need to eliminate efficiency floors from the calculation and application of the individual WACC.

Reactions to chapter 6.3.3: useful life periods

BAK considered shortened useful life periods to be necessary. The number of gas consumers and the quantity of gas consumed would decrease dramatically. Mainly industrial and business customers would remain. Shortening the useful life periods meant frontloading CAPEX, which in turn meant that the costs would be borne by a larger group of customers. At the same time, the gas grid would become cheaper for future customers. There were no negative effects on the system operators and shorter useful life periods would not limit the actual time during which depreciated assets could be used in real life.

WKO criticised the shortening of the useful life periods by another ten years. This would greatly increase the CAPEX for customers. Even though fossil gas needed to be phased out in light of the energy and climate goals, the infrastructure could still be used to transport renewable gas or hydrogen. The regulatory regime explicitly supported system operators in developing future technological solutions through the innovation budget, in particular in the areas of hydrogen and alternative uses for the grid. This contradicted the shorter useful life periods. They should be kept at 30 years.

We are aware that shortening the useful life periods for new pipeline investments from 2023 onwards to 20 years increases the CAPEX to be recovered through current system charges. However, they are borne by a larger customer base. By shortening the useful life, we acknowledge the expectation that the number of metering points at grid level 3 will be shrinking over the coming years. This means a decrease in the number of system users, i.e. those who bear the costs for the gas grid. Our goal is to keep the costs to an acceptable level for both current and future grid users. The shorter useful life strikes an adequate balance.

We are aware of and appreciate the value of the gas infrastructure. In this context, please note that shorter useful life does not equal divestment. Rather, we aim to avoid stranded costs that might otherwise materialise due to the upheavals in the gas industry that we see and expect for the future. Well-functioning existing pipelines can continue to be operated and used (for fossil gas, green gas or other uses) regardless of whether they are fully depreciated or not.

Overall, we consider that shortening the useful life does not have dominating negative effects, neither for the system operators nor for the system users who bear the costs in the medium and long term. This in particular since the useful life period applied in the regulatory regime does not impact the actual useful life in reality. If the depreciation period were too long, we might end up with stranded assets.

The innovation budget and the useful life periods are two elements of the regulatory regime that have different purposes, and we do not see an interaction between them. The shorter useful life periods are meant to reduce the risk of stranded investments and to keep the costs for current and future system users to an adequate level. The innovation budget strengthens innovation among the Austrian gas DSOs and enables them to modify their networks in line with the European and national decarbonisation targets.

Reactions to chapter 7: X-gen

FGW pointed to their own position and to their consultants' final reaction to the draft regulatory regime (Gugler/Liebensteiner (2022c)), arguing that X-gen for the fourth regulatory period must needs be negative.

We refer to the explanations in the main document. We have already adequately taken into account the insecurities of the current situation following Russia's invasion of Ukraine and the political circumstances by choosing an X-gen below the lower limit of the bandwidth recommended by WIK-Consult/DIW Berlin (2022a).

We reject going below 0.4% or even going negative with X-gen. Please keep in mind that we are introducing an innovation budget of 0.5% of the annually allowed controllable OPEX. Taking inspiration from international regulatory practice, it would even be adequate to increase X-gen by a couple of base points in light of such measures to push innovation. For instance, X-gen in Great Britain was increased by 0.2% for the regulatory period RIIO-2 to reflect the expectation that measures to promote innovation during the previous regulatory period RIIO-1 would result in increased productivity growth.[80]

BAK asked for more information about how we calculate X-gen. They considered that the difficult economic situation might also be acknowledged by higher, flexible interest rates for new investments.

WKO pointed to our own statement that we considered the X-gen from the last regulatory period, which was set following joint applications by the statutory parties, to be adequate. Also, this was within the range recommended by our consultants. We more than halved this value and WKO were critical about this; they considered that we should not take a cautious approach in reflecting sectoral productivity growth, as this served to simulate competitive pressure. They held that X-gen should stay at 0.83%.

In this context, please note that the new WACC mechanism does not exclude a cautious approach to X-gen. On the contrary, while $WACC_{new\ investments}$ aims to finance adequate and necessary infrastructure investments towards secure gas supply, X-gen serves to incentivise efficiency increases during the regulatory period. Given the sensitivity of the calculations and the fact that X-gen is a forecast value, we consider a cautious approach to be prudent. By way of example, consider the length of the reference period: the industry consultants advocated for a 5-year reference period, our own consultants use an 8-year period, and the WKO consultants opted for a 13-year period. Also, the current political goals (phase-out of fossil fuels) and the insecurities in the wake of Russia's invasion of Ukraine might act as a limitation on the possibilities of gas distribution system operators to increase their efficiency (which is usually defined as an increase of outputs while keeping the same inputs). We take this as another factor in favour of a cautious course.

