energiavirasto
energimyndigheten

Appendix 2

Dnro 3171/040300/2023

Regulation methods in the sixth regulatory period of 1 January 2024 – 31 December 2027 and the seventh regulatory period of 1 January 2028 – 31 December 2031

Electricity distribution network operations

High-voltage distribution network operations

Energiavirasto
Energimyndigheten
Lintulahdenkuja 2 A
FI-00530 Helsinki
Puhelin 029 505 0000
S-posti kirjaamo@energiavirasto.fi
Internet www.energiavirasto.fi

Table of Contents

1 REGULATION METHODS – SUMMARY

In this document, the Energy Authority (the Authority) sets out the methods for regulating the reasonableness in the pricing of electricity network operations in the period 2024–2031. These methods apply to distribution system operators (DSOs) and high-voltage distribution system operators.

The Authority will confirm the final regulation methods to the DSO as an appendix to the confirmation decision by the end of 2023.

The regulation methods for high-voltage distribution system operators differ in part from those for the distribution system operators. These differences occur in the incentive methods used in the calculation of realised adjusted profit: the quality incentive (which is dealt with in section 6.2 of this document), the efficiency incentive (6.3) and the security of supply incentive (6.5).

The guidelines have been drawn up by government officials in the Energy Authority. The principles governing the choices presented in this document are derived especially from the following legislation:

- Regulation (EU) 2019/943 of the European Parliament and of the Council on the internal market for electricity (Electricity Market Regulation)
- Act on the regulation of the electricity and natural gas market (590/2013, Regulation Act)
- Electricity Market Act (588/2013)
- Government proposal on legislation concerning the electricity and natural gas market (HE 20/2013 vp)
- committee report by the Commerce Committee (TaVM 17/2013 vp)
- other legislation issued by virtue of the Electricity Market Act.

The Energy Authority has also taken into account the decisions of the Market Court and the Supreme Administrative Court on complaints concerning previous regulation methods.

In the development of regulation methods, the Authority has also drawn on the practical experience it has gained from regulation.

The Authority has also used expert reports and statements as background material in the preparation of the guidelines and regulation methods.

The Authority has consulted stakeholders in preparing the guidelines for the regulatory methods. At the beginning of 2022, the Energy Authority established a stakeholder advisory board to enhance the consultations. The stakeholder advisory board had the function of engaging in discussions and thus of assessing the effectiveness of the proposed changes. In 2022, the Energy Authority gave an introduction to the changes to the regulation methods in eight meetings of the advisory board. The Energy Authority prepared published memoranda on the discussions held at the meetings of the stakeholder advisory board and a final report on taking the perspectives of the stakeholders highlighted in the discussion into account in reinforcing the regulation methods.

In addition, when developing the methods of electricity and natural gas network activities, particular attention is paid to the impact assessment of changes to the methods in order to increase transparency throughout the development process.

1.1 Summary of regulation methods

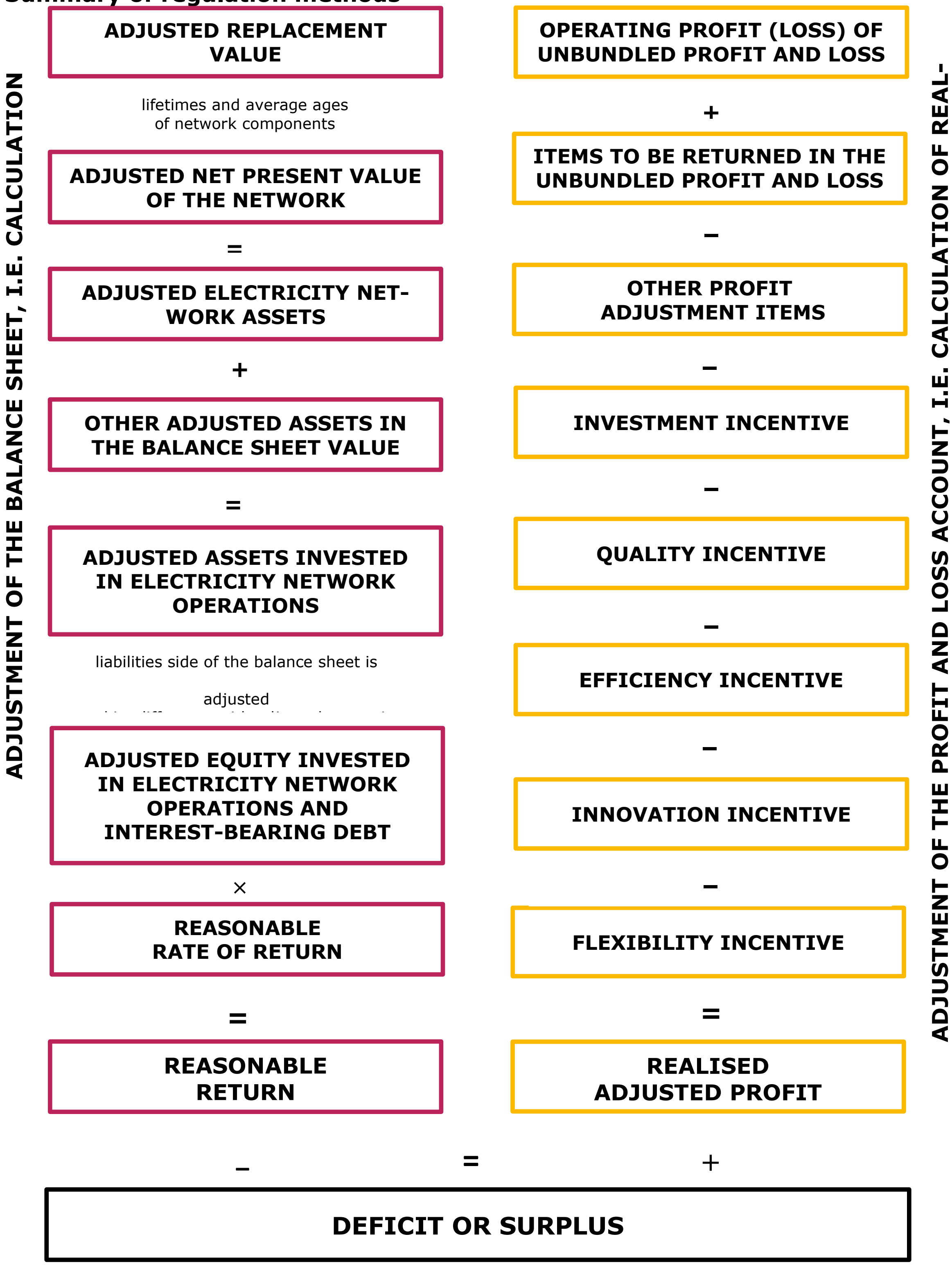

Figure 1. *Regulation methods for regulation periods 2024–2027 and 2028–2031*

The regulation methods include several different methods, which together form the entity shown in Figure 1. This entity is used for regulating the reasonableness of pricing in network operations. All individual methods are described in this document.

The methods of calculating the adjustment of the balance sheet, i.e. reasonable return, are presented on the left-hand side of Figure 1 (2, 3 and 4). The methods of calculating the adjustment of the profit and loss account, i.e. realised adjusted profit, are presented on the right-hand side of the figure (5, 6 and 7).

LEARNING ABOUT THE REGULATION METHODS

For an overview of the regulation methods, first read chapters 1, 4 and 7. For a more detailed description of the methods, see chapters 2, 3, 5 and 6.

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

Adjusted assets invested in network operations consist of adjusted electricity network assets in the non-current assets (2.1), other non-current assets (2.2) and current assets (2.3) in the unbundled balance sheet.

The adjusted capital invested in network operations is obtained by adding together adjusted equity (2.4.1), interest-bearing debt (2.4.2) and non-interest-bearing debt (2.4.2). An equalisation item (2.4.1) is also added to this to reconcile the different sides of the balance sheet.

A reasonable rate of return (3) is calculated on the basis of the weighted average cost of capital (WACC model).

Reasonable return is calculated by multiplying the adjusted capital invested in network operations (2.4) by the reasonable rate of return (3.4).

1.1.2 Adjustment of the profit and loss account, i.e. calculation of realised adjusted profit

The calculation of realised adjusted profit starts with the operating profit (loss) of the DSO's profit and loss account in the unbundled profit and loss account.

In the calculation of the realised adjusted profit, the annual change in refundable connection fees according to the unbundled balance sheet, as well as network rents according to the unbundled profit and loss account, depreciations on goodwill, planned depreciation in the unbundled profit and loss account and write-down of network assets, and the loss of sales resulting from the sale of a network section entered under other operating expenses are returned (5.1). Meanwhile, the profit from the sale of a network section entered under other operating income is deducted (5.1) when calculating the realised adjusted profit.

After that, reasonable costs of financial assets (5.3) are deducted as profit adjustment items.

The impacts of incentives are also deducted. Incentives include investment incentive (6.1), quality incentive (6.2), efficiency incentive (6.3), innovation incentive (6.4) and flexibility incentive (6.5).

The sum total of the calculation is the realised adjusted profit.

1.1.3 Deficit and surplus

The deficit or surplus of the return is obtained by deducting the reasonable return from the realised adjusted profit.

The profit is in surplus if the result of the subtraction is positive. The profit is in deficit if the result of the subtraction is negative.

1.2 The entity formed by regulation methods

In this document, the Energy Authority describes the entity formed by the regulation methods. Reasonable pricing referred to in electricity market legislation is determined based on this entity as a whole.

The regulation methods form a carefully considered entity. As the Market Court has noted in its decision (MAO:271-344/06), in addition to the fact that it must be possible to independently study and assess individual sections and parameters included in the methods, the confirmation decision represents a carefully considered entity. Moreover, the Market Court has stated in its decision (MAO:247/17) that the Energy Authority must, when considering the development of methods, assess the matter from the perspectives of the entire network operation in question and the functioning of its special regulation. Similarly, the Supreme Administrative Court has stated in its decision (KHO:2017:124) that DSO-specific contract arrangements or aspects related to tax legislation have no legal significance in the interpretation context of the confirmation decision. The above must be taken into account when developing the entity and individual methods because the methods and variables interact with one another.

When individual sections are assessed out of the context of the entity formed by the methods, a certain degree of caution should be exercised (precautionary principle). That way, for example, possible changes will not result in an internal conflict, illogicality, or taking the same factors into account several times over in the regulation methods. In addition, even fairly small deviations in the values selected for the parameters may result in differences that are considerable from the viewpoint of the entity of methods.

It is not possible in terms of clarity in the administrative decision, or even in practice, to draw up the regulation methods with a degree of accuracy where the treatment of every single factor is exhaustively justified.

If necessary, the Energy Authority will specify the contents of the regulation methods with written instructions. When issuing supplementary instructions, the Authority will apply the methods and principles of the confirmation decision in order to safeguard equal operating opportunities for DSOs.

OBJECTIVES OF REGULATION

According to electricity market legislation, the main objectives of the special regulation of the natural monopoly are the reasonableness of pricing and a high quality of network services. Therefore, the Energy Authority seeks these with the entity formed by the regulation methods and with the practical steering impacts of the methods on the DSO’s business operations.

In addition to the main targets of regulation, other key targets include equality and network development, as well as the sustainability, continuity, innovation and flexibility of business operations.

According to Article 18 of the Electricity Market Regulation, the distribution tariff methodologies shall provide incentives to distribution system operators for the most cost-efficient operation and development of their networks including through the procurement of services. For that purpose, regulatory authorities shall recognise relevant costs as eligible, shall include those costs in distribution tariffs, and may introduce performance targets in order to provide incentives to distribution system operators to increase efficiencies in their networks, including through energy efficiency, flexibility and the development of smart grids and intelligent metering systems.

Equality means social income distribution between the owners of the regulated enterprises and the customers. The level of profits must not be too high, for example, in relation to investments that the owners could make in other business operations of a similar risk level.

Sustainability, continuity and development mean that regulation must ensure necessary investments and other network development in order to safeguard sufficient security of supply. Other appropriate development and vitality of business operations must also be safeguarded in the long term.

Efficiency means that the service desired by the customer is provided at the lowest cost possible. The pricing of network operations is not subject to market pressure, which means that the DSO has no incentive to improve the efficiency of its operations. As a result, without regulation, higher prices could be used to compensate for any cost ineffectiveness. Therefore, the regulation of the reasonableness of monopoly pricing must be used to ensure that the DSO achieves a cost level that is actually achievable.

Consumer rights

According to the introductory part (4) of the Directive (EU) 2019/944 on common rules for the internal market for electricity, the Energy Union sets out to put citizens at its core, where citizens take ownership of the energy transition, benefit from new technologies to reduce their bills and participate actively in the market, and where vulnerable consumers are protected.

As the national regulatory authority, the Energy Authority has the task of making sure that consumer rights are enforced.

DEVELOPMENT OF REGULATION

For their key parts, the regulation methods have become established on the basis of decisions issued by the Energy Authority and those issued by the Market Court and the Supreme Administrative Court relating to them.

The Authority’s task is to develop the regulation methods. According to the legislative history of the Act on Regulation (HE 20/2013 vp, detailed justification of section 10 of the Act on Regulation), the Energy Authority must prepare a new

confirmation decision, in which the methods of the decision have been developed on the basis of experience, as necessary. The Authority must also ensure that the confirmation decision will be subject to sufficient public discussions at the draft stage.

When developing regulation, the Energy Authority must take into account the targets and principles of the special regulation of a natural monopoly expressed in electricity market legislation and in case law. The Authority must also take these into consideration in applying regulation methods.

DISCRETION

The Energy Authority has ex-ante competence in key regulation issues. The objective of legislation (Directive 2003/54/EC 15 introductory part) in adopting ex-ante regulation was to reduce uncertainty and expensive and time-consuming disputes.

Electricity market legislation leaves wide room for discretion to the Authority with regard to its application. This also applies to regulation methods and their development and application. Even if the regulation methods were drawn up with the utmost detail, there would still remain ambivalent issues, which the Energy Authority as an independent regulatory authority would have to resolve within the limits of its discretionary power.

The Supreme Administrative Court has also ruled (KHO 2010/86) that legislation provides the Energy Authority with a wide margin of discretion in the development of regulation methods.

When developing and applying the regulation methods and in regulation in general, the Authority takes into account the limits of the principles of good administration and fundamental rights in its use of discretion with respect to all parties subject to specific regulation.

EQUALITY AND REASONABLENESS FROM THE DSO’S POINT OF VIEW

The regulated DSOs must be treated equally.

However, the fact that the different elements of the methods produce different outcomes for different DSOs is no justification for the non-application of the method in question. The Supreme Administrative Court has stated in its decision (KHO:2017:124) that DSO-specific aspects have no legal significance in the interpretation context of the confirmation decision.

On the other hand, special obligations resulting from legislation have been accepted in case law as a ground for different treatment of transmission system operators and distribution system operators in the regulation methods (MAO:268/06).

When examining whether the regulation methods have, in reality, achieved a reasonable end result in accordance with their objectives from the DSO's point of view, certain aspects must be taken into account. Based on legislative history (HE 20/2013, detailed justification of section 24), these

include whether the DSO has been able to

- make sufficient investments in the network
- cope with its costs
- pay profits to its owners.

If the DSO has or could have achieved these, the DSO has met it obligations within the scope of the regulation methods.

1.3 Amending the confirmation decision

During the regulatory period, the Energy Authority may amend the confirmation decision with a new decision in situations prescribed in section 13 of the Act on Regulation.

UPDATING THE PARAMETERS OF THE CONFIRMATION DECISION FOR THE REGULATORY PERIOD

For the seventh regulatory period, the Authority will update the following parameters

of the regulation methods during 2027

- market risk premium relating to the reasonable rate of return (3.2.4)
- reference level of outage costs (6.2.3)
- efficiency frontier (6.3.3)

During the period, unit prices will also be updated for the valuation of investments made in the period. The unit prices will be updated during the sixth regulatory period in 2027 and during the seventh regulatory period in 2031 in accordance with the principles set out in Appendix 1.

These updates are not changes in methodology. This is an update of the parameters of the regulation methods, which is comparable to an annual update of the parameters, for example in the calculation of a reasonable rate of return. The value of the risk-free interest rate is updated annually in the calculation of the rate of return. In addition, the reasonable rate of return beta coefficient (3.2.3), the capital structure

(3.2.6) and the debt premium (3.3.2) are updated in the calculation of the rate of return every two years.

The update to the parameters for the seventh regulatory period will be made in the same way as their determination for the sixth regulatory period, using the methods described in this document.

With respect to updates, the Authority will not submit a separate decision, but the DSO will be notified of them in a regulation letter.

1.4 Regulatory data

It is the requirement of regulation that the DSO delivers to the Authority actual copies of the necessary regulatory data in the correct format and on schedule.

By virtue of section 30 of the Act on Regulation, the DSO is obliged to deliver to the Energy Authority the information required in the regulation.

1.4.1 Regulatory data required in regulation

The regulatory data required in the application of the regulation methods is specified in the following documents:

- Ministry of Economic Affairs and Employment Decree on the unbundling of electricity network operations (KTMa 79/2005, decree on unbundling)
- the Energy Authority's regulation on the key figures of electricity network operations and their publication (EMV 963/002/2011, regulation on key figures). The regulation on key figures will be updated during 2023 and published in conjunction with the adoption of confirmation decisions.
- regulation methods (this document).

Key regulatory data includes unbundled financial statements, network structure data, additional data requested by the Authority in relation to determining the network value, and financial and technical key figures. However, it should be noted that all information necessary for the Authority's regulatory task is regulatory data. Therefore, any separate additional information requested by the Authority from the DSO for regulation purposes is also regulatory data.

DECREE ON UNBUNDLING

The DSO must provide the regulatory data of the unbundled financial statements (profit and loss accounts and balance sheets) confirmed in accordance with section 10 (2) of the Decree on unbundling, including additional information and notes.

REGULATION ON KEY FIGURES

The DSO must deliver in the regulatory data the information and key figures referred to in the appendices of the Regulation on key figures.

REGULATION METHODS

The DSO must deliver in its network structure data the quantity and age data of the electricity network's components that are in its possession and actually used by the DSO. The delivered data must be divided according to Appendix 1 and as values corresponding to the situation on the last day of December each year.

The DSO must report the quantity and age data of network components invested in and removed from the electricity network during each year using the same division. If the DSO has purchased or sold sections of the electricity network, the DSO must report the quantity data of network components purchased or sold, including age data, using the same division. In addition, the DSO must report the quantity data of replacement investments using the same division. The lifetimes of network components must also be supplied, if necessary.

The DSO must also report other breakdowns required in the adjustment of the unbundled balance sheet and profit and loss account of network operations. These are referred to in sections 2.1, 2.2, 2.4.2, 5.1, 5.2, 5.3, 6.4.1 and 6.5.2. The DSO must be able to verify the validity of the breakdowns in a reliable way.

1.4.2 Delivering the regulatory data

The network structure data must be delivered to the Energy Authority by the end of March each year. Information about the financial statements and the technical key figures must be delivered to the Energy Authority by the end of May.

As a rule, the DSO must deliver the regulatory data via the online-based regulatory data system of the Energy Authority. Any regulatory data requested as submitted to the Energy Authority in accordance with the instructions provided.

If the DSO neglects to deliver the regulatory data to the Energy Authority, the Authority may impose a penalty payment on it in accordance with paragraph 31 of the Act on Regulation.

1.4.3 Validity of the regulatory data

The regulatory data supplied by the DSO must be valid, i.e. genuine and reliable.

The DSO must comply with the regulatory data when determining and delivering written and oral instructions. The instructions are presented in, among other things:

- the Decree on unbundling
- the Regulation on key figures
- the regulation methods
- the regulatory data systems
- other instructions issued by the Authority

In unclear cases, the DSO must request the Authority for more detailed instructions.

The validity of regulatory data is mainly based on the trust that the Energy Authority has towards the DSO. The DSO calculates and delivers the data independently. The Authority does not have the resources to systematically verify all data. For this reason, emphasis is placed on the DSO's own legal and moral responsibility for the correctness of the regulatory data.

The Energy Authority will correct any incorrect control data it has detected to comply with the regulation methods if the DSO does not do this.

The DSO must be able to verify the regulatory data it has delivered during regulation visits by the Energy Authority or when otherwise separately requested by the Authority.

1.5 Unbundling of operations

According to paragraph 77 of the Electricity Market Act, a DSO shall unbundle electricity network operations from other electricity trade operations, and electricity trade operations from other business operations. The unbundling of operations also applies to legally unbundled DSOs.

In accordance with paragraph 5 of the decree on unbundling, the DSO must enter the income (5.1) and costs (5.2), as well as asset items (2.1, 2.2 and 2.3) and capital items (2.4), which directly pertain to the electricity network operations, directly to the unbundled financial statements of the electricity network operations.

Operations open to free competition by law cannot be unbundled to electricity network operations except as de minis business activities. The construction of connection lines is one example of this. These kinds of operations are also not subject to the regulation methods.

The treatment of matters related to unbundling in the regulation methods is specified in the Energy Authority's recommendation[1] on the imputed unbundling of the electricity and natural gas business operations.

1.6 Leased networks

The DSO is in an equal position regardless of whether it owns the electricity network in its area of responsibility according to the network licence or whether it has otherwise acquired possession of it.

If the DSO has leased an electricity network in its possession either in part or in whole, it operates in a leased network in that respect. The lease arrangement is dissolved in the regulation methods when the unbundled balance sheet as well as the profit and loss account for the electricity network operations are adjusted.

In accordance with the decree on unbundling, a DSO operating in a leased network must also enter the income and costs directly pertaining to the electricity network operations and the asset items and capital items directly in the unbundled financial statements on electricity network operations (1.5).

If the DSO has leased its electricity network or a part thereof, it must provide in the regulatory data information concerning the business operations of the owner of the network. Information must be provided if it concerns the DSO's operations and the network of the area of responsibility determined in the network licence.

A DSO operating in a leased network must deliver, if necessary, an itemisation of the cost items included in the network lease. In accordance with the decision of the Supreme Administrative Court (KHO:2017:124), a company's overhead cost increment and margin included in the unbundled financial statements of its network operations are not deducted when dissolving a lease arrangement in the regulation methods.

1.7 Networks purchased and sold during the regulatory period

The business operations and obligations of networks that merge during the regulatory period are the responsibility of the DSO that continues the business. Similarly, it will gain the rights concerning these networks.

---

[1] Recommendation by the Energy Market Authority, Sähkö- ja maakaasuliiketoimintojen laskennallinen eriyttäminen (Imputed unbundling of electricity and natural gas business operations) (Reg.No. 549/002/2015), 18 December 2025, the recommendation will be updated before the start of the 6th regulatory period

The DSO continuing the network business operations is treated in regulation as an expanded network. This means that the business operation of merged DSOs is treated as a single business.

In a merger that takes place in the middle of the year, the companies form an imputed DSO, which is deemed to carry out activities as a single entity for the entire year in which the merger took place.

CALCULATING THE REPLACEMENT VALUE AND NET PRESENT VALUE

In the adjustment of the value of the buyer's electricity network asset

- the electricity network to be purchased is added to the replacement value and net present value of the buyer's electricity network on the basis of the number of network components and age data
- the lifetime of the network components to be purchased is determined according to the lifetime that has been previously selected for each network component by the buyer.

In an acquisition where only part of the DSO's electricity network transfers to a new owner, the sold electricity network is deducted from the replacement value and net present value of the seller's electricity network on the basis of the number of network components and age data.

REGULATORY DATA

The regulatory data takes account of the merger of DSOs from the start of the year of merger, and the data is combined into a single company in the regulation methods.

The DSO continuing the operations is responsible for submitting the regulatory data for the years preceding and following the merger.

DEFICIT AND SURPLUS

The transferee or the receiving DSO is responsible for equalising the surpluses to the customers of the DSO that is transferring or merging the network. This also applies to the equalisation obligation for the part of regulatory period preceding the transfer or merger.

Correspondingly, the transferee or the receiving DSO will gain the right to equalise deficits. This also applies to the equalisation possibility for the part of the regulatory period preceding the transfer or merger.

The Energy Authority may, at the request of the DSO disposing of its network business operations or of the transferee, issue a separate decision to confirm the deficit or surplus at the time of transfer.

If only part of the DSO's network is merged with or separated to another network and both DSOs continue licensed network operations, the deficits and surpluses of the regulatory periods are not combined.

REGULATORY DECISION

The Energy Authority will submit the regulatory decision after the regulatory period only to the DSO that continues network business operations. The regulatory decision takes into account the receiving and merged network business operations for the entire regulatory period.

1.8 Inflation

The annual change in the monetary value, i.e. the impact of inflation, is taken into account in the calculation of reasonable return and realised adjusted profit as presented below.

INFLATION ADJUSTMENT IN THE CALCULATION OF A REASONABLE RETURN

A reasonable rate of return (WACC %) is determined as a nominal value, i.e. the impact of inflation is not removed from it. To avoid taking inflation into account twice in the calculation of reasonable return, the value of network assets may not be revalued. This refers to an adjustment that resembles a valuation in accordance with accounting in principle, in which separate frozen unit prices reflecting the average acquisition value must be determined for each investment year and used only for the adjustment of investments in that year.

Inflation will be processed in the adjustment of network assets as follows. In the valuation of investments made before 2024, the unit prices in accordance with Appendix 1 will directly apply; in the valuation of investments made only after 2024, the unit prices in accordance with the sixth or seventh year of regulation specific to the given year of investment will apply in the valuation of investments.

In terms of other invested adjusted assets, the values according to the unbundled balance sheet for the year in question will be used.

Reasonable return is obtained by multiplying the adjusted capital invested annually in the electricity network operations and the interest-bearing debt by the nominal reasonable rate of return (WACC %). The nominal reasonable rate of return used in the calculation of the year in question includes the inflation expectation, and therefore the impact of inflation will be taken into account once in the calculation of a reasonable return.

