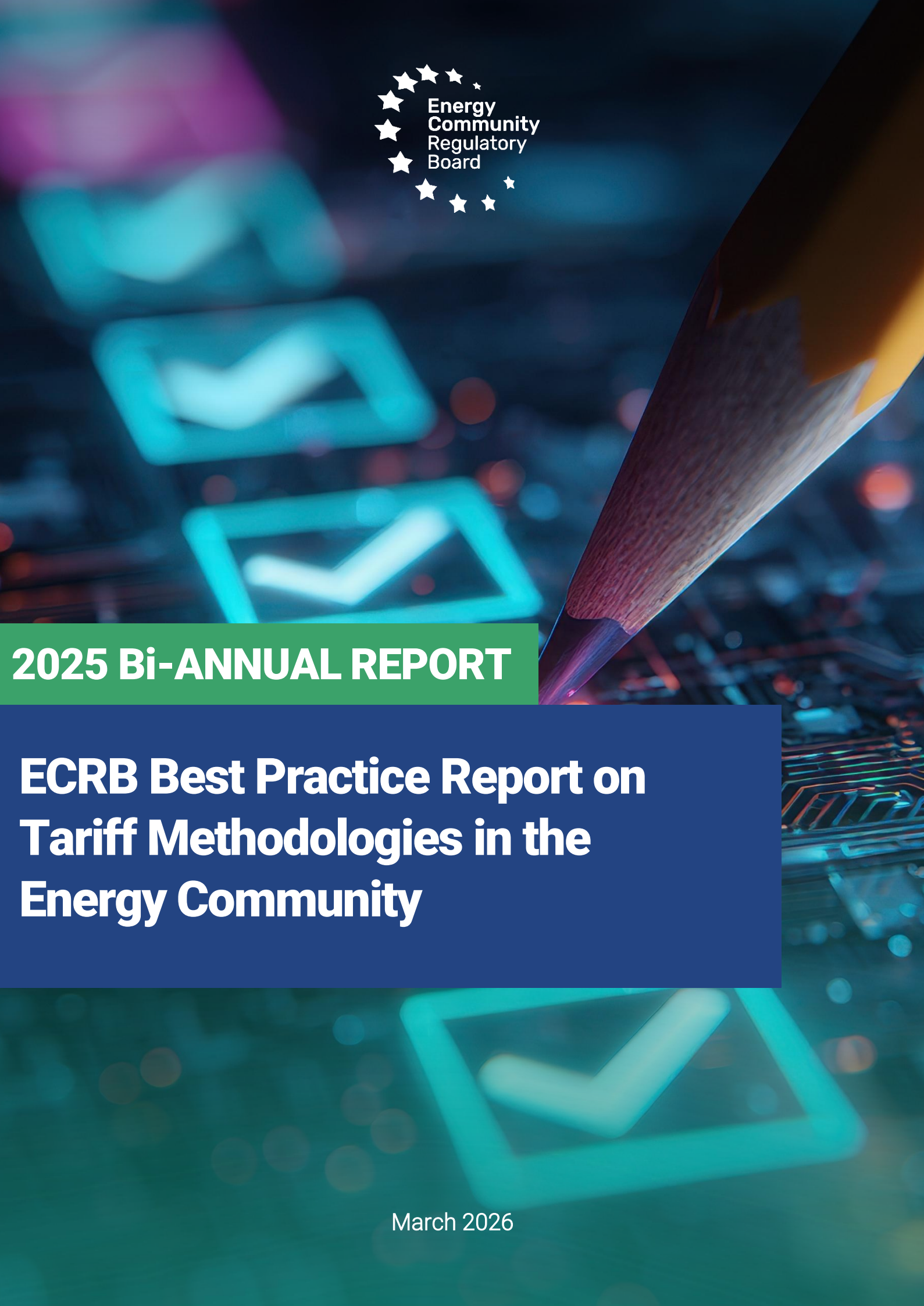


2025 Bi-ANNUAL REPORT

ECRB Best Practice Report on Tariff Methodologies in the Energy Community

March 2026

Best Practice Tariff Methodologies

Contents

1. Introduction 8
1.1. About the Energy Community and the Energy Community Regulatory Board 8
1.2. Background 8
1.3. Methodology and scope 10
1.4. Summary of progress since the 2023 ECRB Tariff Report 11
2. National framework for network tariff setting in Contracting Parties 16
2.1. Legal and regulatory framework 16
2.2. Tariff setting principles and type of regulation 20
2.2.1. Transmission 20
2.2.2. Distribution 22
2.3. Frequency of tariff methodologies revision and tariff value updates 24
2.3.1. Transmission 24
2.3.2. Distribution 27
2.4. Stakeholder involvement and transparency in tariff setting 30
3. Cost model, cost determination and cost recovery 33
3.1. Cost model and cost determination 35
3.2. Costs to be recovered by tariffs 36
3.2.1. Transmission 36
3.2.2. Distribution 41
3.2.3. Transmission and Distribution investments 44
3.2.4. Transmission and Distribution Losses 48
3.3. Cost cascading 56
3.3.1. Transmission 56
3.3.2. Distribution 58
4. Injection and withdrawal network charges 62
4.1. General overview 62
4.1.1. Reasons behind the introduction or non-introduction of injection charges 63

4.1.2. Allocation of the costs between injection and withdrawal charges 64
4.1.3. Share of injection and withdrawal charges in cost recovery 65
4.2. Tariff basis 66
4.2.1. Injection charges 67
4.2.2. Withdrawal charges 69
4.3. G-charge 73
4.4. Groups of network users subject to tariffs 74
4.4.1. Transmission 75
4.4.2. Distribution 77
5. Connection charges 79
5.1. Transmission 79
5.1.1 Recovery of connection costs 79
5.1.2. Connection charges setting principles 80
5.1.3. Variation of the level of the transmission connection charge 82
5.1.4. Charging for the connection of producers, RES producers and battery storage facilities 83
5.2. Distribution 84
5.2.1 Connection charges setting principles 84
5.2.2. Variation of the level of distribution connection charge 86
5.2.3. Charging for the connection of producers, RES producers and EV charging stations 86
6. Reactive energy charges and other network charges 87
6.1. Transmission 87
7. Time-differentiation and locational signals 92
7.1. General overview of time-of-use network charges 92
7.1.1. Transmission 93
7.1.2. Distribution 93
7.2. Locational signals in tariff design 94
7.3. Potential significant changes in the tariff methodology (tariff structure) 94
7.4. Locational connection charges and use of network charges 95
8. Addressing the Energy Community acquis and energy transition 96

8.1. PECI and innovation support 97
8.2. Energy Efficiency 97
8.3. Innovation/ R&D/smart grids/smart metering 98
8.4. Emerging network users 100
8.5. EV charging, power-to-gas, storage and other energy transition activities 100
8.6. Renewable energy communities, citizen energy communities 101
9. Conclusions and recommendations 102
Legal and regulatory framework 102
Tariff setting principles and type of regulation 102
Frequency of tariff methodologies revision and of tariff value updates 103
Stakeholder involvement 104
Transparency in tariff setting 105
Cost model 105
Cost recovery 105
Cost cascading 107
Injection and withdrawal tariffs 107
Connection charges 109
Reactive charges 109
Time-differentiation and locational signals 110
Renewable energy communities, citizen energy communities 110
Addressing the Energy Community acquis and energy transition 111
Annex I: Description of the cost determination and tariffs 113
Annex II: TSO's and DSO's revenue in 2024 122
Annex III: Value of injection and withdrawal charges in 2024-2025 123
Transmission 123
Distribution 127
Annex IV: main goals for designing the structure of withdrawal charges 136
Transmission 136
Distribution 137

