E-CONTROL

Regulatory Regime for the Third Regulatory Period: Electricity Distribution System Operators

1 January 2014 - 31 December 2018

Contents

Figures[1]

[1] This document does not distinguish between figures and tables.

1. Introduction

Some of the electricity distribution system operators (DSOs) in Austria have been under an incentive-based regulatory system since 1 January 2006. This incentive regulation regime extended over two regulatory periods of four years each and ended as of 31 December 2013. The legislative changes introduced by the *Elektrizitätswirtschafts- und -organisationsgesetz* (Electricity Act) 2010 mean that a much greater number of DSOs have come under incentive regulation. Specifically, all system operators with an annual supply volume of more than 50 GWh in the 2008 calendar year are to be included in the regime.

It is therefore necessary to develop a regulatory system for all these operators of electricity distribution systems that is aligned with the objectives of incentive regulation as specified in chapter 2.

In the course of the discussion of the framework for the third regulatory period, beginning as of 1 January 2014, E-Control presented a consultation paper to set forth its views. All parties involved as well as the general public were invited to submit opinions on the paper during the period of 15 February 2013 to 8 March 2013 (refer to http://www.e-control.at/de/marktteilnehmer/strom/netzentgelte/entgeltermittlungsverfahren, in German). In a second consultation paper, to which comments could be submitted between 9 and 30 August 2013, the principles underlying the regulatory formula as presented were supplemented by additional parameters (in particular for determining targets) and the results of the consultation on the first paper were taken into consideration. In the interests of readability, the English version of this general document on the third regulatory period largely represents only the final version of the specifications. The German version includes the arguments and comments submitted throughout the entire consultation process as well as a corresponding evaluation.

In general, a long-term incentive regime that is applied to all companies during a certain period is limited in taking into account any developments and requirements affecting individual companies only.[2] We therefore explicitly make mention of the fact that several elements, such as the system operator price index, are based on average costs as defined in section 59 Electricity Act 2010. The principles presented here were first implemented in detail during the 2013 cost audit (for 2014 tariffs).

It should be noted that the main focus here is on presenting the basic regulatory formula and that we have allowed various details of the formal descriptions to be simplified for the sake of readability.

The authority wishes to point out that the contents of the present document refer only to the third regulatory period for electricity distribution system operators and will not prejudice the framework to be applied in any of the following regulatory periods, even after consultation. This document is based on specific provisions of law as most recently amended

[2] A model is by definition an abstraction of the real situation.

(i.e. the Electricity Act 2010[3] and *E-Control-Gesetz* [E-Control Act][4]); any future amendments to the legal framework can (even during the current regulatory period) result in changes to the regime as presented.

[3] *Elektrizitätswirtschafts- und –organisationsgesetz* (Electricity Act) 2010, Federal Law Gazette (FLG) I no. 110/2010 as amended by FLG I no. 174/2013.

[4] *Energie-Control-Gesetz* (E-Control Act), FLG I no. 110/2010 as amended by FLG I no. 174/2013.

2. The objectives of incentive regulation

A stable long-term incentive regulation regime for a natural monopoly (ideally) pursues a number of – sometimes conflicting – objectives:[5]

- Promotion of efficient behaviour on the part of regulated companies in the interest of achieving the optimum outcome for the economy as a whole;
- Consumer protection;
- Safeguarding the viability of regulated companies' business operations and their planning reliability;
- Security for investments and innovations of the regulated companies (refer to previous item);
- Security of supply and quality of service;
- Transparency of the regime;
- Fair treatment of regulated companies;
- Lowest possible direct costs of regulation;
- Ensuring the general acceptance and the stability of the regulatory system by all stakeholders concerned (i.e. customers, employees, owners and other parties);
- Stable legal framework.

In order for a company to act in a *productively* efficient way, i.e. endeavouring to produce goods and services at the lowest possible costs, the company must be allowed a reward to compensate for this effort, for a certain period of time at least; thus, an *allocatively* inefficient condition must be tolerated during this period.

Excessive *allocative* inefficiency can, however, conflict with the goal of protecting consumer interests and consequently pose a threat to the political acceptance of the system. Any later intervention in the regulatory system for the purpose of skimming off profits that are regarded as inappropriate would, on the other hand, contradict the goal of providing incentives for *productive* efficiency.

When taking any regulatory measures, the companies' financial viability must not be jeopardised. This goal 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's being driven off the market. Consequently, economics literature discusses the issue of the extent to which the regulator may or, in view of the political environment, must allow *soft budget constraint* in the case of regulated companies.

Transparency of the regulatory regime needs to be guaranteed to create acceptance on the part of companies and consumers. Such transparency is given only where the grounds for

[5] Refer to the Explanatory Notes on the *Systemnutzungstarife-Verordnung* (System Charges Ordinance) 2006, pp. 2 et seq.

decisions are disclosed in a way that renders them intelligible. Yet transparency must not be confused with unconditionally accepting any objections raised by regulated companies. Transparency is closely related to planning reliability. The regulated companies must know the regulatory framework *ex ante.*

Fair treatment of regulated companies means that preferential treatment of some companies over others and imposing excessive burdens on any one party is to be avoided.

Regulation also needs to meet the challenge of balancing the objectives in such a way as to ensure that the principle of policy acceptance and stability is upheld for the entire regulatory period.

As was the case in the past (i.e. up to and including the 2005 tariff year), regulation can be based on annual cost reviews, a process that entails substantial effort both for the regulated companies and the regulator. Alternatively, regular yet not yearly cost reviews can take place while a stable, long-term model applies. In view of the goal of keeping to a minimum the direct costs of regulation, longer intervals between cost reviews are to be preferred. During the interim period, tariffs[6] evolve along a pricing rule that uses parameters which are known in advance. Care should be taken, however, to ensure that such pricing rules do not deviate too widely from the underlying cost developments, and for this reason the intervals between cost reviews should not be too long.

In general, the objectives listed above can be achieved to varying extents through various regulatory systems. Regulation by yardstick competition, a theory originating with Shleifer (1985) and considered well-founded in economics literature, is often presented as an alternative to the incentive-based regulation system currently applied. According to the yardstick approach, under the assumption of identical companies the charges for one grid operator are determined as an average of the costs that all other companies in the same sector run up. Agrell/Bogetoft/Tind (2005) formulated a dynamic yardstick approach based on less restrictive assumptions; by accounting for varying efficiency levels among companies this method provides a better model of real conditions. The method requires efficiency to be measured continuously – even on an annual basis (as for example in the Norwegian approach) – in order to determine the cost base underlying the charges.

While several system operators have completed not only numerous cost reviews but also two periods of incentive-based regulation, others have not, given the modified legal framework (i.e. the threshold of 50 GWh specified in section 48 Electricity Act 2010). With the Electricity Act 2010 a great number of specifications have also been introduced for the purpose of determining costs and targets. All of these considerations make it advisable to first adapt the system of incentive-based regulation to the new legal basis and consolidate it with a view to the companies that have recently come under it. Introducing yardstick regulation would mean a major change from the current system of incentive-based regulation. It thus appears justified at least for the third regulatory period to carry on with the current system – with the addition of the modifications over the second regulatory period as set forth in this document.

[6] This document uses the terms 'tariff' and 'charges' synonymously.

3. Scope of application and length of the regulatory period

The regulatory system presented in this document applies in general to all operators of electricity distribution systems in Austria that recorded a supply volume of more than 50 GWh in 2008 (refer to section 48(1) Electricity Act 2010). A total of 38 companies meet this condition (refer to the annex in chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**). The same principles apply to electricity distribution system operators in Upper Austria with a supply volume of less than 50 GWh (refer also to chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**) unless otherwise defined in the official decisions issued to the individual companies.

In determining the length of a regulatory period it is necessary to weigh the magnitude of various effects. As described above in chapter 2, incentives for productive efficiency are created by temporarily decoupling the allowed costs from the actual costs and revenues. The degree to which such incentives are effective within an incentive-based regulatory framework depends in particular on how long this decoupling is maintained – i.e. the length of the regulatory period.[7] Such decoupling intentionally tolerates a temporary situation of allocative inefficiency as a means of generating incentives for productive efficiency. Whereas too short a time span of decoupling can lead to reduced incentives, excessively long spans pose the risk of consumers overestimating or companies underestimating the potential for cost reduction as modelled by the cost path, which is determined *ex ante*. Moreover, estimation becomes increasingly difficult the longer the period lasts.

Current regulatory practice usually provides for regulatory periods lasting between three and five years.[8] In Austria, both the regulatory authority and the companies involved have in recent years gained extensive experience with the system of incentive regulation. It therefore appears advantageous to lengthen the timespan to correspond to the period set for gas distribution. The proposal of a five-year period generally met with agreement during the public consultation. The authority therefore sets the length of the third incentive regulation period at five years.

Another question is whether to require the cost target level to be achieved within just one or more than one regulatory period or over any other longer period of time. During the first two regulatory periods the system operators were required to attain the individual targets that had been set for them *ex ante* within two regulatory periods lasting four years each. Even though extensive cost audits had been performed to determine the initial cost base in each case, the target value remained unaltered at the end of the second regulatory period. Any deviations of the attained cost level from the cost path that had been determined *ex*

[7] Please note that for pure yardstick regulation, the length of a regulatory period is not an issue, since it completely decouples allowed from actual costs (also in the initial year), while incentive regulation does so only for a defined period of time.

[8] As a matter of comparison, these are the lengths of regulatory periods (in years) for electricity (E) and gas (G) distribution system operators in other EU countries: Belgium: 4 (E), 4 (G); Czech Republic: 5 (E), 5 (G); Estonia: 3 (E), 3 (G); Finland: 4 (E), 4 (G); France: 4 (E), 4 (G); Germany: 5 (E), 4 (G); Great Britain: 5 (E), 5 (G); Hungary: 4 (E), 4 (G); Iceland: 5 (E); Italy: 4 (E), 4 (G); Lithuania: 5 (E), 5 (G); Netherlands: 3 (E), 3 (G); Poland: 4 (E), 3 (G); Slovenia: 3 (E), 3 (G); Spain: 4 (E), 4 (G).

ante were accounted for through a carryover mechanism (refer to the Explanatory Notes to the System Charges Ordinance 2010, p. 37).

Alternatively, as a means of minimising the ratchet effect[9] known from the literature – where elevated costs are reported for the 'snapshot' year at the beginning of a new regulatory period – a recurrent (ongoing) benchmarking exercise can be performed prior to the beginning of every subsequent regulatory period. With this procedure it is critical, however, to undertake a number of appropriate adjustments to the initial and benchmark cost so as to avoid that operators strategically shift cost items (e.g. in the areas of maintenance, staff or similar areas). Particularly when reviewing the cost allocation and especially in the case of contributions and charges for internal and external services, strict cost auditing principles must be applied, both in terms of their amounts and the underlying reasons.

The experience of the two previous regulatory periods has revealed carryover systems to be highly complex; this results in reduced acceptance and confronts the regulatory authority with virtually unsolvable capital cost issues where the useful technical life of assets does not correspond to the useful life shown in the books. Within CAPEX it is practically impossible to separate temporary cost savings from permanent cost reductions because there is no factual need to undertake an immediate replacement investment after an asset is fully depreciated. Particularly where the depreciation period on the balance sheet is too short, the effect of 'temporarily postponed' reinvestments is therefore falsely interpreted as an efficiency gain.

For this reason the authority prefers the alternative described above, i.e. ongoing benchmarking. The expanded scope of application (i.e. 50 GWh companies) leads to the general assumption that the affected companies are less able to react strategically within the sector as a whole. In conjunction with the required cost normalisation, this will positively impact the effectiveness of the ongoing relative efficiency benchmarking. 'Ongoing' in this context means that the efficiency comparison must be performed ahead of each regulatory period, so that the resulting cost path is only in effect for one regulatory period.

[9] Refer to Rodgarkia-Dara, A. (2007).

4. Establishing the initial cost base

The business year for which a cost audit is performed does not usually coincide with the initial year of the incentive regulation period. It is consequently necessary to project the audited cost base.

4.1. Audited total costs 2011

In establishing the costs and volumes, E-Control generally observes the principle of consulting the most recent figures. Yet performing a cost audit of all affected companies entails substantial effort on part of both the authority and the companies themselves. In addition, the affected companies should be allowed sufficient time to submit comments on proposed changes in the regulatory regime (including a new efficiency benchmark) and to the official decisions on their allowed costs. And finally, in particular when determining targets, it is not enough for the majority of companies to provide the most recent figures; rather it is necessary to have the relevant data from <u>every</u> company. For all of these reasons cost audits are not based on data of the most recently available business year, which would be 2012, but on the 2011 business year. The decisive date for determining the relevant business year is normally the balance sheet date as defined in section 201 of the *Unternehmensgesetzbuch* (Corporate Code). Thus, where a company's balance sheet refers to 2011, the cost review is based on the balance sheet figures of that the annual financial statement.

As an exception, 2011 data are not used in cases where they are no longer representative on account of structural changes (i.e. changes to the company's legal structure) that are relevant for the coming regulatory period, i.e. where the figures relate to companies that have ceased to exist. In the case of mergers between system operators after 2011, the most recent data available to the regulatory authority are used.

Similarly, to minimise the systemic time lag, the most recent figures are used in some cases to determine the costs of sub-items (e.g. costs beyond the company's control and the input variables for calculating the expansion factors). Appropriate methods are applied to soften any negative effects resulting from the time lag (refer to chapter 11.5).

Apart from the special cases mentioned, the total costs (OPEX and CAPEX) for the 2011 business year (C_{2011}) as audited by the regulatory authority serve as the basis for the third regulatory period. Decisions on whether particular costs are appropriate or not are taken in accordance with the general principles of cost establishment as specified in section 59 Electricity Act 2010. In this, accounting data (i.e. balance sheet figures) are used; it would be inadmissible to calculate allowed costs based on budget figures (refer to the explanatory notes on section 59(1) and (4) Electricity Act 2010). The data for the 2011 business year are additionally checked for plausibility against developments in previous years, and are normalised if required. This way, we avoid a completely isolated consideration of figures on the balance sheet date, we work against any strategic shifting of cost items into the ‘snapshot’ year and we take into account any one-off effects.[10]

4.2. Costs in 2011 within and beyond the company’s control

In accordance with section 59(6) Electricity Act 2010, the cost audit differentiates between the costs that are “within the company’s control” and those that are “beyond the company’s control”, which added together make up the total costs in 2011 (C_{2011}). This distinction is necessary because the costs within the company’s control are subject to the targets specified in section 59(2) Electricity Act 2010 as well as to the network operator price index; those targets are embodied in the cost path, which includes the general and the individual efficiency targets. The “costs beyond the company’s control” (Cbc), on the other hand, are not subject to any targets. They are audited based on the most recent available values and passed through without any mark-ups or offsets, in other words they are added in the regulatory formula (s. chapter 16). The differentiation is also relevant for dealing with the systemic time lag (s. chapter 11.5).

Section 59(6) Electricity Act 2010 lists the following as costs to be considered beyond the distribution system operators’ control in a particular year (Cbc_t):

- the costs for the use of directly or indirectly connected systems in Austria (e.g. upstream network costs);
- the costs for covering system losses by way of a transparent and non-discriminatory procurement procedure (price component for the costs of system losses);
- community levies for the use of public land;
- the costs arising from statutory rules to be followed in cases of *Ausgliederung* (a type of demerger under Austrian law) which existed on the merits of the situation at the time of full opening of the electricity market on 1 October 2001.[11]

4.3. Projection of the initial costs within the company’s control in 2013

The cost adjustment factor for the third regulatory period (CA) is applied for the first time when establishing the allowed cost for 2014. For this, the audited costs within the company’s control in the 2011 business year are projected forward to arrive at the initial costs for incentive regulation, as of 31 December 2013. Assuming a balance sheet date of 31 December, the formula for this projection is this:

[10] 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).

[11] Section 59(6)(1) and (4) Electricity Act 2010 (costs for implementing network development plans and for primary control and secondary control) are not relevant for the distribution system.

$$C_{2013}^{path} = (C_{2011} - Cbc_{2011}) \times \prod_{t=2012}^{2013} \left[(1 + \Delta NPI_t) \times (1 - Xgen_{3rd.period}) \right]$$

Where the financial year deviates from the calendar year, the calculation has to include appropriate adjustments. The following formula results, for instance, for a balance sheet date of 31 March:[12]

$$C_{2013}^{path} = (C_{2011} - Cbc_{2011}) \times (1 + \Delta NPI_{2011})^{0.75} \times (1 + \Delta NPI_{2012}) \times (1 + \Delta NPI_{2013}) \times (1 - Xgen_{3rd.period})^{2.75}$$

In the projection presented above, the newly specified network operator price index (NPI, s. chapter 8) and the general productivity offset (Xgen, s. chapter 5) for the third regulatory period are applied as means of modelling two contrary effects.[13] This formula ensures that both any exogenous price increases occurring during the period and sector-specific productivity are duly accounted for.

[12] The calculation for other balance sheet dates works the same way.

[13] The individual efficiency target (s. chapter 6) is first applied when these initial (2013) costs within the company's control are used to determine the charges for 2014, the first year of the third incentive regulation period. This is presented in formal terms in chapter 16 (regulatory formula).

5. General productivity rate (Xgen)

When introducing incentive regulation for electricity distribution system operators, a general productivity rate (Xgen) factor of 1.95 percent p.a. was specified and applied during the first two regulatory periods (cf. the Explanatory Notes on the System Charges Ordinance 2006 and 2010). During the discussions on the specifications for the third regulatory period, industry requested a major decrease of the general productivity rate to 0.85 percent p.a., submitting a study prepared by consulting firm Polynomics[14]. To ensure that the Xgen factor for the third regulatory period would be set at a justified level, the authority also commissioned a study[15] on the topic. The two expert studies are discussed in the chapters below (5.1 and 5.2).

5.1. Industry study

The study, prepared by the consulting firm Polynomics and entitled "Determining the general productivity rate (Xgen) for the third regulatory period", was submitted to the authority by industry interest group Österreichs Energie during the discussions of the specifications for the third regulatory period.[16] The authority analysed in detail the findings and methods of the expert study. In general it has to be mentioned that such analyses of the productivity rate imply a number of difficulties that need to be taken into account. The issues pertain primarily to the availability of data, data quality and the aggregation level of the time series data, as well as the definition of the reference period (sample period).

The industry study addressed at least some of the problems and gave varying average productivity rates depending on the sample interval. The findings are listed in the figure below.

Period	Average productivity increase (in % per year)
1980-2009 (base model)	0.63%
1980-2007	0.65%
1976-2009	0.25%
1996-2009	1.19%

Figure 1: Scenarios calculated in the industry study (source: Polynomics, Statistics Austria and EU-KLEMS)

[14] Polynomics, 2013, *Berechnung X-Allgemein für die dritte Regulierungsperiode* (Determining the general productivity rate (Xgen) for the third regulatory period), revised version of the Polynomics expert study of 30 September 2008, on behalf of the Austrian electricity industry.

[15] WIK Consult GmbH, 2013, *Genereller Produktivitätsfaktor österreichischer Stromverteilnetzbetreiber* (General productivity rate of Austrian electricity distribution system operators). Study on behalf of E-Control.

[16] Polynomics, 2013, p. 15.

Polynomics advocate using the longest possible sample period when calculating the productivity rate (basic model, first row in

Period	**Average productivity increase (in % per year)**
1980-2009 (base model)	0.63%
1980-2007	0.65%
1976-2009	0.25%
1996-2009	1.19%

Figure 1). The study states that the period from 1976 to 1980 should be excluded due to reservations about the quality of the data available for this period. While the period from 1996 to 2009 offers the advantage of disaggregated data, this only holds for parts of the electricity industry. This fact along with the general preference for the longest possible sample period for calculating the productivity rate led the industry's experts (i.e. Polynomics) to conclude that the basic model should be retained.[17]

The industry study concluded that Xgen would have to be appreciably lower than the previously specified rate of 1.95 percent p.a.

5.2. Regulatory authority study

The regulatory authority commissioned WIK-Consult GmbH with the task of preparing a separate study to determine the general productivity rate (Xgen) of Austrian electricity distribution system operators. The objective of the expert study was to critically evaluate, based on available empirical data, the current rate of 1.95 percent p.a. used during the second regulatory period.

Contrary to the view stated by the industry's experts (Polynomics), who argue for longer sample intervals, WIK-Consult GmbH come out in favour of striking a balance between sample interval length and data consistency that does justice to the issue at hand. Specifically with regard to the second item, they recommend that care be taken to select an industry aggregate that is as precise as possible:

> "When determining sectoral changes in productivity and input prices for Austrian electricity distribution system operators, an aggregate should be used that matches the industry as precisely as possible. In terms of the Austrian classification of economic activities (ÖNACE 2008), aggregate D 35.13 'Distribution of electricity' would appear to meet that requirement. Yet discussions and investigations with Statistics Austria revealed that only for the ÖNACE aggregate D 35.1 'Electric power generation, transmission and distribution' are data available over a sufficiently long time period, if at all (as a rule from 1995 onwards). In addition to distribution, this category comprises

[17] A central issue with all of the calculations submitted by Polynomics is the mixed use of different data sources. Such mixing can only be avoided by resorting to Statistics Austria data and by basing the analysis on a sample interval beginning in 1996 (refer additionally to WIK-Consult GmbH, 2013, Table 3, p. 10).

> the transport and generation of and trade in electricity– in other words the electricity industry's entire value chain. For the period prior to 1995, data are available in most cases only for the ÖNACE aggregate D 35 'Electricity, gas, steam and air conditioning supply', while this category is dominated by developments in the electricity sector. For quantitative analyses, those time series are used that are the most closely related to aggregate D 35.13 and are available for a sufficiently long period of time."[18]

Like the industry's experts (Polynomics), the regulatory authority's experts performed sensitivity analyses using EU KLEMS (from which data are available only for the period up to 2007) and data from Statistics Austria (available until 2011), but beyond that distinguish two possible ways of modelling the output. In addition to displaying the results with reference to the gross production value (GPV; similar to the industry's study), the results are also framed in terms of gross value added (GVA). The choice of output variable (GPV or GVA) is decisive for the input variables to be considered.

To ensure consistent modelling of the input and output side, the three input factors of labour, capital and intermediate input need to be taken into account for the gross value of production, whereas the gross value added represents only labour and capital.