INFLATION ADJUSTMENT IN THE CALCULATION OF REALISED ADJUSTED PROFIT

When calculating realised adjusted profit, inflation adjustment is made on the quality incentive and the efficiency incentive. The consumer price index is applied in the inflation adjustment

In the quality incentive (6.2), inflation adjustment is made on the unit prices of outages presented in the 2021 value of money (Table 7). The adjustment is made annually in the calculation of the reference level of outage costs and the realised outage costs.

In the efficiency incentive, inflation adjustment is made annually in the calculation of the reference level of efficiency costs.

A change in the total index of the total consumer price index (2005=100) is applied in the inflation adjustment.

The average of the index points of the consumer price index for April–September of the year in question shall be used as the index for each year. For example, the average of the index points of the consumer price index for April–September 2024 will be used for 2024.

The change in the consumer price index is presented in Formula 1.

$$\Delta CPI_y = \frac{CPI_y}{CPI_{y-1}} - 1 \tag{1}$$

where

ΔCPI_y = the change in the consumer price index for year y

y = year under review

CPI_y = the average of the index points of the consumer price index (2005=100) for April–September in year y

CPI_{y-1} = the average of the index points of the consumer price index (2005=100) for April–September in year *y-1*

1.9 Calculations to be made during the regulatory period

During the regulatory period, the Energy Authority will calculate the following information for the DSO using the regulatory data system:

- adjusted replacement value of the electricity network assets
- adjusted net present value of the electricity network assets
- adjusted straight-line depreciations of the electricity network assets
- adjusted equity invested in electricity network operations
- adjusted interest-bearing debt invested in electricity network operations
- adjusted non-interest-bearing debt invested in electricity network operations
- adjusted capital invested in electricity network operations
- reasonable return
- realised adjusted profit
- deficit or surplus
- items of a profit-distribution nature.

The Authority will report this information to the DSO through the regulatory data system. In addition, the Authority will make it available to the public, for example, to the DSO's customers and the media.

The Energy Authority will carry out the calculation of the above-mentioned data by applying the regulation methods described in this document and the regulatory data provided by the DSO.

Once the DSO has received the annual calculation for information purposes, the DSO must inspect it and report any errors. If necessary, the Authority will provide a new calculation for information purposes. The annual calculations are not binding on the Energy Authority, and the DSO itself is responsible for providing correct monitoring data.

Even if the DSO did not comment on the annual calculations immediately after receiving them, this does not prevent it from providing a statement at a later date. The final opportunity to comment is with respect to the regulatory decision draft.

However, due to the predictability and efficiency of the regulation process, the Authority recommends that comments are forwarded primarily during the regulatory period immediately after the calculations have been received for information.

The annual calculations made by the Authority during the regulatory period do not include the obligations concerning the DSO and therefore they are not administrative decisions to which a right of appeal would apply. The Energy Authority will confirm the calculations concerning the entire regulatory period after the regulatory period by submitting a regulatory decision (1.10), which is appealable (1.11).

1.10 Regulatory decision issued after the regulatory period

After the end of the regulatory period, the Energy Authority will submit the regulatory decision to the DSO by virtue of section 14 of the Act on Regulation. With this decision, the Authority confirms the amount in euros by which the DSO's realised adjusted profit falls short of or exceeds the amount of reasonable return over the entire course of the regulatory period.

DEFICIT AND SURPLUS

In the regulatory decision, the Authority adds together the realised adjusted profits for different years in the regulatory period using the methods confirmed in the confirmation decision and the regulatory data provided by the DSO and deducts from this the sum of reasonable returns for the corresponding years. The sum total of the calculation is the deficit or surplus for the entire regulatory period.

If the realised adjusted profits accrued over the entire regulatory period fall short of the amount of reasonable returns for the regulatory period, the DSO will accrue a deficit.

If the realised adjusted profits accrued over the entire regulatory period exceed the amount of reasonable returns, the DSO will accrue a surplus.

INTEREST LIABILITY ON THE SURPLUS

If the realised adjusted profit during the regulatory period, from which the possible deficit of the previous regulatory period has been deduced or surplus has been added, has exceeded the amount of a reasonable return by at least five per cent, interest must be paid on the surplus. The interest rate is the average of the reasonable cost of equity (3.2) for the years of the regulatory period in question.

The interest liability on the surplus is taken into account in the regulatory decision when calculating the deficit or surplus transferred to the next regulatory period.

Interest is calculated on the surplus of the regulatory period from which any deficit from the previous regulatory period has been deduced or to which any surplus from the previous period has been added (section 14 of the Regulation Act and MAO 484/15).

DEFICIT OR SURPLUS FOR THE PREVIOUS REGULATORY PERIOD

The regulatory decision takes into account the deficit or surplus accrued for the DSO during the regulatory period preceding the regulatory period in question. The Energy Authority has confirmed the deficit or surplus in the regulatory decision concerning the previous regulatory period.

CALCULATING DEFICIT OR SURPLUS TRANSFERRING FROM THE REGULATORY

PERIOD

The calculation of deficit or surplus transferring from the regulatory period to the next regulatory period is presented in Table 1.

Table 1. *Calculation of deficit or surplus*

+	**Sum of realised adjusted profits for all years of the regulatory period**
-	**Sum of reasonable returns for all years of the regulatory period**
=	**Deficit (-) or surplus (+) accrued for the regulatory period**
+	**Possible interest liability on surplus accrued for the regulatory period**
=	**Deficit (-) or surplus (+) accrued for the regulatory period, including interest liability**
+	**Deficit (-) or surplus (+) in accordance with the regulatory decision accrued for the previous regulatory period***
DEFICIT (-) OR SURPLUS (+) TRANSFERRING TO THE NEXT REGULATORY PERIOD	

* *Deficit accrued from the regulatory period preceding the previous regulatory period is no longer taken into account even if the deficit or a part thereof has not been equalised*

during the previous regulatory period

EQUALISATION OF DEFICIT AND SURPLUS

If on the basis of the calculation described in Table 1 the DSO has a deficit transferring to the next regulatory period, it cannot be equalised until during the following regulatory period.

If on the basis of the calculation described in Table 1 the DSO has a surplus transferring to the next regulatory period, it must be equalised during the next regulatory period. If the surplus is not fully equalised during the following regulatory period, the Energy Authority may propose imposing a penalty fee on the DSO.

However, it is possible to apply for extra time for the equalisation of deficits and surpluses from the Energy Authority on serious grounds.

Based on an application from the DSO, the Energy Authority must extend the deficit compensation period by a maximum of four years if the DSO has been unable to cover the deficit due to the increase ceiling regulation laid down in section 26a of the Electricity Market Act. In this case, the extension applies to the part of the deficit that the DSO could not cover due to the limitation of the increases in transmission and delivery fees laid down in section 26a of the Electricity Market Act. The application must be submitted before the end of the equalisation period.

1.11 Appealing against the confirmation and regulatory decisions

The confirmation decision issued by the Energy Authority before the start of the regulatory period and the regulatory decision issued by it after the end of the regulatory period are administrative decisions. The DSO may appeal against these decisions in accordance with section 36, paragraph 2 of the Act on Regulation.

The appeal is lodged with the Market Court. It is possible to appeal against the decision issued by the Market Court by appealing to the Supreme Administrative Court. The Authority may also appeal against the decision of the Market Court by appealing to the Supreme Administrative Court if the Market Court has by its decision amended the confirmation or regulatory decision.

According to section 38 of the Act on Regulation, the confirmation and regulatory decision must be complied with despite the appeal unless otherwise provided by the Authority in the decision. The court of appeal also has the right to give orders on the implementation of the decision as provided in the Administrative Judicial Procedure Act.

Under section 14 of the Regulation Act, a regulatory decision may not be issued unless the confirmation decision concerning the regulatory period in question is legally valid.

2 ADJUSTED ASSETS AND CAPITAL INVESTED IN NETWORK OPERATIONS

ADJUSTMENT OF ASSETS INVESTED IN NETWORK OPERATIONS

The adjustment of assets invested in network operations is based on the assets side of the DSO's unbundled balance sheet, which is adjusted in the ways presented in sections 2.1, 2.2 and 2.3.

Adjusting the assets side of an unbundled balance sheet gives the value of adjusted assets invested in network operations as the sum total of the adjusted balance sheet.

The adjusted assets invested in network operations consist of the following items:

- adjusted electricity network assets in non-current assets (2.1)
- adjusted other assets in non-current assets (2.2)
- adjusted assets in current assets (2.3)

ADJUSTMENT OF CAPITAL INVESTED IN NETWORK OPERATIONS

The adjustment of capital invested in network operations is based on the liabilities side of the DSO's unbundled balance sheet, which is adjusted in the ways presented in section 2.4.

Adjusting the liabilities side of an unbundled balance sheet gives the value of adjusted capital invested in network operations as the sum total of the adjusted balance sheet.

The adjusted capital invested in network operations consists of the following items:

- adjusted equity (2.4.1)
- adjusted interest-bearing debt (2.4.2)
- adjusted non-interest-bearing debt (2.4.2)
- equalisation item (2.4.1).

2.1 Adjustment of electricity network assets in non-current assets

Although comprised of several different components, the electricity network forms the greatest individual part of the DSO's assets, i.e. the non-current assets in the unbundled balance sheet.

According to the Electricity Market Act, an electricity network refers to an interconnected entity intended for the transmission or distribution of electricity, consisting of

- power lines
- substations
- other electric devices, electric equipment, systems and software serving the use of the electricity network and the production of electricity network services.

The value of electricity network assets is adjusted to correspond to its actual average net value at the time of acquisition using the average unit prices valid at the time of acquisition. The adjustment is carried out so that the value according to the unbundled balance sheet is not used in the calculation of a reasonable return. Instead, the adjusted net present value of the electricity network (2.1.2) calculated based on the adjusted replacement value of the electricity network (2.1.1) is used.

JUSTIFICATIONS FOR THE USE OF UNIT PRICES

The regulation of the reasonableness of pricing should be based on the actual net value of a company's electricity network assets, which describes the market value per company, rather than, for example, on the commercial market value determined on the basis of mergers and acquisitions, which may include valuation or acquisition items not pertaining to electricity network operations. The pricing of network operations is not subject to market pressure, which means that the DSO has no incentive to improve the efficiency of its operations. As higher prices can be used to compensate for any cost ineffectiveness, the assessment of monopoly pricing needs to include evaluating the cost level incurred by the company compared to the costs that the company might actually have to bear. The reasonableness of pricing includes an element that encourages economically efficient operations imposed through regulation, which can be used to ensure the realisation of the cost-effectiveness of the DSO's operations.[2]

---

[2] Government proposal (HE 20/2013 vp, p.82)

The tasks of the Energy Authority include promoting the development of secure, reliable, efficient and non-discriminatory electricity and natural gas networks that meet customers' demands in cost-effective ways, and ensuring appropriate conditions for the efficient and reliable use of electricity and natural gas networks, taking into account long-term objectives. A decision to establish the methodology followed in pricing may be used to lay down the principles for valuing the capital bound to the network operations or service as well as the objectives used to encourage the improvement of the efficiency of the network operations and the methods used to define them as well as the methods employed to apply the objectives in the pricing.[3]

The objectives of special regulation of natural monopoly are equality, continuity and efficiency. Efficiency means that the service desired by the customer is provided at the lowest cost possible.[4]

The methods applied to tariffs must provide appropriate incentives to transmission system operators (TSOs) and DSOs, both in the short and long term, to support efficient investments.[5]

Unit prices are used in the calculation of the adjustments of electricity network assets to ensure that the objectives laid down in the legislation on the regulation of reasonable pricing and the cost-effectiveness of investments can be achieved as well as possible. The objectives set in legislation require a principle that promotes cost-efficiency, which can be used to take a stand on the extent to which a DSO could have achieved a reasonable level of cost in the investments on average. This objective can be achieved with an adjustment made through unit prices.

The DSO's electricity network assets are adjusted annually with frozen unit prices set per investment year and monitoring data collected from DSOs to ensure that the electricity network assets reflect, on average, their actual reasonable net value. However, it should be noted that the methodologies take inflation into account in determining the final net value.

The balance sheet values of the DSOs do not correspond to the actual value of the network due to different accounting practices and shorter depreciation periods. Unit prices are used to impose a requirement of improved efficiency on the investments and prevent artificial or unjustified increases in the value of electricity network assets and to guide DSOs to operate cost-effectively.

---

3 Section 4 of the Act on the supervision of the electricity and gas market
4 Government proposal (HE 127/2004 vp 7)
5 Article 18 (2) of the Regulation on the internal market for electricity

Unit prices encourage DSOs to intensify their investments and prevent the higher costs of inefficient or poorly contracted investments from translating into higher customer prices. In addition, unit prices can be used to make sure through regulation that network assets do not include any irrelevant cost items. The purpose of unit prices is to encourage long-term efficiency gains in investments and to find more cost-effective ways to meet the needs for network construction.

Updating unit prices

Unit prices are average prices per component based on the costs of the actual network investments made by the DSOs. Unit prices are investigated and determined separately for each regulatory period so that they would reflect the reasonable acquisition costs of new network investments in a sufficiently cost-responsive manner on average.

Unit prices are updated every four years. A more frequent update interval is challenging to implement in practice due to the high workload this requires from both the DSOs and the Authority. So far, more frequent updates have not been considered to bring enough additional value that they would be justified.

The unit prices according to Appendix 1 will be updated for investments made in the sixth regulatory period in 2027 during the sixth regulatory period and for investments made in the seventh regulatory period in 2031 during the seventh regulatory period. A unit price survey is used to determine the average unit cost for each network component during the two most recent years of investment. This means that, by default, the unit prices applicable for the period are based on the investment costs valid during the two middle years of the period.

The network components and unit prices and the principles used to determine them are presented in Appendix 1. Similar principles will be used in updating the unit prices for the sixth and seventh regulatory periods.

ADJUSTMENT OF NETWORK ASSETS FOR COMPONENTS NOT INCLUDED IN APPENDIX 1

If a component belonging to regulated electricity network assets is not included in the network components specified in Appendix 1, the component may be taken into account in its balance sheet value in accordance with the financial statements after a case-by-case examination. In other words, if this is a component for which no equivalent component can be found from the unit price list based on average definitions, the investment is not subject to a requirement of the improved efficiency of unit prices. If the cost item is related to a component included in the unit price list, then the cost item is, as a rule, considered to be already included in the unit prices on average, and there are no grounds for the consideration based on balance sheet values. Valuation through balance sheet values is only intended for those components that are not included in any of the entities contained by the components in the unit price list. For example, systems are like this.

The Energy Authority will collect a separate breakdown of the investments in network assets that will be taken into account based on their book value for the network structure data. Each year, the DSO must reconcile and modify this data to ensure it reflects the accounting values and depreciations. In other words, all network components are taken into account through the reporting structure data, regardless of whether or not a unit price is available for a component. This means that all network components must be taken into account through tangible or intangible assets of the network, and the cost items of network components must not be reported as a part of other tangible or intangible assets. As a result, old cost items related to network components in other tangible or intangible assets must be transferred to the electricity network assets side.

When submitting the regulatory data (structure data), the DSO must provide an adequate explanation and justifications which the Energy Authority will use as the basis for assessing whether or not the component is accepted in its balance sheet value. The explanation must indicate why this non-standard component or solution in question has been necessary or rational from the perspective of network operations and, if necessary, demonstrate the cost-effectiveness of the solution compared to other possible solutions.

In 2025, when submitting regulatory data, the DSO must provide the Energy Authority with information on all cost items that have previously been, or continue to be, recorded in other tangible assets or other intangible assets and that have been taken into account in their book value. This procedure is used to check that the electricity network cost item is not taken into account twice. In the same breakdown, the costs on the balance sheet that are not related to electricity network components must also be separated into specific entities.

Network data systems and the communication networks in the supervisory control and data acquisition

Unlike during previous regulatory periods, average unit prices can no longer be applied to systems and communication networks. This is due to the fact that, based on the unit price survey conducted by the Energy Authority, a large share of the costs of the systems are incurred when the systems are acquired largely as services and with annual fees.

However, some DSOs continue to activate some cost items related to data systems or communication networks. In addition, there are considerable differences in annual costs between companies in both costs and activations. In some companies, the costs of systems and communication networks are almost entirely costs, while in others, individual systems have been subject to a more major activation in some year and/or more minor activations in several years.

During the fourth and fifth regulatory periods, unit prices based on a report commissioned by the Authority in 2010 were still used. In this case, the system unit prices valid at the time were used to adjust the network assets of the DSOs by declaring costs as network leases to avoid taking the costs into account twice. As a result, these costs or expenses are not included in the controllable operational costs contained by the efficiency incentive, at least not in all respects.

Referring to the above, systems and communication networks for which a unit price has previously been used will be processed so that in the sixth and seventh regulatory periods and as regards activations, the system solutions that are necessary and cost-effective for network operations will be taken into account in their balance sheet value in accordance with the financial statements. Similarly, costs will be taken into account as pass-through items in the sixth control period, whereas in the seventh control period, they will be taken into account as normal as costs controlled in the efficiency incentive. This enables collecting the actual costs of the systems from all companies for the sixth regulatory period and these costs will be taken into account in the reference level of the efficiency incentive during the seventh regulatory period.

LIFETIMES

Lifetimes are used in the calculation of the adjusted net present value of the electricity network assets and the adjusted straight-line depreciations.

The lifetimes for various network components are presented in Appendix 1. If no lifetime has been determined for a network component, its adjusted net present value will remain at default during the regulatory period. For ditches, lifetime is determined based on the underground cables.

The DSO must choose the lifetimes of its network components within the scope of the lifetime replacement intervals to correspond with actual average techno-economical lifetimes. This refers to the period of time for which the network components are in actual use on average before they are replaced. The DSO's maintenance and investment strategy is taken into account in the chosen lifetimes.

The DSO must include in the structure data of the regulatory data the average techno-economical lifetimes it has chosen for the network components by the end of March 2025 in connection with reporting the structure data for 2024. After that, the DSO may not change the lifetimes it has selected.

During the regulatory period, the Energy Authority will collect age data from the DSOs on the components removed from the electricity network, and use this data as the basis for regulatory that the average lifetimes selected during the regulatory period do not differ significantly from the actual lifetimes. If the selected lifetimes differ significantly from the actual average age data of the removed components, the Energy Authority will correct the lifetimes for the final regulatory decision so that they better correspond to the actual average lifetimes.

AGE DATA

Age data is used in the calculation of the adjusted net present value of the electricity network assets as well as in determining the investment year and the applicable frozen unit price for the removed components in 2024 or later, and also in other calculations when there is a need to determine the applicable frozen unit price.

The DSO must report the actual age data for every component in the electricity network at the end of every regulatory year. This information must also be reported for any removed components made during the year. This age data is used to adjust the network to the correct level as required by the principle of adjustment of the network assets.

Actual age data means the lifetime of a component, i.e. the age calculated from the first moment of use or year of manufacture.

When reporting an investment made in 2024 or later for the first time in the regulatory data, the age of the component is interpreted as 0 years in the case of a completely new investment introduced before the end of the year. The age of a component that was previously in the basis of return is determined as normal based on the time when the component was first included in the basis of return. For investments made before 2024, the actual detailed age of the component calculated from the date of introduction is used. If this is not known, 0.5 years is given as the age.

For components whose real age cannot be established by the DSO, the age used in the calculation for the component is the selected lifetime. In other words, only straight-line depreciation is calculated for these components with the assumption that the component’s age is the same as its lifetime.

ENVIRONMENTAL CONDITION CLASSIFICATION

Various operating environments for investments will be taken into account in the adjustment of network assets not only for component structures but also partly utilising the environmental condition classification specified in the unit price list. The environmental condition classifications are based on map base data maintained by the Finnish Environment Institute. More detailed specifications for different environmental conditions classes are described in the definitions of network components in the unit price list.

The environmental condition classification is applied in the definition of the following network components:

- ditches in the 0.4 kV and 20 kV underground cable network
- ditches in the 110 kV underground cable network
- line area compensations for 110 kV overhead lines
- plots of 110 / 20 kV substation land.

In each year of the regulatory period, the DSO must report the environmental condition classification for the network components in Appendix 1 that require an environmental condition definition. If necessary, the DSO must be able to clearly and transparently verify the condition definition to the Energy Authority. If the DSO is unable to verify the conditions to the Energy Authority on the basis of the map base data, the unit price for the most inexpensive condition will only be used in the calculation.

COMPONENTS NOT PART OF NETWORK OPERATIONS

Components and assets that are not part of the network operations are not included in adjusted assets invested in network operations. These include land areas that are not used in actual network operations. No reasonable return is obtained on these items as they are not part of the network operations.

Components are not part of network operations when they are not

- in the DSO's possession but instead used by the DSO with an arrangement under the law of property, where the possession of the network is not transferred from the owner of the network (so-called participation in another's fixed assets)
- subject to the DSO's development obligation
- DSO's network operations complying with the network licence.

In addition to the above, in a leased network, components that are not included in the lease agreement of the leased network are not part of network operations.

Furthermore, components pertaining to free competition are not included in adjusted assets invested in network operations. These include components ordered to be built by the customer or which meet the characteristics of a connection line as well as components classified as extra services, such as reserve power machines serving individual customers or fixed standby sets serving customers.

A network section serving an individual production plant or several plants, which is

built after 1 September 2013, is not included in network operations unless the network section also simultaneously serves electricity consumption other than that directly related to production.

In the case of a line or cable renovation, which meets the characteristics of a connection line and was owned by the DSO before 1 September 2013, this may still be considered construction that falls under the scope of network operations if the customer refuses to take control of the section in question.

COMPONENTS NOT PART OF ADJUSTED ELECTRICITY NETWORK ASSETS

Components that are not part of the network operations can also not be part of the electricity network assets. In addition, components are not part of the adjusted electricity network assets when they are not

- connected to the network
- in actual use, for example, stored equipment and materials
- a source of acquisition costs to the DS
- necessary for network operation.

Adjusted electricity network assets do not include components that have not been fully activated as investments in accounting. For example, a component that is still partly included in unfinished investments in the accounting may not be reported in adjusted asset items in the structure data, as otherwise the assets will be taken into account twice. The corresponding components must only be reported in the structure data once all incomplete investments have been recorded as complete in accounting.

In addition, components whose expenditure has been recorded as costs may not be reported in adjusted network assets in the network structure data, as this would lead to taking the costs into account twice in the methods.

Special features of a high-voltage distribution network

A network section built after 1 September 2013 and serving an individual electricity consumer or one or more production plants can be included in adjusted electricity network assets in a high-voltage distribution network if it is

- funded by the DSO
- owned by and in the possession of the DSO
- originally designed and dimensioned to also serve the DSO’s other customer’s consumption in the region in the near future and this can be verified
- techno-economically the most sensible network solution for the electricity system and end-users, enabling the production of the transmission service for all network users cost-effectively.

The DSO must provide an account of the components of the high-voltage distribution network serving one or more production plants or one electricity consumer, which it has included in adjusted electricity network assets, and the reasons why it has done so, in connection with delivering the regulatory data. The Authority will assess the handling of these components on the basis of the account.

In a high-voltage distribution network, it must be considered that a project permit for high-voltage lines referred to in section 14 of the Electricity Market Act does not determine how the component or part of the network is processed in the regulation methods.

In the regulation methods, only those parts of the network that can be reasonably found to differ from the characteristics of the connection lines and meet the objectives set in legislation for cost-effectiveness and justified demands for the development of transmission links in a high-voltage network will be accepted into network operations and its network assets. The development of the transmission links in the high-voltage network is necessary and justified if the transmission of electricity can no longer be reasonably managed with the existing network and its transmission links. The high-voltage network must take into account that it is primarily the responsibility of the connecting customer to build the necessary connection line to the high-voltage network instead of the DSO having to build the necessary line section close to the connecting customer's equipment.

For example, a line section built for an individual connecting customer or for several industrial plants, which differs significantly from the most cost-effective route, can be interpreted as a network component that meets the characteristics of the line connection implemented based on the connecting customer's needs or a cost-ineffective network section from the perspective of transmission links of the electricity system and other customers. In such cases, a network will only be accepted into the network assets based on the most cost-effective, i.e. as a rule, the shortest possible route, if the case concerns construction as a part of network operations.

The DSO must provide the Authority with a report if deviating from the shortest and, in principle, the most cost-effective solution for all customers due to one or several connecting customers. This ensures that the high-voltage network, which is part of regulated network operations, would be appropriately constructed in accordance with the efficiency principle as cost-effectively as possible for all end-users only for the development of transmission links, not to meet the demands of individual connecting customers for connection lines. Based on the account, the Authority will assess the share of network assets that can be taken into account when reporting structure data. Within the limits set by project permits, the DSO may continue to implement the high-voltage network as it sees best, but the methodologies presented in this document aim to ensure that end-users do not have to pay higher delivery fees for solutions in which the high-voltage network has been, in practice, only implemented due to the needs of individual connecting customers, despite the fact that the connection could be implemented more cost-effectively for end-users instead of as construction that belongs to electricity network operations regulated with a connection line. Furthermore, this practice aims to ensure that the network is constructed and taken into account in the methods only using cost-effective solutions from the perspective of network development to ensure that transmission prices will not increase due to unnecessarily large network mass.

As legislation changes and influences the interpretation of the aforementioned matters, the content of the valid legislation will naturally be complied with as required.

If necessary, the Authority will provide more detailed guidance on the interpretation of network operations or parts of the network not covered by network assets.

SUBSIDIES RECEIVED FOR THE CONSTRUCTION OF THE NETWORK

The DSO may receive subsidies or other compensation for investing in the network, for example, from the state of Finland or the European Union. As a rule, a subsidy is always involved if a party directly contributes to the DSO’s construction costs.

However, common-use poles are not, as a rule, taken into account in the methods and they must be reported in accordance with the instructions for filling in structure data. The general principle in the reporting of common-use poles is that the common-use pole is quantitatively taken into account only once. The common-use poles between the main grid company and the distribution network company are adjusted for both parties by utilising the unit prices of the main grid for two-circuit poles. The same principle naturally also applies to declaring common-use poles between two DSOs, but here, the DSO's pole structures and unit prices are used.