List of Tables

Table 1.1 - Changes in network tariff methodologies in Contracting Parties since 2022 and planned activities 12
Table 2.1 - Legal and regulatory framework 18
Table 2.2 - Rules for T-tariff revision 25
Table 2.3 - Rules for D-tariff revision 28
Table 2.4 - Transparency of T-tariff relevant information 31
Table 3.1 - Cost category of T-tariff 37
Table 3.2 - Recovery of the cost categories by T-tariffs in Contacting Parties 38
Table 3.3 – Value of recovered costs by T-tariffs in Contacting Parties in 2024 (by cost categories) 41
Table 3.4 - Recovery of the cost categories by D-tariffs in Contracting Parties 42
Table 3.5 – Value of recovered costs by D-tariffs in Contacting Parties (by cost categories) 43
Table 3.6 – Categories of recovered costs by D-tariffs 46
Table 3.7 – Recovering of investments 47
Table 3.8 – Recognised losses and target values 50
Table 3.9 - Shares of electricity withdrawal and T-costs 56
Table 3.10 - Granularity required for the transmission costs 58
Table 3.11 - Cost-cascading method applied for the D-costs in Contracting Parties 58
Table 3.12- - Granularity required for the distribution costs 62
Table 4.1 - Type of transmission and distribution network charges applied in the Contracting Parties 62
Table 4.2 - Primary and secondary goals for the determination of the design of injection charges 67
Table 4.3 – T-tariff basis in the Energy Community Contracting Parties 69
Table 4.4 - D-tariff basis in the Energy Community Contracting Parties 71
Table 4.5 - Categories of network users subject to injection and withdrawal charges for recovering transmission costs 75
Table 4.6 - Categories of network users subject to injection and withdrawal charges for recovering distribution costs 77
Table 5.1 - Type of T-connection charges applied in Energy Community Contracting Parties 80
Table 5.2 - Type of T-connection charges applied in Energy Community Contracting Parties 84

Table 7.1 – Time-of-use T- tariffs in Montenegro and Serbia....93
Table 7.2 - Time-of-use D- tariffs in Bosnia and Herzegovina, Montenegro, Serbia....94
Table A1.1 - The description of the cost determination and/or cost models applied in the Energy Community Contracting Parties....113
Table A1.2 - Average Transmission tariff (excl VAT) in 2020-2024, EUR/MWh....116
Table A1.3 - Average Distribution tariff for HH (excl VAT) in 2020-2024, EUR/MWh....117
Table A1.4 - Average Distribution tariff for non-HH (excl VAT) in 2020-2024, EUR/MWh....117
Table A1.5. - Transmission and distribution losses recognition in tariff regulation....117
Table A3.1 - T-injection and T-withdrawal charges in Contracting Parties....123
Table A3.2 - D-injection and D-withdrawal charges in Contracting Parties....127
Table A4.1 - Primary and secondary goals for the determination of the design of T-withdrawal charges....136
Table A4.2 - Primary and secondary goals for the determination of the design of D-withdrawal charges....137

List of Figures

Figure 3.1 – Share of network tariffs in HH bill in Contracting Parties....33
Figure 3.2 – Share of network tariffs in non-HH bill in Contracting Parties....34
Figure 3.3 – Average network tariffs....35
Figure 3.4 – Allowable transmission losses in Contracting Parties, %....48
Figure 3.5 – Cost of transmission losses, mln EUR....49
Figure 3.6 – Allowable distribution losses in Contracting Parties, %....49
Figure 3.7 – Cost of distribution losses, mln EUR....50
Figure 4.1 - Share of transmission costs recovered by injection and withdrawal charges in 2024 .66
Figure 4.2 - Share of transmission withdrawal costs recovered by energy- and power-based charges in 2024....71
Figure 4.3 - Share of distribution withdrawal costs recovered by energy- and power-based charges in 2024....73
Figure 4.4 - Level of G-charge in Bosnia and Herzegovina and Montenegro in 2023-2024....74
Figure 6.1 - The level of unit charges for reactive withdrawal in 2024....89
Figure 6.2 - The level of unit charges for reactive withdrawal at MV in 2024....91

Figure 6.3 - The level of unit charges for reactive withdrawal at LV in 2024 91
Figure 7.1 - Metering intervals applied in Contraction Parties 92
Figure A2.1 - Collected TSO's and DSO's revenue in 2024 in mil. € 122

1. Introduction

1.1. About the Energy Community and the Energy Community Regulatory Board

The Energy Community[1] is an international organization established in 2006 with the aim to bring together the European Union and its neighbours to create an integrated pan-European energy market. The key objective of the Energy Community is to extend the EU internal energy market rules and principles to countries in South East Europe, the Black Sea region and beyond, based on a legally binding frame. Currently, the Energy Community has nine Contracting Parties: Albania, Bosnia and Herzegovina, Georgia, Kosovo*2, Moldova, Montenegro, North Macedonia, Serbia and Ukraine, while Armenia, Turkey and Norway are Observer Countries.3

As a body of the Energy Community, the Energy Community Regulatory Board (ECRB) operates based on Article 58 of the *Treaty establishing the Energy Community*. The ECRB advises the Energy Community Ministerial Council and Permanent High-Level Group on details of statutory, technical and regulatory rules and should make recommendations in the case of cross-border disputes between regulators. ECRB is the independent regional voice of energy regulators in the Energy Community. ECRB's mission builds on three pillars: providing coordinated regulatory positions to energy policy debates, harmonising regulatory rules across borders and sharing regulatory knowledge and experience.

With transposition of gas and electricity network codes, the package "Clean Energy for all Europeans" and the Electricity Integration Package[4] in the Energy Community legal framework, ECRB gained a number of new competences. This enhances its tools to foster integration of Contracting Parties' energy markets in the internal EU electricity and natural gas markets, in line with the objectives of the Treaty.

This report was prepared by the ECRB Electricity Working Group with active participation and inputs from all Energy Community Regulatory Authorities. ECRB acknowledges the leadership of Mr. Ihor Mitroshichev (NEURC) in preparing this deliverable and thanks Ms. Ketevan Mtsuravishvili (GNERC) for her contribution.

1.2. Background

The Clean Energy Package (hereinafter, EIP) establishes the climate and energy framework by enabling market signals to be delivered for increased efficiency, a higher share of renewable energy

1 https://www.energy-community.org/

2 Throughout this document the symbol * refers to the following statement: This designation is without prejudice to positions on status, and is in line with UNSCR 1244 and the ICJ Advisory Opinion on the Kosovo* declaration of independence.

3 https://www.energy-community.org/aboutus/whoweare.html

4 https://www.energy-community.org/enc-lex/law/acquis/EIP.html

sources, security of supply, flexibility, sustainability, decarbonisation and innovation. Particularly, the EIP promotes the effective development of energy infrastructure to ensure adequate capacity for integration of renewable, storage, and distributed capacities, while ensuring the reliability and security of supply. As one of the tools to gain this objective, the Regulation (EU) 2019/943 on the internal market for electricity[5] as adapted and adopted by the Ministerial Council's Decision D/2022/03/MC-EnC (hereinafter, Electricity Regulation) sets general principles and requirements for the charges and tariffs applied by network operators for access to networks, including connection charges, charges for use of networks, and, where applicable, charges for related network reinforcements. This emphasis is put on the following main principles: cost reflectivity, transparency, consideration of network security and support to system efficiency through signals to network users.

In order to mitigate the risk of market fragmentation, the ECRB is tasked by Article 18 of the Electricity Regulation to prepare the best practice report on transmission and distribution tariff methodologies in Energy Community Contracting Parties biannually. In 2023, the ECRB prepared and published its first Report on Electricity Transmission and Distribution Tariff Methodologies in the Energy Community (2023 ECRB Tariff Report)[6] in line with the Article 18, addressing the national framework for network tariffs setting in Contracting Parties, cost recovery principles applied, structures of network tariffs (e.g. injection/withdrawal, tariff basis, etc.), and other aspects highlighted by Article 18 (9) of the Electricity Regulation, namely:

- the ratio of tariffs applied to producers and tariffs applied to final customers;
- time-differentiated network tariffs;
- locational signals;
- the relationship between transmission tariffs and distribution tariffs;
- methods to ensure transparency in the setting and structure of tariffs;
- groups of network users subject to tariffs, the characteristics of those groups, forms of consumption, and any tariff exemptions;
- losses in high, medium and low-voltage grids.