The regulatory authority's experts argue unequivocally for using the gross value added and against the gross value of production (as used in the industry study):

> "With regard to the choice of time series for the purpose of modelling the output index, calculations within the Austrian regulatory context for electricity distribution system operators should be based on the gross value added (GVA) and not on the gross value of production (GPV). When unbundling generation, network and distribution, intermediate input generated at one stage in the value chain is counted towards the next stage; the overall result is an increase in the gross value of production (compared with the period prior to liberalisation) without any actual change in production processes. By taking intermediate input into account on the input side as well, it was thought that there would be no significant differences between the results obtained with GPV and GPA as long as the intermediate input was recorded correctly. The results […] show that this is not the case. Specifically, intermediate input in particular is regularly the subject of certain revisions to methodology arising from the difficulties in delimiting it from capital expenditure; this ultimately leads to gaps in the time series. Using the gross value added avoids this skewing effect."[19]

The study additionally presents productivity growth as calculated merely in terms of changes in total factor productivity (TFP) and by using the Bernstein and Sappington (1999) method for the factor productivity rate. The results of weighting the two methods at a ratio of 50:50 are also given. The underlying concern here is that the method proposed by Bernstein and Sappington (1999) is hardly appropriate for addressing the issues arising in the Austrian

[18] WIK-Consult GmbH, 2013, p. 7, quote translated from German.

[19] WIK-Consult GmbH, 2013, p. 17, quote translated from German.

regulatory context. The study authors point out that a strictly differential comparison (i.e. in line with the Bernstein and Sappington method) of the two sectors (electricity industry and overall economy) with respect to TFP growth rate and input prices is inappropriate given that in Austria, the network operator price index (NPI) is used to adjust the controllable cost for inflation. The procedure would only be appropriate if inflation adjustment were done using a price index based solely on output prices (e.g. the consumer price index, CPI) and no mixed indices made up to any extent of input price indices (such as the index of collectively agreed wages and salaries) were used. If the adjustment for inflation were done using an index based on input prices only (without including a CPI), TFP growth rates for the sector only would render an Xgen appropriate for addressing the issue. Weighting the two methods (TFP growth rates for the sector only and a differential comparison as described by Bernstein and Sappington) comes closest to the Austrian regulatory context, and for this reason WIK-Consult GmbH advocate this procedure.[20]

In contrast to the approach taken by the industry's experts (Polyonomics), i.e. to use the longest possible time interval for determining productivity rates, WIK-Consult GmbH argue for a sample interval that is as close to the relevant regulatory period as possible:

> "When determining the productivity rate for incentive regulation, the aim is to arrive at a forecast of the productivity gains to be expected of system operators in the future. Such an estimate will obviously draw on observations from the past. Yet, in order for them to maintain a certain validity for the regulatory period in question, those observations should not date back too long. Such validity will especially be given where the system operator's overall operating conditions do not vary too widely between the sample interval and the regulatory period. In consequence, the sample interval should be as close as possible to the regulatory period in terms of timing and not be too far back in the past."[21]

The results presented by WIK-Consult GmbH, based on data provided by Statistics Austria, extend up to 2011.

The recommendations made by the study authors are mentioned above, i.e. to use the gross added value instead of the gross value of production and to average the results of sector-specific TFP growth rates and the results rendered by the Bernstein and Sappington method; implementing those recommendations and using sample intervals that are as close to the present as possible (which implies using Statistics Austria data), the authors arrive at a range extending from 1.1 (sample period of 2001-2011) to 1.8 percent p.a. (sample period of 1996-2011).

The authors conclude the following:

> "The general Xgen should be redefined for the third regulatory period at a level between 1.10 percent p.a. and 1.80 percent p.a. The analysis is based for the most part

[20] Refer to WIK-Consult GmbH, 2013, pp. 2-5.

[21] WIK-Consult GmbH, 2013, p. 18, quote translated from German.

on data comprising the entire value chain of the electricity industry. Thus, a value towards the lower end of the range can be advised for reasons of caution."

5.3. The authority's decision on the Xgen factor

After considering the expertise presented in the two studies, the regulatory authority concludes that it is appropriate not only to use sample intervals that are as close to the present as possible but also to follow the arguments for using the gross added value in the place of the gross value of production, i.e. to circumvent the issue of separately including intermediate input. Furthermore, it is important to identify a calculation method that is appropriate for addressing the issues arising in the Austrian regulatory context (i.e. inflation adjustment of the cost base using a system operator price index with an input price component).

The authority follows the recommendation made by WIK-Consult GmbH to use a value towards the lower end of the range specified in the regulatory authority study (1.10 to 1.80 percent p.a.) for reasons of caution, while also endeavouring to set the rate in the vicinity of the range specified in the industry study (0.63 to 1.19 percent p.a.). After careful consideration of all the arguments presented above, the authority has decided to set the general productivity rate for the third regulatory period at 1.25 percent p.a.

6. Benchmarking of the individual efficiency target (Xind)

The efficiency targets for the individual companies are based on an efficiency benchmark. The various methods that can be used for this purpose are explained and discussed below.

To derive the annual efficiency targets, the inefficiencies to be reduced are first determined and then distributed over a specific time period. This is done in order to reflect influenceability and at the same time provide companies with attractive incentives for productive behaviour. The distribution of efficiency scores has a major impact on determining whether it might be necessary to set a minimum efficiency level and on the period allowed for reducing the inefficiencies. This subject is discussed in chapter 7 below.

The objective of benchmarking is to verify whether the actual costs of system operation are consistent with economical operations management. This responds to the statutory requirement to identify the cost level of one or more comparable companies that are run (relatively) efficiently. This makes it possible to compare the costs incurred by a specific company to the costs run up by one or more other companies that are operated in an efficient way.

The benchmarking analysis can be broken down into several steps:

1. Select the benchmarking method(s).
2. Select the variables on the cost side (input values) and on the service or structure side (output values).
3. Perform the 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 to each other. In consequence, this does not mean that companies showing up as efficient actually have to be efficient in absolute terms, i.e. potential for efficiency could also exist for them. In addition, the fact that this is a statistical analysis means that the efficiency levels could actually shift in future and convergence must not necessarily occur (dynamic aspect).

We expressly point out that the industry representatives have spoken out in favour of further refining the efficiency analysis as performed in 2005, based on the DEA (data envelopment analysis) and MOLS (modified ordinary least squares) benchmarking methods used at the time as well as the model network lengths and peak load values employed as output parameters. The authority has responded to this request by basing the benchmarking process in the third regulatory period in general on the foundations and results of the 2005 exercise. All methods and parameters used in specifying targets must be in accordance with the state of the art (section 59(2) Electricity Act 2010). The issue of calculating efficiency triggered a number of quite extensive responses during consultation. To underscore their views, the industry representation submitted a Consentec expert opinion, which mainly addressed the standardisation of capital expenditure, the form of the function used in the MOLS analysis and the treatment of outliers in efficiency calculations.

It is understandable that the industry presents its arguments with the intention of achieving the best possible outcome, i.e. a high average efficiency score. Basically every detail of the methodological design offers corresponding potential for influencing the outcome, while particular reference should be made in this context to reducing the sample size by eliminating potential outliers from the benchmarking analysis, as this does not entail poorer individual efficiency scores for companies (at least in DEA).

Nonetheless, several companies and legal parties submitted no statement in response to the draft rules for benchmarking, while some even welcomed an efficiency benchmark that would be carried out transparently and using appropriate methods. We therefore conclude that the authority's procedure is largely accepted.

The objections brought against the authority's approach are presented in detail and commented on appropriately at the end of the following chapters.

6.1. Benchmarking methods, forms of functions, and methods of handling zero-output level

Various methods are available for determining targets using benchmarking. Besides using the non-parametric benchmarking method of data envelopment analysis (DEA), efficiency levels are determined by means of the parametric method of modified ordinary least squares (MOLS). In an expert study commissioned by the regulatory authority, Gugler et al. (2012) evaluated 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).[22] In SFA, the residual is divided into one component representing inefficiencies and another representing data noise. The distinction is made using statistical methods that have observations for a sufficient number of companies as a prerequisite. The German regulatory authority Bundesnetzagentur, for example, draws on a data set with well over 100 companies to determine the efficiency levels of electricity and gas distribution system operators. Sample calculations based on studies using the values from the 2008 business year (costs and technical parameters) demonstrated that the available database in Austria is not large enough for an SFA to be applied and that, in the experts' view, SFA cannot be used in the current Austrian regulatory context.

With regard to the hybrid models (including SDEA and StoNED) the experts identify difficulties in comparing the advantages and disadvantages of these methods. Unlike methods such as DEA and MOLS, which are well established and have been sufficiently evaluated, the former methods have not yet been adequately appraised and are hardly applied in practice.

[22] 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), expert study on behalf of E-Control Austria.

Based on the arguments stated above, the authority saw no reason for using methods other than the ones that have proven reliable in the past (DEA and MOLS). These two benchmarking methods continue to reflect the state of the art.

The features as well as the advantages and disadvantages of the two methods are described in the Explanatory Notes on the 2006 and 2008 System Charges Ordinances as well as by the Frontier-Economics/Consentec expert study (2004). Even though the detailed presentation is not repeated in this paper, the analysis in the following chapters makes reference to the main contents of the methods. Where there have been advances in benchmarking analysis in the context of incentive regulation in Austria (benchmarking of electricity and gas distribution system operators) and at the European level (TSO benchmarking), this is pointed out in the text.

6.1.1. Data envelopment analysis (DEA)

As DEA is a non-parametric method, no estimates of underlying cost functions are required, since efficiency frontiers are defined solely based on observations of best practice companies and not with reference to a production context that would be described using econometric estimators.[23] DEA is by far the most widely applied non-parametric benchmarking method. Not only is the method easily understandable, it also allows for a heterogeneous sample of companies to be modelled relatively easily. Another advantage is that the method can be used with constant or variable returns to scale (cf. the discussion of returns to scale below). With this method the quality of data is a key issue, as any deviation from the efficiency frontier is interpreted as inefficiency; the method is classified as 'deterministic'. The major disadvantages are the sensitivity to outliers as well as the discriminatory capacity of the analysis in cases where few observations occur in conjunction with a large number of outputs ('curse of dimensionality'). The more dimensions a DEA has, the greater the risk of a separate dimension for each company, in which by definition no other more efficient company can exist (convergence of efficiency scores towards 1). Best practice companies are assigned a score of 1 (perfect efficiency) and thus represent the efficiency frontier, while the efficiency of the remaining companies is defined in relation to that frontier. Consequently, outliers can exert major impact on the efficiency scores of the 'enveloped' companies.

In view of the aspects mentioned above, the authority put great emphasis on verifying the completeness and correctness in particular of input parameters (using plausibility and validity checks) and on analysing outliers. In addition, the advantages and disadvantages of the second applied method, MOLS, are almost exactly the opposite of those associated with DEA (refer to the next chapter).

[23] Refer in general to the Explanatory Notes on the System Charges Ordinance 2006, pp. 35 et seq.

6.1.2. Modified ordinary least squares (MOLS)

In contrast to DEA, the parametric MOLS analysis requires the relationship between the inputs and outputs to be specified in functional terms.[24] This functional relationship is modelled by means of an OLS estimate, which represents the basic (average) relationship between the inputs and the outputs. To model the efficiency frontier, the OLS line is shifted by the standard error of regression. Where an exponential distribution (of the inefficiency term) is assumed, the shift is by the root mean square error (RMSE), i.e. by the standard error of regression; where a half-normal distribution (of the inefficiency term) is assumed, the shift is by $RMSE \times \frac{\sqrt{2}}{\sqrt{\pi}}$.

The outward shift increases in magnitude with the variance of the residuals and consequently with the estimator for the average inefficiency as well, i.e. the extent the companies deviate from the efficiency frontier. This ensures that the majority of data points, but not all of them, are enveloped. This aspect in particular renders this method less sensitive to outliers than the DEA method described above.

While there are several production or cost functions that could be used to describe the functional relationship, in economics publications log-linear Cobb-Douglas or translog functions are normally applied in this case. Since it includes squares and cross terms, the latter function is more flexible and is thus preferable from an econometric point of view. Empirical testing can determine whether such flexibility is required, serving as a basis for choosing the form of the function, i.e. either a log-linear or a translog function. Where a Wald test shows the sum of the squares and cross products not to be significant, the analysis can proceed using the Cobb-Douglas function.

Within the framework of an analysis carried out in 2005, a basic statistical model including only the significant parameters was defined. This approach is now changed. The regression line is now defined depending on the outcome of the joint Wald test, using either a fully specified translog model (including non-significant terms as well) or the Cobb-Douglas form (where the null hypothesis of the Wald test cannot be rejected). In contrast to DEA, the Cobb-Douglas specification allows for empirical testing, to ascertain whether or not increasing, decreasing or constant returns to scale are present. The Cobb-Douglas specification can also be estimated with constant returns to scale.

A half-normal distribution is assumed for the inefficiency term. Alternatively, an exponential distribution could also be assumed for the error term. The half-normal distribution differs from the exponential distribution in that the efficiency frontier is not shifted out as far, which generally results in higher efficiency scores. In the case of log-linear forms of the function (i.e. Cobb-Douglas or translog functions), efficiency scores are calculated under the assumption of a half-normal distribution using the formula below:

$$efficiency.score\_MOLS = \min\left(1\,;\,\frac{1}{e^{\left(residual + RMSE \times \frac{\sqrt{2}}{\sqrt{\pi}}\right)}}\right)$$

[24] On MOLS, refer in general to the Explanatory Notes on the System Charges Ordinance 2006, pp. 38 et seq.

6.1.3. Scale effects

As explained above, both DEA and MOLS can work with various assumptions concerning scale effects. While parametric methods allow testing for scale effects, from the standpoint of regulatory policy one must nonetheless ask whether preference should not be given to an *a priori* decision in this case; this holds all the more where the selection of an optimum company size falls within the regulated companies' sphere of influence.

Such considerations were extensively discussed in the Explanatory Notes on the System Charges Ordinance 2006, with the results that constant returns to scale were used in DEA. Such an *a priori* decision was not taken, however, in the context of MOLS, which several companies criticised as inconsistent. This issue was addressed during the efficiency benchmarking of gas distribution system operators (s. the Explanatory Notes on the Gas System Charges Ordinance 2008); here the inconsistency was eliminated by using constant returns to scale, both with DEA and with MOLS (applying a more restrictive estimate).

To ensure uniform and consistent procedures as well as comparable results from the two benchmarking methods, constant returns to scale (CRS) are assumed for both methods.

In the authority's view, the selection of the optimum company size does in fact fall within the regulated companies' sphere of influence: system operators are normally able to modify the scope of their business activities by merging, collaborating or selling business units. Management is therefore responsible for any inefficiencies caused by a company size that is less than optimal, and this must be taken into account in the efficiency benchmark. Inefficiencies resulting from less-than-optimal company size must not be passed on to customers in the form of excessive charges. With regard to the choice of a CRS specification for benchmarking, we refer to the Explanatory Notes on the System Charges Ordinance 2006and the Explanatory Notes on the Gas System Charges Ordinance 2008. A single CRS specification was selected for use with both DEA and MOLS back in 2007 when the benchmarking analysis was defined for gas distribution system operators. In the interest of consistency, this same approach is taken for the electricity distribution system operator sector.

6.1.4. Forms of functions, and methods of handling zero-output level

Unlike non-parametric methods for efficiency benchmarking, such as DEA, parametric methods require an initial assumption concerning the form of the function that defines the relationship of inputs to outputs. In general, numerous forms of the function are available for this purpose, including the linear cost function, the separable quadratic specification, the composite specification, the generalised Leontief or the Cobb-Douglas and translog cost functions.

Absolute values are considered with linear functions, which can potentially result in the scores of large companies deviating more strongly from the efficiency frontier than those calculated for small companies. This issue can normally be resolved by standardising all variables by means of a size parameter (i.e. standard variable; estimate of a standardised linear cost function). The choice of a suitable standardisation parameter should normally be based on the following criteria:[25]

- Suitability for modelling size differences: the standard variable should represent a suitable means of adjusting for size differences amongst the system operators;
- Parameter stability: parameters should be selected that are not prone to fluctuating widely;
- Parameter independence: company decisions should not influence the scale variable.

The choice of a suitable standardisation factor is therefore a complex matter and not clear from the outset. According to Coelli et al. (2003), the standard translog specification is the production function most frequently used in the literature; the function can be transformed into a Cobb-Douglas cost function as shown below.

Translog specification:

$$\ln C = \alpha_0' + \sum \alpha_i \ln q_i + \frac{1}{2}\sum\sum \alpha_{ij} \ln q_i \ln q_j + \sum\sum \delta_{ik}' \ln q_i \ln r_k + \sum \beta_k \ln r_k + \frac{1}{2}\sum\sum \beta_{kl} \ln r_k \ln r_l$$

with: $\alpha_0' = \alpha_0 + \beta_0 - 1$ and $\delta_{ik}' = \delta_{ik} + \mu_{ik}$.

When α_{ij}, δ'_{ik} and β_{kl} are each set to equal 0, the standard translog specification is recognisable as a generalisation of the Cobb-Douglas cost function.

Cobb-Douglas specification:

$$\ln C = \alpha_0 + \sum \alpha_i \ln q_i.$$

Hypothesis testing (a Wald test) can be used to verify whether the additional terms of the translog cost function are relevant. Where that is not the case, the Cobb-Douglas function can be used instead. With the Cobb-Douglas and the translog cost functions, the size adjustment is made by logarithmising the data. No standardisation factor is required here.

The two forms of the function indicated above are generally well suited for determining efficiency, for two reasons: first, both are relatively simple to implement (for example, apart from applying the logarithmic function no other data transformation is needed in order to counteract the heteroscedastic error terms); second, both forms of the function offer a sufficient degree of flexibility to ensure a good approximation of the 'true' cost function. E-Control used a translog function or its special Cobb-Douglas specification (i.e. a log-linear

[25] Refer to Frontier et al., 2012, p. 61 et seq.

form of the function) for efficiency benchmarking for the first regulatory period both in electricity and gas incentive regulation. These forms are well established in economics publications. Therefore, E-Control does not on the whole see any need to depart from this approach.

When applied in practice, both the Cobb-Douglas cost function and the translog function have to come to grips with the ‘zero problem’ in the context of output variables to be transformed logarithmically (the logarithm of zero is undefined). In general three major data transformations are available to ensure that forms of the function are capable of handling the ‘zero output problem’ (refer to Gugler et al. [2012]):

- Fourier transformation;
- Box-Cox transformation;
- Introduction of dummy variables.

Alongside these three data transformations for handling zero-output levels, another possibility exists for handling the numerical problem arising in the context of parametric benchmarking methods: combining several related output dimensions. This method was chosen for the MOLS analysis back in 2005; specifically, the individual network lengths of the high-voltage, medium-voltage and low-voltage systems were combined into a weighted model network length. Relative average unit costs were used as weighting factors among the three voltage levels (refer to the detailed discussion in chapter 6.2.2.4 below). The advantage of this method is that it allows a log-linear cost function to be used in conjunction with a MOLS analysis (as noted above, the logarithm of zero is undefined). The expert study by Gugler et al. (2012) points out that the data transformations enumerated above have a number of disadvantages and that their use should be viewed critically in some cases. Yet, as mentioned above, an alternative solution is available, which the authority already used in the past; the authority sees no reason to depart from the tried and tested method.

6.2. Specification of benchmarking parameters

In the context of an efficiency benchmark, the ratio of inputs to outputs as compared among the companies is generally regarded as a measure of efficiency. Here an approach from either the input or the output side can be used. With the first approach, an externally given number of outputs (performance variables) are to be produced at the lowest possible cost (inputs), while in the second approach the highest possible output is to be achieved at a given input level. In the distribution system sector, most of the outputs relevant for electricity system operators have to be considered as beyond the companies’ control (peak load is driven by injection and consumption behaviour, grid connections depend on the customers etc.), and for this reason the input approach has to be regarded as the appropriate one. While cost is often considered the only relevant input (i.e. the efficiency score is the measure of cost efficiency), relevant outputs can be selected through various procedures – main examples of such from practice include expert opinions (cost-driving effects inferred intuitively), approaches based on engineering science (engineering economic analysis) and empirical analysis using significance testing. These selection methods are often combined with each other.

The following chapter discusses the procedures applied in specifying the input and output factors for benchmarking in the present case and the premises underlying the procedures.

6.2.1. Variable selection: input parameters

Either the operating expenditure (OPEX) alone or the total expenditure (OPEX and CAPEX taken together) can be used as the input cost variable. Using the total expenditure offers the advantage that the benchmarking results are not distorted by companies' decisions with regard to the capital intensity of their production processes. If benchmarking focuses exclusively on OPEX this may create incentives to declare OPEX as capital expenditure (e.g. certain maintenance programmes) or even to opt for capital investment over operating cost-intensive solutions simply to improve the OPEX benchmarking result.

In line with the requirement for charges to reflect actual costs, the authority currently holds the view that the benchmarking analysis should not be limited to operating expenses (including maintenance costs) but also include capital expenditure (CAPEX). Suitable incentives should be created in any case for companies to undertake efficient investment activities, and it needs to be ensured that operations are also managed in a way that saves resources.[26] After considering various options, the E-Control Commission decided to use total expenditure as the input variable for the first benchmarking analysis in 2005. The authority continues to view this method as appropriate and consequently the input variables for the benchmarking procedure are based on total expenditure (TOTEX).

When determining the costs to be used in benchmarking, in general the audited costs shown for the relevant review year are used as a basis (refer to chapter 4.1). The total amount of a company's network costs is understood to include the costs of system losses and to exclude the upstream network costs. As regards the costs to cover grid losses, the amount of system loss during the cost review year was multiplied with a uniform rate of EUR 48.20 per MWh.

6.2.1.1. Adjustment of the cost base

Adjustments to the benchmarking cost base may be required to ensure comparability of the companies' costs. In the authority's view, appropriate adjustments may normally be made only under the following conditions:

[26] It should be noted that section 59(1) Electricity Act 2010 expressly specifies an assessment of individual processes as admissible.

- It can be assumed that the company concerned is in a special situation (compared with other companies) that leads to a considerable distortion of the efficiency comparison;[27]
- That special situation represents a cost-driving effect;
- That effect is exogenous and significant;
- The effect is of a sustained nature;[28]
- The company is able to provide transparent evidence of the costs arising from the effect;
- It is possible to clearly measure the corresponding costs (added and reduced costs) and delineate them from other cost items; and; in addition,
- the special situation cannot be modelled in benchmarking through the use of suitable output (based on a corresponding cost-driver analysis).

It is of utmost importance in this respect that adjustments are exclusively intended to avoid any improper distortion of the assessment result. Adjustments thus focus on those components of the cost base that distort the assessment of the relative efficiency, thereby leading to unequal treatment of companies. Whether or not the costs in question are within the company's control is irrelevant; the sole decisive consideration for the purpose of benchmarking is that the input data available are comparable in factual terms.

Based on these principles, the authority made adjustments as listed below for the companies affected:

- Transmission or extra high-voltage network costs;
- Cost of capital from prepayments for installation cost;
- Costs of already executed investments for smart metering;
- Costs to adjust for the integration of wind power stations.