We consider that an X-gen of 0.4% is appropriate for the fourth regulatory period.

[80] Cf. WIK/DIW (2022), pp. 14 and 19.

Reactions to chapter 8: X-ind and benchmarking

FGW welcomed the change towards non-decreasing returns to scale (NDRS) as a positive evolution of the benchmarking model. However, they held that the masking effect outlined by Consentec in connection with the outlier analysis should also be taken into consideration.

Based on the explanations given in chapter 8.5, we do not consider it necessary to account for the masking effect in benchmarking gas DSOs. Rather, we argue that, particularly for a small sample such as ours, it is important to include all companies when calculating the outlier thresholds. Accounting for the masking effect would be a development in the wrong direction and we reject it.

FGW appreciated that we increased the efficiency floor to 80% but were sceptical about the shorter realisation period of 7.5 years. They suggested that 10 years were needed in light of the difficult circumstances gas DSOs find themselves in currently. Overall, no DSO should have an annual efficiency target of more than 3%.

WKO generally welcomed the shorter realisation period. Based on Swiss Economics (2022), who found that the regulatory regime strongly encouraged system operators to maximise their cost in the snapshot year, they even argued that the realisation period should be 1 regulatory period, not 1.5.

FGW's argument of difficult circumstances requiring a 10-year realisation period is void because the benchmarking analysis is input oriented. We have always chosen this perspective for efficiency benchmarks, because most of the relevant DSO outputs are uncontrollable. What counts is for the DSOs to produce the (exogenous) outputs by inputting the least possible costs. It is the very purpose of the output parameters to approximate exogenous circumstances which the system operators have no bearing on. For instance, the required capacity depends on the system users' consumption, and the number of metering points depends on the customers. What is more, the current situation impacts all Austrian gas DSOs the same. It is not relevant for a relative benchmark. We account for this factor separately, in setting X-gen and the WACC. Doing so through the individual efficiency target would contradict the idea behind a relative efficiency benchmark and would create imbalances in the regulatory regime.

Regarding the changes to the efficiency floor and the realisation period, which are introduced at the same time, we would like to point out that they both impact the overall efficiency target but result from different motivations. The realisation period incentivises system operators to align their actual costs with the efficiency target and to avoid inflated cost at the beginning of a regulatory period. The efficiency floor is an instrument of cautious regulatory action (retroactive adjustment of the overall efficiency target). Neither its existence per se nor its level are a result of the calculations, and it is not itself a variable in the efficiency benchmark. Rather, it artificially raises the efficiency score of inefficient companies, reducing their targets for future OPEX. We agree that simultaneously adjusting the efficiency floor and the realisation period might have contrary effects on the overall efficiency target, but both adjustments are sound and reasonable.

We take note of WKO's arguments but hold that a reduction of the realisation period by 2.5 years is an adequate first step; the same was done for electricity DSOs. An even shorter realisation period could be an option for the fifth regulatory period. We also reserve the possibility to conduct our own analysis to identify any ratchet effect, since the WKO consultants' analysis was based on outdated (2018) data. For the time being, we reject a 5-year realisation period.

We also reject a 10-year realisation period but instead stick with 7.5 years.

Reactions to chapter 11: WACC

BAK wondered about the high values used for the market risk premium, the beta factor and the cost of debt. This was particularly concerning since new assets already received a higher interest rate which would automatically be adjusted.

WKO were also irritated that we went beyond our consultants' recommendations and chose 3.65% and 4.48%, respectively. In addition, they argued that whenever the rate for new assets was to be adjusted (because it was a mutable parameter), this should be consulted with the statutory parties.

We would like to underline that the values for both the beta factor and the cost of debt which we have chosen are within the range recommended by our consultants. Our reasons for using values at the upper end of the ranges were explained in the document detailing the draft regulatory regime; also, this is in line with the consultants' recommendations. We do not concur with BAK's view that the values are 'too high'. The market risk premium is the only parameter where we went above our consultants' recommendations, by 0.6 percentage points. The reasons are laid out in detail above, but in short, the market risk premium is particularly sensitive to the methodology chosen and the assumptions made. We cushion this kind of insecurity by granting a market risk premium above the recommended range. Also, the market risk premium was 5% in the previous regulatory periods. Keeping the same value speaks to the stability and predictability of the system. However, please note that we will again scrutinise and analyse this parameter in future.