Based on the findings of the 2023 ECRB Tariff Report, the ECRB provided the recommendations to the NRAs of the Contracting Parties on different aspects of network tariff regulation to bring their practices (where relevant) closer across the Energy Community, acknowledging the requirements of the acquis and the EU best practices[7].

In line with Electricity Regulation, NRAs of CPs shall duly take into consideration the ECRB report when fixing or approving transmission tariffs and distribution tariffs or their methodologies in

5 Incorporated and adapted by the Ministerial Council Decision D/2022/03/MC-EnC of 15 December 2022 on the incorporation of Regulation (EU) 2019/942, Regulation (EU) 2019/943, Regulation (EU) 2015/1222, Regulation (EU) 2016/1719, Regulation (EU) 2017/2195, Regulation (EU) 2017/2196, Regulation (EU) 2017/1485 in the Energy Community acquis, amending Annex I of the Energy Community Treaty, and on the amendments of the Ministerial Council Decisions No 2021/13/MC-EnC and No 2011/02/MC-EnC/

6 https://www.energy-community.org/dam/jcr:86b7c539-54ce-451a-8019-c8b166f24a9d/FINAL_ECRB%20Best%20Practice%20Report%20on%20Tariff%20Methodologies_approved%20by%20ECRB.pdf

7 ACER's *Report on Electricity Transmission and Distribution Tariff Methodologies in Europe*, January 2023, https://www.acer.europa.eu/Publications/ACER_electricity_network_tariff_report.pdf

accordance with Article 59 of Directive (EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC (hereinafter, Directive 2019/944).

This is the second ECRB Report according to Article 18 of the Electricity Regulation. It highlights the key developments and novelties in the network tariffs regulatory framework that have been implemented by the NRAs of the Contracting Parties since 2022, also reflecting (where relevant) on the progress in implementation of the previously provided recommendations.

Having regard to the latest 2025 ACER's report on network tariff practices in Europe[8], in this Report the ECRB investigated additional aspects of network tariffs regulation in Contracting Parties. Particularly, the treatment of new cost categories related to the TSO's tasks under the pan-EU and regional market integration projects; approaches to setting and application of the different tariff bases, including the capacity-based charge are reviewed in more detail. Attention is paid to the treatment of transmission and distribution investments in tariff revenue and recognition of different types of users, including storages, citizen energy communities and renewable energy communities.

Finally, the ECRB recommendations for further development of regulatory framework for transmission and distribution tariffs in the Energy Community Contracting Parties are provided with a view to gradually accommodating current practices to the requirements of the Clean Energy Package/EIP and electricity market realities (where relevant)

1.3. Methodology and scope

ACER's Report on Electricity network tariff methodologies in Europe (2025) is taken into account for the preparation of this Report, as required by Article 18 of the Electricity Regulation.

Data and analyses provided in the present Report are based on information provided by all the regulatory authorities of the Energy Community Contracting Parties. The questionnaires used for the collection of information are updated taking into account the topics covered in the above-mentioned 2025 ACER report, as well as to reflect the requests of the NRAs to explore in more details particular aspects related to the network tariffs regulation.

Where no specific developments were reported by NRAs, this Report refers to the previous 2023 ECRB Tariff Report in order not to duplicate already provided information. At the same time, any new developments in national practices are in focus, reflecting also if they follow the previous ECRB recommendations.

The present Report provides an overview of the transmission tariff (T-tariff) and distribution tariff (D-tariff) methodologies and tariffs, as well as other electricity network charges applied in the Energy Community Contracting Parties as of 2024. Where other period is covered, it is stated explicitly in the Report.

8 Getting the signals right: Electricity network tariff methodologies in Europe, ACER, March 2025, https://www.acer.europa.eu/sites/default/files/documents/Reports/2025-ACER-Electricity-Network-Tariff-Practices.pdf

This Report covers all nine (9) Energy Community Contracting Parties: Albania, Bosnia and Herzegovina, Georgia, Kosovo*, Moldova, Montenegro, North Macedonia, Serbia and Ukraine.

The terminology defined by Directive (EU) 2019/944, Regulation (EU) 2019/943 and ACER Report on Electricity network tariff methodologies in Europe apply in this Report.

1.4. Summary of progress since the 2023 ECRB Tariff Report

The NRAs of Contracting Parties have been asked to indicate any significant amendments to the T-tariff and the D-tariff methodologies following the two-year period after the previous report and its recommendations.

Based on the reported information, since 2022, in almost all Contracting Parties NRAs have introduced changes to the network tariff calculation methodologies to improve (case by case) cost reflectivity, incentivise investments and improve efficiency and quality of supply. Among the most notable, are the adoption of the new T-tariff methodology (in 2023) and D-tariff methodology (in 2025) in Moldova, the change of the base year from t-1 to t-2 for calculation of the T-tariff and D-tariff and introduction of lump sum element into the distribution charge for access to the network in North Macedonia, introduction of power-based element to the distribution injection charge in Montenegro, change of the approach on calculation of connection charges in Ukraine. In November 2024, NRA of Kosovo* (ERO) adopted the Rule on Principles for Determining Distribution Use of System Charges and Connection Charges, defining the main principles for the new D-tariff methodology, particularly, proposing the introduction of new network users, injection tariffs, capacity-based tariffs and alignment with the Energy Community acquis. The proposed principles largely align with the ECRB recommendations as of 2023 and aim to follow EU and regional energy regulatory frameworks.

Regarding the planned activities, the majority of NRAs noted that ongoing transposition of EIP is foreseen as the main driver for revising network tariff methodologies to reflect new types of users and principles for electricity networks development driven by the green transition. NRAs of Moldova (ANRE), North Macedonia (ERC), Montenegro (REGAGEN) and Serbia (AERS) are guided by the relevant national laws to follow the network tariff principles according to the EIP and tasked to develop the new tariff methodologies in the period of 2025-2026.

Also, one more NRA (GNERC, Georgia) has reported the intention to introduce the fixed/capacity-based element of the T-tariff and D-tariff in the following regulatory periods; the application of G-charge is also under consideration by GNERC.

NRA of Ukraine (NEURC) informed about the ongoing reform to separate the costs for renewable support scheme from the transmission tariff to comply with the requirements of the Article 18 of the Electricity Regulation. More details on the planned approach are presented in the country case below in the text.

In Table 1.1 the information per Contracting Party is presented:

Table 1.1 - Changes in network tariff methodologies in Contracting Parties since 2022 and planned activities

Contracting Party	Changes since 2022	Planned activities
Albania	The Methodology for calculating the electricity transmission tariffs was approved by ERE Board with decision no.180, of date 08.11.2017 and there have been no amendments of the T-Tariff regulatory framework. The Methodology for calculating the electricity distribution tariffs was approved by ERE Board with decision no. 182, date 10.11.2017. Since 2022, ERE has continued to adjust tariff components to reflect updated operational costs and investment plans. There have been no radical changes in the regulatory framework, but incremental updates to ensure cost-reflectivity and compliance with EU energy acquis standards have been implemented. Specific updates include revisions in quality of service indicators and slight modifications in allowed revenue parameters.	No planned activities reported
Bosnia and Herzegovina	No changes reported	No planned activities reported
Georgia	There have not been any significant changes in the T-tariff and D-tariff methodologies since 2022. At the moment for both TSO and DSO, GNERC is using a tariff setting methodology that sets 5-year cost-reflective tariffs that are fully volumetric (entirely energy-based). Transmission tariff is uniform for all customers, while each DSO has different tariffs set on three different voltage levels. The Tariff methodology represents a hybrid model of Cost-Plus and Revenue Cap - utilising a "building-blocks" approach, it deploys different incentive schemes for different cost-components: Capital Expenditures are mostly cost-based using historic value of RAB, but allows inclusion of the investment plans for the regulatory period, Controllable OPEX, that includes most of operational expenditures except various taxes, is treated with RPI-X model, while Uncontrollable OPEX is treated with ordinary cost-plus, and Goal-Setting principles are used towards Electricity Losses, using Normative Loss approach. In 2023, the GNERC introduced distribution connection charges for small-capacity power plants.	GNERC intends to introduce fixed and/or power-based charge to the transmission tariff. The corresponding EU Twinning project has been undertaken to discuss the EU experience on this matter in detail. The official process on methodology has not started yet. G-charges are also under consideration. Under the transposition of the Clean Energy Package, GNERC (together with TSO) is working on the mechanisms provided in the package, particularly regarding the regulatory framework for storages. GNERC also takes part in the working group that is developing a methodology that considers the PECI/PMI projects. Regarding the distribution tariff methodology, GNERC intends to introduce Fixed Charges from regulatory period of 2031-2035 to make tariffs more cost-reflective in terms of type of the costs and to stabilise DSO revenues to make them less dependent on consumption fluctuations.