As a rule, common-use poles are taken into account based on the realised cost allocation between two system operators. If neither of them can present more detailed information on this, the poles are taken into account as half of the total amount for both operators. The processing of the common-use poles is verified on a case-by-case basis to ensure that cost items are not taken into account twice or otherwise if no cost item for the adjusted section is visible in the DSO's balance sheet. Regulatory data will be separately collected for common-use poles.

Components funded with the subsidies or compensation received for building the network are not included in the adjusted net present value of the electricity network assets. Equivalent subsidies are eliminated from the calculation by indicating only the part of the network components for which no subsidy has been received. The subsidised section may not be reported in the adjusted structure data. However, the details of the subsidised network section are reported separately in the structure data in accordance with separately provided instructions. This applies to everyone, including older investments.

In connection with providing the network structure data, the DSO must provide an account of the amounts of any subsidies and other compensations it has received for the network components in actual use. This account must itemise the amount of subsidy allocated for each network component.

In the case of revenue generated by line transfers to the DSO at the request of and based on the needs of customers, the charges for line transfer costs will not be counted as subsidised received for the construction of the network. The compensation paid by the customer for network line transfers is not considered to be allocated to the actual investment as regards the methods but to the costs of transferring the network. In this case, these transfer costs should be itemised in the accounting and the compensation in question should be recorded in return for them, either in the profit and loss account or in the balance sheet. In the case of costs affecting the profit or loss, the subsidy would be recorded as income and in the case of items affecting the balance sheet, as a deduction of acquisition costs.

The Energy Authority provides further instructions with respect to reporting the subsidies, if necessary.

LEASED NETWORKS

Components in a leased network are included in adjusted network assets invested in electricity network operations. The leasing arrangement is dissolved according to the same principles with respect to individual components and a larger entity.

The DSO must be able to itemise all the components that are included in the network lease.

It is possible for the DSO to notify the component it has leased in the regulatory data only if the owner of the component has not notified it in its own network assets in accordance with the network licence.

2.1.1 Adjusted frozen replacement value and straight-line depreciations

The correct and justified adjustment of network assets is linked to the determination of a reasonable rate of return.[6] The adjusted frozen replacement value and straight-line depreciations of electricity network assets are determined for all years of the regulatory period based on the situation valid on the last day of December of each year.

The determination of the frozen replacement value is based on a principle simulating book values, in which the value of investments is determined based on the value valid during the year of acquisition using average unit prices. This is done to ensure

[6] DFC Economics S.r.l., Rate-base adjustment for inflation in energy networks regulation: A report for Energiavirasto, 2 October 2023

that inflation is correctly taken into account, as a nominal rate of return will be used to determine a reasonable rate of return.

However, the principle will only be followed on a precise level for investments made from 2024 onwards. The valuation of investments made before 2024 and the determination of the frozen replacement value will be based on the network actually in operation at the end of 2023, which will be revalued using the unit price list and unit prices given in Appendix 1, without inflation adjustment. In other words, the value of the network invested before 2024 is determined directly based on the unit prices set out in Appendix 1, regardless of the years of investment. Similarly, for investments made since 2024, the frozen replacement value is determined based on the unit prices set for each year of investment according to the sixth or seventh regulatory period, described in more detail in the section 'Application and index adjustment of unit prices'.

A dissolution of an investment made before 2024 is calculated on the basis of the unit prices in Appendix 1 and a dissolution of an investment made in or after 2024 is valued using the unit price valid in the year of investment.

The calculation principle of the frozen replacement cost value (hereinafter RCV) for the network component in year n is given in the formula below.

$$RCV_n = RCV_{<2024} + \sum_{2024}^{n}\left(INV_y \times UP_y - Dissolutions_y\right) \qquad (2)$$

$Dissolutions_y$	=	The replacement value calculated for dissolutions in year y using the unit prices of the years of investment during which the dissolutions occurred
$RCV_{<2024}$	=	The RCV of the components in actual use invested in before 2024 in year n
INV_y	=	Investment volume in year y
UP_y	=	Unit price in year y

The formula below shows how the old mass, i.e. the frozen replacement value of the components invested in before 2024 but still in use, is calculated for a network component in year n.

$$RCV_{<2024} = INV_{quantity<2024} \times UP_{appendix1} \qquad (3)$$

$INV_{quantity<2024}$	=	The total quantity of the components in actual use invested in before 2024 in year n

$UP_{appendix1}$	=	Unit price in accordance with Appendix 1

This means that the DSO reports the information on the network components invested in before 2024 using the same principles as in the fifth regulatory period. Systems and communication networks are not taken into account in the calculation because they are taken into account in their balance sheet value.

Application and index adjustment of unit prices

For network mass invested in before 2024 but in actual use, unit prices in accordance with Appendix 1 are always used regardless of the year of investment. However, from 2024 onwards, a separate unit price specific to the year of investment will be determined for each year of investment. To make sure that the unit price would better reflect on average the cost level valid at the time of the investment in the adjustment of the components during the year of investment, i.e. the unit price would be better in line with the value at the time of the investment, the unit prices applied to investments during the regulatory periods will be adjusted by the change in the consumer price index for different years and the unit prices applicable to investments during the regulatory period will be determined separately for each period based on the investment costs of the period.

For the valuation of investments in the sixth regulatory period, unit prices adjusted for inflation in the year of investment based on the cost data of the sixth regulatory period will be applied during the sixth regulatory period (hereinafter the unit prices of the 6th period). Similarly, unit prices based on the costs of investments during the seventh regulatory period will be applied to the investments made during the seventh regulatory period (hereinafter the unit prices of the 7th period). As the final unit prices will only be determined at the end of the regulatory period, the most recent unit prices available for the period, i.e. unit prices updated at the end of the previous period, will be used to estimate the value of investments made during the period in the annual calculations of the annual reasonable return value prior to this. In other words, for the sixth regulatory period, index-adjusted unit prices as set out in Appendix 1 are used for determining the replacement value in calculations of the annual reasonable return value until more detailed and actual unit prices for that period have been established.

This is done in order to adjust the investments for the final calculations of the period at a more accurate level to better reflect the average cost level over the period before the final freezing of unit prices. For example, when the unit prices to be updated during the period are presumably mainly based on investments made in the period 2025–2026, and the unit price list is presented in the 2026 value, the unit price in question does not need to be adjusted using the consumer price index for more than at most a few years and the unit price will describe in more detail the average cost level realised during the sixth regulatory period.

The formula below describes the principle used for determining the unit price during the sixth regulatory period for investments made in the period 2024–2027.

$$UP_y = \frac{CPI_y}{CPI_n} \times UP_{6th\ period\_n} \tag{4}$$

UP_y = unit price for the investments of year *y*

CPI_y = the average of the index points of the consumer price index (2005=100) for April–September in year *y*

CPI_n = the average of the index points of the consumer price index (2005=100) for April–September in year n

$UP_{6th\ period\_n}$ = The unit price for the sixth regulatory period in the year n value

The formula below shows how unit prices will be applied during the seventh regulatory period for investments made in the period 2028–2031 during the seventh regulatory period.

$$UP_y = \frac{CPI_y}{CPI_n} \times UP_{7th\ period\_n} \tag{5}$$

UP_y = unit price for the investments of year y

CPI_y = the average of the index points of the consumer price index (2005=100) for April–September in year *y*

CPI_n = the average of the index points of the consumer price index (2005=100) for April–September in year n

$UP_{7th\ period\_n}$ = The unit price for the seventh regulatory period in the year n value

Based on this principle, the final freezing of unit prices takes into account any component-specific changes as well as other changes in costs in the valuation of investments that have occurred in the industry, when the applicable unit price is based as little as possible on index adjustments and more on actual cost data from the period.

In a situation where no applicable unit price for older investments has previously been found in the unit price list and the component has previously been valued in its book value, but where a unit price would be found for the component from the new unit prices, the available unit price is adjusted backwards to the value valid in the year of investment based on the change in the consumer price index and the valuation made through accounting is replaced by a valuation based on unit prices. For years of investments pre-2024, this adjustment will only be made until 2022.

Calculation of straight-line depreciation

Frozen straight-line depreciation is calculated from the normally frozen replacement value by dividing the frozen replacement value by the lifetime of the network component. The straight-line depreciation of a network component consists of the sum of the frozen replacement values for the different years of investment of that network component on the basis of the components actually in use. In this case, the straight-line depreciation (hereinafter SD) calculated for the entire network is the sum of the straight-line depreciations of the network components in use.

Straight-line depreciation is not calculated for components that do not expire. These include plots of substation land or line area compensations. The principle presented in the below formula is used to determine the straight-line depreciation for the whole network.

$$SD = \sum_i^n \frac{(RCV_i)}{lifetime\ replacement\ interval_i} \qquad (6)$$

RCV_i	=	Sum of frozen replacement values of network component i for different years of investment
lifetime replacement interval$_i$	=	The lifetime replacement interval of network component i

Determining the replacement value of underground cable ditches during the regulatory periods

In the case of underground cables, the valuation takes into account not only the unit price of the underground cable but also the average excavation costs incurred by the DSO, i.e. the price impact of the excavation (EUR/kilometres of underground cable) similarly as in previous methodological periods.

For the underground cable network invested in before 2024, the frozen replacement value of the network component can be calculated directly using the formula below.

$$RCV_y = quantity_y \times \left(UP_{appendix1} + Excavation\,price\,effect_{<2024}\right) \qquad (7)$$

$quantity_y$	=	The quantity of network components actually used in year y
$UP_{appendix1}$	=	Unit price in accordance with Appendix 1
Excavation price effect$_{<2024}$	=	The DSO’s average excavation cost per kilometre of underground cable for the old network mass in actual use invested in before 2024

The price effect of the excavation on the old network mass in actual use invested in before 2024 is determined using the breakdown presented in Appendix 1 and the unit prices reflecting the situation at the end of 2023, after which it will be frozen and remain in the same in calculations concerning underground cables invested in before 2024.

For underground cable investments occurring in 2024 or later, the frozen replacement value of the network component will be calculated for each year of investment in accordance with the formula below.

$$RCV_y = inv\_quantity_y \times \left(UP_y + Excavation\,price\,effect_y\right) \qquad (8)$$

$inv\_quantity_y$	=	Investment quantity in the network component in year y
UP_y	=	The unit price of the underground cable for the network component in year y
Excavation price effect$_y$	=	Average excavation cost per kilometre of underground cable for investments in year y

For investments made as of 2024, the price effect of excavation, i.e. the average annual excavation cost per kilometre of underground cable investments, will be calculated separately for each year of investment on the basis of the year’s investment volume and unit price data. The price effect of the excavation is calculated for underground cable investments made in 2024 and later specifically for the given year of investment based on the investments of the year under review using the following formula.

$$Excavation\ price\ efect_y = \frac{RCV_{ditch\_y}}{inv\_quantity_y} \qquad (9)$$

$inv\_quantity_y$	=	investment volume of ground cables in kilometres in year y
RCV_{ditch_y}	=	Frozen replacement value of ditch excavated in year y

Referring to the above, dissolutions and investments in ditches and the calculation of the net present value are automatically taken into account when calculating the value of underground cables. The current principle is therefore used to first determine the frozen replacement value of the ditch excavated during the year and the quantity of underground cables installed in the ditch, and then to calculate the price effect of the excavation for the year in question, which is added to the unit prices of the different underground cable cross-sections.

Determining and interpreting ditch data

Actual ditch lengths can be determined based on underground cable location data. According to section 123 of the Electricity Market Act, DSOs have had to digitise the data concerning the location of underground cables by the end of 2014 at the latest. It is possible to establish the length of ditches without site-specific verification by developing the network data systems: for example, cables that are in the same ditch can be automatically interpreted as a single ditch when using the systems.

As a rule, underground cables running next to each other on the same side of the road are interpreted to run in a single ditch. Similarly, underground cables running on the opposite sides of the road involve two separate ditches.

In certain exceptional cases, with the permission of the Authority, it may be possible to interpret underground cables that run close to one another on the same side of the road as being located in two separate ditches. However, this requires verification of the data for the Authority and proper criteria to demonstrate that if the underground cables were to be dug up, this would involve digging two separate ditches. In such cases, the DSO must contact the Authority to get confirmation on the matter. If the situation concerns a large area and it can be transparently verified that there are two separate ditches, the Authority can give its approval for the specification of the data. This procedure can therefore not be used to repair individual, minor sites.

Excavation condition classes

The accuracy of the definition of excavation conditions has been improved to better correspond to the costs and be more unambiguous compared to previous regulatory periods. Based on a unit price survey, the Authority has examined which datasets most accurately describe the level of excavation costs. Based on the report, the Authority has decided that the previously used CLC[7] dataset will be abandoned with the exception of rocky soil and replaced with datasets clearly reflecting urban environments and soil. In the future, the conditions will be determined based on the following datasets, which are as detailed as possible:

- Town plan areas
- Urban-rural classification: Inner urban area
- City centre areas: Urban centre, major sub-centre and minor sub-centre
- Soil: Rocky soil

The environmental condition classes for excavations in the distribution network are as follows:

1. Easy: an area outside a town plan area (and other conditions)
2. Regular: within a town plan area (but outside other conditions)
3. Ordinary: rocky soil or CLC rock areas (outside the inner urban area or city centre area classes)
4. Difficult: inner urban area (but outside city centre classes)
5. Extremely difficult: more than 30 squares in the city centre (but less than 100 squares) and large and small sub-centres, which are the sub-centres of a metropolitan area (minimum 100 squares in an urban centre)
6. Extremely difficult: urban centre of at least 100 squares

The above classes are also used to partly assist in determining 110 kV underground cable ditches, line area compensations, and plots of substation land buildings.

If necessary, the Energy Authority will issue more detailed instructions on determining the conditions. If problems arise with regard to the control effects and cost correlation for the data on rocky soil during the control periods, the Energy Authority will remove class 3 from the unit price list for the seventh control period. However, based on the current survey, the Authority considers that the class is justified on the basis of the correlation of costs, even though it is known that the rocky soil data is not very precise and may not very accurately describe issues such as whether there was a need for excavation at a site on a case-by-case basis, for

[7] Corine and land cover dataset

example. However, on a large scale, the Energy Authority considers taking the dataset into account on the basis of current information as a better alternative than ignoring it, as the costs seemed to correlate with the data in the unit price survey.

The DSO must be able to verify the ditch data it has reported. For the parts that the DSO is unable to verify the ditch data it has reported, the ditches' condition will be interpreted as 'easy'.

2.1.2 Adjusted net present value

The adjusted net present value of the electricity network assets is calculated for all years of the regulatory period using the frozen replacement value valid on the last day of December in each year.

The adjusted net present value is calculated for each year of investment on the basis of replacement values frozen for each network component as well as age and lifetime replacement interval data. The net present value of the entire network consists of the sum of the current value of different network components. The calculation principle is summarised below for the adjusted net present value (NPV) of the network component in year n.

$$NPV_n = NPV_{<2024\_n} + \sum_{2024}^{n} NPV_{y\_n} \tag{10}$$

NPV_{y_n}	=	NPV of components invested in the year y in year n
$NPV_{<2024\_n}$	=	The NPV of the components in actual use invested in before 2024 in year n

The adjusted net present value of the old mass, i.e. components invested in before 2024, for the network component in year n, is presented in the formula below.

$$NPV_{<2024\_n} = \left(1 - \frac{average\ age_n}{lifetime\ replacement\ interval}\right) \times RCV_{<2024\_n} \tag{11}$$

$RCV_{<2024\_n}$	=	The total frozen replacement value of the components in actual use invested in before 2024 in year n
$average\ age_n$	=	Average age of the network component in year y
lifetime replacement interval	=	The lifetime replacement interval of the network component

The adjusted net present value of the newer mass, i.e. the investments made since 2024 for the network component, is based on the frozen replacement values per investment year and the sum of the net present values determined by age data. The adjusted net present value of the components invested in year y for the network component in year n is shown below.

$$NPV_{y\_n} = \left(1 - \frac{age\ data_{y\_n}}{lifetime}\right) \times RCV_{y\_n} \qquad (12)$$

$age\ data_{y\_n}$	=	Age of components invested in year y in year n
RCV_{y_n}	=	The total frozen replacement value of the components in actual use invested in year y in year n
lifetime	=	The lifetime of the network component

The calculation is based on the number and age of components in the year under review similarly as previously, but the amount should be distributed over the completed years of investment so that the annual unit price is applied to all investments made as of 2024 and the same unit prices in accordance with the Appendix is applied to all investments made before 2024 regardless of the year of investment. When calculating the net present value, the current value may not be negative for specific components even if the actual age of the component was greater than the lifetime replacement interval.

2.2 Adjustment of other assets in non-current assets

In connection with the adjustment of assets invested in network operations, non-current assets other than electricity network assets in the unbundled balance sheet are basically taken into account in their balance sheet value. These kinds of assets include, e.g. acquisitions in progress. However, in respect of such assets, goodwill and investments are adjusted by eliminating them.

OTHER ASSETS RECORDED IN ELECTRICITY NETWORK ASSETS

The DSO must notify as notes to the financial statements any items recorded in electricity network assets that are not taken into account in the calculation of adjusted replacement value or net present value. These items are taken into account in adjusted assets invested in network operations in their value according to the unbundled balance sheet. Depreciation according to plan based on the unbundled profit and loss account is permitted for them as a reasonable level of depreciation. Such items are, for example, stored equipment and materials related to electricity network operations.

Components included in these kinds of items are not taken into account in the calculation of adjusted replacement value of the electricity network assets even if these components were included in the list of components in Appendix 1. These components are taken into account in their value according to the unbundled balance sheet. If necessary, the DSO must provide an account of the book value of the components.

ELECTRICITY NETWORK COMPONENTS RECORDED IN OTHER THAN ELECTRICITY

NETWORK ASSETS

However, if electricity network components are recorded under items other than the electricity network assets in non-current assets, the balance sheet value of the components is eliminated from these items. Elimination is carried out with respect to components that are referred to in the list of network components in Appendix 1 and are in actual use in the electricity network. These components are taken into account in adjusted assets invested in network operations in their adjusted net present value in accordance with section 2.1.2.

GOODWILL

Goodwill in the unbundled balance sheet is eliminated in connection with the adjustment of assets invested in network operations.

Legislative history (HE 20/2013 vp) takes a stand on acquisitions and other arrangements where the sum paid for electricity network assets is higher than its actual net value.

Therefore, the regulation methods must be based on the actual net value of the DSO’s electricity network assets and not, for example, on the commercial market value determined on the basis of mergers and acquisitions, which may include valuation or acquisition items not pertaining to electricity network operations.

Electricity network assets in accordance with the unbundled balance sheet are adjusted to the adjusted net present value as described in section 2.1. This describes the actual net value of the electricity network assets in the regulation methods.

Based on this, the Energy Authority deems that the goodwill of the unbundled balance sheet arising in connection with an acquisition describes an intangible asset that it has not been possible to allocate to other assets.

Merger assets

The share of goodwill of the merger assets created in the merger is treated in the same way as goodwill.

INVESTMENTS

When adjusting assets invested in network operations, investments in non-current assets according to the unbundled balance sheet are eliminated.

Investments in non-current assets include, e.g. investments that seek profits other than those directly connected to network operations or the expansion of business operations. Such investments cannot be regarded as necessary in terms of network operations. Therefore, it is not justified to include them in any part of adjusted assets invested in network operations.

2.3 Adjustment of assets in current assets

FINANCIAL ASSETS

When calculating adjusted assets invested in network operations, financial assets recorded in the unbundled balance sheet are eliminated.

Financial assets to be eliminated include the following items on the assets side of the unbundled balance sheet:

- short- and long-term receivables
- marketable securities
- cash and bank receivables and comparable items.

In accordance with the decision of the Supreme Administrative Court (KHO:2010:86), trade receivables are not eliminated.

The management of financial assets is not considered actual network operations even in financing theory. Therefore, it is not justified to include it in any part in adjusted assets invested in network operations.

The costs resulting from financial assets necessary to safeguard network operations are taken into account in the calculation of realised adjusted profit as detailed in section 5.3.

INVENTORIES

When calculating adjusted assets invested in network operations, the inventories recorded in the unbundled balance sheet are eliminated.

2.4 Adjustment of capital invested in network operations

The liabilities side of the adjusted balance sheet is determined by dividing the adjusted capital invested in network operations into

- adjusted equity
- adjusted interest-bearing debt
- adjusted non-interest-bearing debt.

2.4.1 Adjustment of equity

In the adjusted balance sheet, equity is regarded as the DSO's equity in accordance with the unbundled balance sheet.

In the adjusted balance sheet, equity is also considered to include voluntary provisions and the depreciation of assets deducted by deferred tax liability as well as refundable connection fees activated on the unbundled balance sheet after 2004. Group contributions are also taken into account in the adjustment of equity.

Furthermore, an equalisation item is added to equity in the adjusted balance sheet.

GROUP CONTRIBUTION

The DSO is in an equal position regardless of whether or not it operates under a group structure.

Granted group contribution

In the adjustment of capital invested in network operations, the amount of group contribution deducted by the deferred tax liability is returned to equity.

This is done regardless of whether a decision has been made on the closing date to grant the group contribution and which either has or has not been paid yet.

Granted group contribution is an item of a profit distribution nature, and in the unbundled balance sheet of a DSO operating without a group structure, it would be entered under ‘profit for the financial period’ in the unbundled balance sheet.

Received group contribution

In the adjustment of capital invested in network operations, the amount of group contribution deducted by the deferred tax liability is deducted from equity. Received group contribution is also an item of a profit distribution nature, and it increases the profit for the financial period.

Receivables are eliminated in the calculation of reasonable return in the way presented in section 2.3 of this document. The amount of received group contributions is taken into account in the elimination.

EQUALISATION ITEM

The equalisation item describes the difference in value between the adjusted assets invested in network operations and the assets side of the balance sheet.

The equalisation item is used to balance the assets and liabilities in the adjusted balance sheet. It is recorded under equity in the liabilities side of the adjusted balance sheet.

The value of the equalisation item is calculated as the difference of the assets and liabilities sides of the adjusted balance sheet.

The equalisation item may also be negative if the value of adjusted assets invested in network operations is lower than the assets side of the unbundled balance sheet.

2.4.2 Adjustment of debt

In the adjustment of capital invested in network operations, debt is divided into interest-bearing and non-interest-bearing debt.

ADJUSTED INTEREST-BEARING DEBT

Interest-bearing debt in the unbundled balance sheet is taken into account as such in adjusted interest-bearing debt. However, the share of equity in the interest-bearing group subsidy liability will be eliminated.

Items in interest-bearing debt include bank, pension and other loans in the non-current liabilities in the unbundled balance sheet, as well as the instalments of the above-mentioned loans in the current liabilities in the unbundled balance sheet.

In the adjustment of capital invested in network operations, any capital loans and other interest-bearing loans granted by the owners of the DSO are treated as interest-bearing debt.

ADJUSTED NON-INTEREST-BEARING DEBT

Non-interest-bearing debt in the unbundled balance sheet is taken into account as such in adjusted non-interest-bearing debt. These items include accounts payable, accruals and other short-term debt. However, the share of equity in the non-interest-bearing group subsidy liability will be eliminated. The share of the non-interest-bearing group subsidy liability and the depreciation of assets deducted by deferred tax liability is considered non-interest-bearing debt.

Mandatory provisions entered in the unbundled balance sheet are treated in full as non-interest-bearing debt.

NEGATIVE FINANCIAL ASSET ACCOUNT BALANCE

When the account for current assets allocated to network operations is negative, the nature of the item is network operations liability. The negative balance of the financial assets item allocated to network operations is added to the adjusted non-interest-bearing debt.

Here, the financial assets item refers to:

- short- and long-term receivables carried forward
- other short- and long-term receivables
- marketable securities
- cash and bank receivables and comparable items.

Negative financial asset items taken into account in non-interest-bearing debt are not taken into account when calculating the reasonable costs of financial assets in accordance with section 5.3.

CONNECTION FEES

Components funded by connection fees are included in adjusted assets invested in network operations.

The DSO is in an equal position regardless of whether it uses refundable or non-refundable connection fees.

Refundable connection fees

Although refunds are rarely made, even a formal refunding condition gives the connection fee the character of a debt. As distinct from other long-term debts, connection fees involve no interest liabilities, i.e. they are a non-interest-bearing debt by nature. Refundable connection fees cannot be entered under equity in the unbundled balance sheet by virtue of the statement by the Accounting Board.[8]

In the adjustment of capital invested in network operations, refundable connection fees entered in the unbundled balance sheet by the end of 2004 are treated as non-interest-bearing equity.

Refundable connection fees recorded in the unbundled balance sheet after 2004 do not increase non-interest-bearing debt in the adjusted balance sheet.

The net change in connection fees is returned in the calculation of realised adjusted profit in accordance with chapter 5.1.

The DSO must itemise as a separate item the annual amount of refundable connection fees entered in the balance sheets of the owner or its other companies as notes to the unbundled financial statements.

Non-refundable connection fees

Non-refundable connection fees are income from network operations in accordance with section 5.1.

3 REASONABLE RATE OF RETURN

3.1 Model for weighted average cost of capital

The method used when determining a reasonable rate of return approved for adjusted capital invested in network operations is the Weighted Average Cost of Capital, or the WACC model.

3.2 Reasonable cost of equity

When determining a reasonable rate of return, the reasonable cost of equity is calculated with the Capital Asset Pricing Model, or the CAP model.