Concerning the annual revision of the WACC for new investments, please note that the adjustment mechanism is clearly laid down and determined, which is why it is not listed among the mutable parameters in chapter 5. For this reason, it will not be necessary to consult the statutory parties each time. In fact, it is precisely the annual update in accordance with a consistent formula that ensures adequacy in line with section 80(1) Gas Act 2011. Consulting the statutory parties would not bring additional value; rather, it might jeopardise the stability that is now built into the system. But the parties will, of course, be consulted on the cost of capital in future cost reviews.

Reactions to chapter 13.1: OPEX factor

BAK suggested that decommissioning of grid connections should be reflected through a new OPEX factor. We reject this suggestion, one of the reasons being that there are insufficient data to calculate appropriate unit costs. Should we see significant decommissioning during the regulatory period, and should this cause considerable costs, we will discuss the issue separately. Also, by deleting the previous OPEX factor, we already compensate system operators for decommissioning, as their allowed costs are not adjusted even though their supply mandate shrinks. Decommissioning can thus mean additional revenue for system operators.

Reactions to chapter 13.3: smart meter investments

BAK were strictly against a blanket roll-out of smart meters for households. The costs for installation and operation outweighed the benefits. Households used gas to heat and cook.

Their consumption curve was inelastic. Even so, using fossil gas sparingly and efficiently contributed to reaching climate targets. Energy efficiency and correct behaviour were the way to go. Smart meters could not promote this, since fossil gas consumption was mainly driven by the need to heat living quarters, which was not responsive to real-time metering. Instead, consumers should be better informed about how they could use energy efficiently. For business and industry, the story was different: here, smart meters and the real-time consumption information they provide could make sense.

We take note of BAK's points and underline that we have not decreed targets on smart meter roll-out.

Reactions to chapter 15: innovation budget

BAK agreed with the idea of a lump-sum innovation budget if it bore benefits for system users. This should be achieved by making the budget conditional on decarbonisation. System operators should have to submit a 'plan for the future', including network planning, which demonstrated that they took decarbonisation seriously and were willing to adapt their grids to this overarching goal. The authority should give concrete instructions to ensure that system operators participate in a coordinated planning process towards the phase-out of gas. This should include feasibility studies and active participation in spatial and energy planning processes at local level, with municipalities, other players from the energy industry and consumers.

We concur with BAK that the usefulness of projects financed through the innovation budget must be adequately documented and that the use of the budget must be tied to conditions. These are explained in chapter 15. For instance, we list the areas for innovation (security of supply, hydrogen compatibility, alternative system uses, digitalisation, reduction of methane emissions, re-dimensioning (rentability), energy efficiency). We also point out that research financed through the innovation budget must focus on making the Austrian gas grid fit for the future, i.e. for decarbonisation and the energy transition, and that there must be a realistic expectation that the results will be useful in practice. Borrowing from section 2(20) Public Procurement Act 2018, we also define innovation (introduction or realisation of new or radically improved processes and methods for operating gas networks). When choosing their innovation projects, system operators must take care to have adequate documentation in place to prove that an innovation has taken place, that it is useful in practice and that it relates to one of the areas listed above. Otherwise, the funds from the innovation budget cannot be made available.

Additionally requiring a 'plan for the future' and applying further requirements does not seem adequate, because they generate no substantial added value. A 'plan for the future' is not necessary for all types of project; rather, we leave it to the system operators how they prove that their innovations are useful. Also, system operators are free to actively participate in local spatial and energy planning processes and to coordinate with the municipalities. We do not see a need to explicitly require them to do so through the regulatory regime; however, we would also like to underline that they may address these areas in their research and innovation activities.

Other reactions: economic tests

BAK considered that the gas distribution systems would have to be downsized continuously to adapt to future requirements. This particularly impacted lines used for space heating. The system operators should evaluate the feasibility of any replacements or expansions, and we should critically verify the results. To ensure that evaluations would be comparable and logical, they should be integrated into the regulatory regime.

We would like to point out that system operators already have the possibility to evaluate both replacements and expansions in terms of their feasibility, and that they are almost compelled to do so in the interest of taking sensible business decisions.

As far as downsizing is concerned, please note that system operators may refuse to connect a new customer if this is economically detrimental to the existing customers (section 59 Gas Act 2011). Also, following the entry into force of the Renewable Heating Act, new buildings may not be equipped with gas-fired heating systems from 2023 onwards, i.e. this coincides with the start of the fourth regulatory period. Both this new legislation and the prohibitive gas prices that have resulted from the Russian invasion of Ukraine basically exclude that new connections for gas heating are made if they are not economically feasible. We see no added value in making economic tests mandatory via the regulatory regime. System operators are free to conduct such tests whenever they see fit.