Kosovo*	Since 2022, there have been no significant amendments to the T-tariff regulatory framework in Kosovo. The **transmission tariff methodology** continues to be based on the "allowed revenues" approach, regulated ex-ante by the Energy Regulatory Office (ERO). Tariffs are reviewed and approved annually, reflecting actual costs, projected demand, and system needs. The methodology includes cost-reflectivity principles and ensures non-discriminatory access to the transmission network. No new components or tariff structures have been introduced during the reporting period. The **TSO methodology** will be developed after the approval of the new laws, that is expected in 2026. Since 2022, a **new Methodology for calculating distribution connection charges** has been established. This methodology is more detailed and has defined the cost of services for each type of connection. ERO approved the **Rule on Principles for Determining Distribution Use of System Charges and Connection Charges** in November 2024. This Rule establishes the new principles for the preparation of the Methodology by the Distribution System Operator (DSO) for determining tariffs for the use of the distribution system and connection charges to the distribution network. The new D—tariff methodology is expected to be prepared by DSO in 2026.	Key new concepts to be introduced to the methodology for determining tariffs for the use of the **distribution system** and **connection charges to the distribution network** according to the approved Rule on Principles: 1) Inclusion of new network users – prosumers, generators, and storage facilities now may be subject to tariffs. 2) Injection tariffs – charging for energy injected into the grid, not only for consumption. 3) Capacity-Based Tariffs – introducing power (kW) tariffs alongside energy (kWh) tariffs. 4) Alignment with the Energy Community – updating principles to match EU and regional energy frameworks. 5) Expanded Tariff Principles – a stronger focus on equity, transparency, incentives, and market integration.
Moldova	ANRE approved the new **transmission tariff methodology** in October 2023 (Decision of NRA nr. 626 from 27.10.2023), which has been applied since 2024. Basically, the new methodology reflects the general principles of the previous one; however, all the regulated revenue components were revised by including the new ones related to TSO obligations under the EIP (including those from the electricity network codes). Also, the new methodology provides an incentive mechanism for efficient usage of allocated financial resources. The incentive mechanism provides an economy sharing mechanism, considering the difference between the actual OPEX costs and those approved in the T-tariff. If the difference is less than 10%, TSO keeps it; if it is more, it is shared with the customers, considering the value of difference. The new T-tariff methodology has no time limit for its application compared with the previous one (which was for five years).	The recent amendment to the Law on Electricity no. 107/2016, transposing the EIP, created the legal background for NRA to consider the **anticipatory investments** into transmission infrastructure when determining and approving the regulated **T-tariffs**. The new principles for cross-border capacity investments are also introduced by the same law. Considering the implementation of the EIP and the new Law on Electricity, most probably some changes in the regulation, including new types of activities like electricity storage and trading, will be introduced in the secondary legislation. Following the adoption of the new Law on Electricity that transposes Electricity Regulation, ANRE is

	ANRE approved a **new D-tariff methodology** in May 2025 (ANRE Decision nr. 247 from 16.05.2025). The new methodology introduced some significant changes: (1) introduced a decreasing rate of technical losses approved in the D-tariff, based on real figures from 2018-2024; (2) For investments above 140% of the annual depreciation, DSO will receive additional two percentage points above the normally applied WACC, the requirement of 140%+ should be met during the whole regulated period (5 years). (3) WACC is constant for the regulated period (previously it was calculated annually).	planning to issue a new connection regulation that will provide specification for battery storage.
Montenegro	Compared to the regulatory framework set in 2022, which was further described in the Transmission and Distribution tariff report prepared in 2023, there were no changes in transmission and distribution tariff methodologies. Regarding the **distribution charge**, from 2022 it is also now applied per capacity as well (unlike the previous practice, when injection charge was applied only per energy).	The draft **T-tariff methodology** is going to be prepared by the end of 2025. The new methodology has to be adopted in order to align this methodology with the new Energy Law. Starting from 2027, the target values for AIT (Average Interruption Time) will be determined for each year of the regulatory period and reward, penalty, or no reward/penalty will apply in accordance with the tariff methodology. Both the **T-tariff and the D-tariff methodologies** are going to be revised in order to consider the energy storages (e.g. battery storages) introduced by the Energy Law.
North Macedonia	The latest **amendments to the T-tariff regulatory framework** were in 2023. Thus, the base year for the calculation of the tariff was set to be t-2 (instead of t-1). The latest **amendments to the D-tariff regulatory** framework were in 2023. With these changes, the base year for calculation was set to be t-2, and the new distribution fee was introduced as a lump sum for access to the grid. Also, ERC changed the approach for the **recognition of distribution losses**, which are now considered in terms of the volume of electricity (kWh). The level is set after previous analyses and results of the measures that were undertaken by DSO.	With the adoption of the new Energy Law, transposing EIP, the ERC is empowered to decide on the **transmission and distribution tariffs** that are time-of-use, considering the locational signals, time and seasonality impact. Also, when designing the new transmission and distribution tariff methodologies, ERC should take into account the impact of all new market entrants, e.g. distributed generation, storage, aggregators, demand response, energy efficiency, and self-consumption, etc. The **new D-tariff methodology** should be adopted by the end of February 2026 and shall recognise the implementation of flexibility as defined by the new Energy Law. Currently, it is

		difficult to say what solutions will be applied.
Serbia	No major amendments in the T-tariff and D-tariff regulatory framework have been introduced since 2022.	AERS plans for adoption by-laws to introduce the flexibility services, which are envisaged by amendments to the Energy Law adopted in 2024.
Ukraine	No significant amendments in the **T-tariff methodology** have been introduced since 2022. During 2022–2023, to implement Regulation (EU) No 838/2010, NEURC amended its regulatory framework to enable the participation of TSO in the ITC mechanism. Particularly relevant lines in the allowed revenue (and costs) were included in the T-tariff methodology. Starting from January 1, 2024, the TSO does not charge additional payments from electricity market participants for import or export operations (except perimeter fee with the perimeter counties). NEURC **amended D-tariff regulatory framework** to reflect the challenges of the special operational period of DSOs associated with martial law in Ukraine. Particularly, starting from 2025: (1) Updated and complemented the provisions regarding regulatory accounting of assets that have been decommissioned/commissioned and are located in temporarily occupied territories of the country and/or over which control has been lost due to the Russian military aggression against Ukraine. (2) Introduced the application of a corrective coefficient of change in actual conditional units of the DSO's energy equipment located in government-controlled territory, to optimise operating controllable and certain items of operating uncontrollable costs of DSOs operating under the incentive-based tariff regulation methodology. (3) the regulatory rate of return on the "old" and "new" RAB for frontline DSOs is set at 3%. (4) The first regulatory period has been extended for one year more for DSOs operating under incentive-based regulation. (5) The timeframe for achieving the target quality indicator of services for DSOs has been prolonged. The regulatory rate of return on the "old" RAB base for frontline DSOs (for 2023–2024), as well as for DSOs whose owners are subject to sanctions, is set at 0.	Funds for the RES support scheme are planned to be gradually separated from the **transmission tariff**. The reform is foreseen to be completed by 2030 in line with the recently adopted governmental Roadmap for 2025-2026[9]. The RES support scheme will be funded through a separate surcharge for renewable energy sources, collected by the TSO independently from the electricity transmission tariff.