The calculation of the model is presented in Formula 13.

$$C_E = R_r + \beta_{equity} \times MRP + LP + CRP \qquad (13)$$

where

[8] Kirjanpitolautakunnan lausunto sähköliittymismaksujen kirjaamisesta (Decision of the Accounting Board on the recording of electricity connection fees) (1650/2001)

C_E = reasonable cost of equity

R_r = risk-free rate

β_{equity} = equity beta coefficient

MRP = market risk premium

LP = premium for lack of liquidity

CRP = country risk premium

3.2.1 Risk-free rate of equity

When determining a reasonable rate of return, the interest of ten-year government bonds of the state of Germany is used as the risk-free rate of interest, which acts as a basis for a reasonable cost of equity. The value is updated annually using the average of the actual daily values from the period from April to September of the previous year. For example, for 2024, the value is determined based on the averages of actual daily values from April–September 2023 and is 2.48%.

The actual daily values have been published by the Deutsche Bundesbank[9].

The value of the above-described risk-free interest rate is also used as risk-free rate, which acts as a basis of the reasonable cost of debt (3.3.1).

3.2.2 Country risk premium

The value used as the country risk premium is the average of the daily values of the interest of the ten-year bonds of the state of Finland in the period from April to September of the previous year, minus the average of the interest of the ten-year bonds of the state of Germany from the same period. The country risk premium is 0.59% in 2024 and will be updated annually.

The actual daily values reflecting Finland's interest rates are published by the Bank of Finland.

The value of the above-described country risk premium rate is also used as the country risk premium to be taken into consideration in the reasonable cost of debt (3.3.1).

[9] https://www.bundesbank.de/en/statistics/money-and-capital-markets/interest-rates-and-yields/daily-yields-of-current-federal-securities-772220

3.2.3 Beta coefficient

In the first half of the sixth regulatory period (2024–2025), the value of equity beta is 0.93 when determining a reasonable rate of return in electricity distribution network operations and high-voltage distribution network operations.

During the methodological period, the equity beta will be updated once every two years by the end of 2025, 2027 and 2029, based on the same calculation method as for the asset beta and capital structure as the one applied during the first half of the sixth control period.

The value used for the asset beta is the median of the range of a reference group defined for the electricity distribution network industry. In the first half of the sixth regulatory period (2024–2025), the value 0.48 will be applied[10,11].

The asset beta coefficient is adjusted as equity beta coefficient using the Hamada formula. The calculation of this adjustment where the debt ratio and the rate of corporate tax are taken into account is presented in Formula 14.

$$\beta_{equity} = \beta_{asset} \times \left(1 + (1 - yvk) \times \frac{g}{1-g}\right) \tag{14}$$

where

β_{equity} = equity beta coefficient

β_{asset} = asset beta coefficient

yvk = the rate of corporate tax

g = share of interest-bearing debt in the optimal capital structure

$1 - g$ = share of equity in the optimal capital structure

The reference group used for the update must include several companies that have electricity distribution network operations at the time the beta coefficient is updated. Otherwise, the Authority will apply the latest confirmed beta coefficient value.

---

10 The asset beta coefficients have been calculated by dividing the covariance of the control company and the comparable index returns by the variance of return using weekly returns from a two-year period on the date of valuation. Each asset beta has been ultimately adjusted using the Blume method (the so-called adjusted beta), in which the raw beta value is adjusted by emphasising one third of the average market risk: $\beta_{oikaistu} = \frac{2}{3} \times \beta_{oikaisematon} + \frac{1}{3} \times 1$

11 Fortum Oyj and RWE AG, which do not have electricity distribution network operations, have been removed from the reference group applied by KPMG.

3.2.4 Market risk premium

In the sixth regulatory period (2024–2027), a market risk premium value based on an implicit equity market risk premium in an AAA-rated country is used to determine a reasonable rate of return[12].

For the seventh regulatory period (2028–2031), the market risk premium will be updated by the end of 2027 based on a corresponding calculation method.

The value to be applied for each regulatory period will be based on the average of the most recent April–September period available at the time of the update. Therefore, in the sixth regulatory period, the market risk premium is based on April–September 2023, and is 4.61 %.

If the database is not available at the time of the update, the Authority will apply a market risk premium of 5% in the seventh regulatory period.

3.2.5 Premium for lack of liquidity

The value of the premium for lack of liquidity is 0.6% when determining a reasonable rate of return.

3.2.6 Capital structure

The median of the capital structure range derived from the control companies is used to determine the reasonable rate of return. In the first half of the sixth regulatory period (2024–2025), the weighting of interest-bearing debt is 54% and the weight of equity is 46%[13].

The capital structure will be updated every two years during the methodological period by the end of 2025, 2027 and 2029 using a similar method.

The reference group used for the update must include several companies that have electricity distribution network operations at the time the capital structure is updated. Otherwise, the Authority will apply the latest confirmed capital structure.

3.3 Reasonable cost of debt

The calculation of the model describing the reasonable cost of debt is presented in Formula 15.

---

12 The used source is the implicit market risk premium "ERP (T12 m with sustainable payout)" published monthly by Professor Damodaran based on the results, dividends and repurchases in the previous 12 months.

13 Fortum Oyj and RWE AG, which do not have electricity distribution network operations, have been removed from the reference group applied by KPMG.

$$C_D = R_r + DP + CRP \quad (15)$$

where

C_D = reasonable cost of debt

R_r = risk-free rate

DP = debt premium

CRP = country risk premium

3.3.1 Risk-free rate of debt and country risk premium

When determining a reasonable rate of return, the value of a risk-free rate and country risk ratio, which are the basis for the reasonable cost of debt, is calculated in the same way as with equity (3.2.1 and 3.2.2).

3.3.2 Debt premium

The median of the range derived from control companies is used as the debt premium value when determining a reasonable rate of return. In the first half of the sixth regulatory period (2024–2025), the value 2.10%. will be applied.

The debt premium will be updated every two years during the methodological period by the end of 2025, 2027 and 2029 using a similar method.

The reference group mentioned above must include several companies at the time the risk premium is updated. Otherwise, the Authority will apply the latest confirmed value as the debt premium.

3.4 Calculating a reasonable rate of return

The weighted average costs of adjusted capital invested in network operations are used as the reasonable rate of return (WACC %) in the regulation methods.

A reasonable pre-tax rate of return is used in the regulation methods.

A reasonable rate of return is first calculated post-tax in the way presented in Formula 16.

$$WACC_{post-tax} = C_E \times (1 - g) + C_D \times (1 - yvk) \times g \quad (16)$$

where

$WACC_{post\text{-}tax}$	=	reasonable rate of return after corporate tax
C_E	=	reasonable cost of equity
C_D	=	reasonable cost of interest-bearing debt
g	=	share of interest-bearing debt in the optimal capital structure
$1 - g$	=	share of equity in the optimal capital structure
yvk	=	current rate of corporate tax

After that, the post-tax reasonable rate of return will be adjusted with the current rate of corporate tax. This will give the pre-tax reasonable rate of return, the calculation of which is presented in Formula 17.

$$WACC_{pre-tax} = \frac{WACC_{post-tax}}{(1 - yvk)} \tag{17}$$

where

$WACC_{pre\text{-}tax}$	=	reasonable rate of return before corporate tax

A fixed capital structure where the interest-bearing debt and equity are derived from the control companies is applied to the DSO. That way, the calculation of pre-tax reasonable rate of return before corporate tax is carried out in accordance with Formula 18.

$$WACC_{pre-tax} = \frac{C_E \times (1 - g)}{(1 - yvk)} + C_D \times g \tag{18}$$

3.5 The reference group used for determining and updating parameters for a reasonable rate of return and related criteria

An industry-specific beta value used in calculating the reasonable cost of equity, debt premium as well as the optimal equity structure used in calculating weighted average cost are derived based on an industry-specific reference group. The reference group applicable during the methodology period for electricity distribution network operations and high-voltage distribution network operations is shown in the table below.

Table 2. *Reference group for electricity distribution network operations and high-voltage distribution network operations*

Table: Reference group for electricity distribution network operations and high-voltage distribution network operations
E ON SE
Edison International
EDP Energias de Portugal SA
Electricite de France SA
Enel SpA
Iberdrola SA
SSE PLC

If there are significant changes in the reference group during the methodology period and a significant proportion of the control companies no longer engage in network business, the last confirmed value determined for each parameter will be applied.

4 REASONABLE RETURN

The DSO's reasonable return is calculated by multiplying the adjusted capital invested in network operations (2.4) by the reasonable rate of return (3.4).

Therefore, the DSO receives a reasonable return on

- adjusted equity invested in network operations
- interest-bearing debt invested in network operations.

No reasonable return is obtained on non-interest-bearing debt invested in network operations as its returns requirement is zero.

The calculation of pre-tax reasonable return before corporate tax is presented in Formula 19.

$$R_{k,\ pre\text{-}tax} = WACC_{pre\text{-}tax} \times (E + D) \tag{19}$$

where

$R_{k,\ pre\text{-}tax}$	=	reasonable return before corporate tax, EUR
$WACC_{pre\text{-}tax}$	=	reasonable rate of return, per cent
E	=	adjusted equity invested in network operations, EUR
D	=	adjusted interest-bearing debt invested in network operations, EUR
$E + D$	=	adjusted capital invested in network operations, EUR

4.1 Adjusted assets and capital invested in network operations

ADJUSTED ASSETS INVESTED IN NETWORK OPERATIONS

Adjusted assets invested in network operations consist of adjusted electricity network assets in the unbundled balance sheet (2.1), other non-current assets (2.2) and current assets (2.3).

Electricity network assets in non-current assets of the unbundled balance sheet, which constitute the most important asset item of electricity network operations, are replaced with adjusted electricity network assets (2.1) They consist of adjusted net present value of the electricity network (2.1.2), which is calculated from the adjusted replacement value of the electricity network (2.1.1)

Other assets invested in electricity network operations are adjusted next (2.2 and 2.3).

Table 3 shows the adjustment of the assets side of the balance sheet in the calculation of the adjusted assets invested in network operations in the form of a balance sheet calculation.

Table 3. *The principle of adjusting the assets side of the balance sheet*

ASSETS

UNBUNDLED BALANCE SHEET	**ADJUSTED BALANCE SHEE**
Non-current assets	**Adjusted non-current assets**
Electricity network	Adjusted net present value of the electricity network assets
Goodwill	
Investments	
Other non-current assets	Other non-current assets in the balance sheet value
Current assets	**Adjusted current assets**
Inventories	Acquisitions recorded in the balance sheet value by the network licence holder of a leased network in inventories corresponding to incomplete investments linked to the network
Trade receivables	Trade receivables in the balance sheet value
Financial assets	
TOTAL ASSETS	**ADJUSTED BALANCE SHEET TOTAL**

ADJUSTED CAPITAL INVESTED IN NETWORK OPERATIONS

The adjusted capital invested in network operations is obtained by adding together adjusted equity (2.4.1), adjusted interest-bearing debt (2.4.2) and adjusted non-interest-bearing debt (2.4.2). An equalisation item (2.4.1) is also added to this to reconcile the different sides of the balance sheet.

Table 4 shows the adjustment of the assets side of the balance sheet in the calculation of the adjusted capital invested in network operations in the form of a balance sheet calculation.

Table 4. *The principle of adjusting the liabilities side of the balance sheet.*

LIABILITIES

UNBUNDLED BALANCE SHEET	ADJUSTED BALANCE SHEE
Equity	**Adjusted equity**
Equity	Equity in the balance sheet value
	Granted group contributions, deducted by deferred tax liability
	Depreciation difference of assets deducted by deferred tax liability, and voluntary provisions.
	Net change in accumulated connection fees since 2004
	Received group contributions, deducted by deferred tax liability
	Equalisation item of adjusted balance sheet
Accumulated appropriations	
Depreciation difference and provisions	
Mandatory provisions	
Mandatory provisions	

Debt	**Adjusted debt**
Interest-bearing	**Interest-bearing**
Interest-bearing debt	Interest-bearing debt in the balance sheet value
Capital loans	Capital loans in the balance sheet value
	- Share of equity in interest-bearing group contribution that is granted but not paid
Non-interest-bearing	**Non-interest-bearing**
Non-interest-bearing debt	Non-interest-bearing debt in the balance sheet value
	- Share of equity in non-interest-bearing group contribution that is granted but not paid - Net change in accumulated connection fees since 2004 Mandatory provisions in the balance sheet value
	Share of deferred tax liability
	Negative balance of financial assets accounts
TOTAL LIABILITIES	**ADJUSTED BALANCE SHEET TOTAL**

4.2 Reasonable rate of return

Reasonable rate of return is calculated on the basis of the weighted average cost of capital (WACC model).

When the definition of a reasonable rate of return in accordance with Formula 19 is entered in Formula 18, the calculation of a reasonable rate of return after corporate tax on adjusted capital invested in network operations (pre-tax) will comply with Formula 20.

$$R_{k,pre-tax} = \left(\frac{C_e \times (1-g)}{(1-yvk)} + C_D \times g \right) \times (E + D) \qquad (20)$$

The reasonable cost of adjusted equity invested in network operations in Formula 17 is calculated in accordance with Formula 21.

$$C_E = R_r + \beta_{asset} \times \left(1 + (1-yvk) \times \frac{g}{1-g} \right) \times MRP + LP + CRP \qquad (21)$$

The reasonable cost of adjusted interest-bearing debt invested in network operations in Formula 17 is calculated in accordance with Formula 22.

$$C_D = R_r + DP + CRP \qquad (22)$$

in formulae 20, 21 and 22

$R_{k,\,pre\text{-}tax}$	=	reasonable return before corporate tax
C_E	=	reasonable cost of equity
C_D	=	reasonable cost of interest-bearing debt
yvk	=	the rate of corporate tax
E	=	adjusted equity invested in network operations
D	=	adjusted interest-bearing debt invested in network operations
g	=	share of interest-bearing debt in the optimal capital structure
$1 - g$	=	share of equity in the optimal capital structure
R_r	=	risk-free rate
β_{asset}	=	asset beta coefficient
MRP	=	market risk premium
LP	=	premium for lack of liquidity
DP	=	debt premium
CRP	=	country risk premium

Table 5 shows the parameters for a reasonable rate of return applied in the sixth and seventh regulatory periods.

Table 5. *Parameters of a reasonable rate of return in the sixth and seventh regulatory period*

PARAMETER	VALUE APPLIED	UPDATE FREQUENCY

RISK-FREE RATE	2.48% in 2024, the average of daily values of 10-year government bond interest rates in the state of Germany between April and September of the previous year	Annually
COUNTRY RISK PREMIUM	0.59% in 2024, the difference in the average of daily values of 10-year government bond interest rates in the state of Germany between April and September of the previous year	Annually
ASSET BETA	0.48, updated using weekly returns from a two-year period on the date of valuation.	Once every two years
EQUITY BETA	0.93, updated in the same context as the asset beta and capital structure	Once every two years
MARKET RISK PREMIUM	4.61%, average for April–September preceding the update of the Damodaran database (in 2023 and 2027)	Once every four years
PREMIUM FOR LACK OF LIQUIDITY	0.6%	
CAPITAL STRUCTURE (liabilities/equity)	54% / 46%, updated using the value on the date of valuation	Once every two years
DEBT PREMIUM	2.10 % updated using the average of the returns of the week preceding the date of valuation (Mid Yield)	Once every two years
CORPORATE TAX RATE	20%	

UPDATING THE PARAMETERS OF A REASONABLE RATE OF RETURN

The Energy Authority updates:

- the risk-free interest rate and the value of the country risk premium each year;
- the rate of corporate tax to correspond with the current value, if necessary
- the debt premium, asset and equity beta and the capital structure once every two years
- the market risk premium for each regulatory period (once every four years).

The value of the premium for lack of liquidity remains the same throughout the eight-year methodology period.

5 INCOME AND COSTS OF NETWORK OPERATIONS

The basis for calculating realised adjusted profit is the operating profit (loss) in accordance with the unbundled profit and loss account of the network operations. This is adjusted with the profit adjustment items described in this chapter. After that, the impact of incentives will be deducted in the calculation of realised adjusted profit (6).

5.1 Income from network operation

Income entered before the operating profit (loss) in the unbundled profit and loss account are used as returns on network operations in the calculation of realised adjusted profits.

Income from network operations include

- income from network service fees
- income from other services related to network operations
- non-refundable connection fees
- rental income from common-use poles
- income comparable to the above.

The following adjustment items are returned in the calculation of realised adjusted profit:

- annual net change in refundable connection fees
- network rents
- planned depreciation and reduction in value of electricity network assets in non-current assets
- planned amortisation of goodwill
- sales loss resulting from the sale of a network section.

The profit from the sale of a network section entered under other operating income is deducted when calculating the realised adjusted profit.

CONNECTION FEES

In the calculation of the realised adjusted profit, the annual net change in refund-able connection fees entered in the unbundled balance sheet is returned.

The annual net change in connection fees is obtained by deducting the amount of connection fees in the unbundled balance sheet of the previous accounting period from the amount of connection fees in the unbundled balance sheet in the accounting period.

Non-refundable connection fees are treated as returns on network operations.

The way of treating connection fees in balance sheet adjustment is described in section 2.4.2.

Connection fees are not deferred

The Authority has considered an alternative method of treating connection fees in order to defer their high accruals. This matter has also been dealt with in DSO public hearings and in a previously commissioned study, as well as in n the court of law based on complaints by DSOs (MAO:13/10 and MAO:427–501/12).

No such alternative method of treating connection fees has been presented that would safeguard the equal treatment of DSOs.

As a result, connection fees are not deferred, but they are instead treated as returns on network operations in the accounting period during which they have been entered into the financial statements.

NETWORK RENTS

The rental costs of a leased network must be reported in the regulatory data as network rents.

The network rents paid by the DSO in accordance with the unbundled profit and loss account are returned in full in the calculation of actual adjusted profit.

However, network rents may also include operating or maintenance costs of the leased network. If the DSO wishes that these costs are not returned in the calculation of realised adjusted profit, it must provide an account of its share of the network rent in connection with providing the regulatory data. The account must be verifiable on the basis of the DSO’s accounts. The Authority will assess the account and decide on the handling of these costs on its basis.

The overhead cost increment and margin included in the unbundled financial statements of the network operations are not deducted as a cost when dismantling the lease arrangement in the regulation methods.

DEPRECIATION OF ELECTRICITY NETWORK ASSETS IN NON-CURRENT ASSETS

In the unbundled profit and loss account, planned depreciations of electricity network assets are returned in the calculation of realised adjusted profit.

Amortisation of electricity network assets recorded in non-current assets in the unbundled financial statements are also added to planned depreciations to be returned.

In terms of a DSO operating in a leased network, depreciations and reductions in the value of electricity network assets entered in the DSO's balance sheet are not returned. The depreciation cost of these components is already included in the network rents returned in the calculation of realised adjusted profits.

PLANNED AMORTISATION OF GOODWILL

Planned amortisation of goodwill on the unbundled profit and loss account is returned in the calculation of realised adjusted profit.

SALES PROFIT AND LOSS RESULTING FROM THE SALE OF A NETWORK SECTION

If the profit from the sale of a network section is entered under other operating income in an unbundled profit and loss account, the amount of sales profit is deducted when calculating the realised adjusted profit.

If, on the other hand, a sales loss has been recorded under other operating expenses in the unbundled profit and loss account, the sales loss is returned in the calculation of realised adjusted profit.

LEASED NETWORKS

The network operations of a DSO that has leased an electricity network in its possession in part or in whole include all the same income from network operations as those of a DSO that owns its electricity network.

In addition, for example, returns that a DSO receives on network construction it has carried out on the DSO's electricity network are included in full in the income from network operations.

5.2 Costs of network operations

In the calculation of realised adjusted profit, the costs entered in the unbundled profit and loss account are used as the costs of network operations. These are adjusted with the adjustment items described in this section.

According to section 3, paragraph 6 of the Electricity Market Act, electricity network operations refer to placing the electricity network at the disposal of those needing electricity transmission and other network services in return for consideration. Electricity network operations include

- design, construction, maintenance and operation of the electricity network
- connecting customers' electrical devices to the network
- metering of electricity
- other measures required in the transmission of electricity that are necessary for electricity transmission and other network services.

The costs related to these functions constitute the costs of network operations.

Standard compensations and other compensations on outages paid by the DSO to its customers are also costs of network operations.

In accounting, the costs must be allocated to business operations in accordance with the matching principle.

PROCESSING OF INVESTMENTS AND OPERATIONAL COSTS

The DSO is in an equal position regardless of whether it capitalises its costs pertaining to investment or records them as expenses.

The cost of components is not taken into account twice in the regulation method.

<u>Demolition costs of replacement investments in network assets</u>

The demolition costs of replacement investments in network assets are treated as costs.

The capitalised demolition costs of replacement investments in network assets are adjusted on the calculation of reasonable return as if they had been recorded as expenses. Costs capitalised in the balance sheet are adjusted from the adjusted balance sheet along with the network assets in non-current assets (Chapter 2.1).

The demolition costs of replacement investments are not included in the adjusted replacement value or adjusted net present value of network assets.

Depreciations related to the demolition costs of replacement investments in network assets are returned to the adjusted profit as a part of the planned depreciation and reduction in the value of electricity network assets in non-current assets.

The demolition costs of replacement investments in network assets capitalised during the financial period are deduced from the profits and controllable operational costs (KOPEX) and the general efficiency target reference level (SKOPEX).

During the sixth (2024–2027) and seventh (2028–2031) regulatory period, 1/8 of the capitalised demolition costs of replacement investments in network assets in accordance with the 2023 financial statements will be deducted from the operating profit. These demolition costs capitalised before 2024 will be considered as controllable operational costs.

COSTS NOT PART OF NETWORK OPERATIONS

In the calculation of actual adjusted profit, only costs for which the DSO receives compensation are accepted as costs of network operations.

Uncompensated costs are treated as items of profit distribution nature and they are returned in the calculation of realised adjusted profit. These uncompensated costs include

- tariff difference compensations
- resource and resource provision compensations
- component placing compensations.

If the DSO wishes that these costs are accepted as costs of network operations, the DSO must provide an account of the matter in connection of delivering the regulatory data. The actual compensation received against the DSO's costs must be verified in the account. The Authority will assess the account and decide on the handling of these costs on its basis.

STANDARD COMPENSATIONS

Standard compensations and other compensations on outages paid by the DSO to its customers by virtue of section 100 of the Electricity Market Act are costs of network operations. Standard compensations treated as sales adjustment are also costs of network operations.

The DSO must specify the standard compensations and other compensations on outages paid to the customers as their own cost items as notes to the unbundled financial statements.

COSTS ARISEN FROM JOINING THE ELECTRICITY NETWORK OF ANOTHER DSO

The treatment of the costs of joining another DSO's electricity network, including connection fees, depends on whether they are refundable or non-refundable.

Refundable costs

Refundable costs and connection fees for joining the electricity network of another DSO are eliminated because they have to be recorded under 'Other receivables' in investments in non-current assets in the unbundled balance sheet in accordance with the statement by the Accounting Board (1670/2001).[14] The elimination is carried out in the same way as investments (2.2).

Non-refundable costs

Non-refundable costs and connection fees of joining the electricity network of another DSO are taken into account in adjusted assets invested in network operations if the DSO has entered them in 'Intangible rights' in non-current assets in the unbundled balance sheet in accordance with the statement by the Accounting Board (1905/2013).[15] They are taken into account in their balance sheet value in the way described in chapter 2.2

If the DSO has recorded non-refundable costs as an expense, they have already been taken into account in the operating profit (operating loss) in the unbundled profit and loss account.

DEPRECIATION OF OTHER ASSETS IN NON-CURRENT ASSETS

The calculation of the DSO's realised adjusted profit uses depreciation according to the plan based on the unbundled profit and loss account with respect to the depreciation of non-current assets other than network assets. These items have already been taken into account in the operating profit (operating loss) in the

[14] Kirjanpitolautakunnan lausunto sähköliittymismaksujen kirjaamisesta (Decision of the Accounting Board on the recording of electricity connection fees) (1670/2001)
[15] Kirjanpitolautakunnan lausunto kantaverkon liittymismaksujen merkitsemisestä liittyjän tilinpäätökseen (Decision of the Accounting Board of the recording of transmission grid connection fees in the connecting customer's financial statements) (1905/2013)

unbundled profit and loss account. Therefore, no separate adjustment is made on them in the calculation of realised adjusted profit.

However, if electricity network components are recorded under items other than the electricity network assets in non-current assets, depreciations made from these components are eliminated from depreciations made on other assets in non-current assets. This is carried out because electricity network components are taken into account in adjusted straight-line depreciations in accordance with chapter 6.1.1.

CONTROLLABLE AND NON-CONTROLLABLE OPERATIONAL COSTS

The costs arising from electricity network operations incurred by the DSO, entered through profit and loss, are divided in the calculation of actual adjusted profit into controllable and non-controllable operational costs. Controllable operational costs are subject to an efficiency target in accordance with the efficiency incentive (6.3).

The definition of controllable operational costs (KOPEX) is presented in Table 6.

Table 6. *Controllable operational costs*

KOPEX = Materials, supplies and goods		
	+	Increase or decrease in stocks (unless included in Materials, supplies and goods)
	+	Personnel expenses
	+	Operation and maintenance expenses included in network rents and network leasing fees
	+	Cost of leasing
	+	Other external services
	+	Other operating expenses
	+	Standard compensation paid (unless included in other costs)
	+	Demolition costs of replacement investments in network assets capitalised during the financial year
	+	Costs of components recorded as expenses (unless included in unit prices or other items above)
	–	Loss energy purchasing costs
	–	Production for own use
	–	Costs of building the DSO's own network in a leased network
	–	DSO Entity membership fee

Costs of network operations other than those referred to in Table 6 are non-controllable operational costs. These include main grid service charges and service charges for the centralised exchange of information outsourced to Fingrid Datahub Oy.

<u>Capitalised demolition costs of replacement investments in network assets</u>

The demolition costs of replacement investments in network assets capitalised on the balance sheet during the financial period are added to the controllable operational costs by means of the calculation of reasonable return.

LEASED NETWORKS

The network operations of a DSO that has leased an electricity network in its possession in part or in whole include all the same costs from network operations as those of a DSO that owns its electricity network.