The networks operated by some of the companies include extra high-voltage lines and lines currently or previously used for transmission. To ensure comparability of the electricity distribution system operators (with a sufficient number of degrees of freedom), in the case of those companies the extra high-voltage network costs have to be deducted from the cost basis, so that the efficiency benchmark takes into account only the distribution network costs. The companies concerned are Netz Niederösterreich GmbH, Wiener Netze GmbH, TINETZ-Stromnetz Tirol AG, Vorarlberger Energienetze GmbH and KNG-Kärnten Netz GmbH. In the case of the latter three companies the adjustments additionally relate to parts of network level 3, where these are used both for transmission and distribution. On this issue all three companies have asserted that the typical use of certain lines for transmission incurs

[27] It is unlikely that a special situation exists when more than one company is impacted by a certain effect; this is examined in the individual case and the authority may conduct relevant investigations if required.

[28] One-off effects during one cost review year are distributed by normalisation over several years in the individual case.

capital and operating expenses not to be compared with other lines. They argued that such lines have to be suitably dimensioned as well as operated and maintained. The fact that the lines operated by TINETZ-Stromnetz Tirol AG and Vorarlberger Energienetze GmbH are also used for transmission was demonstrated through the ITC mechanism, which recognises various sections of the lines to a corresponding (proportional) extent (the Inter-Transmission System Operator Compensation or ITC mechanism serves to determine those network costs incurred by transit which are to be covered by an international compensation fund). Those network facilities would not have been included in the international cost compensation mechanism were they not significant for the cross-border transit of electricity. Both companies additionally provided evidence of the load situation at the handover points of the lines typically used as transmission systems. The proportion of such loads to the total peak load at all handover points is a further measure, in addition to the extent to which the lines are recognised in the ITC mechanism, for assessing the typical use of the lines for transmission. The two factors consequently serve as criteria for deciding on any adjustments. Among the comments submitted by KNG-Kärnten Netz GmbH in response to the preliminary assessment report was a statement of the facts, backed by an expertise issued by Prof. Renner (Graz University of Technology). In the statement, the company presented the view that its 110 kV network served to fulfil transmission tasks at the supra-regional level, in addition to regional transportation tasks. The author of the expertise additionally observed that such tasks involved no other electricity distribution system operator. In its statement, KNG draws attention to the special combination of power generation facilities and network topology that currently exists within its network area. For these reasons, adjustments are also made in the benchmarking analysis to proportionally account for the costs of the 110 kV network operated by KNG-Kärnten Netz GmbH.

The Austrian distribution system operators have varying weightings of prepayments for installation costs. The differences arising from this aspect of tarification must be neutralised for benchmarking purposes, as firms with lower weightings of such prepayments would otherwise be systematically disadvantaged. This bias is neutralised when the cost of capital is calculated. The prepayments for installation costs (or, as referred to in the current legal framework, the system provision charges actually collected and system admission charges) as reported in system operators' balance sheets are deducted from the interest-bearing capital when determining tariffs and included in interest-bearing capital for the purpose of benchmarking. The adjusted cost of capital is derived from this increased capital base for the purpose of benchmarking ("fictitious costs of capital from consumer prepayments for installation costs (prepIC)"). That adjustment applies to all electricity distribution system operators included in the current efficiency benchmark.

In the last benchmarking exercise, the cost of social capital was deducted from the overall cost of capital to avoid double counting of this expenditure (the costs are already included in personnel expenses). This approach is maintained in benchmarking for the third regulatory period.

In contrast to the benchmarking analysis in 2005, the metering costs are not excluded from the benchmarking cost base in order to ensure that the efficiency estimate reflects an overall view. Metering is a service that all electricity distribution system operators are required to provide to a comparable extent and one that is typically within a company's control. In this light the authority considers it appropriate for efficiency benchmarking to encompass that process as well. Adjustments are required only for three companies; compared with the others, those represented a special case within the benchmarking sample with regard to the degree to which smart metering had been introduced as of the 2011 business year. The companies, specifically LINZ STROM Netz GmbH, Netz Oberösterreich GmbH and Stadtwerke Feldkirch, had already started with smart meter roll-out. In order to account for this special situation in the relative efficiency benchmark, a simulated Ferraris meter scenario over the 2011 business year is used for those distribution system operators instead of actual metering costs (including both OPEX and CAPEX).[29] It should be noted that this is a one-off adjustment to compensate for the special situation of the three electricity distribution system operators with regard to the extent of smart meter roll-out. As the extent of roll-out is defined in section 1(1) of the *IME-VO* (Smart Meter Rollout Ordinance), such an adjustment will not necessarily be repeated in future benchmarkings (depending on the year of the next analysis). The smart meter roll-out is legally required in principle, with an ordinance specifying items such as a multi-phase schedule as well as minimum technical requirements. Substantial latitude nonetheless exists for achieving the defined objective and for implementing the schedule, so that future efficiency benchmarks will have to include the efficiency shown in implementing the measures.[30]

Due to a lack of any suitable output variable to model the wind energy fed into the grid, the cost side of CAPEX will be adjusted for two distribution system operators (Netz Burgenland Strom GmbH and Netz Niederösterreich GmbH). Both of them have provided evidence to allow the related cost burden to be clearly delineated from other costs. In the case of one of the two companies (Netz Niederösterreich GmbH) it was necessary to adjust the number of connections to the high-voltage network (refer to chapter 6.2.2.1) in order to ensure that cost adjustments were congruent with outputs (modelled high-voltage network length). It should be noted in this context that, while the costs of grid expansion are largely covered by the prepayments for installation costs of wind power stations, these effects will be eliminated when setting the benchmarking cost base, as described above. A major difference to other parties injecting renewable energy into systems is that it has up to now been possible to integrate for example photovoltaic systems into existing grids without any substantial expansion and this has affected every system operator, although to a varying degree. In the authority's view it cannot therefore be concluded that certain system operators are currently in a special situation. As previously mentioned, the benchmarking cost base (input) described above is generally based on data from the annual financial statements, while including adjustments arising from the audit. Apart from the inclusion of metering and system loss costs, the calculation method thus corresponds in general to the

[29] Additional OPEX (in the roll-out phase) and CAPEX will be balanced against OPEX savings. Added CAPEX will arise from meters that are replaced by a smart meter prior to expiry of the calibration period or the end of useful life, while OPEX savings are expected through optimisation of processes and from discontinuing meter readings.

[30] Refer to chapter 12 on this issue.

procedure used in the first benchmarking exercise in 2005 (in which adjustments were also made for the transmission system).

6.2.1.2. Standardisation of capital expenditure

A significant addition over the analysis in 2005 has nevertheless been made. The use of accounting data can result in 'older' systems in some cases having an advantage over 'newer' grids, since not only is the CAPEX lower due to carrying amounts being written down but also is it based on historically lower acquisition ('at cost') and production costs at nominal prices. Situations that in the authority's view should be avoided include such where companies set the efficiency frontier for other system operators simply because they have applied comparatively short depreciation periods in the past and/or their assets in operation have a high average age. Distortions of capital expenditure can generally be caused by the following factors:

- Varying age structures: differing situation of companies within the investment cycle;
- Heterogeneous depreciation methods: companies apply varying depreciation periods;
- Varying capitalisation methods: differing capitalisation policies, particularly with regard to replacing assets.

Whereas ways exist that allow the first two sources of distortion to be largely eliminated, that is not the case with regard to varying capitalisation policies in the past. It can be assumed, however, that appropriate accounting standards have limited the degree of discretion that companies are able to exercise.

The distortions in CAPEX described above can be mitigated by using standardised CAPEX data, with the annuity method being appropriate. What makes the method suitable is the fact that the authority has access to a consistent database comprising the investments made by the companies since 2005, broken down by asset class. Specifically, the costs incurred by acquiring or producing the items in the individual asset categories are indexed by first year of operation, allowing the current replacement values to be calculated. This data, in combination with standardised values for useful life and a real interest rate, provide the basis for calculating annuities (i.e. constant cash flows over the entire useful life). Such annuities are to be preferred over simply using a standardised value for the depreciation period as the method also takes into account the investment cycle and thus also the age of the asset, i.e. the investment costs are represented independently of any specific investment cycle.

To calculate annuities, the following steps are required:

- Record the investment time series for all asset categories (provided by the asset class data for the electricity sector since 2005);
- Determine a suitable index for the average price changes of the fixed assets;
- Determine the term of the annuity ('depreciation period');
- Determine the interest rate for the annuity (weighted average cost of capital, WACC).

In this way a price index is applied to the historical acquisition and production costs to calculate indexed acquisition and production costs or the replacement value. No specific inflation rates are available for the various asset categories during the required period (50 years in many cases);[31] all asset categories are therefore indexed using the consumer price index (CPI). After calculating the indexed acquisition and production costs for each asset category, the annuities (i.e. the standardised cost of capital) are determined using a uniform real interest rate[32] (=(1+WACC)/(1+CPI)-1) and a uniform depreciation period for each asset category. The classic form of the annuity formula is used for the calculation:

$$Annuity_i = \sum APC_i^{ind} \times \frac{(1+rZ)^{AD,i} \times rZ}{(1+rZ)^{AD,i}-1},$$

where $\sum APC_i^{ind}$ is the sum of the indexed costs of acquisition and production for asset category *i*, *rZ* is the real interest rate, and *DP,i* is the depreciation period of asset category *i*. The standardised CAPEX (not normalised) results from the sum of all relevant asset categories.[33]

To allow uniform depreciation periods to be applied for each asset category, we have adopted the scheme proposed by OE, as given in the table below:

Asset class	Standardised useful life (in years)	**Asset class**	Standardised useful life (in years)
A.2 Software	4	B14b Meters (remote reading)	15
A.3 Easements and other rights	20	B15 Power generators for outages	10
A.4 Prep. f. installation costs	20	B16 Business premises	33
A.5 Other immaterial goods	1	B17 Operational buildings	33
B5 Overhead lines (36> to 110 kV)	33	B18 Land	
B6 Cables (36> to 110 kV)	33	B19 Motor vehicles	7
B7 Transformers (HV-MV)	20	B20 Machinery	9
B8 Overhead lines (10+20k)	20	B21 IT equipment	4
B9 Cables (10+20k)	20	B.22 Telecoms equipment	10
B10 Transformers (MV-MV)	20	B.23 Low-value assets	1
B11 Transformer station	20	B.24 Other	5
B12 Overhead line (<1kV)	20	B.25 Adv. paym. & plant u. cons.	25
B13 Cables (<1kV)	20	B.26 Other non-durables	1
B14a Meters and metering equipment	15		

Figure 2: Standardised values for useful life used in calculating annuities

[31] In Germany, a specific inflation rate was used for each individual asset. Neither industry representatives nor industry experts (Consentec) raised any objections to using the CPI or proposed better suited methods.

[32] Indexing the investment time series requires the use of a real interest rate. The CPI is based on the same period as was used in determining the risk-free interest rate for the WACC (five years).

[33] The following asset categories are not included: A.1. Goodwill, B.1.-B.4. Extra-high voltage lines and network level 2 transformer substations, and C.1. Prepayments for installation costs recorded as liabilities. Despite exclusion, the latter costs are implicitly taken into account, in a manner comparable to the calculation approach; this is given through the fact that the costs of acquisition and production for the relevant asset categories reflect the total gross amounts of investment, which are independent of cost allocation.

The main advantage of using annuities is that the investment cycle no longer affects the level of capital expenditure. Stated simply, this method results in the same capital expenditure for an old system as for a new one. Yet this immediately brings the disadvantage into view. Using 'economic' depreciation values does not take into account the give-and-take between operating expenditure and capital expenditure over time. While an old system incurs lower capital expenditure, higher operating costs are run up at the same time due to necessary maintenance, with the reverse being true for a new system. Using annuities could tend to disadvantage older systems. To address this issue, the better of two values, the weighted efficiency scores resulting from the calculation approach and the standardised approach, is taken (refer to chapter 6.7).

In addition, the authors of the industry's expert study (Consentec) requested that the standardised capital expenditure be normalised.

Consentec's rationale is that the sum of the annuities (i.e. standardised CAPEX prior to normalisation) is systematically greater than the calculated, i.e. non-standardised, CAPEX. The effect would not be significant if the efficiency benchmark were based on CAPEX alone, since the increase in the case of older systems is higher than for newer ones, and in this way the intended levelling of the varying age structures would be achieved through CAPEX. Yet the comparison is in fact based on total expenditure, i.e. the sum CAPEX and OPEX. Systematically increasing CAPEX would thus disadvantage companies whose proportion of CAPEX to total expenditure is higher than average, regardless of the reason for differing shares of CAPEX within the sector. Consentec sees this effect as potentially running against, in the individual case, the intended effect of standardising CAPEX. This is avoided by normalising the standardised CAPEX value, since then the standardised CAPEX deviates from the calculated CAPEX only in the case of individual companies and not on average for the sector. The authority sees no reason not to follow the industry experts' proposal, even in conjunction with the use of the better result as applied.

This involves determining for each individual company the ratio of standardised capital expenditure (annuities) to calculated capital expenditure and then applying the average ratio of standardised and non-standardised/calculated capital expenditure as a normalisation factor across all companies. The standardised capital expenditure is then divided by the sectoral normalisation factor to render the normalised standardised capital expenditure. These relationships can be expressed in a formula as shown below:

$$normalised\ standardised\ CAPEX\ = \frac{standardised\ CAPEX}{general\ normalisation\ factor}$$

where the general (sectoral) normalisation factor is determined as

$$general\ normalisation\ factor\ = \frac{\sum_{j=1}^{n} individual\ normalisation\ factor_j}{number\ of\ companies}$$

and the normalisation factor for the company *j* is defined as

$$individual\ normalisation\ factor_j\ = \frac{standardised\ CAPEX_j}{calculated\ CAPEX_j}$$

The two input variables (calculated and standardised capital expenditure) are determined as follows:

Total costs of company's own system (including costs to cover grid losses)	Total costs of company's own system (including costs to cover grid losses)
- extra-high voltage grid costs	- calculated CAPEX
+ fictitious cost of capital from prepayments for installation costs	+ normalised standardised CAPEX
+/- individual adjustments for the company[34]	+/- individual adjustments for the company[34]
= Calculated TOTEX – input	**= Standardised TOTEX – input**

Figure 3: Definition of input derived through the calculation method and through standardisation

For each method (MOLS and DEA), an individual efficiency value is determined using the calculated TOTEX and the standardised TOTEX. After appropriately weighting the methods, the better of the two scores resulting from the calculated and the standardised input definitions is used (refer to chapter 6.7).

6.2.2. Variable selection: output parameters (structural and performance variables)

Efficiency analyses must encompass performance and structural 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 for the available sample size should be used. In addition, they must have a cost-driving effect and should consist of available data where possible.

In the efficiency analysis in 2005, a two-step process was used for selecting the output parameters:

- Approach based on engineering science (engineering economic analysis, with model network lengths);
- Significance analysis for assessing the relevance of additional parameters.

The major reason for the use of model network lengths instead of real line lengths is the general requirement for output parameters that they should not be within the system operator's control. Against this backdrop, the authority considers the use of real line lengths inappropriate and has often pointed out the issue of "wrong incentives" in the dynamic context (ongoing benchmarking). If we were to use real line lengths, there would be an

[34] This includes adjustments for smart metering and for the use of network level 3 for transmission; refer to chapter 6.2.1.1 for details.

inherent incentive to oversize existing grid structures and/or not to disassemble any lines – wrong incentives which can be avoided by applying exogenous factors, e.g. grid connections.

The engineering economic analysis examined which relevant cost drivers exist and which functional correlations exist between them. It revealed that no individual factor sufficiently explains the entire facility (lines, transformer substations). The cumulative load density (peak load per area) of all the downstream grid levels has a significant influence on the dimension of the transformer grid levels. The relationship between these variables is linear. The relation between the area load densities and the system peak load can be described as follows:

$$\frac{TSS_i}{A_i} = a \times \frac{PL_i}{A_i},$$

where TSS_i represents the number of transformer substations in area segment i, $A_i$the size of area segment i, PL_i the peak load in area segment i and a corresponding scale variable. As the size of the area segments (A_i) is cancelled on both sides, the relationship can be described as follows:

$$TSS_i = a \times PL_i.$$

The resulting relationship for all area segments can be described as follows:

$\sum_{i=1}^{n} TSS_i = \sum_{i=1}^{n} a \times PL_i = a \sum_{i=1}^{n} PL_i$ and consequently

$$TSS = a \times PL.$$

While the low-voltage peak load serves as an output for the dimensioning of transformer grid level 6, the dimensioning of level 4 is determined by the entire peak load of at medium and low voltage level. The network density (levels 7, 5 and 3) is influenced by the connection density in each case with the correlation being non-linear. In general, the corresponding model network length is derived from the area connection density:

$$\frac{l_i}{A_i} = \sqrt{\frac{GC_i}{A_i}},$$

where l_i represents the network length in area segment i, GC_i the number of grid connections in area segment i and A_i the size in area i. The above relationship can be described as

$$l_i = \sqrt{GC_i \times A_i}$$

and can be further simplified to

$$l = \sum_{i=1}^{n} l_i = \sum_{i=1}^{n} \sqrt{GC_i \times A_i}.$$

In contrast to peak load, the size of the area segments A_i is not cancelled in this formula and the line length l_i must therefore be calculated for each area segment. The model network length, which is aggregated across all area segments, includes all information about the area of supply and the connection density (“supply mandate”). The functional relationships shown were merged with real company data and model network lengths (transformed area weighted grid connection densities, taGCD) were determined for high, medium and low voltage (refer to the Explanatory Notes on the System Charges Order 2006).

For statistical and mathematical reasons (and in order to reflect differences in system installation costs), the performance of statistical significance tests and the MOLS analysis required the aggregation of $taGCD_{hv}$, $taGCD_{mv}$ and $taGCD_{lv}$ to obtain the overall connection density, $taGCD_{hmlv}$. (refer to chapter 6.1). The mathematical reason is the fact that the cost function for the regression is expressed in logarithmic form, but some firms do not have a $taGCD_{hv}$, and the logarithm of zero is undefined. The authors of the industry expert study (Consentec) noted that although this problem could be solved technically or mathematically in principle, the small samples caused by subdividing *taGCD* would reduce the precision of the results.

Basically, it is assumed that the principles for the 2005 analysis defined on the basis of the engineering economic analysis are still valid. This assumption was also confirmed by the industry experts (Consentec). Nonetheless, some adjustments are carried out with regard to model network lengths and the definition of peak load in comparison to the analysis carried out in 2005. The modifications are discussed in the following chapter.

Although extensive discussions were held on output parameters used in benchmarking (peak loads and model network length) among the industry representatives of OE, the industry experts Consentec and the authority over a period of two years, these were challenged by a number of statements on the second consultation paper. The corresponding comments as well as the authority’s considerations are explained after the following chapters.

6.2.2.1. $taGCD_{hv}$: high-voltage model network length

As a basis for the calculation of model network lengths, the iSPACE project was updated with the current data and the authority’s valid definitions.[35] Similarly to the specifications of the analysis in 2005, the high-voltage network connections at municipality level are not disaggregated.

$$taGCD_{hv,i} = \sqrt{N_{GC,hv,i} \cdot \sum_{\forall j} \left(A_{CT,iSPACE,i,j}\right)}$$

where

$N_{GC,hv,i}$ = number of high voltage connections to *i* company’s network

$A_{CT,iSPACE,i,j}$ = iSPACE area of *i* company’s census tract *j*

[35] The analyses of iSPACE Studio for the benchmarking carried out in 2005 were conducted on behalf of industry representatives.

However, modifications are made with regard to the relevant area. In addition to iSPACE areas (of category A)[36] of the respective company, the downstream system operators' areas are added to the ones of upstream system operators, provided that the following condition is fulfilled:

- o The downstream system operator does not operate a high voltage network (yes/no criterion for high voltage lines).

Areas of downstream electricity distribution system operators – provided they do not operate high voltage systems – are included because the upstream system operator's high voltage network must be dimensioned for these areas. However, where downstream electricity distribution system operators operate their own high voltage network, dimensioning on the part of the upstream electricity distribution system operator is not needed.

6.2.2.2. $taGCD_{mv}$: medium-voltage model network length

Generally, the specification of the transformed connection density at the medium voltage level ($taGCD_{mv}$) remains unchanged compared to the previous benchmarking. In contrast to the calculation of the high-voltage model network length, the medium-voltage model network length is determined first at area segment (municipality) level before being aggregated.

$$taGCD_{mv,i} = \sum_{\forall k} \sqrt{N_{GC,mv,mun,k,i} \cdot \sum_{\forall j \cdot in \cdot muni \cdot k} \left(A_{CT,iSPACE,i,j}\right)}$$

where
$N_{GC,mv,mun,k,i}$ = number of medium voltage connections to *i* company's network in local authority area *k*
$A_{CT,iSPACE,i,j}$ = iSPACE area of *i* company's census tract *j*

As was done when including the downstream system operators' areas in the calculation of the upstream system operators' high-voltage model network length, the relevant area is also extended for the medium-voltage model network length, provided that the following condition is fulfilled:

- o The downstream system operator does not operate a medium voltage network (yes/no criterion for medium voltage systems).

Where the downstream system operator does not operate a medium voltage network, the relevant census tract areas (of category A) of other system operators in the respective municipality are merged into the upstream system operators' municipalities, provided that the latter have positive network connections within each municipality. The only non-

[36] Relevant reference areas of category A and B are discussed in the chapter on the calculation of $taGCD_{lv}$.

allocable census tract areas of downstream system operators are those that cannot be allocated to any municipalities of upstream system operators because they do not have any medium-voltage network connections in these municipalities.

In addition, a query was performed on medium voltage systems covering other system operators' census tracts and/or other system operators' shares of census tracts; in this context, the real medium-voltage line length within other system operators' census tracts and/or shares of census tracts had to be indicated. This issue particularly concerns electricity distribution system operators in strongly fragmented grid areas such as Tyrol, Upper Austria and Styria. In order to account for the significance of such medium voltage systems, the spanned census tracts of other system operators are allocated to the spanning electricity distribution system operators if

- o the extent of the spanning medium voltage system (real medium voltage system kilometres within other system operators' census tracts and/or share of census tracts) is larger than the radius of other system operators' share of census tracts; and
- o this area has not yet been taken into account by the inclusion of census tract areas of the downstream distribution system operator without a medium voltage network.

Thus, distinct instead of negligible secants are reflected. If this threshold value is exceeded in a certain census tract (extent of the spanning medium voltage system is larger than the radius), the census tract areas of other system operators are allocated to the upstream system operators' municipalities in which the upstream distribution system operator has positive medium-voltage network connections.