9 Order of the Cabinet of Ministers of Ukraine of 25 June 2025 No. 612-r "On Approval of the Roadmap for Unbundling the Renewable Energy Surcharge from the Tariff for Electricity Transmission Services and the Action Plan for Implementing the Roadmap for 2025–2026."

	A new approach to calculating the standard connection fee rates was introduced. Instead of basing the calculation on the actual capital expenditures of DSOs during the base period, the new approach relies on average construction cost indicators in accordance with regulatory and technical documentation.

Country case: Separation of renewable costs from the transmission system tariff in Ukraine

Following the Ukraine's commitments on European integration and harmonisation of national legislation with European standards, and within the framework of the Ukraine Support Plan, the Cabinet of Ministers of Ukraine adopted Resolution No. 612-r of 25 June 2025 "On the Approval of the Roadmap for Unbundling the Renewable Energy Surcharge from the Electricity Transmission Tariff and the Action Plan for Implementation of the Roadmap for Unbundling the Renewable Energy Surcharge from the Transmission Tariff for 2025–2026"[10] (hereinafter – the Roadmap).
To implement the first stage of the Roadmap's action plan, NEURC introduced amendments to the Procedure for Establishing (Forming) the Electricity Transmission Tariff[11].These amendments set out the approaches for forming and calculating the RES PSO costs included in the transmission tariff and introduced requirements for maintaining separate accounting of costs and revenues associated with these expenditures. This mechanism will be in force until 31 December 2029 for existing RES producers, which were granted support until 1 July 2026.

Furthermore, amendments were made to the Transmission System Code[12], which provides for issuing, as of 1 January 2026, transmission service invoices that include the TSO's costs of performing special obligations as a component of the transmission tariff.
The second stage of the Roadmap action plan provides for the introduction of a new financing mechanism through a separate renewable energy surcharge (introducing the new term "RES surcharge"), payable by transmission system users to the TSO to ensure the fulfilment of special obligations aimed at increasing the share of electricity produced from renewable energy sources, specifically to support producers of electricity from renewable sources who, starting from 1 July 2026, obtain the right to support as a result of RES auctions (hereinafter – Auction Winners). Finally, as of 1 January 2030 it is expected that funds for the entire RES support scheme will be collected through the separate RES surcharge.
In this regard, the Regulator developed the relevant draft Law which is undergoing the interagency (governmental) approval procedure.

2. National framework for network tariff setting in Contracting Parties

2.1. Legal and regulatory framework

Since the previous report, the main developments in the legal and regulatory framework regarding the network tariffs have been driven by the ongoing transposition of the Electricity Integration Package into the national laws of Energy Community Contracting Parties. As of the date of this report, four Contracting Parties (Moldova, Montenegro, North Macedonia and Serbia) have

10 https://zakon.rada.gov.ua/laws/show/612-2025-%D1%80#Text

11 NEURC Resolution No. 1461 of 16 September 2025

12 NEURC Resolution No. 1462 of 16 September 2025

progressed with the transposition of EIP, aligning their legal frameworks, particularly, with the provisions of the Electricity Directive and the Electricity Regulation related to the network tariffs. With this, NRAs are tasked to consider the new network users in network tariff calculation, to decide on the introduction of time-of-use tariffs (e.g., North Macedonia), to create a regulatory framework for flexibility services (North Macedonia and Serbia).

The national energy laws in Contracting Parties set out the general requirements for network tariffs regulation as well as the scope of tariff methodologies. Since the last report, the institutional framework for network tariffs regulation has not changed, and NRAs in Contracting Parties (with some exceptions) are responsible for development and/or approval of the network tariff methodologies (covering, e.g. transmission tariff, distribution tariff, connection charges, and reactive power charges) and setting the relevant tariffs/charges. In Kosovo* and Ukraine, there are two types of tariffs (and relevant methodologies) for services, provided by the relevant TSOs, one for the use of system/transmission services and the second for system operator/dispatch services.

When developing the network tariff methodologies, NRAs cooperate with the relevant stakeholders (TSOs, DSOs) and conduct public consultations on the draft act prior to its approval. Specifically, in Kosovo*, the relevant operators (TSO, DSO) develop the draft methodologies based on principles approved by the NRA, which are further subject to approval by the NRA after public consultations. In Albania, the TSO proposes the methodology for the connection charge, which is approved by the NRA.

Two Contracting Parties (Moldova and Ukraine) reported the role of other authorities in the process of T-tariff and D-tariff methodologies approval. In Moldova, the T-tariff methodology is developed by the NRA and is subject of the approval by the Ministry of Justice, the National Anticorruption Center under the provisions of the Law nr. 100/2017 on normative acts. The Ministry of Energy, as well as other involved stakeholders, are being consulted during the public consultations of the draft methodologies. Both the T-tariff and D-tariff methodologies should receive approvals from the Commission on Regulation of Entrepreneur Activity and from the Ministry of Justice. However, the final approval is the NRA's prerogative. Overall, NRA has the discretion to consider or not the proposals from these authorities.

In Ukraine, tariff methodologies are approved by NEURC following the principles of regulation of natural monopolies (e.g. transmission and distribution), which are defined by the Law on Natural Monopolies. This law also provides that to introduce the incentive-based regulation, e.g. for network activity, NEURC needs to agree on this decision with the Ministry of Economy and the Ministry of Energy. In Ukraine, NEURC has no powers regarding the methodology defining the reactive charges, and they are calculated and applied by the network operators according to the methodology approved by the Ministry of Energy.

In majority of Contracting Parties, NRAs are also empowered to independently establish the regulatory parameters for the relevant tariff methodologies, e.g. WACC, Rate of Return (RoR), Regulatory Asset Base (RAB), where applicable. NEURC is empowered to define the RoR per type of activity, but it may not exceed the maximum value defined by the Ministry of Economy. The methodology for RAB evaluation is approved by the State Property Fund.

Table 2.1 - Legal and regulatory framework

Contracting Party	Transmission	Distribution
Albania	**Number of TSOs**: 1 **Methodology**: NRA (ERE) **Type of regulation**: Energy Law, Methodology **Regulatory parameters:** NRA **Consultations**: Public consultations **Tariff-related information:** publicly available	**Number of DSOs**: 1 **Methodology**: NRA (ERE) **Type of regulation:** Energy Law, Methodology **Regulatory parameters:** NRA **Consultations**: Public consultations **Tariff-related information:** publicly available
Bosnia and Herzegovina	**Number of TSOs**: 2[13] **Methodology**: NRA (SERC) **Type of Regulation**: Methodology **Regulatory parameters:** NRA **Consultations**: Public and specific consultations **Tariff-related information:** publicly available (including in English)	**Number of DSOs**: 8[14] **Methodology**: NRAs - FERK (Federation of Bosnia and Herzegovina), RERS (Republika Srpska) and SERC (Brcko District). **Type of Regulation**: Regulatory Methodologies **Regulatory parameters:** NRAs **Consultations**: Public consultations **Tariff-related information:** publicly available
Georgia	**Number of TSOs**: 1 **Methodology**: NRA (GNERC) **Type of Regulation**: Methodology **Regulatory parameters:** NRA **Consultations**: Specific consultations **Tariff-related information:** publicly available (including in English)	**Number of DSOs**: 2 **Methodology**: NRA (GNERC) **Type of Regulation**: Methodology **Regulatory parameters:** NRA **Consultations**: Public and specific consultations **Tariff-related information:** publicly available (including in English)
Kosovo*	**Number of TSOs**: 1 **Methodology**: TSO subject to NRA (ERO) approval **Type of Regulation**: Primary Law, Methodology **Regulatory parameters:** NRA **Consultations**: Public consultations **Tariff-related information:** publicly available	**Number of DSOs**: 1 **Methodology**: DSO subject to NRA (ERO) approval **Type of Regulation**: Primary Law, Methodology **Regulatory parameters:** NRA **Consultations**: public consultations **Tariff-related information:** publicly available
Moldova	**Number of TSOs**: 1 **Methodology**: NRA (ANRE) **Type of Regulation**: Methodology **Regulatory parameters:** NRA **Consultations**: Public consultations, specific consultations on sub-elements	**Number of DSOs**: 2 **Methodology**: NRA (ANRE) **Type of Regulation**: Methodology **Regulatory parameters:** NRA **Consultations**: Public and specific consultations