A DSO operating in a leased network must specify the operational costs resulting from investments made in the leased network as their own cost items as notes to the unbundled financial statements. These costs are not included in controllable operational costs.

The margin and unitemised cost increases included in the sale price of network sections built in the network by the system operator and network licence holder of a leased network and sold to the network owner are not deducted from controllable operational costs or from network rents.

5.3 Financing costs of network operations

Reasonable costs of financial assets are taken into account as financing costs when calculating the realised adjusted profit.

REASONABLE COSTS OF FINANCIAL ASSETS

Running network operations requires certain financial assets. They are needed to make regular payments because the payment transactions of the DSO take place at somewhat different times from cash payments. They are also needed to make provisions for unexpected expenses.

For this reason, the reasonable costs arising from financial assets necessary to safeguard network operations are taken into account in the calculation of realised adjusted profit. This is carried out using a method of calculation, on the basis of which the costs of financial assets are not unreasonably small or insufficient from the DSO’s point of view by virtue of a decision by the Supreme Administrative Court (KHO:2010:86).

The following are taken into account in the financial assets recorded in the unbundled balance sheet:

- short- and long-term receivables with the exception of trade receivables
- marketable securities
- cash and bank receivables and comparable items.

The following are not taken into account in the financial assets recorded in the unbundled balance sheet:

- trade receivables
- the financial asset accounts listed above with a negative balance.

When calculating realised adjusted profit, the amount taken into account with respect to financial assets shall correspond to a maximum of 10% of the turnover of network operations.

The reasonable costs of financial assets can be calculated by multiplying the maximum amount of financial assets by the reasonable cost of debt used in the calculation of a reasonable rate of return (3.3).

This gives the reasonable costs of financial assets required for safeguarding network operations, and they are deducted when calculating the realised adjusted profit.

6 INCENTIVES

6.1 Investment incentive

The investment incentive encourages the DSO to make its investments cost-effectively on average and to enable the collection of reasonable investment costs from customers for investments made.

The investment incentive consists of the incentive impact of unit prices and the straight-line depreciation calculated from the adjusted replacement value.

The incentive impact of unit prices directs the DSO to invest more effectively than on average and to find more cost-effective methods of implementation than before. At the same time, unit prices limit inefficiency and ensure that DSOs have no interest in increasing their own investment costs when unit prices prevent transferring the cost inefficiency of investments to customer prices.

The incentive impact arises from the difference between investments calculated with unit prices and the cost of realised investments. When investing cost-effectively on average, the DSO reaps benefits from the adjustment of network assets; similarly, when a DSO invests ineffectively, unit prices cut off overheads in the adjustment of network assets.

The incentive impact of the straight-line depreciation arises from the fact that the methods allow for the DSO an annual depreciation level based on average adjusted straight-line depreciation on the basis of the lifetimes selected by the DSO. Imputed straight-line depreciations are always allowed in full as far as the component is in actual use. Therefore, imputed straight-line depreciation is calculated for the component even after the end of the lifetime if the component is still in actual use. Together with the net present value, the incentive impact of the straight-line depreciation calculated from the DSO’s adjusted replacement value directs the DSO to maintain its network in accordance with the lifetimes it has selected in actual use for as long as possible. This, in turn, leads to proactive maintenance and longer component lifecycles.

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

6.1.1 Adjusted straight-line depreciation

The adjusted straight-line depreciations on the electricity network assets are calculated per network component from the adjusted replacement value of the electricity network assets (2.1.1). Adjusted straight-line depreciations are calculated for all years of the regulatory period in the situation on the last day of December in the year in question.

The calculation of adjusted straight-line depreciation of the individual component *i* for the sixth and seventh regulatory period is presented in the formula below.

$$SD_i = \frac{RCV_i}{lifetime_i} \qquad (23)$$

Adjusted straight-line depreciations for the entire electricity network is calculated as a sum of adjusted straight-line depreciations of the network components as presented in the formula below.

$$SD = \sum_{i=1}^{n} \left(\frac{RCV_i}{lifetime_i} \right) \qquad (24)$$

in formulae 23 and 24

SD_i = adjusted straight-line depreciation of network component *i*

SD = adjusted straight-line depreciations of total electricity network assets

RCV_i = adjusted replacement value of network component *i*

$lifetime_i$ = techno-economical lifetime of network component *i*

6.1.2 Investment incentive in the calculation of the realised adjusted profit

The calculation takes into account any cost-efficiency benefits when calculating annual straight-line depreciation for customers within the regulatory period.

During the regulatory periods, 15% of the cost benefit of straight-line depreciation obtained by the DSO is deducted from the sum of straight-line depreciation in relation to unit prices if the DSO has been able to make investments in that year at a cost lower than the unit prices. Therefore, 15% of the benefits brought by cost-effectiveness to the DSO are directly allocated to customers and 85% remain with the DSO.

The Energy Authority has estimated that by leaving the DSO with a cost-benefit achieved through the investment efficiency obtained from the straight-line depreciation of 85% during the component life cycle, this incentive will continue to direct the DSO to invest cost-effectively, which will create benefits for customers in the valuation of future investments in connection with the unit price update.

For example, if the DSO's investments total EUR one million at a lower cost than unit prices in the year under review, then EUR 150 000 will be reduced from the sum of the straight-line depreciations. As a result, the DSO will benefit from the unit prices through depreciations by EUR 850 000 in the price margin during the component lifetime, and customers will be able to benefit from the DSO’s price margin which is EUR 150 000 lower immediately during the regulatory period.

Based on the above, the impact of investment incentives on the realised adjusted profits is calculated annually in accordance with the formula below, if the DSO has been able to invest at prices lower than average unit prices.

$$III = SD - (investments_{up} - investments_{bs}) \times 15\,\% \qquad (25)$$

where

III	=	the impact of the investment incentive in the adjusted profits
SD	=	network straight-line depreciation calculated based on the replacement value
$investments_{up}$	=	investments calculated with unit prices
$investments_{bs}$	=	investments based on the balance sheet

For DSOs that have failed to invest cost-effectively at prices lower than the unit prices given in the unit price list, the impact of the investment incentive on the actual adjusted profits is calculated directly in accordance with the normal straight-line depreciation. In other words, the impact is the sum of the straight-line depreciation of the network components in actual use.

The above principle is used to improve the cost-equivalence of pricing, as in efficiently operating companies a part of the benefit will be inevitably allocated to customer pricing and the apparent efficiency of potentially lagging accounts does not lead to unjustified profits.

6.2 Quality incentive

The purpose of the quality incentive is to encourage the DSO to develop the quality of electricity transmission and distribution.

The DSO is encouraged to achieve at least the level of security of supply required by the Electricity Market Act. The Authority aims to guide the DSO to also develop the quality of electricity transmission and distribution of its own accord to a level higher than the minimum level required by law.

Some DSOs have already achieved the above level of security of supply, and as the measures to develop the network progress, an increasingly large share of the DSOs will achieve this level. For these DSOs, the purpose of the quality incentive is above all to encourage the maintenance of good network security.

6.2.1 Regulatory outage costs

Regulatory outage costs, i.e. the disadvantage caused by outages, are calculated on the basis of the number and duration of outages, as well as the unit prices of outages

OUTAGES

Outages used in the quality incentive consist of the information about the number and duration of outages declared by the DSO in the regulatory data in accordance with the regulation on key figures.

DISTRIBUTION SYSTEM OPERATOR

In the sixth and seventh regulatory, the following information is taken into account, resulting from the medium-voltage distribution network and high-voltage distribution network

- the number and duration of unexpected outages
- the number of high-speed autoreclosers
- the number of time-delayed autoreclosers

The number and duration of planned outages is only taken into consideration in the medium-voltage distribution network.

In addition, in the sixth and seventh regulatory periods, the following will be taken into account for the low-voltage distribution network for the first time

- the number and duration of planned outages
- the number and duration of unexpected outages.

HIGH-VOLTAGE DISTRIBUTION SYSTEM OPERATOR

In the sixth and seventh regulatory, the following information is taken into account, resulting from the high-voltage distribution network

- the number and duration of unexpected outages
- the number of high-speed autoreclosers
- the number of time-delayed autoreclosers

UNIT PRICES OF OUTAGES

The values presented in Table 7 are used as the unit prices of outages. These values are based on the study commissioned by AFRY Management Consulting Oy[16].

Based on the analytical method and statistical baseline data, the report defines unit prices separately for households, agriculture, public and private services and industry. The parameters used in the calculations also take into account stakeholder interviews organised as part of the study. On this basis, the unit prices applicable for the calculation of the quality incentive have been established.

The unit prices in the table are in the 2021 value of money. In the calculation of the reference level of the regulatory outage costs and realised regulatory outage costs, the unit prices are adjusted to the value of money in each year using the consumer price index in accordance with chapter 1.8.

[16] AFRY Management Consulting Oy / Tkachenko Evgenia, Vihavainen Petri, Selvitys keskeytyksen aiheuttaman haitan kustannuksista, (A report on the costs of the disadvantage caused by outages), November 2022

Table 7. *Unit prices of the disadvantage caused by outages*

Unexpected outage		Planned outage		Time-delayed autorecloser	High-speed autorecloser
$h_{E,unexp}$	$h_{W,unexp}$	$h_{E,plann}$	$h_{W,plann}$	h_{TDA}	h_{HSA}
€ / kWh	€ / kW	€ / kWh	€ / kW	€ / kW	€ / kW
11.16	**1.05**	**6.14**	**0.58**	**1.05**	**0.53**

6.2.2 Calculation of outage costs during the sixth and seventh regulatory periods

The outage costs are calculated by voltage levels in accordance with formulae 26, 27 and 28.

The calculation of the reference level of regulatory outage costs in the low-voltage distribution network is presented in formula 26.

$$DCO_{y,k}^{LV} = \begin{pmatrix} DT_{unexp,y}^{LV} \times h_{E,unexp} + DN_{unexp,y}^{LV} \times h_{W,unexp} + \\ DT_{plann,y}^{LV} \times h_{E,plann} + DN_{plann,y}^{LV} \times h_{W,plann} \end{pmatrix} \times \left(\frac{W_y}{T_y}\right) \times \left(\frac{CPI_k}{CPI_{2021}}\right) \tag{26}$$

The calculation of the reference level of regulatory outage costs in the medium-voltage distribution

network is presented in formula 27.

$$DCO_{y,k}^{MV} = \begin{pmatrix} DT_{unexp,y}^{MV} \times h_{E,unexp} + DN_{unexp,y}^{MV} \times h_{W,unexp} + \\ DT_{plann,y}^{MV} \times h_{E,plann} + DN_{plann,y}^{MV} \times h_{W,plann} + \\ TDA_y^{MV} \times h_{TDA} + HSA_y^{MV} \times h_{HSA} \end{pmatrix} \times \left(\frac{W_y}{T_y}\right) \times \left(\frac{CPI_k}{CPI_{2021}}\right) \tag{27}$$

The calculation of the reference level of regulatory outage costs in the high-voltage distribution network is presented in formula 28.

$$DCO_{y,k}^{HV} = \begin{pmatrix} DT_{unexp,y}^{HV} \times h_{E,unexp} + DN_{unexp,y}^{HV} \times h_{W,unexp} + \\ \\ TDA_y^{HV} \times h_{TDA} + HSA_y^{HV} \times h_{HSA} \end{pmatrix} \times \left(\frac{W_y}{T_y}\right) \times \left(\frac{CPI_k}{CPI_{2021}}\right) \tag{28}$$

in formulae 26, 27 and 28:

$DCO^{LV,MV,HV}_{y,k}$ =realised regulatory outage costs in each voltage level (LV, MV, HV) in year *y* in the value of money of year *k*, EUR

$DT^{LV,MV,HV}_{unexp,y}$= downtime caused by the unexpected outages in the given voltage level (LV, MV, HV) weighted by annual energies, hours

$h_{E,unexp}$ = unit price of disadvantage for the outage period, caused by unexpected outages, EUR/kilowatt-hour

$DN^{LV,MV,HV}_{unexp,y}$=downtime caused by the unexpected outages in the given voltage level (LV, MV, HV) weighted by annual energies, number

$h_{W,unexp}$ = unit price of disadvantage for the number of outages, caused by

unexpected outages, EUR/kilowatt

$DT^{LV,MV,HV}_{plann,y}$= downtime caused by the planned outages in the given voltage level (LV, MV, HV) weighted by annual energies, hours

$h_{E,planned}$ = unit price of disadvantage for the outage period, caused by planned outages, EUR/kilowatt-hour

$DN^{LV,MV}_{plann,y}$= downtime caused by the planned outages in the given voltage level (LV, MV, HV) weighted by annual energies, number

$h_{W,plann}$ = unit price of disadvantage for the number of outages, caused by

planned outages, EUR/kilowatt

$TDA^{MV,HV}_{y}$ = downtime caused by time-delayed autoreclosers in the given voltage level (MV, HV) weighted by annual energies, number

h_{TDA} = unit price of disadvantage for the number of outages, caused by

time-delayed autoreclosers, EUR/kilowatt

$HSA^{LV,MV,HV}_{y}$= downtime caused by high-speed autoreclosers in the given voltage level (LV, MV, HV) weighted by annual energies, number

h_{HSA} = unit price of disadvantage for the number of outages, caused by high-speed autoreclosers, EUR/kilowatt

W_k = amount of energy transmitted through the given voltage level in year *k*, kWh

W_y = amount of energy transmitted through the given voltage level in year *y*, kWh

H_y = number of hours in year *y*

CPI_k = consumer price index in year *k*

CPI_{2021} = consumer price index in year *2021*

k = year under review, i.e. year 2024, 2025, 2026 or 2027 in the sixth regulatory period, and year 2028, 2029, 2030 or 2031 in the seventh regulatory period

y = *k*

DISTRIBUTION SYSTEM OPERATOR

The realised regulatory outage costs per DSO are composed of the sum of regulatory outage costs in the low-voltage distribution network, medium-voltage distribution network and the high-voltage distribution network in accordance with formulae 26, 27 and 28, and as a sum, formula 29.

$$DCO_y = DCO^{LV}{}_y + DCO^{MV}{}_y + DCO^{HV}{}_y \tag{29}$$

The difference with formulae 26, 27 and 28 is:

$t = k$ = year under review, i.e. year 2024, 2025, 2026 or 2027 in the sixth regulatory period, and year 2028, 2029, 2030 or 2031 in the seventh regulatory period

W_k = In accordance with regulation letter 2538/402/2020, regarding the DSO’s high-volume distribution network, the electric energy received in the high-volume distribution network of which a fixed loss percentage is deduced, is used as the volume of energy transmitted with this volume level in year *k.* The fixed loss percentage of 4% is applied.

HIGH-VOLTAGE DISTRIBUTION SYSTEM OPERATOR

The realised outage costs of the high-voltage distribution system operator $DCO^{HV}{}_{y}$ are calculated in accordance with formula 28.

6.2.3 The reference level of regulatory outage costs in the sixth and seventh regulatory period

The determination of the reference level of the quality incentive has been examined in the study commissioned by the Energy Authority from Gaia Consulting Oy[17]. In the study, the matter was examined especially from the viewpoint of the security of supply requirements of the Electricity Market Act. The topic was also explored in a study commissioned by the Authority from the Tampere University of Technology and the Lappeenranta University of Technology[18]. In this study, the topic was particularly examined from the viewpoint of the risk of major supply interruptions. The definition of the reference level has been further discussed in the opinion of the Academic Working Group appointed by the Ministry of Economic Affairs and Employment[19].

The DSO's average realised regulatory outage costs for the two previous regulatory periods, i.e. eight years, are used as the reference level of regulatory outage costs. In the sixth regulatory period, the average realised regulatory outage costs for 2016–2023 will be used as the reference level (excluding the high-voltage distribution network, for which the average realised regulatory outage costs for 2018–2023 will apply); in the seventh regulatory period, the average realised regulatory outage costs for 2020–2027 will be used as the reference level.

When the reference level is calculated, the impacts of major supply interruptions are not removed from the technical key figures, but in the seventh regulatory period, the impact of the exceptional years on the reference level will be adjusted in that the outage costs taken into consideration in the reference level will be limited based on the incentive impact valid in the given year in the quality incentive. In this case, if the realisation of the quality incentive in a given year is limited to the

[17] Gaia Consulting Oy, Karttunen Ville, Vanhanen Juha, Partanen Jarmo, Matschoss Kaisa, Bröckl Marika, Haakana Juha, Hagström Markku, Lassila Jukka, Pesola Aki and Vehviläinen Iivo, Selvitys laatukannustimen toimivuudesta ja kehitystarpeista vuosille (Report on the functioning and development needs of the quality incentive for the period) 2016–2023, 27 October 2014

[18] Tampere University of Technology, Lappeenranta University of Technology / Verho Pekka;Strandén Janne; Nurmi Veli-Pekka; Mäkinen Antti; Järventausta Pertti; Hagqvist Olli;Partanen Jarmo; Lassila Jukka; Kaipia Tero; Honkapuro Samuli: Nykyisen valvontamallin arviointi – suurhäiriöriski (Assessment of the current regulatory model – risk of major disturbance), 24 November 2010

[19] Järventausta Pertti, Collan Mikael, Liski Matti, Huhta Kaisa, Akateeminen työryhmä sähkönsiirron ja –jakelun tariffien laskentamenetelmistä, työryhmän lausunto Energiavirastolle (Academic working group on tariff calculation methods for electricity transmission and distribution, working group statement to the Energy Authority), 31 May 2022

ceiling level according to the method, which is at most 15% of the reasonable return, the outage costs to be taken into account in the reference level are calculated in accordance with formula 31 for that year. For the sake of symmetry, in years when the quality incentive is limited to the floor level, the outage costs to be taken into account in the reference level are calculated according to formula 32. If the incentive impact is not limited to the floor or ceiling level in said year, the actual outage costs for the year in question are used in calculating the reference level in accordance with formula 30.

$$DCO_{y,k} = DCO_{real,k}, \text{ when } DCO_{ref,y,k} - CO_y \times RR_{y,k} \leq DCO_{real,k} \leq DCO_{ref,y,k} + CO_y \times RR_{y,k} \quad (30)$$

$$DCO_{y,k} = DCO_{ref,y,k} + CO_y \times RR_{y,k}, \text{ when } DCO_{real,k} > DCO_{ref,y,k} + CO_y \times RR_{y,k} \quad (31)$$

$$DCO_{y,k} = DCO_{ref,y,k} - CO_y \times RR_{y,k}, \text{ when } DCO_{real,k} < DCO_{ref,y,k} - CO_y \times RR_{y,k} \quad (32)$$

in formulae 30, 31 and 32:

$DCO_{y,k}$ = The disadvantage caused by outages used to calculate the reference level in year *t* in the value of money for year *k*, EUR

$DCO_{real,k}$ = Realised regulatory outage costs i.e. the realised outage costs in the distribution network of the given voltage level (LV, MV, HV) in accordance with formulae 26, 27 and 28 in year *t* in the value of money for year *k*, EUR

CO_y = The cut-off level, i.e. floor and ceiling level, of the realised quality incentive in year t, 0–0.15 (0–15% of the reasonable return).

$RR_{y,k}$ = Reasonable return in year t, in the value of money for year *k*, EUR

$DCO_{ref,y,k}$ = The reference level of the quality incentive in year t, in the value of money for year *k* based on unit prices presented in table 7, EUR

k = year under review, i.e. year 2028, 2029, 2030 or 2031 in the seventh regulatory period

y = reference year, i.e. year 2020, 2021, 2022, 2023, 2024, 2025, 2026 or 2027 in the seventh regulatory period

The reference level is adjusted with the annual energy transmitted to the customers in order to make the reference level of regulatory outage costs comparable with the realised regulatory outage costs with respect to the transmitted energy.

DISTRIBUTION SYSTEM OPERATOR

The reference level applied in the sixth regulatory period is the average of the realised outage costs of the distribution network in the period 2016–2023 and the average of the realised outage costs of the high-voltage distribution network between 2018 and 2023. The calculation of the DSO's reference level for regulatory outage costs in the sixth regulatory period is presented in Formula 33.

$$DCO_{ref,k} = \frac{\sum_{y=2016}^{2023}\left[DCO_{y,k}^{LV} \times \left(\frac{W_k}{W_y}\right) + DCO_{y,k}^{MV} \times \left(\frac{W_k}{W_y}\right)\right]}{8} + \frac{\sum_{2018}^{2023}\left[DCO_{y,k}^{HV} \times \left(\frac{W_k}{W_y}\right)\right]}{6} \tag{33}$$

$DCO_{ref,k}$ = reference level for regulatory outage costs *k*, EUR

$DCO^{LV,MV,HV}{}_{y,k}$= realised regulatory outage costs in the given voltage level (LV, MV, HV) in accordance with formulae 26, 27 and 28 in year *y* in the value of money of year *k*, EUR

k = year under review, i.e. year 2024, 2025, 2026 or 2027 in the sixth regulatory period

y = reference year, i.e. year 2016, 2017, 2018, 2019, 2020, 2021, 2022 or 2023 in the sixth regulatory period

The reference level applied in the seventh regulatory period is the average of the realised outage costs of the distribution network in the period 2020–2027. If the realisation of the quality incentive during the reference year is limited to the ceiling or floor level in accordance with the methodology, the calculation of the reference level is based on the reasonable outage costs in accordance with formula 31 or 32. The calculation of the DSO's reference level for regulatory outage costs in the seventh regulatory period is presented in Formula 34.

$$DCO_{ref,k} = \frac{\sum_{y=2020}^{2027}\left[DCO_{y,k}^{LV} \times \left(\frac{W_k}{W_y}\right) + DCO_{y,k}^{MV} \times \left(\frac{W_k}{W_y}\right) + DCO_{y,k}^{HV} \times \left(\frac{W_k}{W_y}\right)\right]}{8} \tag{34}$$

$DCO_{ref,k}$ = reference level for regulatory outage costs *k*, EUR

$DCO^{LV,MV,HV}{}_{y,k}$= realised regulatory outage costs in the given voltage level (LV, MV, HV) in accordance with formulae 26, 27 and 28 in year *y* in the value of money of year *k*, EUR

k = year under review, i.e. year 2028, 2029, 2030 or 2031 in the seventh regulatory period

y = reference year, i.e. year 2020, 2021, 2022, 2023, 2024, 2025, 2026 or 2027 in the seventh regulatory period

HIGH-VOLTAGE DISTRIBUTION SYSTEM OPERATOR

The reference level applied in the sixth regulatory period is the average of the realised outage costs of the high-voltage distribution network in the period 2018–2023. The calculation of the reference level for the regulatory outage costs in the high-voltage distribution network in the sixth regulatory period is presented in Formula 35.

$$DCO_{ref,k} = \frac{\sum_{y=2018}^{2023}\left[DCO_{y,k}^{HV} \times \left(\frac{W_k}{W_y}\right)\right]}{6} \quad (35)$$

where

$DCO^{HV}{}_{y,k}$ = realised regulatory outage costs in the high voltage distribution network in year y in the value of money of year k, EUR.

k = year under review, i.e. year 2024, 2025, 2026 or 2027 in the sixth regulatory period

y = reference year, i.e. year 2018, 2019, 2020, 2021, 2022 or 2023 in the sixth regulatory period

The reference level applied in the seventh regulatory period is the average of the realised outage costs of the high-voltage distribution network in the period 2020–2027. If the realisation of the quality incentive during the reference year is limited to the ceiling or floor level in accordance with the methodology, the calculation of the reference level is based on the reasonable outage costs in accordance with formula 31 or 32. The calculation of the reference level for the regulatory outage costs in the high-voltage distribution network in the seventh regulatory period is presented in Formula 36.

$$DCO_{ref,k} = \frac{\sum_{y=2020}^{2027}\left[DCO_{y,k}^{HV} \times \left(\frac{W_k}{W_y}\right)\right]}{8} \quad (36)$$

k = year under review, i.e. year 2028, 2029, 2030 or 2031 in the seventh regulatory period

y = reference year, i.e. year 2020, 2021, 2022, 2023, 2024, 2025, 2026 or 2027 in the seventh regulatory period

6.2.4 Quality incentive in the calculation of the realised adjusted profit

The impact of the quality incentive is added to the operating profit when calculating realised adjusted profit.

The impact of the quality incentive is calculated so that the costs according to the reference level for the realised regulatory outage costs are deducted from the realised regulatory outage costs.

The maximum impact of the quality incentive in the calculation of realised adjusted profit is made reasonable. The greatest deviations in annual outage numbers and durations are taken into account by setting limit values, or so-called floor and ceiling levels, for the quality incentive. This means that the difference between the reference level of regulatory outage costs and the realised imputed regulatory outage costs that is higher than the set limit value will have no impact on the calculation of the DSO's realised adjusted profit.

The impact of the quality incentive taken into account in the calculation of realised adjusted profit may not be higher than 15% of the DSO's reasonable return in the year in question. This applies to the quality bonus for improved quality and the quality sanction resulting from a reduction in quality.

The quality incentive must also be symmetric for the DSO whose highest possible quality bonus is less than 15% of the DSO's reasonable return for the year in question. For this reason, the maximum amount of any quality sanction may only be as high as the maximum possible quality bonus.

6.3 Efficiency incentive

The purpose of the efficiency incentive is to encourage the DSO to operate in a cost-effective way. The operation of a DSO is cost-effective when the input, or costs, used in its operations are as small as possible in relation to the output of operation.

In the context of electricity distribution network operations, the cost level of efficient operational activities is assessed using efficiency measurement methods, in which case the efficiency frontier is estimated on the basis of the input and output data of all DSOs. The potential of an individual DSO to enhance its operational efficiency is identified by comparing its realised costs with those of the efficiency front.

The efficiency analysis is generally based on the examination of static and dynamic performance. Static efficiency examines efficiency at a given point in time in relation to peer companies and encourages inefficient companies to act more effectively. The examination of static efficiency requires measuring the level of cost-effectiveness in a reference set. Meanwhile, dynamic efficiency describes technological developments over time and encourages efficient companies to further improve their efficiency. The examination of dynamic efficiency requires measuring change in the level of cost-effectiveness.