Taking into account these factors (allocable downstream census tract areas and census tract areas with spanned medium voltage systems), the calculated medium-voltage network length ($taGCD_{mv}$) is adapted to include the extent of the non-allocable downstream census tract areas and/or spanned census tract areas (double counting excluded) as follows:

$$taGCD_{mv;i\_adapted} = \sqrt{\frac{(areas_{own} + areas_{allocated\_spanned\_or\_downstream} + areas_{non\_allocable})}{areas_{own} + areas_{allocated\_spanned\_or\_downstream}}} * taGCD_{mv,i}$$

6.2.2.3. $taGCD_{lv}$: low-voltage model network length

Following the same procedures as those applied during the efficiency benchmark carried out in 2005 to determine the connection density at the low voltage level ($taGCD_{lv}$), the number of connections per municipality must be disaggregated to individual census tract level so that the model network length per area segment (in this case, per census tract) can be determined. Assuming that the number of connections is proportional to the number of buildings in the census tract, the disaggregation[37] is carried out as follows:

[37] In the course of the first efficiency benchmark performed in 2005, two disaggregation options were described. Firstly, one for companies that were able to indicate the number of low-voltage network connections per municipality and, secondly, one for those companies that only indicated the total number of low-voltage network connections across all municipalities. As data for the 2011 business year are available from all required companies per municipality, the second option is not applicable.

$$N_{GC,lv,CT,j,i} = \frac{N_{build,j} \cdot \frac{A_{CT,j,i}}{A_{CT,j}}}{\sum\limits_{\forall census.tract \cdot m \cdot in \cdot muni \cdot k} N_{build,m} \cdot \frac{A_{CT,m,i}}{A_{CT,m}}} \cdot N_{GC,lv,muni,k,i}$$

where

$N_{GC,lv,muni,k,i}$ = number of low voltage connections to *i* company's network in municipality *k*
$N_{build,j}$ = number of buildings in census tract *j*
$A_{CT,i}$ = area of census tract *j*
$A_{CT,j,i}$ = *i* company's share of the area of census tract *j*

Subsequently, the connection density at the low voltage level is calculated using the following formula:

$$taGCD_{lv,i} = \sum_{\forall j} \sqrt{N_{GC,lv,CT,j,i} \cdot A_{CT,relRA,j} \cdot \frac{A_{CT,j,i}}{A_{CT,j}}}$$

where

$N_{GC,lv,CT,j,i}$ = number of low voltage connections to *i* company's network in census tract *j*
$A_{CT,\ relRA,i}$ = relevant reference area for census tract *j*
$A_{CT,j}$ = area of census tract *j*
$A_{CT,j,i}$ = *i* company's share of the area of census tract *j*

In contrast to the procedure for determining medium-voltage and high-voltage network lengths, a criterion relating to the relevant area is used for calculating low-voltage model network lengths. The choice of reference areas depends on the settlement patterns in the relevant census tract. For the previous efficiency benchmark, iSPACE areas served as a basis for high and medium voltage, whereas low voltage was based on areas of Statistics Austria. Depending on the existence of "isolated buildings" within a certain census tract – as an indicator of the settlement pattern – either the area devoted to road transport, buildings and gardens ("VBG area") and/or the area of permanent settlement of the relevant census tract was used.

For reasons of consistency, iSPACE areas are used exclusively in the course of the efficiency comparison for the third regulatory period, even if the areas are defined differently depending on the settlement pattern and a decision criterion for the relevant area has to be applied to reflect the settlement pattern.

Relevant reference area and decision criterion to reflect the settlement pattern

Two reference areas (category A and B) are applied and weighted, which are defined as follows:

iSPACE area of category A

Weighting factor	Classification
100%	Settlement areas
100%	Agricultural areas excl. roads
100%	Forests excluding roads
100%	Roads above 1,800 metres
100%	Roads in other areas
100%	Roads in forests
100%	Roads in agricultural areas

iSPACE area of category B

Weighting factor	Classification
100%	Settlement areas

Figure 4: Area classification for the calculation of model network lengths

When determining the relevant areas, CORINE Land Cover data are used as basis and areas up to an altitude of 1,800 metres as well as an inclination of 25° are included (refer to Studio iSpace 2010). Tele Atlas data are used for determining the road corridors included. It should be noted that originally, OpenStreetMap data were used as a data basis; however, industry representatives supported the use of commercial databases. The authority is aware of the fact that depending on the specification, there may be deviations with regard to the classification of the areas. In terms of weighting individual area classifications, the authority's approach is non-discriminatory, i.e. supply areas characterised by agricultural use and woodland are treated equally.

The following condition relating to the settlement pattern is used to apply one of the two abovementioned reference areas (category A or B). The iSPACE area of category A serves as a basis if:

- The minimum settlement cluster within the census tract is ≤ 20,000 m^2; and
- The ratio between the maximum settlement cluster and the settlement area is ≤ 85%

Hence if a census tract is considered to have a dense settlement pattern, the broader area of category A is applied; if this is not the case, the smaller area of category B is applied. Some companies drew the authority's attention to the fact that some roads and/or areas that are of relevance were not taken into account and/or not classified. In this context, it needs to be borne in mind that there may be both positive and negative deviations due to the fact that areas without any networks may be included, while other areas might not be included. The differences are considered to be at least roughly balanced across the entire supply area of the individual electricity distribution system operators.

6.2.2.4. $taGCD_{hmlv}$: weighted model network length at high, medium and low voltage levels

In the analysis, a total $taGCD_{hmlv}$ (weighted model network length of high, medium and low voltage levels) is taken into account along with the separate model network lengths of high, medium and low voltage. When aggregating individual model network lengths to an overall combined parameter, they have to be weighted to reflect differences in network installation costs (cf. discussion in chapter 6.1 on the discriminatory capacity of the DEA method and methods of handling zero-output levels in MOLS). For the analysis carried out in 2005, the authority had proposed the following weighting factors for the aggregation: 235% (high voltage), 135% (medium voltage) and 100% (low voltage). At the same time it invited views on these weighting factors, and firm-specific factors were requested from the regulated companies.

An analysis of the responses yielded ranges (adjusted to accommodate for outliers) of 380–900% for the high voltage and 122–233% for the medium voltage level. Due to the implausible responses from some companies the authority decided to dispense with firm-specific weighting factors. Instead, it examined the possibility of assigning different weighting factors to urban (high voltage 730%; medium voltage 158%; low voltage 100%) and rural companies (high voltage 554%; medium voltage 165%; low voltage 100%). However, the calculations revealed no significant differences between the results yielded by standard or urban/rural weighting factors. Uniform weighting factors (high voltage 583%; medium voltage 166%; low voltage 100%) were therefore used for the efficiency analysis carried out in 2005.

For the present benchmark, the weighting factors had to be re-evaluated. Starting from costs specific to grid levels and based on average costs (cf. section 59(1) Electricity Act 2010), the following values were established: high voltage 373%, medium voltage 114%, low voltage 100%. When determining these values, the audited TOTEX specific to grid levels (incl. adjustments) of 49 cost-audited companies was used as a basis.

An internal survey carried out by OE revealed weighting factors which deviated significantly (i.e. they tended to be higher). According to industry representatives, the sample contained only some 12 companies and unaudited costs were used as the basis. In the course of the discussion, industry representatives argued that cost allocation to different grid levels was to be seen critical, especially in the case of companies operating only low grid levels, because their cost accounting was not sufficient. However, from the authority’s point of view, the opposite is true – distortions should be less significant in particular in companies which only operate one or two grid levels as a more distinct allocation is possible than for companies with a larger number of grid levels (this argument is particularly true for the allocation of operating costs).

Consequently, weighted model network lengths of high, medium and low voltage levels are specified on the basis of the following relation:

$$taGCD_{\text{hmlv},i} = taGCD_{\text{lv},i} + 1.14 \times taGCD_{\text{mv},i} + 3.73 \times taGCD_{\text{hv},i}\ .$$

6.2.2.5. Peak loads

Some adjustments are also made with regard to the definition of peak loads. The peak load is the parameter which has a significant influence on the dimensioning of the downstream transformer levels; this is due to the fact that in general, the grid must be dimensioned for the highest occurring load. The analysis carried out in 2005 already showed that the peak load has a pronounced cost-driving effect and strongly influences efficiency scores. In order to minimise both the effect of random variations and the possibility of being influenced by the electricity distribution system operator, the following benchmarking approach is applied for the specification of peak loads: as a basis, companies were asked for data on their quarter-hourly loads (taking into account refeed as well as supplies to withdrawers and distributors on the relevant grid level) for the 2010, 2011 and 2012 business years.[38]

For grid levels 3-7, two variants were calculated – for the first variant the refeed was netted (peak load 3-7 “netted”), for the second variant the refeed was not subtracted (peak load 3-7 “plus refeed”). The “plus refeed” category implicitly takes into account injected volumes because large volumes of energy refed into upstream grid levels may increase the network load (depending on the ratio of the volume withdrawn and the volume generated). This peak load variant minimises the dimension of the analysis as no separate parameters are required to accommodate injected volumes.

Furthermore, peak loads of levels 4-7 and levels 6-7 were determined for the three years mentioned. In each case the four highest quarter-hourly values (i.e. only one hour in total) were removed. The fifth highest value of the time series thus constitutes the maximum value and hence the corresponding peak load for the respective year. Initially, the authority had considered to determine the maximum for the years 2010-2012 in a next step.

In the course of the discussion with industry representatives, the industry experts (Consentec) argued that for reasons of cost-base consistency, 2012 should not be included. The authority accepted this objection and calculates the maximum of 2010 and 2011. It is examined in detail whether relevant changes to be considered have occurred between the years (e.g. relevant changes to the customer base, changes in company structure, etc.). If a certain annual value is not available for a company (because it has not been submitted), the available data basis will be used. The peak load relevant for benchmarking therefore results from the following steps:

- Determining the fifth highest value of 2010 and 2011;

[38] For companies with a balance sheet date other than 31 December, the period examined was also a full calendar year, in order to reflect the seasonal specifics of all four seasons.

- Calculating the maximum of 2010 and 2011.

This way random fluctuations of peak load are balanced over the years and the influence of the electricity distribution system operator is minimised.

6.2.2.6. Outputs based on engineering science considerations

Based on the considerations relating to engineering science, which were mentioned in the previous chapter, the following parameters are of particular relevance for carrying out the efficiency benchmark:

- High, medium and low voltage model network lengths and their weighted aggregation as well as the
- peak load of levels 4-7 and 6-7.

These parameters form the basis for a basic model for subsequent statistical analysis of further output candidates. Starting from the weighted model network length, which continues to be considered relevant, and calculated peak loads, we examine whether further significant cost drivers should be taken into consideration; this examination is carried out using a forward regression approach (on the basis of a log-linear Cobb-Douglas cost function in CRS specification).

Further and/or alternative output parameters are included in the model if:

- the cost driver is significant; and
- the explanatory value of the estimate is increased by adding the parameter and the cost-driving effect has not been covered by the factors available in the model (verification by means of R^2 of the regression and information criteria such as AIC and Schwarz).

6.2.2.7. Statistical and conceptual analysis of further output candidates

Another analysis seems to be necessary to find out to what extent the changes to the supply mandate of companies since the previous benchmarking are relevant (cost-driving effect) and should be taken into account. On the basis of long-term investigations, relevant factors were established to be the introduction of smart metering as well as the decentralised feed-in of electricity (see below).

With regard to smart metering, a regression taking into account the number of smart meters would not be very useful because up to now only a small number of companies have started with the roll-out and therefore no cost-driving effects are to be expected. It should be pointed out however that a roll-out influences the comparability of companies (refer to the discussion in chapter 6.2.1 on the specification of the input basis). The annual survey carried out by the authority revealed that the degree to which smart meters have been introduced greatly varies among electricity distribution system operators – while a small number of companies have installed a considerable number of smart meters, other companies (the majority of electricity distribution system operators) have not yet started their roll-out. Consequently, the cost bases – both in terms of OPEX and CAPEX – are skewed by the new metering technology and the companies are not comparable. While the effects on capital expenditure are relatively clear – depending on capitalisation policies, the new metering technology generally leads to higher book values and therefore higher capital expenditure – effects on operating expenditure are not clear. In this context, factors increasing costs (e.g. replacement of the metering equipment) are levelled off by cost-reducing effects (no meter readings required).

If relevant cost effects cause comparability issues, corrections may be made both in terms of input and output. In order to avoid detrimental effects for the companies because certain effects are not taken into account, additional output parameters may be used. However, depending on the sample size, this might reduce the discriminatory capacity of the analysis. As an alternative, the cost base may be adjusted to accommodate for the effect. However, this requires that the relevant costs can be delineated clearly and evaluated accordingly.

In order to ensure comparability of the companies, the authority consequently considers it appropriate to adjust the total expenditure to include costs already incurred by smart metering. The companies concerned calculate to what extent both CAPEX and OPEX were influenced by the introduction of smart metering. For determining the effect, the actual cost level was compared with a hypothetical cost level without smart meter costs. Hypothetical costs without smart meters were calculated by including, for example, the costs of the installation of Ferraris meters and taking into account previous calibration and replacement cycles, OPEX effects, etc. The resulting difference is then subtracted from the benchmarking cost base.

In recent years, the number of decentralised generation facilities has increased. This applies in particular to photovoltaics and wind energy. In general, all electricity distribution system operators are affected by this development, albeit to a varying extent. Recent discussions addressed the special situation of two electricity distribution system operators in the eastern part of Austria. Due to a lack of any suitable output variable to model the wind energy fed into the grid, the cost side was adjusted because the related cost burden can be clearly delineated from other costs (refer to discussion in chapter 6.2.1 regarding the specification of the input base).

On the basis of the discussions on useful output parameters outlined above, the basic models for the further analysis of cost drivers (and the MOLS benchmarking method) are as follows depending on how expenditure parameters are taken into account (calculated TOTEX and standardised TOTEX):

The cost function which is applied in the modified ordinary least squares method can be expressed in formal terms as shown below, with K representing the costs (TOTEX) and Y representing output parameters:

$$\ln C = \beta_0 + \beta_1 \cdot \ln Y_1 + ... + \beta_n \cdot \ln Y_n + \varepsilon$$

Some companies have a value of zero for certain output parameters (e.g. high-voltage model network length); however, as the logarithm of zero is not defined, high, medium and low voltage model network lengths are aggregated into one output parameter, taking into account system-level specific weighting factors (cf. chapter 6.2.2.4).

The basis for calculating the cost-driver analysis (and the MOLS efficiency scores) is a log-linear cost function:

$$\ln C = \beta_0 + \beta_1 \cdot \ln taGCD_{wgh} + \beta_2 \cdot \ln PL_{NL\,6-7} + \beta_3 \cdot \ln PL_{NL\,4-7} + \varepsilon$$

(Equation 1)

where
C[39] = calculated and/or standardised TOTEX incl. grid losses
$taGCD_{wgh}$ = transformed weighted connection density (weighted model network lengths)
PL_{NL6-7} = peak load at grid levels 6 to 7
PL_{NL4-7} = peak load at grid levels 4 to 7

In the DEA method, the specification of constant returns to scale results from the regulatory policy decision that company size should not have any influence on the efficiency of a company. In order to ensure that DEA is comparable to MOLS efficiency scores, the company size must not have any influence on efficiency scores in the MOLS specification either; otherwise, differences between efficiency scores could be contingent on the company size.

For this purpose, the restriction of constant returns to scale is included in the cost function. This can be expressed in the following formula:

$$\beta_1 + \beta_2 + \beta_3 = 1$$

The admissibility of this restriction can be verified statistically by means of a Wald test. The restriction is fulfilled at a significance level of 95% for both specifications of expenditure parameters (input either standardised TOTEX or non-standardised, i.e. calculated TOTEX) for the company sample taken into consideration:

Wald test:
Equation: CD_calculated_FULL
Input: calculated TOTEX

Test statistic	Value	df	Probability
t-statistic	1.045514	34	0.3032
F-statistic	1.093099	(1, 34)	0.3032
Chi-square	1.093099	1	0.2958

Null hypothesis: C(1)+C(2)+C(3)=1

Wald test:
Equation: CD_standardised_FULL
Input: standardised TOTEX

Test statistic	Value	df	Probability
t-statistic	0.968507	34	0.3396
F-statistic	0.938007	(1, 34)	0.3396
Chi-square	0.938007	1	0.3328

Null hypothesis: C(1)+C(2)+C(3)=1

[39] according to Figure 3 in chapter 7.2.1.

Null hypothesis summary:			Null hypothesis summary:		
Normalised restriction (= 0)	Value	Std. Err.	Normalised restriction (= 0)	Value	Std. Err.
-1 + C(1) + C(2) + C(3)	0.016944	0.016207	-1 + C(1) + C(2) + C(3)	0.016195	0.016721

Figure 5: Wald test for verifying the restriction for constant returns to scale

As a next step, the cost-driver analysis is determined under the restriction of constant returns to scale. For this purpose, equation 1 needs to be transformed into:

$$\ln C - \ln PL_{NL\,4-7} = \beta_0 + \beta_1 \cdot (\ln taGCD_{wgh} - \ln PL_{NL\,4-7}) + \beta_2 \cdot (\ln PL_{NL\,6-7} - \ln PL_{NL\,4-7})$$
$$+ (\beta_1 + \beta_2 + \beta_3 - 1) \cdot \ln PL_{NL\,4-7} + \varepsilon$$

(Equation 2)

If the returns to scale are constant, ($\beta_1+\beta_2+\beta_3-1=0$) applies; thus, equation 2 is reduced to

$$\ln C - \ln PL_{NL\,4-7} = \beta_0 + \beta_1 \cdot (\ln taGCD_{wgh} - \ln PL_{NL\,4-7}) + \beta_2 \cdot (\ln PL_{NL\,6-7} - \ln PL_{NL\,4-7}) + \varepsilon$$

(Equation 3)

Consequently, equation 3 defines the basic model for the cost-driver analysis, which – after adding further parameters – is used for testing whether additional outputs should be added to the basic model.

On the basis of this model specification, all previously mentioned variables of the basic model are significant at a significance level of 95% and VIF values (variance inflation factors, as a measure for the abovementioned multicollinearity) are well below the value of 10, which is considered to be critical (in practice).

Dependent variable: LOG(TOTEX_calculated_INCL/PL_47)
Method: Least squares
Sample: 1 38
Included observations: 38

Variable	Coefficient	Std. error	t-statistic	Prob.
LOG(PL_67/PL_47)	0.540721	0.095859	5.640818	0.0000
LOG(taGCDhmlv/PL_47)	0.159913	0.039633	4.034863	0.0003
C	4.793982	0.140668	34.08017	0.0000

R-squared	0.643667	Mean dependent var	5.147388
Adjusted R-squared	0.623305	S.D. dependent var	0.257232
S.E. of regression	0.157877	Akaike info criterion	(-0.778343 EUR - 3,330K)
Sum squared resid	0.872381	Schwarz criterion	-0.649060
Log likelihood	17.78852	Hannan-Quinn criter.	-0.732345
F-statistic	31.61141	Durbin-Watson stat	1.456245
Prob(F-statistic)	0.000000		

Dependent variable: LOG(TOTEX_standardised_INCL/PL_47)
Method: Least squares
Sample: 1 38
Included observations: 38

Variable	Coefficient	Std. error	t-statistic	Prob.
LOG(PL_67/PL_47)	0.630089	0.098682	6.385018	0.0000
LOG(taGCDhmlv /PL_47)	0.139593	0.040800	3.421368	0.0016
C	4.878648	0.144811	33.68965	0.0000

R-squared	0.658208	Mean dependent var	5.139209
Adjusted R-squared	0.638677	S.D. dependent var	0.270383
S.E. of regression	0.162528	Akaike info criterion	-0.720279
Sum squared resid	0.924534	Schwarz criterion	-0.590996
Log likelihood	16.68531	Hannan-Quinn criter.	-0.674281
F-statistic	33.70067	Durbin-Watson stat	1.736470
Prob(F-statistic)	0.000000		

Figure 6: Results of the estimates for the basic model (calculated and standardised TOTEX)

On the basis of the two basic models outlined above (with calculated and standardised TOTEX), we examined to what extent the following potential factors have a significant cost-driving effect:

- Injection capacity of (all) generation facilities (levels 3-7)
- Injected volumes of (all) generation facilities (levels 3-7)
- (Total) number of generation facilities (levels 3-7)
- Injection capacity of (all) wind power plants (levels 3-7)
- Injected volumes of (all) wind power plants (levels 3-7)
- Number of wind power plants (levels 3-7)
- Injection capacity of photovoltaic plants (levels 3-7)
- Injected volumes of photovoltaic plants (levels 3-7)
- Number of photovoltaic plants (levels 3-7)

The analysis shows that at a significance level of 95%, none of these parameters needs to be included in the model as an additional explanatory variable.

In addition, alternative specifications were tested for the peak load of levels 4 to 7:

- Peak load levels 3-7 “netted”
- Peak load of system levels 3-7 “plus refeed”

These alternative specifications (“netted” and/or “plus refeed”) are used to reflect distributed energy generation, especially volumes fed in at network levels 3 to 5, which may be refed from the distribution system into the upstream transmission system (refer to the explanations in chapter 6.2.2.5). The decision about the suitability of the basic specification (peak load 4-7) compared to its alternatives is made by applying information criteria (Akaike and Schwarz). As the information criteria are sensitive to differing levels of the dependent variable (TOTEX), the verification is made without normalisation, i.e. in a log-linear VRS specification. The analysis shows that for both criteria (whereas lower values are considered more advantageous) the original use of peak loads 4-7 is preferable.[40]

		calculated TOTEX	standardised TOTEX
Peak load 4-7	Akaike info criterion	-0.757355	-0.694862
	Schwarz criterion	-0.584978	-0.522485
Peak load 3-7 "netted"	Akaike info criterion	-0.743887	-0.680143
	Schwarz criterion	-0.571509	-0.507766
Peak load 3-7 "plus refeed"	Akaike info criterion	-0.678344	-0.632737
	Schwarz criterion	-0.505967	-0.460360

Figure 7: Model quality using alternative peak load specifications

On the basis of the analyses performed, no evidence could be provided of a cost-driving effect of the output candidates considered. As in the analysis performed back in 2005, the model network lengths and the cumulative peak loads are therefore considered as the relevant cost drivers.

6.3. Calculation of efficiency scores - MOLS

On the basis of the explanations given above, the model specification for determining the efficiency scores using MOLS can be described as follows:

- Form of the function – log-linear
- Specification of returns to scale – constant returns to scale
- Inputs – calculated and standardised total expenditure;
- Outputs
  - Transformed area weighted connection densities (model network lengths)
  - Peak load levels 4-7
  - Peak load levels 6-7
- Distribution assumption of inefficiencies – half-normal distribution

[40] Please note that the figures are negative values.

The MOLS analysis is performed with equation 3 (refer to previous chapter) and the error term transformation (calculation of efficiency scores) is performed according to the formula described in chapter 6.1 (MOLS).

6.4. Calculation of efficiency scores - DEA

In principle, there is no mathematical need for weighting transformed connection densities (model network lengths) in DEA since this benchmarking method can - in contrast to MOLS - easily handle zero-output levels. Moreover, the major advantage of DEA is that through the data themselves, individual weightings are determined for individual output parameters for each company and efficiency scores are calculated on the basis of these weightings.