13 transmission operator's activities are performed by two entities, Independent System Operator (ISO) BIH and TRANSCO. ISOBIH manages the transmission network, procures ancillary services and maintains the balance of the system, while TRANSCO owns all transmission assets and deals with the maintenance, development and construction of the network.

14 Out of eight DSOs in Bosnia and Herzegovina – one in the Brcko District, two in BA's entity Federation of Bosnia and Herzegovina and five in BA's entity Republika Srpska.

	Tariff-related information: publicly available	**Tariff-related information:** publicly available
Montenegro	**Number of TSOs**: 1 **Methodology**: NRA (REGAGEN) **Type of Regulation**: Primary Law, Methodology **Regulatory parameters:** NRA **Consultations**: Public consultations **Tariff-related information:** publicly available	**Number of DSOs**: 1 **Methodology**: NRA (REGAGEN) **Type of Regulation**: Primary Law, Methodology **Regulatory parameters:** NRA **Consultations**: Public consultations, specific consultations on sub-elements **Tariff-related information:** publicly available
North Macedonia	**Number of TSOs**: 1 **Methodology**: NRA (ERC) **Type of Regulation**: Methodology **Regulatory parameters:** NRA **Consultations**: Public and specific consultations **Tariff-related information:** publicly available	**Number of DSOs**: 2 **Methodology**: NRA (ERC) **Type of Regulation**: Methodology **Regulatory parameters:** NRA **Consultations**: Public and specific consultations **Tariff-related information:** publicly available
Serbia	**Number of TSOs**: 1 **Methodology**: NRA (AERS) **Type of Regulation**: Methodology **Regulatory parameters:** NRA **Consultations**: Public consultations **Tariff-related information:** publicly available	**Number of DSOs**: 1 **Methodology**: NRA (AERS) **Type of Regulation**: Methodology **Regulatory parameters:** NRA **Consultations**: Public consultations **Tariff-related information:** publicly available
Ukraine	**Number of TSOs**: 1 **Methodology**: NRA (NEURC) **Type of Regulation**: Primary Law, Methodology **Regulatory parameters:** NRA (for cost+), NRA and other authorities for incentive regulation. **Consultations**: Public and specific consultations **Tariff-related information:** publicly available	**Number of DSOs**: 32 **Methodology**: NRA (NEURC) **Type of Regulation**: Primary Law, Methodology **Regulatory parameters:** NRA (for cost+), NRA and other authorities for incentive regulation. **Consultations**: Public and specific consultations **Tariff-related information:** publicly available

In all Contracting Parties, network tariff methodologies are approved for an indefinite time and are subject to amendments (if necessary). In most cases, the T-tariff and D-tariff methodologies are applied to define tariffs for all relevant operators (TSOs and DSOs) in the country/jurisdiction. However, in North Macedonia, although NRA uses the same methodology for setting the maximum allowed revenue for both DSOs, the tariff systems are differentdue to the different structures of the distribution systems. For example, one DSO manages the system in the whole territory of the country, while the second manages only the system in the specific territory for industrial customers in the capital of Skopje. As networks and types of users are different, the same tariffs cannot apply.

Three Contracting Parties reported the existence of close distribution system operators (CDSO), which are licensed/authorised by relevant NRAs: sixteen (16) CDSO in Moldova, four (4) CDSO in Montenegro and five (5) in Serbia[15]. ANRE (Moldova) approved the one tariff methodology that is

15 https://aers.rs/electricity-distribution-and-closed-distribution-system-operation-0)

applied by all CDSO when determining the relevant tariffs. Other NRAs do not set the tariff methodologies for CDSOs.

2.2. Tariff setting principles and type of regulation

NRAs of Contracting Parties reported no substantial changes in the regulatory methods for the calculation of transmission and distribution tariffs. One of the reasons for this may be that in some CPs (Georgia, Kosovo*, Montenegro, North Macedonia) the introduced regulatory periods are still in force; therefore, the methodologies are not subject to modifications. NRAs also have been expecting EIP transposition to see what the primary legislation would prescribe and what will be new costs and revenues for TSO and DSO that should be further elaborate in the methodology.

Additionally, NRA of Georgia informed that the new regulatory period is 2026-2030, and there have not been any substantial amendments introduced in the methodology.

2.2.1. Transmission

In six (6) Contracting Parties (Albania, Georgia, Kosovo*, Moldova, Montenegro and North Macedonia), NRAs continued to apply incentive-based T-tariff regulation, mostly presented by a revenue cap approach.

Only in Albania, the price cap approach is used from the beginning of tariff regulation. This method proposed by the consultant that assisted ERE as more adequate for the Albanian energy sector and was applicable to other countries with the similar background. It has been applied to all the companies that were created after the unbundling process and it still is considered suitable for tariff calculation.

NRA of Moldova noted that the revenue cap approach showed good results over the past years and is still considered appropriate.

In North Macedonia, performance-based indicators could be introduced with the new methodology if supported by the quality of data and analysis performed by TSO and ERC.

Two Contracting Parties use hybrid models of regulation. In Georgia, the T-tariff methodology represents a mix of cost-plus and revenue cap regulation – a hybrid model. A "building-blocks" approach is applied, i.e., different incentive schemes apply to different cost components. In Montenegro, another hybrid regulatory model is implemented, which includes incentive-based and performance-based regulatory methods. This regulatory model aims to incentivise TSO to reduce its operational costs (revenue cap), increase its efficiency and improve the quality of service provided by the TSO.

The cost-plus regulation of T-tariff is still applied in Bosnia and Herzegovina, Serbia and Ukraine. In case of Bosnia and Herzegovina, when considering the methodology and tariffs for electricity transmission services, it is borne in mind that the transmission network is well developed, operates at a high level of reliability and with very low losses. Therefore, the introduction of an incentive tariff would not give significant results in terms of improving work and increasing efficiency, so the cost-plus based method is retained for a detailed review of all costs and control of the tariff level.

In Ukraine, the T-tariff methodology provides for the possibility of determining the transmission service revenue and calculating the electricity transmission service tariff under incentive-based regulation, but it is not applicable at the moment. Thus, the cost-plus approach is applied as a transitional step. Due to the consequences of the ongoing aggression of the Russian Federation and in order to prevent a critical situation in the electricity market and to ensure security of electricity supply in the power system of Ukraine as a whole, the update of the regulatory framework, including the definition of key parameters for the potential application of incentive-based tariff regulation for the TSO, should be considered after the end of martial law period.