ON THE CALCULATION OF THE EFFICIENCY INCENTIVE

The calculation of the DSO's efficiency incentive consists of six different factors:

- general efficiency target (6.3.1)
- variables in the measuring of company-specific efficiency (6.3.2)
- reference level of company-specific efficiency costs (6.3.3)
- company-specific realised efficiency costs (6.3.4)
- efficiency incentive in the calculation of realised adjusted profit (6.3.5).

The calculation of the efficiency incentive for a high-voltage distribution system operator is described in section 6.3.7. Section 6.3.8 also deals with the calculation.

6.3.1 General efficiency target

The purpose of the general efficiency target is to encourage DSOs, including those found to be efficient in the efficiency measurement, to improve the efficiency of their operations in accordance with the general productivity development. The general efficiency target, i.e. the dynamic component of the efficiency incentive, is set at the same level for all companies, and it strives to take into account the potential for improving efficiency created by the technical development of the sector.

In the regulation of monopoly operations, it is natural to set a general efficiency

target for enterprises.

PRODUCTIVITY DEVELOPMENT IN THE NETWORK INDUSTRY

A study[20] commissioned by the Energy Authority has assessed the level of the general efficiency target by examining productivity development in various network activities. The productivity figures vary depending on the network operations and the period under review. The study recommends defining the general efficiency target on the basis of long-term productivity development.

Based on this, the study recommends the same annual general efficiency target

with a value of two per cent for all electricity network activities.

THE LEVEL TO BE APPLIED

The value of the general efficiency target used in the sixth regulatory

period is 0% instead of the two per cent determined on the basis of the long-term productivity development. In the seventh regulatory period, 1% will be applied as the value of the general efficiency target.

A more moderate general efficiency target level is used to take into account the cost pressure regarding operative costs arising from the more complex operating environment and new operating methods and requirements.

6.3.2 Variables in the measuring of company-specific efficiency

The variables used in the measurement of company-specific efficiency target consist of the input variables, output variables and the operating environment variable. In addition, a control variable is used in the first phase of the estimation of the cost frontier.

INPUT VARIABLES

The following are used as input variables:

- controllable operational costs (KOPEX), EUR
- the net present value of the electricity network (NPV), EUR

[20] ECKTA Oy / Kuosmanen, T. Yleinen tehostamistavoite sähkön ja maakaasun verkkotoiminnoissa 6. ja 7. valvontajaksoilla 2024–2031 (General efficiency target for electricity and natural gas network operations in the 6th and 7th regulatory periods 2024–2031), 15 November 2022

The controllable operational costs and the replacement value are handled as separate variables and are not added together.

The controllable operational costs are modelled as a variable input, which the efficiency target is aimed at. The net present value is modelled as a fixed input that is not subject to an efficiency target. The determination of the net present value for the sixth and seventh regulatory periods for the efficiency incentive is described in section 6.3.3.

The items included in controllable operational costs are presented in Table 6 in chapter 5.2.

OUTPUT VARIABLES

The following are used as output variables:

- volume of transmitted energy, GWh
- total length of the electricity network, km
- metering points, number
- regulatory outage costs (KAH), EUR.

The amount of transmitted energy takes into account the average load of the electricity network and the resulting costs. The volume of energy is weighted with the average national transmission tariffs for different voltage levels.

The total length of the electricity network and the number of metering points take into account the costs resulting from the extent of the network. These variables and their ratio (total length / number of metering points) also distinguish DSOs

operating in population centres and rural areas from one another.

The regulatory outage costs take into account the costs resulting from outages and the costs resulting from avoiding them. Regulatory outage costs are not ordinary output variables. Outputs cannot be increased by increasing regulatory outage costs. They are not necessary in terms of the operations, either, but are only a by-product. Therefore, they are modelled as an unwanted output variable, i.e. a disadvantage. With regard to the calculation of regulatory outage costs, the updated unit prices for outages in accordance with the report commissioned by AFRY Management Consulting Oy will be taken into account.

OPERATING ENVIRONMENT VARIABLE

The ratio of the number of connections and metering points (connections / metering points, C/M ratio) is used as the operating environment variable.

The C/M ratio takes into account higher costs resulting from a sparsely populated operating environment. The ratio describes the proportion of metering points connected to the network through the same connection. This ratio is also suitable for modelling because it remains fairly stable over time.

The value of the ratio is limited between zero and one. It is the smallest with DSOs operating in urban conditions. It is close to one with many DSOs operating in sparsely populated areas.

CONTROL VARIABLE

The so-called endogeity bias[21] can be mitigated by including a control variable at the estimation stage. The DSOs' annual loss electricity percentage is used as the control variable.

The control variable$\tilde{z}_{i,t}$ is explicitly modelled only in the estimation phase 1), instead in the efficacy analysis phases 2) and 3) the control variable is not used because the purpose is to estimate the inefficiency term $u_{i,t}$.

6.3.3 Company-specific efficiency target

The purpose of the company-specific efficiency target is to encourage DSOs found to be inefficient in the efficiency measurement to achieve a cost level in accordance with efficient operation.

The Authority has commissioned a study on efficiency measurement from ECKTA Oy[22], which assessed the StoNED method (Stochastic Non-smooth Envelopment of Data) applied in measuring the efficiency of DSOs. The study found that the model based on the conditional yardstick competition presented in the efficiency measurement report commissioned by the Energy Authority in 2014 from Sigma-Hat

[21] In econometrics, an endogenous variable refers to an explanatory variable in the model that correlates with an error term. Endogeneity bias is corrected by applying a control variable that can be used to refine estimates and to further distinguish the effect of explanatory variables from the error term.

[22] ECKTA Oy / Kuosmanen, T., Kuosmanen, N, Dai, S., Kohtuullinen muuttuva kustannus sähkön jakeluverkkoyhtiöiden valvontamallissa: Ehdotus tehostamiskannustimen kehittämiseksi 6. ja 7. valvontajaksoilla vuosina 2024–2031 (Reasonable variable cost in the regulatory model for electricity distribution system companies: A proposal for the development of an incentive for the 6th and 7th regulatory period in 2024–2031), 12 September 2022

Economics Oy[23] remains the recommended method for determining the reference level of the controllable operational costs. However, ECKTA Oy's report presented proposals for further development regarding the method and the choices of variables made in the applied model. The method has been developed for the efficiency incentive in terms of model specification and estimation.

MODEL SPECIFICATION FOR THE EFFICIENCY FRONTIER

The efficiency frontier is estimated with the StoNED method. The model specification used in the calculation is presented in formula 37.

$$ln\, x = ln\, IR(\boldsymbol{x}, \boldsymbol{y}) + \boldsymbol{\delta}'\boldsymbol{z} + u + v \qquad (37)$$

where

x = controllable operational costs

IR = input need function that meets the set conditions of monotony, concave and scale returns

$\boldsymbol{x}$ = vector for fixed inputs

$\boldsymbol{y}$ = output vector

$\boldsymbol{\delta}'$ = vector describing the marginal impacts of heterogeneity

$\boldsymbol{z}$ = vector for factors describing heterogeneity

u = expected value of inefficiency – estimated without distribution assumptions with the nonparametric kernel deconvolution method

v = random error

ESTIMATION OF EFFICIENCY FRONTIER

The efficiency frontier, on the basis of which the DSO-specific efficiency incentive is calculated, is estimated with the methods presented in this appendix. The Energy

23 Sigma-Hat Economics Oy / Kuosmanen, T., Saastamoinen, A., Keshvari, A., Johnson, A., & Parmeter, C., Tehostamiskannustin sähkön jakeluverkkoyhtiöiden valvontamallissa: Ehdotus Energiaviraston soveltamien menetelmien kehittämiseksi neljännellä valvontajaksolla 2016–2019 (The efficiency incentive in the regulatory model for electricity distribution network companies: a proposal for the development of methods applied by the Energy Authority in the fourth regulatory period 2016–2019), 21 October 2014

Authority estimates the efficiency frontier and calculates DSO-specific efficiency

targets once all the necessary initial data has been inspected by the end of 2024.

The efficiency frontier is estimated for the fourth regulatory period and it will not be estimated in the other years of the regulatory period. In the estimation, the DSO's regulatory data for 2016–2022 is used as the initial data for variables in accordance with section 6.3.2.

The expense items in accordance with the regulatory data for 2008–2014 are used as the controllable operational costs. These are adjusted with the consumer price index to the 2022 level.

In the estimation of the cost frontier for the efficiency incentive, the current net value of the network modelled as a fixed input variable will be defined and harmonised for the period 2016–2023 using the unit price list in Appendix 1. In other words, for the efficiency incentive, a parallel calculation of the net present value is applied for the years covered by the data, in the calculation of which the applied baseline is the net present values determined for 2023. On this basis, the net present values for 2016–2022 are calculated retrospectively. This procedure is used to ensure the most consistent development and comparability of the value of the network from the perspective of the efficiency incentive in the data periods applied in the cost frontier during the sixth and seventh regulatory periods.

The calculation of the net present value is based on the calculation method used in the second regulatory period, in which case the net present value of the preceding year is always based on the net present value of the examined year minus the investments of the year under review and plus the straight-line depreciations of the year under review. The calculation method may also be presented in accordance with formula 38:

$$NPV_{y-1} = NPV_{y,UPAppendix1} - inv_{y,UPL2016} + SD_{y,UPL2016} \qquad (38)$$

where

$NPV_{y,UPAppendix1}$ = the net present value of year y in accordance with the unit price list provided in Appendix 1

NPV_{y-1} = net present value of year t-1 for estimation

$inv_{y,UPL2016}$ = investments of year t in accordance with the 2016 unit price list

$SD_{y,UPL2016}$ = straight-line depreciations of year t in accordance with the 2016 unit price list

When calculating the net present values as described above, the network values can be harmonised throughout the dataset period, and in this case, the net present values used to calculate the annual reference level values during the regulatory period are based on the network values calculated according to the same unit price list. In this case, from the perspective of the efficiency incentive, the network value will not be subject to variation in network value during the data period due to updates to the unit prices, and the net present value will develop more evenly from the perspective of the model. The calculation will utilise the data from the previous regulatory period in investigating investments and straight-line depreciations, which have been calculated using an older component breakdown, because it would be too challenging to retrospectively determine the investment data and straight-line depreciations for the older years included in the data period with a newer component breakdown until 2016.

For the purposes of the calculation, DSOs are required to submit to the Authority, by June 2024, the quantity and average age data of the network components in actual use as well as the required lifetime data based on the new breakdown in accordance with Appendix 1 depicting the status valid at the end of 2023. The Authority will issue instructions for providing the necessary information during spring 2024.

For the sixth regulatory period, the adjusted net present value of the electricity network assets defined as presented above will be used as the net present value in the period 2016–2022. These are adjusted with the consumer price index to the 2022 level.

The efficiency front will be re-estimated for the seventh regulatory period in 2027. The estimation is carried out in the same way as for the sixth regulatory period. In the estimation, the regulatory data for 2020–2026 is used as the initial data for variables in accordance with section 6.3.2. Monetary variables will be adjusted by the consumer price index to the 2026 price level. For the applicable net present values, the period 2020–2023 will be based on the net present values determined as described above; in the period 2024–2026, network value data will be directly obtained from network value calculations in accordance with the network data system.

The material used in the estimation of the efficiency frontier is treated as unbalanced panel material.

DSOs that have ceased network operations are treated in the material as separate observation units until they have ceased operations. Merged DSOs are handled as a single observation unit from the year of the merger.

EFFICIENCY FIGURE

The efficiency figure tells the ratio between a reasonable cost level and a realised cost level. The efficiency figure can be calculated for every year used in the estimation in connection with the estimation of the efficiency frontier.

The transition period and company-specific efficiency targets applied in the efficiency incentive were abandoned during the fourth regulatory period of 2016–2019 as of 2020. Therefore, the realised controllable operational costs of the DSO are directly compared to the level of the reasonable controllable operational costs in accordance with the efficiency frontier. In practice, the efficiency figure is calculated annually as the quotient of reasonable and realised controllable operational costs in accordance with the efficiency front as shown in formula 39.

$$EF_y = \frac{SKOPEX_y}{KOPEX_y} \qquad (39)$$

where

$SKOPEX_y$	=	DSO’s reference level for efficiency costs i.e. reasonable controllable operational costs in year *y*
$KOPEX_y$	=	DSO’s realised controllable operational costs in year *y*
EF_y	=	DSO's efficiency figure in year *y*
y	=	year 2024, 2025, 2026, 2027, 2028, 2029, 2030 or 2031

REASONABLE COSTS IN ACCORDANCE WITH THE EFFICIENCY FRONTIER

The efficiency frontier is used for determining the DSO’s reasonable controllable operational costs at an output level according to efficient operations. These reasonable costs (SKOPEX) are used as the reference level for realised controllable operational costs.

The DSOs’ different operating environments and output profiles are taken into account in the estimation of the efficiency frontier with different shadow price profiles.

The efficiency frontier can be presented as shadow price profiles, which are based on marginal costs. The shadow price tells the sum in euros, the change of one unit in the output variable of which has an impact on the calculation of SKOPEX. The replacement value of the electricity network is also estimated in the model in the same way as the output variable, and a shadow price is obtained.

The shadow price profiles of the efficiency frontier differ from one another with respect to the height of the shadow price they allow for different output variables. Some shadow price profiles put more weight, for example, on the amount of transmitted energy, some on the number of customers or the network length.

With the exception of regulatory outage costs, the shadow prices of output variables always have positive values, i.e. they have an increasing impact on SKOPEX. The shadow price of regulatory outage costs may have positive and negative values, i.e. it has an increasing or decreasing impact on SKOPEX. The shadow price of the replacement value of the electricity network is always negative or zero, i.e. it has a decreasing or no impact on SKOPEX.

A shadow price profile that maximises the DSO’s SKOPEX is selected automatically.

SKOPEX is calculated as the product of the shadow price profile that maximises it and the outputs, and this product is multiplied by the impact of the operating environment variable and the expected value of inefficiency.

The calculation of reasonable controllable operational costs is presented in formula 40.

$$SKOPEX = I\hat{R}^{StoNED}(x,y) \times exp(\hat{\delta}'z) \qquad (40)$$

where

$I\hat{R}^{StoNED}(x,y)$	=	the product of outputs and the shadow prices according to the shadow price profile that maximises SKOPEX
$exp(\hat{\delta}'z)$	=	impact of the operating environment variable and the expected value of inefficiency

6.3.4 Reference level of efficiency costs

The reasonable controllable operations costs (SKOPEX) are used as the reference level of efficiency costs. The reference level is calculated annually. When the reference level is calculated annually, the changes taking place in the output variables are also taken into account.

In the fourth and fifth regulatory periods, the replacement value of the electricity network and regulatory outage costs were fixed to the four-year average level in the calculation of the annual reference level. However, setting an average for the variables will be abandoned in the sixth and seventh regulatory period; instead, in setting a reference level for the costs of each year, the net present value and realised regulatory outage costs of the given year will apply. This allows also paying attention to any changes in the capital stock in the calculation of annual reasonable operational costs.

In the inflation adjustment, the average values of the consumer price index in April–September of the year under review are used in the way presented in section 1.8.

REFERENCE LEVEL IN THE SIXTH REGULATORY PERIOD

The calculation of the reference level in the period 2024–2027 is presented in Formula 41.

$$SKOPEX_y = I\hat{R}^{StoNED}(x_y, y_y) \times exp(\hat{\delta}' z_y) \times (CPI_y / CPI_{2022}) \qquad (41)$$

where

$SKOPEX_y$	=	reference level for efficiency costs i.e. reasonable controllable operational costs
$I\hat{R}^{StoNED}(x_y, y_y)$	=	the product of outputs and the shadow prices according to the shadow price profile that maximise SKOPEX
$exp(\hat{\delta}' z_y)$	=	impact of the operating environment variable and the expected value of inefficiency
CPI_y	=	consumer price index in year *y*
CPI_{2022}	=	consumer price index in year *2022*
y	=	year 2024, 2025, 2026 or 2027

REFERENCE LEVEL IN THE SEVENTH REGULATORY PERIOD

The calculation of the reference level in the period 2028–2031 is presented in Formula 42.

$$SKOPEX_y = I\hat{R}^{StoNED}(x_y, y_y) \times exp(\hat{\delta}' z_y) \times (1 - YL)^{y-2027} \times (CPI_y / CPI_{2026}) \qquad (42)$$

where the differences with Formula 41 are

CPI_{2026}	=	consumer price index in year *2026*
$(1 - YL)^{y-2027}$	=	technical development in the period 2028–2031
y	=	year 2028, 2029, 2030 or 2031

6.3.5 Handling of a merged DS

When two or more DSOs merge, the reference level of the merged company, i.e. reasonable controllable operational costs (SKOPEX), are determined in relation to the estimated efficiency frontier. The efficiency frontier is estimated in the way described in section 6.3.3.

6.3.6 Realised efficiency costs

Controllable operational costs are used as realised efficiency costs. Realised efficiency costs are calculated annually.

Cost items according to the unbundled profit and loss account for each year are used as controllable operational costs. The items included in controllable operational costs are presented in Table 6 in chapter 5.2.

In the sixth and seventh regulatory periods, demolition costs of replacement investments in network assets capitalised on the balance sheet will be considered as part of the controllable operational costs for the year in question and they are therefore also included in the efficiency incentive. To ensure that the demolition costs would also be taken into account in the determination of the reference level of the efficiency incentive, the Energy Authority will collect data on the activated demolition costs for 2016–2023 by means of a separate request for information, and the corresponding costs will be added to the actual operative costs used in calculating the reference level. The treatment of demolition costs during the sixth and seventh regulatory periods has been examined in section 5.2.

The costs of the network data systems and the communication networks in the supervisory control and data acquisition will also be fully included in the controllable operational costs, also for the parts that have not been previously considered, if the costs have been previously recorded in network rents. In the sixth regulatory period, the costs in question, which were previously reported in network rents and partly taken into account through unit prices, are processed as pass-through items, and in the seventh regulatory period, the costs are included as a part of the controllable operational costs under the efficiency incentive. To ensure that the costs will also be taken into account in the calculation of the reference level during the seventh regulatory period, the Energy Authority will collect data on similar costs by means of a separate request for information for 2020–2023. The treatment of the costs of the network data systems and the communication networks in the supervisory control and data acquisition during the sixth and seventh regulatory period are examined in section 2.1.

In the seventh regulatory period, the costs of flexibility solutions procured on market terms will be treated as a pass-through item and they will thus not be included as costs included in the efficiency incentive. In the sixth regulatory period, the costs related to flexibility are included in the controllable operational costs, but are subject to a separate bonus mechanism through the flexibility incentive.

6.3.7 The efficiency of the high-voltage distribution system operator

The value of the general efficiency target used in the sixth regulatory

period is 0% instead of the two per cent determined on the basis of the long-term productivity development. In the seventh regulatory period, 1% will be applied as the value of the general efficiency target (6.3.1).

Therefore, measuring the efficiency of a high-voltage distribution system operator consists of comparing the DSO's cost level with its own previous cost level and the overall efficiency target.

REFERENCE LEVEL IN THE SIXTH REGULATORY PERIOD

The calculation of the reference level in 2024 is presented in Formula 43.

$$SKOPEX_{2024} = \frac{1}{4}\sum_{y=2020}^{2023}((1 + \Delta CPI_{2024}) \times (1 + \Delta K_{2024}) \times KOPEX_y) \qquad (43)$$

where

$SKOPEX_{2024}$	=	reference level for efficiency costs i.e. reasonable controllable operational costs for year 2024
ΔK_{2024}	=	change in network volume from year *y* to year 2024
ΔCPI_{2024}	=	change in the consumer price index from year *t to year* 2024
$KOPEX_y$	=	realised controllable operational costs in year *y*

The calculation of the reference level for the following years 2025–2027 of the regulatory period is presented in formula 44.

$$SKOPEX_y = \left(1 + \Delta CPI_y\right) \times \left(1 + \Delta K_y\right) \times SKOPEX_{y-1} \tag{44}$$

where

$SKOPEX_y$	=	reference level for efficiency costs i.e. reasonable controllable operational costs for year *t*
$SKOPEX_{y-1}$	=	reference level for efficiency costs i.e. reasonable controllable operational costs for year *y-1*
ΔK_y	=	*change in network volume from year y-1 to year y*
ΔCPI_y	=	*change in the consumer price index from year y-1 to year y*
y	=	year 2025, 2026 or 2027

REFERENCE LEVEL OF EFFICIENCY COSTS IN THE SEVENTH REGULATORY PERIOD

The calculation of the reference level in 2028 is presented in Formula 45.

$$SKOPEX_{2028} = \frac{1}{4}\sum_{y=2024}^{2027}((1 + \Delta CPI_{2028}) \times (1 + \Delta K_{2028}) \times (KOPEX_y) \times (1 - YL)^1 \tag{45}$$

where

$SKOPEX_{2028}$	=	reference level for efficiency costs i.e. reasonable controllable operational costs for year 2028
$(1- YL)^1$	=	technical development in year 2028
ΔK_{2028}	=	change in network volume from year *y* to year 2028
ΔCPI_{2028}	=	change in the consumer price index from year *t to year* 2028
$KOPEX_y$	=	realised controllable operational costs in year *y*

The calculation of the reference level for the following years 2029–2031 of the regulatory period is presented in formula 46.

$$SKOPEX_y = (1 + \Delta CPI_y) \times (1 + \Delta K_y) \times SKOPEX_{y-1} \times (1 - YL)^{y-2027} \tag{46}$$

where

$SKOPEX_y$	=	reference level for efficiency costs i.e. reasonable controllable operational costs for year *t*
$SKOPEX_{y-1}$	=	reference level for efficiency costs i.e. reasonable controllable operational costs for year *y-1*
$(1 - YL)^{y-2027}$	=	technical development in the period 2029–2031
ΔK_y	=	*change in network volume from year y-1 to year y*
ΔCPI_y	=	*change in the consumer price index from year y-1 to year y*
y	=	year 2029, 2030 or 2031

NETWORK VOLUME CORRECTION

Changes in the scope of operation of the high-voltage distribution system operator are taken into account in accordance with the model presented in the report[24] commissioned by the Authority from PA Consulting Group Oy.

The network volume of the component is calculated by multiplying the number of components by the coefficient corresponding to each component as shown in Table 8. The network volume of the entire network is calculated by adding together the network volumes per component.

[24] PA Consulting Group Oy / Kuusela Akke, Sähkön jakeluverkkotoiminnan laajenemisen kustannusvaikutuksiin liittyvä konsulttityö (Consultancy work related to the cost impact of the expansion of electricity distribution network operations), 24 May 2004

Table 8. *Coefficients describing the extent of the network of the high-voltage distribution system operator*

Component	Coefficient
1 km 110 kV overhead line	4.2
1 km 110 kV underground cable	2.3
1 customer	0.025

The calculation of network volume is presented in Formula 47.

$$NV = 4{,}2 \times OL_{hv} + 2{,}3 \times UC_{hv} + 0{,}025 \times CN \tag{47}$$

where

NV = extent of total network, i.e. network volume

OL_{hv} = length of 110 kV overhead line network, kilometres

UC_{hv} = length of 110 kV underground cable network, kilometres

CN = number of customers connected to the network, number

The calculation of change in the network volume for 2024 is presented in Formula 48.

$$\Delta K_{2024} = \frac{NV_{2024}}{NV_y} - 1 \tag{48}$$

where

ΔK_{2024} = change in the network volume for year 2024

NV_{2024} = network volume at the end of year 2024

NV_y = network volume at the end of year *y*

The calculation of change in the network volume for 2028 is presented in Formula 49.

$$\Delta K_{2028} = \frac{NV_{2028}}{NV_y} - 1 \tag{49}$$

where

ΔK_{2028} = change in the network volume for year 2028

NV_{2028} = *network volume at the end of year 2028*

NV_y = network volume at the end of year *y*

The calculation of change in the network volume for the years 2025–2027 is presented in formula 50.

$$\Delta K_t = \frac{NV_y}{NV_{y-1}} - 1 \tag{50}$$

where

ΔK_y = change in network volume for year y

NV_y = network volume at the end of year *y*

NV_{y-1} = network volume at the end of year *y -1*

y = year 2025, 2026, 2027, 2029, 2030 or 2031

REALISED EFFICIENCY COSTS

Controllable operational costs are used as realised efficiency costs. Realised efficiency costs are calculated annually.

Cost items according to the unbundled profit and loss account for each year are used as controllable operational costs. The items included in controllable operational costs are presented in Table 6 in chapter 5.2.

6.3.8 Efficiency incentive in the calculation of the realised adjusted profit

The impact of the efficiency incentive is added to the operating profit when calculating realised adjusted profit.

The impact of the efficiency incentive is calculated so that the costs according to the reference level for the realised efficiency costs of the same year are deducted from the realised efficiency costs.

The maximum impact of the efficiency incentive in the calculation of realised adjusted profit is made reasonable. The greatest deviations in the annual controllable operational costs are taken into account by setting limit values, i.e. floor and ceiling levels, for the efficiency incentive. This means that the difference between the reference level of the efficiency costs and the realised efficiency costs that is higher than the set limit value will have no impact on the calculation of the DSO's realised adjusted profit.

The impact of the efficiency incentive taken into account in the calculation of realised adjusted profit may not be higher than 20% of the DSO's reasonable return in the year in question. This applies to the efficiency bonus received from the calculation of costs and the efficiency sanction resulting from increased costs.

6.4 INNOVATION INCENTIVE

The purpose of the innovation incentive is to encourage the DSO to develop and use innovative technical and operational solutions actively in its network operations.[25]

6.4.1 Research and development costs

In network operations, the key objectives of research and development activities are the development and introduction of smart grids and other new technologies and methods of operation. Above all, the innovation incentive aims to encourage network operators to develop smart grid projects.