Nevertheless, the weight of individual output factors may have to be restricted in certain cases since the discriminatory capacity of DEA decreases with an increasing number of parameters and, in addition, specific input and output dimensions may be unique. Certain input/output relations distort the efficiency scores, which has to be avoided by all means. The issue of uniqueness can be mitigated either by weighting the input/output contributions or by aggregating multiple parameters into one output variable. In both variants, the influence of an input/output relation on the efficiency of a company is restricted.

In the course of the discussions on the design of the benchmarking model, the industry experts (Consentec) argued against restricting input/output contributions because:

- According to engineering logic, all outputs are equally important in this case; this is why a restriction (such as in case of the gas distribution system operator benchmarking carried out in 2008[41] and in the international TSO benchmarking study (e3grid2012[42]) completed in 2013) should not be carried out; and
- The "issue" referred to above had to be seen as inherent to DEA and would therefore also arise if only a single output was used.

It has to be mentioned in response to the above that the second objection is certainly correct; yet the discriminatory capacity of a DEA specification decreases with the number of outputs used. Contrary to the view provided by the industry experts (Consentec), the first objection, however, can be interpreted as an argument in favour of restriction (which may ultimately even result in equal output weightings); the equal importance of outputs vis-a-vis each other can hardly be interpreted as advocating that there might be cases where a company's efficiency is determined by a single output. For instance, this would mean that a company could reach an efficiency score of 100% on the basis of the high-voltage model network length alone, regardless of what the model network length is at other grid levels

[41] Refer to Explanatory Notes on the Gas System Charges Ordinance 2008.

[42] Frontier Economics, Consentec, Sumicsid, 2013, p. 43.

and/or how transformer levels are dimensioned. In the authority's point of view, this approach is by no means appropriate.[43]

Similar discussions took place in the benchmarking of the first regulatory period and DEA was consequently carried out in two different specifications (firstly, with three separate model network lengths and the peak loads of levels 4-7 and 6-7, i.e. 5 outputs, and secondly, with the weighted model network length and two peak loads of levels 4-7 and 6-7) in order to increase the discriminatory capacity on the one hand and to ensure retaining the major benefit of DEA on the other. The authority continues to consider this approach appropriate and therefore defines two DEA models: the first one is specified by the weighted model network length and the second one with separate model network lengths of high, medium and low voltage.

The *specification of DEA 3* is as follows:

- Input oriented analysis;
- Specification of returns to scale – constant returns to scale;
- Inputs – calculated and standardised total expenditure;
- Outputs:
  - Transformed area weighted connection density of low, medium and high voltage (weighted model network lengths of low voltage, medium voltage and high voltage), $taGCD_{hmlv}$
  - Peak load levels 4-7
  - Peak load levels 6-7

The *specification of DEA 5* is as follows:

- Input oriented analysis;
- Specification of returns to scale – constant returns to scale;
- Inputs – calculated and standardised total expenditure;
- Outputs:
  - Transformed connection density of low voltage (low voltage model network length), $taGCD_{lv}$
  - Transformed connection density of medium voltage (medium voltage model network length), $taGCD_{mv}$

[43] It should be noted that Consentec participated in the e3grid2012 project, in which input/output contributions were restricted for DEA. Restrictions were also applied in the gas distribution system operator benchmarking.

- Transformed connection density of high voltage (high voltage model network length), $taGCD_{hv}$
- Peak load levels 4-7
- Peak load levels 6-7

Within the scope of the MOLS procedure – as already indicated above – the weighted model network length is used to avoid “zero-output” levels just as in DEA 3. The figure below provides an overview of the specification of the benchmarking models used:

	MOLS		DEA 3		DEA 5	
Specification	**log-linear CRS**		**CRS**		**CRS**	
Input	TOTEX calculated	TOTEX standardised	TOTEX calculated	TOTEX standardised	TOTEX calculated	TOTEX standardised
Outputs	Peak load 4-7	Peak load 4-7	Peak load 4-7	Peak load 4-7	Peak load 4-7	Peak load 4-7
	Peak load 6-7	Peak load 6-7	Peak load 6-7	Peak load 6-7	Peak load 6-7	Peak load 6-7
	$taGCD_{hmlv}$	$taGCD_{hmlv}$	$taGCD_{hmlv}$	$taGCD_{hmlv}$	$taGCD_{hv}$	$taGCD_{hv}$
					$taGCD_{mv}$	$taGCD_{mv}$
					$taGCD_{lv}$	$taGCD_{lv}$

Figure 8: Summary of benchmarking methods used

A total of six different efficiency scores are calculated per company. The calculation of the final company-specific efficiency score is presented in more detail in chapter 7.2.7.

6.5. Analyses of outliers

The general aim of analyses of outliers is to exclude system operators having a strong influence on the majority of the other system operators from the calculation of efficiency scores. In the classification of outliers, a distinction between the methods used (DEA and MOLS) must be made.

In parametric methods (MOLS), a company is considered an outlier if it is capable of influencing the calculated regression line to a considerable extent. Within this regression procedure, the influenceability is independent of the efficiency of the outlier. Accordingly, it is possible that distribution system operators with below average efficiency constitute “influential data points” and distort the estimated regression line in “their” direction. Therefore, statistical tests aim at generally identifying “influential data points”. Besides DFBETAS, leverage plots, studentised residuals, DFFITS, dropped residuals, covariance ratios and Cook’s distance may be used; the latter has practical relevance and has been explicitly specified in Annex 3 of the *Anreizregulierungsverordnung* (*AregV,* the German Incentive Regulation Ordinance) as one of the methods for identifying outliers. Cook’s distance measures the effect of deleting a given observation when performing least squares regression analysis. Data points showing high absolute residuals and/or unusually high or low values in independent variables can distort the result of the regression; they can be identified through the measure of Cook’s distance. If Cook’s distance of a certain observation exceeds a previously defined threshold value, the companies concerned are treated as outliers and the analysis is continued without taking these companies into account. (4/n-k-1) serves as a basis for the threshold value, with n being the number of observations and k the number of parameters.

As the industry experts (Consentec) argue unequivocally for the use of Cook's distance, the analyses of outliers in parametric methods for measuring efficiency is performed using this method in order to ensure general acceptance.

In the non-parametric method for measuring efficiency (DEA), the concept of "super-efficiencies" is used for identifying outliers. It allows a quantification of the influence of extremely high efficiency scores (in this case, there is no restriction to 100 percent). By looking at the distribution of "super-efficiencies", conclusions can be drawn regarding possible outliers, which form the efficiency frontier and may result in it being set excessively far from the remaining companies. With regard to the analysis of super-efficiencies, 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 (ranges between the 75 and the 25 percent quantile) must be classified as outliers. An identical approach was suggested by the industry experts (Consentec) and is considered appropriate by the authority.

For each of the specified benchmarking models (MOLS, DEA 3 as well as DEA 5), analyses of outliers are carried out and outliers are eliminated from the underlying sample. This guarantees that these companies do not set the efficiency frontier for other companies in the corresponding model and that there are no detrimental effects for other companies in the relevant benchmarking sample.

On the basis of the procedure outlined above, the following overview of identified outliers can be provided, depending on the input specification and benchmarking model.

Calculated costs			
Benchmarking model	MOLS	DEA 3	DEA 5
Identification of outliers according to	Cook's distance	Distribution of super-efficiencies	Distribution of super-efficiencies
Critical threshold value	0.1176 =4/(38-3-1)	94.23% =Q(75%)+1.5x(Q(75%)-Q(25%))	130.58% =Q(75%)+1.5x(Q(75%)-Q(25%))
Number of outliers	1	3	4

Standardised costs			
Benchmarking model	MOLS	DEA 3	DEA 5
Identification of outliers according to	Cook's distance	Distribution of super-efficiencies	Distribution of super-efficiencies
Critical threshold value	0.1176	89.27 %	125.87 %

	=4/(38-3-1)	=Q(75%)+1.5x(Q(75%)-Q(25%))	=Q(75%)+1.5x(Q(75%)-Q(25%))
Number of outliers	3	4	3

Figure 9: Analyses of outliers according to input specification and benchmarking model

6.6. Documentation of results

Based on the explanations provided in the previous parts of this chapter, the distribution of efficiency scores is as shown below.

	MOLS		DEA 3		DEA 5	
Specification	log-linear CRS		CRS		CRS	
Input	TOTEX calculated	TOTEX standardised	TOTEX calculated	TOTEX standardised	TOTEX calculated	TOTEX standardised
Outputs	Peak load 4-7	Peak load 4-7	Peak load 4-7	Peak load 4-7	Peak load 4-7	Peak load 4-7
	Peak load 6-7	Peak load 6-7	Peak load 6-7	Peak load 6-7	Peak load 6-7	Peak load 6-7
	$taGCD_{hmlv}$	$taGCD_{hmlv}$	$taGCD_{hmlv}$	$taGCD_{hmlv}$	$taGCD_{hv}$	$taGCD_{hv}$
					$taGCD_{mv}$	$taGCD_{mv}$
					$taGCD_{lv}$	$taGCD_{lv}$
Average efficiency score	89.44%	88.85%	85.80%	90.28%	89.26%	82.48%
Minimal efficiency score	69.03%	74.23%	62.83%	70.14%	63.07%	54.05%
Number of 100% efficient companies (incl. Outliers)	6	9	6	9	13	10

Figure 10: Overview of the preliminary distribution of efficiency scores by model

Please note that both the industry experts (Consentec) and Frontier Economics confirmed the correctness of the calculations on the basis of the methodology outlined above[44].

6.7. Calculation of the final (weighted) efficiency score - Xind

As already indicated above, the two benchmarking methods MOLS and DEA are performed using two different input specifications regarding calculated and standardised capital expenditure (s. chapters 6.2.1 and/or 6.4) and three or five outputs are used within the scope of DEA (s. chapters 6.2.2 and 6.4). This way the input specification is designed to include a "standardised" approach in addition to the "calculation" approach applied up to now with regard to capital expenditure. Due to the fact that the "basis of costs within the company's control" (based on accounting data), i.e. the costs impacted by a company's individual target, may differ strongly from the cost base used in benchmarking, the better (maximum) weighted (between the efficiency results of the two DEAs and the MOLS) efficiency score is used – taking into account the CAPEX with and without standardisation – for determining these company-specific targets. After appropriately weighting the results of the methods, the better of the two results from the calculation approach and the standardised approach is taken. Using the better value ensures that the benchmarking score of a company can only improve but not deteriorate if standardised capital expenditure is taken into account also. However, it is important to note that scores are calculated with both methods using calculated and standardised CAPEX data; for determining the target, the better score (better from the company's perspective) is used (after appropriate weighting of the methods). However, this should not prejudice the approach in subsequent regulatory

[44] Refer to Frontier Economics, 2013c.

periods, as the calculation of efficiency scores could also be based on standardised costs only (s. the Explanatory Notes on the Gas System Charges Ordinance 2008).

In terms of weighting the individual methods for determining the final target, the authority suggested in the second consultation paper that the MOLS be weighted at 45 percent, DEA 3 at 15 percent and DEA 5 at 40 percent. The decision on the weighting was based on some basic considerations: the scores[45] used for the first regulatory period had to be taken into account; the methods should be weighted as equally as possible, i.e. MOLS on the one hand and DEA 3 and DEA 5 on the other should be given equal weighting in order to do justice to the advantages and disadvantages that are specific to the methods. In the course of the consultation process, no substantiated objections were raised against the weighting proposal. Therefore, the authority sticks to the weighting outlined above; for more details, refer to the following example:

Calculation of the final efficiency score				
Input specification *(Weighting factor)*	**MOLS** *(45%)*	**DEA 5** *(40%)*	**DEA 3** *(15%)*	**Weighted efficiency score** *(0.45*MOLS + 0.40*DEA 5 + 0.15*DEA 3)*
Not including standardised CAPEX	95%	94%	92%	= 0.45*0.95 + 0.40*0.94 + 0.15*0.92 = **0.94**
Including standardised CAPEX	97%	90%	91%	= 0.45*0.97 + 0.4*0.90 + 0.15*0.91 = **0.93**
Better value	=max(0.45*0.95 + 0.40*0.94 + 0.15*0.92; 0.45*0.97 + 0.4*0.90 + 0.15*0.91) = **0.94**			

Figure 11: Calculation of the final efficiency score

[45] MOLS 40 percent, DEA 3 40 percent, DEA 5 20 percent - refer to the slightly different specification of DEA variants; also refer to the Explanatory Notes on the System Charges Ordiannce 2006*,* p. 57 et seq. for more details.

The following final distribution of efficiency scores arises based on the abovementioned weightings and the better of the two weighted partial results of the calculated and standardised approach:

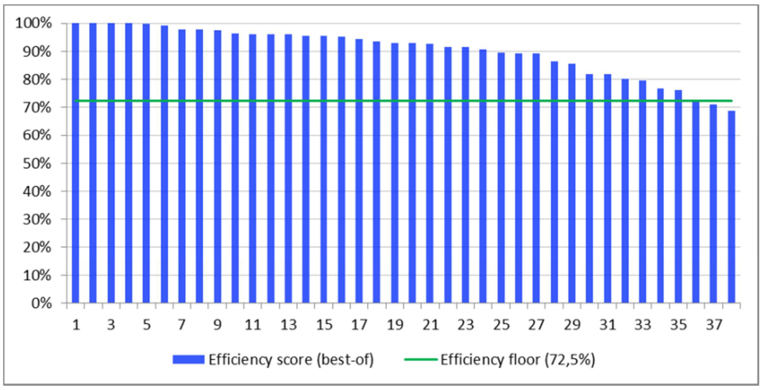

Figure 12: Distribution of final efficiency scores

7. Efficiency targets during the regulatory period – determining the cost adjustment factor

As previously, the cost adjustment factor (CA) comprises both the general efficiency target (Xgen) and the efficiency target for the individual company (Xind) (s. the Explanatory Notes on the System Charges Ordinance 2006). As in the first two regulatory periods, the efficiency scores are directly transformed into annual targets, with linear adjustment over a certain period of time. In principle, the period (which determines the maximum annual individual target) is to be specified on the basis of the benchmarking analysis performed and consideration of the incentive regulation targets (productive efficiency versus allocative inefficiency). At the beginning of the first incentive regulatory period, the annual efficiency-increase potential for the individual companies was set at 3.5 percent p.a. over a period of 8 years, which constituted a minimum efficiency of 74.76 percent. A new efficiency benchmark was carried out in order to determine the corresponding efficiency targets for the third regulatory period. Any inefficiencies identified do not necessarily have to be eliminated within one regulatory period; rather, realistic cost-reduction potential should be estimated. In order to ensure system stability, a minimum efficiency level has to be determined and an appropriate period of time has to be specified during which the targets can be achieved. Irrespective of the distribution of inefficiencies over a certain period, a new relative efficiency benchmarking has to be performed before the onset of the next regulatory period; thus, depending on the score of the respective company in the benchmark, individual efficiency targets may be modified, resulting in an updated assessment of cost reduction potentials. The period for the distribution of inefficiencies, the minimum efficiency level and the duration of the following regulatory period have to be defined for each regulatory period.

Based on the considerations above, the minimum efficiency for the third regulatory period is reduced to 72.5 percent and the annual maximum rate of efficiency increase is set at 3.165 percent – this corresponds to an elimination of inefficiencies over a period of 10 years. This means that the maximum annual cost adjustment factor is 4.375 percent. In accordance with the approach adopted in the first two regulatory periods, the cost adjustment factor is calculated in two steps (determination of the target cost level as of the end of 2018 and calculation of the cost adjustment factor):

$$C_{2023} = C_{2013} \cdot (1 - CA)^{10}$$

$$CA = 1 - \sqrt[10]{\frac{C_{2023}}{C_{2013}}} = 1 - \sqrt[10]{\frac{C_{2013} \cdot (1 - Xgen)^{10} \cdot ES_{2013}}{C_{2013}}} = 1 - (1 - Xgen) \cdot \sqrt[10]{ES_{2013}}$$

The annual cost adjustment factor will remain unchanged over the entire third regulatory period. For subsequent periods, an entirely new regulatory system will be established; therefore, the efficiency scores of the third regulatory period do not prejudice the future treatment of electricity distribution system operators. For an efficient company, the Xgen factor corresponds to the cost adjustment factor. Consequently, there is a linear relationship between the efficiency scores and the corresponding cost adjustment factors as follows:

Efficiency score	Cost adjustment factor
72.5%	4.375%
75%	4.050%
80%	3.429%
85%	2.842%
90%	2.285%
95%	1.755%
100%	1.250%

Figure 13: Correlation between cost adjustment factor and efficiency score

8. Network operator price index (NPI)

In order to comply with the principle of cost orientation, it is necessary to adjust the costs in the course of the regulatory period using an inflation factor. This way exogenous cost increases (i.e. costs increases beyond the company's control) are accommodated.

Section 59(5) Electricity Act 2010 stipulates that the system operator inflation rate has to be derived from a system operator price index combining public indices that reflect the system operators' average cost structure.

The cost increases of system operators were hitherto accounted for by the change in the network operator price index (ΔNPI), which comprises the following indices (based on average costs of the sector):

- *Index of collectively agreed wages and salaries* (general index), WSI, which is compiled and published by Statistics Austria. The change in this index serves as an approximation of average changes in personnel costs (weighting: 40 percent).
- *Construction price index* (overall), ConPI, which is compiled and published by Statistics Austria. The change in this index serves as an approximation of average changes in capital expenditure in the construction sector (weighting: 30 percent).
- *Consumer price index,* CPI, published by Statistics Austria. The change in CPI serves as an approximation of average changes in other costs (weighting: 30 percent).

The principle of modelling exogenous cost increases during a regulatory period by means of an NPI is retained.

As the investment factor covers the development of capital expenditure during one regulatory period directly and immediately, there is no need for the construction price index (for modelling price increases in terms of CAPEX) anymore. The relationship between WSI and CPI (i.e. personnel costs to other expenditure) is still appropriate; however, in the absence of the ConPI, the weighting of public indices must be scaled accordingly.[46]

Consequently, the following NPI results for the third regulatory period:

- *WSI* with a weighting of 57 percent (= 40 × 100/70),
- *CPI* with a weighting of 43 percent (= 30 × 100/70),

As an alternative to applying the general index of collectively agreed wages and salaries, personnel cost increases could also be integrated on the basis of collective bargaining results. According to section 59(5) Electricity Act 2010*,* however, an appropriate sub-index would first have to be generated and published for this purpose. Moreover, in the authority's view, the collective agreement for employees of electricity suppliers *(Kollektivvertrag für Angestellte der Elektrizitätsversorgungsunternehmungen Österreichs, EVU-Kollektivvertrag)* is not representative of the average cost structure of electricity

[46] This largely corresponds to the projection of costs for the second regulatory period (refer to the Explanatory Notes on the System Charges Ordinance 2010).

distribution system operators as required by section 59(5) Electricity Act 2010 for a great number of system operators because electricity distribution system operators:

- are subject to various collective agreements (depending on occupational group – blue-collar workers, white-collar workers, civil servants) and
- at least some of them purchase a significant share of network services from third parties.

Therefore, company-specific circumstances would have to be taken into account and consequently, company-specific indices of collectively agreed wages and salaries would have to be generated, which would presumably tend towards a general index of collectively agreed wages and salaries. The authority in any case rejects the approach of exclusively focusing on one of the collective agreements (e.g. collective agreement for employees of electricity suppliers), as the corresponding figures neither represent average costs nor do they reflect the actual circumstances of the individual electricity distribution system operators; also, this approach does not comply with the requirements of section 59(5) Electricity Act 2010. As a consequence, using average costs on the basis of the index of collectively agreed wages and salaries is considered appropriate by the authority.

For calculating the annual change rate ΔNPI_t, the most recent figures are used and, as in the approach taken during the first two regulatory periods, forecasts do not serve as a basis. Both the index of collectively agreed wages and salaries (WSI) and the consumer price index (CPI) are published monthly, with the final values of the CPI being available with a delay of approximately 1.5 months and the index of collectively agreed wages and salaries with a delay of 3.5 months if the preliminary data are revised. In order to ensure that the ΔNPI_t is determined in due time for the corresponding tarification procedure, values up to December of the preceding calendar year may be considered, taking into account the underlying time restrictions (in particular in terms of the WSI).

The calculation of the two individual indices can hence be expressed in formal terms as follows:[47]

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

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

The two indices are combined in line the weighting outlined above:

[47] Exemplary description of tariffs for 2014:

$$\Delta CPI_{2014} = \frac{CPI_{01.2012} + \ldots + CPI_{12.2012}}{CPI_{01.2011} + \ldots + CPI_{12.2011}} - 1$$

$$\Delta WSI_{2014} = \frac{WSI_{01.2012} + \ldots + WSI_{12.2012}}{WSI_{01.2011} + \ldots + WSI_{12.2011}} - 1$$

$$\Delta NPI_t = 0.57 \times \Delta WSI_t + 0.43 \times \Delta CPI_t$$

9. Weighted average cost of capital (WACC)

Section 60(1) Electricity Act 2010 stipulates that the cost of capital must comprise the reasonable cost of interest on debt and equity, taking capital market conditions into account. The cost of capital has been previously determined using the WACC approach, and this method is maintained for the third incentive regulation period as well.

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 (the Averch-Johnson effect), while too low a WACC entails the risk that necessary investments in the regulated infrastructure are not carried out. Ensuring appropriate networks in the long term and, related to that, the high quality of network services is a vital concern for E-Control.

For the second incentive regulatory period of the gas distribution systems, an expert study ("Regulatory System for the Second Regulatory Period: Gas", p. 29)[48] was used to determine the appropriate WACC before taxes (6.42 percent p.a.).

Based on a separate expert study[49], the electricity distribution system operators requested the WACC before taxes to be set at 7.21 percent p.a., a value substantially higher than that of preceding periods and higher than the figure determined for gas distribution systems in 2012. The industry representatives also repeatedly pointed out that the sector would be confronted with considerable challenges with regard to investments to be made in the near future: smart meter roll-out, developments towards smart grids, distributed electricity infeed, etc. were mentioned in this context.

From the authority's point of view, the argument of network expansion - where investments are certainly required - has to be considered in light of the ownership structure of energy grids: more often than not, the gas grid and the electricity grid in a particular area have the same owner. If the WACC for electricity were to diverge strongly from the gas WACC, misguided incentives could arise, as companies generally invest the funds available to them in the area generating higher returns at comparable risks (principle of maximising benefits from scarce resources). This would be even reinforced by the fact that the two sectors are facing the same risks, which was outlined empirically in Frontier Economics 2012. Also the regulatory periods in the gas and electricity system operator sector are of the same length and diverge by only one year, making for a four-year overlap (2014-2017).[50]

When determining the cost of capital rate for an extended future period, thought should be given to the extent to which developments during the period can be anticipated. Specifically in the case of the third regulatory period, the current interest level, which is very low, can be expected to rise within the next five years (derived on the basis of forward rates for Austrian

[48] For details on the individual parameters, also refer to the abovementioned paper.