Quality of service regulation in transmission

Since the previous report, Contracting Parties have not progressed with the introduction of quality regulation into the T-tariff methodologies. Thus, currently, the quality factor is practically applied only in Bosnia and Herzegovina and Kosovo*. In Bosnia and Herzegovina, NRA shall examine the justification of an investment from the aspect of improvement of the quality and security of supply, in accordance with the projected increase of demand. In Kosovo* premium (reward)/penalty for better performance/not compliance with the standards is applied according to the methodology. In Montenegro starting from 2027, the target values for AIT (Average Interruption Time) will be determined for each year of the regulatory period. When determining the regulatory allowed revenue for the next period, the realised value of AIT will be compared with the target value. Depending on the distance of realised value to the target one, reward, penalty, or no reward/penalty will apply, in accordance with the tariff methodology. The value of the reward/penalty is capped. In Ukraine, under the incentive-based T-tariff methodology[16], the allowed revenue is subject to adjustment (decrease) for exceeding the target index of the average duration of outages in the system and/or target values of electricity quality indicators in electrical networks. Summary of status with the quality-of-service regulation in Contracting Parties presented in Figure 2.1.

[16] not in use

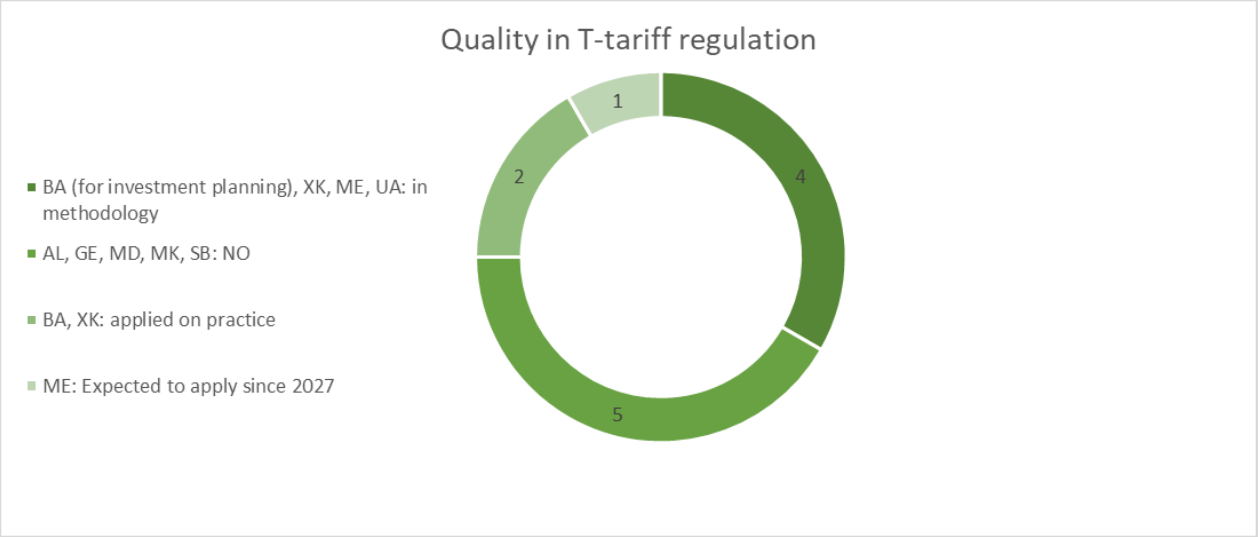


Figure 2.1 – Quality in T-tariff regulation

2.2.2. Distribution

NRAs have not changed the approach to D-tariff regulation since the previous report. In majority of Contracting Parties the incentive-based regulation is applied for D-tariff calculation in the Energy Community [17]. In most cases, NRAs apply a revenue cap approach, while Albania opted for the price cap model. D-tariff methodologies also include performance-based indicators (e.g. performance indicators such as efficiency factor, loss reduction target, quality factor[18] etc.). In Ukraine, for most of the DSOs (26), the incentive-based regulation applies, however, tariffs of six (6) DSOs are regulated on the cost-plus methodology. To switch to incentive-based regulation, DSO shall apply to the NEURC and comply with a number of conditions set by the regulatory framework[19].

Georgia and Montenegro reported the hybrid approach (with elements of revenue cap) similar to T-tariff regulation.

Quality of service regulation in distribution

Following the ECRB recommednations, the status of quality regulation through the D-tariff methodology has progressed since 2022 and is now present in five (5) Contracting Parties (Albania, Georgia, Kosovo*, Montenegro and Ukraine).

17 Georgia reported a hybrid type of regulation (Cost-plus and Revenue-cap methods applying to different cost components)

18 Except in Albania.

19 NEURC Resolution "On the application of incentive regulation in the conduct of economic activity on the electricity distribution".

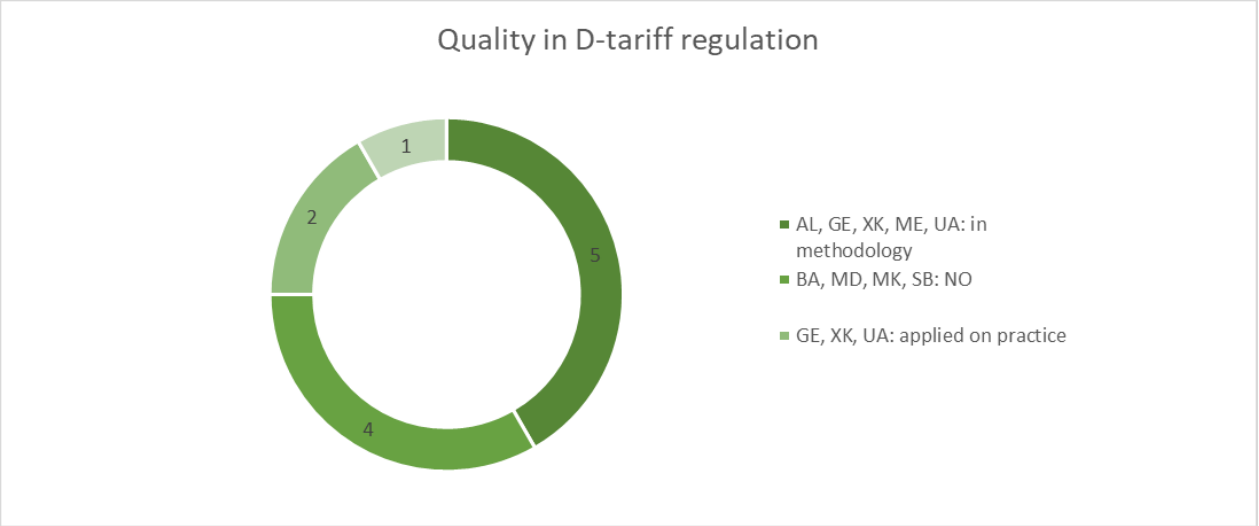


Figure 2.2 – Quality in D-tariff regulation

Thus, in Albania, the NRA modified the D-tariff methodology for calculating the tariffs of the electricity DSO with the provisions related to quality of service indicators. According to the methodology ERE shall add to the formula of D-tariff a performance improvement factor (Q) based on the quality of supply to final customers. These performance improvement factors must be defined very clearly and simply, and the DSO must assure ERE that it is able to provide the necessary quality-of-supply data required to accurately measure performance improvement.

In Georgia, based on the "*Quality of Service Rules*" approved in 2021, the GNERC applies the reward/penalty principle depending on the standard that the specific DSO improved/violated compared to the previous year. *Quality of Service Rules* set the overall and guaranteed standards. Guaranteed standards consider compensation of a particular customer (e.g., if the DSO delays the network connection time, the customer pays 50% of the connection fee set by the GNERC), while the overall standard may increase or decrease the DSO tariff.

In Kosovo*, the quality factor is part of the distribution tariff methodology and links the DSO's allowed revenues with the quality of service provided. It includes indicators such as continuity of supply and voltage quality, which can lead to financial incentives or penalties. The Rule on Quality Standards of Electricity Supply Service is approved in 2019, defines several indicators that are not yet fully applicable in the financial aspect but are expected to be reviewed in the future.