The Authority encourages the DSO to make active efforts in research and development by deducting reasonable research and development costs in the calculation of realised adjusted profit.

Acceptable research and development costs must be directly related to the creation of new knowledge, technology, products or methods of operation in network operations for the sector. As the DSO may incur research and development costs even before the new technologies and operating methods are fully in place and can be

[25] In a study21 commissioned by the Authority from Gaia Consulting Oy, the functioning of the innovation incentive was assessed and proposals for its development were made. Gaia Consulting Oy / Vehviläinen Iivo; Ryynänen Erkka; Hjelt Mari; Descombes Laura; Vanhanen Juha: Energiaviraston valvontamenetelmissä sovellettavan innovaatiokannustimen arviointi (Assessment of the innovation incentive applied in the Energy Authority's regulation methods), 18 September 2014

fully utilised, it is also possible, under certain conditions, to include research and development costs related to the efforts to plan a project in the innovation incentive.

The results of projects whose costs have been accepted in the innovation incentive must be public and, for example, they can be utilised by other DSOs in their network operations. However, it is not necessary to publish confidential information concerning customers. Results protected by industrial property rights need not be published, either. The results to be published must be delivered to the Energy Authority, which will publish them on its website.

Acceptable research and development costs must be recorded in the unbundled profit and loss account as expense. Capitalised research and development costs are not accepted to be included in the calculation of the innovation incentive.

The DSO must itemise non-capitalised research and development costs as their own cost items as notes to the unbundled financial statements.

6.4.2 Innovation incentive in the calculation of realised adjusted profit

The impact of the innovation incentive is deducted when calculating realised adjusted profit.

The impact of the innovation incentive is calculated so that a share corresponding to a maximum of 0.5% of the DSO’s total turnover from network operations in the unbundled profit and loss accounts in the regulatory period are treated as reasonable research and development costs. The aim is to direct the steering effect of the incentive towards the development of flexible solutions.

Therefore, the amount of acceptable research and development costs in a single year may exceed or fall below the share corresponding to one per cent of the turnover from network operations in the year in question.

6.5 FLEXIBILITY INCENTIVE

The Energy Authority encourages DSOs to develop and utilise flexible solutions in distribution network operations, so a separate flexibility incentive will be included in the regulation methods. This section describes the content of the flexibility incentive. The purpose of the flexibility incentive for the regulatory period 2024–2027 is to encourage network companies to develop different flexibility solutions, while the flexibility incentive for the regulatory period 2028–2031 aims to guide the introduction of the solutions developed during the previous regulatory period as a part of the DSOs' operations. For this reason, separate flexibility incentives have been created for each regulatory period.

In connection with the flexibility incentive, the Energy Authority defines flexibility as defined in section 3, subsection 1, paragraph 30 of the Electricity Market Act (588/2013). According to that paragraph, *flexibility* refers to a change in the amount of electrical energy or load fed into the network in response to market signals or to the acceptance of a bid submitted either individually or through an aggregation concerning the upward or downward change in the amount of electricity fed into or taken from the network. Similarly, the Energy Authority defines demand response as defined in section 3, subsection 1, paragraph 30 a of the Electricity Market Act. According to that paragraph, *demand response* refers to change in the end-user's load compared to its normal or current consumption patterns in response to market signals, time-based electricity prices or incentive payments, or in response to the acceptance of an offer made by the end-user, either alone or through an aggregation, to sell in order to reduce or increase demand at a certain price as defined for the organised market place in Article 2(4) of the Commission Implementing Regulation (EU) No 1348/2014 of 17 December 2014 on data reporting implementing Article 8(2) and Article 8(6) of Regulation (EU) No 1227/2011 of the European Parliament and of the Council on wholesale energy market integrity and transparency.

6.5.1 Flexibility incentive in the regulatory period 2024–2027

The purpose of the flexibility incentive is to encourage DSOs to actively undertake innovative projects to achieve a wider use of demand response in network operations. This part of the incentive should contribute specifically to promoting innovative demand response solutions in the early stage whose cost-benefit ratio has not yet reached maturity. The novelty requirement related to the innovation incentive for the sector regarding producing new information does not apply to projects recorded under the flexibility incentive, as the flexibility incentive projects and solutions are likely to be very similar between companies. Similarly, the flexibility solutions used by DSOs may already be used in the sector.

COSTS

Of course, costs cannot, however, be included in both innovation and flexibility incentives at the same time. Despite this, costs incurred as a result of the potential follow-up measures of a previously approved flexibility project as part of the innovation incentive (in the previous regulatory period) can be accepted as a part of the flexibility incentive in a later regulatory period.

FLEXIBILITY INCENTIVE IN THE CALCULATION OF REALISED ADJUSTED PROFIT

The impact of the flexibility incentive is deducted when calculating realised adjusted profit.

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

Therefore, the share of costs recorded in the flexibility incentive for an individual regulatory year may exceed or fall below a share corresponding to 1% in the total turnover from network operations for that year.

6.5.2 Flexibility incentive in the regulatory period 2028–2031

This section describes the content of the flexibility incentive for the regulatory period 2028–2031. The Energy Authority considers the sixth regulatory period as a transition period for creating market-based flexibility, and will enable the invoicing of pass-through expenses resulting from the flexibility during the seventh regulatory period. Therefore, the flexibility incentive will also be included in the regulation methods for the 2028–2031 regulatory period, in which case the main purpose of the incentive will be to encourage DSOs to introduce market-based flexibility solutions developed during the 2024–2027 regulatory period.

COSTS

The costs of flexible solutions acquired on a market basis during the regulatory period 2028–2031 constitute a pass-through item for DSOs. The DSO may include up to 2% of the sum of its turnover in the unbundled profit and loss account during the regulatory period in the pass-through item.

7 REALISED ADJUSTED PROFIT

The calculation of realised adjusted profit is started from the operating profit (loss) of the unbundled profit and loss account.

When calculating the realised adjusted profit, the annual change in refundable connection fees according to the unbundled balance sheet, as well as network rents according to the unbundled profit and loss account, planned depreciation of electricity network assets and amortisation, amortisation of goodwill, and the loss of sales resulting from the sale of a network section entered under other operating expenses are returned first (5.1). Meanwhile, the profit from the sale of a network section entered under other operating income is deducted (5.1) when calculating the realised adjusted profit.

After that, reasonable costs of financial assets (5.3) and capitalised demolition costs of replacement investments in network assets (5.2) are deducted as profit adjustment items.

The impacts of incentives are also taken into consideration in the calculation of realised adjusted profit. Incentives include investment incentive (6.1), quality incentive (6.2), efficiency incentive (6.3), innovation incentive (6.4) and flexibility incentive (6.5).

The impact of the investment incentive is calculated by deducting the adjusted straight-line depreciation of the electricity network assets.

The impact of the quality incentive is calculated by deducting the realised outage costs from the reference level of outage costs. The impact of the quality incentive is added to the operating profit.

The impact of the efficiency incentive is calculated by deducting costs in line with the reference level of efficiency costs from the efficiency costs. The impact of the efficiency incentive is added to the operating profit.

The impact of the innovation incentive is calculated from the DSO’s reasonable research and development costs. The impact of the incentive is deducted from operating profit.

The impact of the flexibility incentive is calculated from the reasonable costs the implementation of the flexibility incentive. The impact of the incentive is deducted from operating profit.

The sum total of the calculation is the realised adjusted profit.

The above-described calculations are presented in Table 9.

Table 9. *The calculation of realised adjusted profit*

OPERATING PROFIT (LOSS) OF THE UNBUNDLED PROFIT AND LOSS ACCOUNT OF NETWORK OPERATIONS
+ Refundable items in the unbundled profit and loss account
+ Net change in refundable connection fees
+ Paid network rents
+ Planned amortisation of goodwill
+ Loss of sales of the network section recorded in other expenses
- Profit on sales of the network section recorded in other income
+ Planned depreciations and value reductions from network assets
- Profit adjustment items
- Reasonable costs of financial assets
- Demolition costs of replacement investments in network assets capitalised during the financial year
- 1/8 of the balance sheet value of the demolition costs of replacement investments in network assets in accordance with the 2023 financial statements
- Investment incentive
- Adjusted straight-line depreciations of the electricity network assets
+ Quality incentive
+ Realised outage costs
- Reference level of outage costs
+ Efficiency incentive
+ Realised efficiency costs
- Reference level of efficiency costs
- Innovation incentive
- Reasonable costs of research and development activities
- Flexibility incentive 2024–2027
- Reasonable costs of the implementation of flexibility
= REALISED ADJUSTED PROFIT

REFERENCES

1 Recommendation by the Energy Market Authority, Sähkö- ja maakaasuliiketoimintojen laskennallinen eriyttäminen (Imputed unbundling of electricity and natural gas business operations) (Reg.No. 549/002/2015), 18 December 2025

2 Government proposal (HE 20/2013 vp)

3 Act on the supervision of the electricity and gas market 590/2013

4 Kirjanpitolautakunnan lausunto sähköliittymismaksujen kirjaamisesta (Decision of the Accounting Board on the recording of electricity connection fees) (1650/2001)

5 KPMG Oy Ab, Selvitys kohtuullisen tuottoasteen määrittämisestä sähkö- ja maakaasuverkkotoimintaan sitoutuneelle pääomalle (Report on determining a reasonable rate of return for capital committed to electricity and natural gas network activities), 20 September 2022

6 Martikainen Teppo, Lausunto Sähkömarkkinakeskukselle jakeluverkkotoimintaan sitoutuneen pääoman kohtuullisesta tuottoasteesta (Statement to the Electricity Market Centre on the reasonable rate of return on capital invested in distribution network operations), 4 November 1998

7 PricewaterhouseCoopers, Lausunto koskien sähkön jakeluverkkotoiminnan pääoman keskikustannusta (Statement on the average costs of capital in the electricity distribution

network operations), 7 April 2004

8 Deloitte & Touche, Energiamarkkinavirasto – Sähköverkkotoiminnan WACC-mallin ja sen parametrien arviointi (Assessment of the WACC model and its parameters in electricity

network operations), 6 August 2010

9 DFC Economics S.r.l., Rate-base adjustment for inflation in energy networks regulation: A report for Energiavirasto, 2 October 2023

10 Kallunki, Juha-Pekka, Lausunto Energiamarkkinaviraston käyttämästä sähköverkkotoiminnan valvontamallista (Statement on the regulatory model for electricity network operations used by the Energy Market Authority), 29 April 2011

11 Kirjanpitolautakunnan lausunto sähköliittymismaksujen kirjaamisesta (Decision of the Accounting Board on the recording of electricity connection fees) (1670/2001)

12 Kirjanpitolautakunnan lausunto kantaverkon liittymismaksujen merkitsemisestä liittyjän tilinpäätökseen (Decision of the Accounting Board of the recording of transmission grid connection fees in the connecting customer's financial statements) (1905/2013)

13 AFRY Management Consulting Oy / Tkachenko Evgenia, Vihavainen Petri, Selvitys keskeytyksen aiheuttaman haitan kustannuksista, (A report on the costs of the disadvantage caused by outages), November 2022

14 Gaia Consulting Oy, Karttunen Ville, Vanhanen Juha, Partanen Jarmo, Matschoss Kaisa, Bröckl Marika, Haakana Juha, Hagström Markku, Lassila Jukka, Pesola Aki and Vehviläinen Iivo, Selvitys laatukannustimen toimivuudesta ja kehitystarpeista vuosille 2016–2023 (Report on the functioning and development needs of the quality incentive for the period 2016–2023), 27 October 2014

15 Tampere University of Technology, Lappeenranta University of Technology / Verho Pekka;Strandén Janne; Nurmi Veli-Pekka; Mäkinen Antti; Järventausta Pertti; Hagqvist Olli;Partanen Jarmo; Lassila Jukka; Kaipia Tero; Honkapuro Samuli: Nykyisen valvontamallin arviointi – suurhäiriöriski (Assessment of the current regulatory model – risk of major disturbance), 24 November 2010

16 Järventausta Pertti, Collan Mikael, Liski Matti, Huhta Kaisa, Akateeminen työryhmä sähkönsiirron ja- jakelun tariffien laskentamenetelmistä, työryhmän lausunto Energiavirastolle (Adademic working group on tariff calculation methods for electrivity transmission and distribution, working group statement to the Energy Authority), 31 May 2022

17 ECKTA Oy / Kuosmanen, T. Yleinen tehostamistavoite sähkön ja maakaasun verkkotoiminnoissa 6. ja 7. valvontajaksoilla 2024–2031 (General efficiency target for electricity and natural gas network operations in the 6th and 7th regulatory periods 2024–2031), 15 November 2022

18 ECKTA Oy / Kuosmanen, T., Kuosmanen, N, Dai, S., Kohtuullinen muuttuva kustannus sähkön jakeluverkkoyhtiöiden valvontamallissa: Ehdotus tehostamiskannustimen kehittämiseksi 6. ja 7. valvontajaksoilla vuosina 2024–2031 (Reasonable variable cost in the regulatory model for electricity distribution system companies: A proposal for the development of an incentive for the 6th and 7th regulatory period in 2024–2031), 12 September 2022

19 Sigma-Hat Economics Oy / Kuosmanen, T., Saastamoinen, A., Keshvari, A., Johnson, A., & Parmeter, C., Tehostamiskannustin sähkön jakeluverkkoyhtiöiden valvontamallissa: Ehdotus Energiaviraston soveltamien menetelmien kehittämiseksi neljännellä valvontajaksolla 2016–2019 (The efficiency incentive in the regulatory model for electricity

distribution network companies: a proposal for the development of methods applied by the Energy Authority in the fourth regulatory period 2016–2019)., 21 October 2014

20 PA Consulting Group Oy / Kuusela Akke, Sähkön jakeluverkkotoiminnan laajenemisen kustannusvaikutuksiin liittyvä konsulttityö (Consultancy work related to the cost impact of the expansion of electricity distribution network operations), 24 May 2004

21 Gaia Consulting Oy / Vehviläinen Iivo; Ryynänen Erkka; Hjelt Mari; Descombes Laura; Vanhanen Juha: Energiaviraston valvontamenetelmissä sovellettavan innovaatiokannustimen arviointi (Assessment of the innovation incentive applied in the Energy Authority's regulation methods), 18 September 2014

APPENDIX 1 NETWORK COMPONENTS, UNIT PRICES AND LIFETIME REPLACEMENT INTERVALS

The unit prices in the Appendix have been determined based on a unit price survey carried out in 2023. The unit prices in the Appendix are applied as such to adjust investments made before 2024.

The unit prices will be updated separately for the investments of the sixth and seventh regulatory periods. The breakdown and structure of the unit price list will remain primarily unchanged to make it easier for DSOs to prepare for reporting their costs. However, the list may be subject to minor justified changes and clarifications, for example, if entirely new components need to be added to the list or if needs for improving accuracy are identified in the current breakdown.

All distribution system operators and high-voltage distribution system operators were asked to respond to the unit price survey on the basis of actual investment costs. Responses that could be used to inform the determination of unit prices were obtained from 73 different system operators.

DETERMINING UNIT PRICES

The unit price survey was used to examine the unit cost of each network component based on the two most recent investment years in the previous five-year period and the unit cost of rare components in the previous 10 years. Unit prices mainly consist of investment projects carried out in 2021 and 2022. The unit cost of the network components made before 2022 has been index-adjusted on the basis of the averages of the consumer price index to the 2022 status before determining the unit price. The unit prices of the list are presented in the 2022 value of money.

Unit prices are mainly based on the average weighted by investment volumes. The determination of the weighted average often makes use of correction based on standard deviation where the weighted average is calculated based on the information within the standard deviation calculated from the median. In principle, the correction of the standard deviation has only been used if this does not lower the sample significantly and if, based on the Authority's estimate, it leads to more realistic linear and justified unit prices that better reflect the average investment project.

For some unit prices, other methods have also been used due to small samples and non-linear results. These include, for example, an average determined based on DSOs' responses or a unit price determined based on the unit prices of other similar network components. If determining the unit price has still not been possible despite these measures, the unit price valid during the previous regulatory period has been set as the unit price. In individual cases, it has also been necessary to rely on the responses of individual DSOs in the determination, for example to identify the cost difference between two components with different structures, which has enabled setting missing or inconsistent small sample results in line with other results.

It has been necessary to use the different calculation principles listed above when determining unit prices to ensure that the unit prices of similar network components in a group of components would be in a linear proportion to one another and would also otherwise result in entities that make sense, corresponding to costs and reflecting the actual situation.

Although the determination is ultimately based on information on the DSOs' actual costs for each network component, for some less common network components, it has not been possible to make the determination as straightforwardly as for more common network components. The main principle has been to establish for each network component an average unit price responsive to the costs of a regular investment project.

UNIT PRICE LIST

The content definitions of network components will be mainly found in the unit price survey system of the Energy Authority and they will be specified as necessary during the regulatory periods.

Unit prices have been rounded to the nearest hundred euros and those in component groups including network components of under a thousand euros to the nearest ten euros.

The Authority has determined the lifetime replacement intervals on the basis of responses to the unit price survey carried out in 2023.

Network component	Unit	€/unit	Lifetime re-placement interval
OVERHEAD LINE NETWORK IN THE DISTRIBUTION NETWORK			
0.4 kV Overhead lines			
AMKA 16 -25 mm2	km	16,400	35–45
AMKA 35 - 50 mm2	km	16,900	35–45
AMKA 70 mm2	km	18,200	35–45
AMKA 95 mm2	km	19,500	35–45
AMKA 120 mm2	km	20,900	35–45
0.4 kV Pole fuses			
Pole fuse	pcs	476	30–45
20 kV Overhead lines			
SPARROW or smaller	km	22,900	40–50
RAVEN	km	23,900	40–50
PIGEON	km	27,200	40–50
AL132 mm2 or larger	km	34,900	40–50
Covered overhead line 35 mm2	km	27,900	40–50
Covered overhead line 50 mm2	km	29,400	40–50
Covered overhead line 70 mm2	km	31,300	40–50
Covered overhead line 95 mm2	km	34,600	40–50
Covered overhead line 120 mm2	km	40,600	40–50
Covered overhead line 160 mm2	km	44,400	40–50
Universal cable 70 mm2 or smaller	km	46,100	40–50
Universal cable 95 mm2	km	48,600	40–50
Universal cable 120 mm2	km	53,200	40–50
Universal cable 150 mm2	km	60,800	40–50
20 / 0.4 kV Pole mounted transformer substations			
1-pole mounted transformer substation	pcs	4,400	35–45
2-pole mounted transformer substation	pcs	6,100	35–45
4-pole mounted transformer substation	pcs	6,400	35–45
Line disconnectors and disconnector stations in the 20 kV overhead line network			
Line disconnector: 3-phase maintenance disconnector that can be disconnected in 1 phase	pcs	1,800	25–35
Line disconnector: light	pcs	3,100	25–35
Line disconnector: with circuit breaker chamber	pcs	5,600	25–35

Disconnector station: 1 disconnector	pcs	9,900	25–35
Disconnector station: 2 disconnectors	pcs	16,500	25–35
Disconnector station: 3 disconnectors	pcs	22,200	25–35
Disconnector station: 4 disconnectors	pcs	35,500	25–35
Protection and automation in the 20 kV overhead line network			
Pole recloser: recloser specific	pcs	19,400	25–35
Remote control equipment: motor controller, disconnector or recloser specific	pcs	3,500	25–35
Overhead line fault localization equipment: disconnector specific	pcs	2,700	15–25
Data transmission equipment: transformer substation or discon-nector station specific	pcs	2,800	15–25
45 kV Overhead line network			
Wood pole cable	km	45,000	45–55
Disconnector station: 1 disconnector	pcs	14,900	45–55
CABLE NETWORK IN THE DISTRIBUTION NETWORK			
Earth conductors			
Separate earthing conductor installed in a cable ditch Cu 16 mm2	km	2,600	40–55
Separate earthing conductor installed in a cable ditch Cu 25 mm2	km	3,300	40–55
Separate earthing conductor installed in a cable ditch Cu 35 mm2	km	3,700	40–55
Separate earthing conductor installed in a cable ditch Cu 50 mm2	km	6,300	40–55
Separate earthing conductor installed in a cable ditch Cu 70 mm2	km	12,900	40–55
Separate earthing conductor installed in a cable ditch Cu 95 mm2 or larger	km	18,700	40–55
0.4 kV Underground cables			
Underground cable 25 mm2 or less	km	6,800	35–50
Underground cable 35 mm2	km	7,400	35–50
Underground cable 50 mm2	km	8,000	35–50
Underground cable 70 mm2	km	10,100	35–50
Underground cable 95 mm2	km	10,700	35–50
Underground cable 120 mm2	km	12,700	35–50
Underground cable 150 mm2	km	13,800	35–50
Underground cable 185 mm2	km	18,000	35–50
Underground cable 240 mm2	km	20,800	35–50
Underground cable 300 mm2	km	28,600	35–50
0.4 kV Underwater cables			
Underwater cable 35 mm2 or less	km	12,000	35–50
Underwater cable 50 mm2	km	13,600	35–50
Underwater cable 70 mm2	km	16,600	35–50
Underwater cable 95 mm2	km	22,200	35–50

Underwater cable 120 mm2	km	25,000	35–50
Underwater cable 150 mm2	km	27,800	35–50
Underwater cable 185 mm2	km	28,400	35–50
Underwater cable 240 mm2 or over	km	34,200	35–50
Armoured underwater cable 35 mm2 or less	km	20,400	35–50
Armoured underwater cable 50 mm2	km	23,200	35–50
Armoured underwater cable 70 mm2	km	28,200	35–50
Armoured underwater cable 95 mm2	km	37,800	35–50
Armoured underwater cable 120 mm2	km	42,500	35–50
Armoured underwater cable 150 mm2	km	47,200	35–50
Armoured underwater cable 185 mm2	km	48,200	35–50
Armoured underwater cable 240 mm2 or over	km	58,100	35–50
Landing of underwater cable			
Landing of underwater cable	pcs	1,610	40–50
Landing of armoured underwater cable	pcs	2,000	40–50
0.4 kV Underground cable accessories			
0,4 kV branching box (no fuses, also house fuse box-like structures without fuses are reported here)	pcs	370	30–45
0.4 kV house fuse box	pcs	460	30–45
0.4 kV branching cabinet	pcs	520	30–45
0.4 kV Branching cabinet rail connector	pcs	70	30–45
0.4 kV fuse-switch disconnector 100 A or less	pcs	150	30–45
0.4 kV fuse-switch disconnector 160 A	pcs	180	30–45
0.4 kV fuse-switch disconnector 250 A	pcs	230	30–45
0.4 kV fuse-switch disconnector 400 A	pcs	270	30–45
0.4 kV fuse-switch disconnector 630 A	pcs	370	30–45
0.4 kV fuse-switch disconnector over 630 A	pcs	530	30–45
0.4 kV Distribution cabinets			
Non-metal distribution cabinets In 630 A or less			
0.4 kV distribution cabinet: non-metal (width less than 400 mm)	pcs	680	30–45
0.4 kV distribution cabinet: non-metal 00 (400 - less than 600 mm)	pcs	820	30–45
0.4 kV distribution cabinet: non-metal 0 (600 - less than 800 mm)	pcs	1,080	30–45
0.4 kV distribution cabinet: non-metal 01 (800 - less than 990 mm)	pcs	1,230	30–45
0.4 kV distribution cabinet: non-metal 02 or 03 (990 - less than 1200 and over 1200 mm)	pcs	1,680	30–45
Non-metal In 1000 A or more			
0.4 kV distribution cabinet: non-metal (width less than 400 mm)	pcs	1,230	30–45
0.4 kV distribution cabinet: non-metal 00 (400 - less than 600 mm)	pcs	1,390	30–45
0.4 kV distribution cabinet: non-metal 0 (600 - less than 800 mm)	pcs	1,640	30–45
0.4 kV distribution cabinet: non-metal 01 (800 - less than 990 mm)	pcs	1,810	30–45

0.4 kV distribution cabinet: non-metal 02 (990 - less than 1200 mm)	pcs	1,970	30–45
0.4 kV distribution cabinet: non-metal 03 (1200 mm and over)	pcs	2,200	30–45
Metal distribution cabinets In 630 A			
0.4 kV distribution cabinet: metal (width less than 400 mm)	pcs	840	30–45
0.4 kV distribution cabinet: metal 00 (400 - less than 600 mm)	pcs	1,000	30–45
0.4 kV distribution cabinet: metal 0 (600 - less than 800 mm)	pcs	1,150	30–45
0.4 kV distribution cabinet: metal 01 (800 - less than 990 mm)	pcs	1,440	30–45
0.4 kV distribution cabinet: metal 02 (990 - less than 1200 mm)	pcs	1,580	30–45
0.4 kV distribution cabinet: metal 03 (1200 mm and over)	pcs	2,040	30–45
Metal distribution cabinets In 1000 A or more			
0.4 kV distribution cabinet: metal (width less than 400 mm)	pcs	1,430	30–45
0.4 kV distribution cabinet: metal 00 (400 - less than 600 mm)	pcs	1,630	30–45
0.4 kV distribution cabinet: metal 0 (600 - less than 800 mm)	pcs	1,920	30–45
0.4 kV distribution cabinet: metal 01 (800 - less than 990 mm)	pcs	2,120	30–45
0.4 kV distribution cabinet: metal 02 (990 mm - less than 1200 mm)	pcs	2,300	30–45
0.4 kV distribution cabinet: metal 03 (1200 mm and over)	pcs	2,580	30–45
1.0 kV Special network components			
1.0 kV protective equipment	pcs	2,700	25–35
1 kV / 0.4 kV park transformer substation	pcs	6,300	35–50
1 kV / 0.4 kV pole mounted transformer substation	pcs	5,600	35–45
20 kV Underground cables			
Underground cables without a messenger wire			
Underground cable 70 mm2 or less	km	11,900	40–55
Underground cable 95 mm2	km	14,600	40–55
Underground cable 120 mm2	km	16,200	40–55
Underground cable 150 mm2	km	17,900	40–55
Underground cable 185 mm2	km	22,400	40–55
Underground cable 240 mm2	km	25,800	40–55
Underground cable 300 mm2	km	29,800	40–55
Underground cable 400 mm2	km	36,500	40–55
Underground cable 500 mm2	km	43,300	40–55
Underground cable 630 mm2	km	52,000	40–55
Underground cable 800 mm2	km	63,500	40–55
Underground cables with a messenger wire			
Underground cable 70 mm2 or less	km	19,400	40–55
Underground cable 95 mm2	km	21,400	40–55
Underground cable 120 mm2	km	23,200	40–55
Underground cable 150 mm2	km	24,400	40–55
Underground cable 185 mm2	km	27,400	40–55