[49] Becker, Büttner, Held, 2012.

[50] In the past, the WACC differed only slightly for the electricity and gas sectors (electricity: 7.025 percent p.a. and gas: 6.97 percent p.a.).

government bonds). To take this into account, we use an average over five years of the *Oesterreiche Nationalbank (OeNB)* secondary market yield to determine the risk-free interest rate. By using this longer period, we avoid focusing exclusively on the current low-interest period and thus exposing the electricity distribution system operators to the risk of shortfall. In addition, the authority considers the risk of postponed (re)investments for system users and the associated danger to the security of supply higher than the risk of excessive compensation of the owners.

Based on the considerations outlined above, the authority deems it appropriate to apply the same WACC as for gas distribution systems. As a result, the following structure applies:

WACC calculation 3rd regulatory period - electricity DSOs	
risk-free interest rate	3.27%
risk premium for debt	1.45%
debt interest rate (pre tax)	**4.72%**
market risk premium	5.00%
beta factor (unlevered)	0.325
beta factor (levered)	0.691
equity interest rate (post tax)	**6.72%**
gearing	60.00%
tax rate	25.00%
WACC (pre tax)	**6.42%**

Figure 14: WACC structure for the third regulatory period of electricity distribution system operators

10. Regulatory asset base (RAB)

According to section 60(4) Electricity Act 2010, the regulatory asset base consists of the sum of the intangible assets and the tangible assets minus the system admission and provision charges collected (consumer prepayments for installation costs) that are recorded as liabilities and any goodwill, all of which as shown on the balance sheet.

Composition of the regulated asset base
Total immaterial assets
total fixed assets
total leased assets
- prepayments for installation costs (no interest)
- restructuring/goodwill
other corrections
regulated asset base

Figure 15: Procedure for determining the regulatory asset base

This procedure for determining the regulatory assets has proven to be appropriate during the second regulatory period (s. the Explanatory Notes on the System Charges Ordinance 2010) and is maintained for the third regulatory period. Installation investments are taken into account both in the regulatory asset base (tangible assets) and the investment factor. For the sake of completeness, it should be noted that as previously, we make adjustments for subsidised loans, which are included with their actual subsidised cost of capital, in the "other adjustments". Further examples of "other adjustments" are those concerning fixed assets, e.g. as a result of unbundling.

11. Expansion factors

Incentive regulation implies that the regulated costs, i.e. the costs as projected based on the regulatory path, are decoupled from actual costs. These sets of costs can consequently diverge. Recalculation of the costs normally only occurs before the outset of a new regulatory period; it is therefore useful to take into account - as far as possible - expansion factors to reflect the development of the supply mandate that may occur during this period in order to avoid shortages on the company side and in this way provide corresponding investment incentives.

Both an operating cost factor and an investment factor were introduced to the regulatory scheme during the second regulatory period. They reflect changes in the supply mandate (actual supply situation) that occur during the regulatory period in comparison with the initial year of the regulatory period. Please note that the expansion factors do not seek to take every single cost increase during the regulatory period into account. After all, the incentive regulation regime is specifically geared to decoupling the revenues temporarily from the current developments.

Previous experience has shown these elements to be effective, so that they are maintained, even though adaptations in isolated areas appear warranted. The detailed design of the two factors in the third period is presented in the following chapters.

11.1. Operating cost factor

The operating cost factor, in its redesigned form for the third regulatory period, is used for the first time for 2014 tarification (i.e. the initial year of the third regulatory period) and largely reflects the change in the supply mandate – as far as operating costs are concerned- in 2012 compared with 2011 (cost review year).

The previous operating cost factor, from the second regulatory period, was determined on the basis of empirical studies: audited costs of the 2008 business year were used to identify significant cost drivers. The operating costs calculated for low voltage grid kilometres were then combined with weighting factors (the same ones also used in benchmarking) to derive the costs for grid kilometres at the medium and high voltage levels.[51] We basically continue using this approach for the operating cost factors for the individual network levels in the third regulatory period. However, the weighting factors employed for low, medium and high voltage now differ between operating cost factor and efficiency analysis. Whereas the weighting factors for benchmarking are determined on the basis of the TOTEX specific to the network level, the scale variables for the operating cost factor are determined on the basis of the audited OPEX specific to the network level of the business year 2011.

[51] It should be noted that the selected analytical approach merely allows the determination of the average cost level. In principle, a panel data estimation would be preferable when it comes to estimating cost increases during a particular period of time. As, however, no audited OPEX values are available for a continuous period, it is not possible for the authority to use this "superior" estimation method.

The scale variables are determined based on the figures of 49 audited companies. The first step involves determining the average unit OPEX for low voltage, medium voltage and high voltage lines for each company *i*. In formal terms this can be presented in the following manner:

$$unit\ costs\ HV_i = \frac{OPEX_{i,network\ level\ 3}}{system\ length_{i,network\ level\ 3}},$$

$$unit\ costs\ MV_i = \frac{OPEX_{i,network\ level\ 5}}{system\ length_{i,network\ level\ 5}},$$

$$unit\ costs\ LV_i = \frac{OPEX_{i,network\ level\ 7}}{system\ length_{i,network\ level\ 7}}.$$

In a next step, the median of the unit cost values of each company is determined.[52] For the low voltage level the median is 2,883, for medium voltage 3,225 and for high voltage 8,415. With the low voltage values functioning as reference, the resulting scale variable for medium voltage is 1.12 and that for high voltage is 2.92.[53] The operation of one kilometre of medium voltage line (on average) leads to costs that are 1.12 times higher than those for low voltage lines.

In terms of the empirical data used to determine the operating cost factor, we reviewed various investment categories at the low, medium and high voltage levels. Grid kilometres (actual system lengths), which had already been included in the past, were again used as were the metering points for withdrawing parties. As the authority has seen increased growth in decentralised generating facilities – mainly photovoltaics – their impact on the operating costs was evaluated. To this end, a combined parameter of injection and withdrawal metering points and metering points that measure in both directions was examined in the analysis (separate examination of the injection metering points leads to non-significant results for both injection and for weighted line lengths. Hence, the model is classified as non-plausible, see presentation in the Annex).

In principle, the total operating costs of network levels 3-7 are used to determine the appropriate rates. Adjustments are needed for the companies of LINZ STROM Netz GmbH, Netz Oberösterreich GmbH, Stadtwerke Feldkirch, TINETZ-Stromnetz Tirol AG, Vorarlberger Energienetze GmbH and KNG-Kärnten Netz GmbH as they incur operating costs for transmission network efforts at network level 3 and for the roll-out of smart meters, which must not be taken into account in determining the rates.

The remaining OPEX block is explained by the sum of metering points (withdrawing and injecting parties and the points that measure in both directions at network levels 3-7, unweighted) and the weighted actual system lengths (in kilometres) at the low, medium and

[52] In contrast to the arithmetic mean, the median is not so sensitive to outliers (i.e. it is more robust).

[53] The value for the low voltage level is standardised to 1.

high voltage levels as part of a linear regression model.[54] The estimating equation is as follows:

*OPEX minus adjustments= constant + total metering points + (actual LV line length in km + 1.12*actual MV line length in km + 2.92*actual HV line length in km) + error term*

The result of the estimation from the above equation is given in **Figure 16**. Compared to the presentation in the second consultation paper, numerous updates were made to the costs and to the cost drivers. This is why the rates have to be recalculated. The final rates are given in the following table.

Parameter	Coefficient	t-statistics
Metering point	74.70	9.35***
System kilometres	1,233.7	6.70***
*) slightly significant, **) significant, ***) highly significant		

Figure 16: Estimation result - rates for the operating cost factor

The calculations result in the following rates for additional OPEX that are taken into account in the operating cost factor:

- 74.70 EUR per metering point (independently of the network level, injection or withdrawal and conventional/smart metering equipment);
- 1,233.70 EUR per km actual low-voltage system length;
- 1,381.80 EUR (1,233.70 x 1.12) per km medium-voltage system length;
- 3,602.50 EUR (1,233.70 x 2.92) per km system length of high/extra-high voltage levels.

With a view to metering points, we abandoned the distinction made in the second consultation paper between different types of metering technology, i.e. the same rate applies for conventional and intelligent metering devices. The development of metering points (sum of all the company's metering points) always uses the baseline year as a reference. In formal terms, the operating cost factor (in this case, for 2014) is calculated in the following way:

[54] Please note that the scale variables were determined on the basis of (actual) system kilometres associated with the OPEX of network levels 3-7.

$$
\begin{aligned}
&OPEX.factor_{2014} = \\
&(metering.pts_{2012} - metering.pts_{2011}) \times 74.70 + \\
&(system.length.LV_{2012} - system.length.LV_{2011}) \times 1233.70 + \\
&(system.length.MV_{2012} - system.length.MV_{2011}) \times 1381.80 + \\
&(system.length.HEHV_{2012} - system.length.HEHV_{2011}) \times 3602.50
\end{aligned}
$$

Where:

$$metering.pts = \sum_{grid.level=3}^{7} injecting.pts + withdrawin\ g.pts + bidirectio\ nal.pts$$

$$system.length.HEHV = system.lengh.HV + system.length.EHV$$

As the operating cost factor is intended to reflect the development of the supply mandate during the regulatory period in terms of the OPEX, it can of course take on negative values (in the event of a reduction in lines or metering points). The reference year is always 2011.

11.2. Investment factor

The investment factor introduced in the second regulatory period has proved its worth in contrast to the flat-rate volume cost factor used in the first regulatory period, as the CAPEX development is now properly reflected over the regulatory period. Some adjustment of the previous investment factor is nevertheless necessary (as a result of other modifications introduced at the beginning of the third regulatory period).

The investment factor applied for the second regulatory period was based on book value developments and featured, in addition to a mark-up (on the cost of capital for new investments since 2009) and a deadband for negative investment developments, a distinction between old and new investments. This is why old and new investments had different targets.

For the sake of completeness the investment factor applied up to now is represented here, by way of example, for 2011 tarification:

$$
\begin{aligned}
&inv.f_{2011} = \\
&+CAPEX_{2009}(= depr._{2009} + BV_{assets\_2009} * (WACC)) \\
&-CAPEX_{2008\_investments.up.to.2005} * (1 + NPI_{2011}) * (1 - X_{gen}) \\
&-CAPEX_{2008\_investments.from.2006} * (1 + NPI_{2011}) * (1 - CA) \\
&+Mark\_Up\ (= BV_{investments\_2009} * 1.05\%)
\end{aligned}
$$

Where:

$CAPEX_{2009}$ = depreciation in the business year 2009 + cost of capital on the basis of 2009 (book values of asset base 2009 multiplied by the WACC)

$CAPEX_{2008\_investments.up.to.2005} * (1+NPI) * (1-X_{gen})$ = seen in conjunction with the general regulatory formula, capital costs for investments up to 2005 are only subject to a reduction by Xind

$CAPEX_{2008\_investments.from.2006} * (1+NPI) * (1-CA)$ = in the context of the general regulatory formula, investments made since 2006 are no longer subject to any mark-ups (NPI) or offsets (cost adjustment factor)

$Mark\_Up\,(= BV_{invesments2009} * 1.05\%)$ = based on the book value of additional investments since 2009, a mark-up of 1.05 percent is granted as additional investment support

This design in the second regulatory period means that for old investments up to 2005 ($CAPEX_{2008\_investments.up.to.2005}$) only the individual target remains as the term $(1+NPI)*(1-X_{gen})$ is cancelled in the general regulatory formula. Hence, neither a system operator price index nor a general productivity rate applies to old investments. New investments since 2006 are not subject to any reductions in this specification.

The three elements mentioned (mark-up, deadband and distinction between old and new investments) are reconsidered for the third regulatory period. Details are given below.

Discontinuation of the mark-up for new investments

In the second regulatory period a mark-up up of 1.05 percent on the WACC for the book value additions from 2009 was introduced as an additional incentive to promote future investment in the network.

Section 60(1) Electricity Act 2010 states that the cost of capital has to comprise the reasonable cost of interest on debt and equity. This “reasonable” cost of capital generally ensures sufficient investment incentives (cf. chapter 9). According to this logic, an additional incentive in the form of a mark-up would suggest that either the cost of capital itself or the mark-up were inappropriate. The requirements of section 60 Electricity Act 2010 therefore mean that there can be no mark-ups on the WACC, regardless of the objective pursued (s. chapter 11.5).

Based on these considerations, the mark-up of 1.05 percent on book value additions no longer applies at all to the investment factor in the third regulatory period.

Change in the amount of the deadband

In order to promote only necessary investment and ensure pertinent investment incentives, the investment factor in the second regulatory period could assume a negative value. However, this was cushioned by the introduction of an appropriate deadband to the amount of the general productivity rate (Xgen).

A negative investment factor (prior to taking into account any applicable mark-up) was only applied if it was higher than 1.95 percent of the regulatory CAPEX. The negative investment factor exceeding the tolerance threshold was then corrected by the positive mark-up on additional investment. During the preparations for the second regulatory period, the electricity distribution system operators comprehensively explained that, in future, there would be a need for a higher level of investment and documented this in an expert report. Therefore, it was assumed that a negative investment factor would not materialise. In the discussions about the design of the third regulatory period, the system operators repeatedly pointed out that – particularly against the backdrop of increasing distributed injection, the development and conversion of the network into a smart grid and the implementation of smart meter objectives – they did not expect investments to slow down significantly. Although the arguments presented at the beginning of the second regulatory period have indeed proved to be true on average across the industry, negative investment factors were observed in individual cases. Based on this experience it still seems appropriate to envisage a deadband for negative CAPEX developments. However, the authority is of the opinion that a reduction of the deadband is advisable in the interests of system users. As in the past, the band is set on the level of the revised Xgen (s. chapter 5).

The deadband disincentivises unnecessary investments (which might otherwise be made to avoid a negative investment factor) while ensuring that significant reductions in investments are not encouraged. In this way the investment factor is an investment incentive, generating the funds needed to preserve the assets of the Austrian distribution systems.

Moving the boundary between old and new investments

The boundary between old and new investments determines up to which point in time individual efficiency scores can be taken into account in the capital costs. In the Explanatory Notes to the System Charges Ordinance 2010 there is a comment that the boundary introduced between old and new investments (2005 and 2006) is based on the assumption that since the introduction of incentive regulation on 1 January 2006 all distribution system operators are generally deemed to engage in efficient investment behaviour during the second regulatory period. The authority is of the opinion that this hypothesis is not applicable to the subsequent regulatory periods for the following reasons:

- The incentive regulation regime introduced in 2006 only encompassed a small proportion of Austrian distribution system operators. The enlargement of the participating DSOs was discussed in detail in chapter 1 (50 GWh companies).
- The efficiency benchmark delivers a measure of relative efficiency. This means that the efficiency scores depend on the companies considered in the analysis and changes have to be expected if the sample changes.
- Actually efficient investment behaviour would also be reflected in the benchmarking results of the respective distribution system operators. Companies that have invested efficiently (relative to the other companies considered) need not fear any negative effects from an appropriately specified benchmarking analysis.

- If the distinction between old and new investments were maintained, the risk of non-efficient investment would remain entirely with the system users. The authority believes that continuing such an asymmetrical approach merely on the basis of a hypothesis is not appropriate. Therefore, an *ex post* examination of the efficiency of investment should be carried out during the regulatory period in order to ensure efficient investment behaviour.
- Furthermore, the retention of the boundary as is would result, in the long term, in capital costs no longer being subject to any efficiency scores (depending on the useful life) at the latest in 50 years' time; and the capital costs that accrue in the meantime – efficient or not – would have to be accepted without any reductions.
- Additionally, reference has to be made to compensation for the capital that is tied up in the company. In the WACC for the third regulatory period an interest rate for equity of 6.72 percent after taxes is applied and accommodates the corresponding risks of the equity investor. Pursuant to section 60 Electricity Act 2010, distribution system operators are legally entitled to compensation for the reasonable cost of capital. If the efficiency frontier were to be retained as required by the industry, the elimination of all efficiency parameters in the CAPEX in the long term, as outlined above, would result in excessive compensation for the claims of the equity investors. This would contravene the provisions of section 60 Electricity Act 2010 (refer to section 60(3) Electricity Act: “market risk premium”). This would mean that in the long term compensation would only apply for a risk-free interest rate, a small mark-up for debt financing and the cost recognition risk in the OPEX. The authority holds that avoiding CAPEX risks cannot go hand in hand with simultaneous compensation for a risk-weighted interest rate for equity as this would be contrary to the provisions of section 59(1) in conjunction with section 60 Electricity Act 2010 *("... Costs which are reasonable in their origin and amount shall be allowed.")*.

For the above-mentioned reasons, the boundary between old and new investments is shifted to 2011 within the scope of the investment factor.

The investment factor can, therefore, be expressed in formal terms for the third regulatory period as follows:[55]

$$
\begin{aligned}
&inv.f_t = \\
&+CAPEX_{t-2}(=depr._{t-2} + BV_{assets\_t-2} \times (WACC)) \\
&-CAPEX_{2011\_investments.up.to.2011} * \prod_{i=2012}^{t}(1+\Delta NPI_i)\times(1-X_{gen})^{t-2011}
\end{aligned}
$$

This specification of the investment factor ensures that the CAPEX development is appropriately reflected, adequate investment incentives are granted and mostly only

[55] It should be noted that adjustments are needed where the financial year deviates from the calendar year (see chapter 16).

individual efficiency offsets (aside from a certain degree of inaccuracy resulting from multiplying mark-ups and offsetting factors and applying them to different bases) impact old investments up to 2011. The capital expenditure of the business year 2011 is also part of the TOTEX benchmarking and the efficiency scores derived only impact the asset base in the same business year. No targets for investment are applied to the expansion factors (specifically the investment factor) during a regulatory period, as these reflect a change in the supply mandate during the period. Consequently, investments are deemed to be efficient until a new benchmarking exercise is carried out and the boundary between old and new investments is shifted again.[56]

Throughout the third regulatory period we check whether any changes to existing accounting practices result in a shift of individual items (such as maintenance work and other operating costs) from OPEX to CAPEX. If such changes are identified, corresponding corrections to operating costs might be necessary. If any such adjustments are required, they have to be made on the basis of the audited annual accounts duly confirmed by independent auditors (auditors' report). This is imperative because the total cost benchmarking that was selected for incentive regulation.

The newly specified investment factor for the third regulatory period is used for the first time in 2014 tarification (cost determination procedure 2013). It reflects the change in the supply mandate – as regards capital costs – in 2012 compared with the baseline year 2011. While there is no change to the baseline year when calculating the investment factors for the subsequent years, the projection based on the network operator price index and the general productivity rate will be adjusted accordingly.

11.3. Treatment of smart meter and smart grid investments

This chapter first looks at the distinction between “smart” and “conventional” investment and raises the question about the extent to which smart investment requires special consideration in the regulatory framework. It then addresses the need to reflect additional operating costs resulting from the introduction of smart meters using a cost-plus method.

11.3.1. Distinction between “smart” and “conventional” investments

The growing importance of investment in intelligent metering devices (smart meters) and intelligent networks (smart grids), raises the fundamental question – irrespective of the necessary differentiation between smart meters and smart grids – about the extent to which

[56] An ongoing efficiency review of new investment during the regulatory period would run counter to the basic idea of incentive regulation (decoupling of allowed from actual costs) and their long-term character.

a distinction can and must be made between "conventional technologies" on the one hand and technical innovations and developments on the other.

The main goal of incentive regulation is to provide a framework that encourages efficient behaviour on the part of regulated companies in the interest of achieving the optimum outcome for the economy as a whole (whilst protecting customer interests and security of supply). The regime must, therefore, be designed in a neutral manner; this means that the choice of a certain technology has to be made in the context of what is best for the economy as a whole and none of the implementation options is given preferential or non-preferential treatment *ex ante* as long as an optimum outcome can be achieved through the free actions of the stakeholders. Where this does not come about on its own or where more rapid implementation is desirable, interventions may be legitimate.

The decision to roll out a particular technology to achieve the economic optimum, based on cost-benefit analysis, may in such cases be taken by the legislator (on both the EU and the national level) an results in concrete statutory implementation obligations that are geared towards achieving the targets set. This procedure was chosen, for example, for the introduction of smart meters.

As a rule, however, it is the companies themselves that have to decide, within the regulatory framework given (as presented in this document), whether to plan, expand and then operate the network with "smart" or "conventional" solutions. The basic assumption in this context is that conventional implementation primarily entails the construction of pipelines, while "smart" implementation uses additional switches, software, system control measures, etc.;[57] furthermore, it is assumed that both approaches can produce the same result. The question now is how the selected regulation parameters (should) influence entrepreneurial decision-making. The method used to determine the targets and establish the expansion factors is particularly important.

The model network lengths currently used in benchmarking are, in principle, technology-neutral and do not favour the conventional approach (as would be the case if actual line lengths were used) as they are determined solely by the spatial distribution of connections. As the system dimensions are designed to accommodate the maximum load in the system, the role of peak load as an output parameter in future efficiency benchmarks must be critically discussed early on. This applies particularly given that the main effect of smart grids is to reduce the parallel peak load and any related dimensioning measures. Sticking to the peak load output parameter without taking into account capacity utilisation might hamper the shift to intelligent power grids. As smart grid projects are currently only being implemented on a limited local scale or are still in the test or early development stage, there does not appear to be a need either to adjust the benchmarking cost base (for the purposes of comparability) or generally shift away from peak loads as the output parameters for the current benchmarking (on the basis of business year 2011). Nevertheless, future

[57] It is implicitly assumed that both "conventional" and "smart" solutions are mainly associated with CAPEX. Furthermore, it is assumed that the two solutions both are within the influence and responsibility of the system operator. Purchasing third-party services in this field is deemed to be highly unlikely (in contrast to smart meter solutions - see the following discussion).

developments will be assessed by the authority and taken into account as relevant and appropriate in future efficiency analyses.

As the incentive regulation regime generally promotes productive behaviour of the regulated companies, there is in any case an inherent incentive to select the most cost-effective technology. The regulatory model, like the investment factor in general, is therefore technology-neutral as it is geared to the development of net additions to the company's required fixed assets. Hence, it encompasses all investments – whether "smart" or "conventional" – within a regulatory period.

A fundamental distinction in regulatory treatment would not be justified because in particular with a view to smart grids there were comparable developments of a similar nature in the past.[58] The authority is of the opinion that this is an evolutionary development of electricity networks: irrespective of the technology used, smart grids stand for the planning, operation, maintenance and expansion of electricity networks in the future, with the goal of integrating power generation from renewable resources (both large-scale technologies and distributed generation), actively involving system users, integrating forward market integration and market access, and achieving and guaranteeing a high level of security of supply.