Underground cable 240 mm2	km	29,700	40–55
Underground cable 300 mm2	km	33,700	40–55
Underground cable 400 mm2	km	40,500	40–55
Underground cable 500 mm2	km	47,200	40–55
Underground cable 630 mm2	km	56,000	40–55
Underground cable 800 mm2	km	67,400	40–55
20 kV Underwater cables			
Underwater cable 70 mm2 or less	km	26,800	40–55
Underwater cable 95 mm2	km	28,700	40–55
Underwater cable 120 mm2	km	31,000	40–55
Underwater cable 150 mm2	km	33,700	40–55
Underwater cable 185 mm2	km	36,900	40–55
Underwater cable 240 mm2	km	42,000	40–55
Underwater cable 300 mm2 or larger	km	47,500	40–55
Armoured underwater cables			
Armoured underwater cable 70 mm2 or less	km	66,200	40–55
Armoured underwater cable 95 mm2	km	86,900	40–55
Armoured underwater cable 120 mm2	km	89,800	40–55
Armoured underwater cable 150 mm2	km	93,200	40–55
Armoured underwater cable 185 mm2	km	97,300	40–55
Armoured underwater cable 240 mm2	km	103,700	40–55
Armoured underwater cable 300 mm2 or larger	km	108,700	40–55
Landing of underwater cable			
Landing of underwater cable	pcs	1,960	40–55
Landing of armoured underwater cable	pcs	2,340	40–55
20 kV Cable accessories			
Terminations and branching cabinets			
Outdoor termination, air-insulated	pcs	1,370	35–50
Indoor termination, air-insulated	pcs	640	35–50
Separable connector	pcs	830	35–50
20 kV branching cabinet	pcs	4,240	35–50
Surge protective device 20 kV in cable and pole terminals and distribution substations			
Surge protective device, air-insulated	pcs	640	35–50
Surge protective device, cable coupler	pcs	1,350	35–50
Joints			
Plastic cable joint 150 mm2 or less	pcs	880	35–50
Plastic cable joint over 150 mm2	pcs	1,260	35–50
Mixed or oil-filled cable joint (plastic-paper and paper-paper) 150 mm2 or less	pcs	1,370	35–50

Mixed or oil-filled cable joint (plastic-paper and paper-paper) over 150 mm2	pcs	1,820	35–50
Underwater cable joints			
Underwater cable joint	pcs	980	35–50
Armoured underwater cable joint	pcs	3,940	35–50
Distribution substations in 20/0.4 kV underground cable network			
Park transformer substations, LV centre In 630 A or less			
Park transformer substation, externally managed category 0: without disconnector	pcs	7,500	35–50
Park transformer substation, externally managed category 1: 1 cell with disconnector	pcs	13,100	35–50
Park transformer substation, externally managed category 2: 2 cells with disconnectors	pcs	14,600	35–50
Park transformer substation, externally managed category 3: 3 cells with disconnectors	pcs	16,300	35–50
Park transformer substation, externally managed category 4: 4 cells with disconnectors	pcs	19,200	35–50
Park transformer substation, internally managed category 0: without disconnector	pcs	13,400	35–50
Park transformer substation, internally managed category 1: 1 cell with disconnector	pcs	15,800	35–50
Park transformer substation, internally managed category 2: 2 cells with disconnectors	pcs	18,200	35–50
Park transformer substation, internally managed category 3: 3 cells with disconnectors	pcs	20,100	35–50
Park transformer substation, internally managed category 4: at least 4 cells with disconnectors	pcs	23,100	35–50
Park transformer substations, LV centre In over 630 A			
Park transformer substation, externally managed category 1: at most 1 cell with disconnector	pcs	13,600	35–50
Park transformer substation, externally managed category 2: 2 cells with disconnectors	pcs	19,100	35–50
Park transformer substation, externally managed category 3: 3 cells with disconnectors	pcs	22,000	35–50
Park transformer substation, externally managed category 4: 4 cells with disconnectors	pcs	24,000	35–50
Park transformer substation, externally managed category 5: at least 5 cells with disconnectors	pcs	28,800	35–50
Park transformer substation, internally managed category 1: at most 1 cell with disconnector	pcs	21,100	35–50
Park transformer substation, internally managed category 2: 2 cells with disconnectors	pcs	24,200	35–50
Park transformer substation, internally managed category 3: 3 cells with disconnectors	pcs	27,400	35–50
Park transformer substation, internally managed category 4: 4 cells with disconnectors	pcs	30,500	35–50
Park transformer substation, internally managed category 5: at least 5 cells with disconnectors	pcs	33,700	35–50
Fire insulated park transformer substations			
Fire insulated park transformer substation category 1: at most 4 cells with disconnectors	pcs	40,400	35–50

Fire insulated park transformer substation category 2: at least 5 cells with disconnectors	pcs	45,400	35–50
Indoor transformer substation			
Indoor transformer substation category 1: at most 3 cells with disconnectors	pcs	49,400	35–50
Indoor transformer substation category 2: 4 cells with disconnectors	pcs	51,600	35–50
Indoor transformer substation category 3: at least 5 cells with disconnectors	pcs	77,500	35–50
Double-ended transformer substations			
Double-ended park transformer substation: at least 4 cells with disconnectors	pcs	44,700	35–50
Fire insulated double-ended park transformer substation: at least 4 cells with disconnectors	pcs	85,500	35–50
Double-ended indoor transformer substation: at least 4 cells with disconnectors	pcs	76,900	35–50
Disconnector stations in the 20 kV underground cable network			
Disconnector station: park transformer substation type structure category 1: 1 cell with disconnector	pcs	6,900	35–50
Disconnector station: park transformer substation type structure category 2: 2 cells with disconnectors	pcs	13,400	35–50
Disconnector station: park transformer substation type structure category 3: 3 cells with disconnectors	pcs	19,200	35–50
Disconnector station: park transformer substation type structure category 4: 4 cells with disconnectors	pcs	22,300	35–50
Disconnector station: park transformer substation type structure category 5: at least 5 cells with disconnectors	pcs	25,900	35–50
Protection and automation in the 20 kV underground cable network			
Switch: at a transformer substation or disconnector station, disconnector-specific	pcs	12,100	30–40
Remote control equipment: disconnector or recloser specific motor controller	pcs	790	20–35
Ground contact fault indication equipment: installed in a transformer substation or a disconnector station, primary	pcs	700	15–30
Data transmission equipment: transformer substation or disconnector station specific	pcs	4,500	15–30
45 kV Underground cables			
30 to 45 kV Underground cable 300 mm2 and below	km	34,300	40–55
Distribution network underground cable excavation (0.4 KV - 45 KV)			
1. Easy: an area outside a town plan area and other conditions	km	14,600	
2. Regular: :within a town plan area but outside other conditions	km	26,300	
3. Regular: Overground rock areas and rocky soil in regular or easy conditions	km	46,600	
4. Difficult: Inner urban area	km	79,700	
5. Extremely difficult: Sub-centres of large cities (central area over 100 squares) and centre areas in urban regions (over 30 squares)	km	109,800	
6. Extremely difficult: Wide inner city centres of large cities (central area over 100 squares)	km	166,400	
TRANSFORMERS IN THE DISTRIBUTION NETWORK			

20 / 0.4 kV Distribution transformers			
Transformers tier 2			
Transformer 16 kVA	pcs	3,100	35–45
Transformer 30 kVA	pcs	3,300	35–45
Transformer 50 kVA	pcs	4,200	35–45
Transformer 100 kVA	pcs	5,300	35–45
Transformer 200 kVA	pcs	7,500	35–45
Transformer 315 kVA	pcs	9,000	35–45
Transformer 400 kVA	pcs	10,400	35–45
Transformer 500 kVA	pcs	12,000	35–45
Transformer 630 kVA	pcs	13,000	35–45
Transformer 800 kVA	pcs	14,900	35–45
Transformer 1000 kVA	pcs	19,100	35–45
Transformer 1250 kVA	pcs	22,900	35–45
Transformer 1600 kVA	pcs	28,200	35–45
Transformers tier 1 or tier 0			
Transformer 16 kVA	pcs	2,700	35–45
Transformer 30 kVA	pcs	2,900	35–45
Transformer 50 kVA	pcs	3,000	35–45
Transformer 100 kVA	pcs	3,900	35–45
Transformer 200 kVA	pcs	5,000	35–45
Transformer 315 kVA	pcs	6,100	35–45
Transformer 400 kVA	pcs	7,100	35–45
Transformer 500 kVA	pcs	7,800	35–45
Transformer 630 kVA	pcs	9,100	35–45
Transformer 800 kVA	pcs	10,600	35–45
Transformer 1000 kVA	pcs	13,100	35–45
Transformer 1250 kVA	pcs	17,800	35–45
Transformer 1600 kVA	pcs	20,800	35–45
1 / 0.4 kV Distribution transformers			
Transformer 30 kVA	pcs	2,900	35–45
Transformer 50 kVA	pcs	3,400	35–45
Transformer at least 100 kVA	pcs	4,700	35–45
Other transformers in the distribution network and voltage control			
3-winding transformer at most 150 kVA	pcs	6,800	35–45
3-winding transformer over 150 kVA	pcs	8,200	35–45
Transformer 20 / 10 kV (Report unit cost for different power levels in additional information)	pcs	165,300	35–45
Transformer 45 / 20 kV (Report unit cost for different power levels in additional information)	pcs	194,200	35–45

Voltage control regulator in the LV network	pcs	7,700	35–45
Energy meters			
Energy metering equipment (Customer metering)			
Energy meter: remotely read direct measurement (previously at most 63 A)	pcs	200	10–20
Energy meter: remotely read current transformer measurement (previously over 63 A)	pcs	470	10–20
Energy meter: remotely read 10-45 kV	pcs	1,030	10–20
Energy meter: remotely read over 45 kV	pcs	2,390	10–20
High-voltage network and substation equipment			
110 kV Overhead lines			
Poles			
Timber poles			
Timber pole, unguyed	pcs	19,500	50–60
Timber pole, guyed	pcs	22,100	50–60
Timber pole, guyed, 2 subconductors	pcs	24,100	50–60
Tubular poles, guyed			
Tubular pole: one circuit, one subconductor	pcs	23,100	50–60
Tubular pole: one circuit, two subconductors	pcs	25,100	50–60
Tubular pole: two circuits, one subconductor	pcs	31,400	50–60
Tubular pole: two circuits, two subconductors	pcs	33,400	50–60
High tension pole: one circuit, one subconductor	pcs	33,600	50–60
High tension pole: one circuit, two subconductors	pcs	35,600	50–60
High tension pole: two circuits, one subconductor	pcs	39,300	50–60
High tension pole: two circuits, two subconductors	pcs	41,300	50–60
Steel lattice poles, guyed			
Steel lattice pole, guyed: one circuit, one subconductor	pcs	25,800	50–60
Steel lattice pole, guyed: one circuit, two subconductors	pcs	28,100	50–60
Steel lattice pole, guyed: two circuits, one subconductor	pcs	35,200	50–60
Steel lattice pole, guyed: two circuits, two subconductors	pcs	37,500	50–60
High tension pole: one circuit, one subconductor	pcs	37,700	50–60
High tension pole: one circuit, two subconductors	pcs	39,900	50–60
High tension pole: two circuits, one subconductor	pcs	44,000	50–60
High tension pole: two circuits, two subconductors	pcs	46,300	50–60
Steel lattice pole, free-standing			
Steel lattice pole, free-standing: one circuit, one subconductor	pcs	57,700	50–60
Steel lattice pole, free-standing: one circuit, two subconductors	pcs	59,700	50–60
Steel lattice pole, free-standing: two circuits, one subconductor	pcs	81,800	50–60

Steel lattice pole, free-standing: two circuits, two subconductors	pcs	83,800	50–60
High tension pole: one circuit, one subconductor	pcs	89,700	50–60
High tension pole: one circuit, two subconductors	pcs	91,700	50–60
High tension pole: two circuits, one subconductor	pcs	158,300	50–60
High tension pole: two circuits, two subconductors	pcs	160,300	50–60
Conductors (per conductor type)			
ACSR 67 - 149 mm2 (Suursavo and Suursavo strong)	km	2,300	50–60
ACSR 150 - 299 mm2 (Ostrich and Hawk)	km	5,500	50–60
ACSR 300 - 459 mm2 (Duck)	km	8,600	50–60
ACSR 450 - 650 mm2 (Finch)	km	10,300	50–60
Ground wire	km	2,900	50–60
Optical ground wire (OPGW)	km	7,400	50–60
Line disconnectors in the 110 kV overhead line network			
Line disconnector, locally controlled	pcs	31,600	40–50
Line disconnector, remote-controlled	pcs	44,300	40–50
Earthing disconnector/switch	pcs	4,400	40–50
Line area compensations in the 110 kV overhead line network			
Line area compensation easy: an area outside the town plan	km	7,800	
Line area compensation regular: an area inside the town plan	km	15,700	
Line area compensation difficult: inner urban area inside the town plan	km	54,400	
Line area compensation very difficult: city centre areas (cohesive area of over 30 squares) and sub-centres in large cities within the inner urban area	km	76,300	
110 kV Cables (3 stages)			
Aluminium cables			
Underground cable Al 500 mm2 or less	km	234,200	50–60
Underground cable Al 800 mm2	km	275,600	50–60
Underground cable Al 1000 - 1200 mm2	km	311,300	50–60
Underground cable Al 1600 mm2	km	376,700	50–60
Underground cable Al 2000 mm2	km	442,143	50–60
Underground cable Al at least 2500 mm2	km	505,300	50–60
Copper cables			
Underground cable Cu 1600 mm2 or less	km	568,900	50–60
Underground cable Cu over 1600 mm2	km	637,300	50–60
Underwater cables (3 stages)			
Armoured underwater cable	km	1,236,200	50–60
110 kV Cable accessories			
Terminals			

Switchgear terminal (GIS), 800 mm2 or less	pcs	25,600	45–55
Switchgear terminal (GIS), 1000 - 1600 mm2	pcs	27,400	45–55
Switchgear terminal (GIS), over 1600 mm2	pcs	29,300	45–55
Pole terminal, 800 mm2 or less	pcs	21,400	45–55
Pole terminal, 1000 - 1600 mm2	pcs	27,500	45–55
Pole terminal, over 1600 mm2	pcs	33,500	45–55
Joints			
Joint	pcs	19,700	45–55
Joint crossbonding	pcs	29,100	45–55
Armoured underwater cable joint	pcs	45,000	45–55
Landing of underwater cable			
Landing of armoured underwater cable	pcs	40,000	45–55
110 kV Underground cable excavation			
1. Easy: an area outside the town plan and other conditions	km	22,700	
2. Regular: areas inside the town plan but outside other conditions	km	102,900	
3. Difficult: inner urban area inside the town plan	km	303,400	
4. Extremely difficult: Sub-centres of large cities (central area over 100 squares) and centre areas in urban regions (over 30 squares)	km	544,900	
5. Extremely difficult: Wide inner city centres of large cities (central area over 100 squares)	km	815,700	
110 kV Generator transformers and foundations			
Generator transformers			
Generator transformer 6 MVA	pcs	256,200	40–65
Generator transformer 10 MVA	pcs	268,300	40–65
Generator transformer 16 MVA	pcs	336,500	40–65
Generator transformer 20 MVA	pcs	364,300	40–65
Generator transformer 25 MVA	pcs	398,300	40–65
Generator transformer 31.5 MVA	pcs	472,800	40–65
Generator transformer 40 MVA	pcs	481,900	40–65
Generator transformer 50 MVA	pcs	549,300	40–65
Generator transformer 63 MVA	pcs	630,500	40–65
Generator transformer 80 MVA	pcs	736,700	40–65
Generator transformer 100 MVA	pcs	861,600	40–65
110 kV generator transformer or reactor foundations			
Transformer foundation	pcs	64,200	40–65
Transformer foundation with protective walls	pcs	130,000	40–65
Transformer foundation covered bunker	pcs	292,700	40–65
110 kV Air insulated switchgear			
Switchgear: Air			

1-busbar switchgear's incoming and outgoing field with a circuit-breaker	pcs	189,300	40–50
1-busbar switchgear's field with disconnector(s) only	pcs	52,800	40–50
2-busbar switchgear's incoming and outgoing field with a circuit-breaker	pcs	208,800	40–50
2-busbar switchgear's field with disconnector(s) only	pcs	56,600	40–50
Bus coupler circuit-breaker field	pcs	123,300	40–50
Measurement field (busbar voltage transformer) or line voltage transformer	pcs	33,800	40–50
Busbar earthing disconnector	pcs	14,600	40–50
Multi-group switchgear			
Ground separator	pcs	22,800	40–50
Ground separator automation	pcs	24,500	20–30
Protection automation			
Protection and automation equipment for 1-busbar switchyard: sub-station-specific part	pcs	37,300	20–30
Protection and automation equipment for 2-busbar switchyard: sub-station-specific part	pcs	62,500	20–30
Field protection and automation equipment: field-specific section	pcs	27,900	20–30
110 kV SF6-Insulated switchgear			
Switchgear: SF6			
1-busbar switchgear: incoming or outgoing feeder bay with a circuit-breaker	pcs	227,900	40–50
1-busbar switchgear bay with disconnector(s) only	pcs	63,600	40–50
2-busbar switchgear: incoming or outgoing feeder bay with a circuit-breaker	pcs	251,400	40–50
2-busbar switchgear bay with disconnector(s) only	pcs	70,100	40–50
Bus coupler circuit-breaker bay	pcs	176,900	40–50
Measurement field (busbar voltage transformer) or line voltage transformer	pcs	37,800	40–50
Busbar earthing disconnector	pcs	28,900	40–50
Multi-group switchgear			
Ground separator	pcs	34,800	40–50
Ground separator automation	pcs	24,500	20–30
Protection automation			
Protection and automation equipment for 1-busbar switchyard: sub-station-specific part	pcs	59,700	20–30
Protection and automation equipment for 2-busbar switchyard: sub-station-specific part	pcs	74,900	20–30
Field protection and automation equipment: field-specific section	pcs	47,600	20–30
Busbar differential relay protection SF6 or air insulated			
Busbar differential relay protection for 1-busbar switchyard: substa-tion-specific part	pcs	16,500	20–30
Busbar differential relay protection for 2-busbar switchyard: substa-tion-specific part	pcs	23,400	20–30

Busbar differential relay protection: field-specific part	pcs	6,800	20–30
45 kV Switchgear			
Switchgear			
1-busbar switchgear's incoming and outgoing field with a circuit-breaker	pcs	146,600	40–50
1-busbar switchgear's field with disconnector(s) only	pcs	40,900	40–50
2-busbar switchgear's incoming and outgoing field with a circuit-breaker	pcs	161,700	40–50
2-busbar switchgear's field with disconnector(s) only	pcs	43,900	40–50
Bus coupler circuit-breaker field	pcs	95,500	40–50
Measurement field (busbar voltage transformer) or line voltage transformer	pcs	26,100	40–50
Busbar earthing disconnector	pcs	21,000	40–50
Protection automation			
Protection and automation equipment for 1-busbar switchyard: sub-station-specific part	pcs	31,000	20–30
Protection and automation equipment for 2-busbar switchyard: sub-station-specific part	pcs	49,000	20–30
Field protection and automation equipment: field-specific section	pcs	18,000	20–30
20 kV Switchgear			
Air insulated switchgear			
1-busbar switchgear: incoming or outgoing feeder bay with a circuit-breaker	pcs	21,600	40–50
1-busbar switchgear bay with disconnector(s) only (own consump-tion bay)	pcs	13,100	40–50
2-busbar switchgear: incoming or outgoing feeder bay with a circuit-breaker	pcs	34,600	40–50
2-busbar switchgear bay with disconnector(s) only (own consump-tion bay)	pcs	24,500	40–50
Bus coupler circuit-breaker bay	pcs	29,900	40–50
Measurement field (busbar voltage transformer)	pcs	13,000	40–50
Line voltage transformer (incoming or outgoing feeder bay costs not included)	pcs	5,800	40–50
Busbar earthing disconnector	pcs	5,000	40–50
Multi-group switchgear			
Ground separator	pcs	10,300	40–50
Protection automation			
Protection and automation equipment for 1-busbar switchyard: sub-station-specific part	pcs	24,800	20–30
Protection and automation equipment for 2-busbar switchyard: sub-station-specific part	pcs	35,500	20–30
Field protection and automation equipment: field-specific part	pcs	8,200	20–30
SF6 gas-insulated switchgear			
1-busbar switchgear: incoming or outgoing feeder bay with a circuit-breaker	pcs	25,300	40–50

1-busbar switchgear bay with disconnector(s) only (own consumption bay)	pcs	9,200	40–50
2-busbar switchgear: incoming or outgoing feeder bay with a circuit-breaker	pcs	41,900	40–50
2-busbar switchgear bay with disconnector(s) only (own consumption bay)	pcs	15,300	40–50
Bus coupler circuit-breaker bay	pcs	36,500	40–50
Measurement field (busbar voltage transformer)	pcs	15,100	40–50
Line voltage transformer (incoming or outgoing feeder bay costs not included)	pcs	5,500	40–50
Busbar earthing disconnector	pcs	5,000	40–50
Multi-group switchgear			
Ground separator	pcs	10,300	40–50
Protection automation			
Protection and automation equipment for 1-busbar switchyard: substation-specific part	pcs	28,300	20–30
Protection and automation equipment for 2-busbar switchyard: substation-specific part	pcs	40,600	20–30
Field protection and automation equipment: field-specific part	pcs	7,900	20–30
20 kV Compensation equipment			
Capacitors (centralised)			
Capacitor 3 Mvar or less	pcs	38,800	40–50
Reactors (centralised)			
Reactor 1 Mvar or less	pcs	36,000	40–50
Reactor 2 Mvar or less (and over 1 Mvar)	pcs	46,200	40–50
Reactor 3 Mvar or less (and over 2 Mvar)	pcs	59,300	40–50
Reactor 4 Mvar or less (and over 3 Mvar)	pcs	85,700	40–50
Reactor 6 Mvar or less (and over 4 Mvar)	pcs	118,200	40–50
Reactor 8 Mvar or less (and over 6 Mvar)	pcs	150,600	40–50
Reactor sequence switch	pcs	3,600	40–50
Reactor step switch	pcs	42,200	40–50
Motor-drive mechanism for reactor sequence switch or step switch	pcs	11,000	40–50
Reactor foundations and open protective structure/box	pcs	19,600	40–50
Chokes (centralised)			
Centralised earth-fault current compensation coils:			
Earth-fault current compensation equipment 50 - 140 A (Coil without adjuster)	pcs	59,200	40–50
Earth-fault current compensation equipment 200 - 320 A (Coil without adjuster)	pcs	71,900	40–50
Earth-fault current compensation equipment over 320 A (Coil without adjuster)	pcs	106,700	40–50
Earthing transformers (neutral point transformers) for short-circuit to earth compensation equipment:			

Transformer at most 5000 kVA	pcs	39,400	40–50
Central compensation control:			
Compensation equipment controller with possible integrated injection equipment	pcs	15,200	25–40
Earth-fault current compensation equipment booth, if there is no space at the station:			
Earth-fault current compensation equipment booth	pcs	18,200	40–50
Distributed compensation			
Parallel choke with earth-fault current and reactive power compensation or only earth-fault compensation equipment (based on maximum setting)			
Distributed compensation equipment	pcs	10,500	40–50
Distribution transformer with earth-fault current compensation			
Transformer at most 50 kVA	pcs	11,400	40–50
Transformer 100 - 200 kVA	pcs	12,700	40–50
Transformer at least 315 kVA	pcs	14,700	40–50
Distribution transformer with parallel choke and earth-fault current compensation			
Transformer with parallel choke and earth-fault current compensation	pcs	22,000	40–50
110 kV Compensation equipment			
110 kV compensation equipment (generator transformer foundations)			
Reactor ONAN/ONAF cooling			
Reactor 6 Mvar	pcs	230,900	40–50
Reactor 10 Mvar	pcs	298,800	40–50
Reactor 16 Mvar	pcs	400,700	40–50
Reactor 20 Mvar	pcs	468,600	40–50
Reactor 25 Mvar	pcs	553,500	40–50
Reactor 30 Mvar	pcs	638,400	40–50
Reactor 40 Mvar	pcs	808,200	40–50
Reactor 50 Mvar or more	pcs	978,100	40–50
Neutral point choke			
At most 100 kVar	pcs	38,000	40–50
Substation buildings			
Factory-built/sectional			
Small light substation (less than 30 m2)	pcs	137,800	45–55
Substation in a non-built-up area (30 - 90 m2)	pcs	194,000	45–55
Substation in an urban area (more than 90 m2 and less than 270 m2)	pcs	271,900	45–55
Built on site in an urban environment			
Urban substation (200 - 600 m2)	pcs	552,000	45–60
Large urban substation (more than 600 m2)	pcs	2,864,400	45–60
Large substation in the centre of a large city (at least 800 m2)	pcs	5,795,300	45–60

Substation plots		
Sparsely populated area (outside the inner urban area)	pcs	39,400
City/agglomeration (distribution network excavation ratio 4)	pcs	123,100
Centre of a large city (distribution network excavation ratio 5 and 6)	pcs	415,100