Consequently, the authority does not see the need for concrete recommendations for specific technologies in conjunction with smart grids that limit the scope of companies or for explicit additional incentives for specific technologies (s. the discussion on the investment factor in chapter 11.2). To ensure productive behaviour by companies, it is however necessary to evaluate the efficiency of the (investment) decisions taken *ex post* within the framework of benchmarking and to translate this into efficiency targets for the following periods. This applies in principle to all investments made and encompasses both the roll-out of smart meters and the development towards a smart grid.[59]

11.3.2. Need to reflect smart meter investments in the regulatory framework

The aspects discussed above are generally valid for all investment decisions in regulated businesses. However, there are major differences between investments in general and smart meter investments. First, there is a statutory mandatory implementation time frame for the latter: pursuant to section 1(1) of the Smart Meter Rollout Ordinance), distribution system operators are required to equip at least 10 percent of the metering points connected to the system with smart meters by the end of 2015, at least 70 percent by the end of 2017 and, depending on technical feasibility, at least 95 percent by the end of 2019.

For the purposes of cost determination, this initially raises the question of whether the costs resulting from the statutory targets (and as a further consequence, from the technical

[58] What is commonly known today as a ripple control system could just as easily have been called a "smart" or "intelligent" facility in the 1980s.

[59] Should there be differences between the degree of implementation (specifically in conjunction with smart meter roll-out), it may be necessary (for the purposes of comparability) to make corresponding adjustments to the efficiency benchmarking procedure.

requirements laid down by the regulatory authority in the ordinance) are to be deemed to be within the company's control according to section 59(6) Electricity Act 2010.

In principle, the authority is of the opinion that all costs linked to system operation and the related tasks are within the control of the distribution system operators.[60] The statutory framework for smart meters merely lays down targets that are to be met (see comments below), while giving system operators sufficient leeway for implementation. The targets in the *IMA-VO* (Requirements for Smart Meters Ordinance) 2011 are also worded in a technology-neutral manner and merely constitute minimum functional requirements, i.e. concrete technical implementation is left to the system operators. Furthermore, the targets in the ordinance constitute the basis for tarification pursuant to section 83(2) Electricity Act 2010. Both in the smart metering and in smart grids, regulation must ensure that the companies take decisions that facilitate efficient and hence low cost implementation for system users. The need to monitor the efficiency of the roll-out results not least from section 59(1) Electricity Act 2010, according to which the costs arising from the efficient implementation of new technologies have to be included in the system charges appropriately.

In general, companies can choose from among a variety of strategies for the implementation of the statutory rollout provisions. They may take on all aspects of the roll-out themselves, i.e. all the equipment required for metering and the data transmission infrastructure is within the system operator’s control; alternatively, companies may select a service option where all the equipment, in extreme cases, is owned by third parties. Of course, mixed forms of these options are possible. Furthermore, different approaches may be taken towards installation. While some companies initially build up their complete communications infrastructure and then continuously install the smart meters, others adopt a diametrically opposed concept by installing meters that will be equipped for communication at a later stage. A gradual approach is also possible, where infrastructure expansion and meter installation are embarked on simultaneously.

In terms of the costs generated, this means that there is a large cost block for some companies already relatively early on whereas others face continuous cost increases. Furthermore, third-party services (on the basis of service agreements) generally have a significant effect on the OPEX whereas asset ownership generally causes CAPEX increases. Please note that the authority is of the opinion that the introduction of smart meters should not lead to any cost increases for customers during the entire technology life cycle. Any cost increases in the installation phase (meter charges, meter installation costs and establishment of the communications infrastructure, etc.) are generally offset by cost savings mainly in operations (end to manual meter reading, more efficient billing and customer invoicing, more efficient metering processes in general, etc.). The study commissioned by E-Control on the introduction of smart metering in Austria even assumes a benefit for distribution system operators of up to € 400 million.[61]

[60] Cost categories where the system operator has no latitude about the origin or the amount are the exception. Such costs are beyond the company's control as set forth in section 59(6) Electricity Act 2010.

[61] PwC Österreich, 2010, p. 59 et seq.

In the regulatory framework presented in this document the cost increases caused by investment are taken into account in the expansion factors (investment and operating cost factors). Whereas the investment factor accounts for increases in book values (including those caused by smart meters and smart grids), the OPEX increases during the regulatory period are covered on the basis of the changes in metering points and line lengths. This highlights the problem of the introduction of smart meters in terms of operating costs.

As the replacement of conventional meters by smart meters does not lead to any increase in the number of metering points, OPEX increases caused by the roll-out of intelligent metering devices are not covered by the operating cost factor.

Industry representatives therefore asked to incorporate a smart meter parameter into the operating cost factor in addition to the investment factor. In general, companies should be compensated for cost increases as soon as possible. However, the approach of including flat-rate cost rates in an operating cost factor involves numerous difficulties. Up to now only three companies – Netz Oberösterreich GmbH, Stadtwerke Feldkirch and LINZ STROM Netz GmbH – have started rolling out smart meters.

The very limited experience to date and the currently available data do not objectively justify that cost rates be derived and applied to an entire industry over several years. Furthermore, the authority sees the risk that the system of expansion factors for various smart meter roll-outs would not be able to provide an adequate framework as companies could, in general, prefer CAPEX-driven implementation options – based on a fixed interest rate, the investment factor and potentially inadequate reflection in the operating cost factor. A purely OPEX-based option (based on a service agreement with third parties) is not reflected in the investment factor or in the operating cost factor. This also constitutes a fundamental difference to the smart grid issue: whereas in the authority's opinion smart grids comply with the principle of technology neutrality, neutrality must also be guaranteed with respect to the various approaches in the current regulatory set-up for smart meter roll-out.

In this context, E-Control again stresses the technology neutrality of smart metering since, as already mentioned, the decision in favour of a technical implementation option (CAPEX versus OPEX) is, within the scope of the legal and technical framework conditions (ordinances, standards and norms), the responsibility of the respective company. Furthermore, the authority is not currently in a position to assess *ex ante* which implementation option in the field of smart metering will lead to the best solution for the overall economy. For this reason and given the current data situation, regulation should definitely avoid any intervention. In principle, the companies are free to decide how to organise their roll-out. Based on the fundamental principle of technology neutrality outlined above, non-discrimination and the statutory foundation of section 59(1) Electricity Act 2010 requiring the authority to ensure efficient implementation of new technologies on the basis of appropriate costs, the authority is in favour of setting up an alternative "neutral" and transparent system in addition to the incentive regulation regime described in this document.

In any case until the completion of the roll-out at the end of 2019, the use of a cost-plus method seems to be the best option for the additional costs (OPEX) generated by the smart meter roll-out. This means that the costs incurred are reviewed on an ongoing basis (if necessary annually) and taken into account in an appropriate manner in the charges.[62]

This would require a clear demarcation between smart meter services (in particular IT and telecommunications), including the related costs, and the remaining OPEX cost base in order to avoid cost shifting. In this context, particular consideration should be given to the total metering costs and the association with the two expansion factors (especially the costs of the indirect service areas compensated in the operating cost factor).

11.4. Targets for cost increases through expansions

Cost increases (i.e. increases in capital as well as operating costs) arising from investments are compensated in tarification for the third regulatory period by adding the investment and operating cost factors and the additional costs on the operating side generated by the introduction of smart meters (cost-plus method), without applying efficiency targets or the network-specific inflation rate.[63] Addition of these three elements ensures that any changes in cost levels resulting from investments during the third regulatory period are preliminarily considered to be efficient and are not subject to any offsets before the next benchmarking exercise takes place (prior to the beginning of the fourth regulatory period). It should be noted that future efficiency evaluations will of course include (new) investments, with appropriate offsets subsequently being applied to these investments. This means that, as a result of a new benchmarking exercise, investments will be correspondingly reclassified as “old” or “new”, and thus relative changes in costs (OPEX and CAPEX) will affect the efficiency score. This procedure ensures suitable incentives for making efficient investments.

11.5. Dealing with the systematic time lag

The principle of using the most recent data (balance sheet, calculated and technical variables) generally leads to deviations when the actual values in the year in which the charges apply deviate from the "regulatory (i.e. most recent) values" of the corresponding year (t-2 lag). For instance, the operating cost and the investment factor for 2013 are calculated using the historical values from the business year 2011. It can be assumed that the actual values for 2013 deviate from the values taken as the basis (2011). Besides the two expansion factors, which reflect cost increases in capital and operating costs during the regulatory period (they are seen as temporarily efficient), this also affects the costs beyond the company's control mentioned in section 59(6) Electricity Act 2010 (upstream network costs, levy for public land use and price components of the costs for covering grid losses) and the additional operating costs generated by the introduction of smart meters. We would like

[62] Opportunity cost considerations are not an option.

[63] Targets as defined in section 59(2) Electricity Act 2010 refer to the general productivity factor as well as individual efficiency scores.

to explicitly point out that this does not encompass costs specified by regulation which are within the company's control during the regulatory period. In general, the systematic time lag may constitute a certain obstacle to investment for the companies as cost increases can only be covered with a time lag (two years) as part of the expansion factors and, consequently, as part of the charges. This means that companies must prefinance these expenses, i.e. they are exposed to a certain interest rate and liquidity risk. Vice versa, cost savings are not passed on immediately either, thereby creating at least temporarily elevated charges for the customers.

In the opinion of the authority, the applied regulatory values are to be aligned with the actual values (see following comments) in order to credit a systematic shortfall to companies in the case of continuous investment in expansion or to credit a systematic overhang in the case of a continuous reduction to system users in the ensuing periods. The problems described are illustrated using the previous operating cost factor of the low voltage grid level:

The previous operating cost factor of the low voltage level (second regulatory period) includes in its calculation the number of metering points (€ 50 per additional metering point) and the length change in the low voltage system (€ 1,900 per kilometre) in comparison with the baseline year of 2008.

This means the operating cost factor for 2012 tariffs is calculated from the change in metering points and system lengths for 2010 compared with the baseline year 2008. Normally the 2012 numbers will deviate from the historical values.

annual growth of metering points and system lengths	2%
metering points in base year 2008	10,000
system length low-voltage level in base	2,500
price/cost per metering point	50
price/cost per km low-voltage system length	1,900

Example for 2nd regulatory period

Year	System length low-voltage	Metering points	Operating cost factor in TEUR [a]	Actual situation* in TEUR (additional OPEX) [b]	Difference in TEUR [z]=[a]-[b]
2008	2,500.00	10,000.00		-	0.00
2009	2,550.00	10,200.00		105.00	-105.00
2010	2,601.00	10,404.00		212.10	-212.10
2011	2,653.02	10,612.08	105.00	321.34	-216.34
2012	2,706.08	10,824.32	212.10	432.77	-220.67
2013	2,760.20	11,040.81	321.34	546.42	-225.08
2014	2,815.41	11,261.62	432.77	662.35	-229.58
2015	2,871.71	11,486.86	546.42	780.60	-234.18

Remark

* estimated values. Naturally, the actual costs of the indivdiual company might differ from the uniform price foreseen by the operating cost factor.

blue shaded area illustrates the regulatory calculation. Re-calculations from 2016 onw ard are based on new ly specified factors.

Figure 17: Systematic time lag

The systematic time lag affects not only the operating and capital costs, and the costs from the cost-plus system for additional smart meters, but also the costs beyond the company's control mentioned in section 59(6) Electricity Act 2010. In principle there are three options for reducing it:

- Use of budget figures or investment budget (liquidity-based approach);
- Compensation of the net cash value loss (based on the t-2 time lag) through a higher interest rate (yield-based approach);
- Adjustment of the regulatory values to reflect the actual values (shortfall or overhang) and the corresponding treatment in the following procedures.

The above-mentioned approaches cannot be applied simultaneously as they pursue the same goal. The options are briefly discussed below.

The liquidity-based approach makes sense when investments cause a "liquidity bottleneck" in companies, which cannot be funded from free cash flow. In general, it can be assumed that there will not be any liquidity problems in Austria’s electricity distribution systems. Given the nature of this approach, it is more suited to large-scale investments that require pre-financing (in this case for two years). This could be implemented by approving the investment budget or by providing pertinent plan figures in the budget. However, this approach would mean that preliminary financing by the company would be replaced by preliminary financing by the customer; it would merely reverse the direction of the t-2 time lag. Furthermore, companies are tempted to state elevated budget plan figures in order to improve the company's results in the short term. To ensure that companies do not give elevated budget figures, corresponding incentive mechanisms would definitely have to be introduced and possibly supplemented by an *ex ante* review of efficiency (e.g. using standard costs). Furthermore, it has already been pointed out in this document that the Austrian regulatory system is generally based on accounting data, and the figures of the audited annual financial statements are to be used as the basis for cost determination (see the explanatory notes on section 59(1) and (4) Electricity Act 2010). Hence, the authority is of the opinion that it is not possible to use plan figures.[64]

If a yield-based approach is adopted, it should usually be possible to finance investments from free cash flow (as opposed to the liquidity-based approach). This is generally deemed to be the case for Austrian distribution systems. Companies and investors are compensated for the net cash value loss caused by the t-2 time lag by a higher interest rate. This could be achieved either through a one-off mark-up on the WACC or an appropriate mark-up spanning several years. A mark-up on the WACC for new investment since 2009 was already applied to the investment factor in the second regulatory period. The main challenge in this approach is to determine the appropriate amount of the mark-up as the net cash value loss varies depending on the useful life of the assets concerned. As the WACC already implies an

[64] This is not the case for measures which are contained in the network development plan of transmission system operators because of the explicit provisions in section 38(4) Electricity Act 2010. Any appropriate expenses including preliminary financing costs are allowed when setting the system charges.

adequate interest rate on the capital invested, mark-ups (even if earmarked for specific purposes) must generally be used with caution.

The third option for reducing the time lag is adjusting the allowed costs to the companies' actual costs. Although the regulatory cost base is normally decoupled from the company's actual costs, this option seems to be particularly suited if this basic premise of incentive regulation has already been deviated from elsewhere. The costs beyond the company's control pursuant to section 59(6) Electricity Act 2010, the costs from the expansion factors and the additional operating costs from the introduction of smart metering constitute specific types of expenses which are not subject to any cost path but are "passed through" with a t-2 time lag at least until the end of a regulatory period. As already outlined above, the companies' allowed revenues and their actual revenues are reconciled within the scope of the regulatory account, based on the volumes recorded. It seems reasonable to apply the same procedure for those cost components which do not follow any regulatory cost path. Applying this approach to the "costs within a company's control", which are governed by the cost path of incentive regulation (mechanism aiming to promote productive efficiency by introducing specific incentives, refer to section 59(2) and (3) Electricity Act 2010), can definitely be ruled out, as general retroactive re-calculation runs counter to the goals of incentive regulation. Furthermore, it has to be explicitly mentioned that the focus here is on selecting a method, as in principle there is no analogy between the regulatory account and dealing with the systematic time lag. Whereas recalculation in terms of amounts is required according to section 50(1) Electricity Act 2010, the re-calculation of costs merely constitutes a correction of the compensation as part of the expansion factors, of the additional operating costs from the introduction of smart metering[65] and of the costs beyond a company's control. This avoids generating any disadvantages for companies through delayed compensation of costs which they cannot control (costs beyond a company's control pursuant to section 59(6) Electricity Act) or which they cannot control temporarily (expansion factors and additional operating costs from the introduction of smart metering). These cost items are reviewed at the introduction of the regulatory account (see chapter 12) as part of the calculated costs for 2014 (2014 tarification). As for the regulatory account, any deviations determined are taken into account without interest. An asymmetric design would lead to unequal treatment of the expenditure and revenue figures. Furthermore, an additional interest component would increase the complexity (determination of one or different interest rates depending on the type of deviation) and hence the administrative effort without generating any additional benefit. This applies in any case if the expenditure and revenue balances are on average in equilibrium.

In the above-mentioned example for the *operating cost factor*, the shortfall or overhang from the tarification for 2012 compared with the tarification for 2014 is used in addition to the operating cost factor for the respective year. Based on the example already given the adjustment is as follows:

[65] Although the additional operating and capital costs during a regulatory period - due to the lack of efficiency benchmark - are not subject to any targets and can, therefore, be described as being temporarily beyond a company's control or as temporarily efficient, they are to be designated as within a company's control from the point in time of the next efficiency benchmark and be treated correspondingly.

Year	System length low-voltage	Metering points	Operating cost factor in TEUR [a]	Actual situation* in TEUR (additional OPEX) [b]	Re-calculation in TEUR [c]=[a(t)]-[a(t-2)]	Difference after re-calculation in TEUR [z]=[a]-[b]+[c]
2008	2,500.00	10,000.00		-		
2009	2,550.00	10,200.00		105.00		
2010	2,601.00	10,404.00		212.10		
2011	2,653.02	10,612.08	105.00	321.34		
2012	2,706.08	10,824.32	212.10	432.77		
2013	2,760.20	11,040.81	321.34	546.42		
2014	2,815.41	11,261.62	432.77	662.35	220.67	-8.92
2015	2,871.71	11,486.86	546.42	780.60	225.08	-9.09

Anmerkungen * estimated values. Naturally, the actual costs of the indivdiual company might differ from the uniform price foreseen by the operating cost factor.

blue shaded area illustrates the regulatory calculation. Re-calculations from 2016 onward are based on newly specified factors.

Figure 18: Correction for the systematic time lag using the example of the operating cost factor

The operating cost factor for 2012 tarification is based on data from the 2010 business year (change in metering points and system lengths compared with the baseline year of 2008). The change during the 2012 business year could, however, have been larger or smaller than was assumed on the basis of the historical values (t-2 principle). The actual growth in the business year 2012 is known when costs are reviewed in 2013 and therefore used in tarification for 2014. If networks are expanded or reduced continuously, the system operators or system users would have a sustained monetary disadvantage. In a review procedure towards tarification for 2014, the difference between the regulatory values for the 2012 charges (based on data from 2010 according to the t-2 principle) and the actual growth or reduction in 2012 is determined and taken into account.

This re-calculation eliminates for the most part the difference (between the actual costs and the total of the "current" operating cost factor as well as of the "previous" operating cost factor) and compensates for any shortfall or overhang arising from the t-2 time lag.

The lines drawn in Figure 17 and Figure 18 show the system change between the second and third regulatory periods. As shown by the discussion of expansion factors in chapter 11, updated rates for updated parameters are used to depict an amended supply mandate in the operating cost factor and an amended investment factor is applied during the third regulatory period. In order to ensure continuous re-calculation to accommodate the t-2 time lag for the two factors, the previous specification for the years 2014 and 2015 must be continued as a separate regulatory calculation in order to identify the deviations. For the corresponding adjustments starting from 2016 onwards these separate calculations are no longer needed as the expansion factors will then be fully calculated according to the current specification from then onwards.

Compensation for the time lag in the *investment factor* (re-calculation) is carried out along the same lines as for the operating cost factor: The differences between the investment factor applied to the 2012 charges (basis CAPEX 2010) and an updated hypothetical investment factor for the 2012 charges (basis CAPEX 2012) are to be used in line with the prior specification. The investment factor for the 2012 charges can be expressed in formal terms as follows:

inv.factor $^{prev.specification}_{2012}$ = *inv.factor (basis actual_values $_{2010}$) =*
+ CAPEX 2010
- CAPEX 08 up to 05(1+NPI$_{2011}$)*(1+NPI$_{2012}$)*(1-Xgen)^2*
- CAPEX 08 since 06(1+NPI$_{2011}$)*(1+NPI$_{2012}$)*(1-CA)^2*
*+ mark-up (=BVinvestments$_{09,10}$*1.05 percent)*

This investment factor must now be compared with a (hypothetical) updated investment factor which takes into account the CAPEX in 2012:

inv.factor $^{prev.updated.specification}_{2012}$ = *inv.factor (basis actual_values $_{2012}$) =*
+ CAPEX 2012
- CAPEX 08 up to 05(1+NPI$_{2011}$)*(1+NPI$_{2012}$)*(1-Xgen)^2*
- CAPEX 08 since 06(1+NPI$_{2011}$)*(1+NPI$_{2012}$)*(1-CA)^2*
*+ mark-up (=BVinvestments$_{09,10,11,12}$*1.05 percent)*

The first re-calculation and adjustment for the 2014 charges is carried out by determining the difference between:

$$recalc\_inv.factor_{2014} = +inv.factor_{2012}^{pref.updated.specification} - inv.factor_{2012}^{prev.specification}$$

As the mean terms of the two investment factors (highlighted above in colour) can be cancelled from the equation, the re-calculation only covers the deviation in capital costs for the years 2012 and 2010 and the mark-up, in this case the difference for the years 2011 and 2012. The re-calculation for 2015 is carried out analogously.

Re-calculation from 2016 onwards will be performed on the basis of the newly specified investment factor:

$$\begin{aligned} &recalc\_inv.factor_{2016} = \\ &+\left[CAPEX_{2014} - CAPEX_{2011} \times (1+NPI_{2012}) \times (1+NPI_{2013}) \times (1+NPI_{2014}) \times (1-Xgen)^3\right] \\ &-\left[CAPEX_{2012} - CAPEX_{2011} \times (1+NPI_{2012}) \times (1+NPI_{2013}) \times (1+NPI_{2014}) \times (1-Xgen)^3\right] \end{aligned}$$

The difference is calculated between the updated investment factor for 2014 (first term with inclusion of the CAPEX for 2014) and the investment factor used for 2014 (second term with inclusion of the CAPEX for 2012 based on the t-2 principle.)

Mention should be made that, in line with the regulatory account (refer to chapter 12), no interest is calculated for the period between the first application and re-calculation.

The review and re-calculation of the above-mentioned categories (operating and investment factors, costs beyond the company's control pursuant to section 59(6) Electricity Act 2010 and additional costs resulting from the introduction of smart metering on the operating costs side) can be expressed as shown in the formula below; the additional costs resulting from the introduction of smart metering on the operating costs side are for the first time re-calculated in the cost review for 2016 because these cost developments are included for the first time in the cost review for 2014 (difference between the business year 2012 and the baseline year 2011):[66]

$$recalc_{2014} = OPEXfactor_{2014}^{prev.specification} - OPEX.factor_{2012}^{prev.specification}$$
$$+ inv.factor_{2012}^{prev.updated.specification} - inv.factor_{2012}^{prev.specification}$$
$$+ Cbc_{2012} - Cbc_{2010}$$

$$recalc_{2015} = OPEXfactor_{2015}^{prev.specification} - OPEX.factor_{2013}^{prev.specification}$$
$$+ inv.factor_{2013}^{prev.updated.specification} - inv.factor_{2013}^{prev.specification}$$
$$+ Cbc_{2013} - Cbc_{2011}$$

For re-calculations from 2016:

$$recalc_{t} = OPEX.factor_{t}^{new.specification} - OPEXfactor_{t-2}^{new.specification}$$
$$+ inv.factor_{t-2}^{prev.updated.specification} - inv.factor_{t-2}^{prev.updated.specification}$$
$$+ Cbc_{t-2} - Cbc_{t-4}$$
$$+ SM\_OPEX\_CostPlus_{t-2} - SM\_OPEX\_CostPlus_{t-4}$$

[66] To avoid any confusion, it should be noted that the annual indices for the costs beyond a company's control and the capital costs since the re-calculation for 2016 constitute actual values whereas the indices in the expansion factors indicate the year of application (for instance the operating cost factor for 2014 is based on actual values for 2012). Furthermore, it should be borne in mind that costs arising from *Ausgliederungen* (section 59(6)(6) Electricity Act 2010), i.e. demergers, that were effective due to their origin at the point of time of full liberalisation of the electricity market on 1 October 2001, are not presently included by re-calculation because this provision only enters into force after the enactment of a corresponding ordinance by the authority.

12. Regulatory account

The charges are established on the basis of the most recent supply volumes by the companies (as a rule, the values from the previous year). Company revenues are calculated by multiplying the actual volumes in the respective year by the stipulated tariffs. This results in a difference between the revenue assumptions in the ordinance (due to the reference to the past) and the actual revenues generated in the tariff year. The difference can be positive or negative and, therefore, lead to overhangs or shortfalls for the companies.

For the purposes of cost determination, section 50(1) Electricity Act 2010 specifies that any differences between the actual revenues earned and the revenue assumptions in the System Charges Ordinance are to be taken into account when establishing the allowed costs for the next charges ordinances that are to be enacted.

As a consequence of this statutory situation, these (positive or a negative)[67] differences are re-calculated with immediate effect and recognised as cost-reducing or cost-increasing factors when establishing the allowed costs pursuant to section 48 Electricity Act 2010. The review and re-calculation is based on the available most recent (actual) quantity data. If further deviations become apparent at a later stage (e.g. upon the next clearing), they are taken into account promptly in the following annual re-calculation.

The general procedure is illustrated in the figure below.

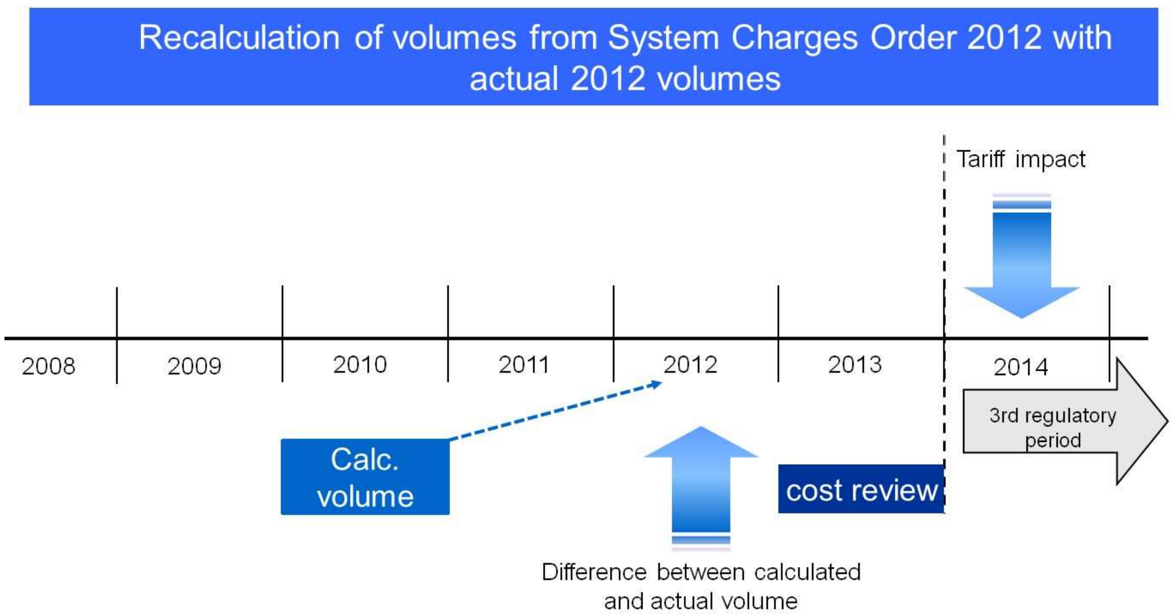

Figure 19: Use of the electricity regulatory account (system utilisation charge)

Tarification for 2012 were established on the basis of the 2010 quantities (most recently available data), and the actual quantities were bound to differ from this value. Revenues

[67] This balance is correspondingly represented as a plus or minus in the regulation formula.

exceeding or falling short of the assumptions were determined for the first time in the following procedure (2013, as part of the regulatory account process) and reflected in the charges for 2014.

The regulatory account was used for the first time in the cost determination procedure for 2013. Already in 2012 it had a full effect on the balance sheet (the regulatory account has to be included in the corporate balance sheet); the related charges took effect in 2014. The distribution system operators were required, as part of the preparation of the balance sheet for the business year 2012, to already carry out the corresponding calculations and to include the results in their balance sheets. In this context a full effect on the balance sheet means that the payables and receivables recorded in the regulatory account pursuant to section 50(7) Electricity Act 2010 are to be included in the annual financial statements as assets or liabilities. These items are to be recognised in the balance sheet according to the applicable accounting standards. It should be added that the accounting in the annual financial statements and the pertinent auditor's report cannot prejudice any review by the authority in the next review process.

The regulatory account is generally applicable to all charge components pursuant to section 51(2) Electricity Act 2010. Differences between the actual revenues and the revenue assumptions in the ordinance are, therefore, to be reviewed for:

- the system utilisation charge;
- the system loss charge;
- the charge for system services;
- the metering charges;
- other charges[68;]
- the reversal of installation costs;[69] and
- the charge for international transactions (not relevant for the distribution level).

This arrangement is without prejudice to the option of distributing large extraordinary revenues or expenses using the regulatory account, as specified in section 50(2) Electricity Act 2010, or the option, set forth in section 61 Electricity Act 2010, of adjusting the energy and capacity rates for any considerable current or expected volume trends in advance in the procedures resulting in official decisions. These estimates based on the ordinance are also to be reconciled with the actual quantities through the regulatory account. Finally, the regulatory account also reflects the impact of legal remedies on the statements made in the first instance of the cost determination procedure (section 50(3) and (5) Electricity Act 2010).

[68] In the first two years of application the other revenue generated must be compared with the incidental services charged prior to the changes required by the Electricity Act 2010.

[69] This applies to system admission and provision charges.

In the case of distribution system operators with a business year other than the calendar year, this is based on the quantity data for the audited business years.

The revenue-driven deviations determined are taken into account without interest. This also corresponds to the procedure used to treat the systematic time lag in the expansion factors, the additional operating costs resulting from the introduction of smart metering and costs beyond the company's control. An asymmetric design would lead to the unequal treatment of the expenditure and revenue figures. Furthermore, an additional interest component would increase the complexity (determination of one or different interest rates depending on the type of deviation) and hence the administrative effort without generating any significant benefit. This applies in any case if the expenditure and revenue balances are on average in equilibrium.

13. Quality element

Section 59(1) Electricity Act 2010 stipulates that quality criteria can be taken into account when establishing cost. Certain steps are first required to be able to appropriately take into account a quality element (Q) in the regulatory formula. Necessary perquisites include defining the relevant quality criteria and collecting corresponding data. To define the quality criteria pursuant to section 19 Electricity Act 2010 the *Netzdienstleistungsverordnung Strom* (Ordinance on Electricity System Service Quality) 2012, FLG ll 477/2012 as amended by FLG ll 192/2013, was enacted.

It is a matter of course to use the quality criteria defined in the ordinance for specification of the quality element Q. However, an implementation of the quality element Q as of the beginning of 2014 was not realistic, since the ordinance was issued only in the course of 2012 and comprehensive critical examination of this entire topic is needed. There are major questions about, amongst other things, the quality dimensions covered, the consideration of reference values, the assessment of deviations from these values and possible implementation in the general regulatory formula or other options. Therefore, no quality element will be used in the general regulatory formula up to the end of the third regulatory period (unless there are major changes to the regulatory framework or the laws to be applied).

14. Costs to cover grid losses

Physical system losses occur during the transport of electrical energy in the system. System operators have a number of measures at their disposal to influence the proportion between system losses and the quantities supplied. For instance, changes to the system structure can be made, equipment causing high system losses (transformers and pipelines) can be replaced, etc. Besides these physical losses there are also commercial losses (caused for instance by billing errors or electricity theft, etc.), the level of which system operators can likewise influence. Whether the loss reduction impact of a specific measure is reasonable from an economic point of view can be determined by weighing the cost-benefit ratios of the individual options and is, therefore, in the system operator's decision-making sphere.

Recourse to measures that are deemed reasonable protects system users from unnecessary cost increases. In the event of necessary expansion or replacement investments, there must be incentives which influence system structure and investment decisions and keep the total costs over the life cycle of an investment decision to a minimum.[70] In addition to the actual capital costs, these total costs also encompass the operating costs including costs to cover for grid losses. As electricity distribution system operators must procure the system loss quantities that arise and as they are price takers on these procurement markets, the price component of system losses ranks amongst the costs that are beyond a company's control as specified in section 59 (6)(3) Electricity Act 2010. This applies certainly if the quantities are procured in a transparent, non-discriminatory manner.

However, in terms of the quantities needed, the legislator considers that these are within the companies' control to some degree. Hence, section 53(1) Electricity Act 2010 stipulates that the system loss charge serves to compensate distribution system operators for costs incurred in the transparent and non-discriminatory procurement of adequate energy volumes to offset physical grid losses. When determining the appropriateness of energy volumes, using average values is acceptable.

Hence, the task of regulation is to create incentives for taking system loss-reducing measures in order to bring excessive system losses of individual distribution system operators down to an appropriate level and relieve the burden on system users. During the second regulatory period the determination of system losses on the basis of data from the 2008 business year (volume of system losses in reference to the supply to final and non-final customers) was based on an incentive system that had been developed against the backdrop of influenceability and energy efficiency. The base value was taken from the expert study of Haubrich and Swoboda (1998). The "target value" of 4 percent was used as the benchmark; it fell by 1 percent per annum. If a distribution system operator's system loss in the 2008 business year was higher than 4 percent, an additional annual offset applied. If the annual system losses were above the rate of the incentive path, only the system loss quantities based on the incentive path were compensated. If they were below the target value (4 percent in the initial year, 3.96 percent the following year, etc.) or below the value indicated

[70] This goal also meets the requirements of Article 15 of Directive 2012/27/EU (Energy Efficiency Directive [EED]) of the European Parliament and of the Council of 25 October 2012.

in the incentive path in the following years, the actual system loss quantities were compensated.

The discussions about the design of the third regulatory period also addressed the question of whether the expert study from back then (15 years ago) still applied to the current situation and particularly to the changed supply structures. Furthermore, several parties (mainly distribution system operators with facilities only on the lower voltage levels) criticised that the cap imposed did not adequately reflect the respective structural differences. As a result, the consulting firm CONSENTEC was jointly commissioned by OE and E-Control to establish appropriate system loss values for each network level.[71] Using model yet representative scenarios, plausible ranges of system loss rates were calculated and verified against the actual average values from the company surveys available to the authority. Considerations included the system structures typical for the Austrian distribution system, network sections, the injection scenarios, the age distribution of transformer substations, etc. The results from the model calculation were examined using sensitivity analyses and are shown in the following figure.

Network level	Minimum	Mean	Standard deviation
Network level 3	0.3 percent	0.6 percent	0.4 percent
Network level 4	0.2 percent	0.3 percent	0.1 percent
Network level 5	0.2 percent	0.9 percent	0.5 percent
Network level 6	1.0 percent	1.6 percent	0.3 percent
Network level 7	1.2 percent	3.1 percent	1.4 percent

Figure 20: Model-based calculation of system loss per network level

Based on the results of the joint study, a possible updated and adapted system for system loss quantities was discussed with industry representatives. The proposed system envisaged that, based on a maximum system loss rate for each individual company in the initial year, a regulatory target, using an adjustment path, based on the values determined by the commissioned consulting firm for an ideal system (not company-specific) could have been achieved over a period of 20 years. During the discussions with industry representatives it became clear that the discussed system generally had a sub-optimal impact as it would have tended to place structurally weak companies at a disadvantage and the system would scarcely have offered any incentives to companies to reduce system loss quantities, particularly as “unrealistic” targets are rejected by industry.

Establishing company-specific system loss rates based on a structurally ideal system requires a very high input of data and resources. As concerns were raised about the data quality of the initial parameters required for analysis in conjunction with the establishment of a

[71] Consentec, 2013.

generally valid ideal system, the derivation of individual company targets did not appear suitable at least for the third regulatory period.

The authority believes that one viable alternative is to assess system loss quantities within the framework of benchmarking using a uniform system loss charge (s. chapter 6.2.1) and to include this in the benchmarking cost base. The derived efficiency scores are, therefore, also based on the costs to cover grid losses and are included in the Xind, too. This procedure is consistent in that, as already outlined in the beginning, there is a non-negligible relationship between the CAPEX or the total costs of a company and its system loss rates or costs to cover grid losses. Individual company structures and peak loads are already sufficiently taken into account in the model system lengths (see chapter 6.2.2). In the relative efficiency benchmark companies with good structural conditions and high system losses appear inefficient compared with companies with a poor structure and low costs to cover for grid losses. As the individual company offsets impact total costs, this procedure constitutes an implicit incentive for companies to factor the development of costs to cover grid losses into their system planning considerations and, where appropriate, to reduce their system losses over the course of time.

The incentive could be increased by setting individual company targets for the system loss rates in each case in addition to the offsets on total costs. However, as the determination of ideal rates for the specific company and specific network level is problematic at the present time (see previous discussion), no offsets for system loss quantities are implemented at the present time and it is left to the companies to optimise their situation in the medium term with regard to the total costs. Additional alternative incentive systems are, however, being evaluated for the following regulatory periods.

The authority follows the outlined procedure by including the costs to cover grid losses to generate corresponding incentives in the efficiency score determination. However, because of long-term influenceability it provides compensation without any offsets for the system loss quantities as part of the calculated costs.

15. Carry-over from previous periods

The benefit of incentive regulation lies in the temporary decoupling of prices and revenues from actual costs. The incentive for companies depends on the duration of the regulatory period - the longer it lasts, the longer the company can benefit from cost reductions. At the same time, the strength of the incentive for productive efficiency depends on how companies' cost reductions are factored into the specification of the regulatory parameters in the next regulatory period. If cost savings are skimmed off during the transition to a new regulatory period, the incentives to make cost savings are reduced and companies are encouraged to postpone cost savings, realising them mainly at the beginning of the period in order to benefit from the positive effect as long as possible. These effects are called "ratchet effects" in the economic literature (s. Rodgarkia-Dara, 2007). The ratchet effect can be avoided by using the following regulatory instruments:

- Yardstick competition: The individual company's data from the past are restricted when setting the new targets (for the following periods). Ongoing benchmarking by companies is the basis.
- Efficiency carry-over mechanism: Companies can benefit from efficiency gains from earlier periods in the following periods, too. A carry-over mechanism was selected for the transition from the first to the second regulatory period for electricity distribution networks. On this basis, 50 percent of the additional cost savings (below the stipulated cost path) achieved during the two regulatory periods were passed on to consumers. The carry-over value determined in this way could be negative (in the case of cost increases). 25 percent of the additional efficiencies realised were taken into account already in 2010 tarification. The remaining 25 percent were taken into account after the end of the second period in the charges over the next eight years.

In the course of discussions on the second regulatory period the concept of a second cost review to establish the level of the carry-over was suggested as a possible option. However, this is not part of the cost review for the third period. The main reason is that to identify the exact carry-over, there would have to be a cost review for 2011 on the same basis as the 2003 one. Against the backdrop of the major changes to company structures, supply mandates and the various extraordinary effects in 2003 and 2011, this task almost seems impossible. For reasons of acceptability and practicability, the results from the second regulatory period, i.e. the values determined at that time, are used. This ensures that from 2014 onwards system users can benefit from additional efficiency gains in the first two periods over a period of eight years.

The companies and legal parties criticised the relatively complicated calculation method and the related difficulty in understanding it. Furthermore, the authority is of the opinion that it is not very appropriate or easily feasible to determine further carry-over values (with positive or negative effects) because of the shorter period for efficiency improvements (five instead of eight years) and because of the existing distribution of the carry-over from prior periods across eight years. The related incentive for the following periods must, therefore, be viewed critically.

In the view of the authority recurrent benchmarking prior to the onset of each further regulatory period ensures that the ratchet effect is kept to a minimum. This procedure can thus be seen as an alternative to an explicit carry-over system, which also pursues the objectives of limiting the ratchet effect to a minimum and of maintaining an incentive for productive behaviour. As a result of the above considerations, no further carry-over for the third regulatory period is determined. However, the effects from the first two regulatory periods impact cost determination from 2014 onwards.

16. Regulatory formula

In conclusion, the contents of this paper are presented once again in formal terms in this section.[72] The examples illustrating how allowed costs are established (as the basis for tarification) are for the years 2014 and 2015. Pursuant to section 59(1) and (7) Electricity Act 2010, the allowed cost from which the system charges is derived is to be determined for each network level separately. However, in the interest of clarity, the present paper takes an overall company point of view. The adjustments with regard to network levels and the following years may be derived by analogy.

[72] E-Control reserves the right to correct any lack of clarity or errors in the formulae presented in this document in accordance with the principles presented.

Establishing the allowed costs for the purpose of setting the 2014 tariffs:

Formula 1

$$C_{2014}^{allowed} = C_{2013}^{path} \times (1 + \Delta NPI_{2014}) \times (1 - CA_{3rd.period}) \pm inv.factor_{2014} \pm OPEX.factor_{2014} + Cbc_{2012} \pm regl.acct_{2014} \pm recalc_{2014} \pm CarryOver - prepIC_{2012} - MC_{2012} - other.chges_{2012} + SM\_OPEX\_CostPlus_{2012}$$

The following applies using the example of the balance sheet date 31 December:

$$C_{2013}^{path} = (C_{2011} - Cbc_{2011}) \times \prod_{t=2012}^{2013} \left[(1 + \Delta NPI_t) \times (1 - Xgen_{3rd.period}) \right]$$

Using the example of the balance sheet date 31 March:

$$C_{2013}^{path} = (C_{2011} - Cbc_{2011}) \times (1 + \Delta NPI_{2011})^{0.75} \times (1 + \Delta NPI_{2012}) \times (1 + \Delta NPI_{2013}) \times (1 - Xgen_{3rd.period})^{2.75}$$

Analogously for alternative balance sheet dates.

$$\Delta NPI_{2014} = 0.57 \times \Delta WSI_{2014} + 0.43 \times \Delta CPI_{2014}$$

Where:

$$\Delta CPI_{2014} = \frac{CPI_{01.2012} + \ldots + CPI_{12.2012}}{CPI_{01.2011} + \ldots + CPI_{12.2011}} - 1$$

$$\Delta WSI_{2014} = \frac{WSI_{01.2012} + \ldots + WSI_{12.2012}}{WSI_{01.2011} + \ldots + WSI_{12.2011}} - 1$$

$$CA = 1 - \sqrt[10]{\frac{C_{2023}}{C_{2013}}} = 1 - \sqrt[10]{\frac{C_{2013} \cdot (1 - Xgen)^{10} \cdot ES_{2013}}{K_{2013}}} = 1 - (1 - Xgen) \cdot \sqrt[10]{ES_{2013}}$$

Where:

$$C_{2023} = C_{2013} \cdot (1 - CA)^{10}$$

$OPEX.factor_{2014} =$ operating cost factor for 2014 where

$$\begin{aligned}
&OPEX.factor_{2014} = \\
&(metering.pts_{2012} - metering.pts_{2011}) \times 74.70 + \\
&(system.length.LV_{2012} - system.length.LV_{2011}) \times 1233.70 + \\
&(system.lenght.MV_{2012} - system.length.MV_{2011}) \times 1381.80 + \\
&(system.length.HEHV_{2012} - system.length.HEHV_{2011}) \times 3602.50
\end{aligned}$$

and

$$metering.pts = \sum_{grid.lvl=3}^{7} injecting.pts + withdrawing.pts + bidirectional.pts$$

and

$$system.length.HEHV = system.lengh.HV + system.length.EHV$$

$inv.f_{2014} =$ investment factor for 2014

Using the example of the balance sheet date 31 December:

$$inv.f_{2014} =$$
$$+CAPEX_{2012}(= depr._{2012} + BV_{assets\_2012} \times (WACC)$$
$$-CAPEX_{2011\_investments.up-to.2011} \times (1+\Delta NPI_{2012}) \times (1+\Delta NPI_{2013}) \times (1+\Delta NPI_{2014}) \times (1-X_{gen})^{3}$$

Using the example of the balance sheet date 31 March:

$$inv.f_{2014} =$$
$$+CAPEX_{2012}(= depr._{2012} + BV_{asstes\_2012} \times (WACC)$$
$$-CAPEX_{2011\_investments.up.to.2011} \times (1+\Delta NPI_{2011})^{0.75} \times (1+\Delta NPI_{2012}) \times (1+\Delta NPI_{2013}) \times (1+\Delta NPI_{2014}) \times (1-X_{gen})^{3.75}$$

Analogously for alternative balance sheet dates.

Costs beyond the company's control during the 2012 business year

Differences taken into account as part of the regulatory account (first introduced for the charges for 2014)

$prepIC_{2012} =$ reversal of consumer prepayments for installation costs for the 2012 business year

$MC_{2012} =$ revenues from the metering charge in the 2012 business year

$other.chges_{2012} =$ revenues from other charges as defined in section 11 System Charges Ordinance as last amended

$SM\_OPEX\_CostPlus_{2012}$ = increased operating costs due to smart meter roll-out

The cost determination for tarification for 2015 is done in an analogous manner.

17. Outlook: Transition to the following regulatory period

Although from today's perspective it is not yet possible to estimate which regulatory model will be used for a forthcoming regulatory period, it does make sense to already reflect on the transition between periods. As already outlined, ongoing benchmarking is the preferred option instead of distributing inefficiencies over two regulatory periods. This procedure has the advantage that the degree of relative efficiency can be repeatedly determined and adequate targets can be communicated to the companies in a timely fashion. During the regulatory period the companies can benefit fully from their additional efficiencies (i.e. those beyond the regulatory path). This is in line with the goal of the regulatory regime to increase the productive efficiency of the distribution system operators and is therefore also in the interest of system users. In addition, this simple and transparent procedure has the advantage of smoothing the transition to a subsequent system (for instance based on a yardstick mechanism) as no effects from previous periods (cf. carry-over mechanism) would have to be taken into account.

The details of the parameters for the next regulatory period, including the transition to the following period, have yet to be discussed and specified.