In Montenegro, since 2022 the D-tariff methodology includes an incentive for the DSO to increase the quality of the service, by introducing the reward/penalty principle, but it has not been applied so far. The approach is similar to T-tariff methodology and provides that, from 2027, the target values for SAIDI (System Average Interruption Duration Index) will be determined for each year of the regulatory period. When determining the regulatory allowed revenue for the next period, the realised value of SAIDI will be compared with the target value. Depending on the distance of realised value to the target one, reward, penalty or no reward/penalty will apply, in accordance with the tariff

methodology. The value of the reward/penalty is capped by REGAGEN according to the methodology and can be a maximum of 2% of the regulatory allowed revenue that is transposed into prices. No special formulas are applied.

In Ukraine, target values of SAIDI for DSOs are established by NEURC under the incentive-based regulation, with the final target to be achieved in the 16th year from the year of application of the incentive-based regulation. For each regulatory period, the interim target is also introduced[20].

Additionally, for North Macedonia, ERC reported that the new Energy Law prescribes obligation for ERC to adopt Rulebook on monitoring technical and performance (business) indicators and regulating the quality of electricity delivery and supply in the course of 2026.

2.3. Frequency of tariff methodologies revision and tariff value updates

Since last reporting regarding the validity of network tariff methodology, NRA of Moldova (ANRE) changed approach to the approval of T-tariff and D-tariff methodologies, switching from a 5-year cycle to no expiry date.

The regulatory periods vary among the Contracting Parties from 1 to 5 years, as indicated in the following sections. Although set for the regulatory period, the T-tariff and D-tariff values are subject to revision under predefined conditions in all Contracting Parties.

2.3.1. Transmission

In most of the Contracting Parties, the T-tariff methodologies are approved by NRAs with no expiry date, i.e., until changed by the relevant NRAs. Only in Kosovo*, the new methodology for each new regulatory period is developed and approved, defining the regulatory parameters for this period[21].

The regulatory period in most of the Contracting Parties is fixed by the methodology and varies from one year in Serbia and Ukraine (cost-plus model) to three years in Albania and North Macedonia, and five years in Georgia, Kosovo* and Moldova where incentive-based models are applied. In Bosnia and Herzegovina, according to the Tariff Pricing Methodology for Services of Electricity Transmission, the "*Tariff period*" means the period in which the tariff approved by NRA remains unchanged and which usually lasts one calendar year but may be longer or shorter. The latest tariff decision was in 2019. In Montenegro, the NRA is flexible and defines the length of the next regulatory period prior to the end of the ongoing one (therefore, it may differ). The latest practice with the few previous regulatory periods was three years, including the ongoing regulatory period (January 2023 - December 2025).

20 Due to the martial law NEURC does not adjust allowed revenue for incompliance with the quality targets.

21 The latest regulatory period for network operators is a five-year period, lasting from 1 April 2023 to 31 March 2027.

In all Contracting Parties during the tariff regulation period, T-tariffs are subject to adjustment; however, the T-tariff methodologies does not always define clear conditions for tariff review. In most cases, the factors for tariff review include those that are out of TSO control (e.g. change of forecasted parameters) and may not require a regulatory audit of costs. Some NRAs (SERC, NEURC) may also initiate tariff review after the regulatory audit. The values of the deviation factor are set in the T-tariff methodologies in Georgia, Moldova, Montenegro and Ukraine (as presented in Table 2.2).

Table 2.2 - Rules for T-tariff revision

Contracting Party	Rules for T-tariff revision
Albania	The T-tariff methodology does not specify in what cases the tariff is updated within the regulatory period. However, if there are circumstances under which the TSO is affected with extraordinary costs (for example, the energy crisis that happened in 2021-2022), the operator can apply for re-evaluation of the allowed revenues and the tariff revision. If there are no extraordinary circumstances, the methodology foresees the adjustments at the end of the regulatory period for all the costs of the transmission operator activity.
Bosnia and Herzegovina	Regulator may decide to perform an audit of the RAB. For the purpose of establishing a cost-reflective transmission tariff to the extent possible, the audit of the RAB may be initiated in any tariff period.
Georgia	During the tariff regulation period, tariffs are subject to adjustment based on factors that do not require a regulatory audit of costs: a) The amount of transmitted and distributed electricity; b) The cost of purchasing normative electricity losses; c) Imbalance costs; d) Actual inflation rates; e) Changes in the forecasted values of the factors listed in subparagraphs 'b', 'c', and 'd' of this paragraph; f) Forecasted changes in special operational expenditures (spOPEX); g) Changes made to the investment plan agreed with the Commission. In the event that, during the tariff regulation period, the absolute value of the total adjustment components caused by the factors listed in subparagraphs (a), (b), (c), and (d) exceeds 7% of the average annual amount of the base of regulated costs defined for the same tariff regulation period, and if the TSO submits a tariff application, the Commission shall adjust the tariffs set for the tariff regulation period based on the above-mentioned adjustment components, starting from the beginning of the next tariff year following the occurrence of this circumstance. If, during the tariff regulation period, the absolute value of the total adjustment components caused by the factors listed in subparagraphs (e), (f), and (g) exceeds 10% of the average annual amount of the base of regulated costs defined for the same tariff regulation period, and if the TSO submits a tariff application, the Commission is authorized to adjust the tariffs set for the tariff regulation period based on the above-mentioned adjustment components, starting from the beginning of the next tariff year following the occurrence of this circumstance.

Kosovo*	T-tariff revision is allowed during the regulatory period. It can be triggered by significant deviations in costs or revenues, changes in legal/regulatory framework, or force majeure events. TSO may also request a revision based on justified needs. However, reviews do not include the input values (regulatory parameters) determined at the beginning of the five-year regulatory period, such as losses, WACC, efficiency factor, asset lifetime, asset categorisation, except CAPEX and operating and maintenance expenses (where these are beyond TSO control and there are legal or tax changes), etc. All revisions are subject to review and approval by ERO.
Moldova	Tariff values are updated annually on the basis of a methodology which remains the same throughout the regulatory period. The criteria for revision is a 5% deviation of the approved regulated revenue.
Montenegro	Tariffs are set at a different level for each year of the regulatory period (depending on the different forecasted costs and quantities) according to the methodology and there is a possibility to revise them during the regulatory period. If the annual deviation of operational costs that cannot be controlled, income from regulated activities, other revenues, depreciation and return on assets is cumulatively greater than 10% of the determined regulatory allowed revenue for the concerned year, the REGAGEN adjusts the regulatory allowed revenue and T-tariffs during the regulatory period.
North Macedonia	Every year, the TSO submits a request for tariff correction. The correction is based on revising the electricity costs to cover the losses, pass-through costs, and checking whether the MAR has been reached. Consequently, the correction factor is calculated and applied to the calculation of the MAR.
Serbia	T-tariff Methodology prescribes that TSO submits to NRA information according to Regulatory accounting guidelines and info code tables for regular annual reporting. TSO may request approval of a new T-tariff when submitting to NRA info code tables for tariff calculation and other data requested by NRA after each tariff period. Also, according to Energy Law and T- tariff Methodology, if NRA finds that the system operator generates revenues that are higher than the justified revenue obtained by applying this methodology, NRA may request TSO to revise tariffs within 30 days from the date of receipt of NRA request (in this case TSO is required to submit a new decision establishing revised tariff to NRA for approval).
Ukraine	In accordance with the current cost-plus methodology, the tariff is set for a transitional period with the possibility of reviewing its level during the year. NEURC may initiate, including based on annual reporting and/or upon the licensee's request, the establishment of a tariff as a means of state regulation in the energy sector: 1) in the event of failure to implement the investment program, provision of unreliable data by the licensee, errors in calculating the required income; 2) in the event of a change in the total volumes of electricity transmission relative to those taken into account when calculating the current tariff by more than 5%; 3) in the event of a deficit or surplus of funds from the provision of services for connecting customers' electrical installations to electrical networks in the year t-1, which is confirmed by the licensee's extended report and the results of monitoring compliance with the License Terms; 4) in the event of the licensee's failure to submit reports to the NEURC in the period established by the regulatory acts.

If the decision to set a tariff is based on reporting, the NEURC may adjust the tariff based on the results of the control of TSO compliance with the License Terms.

2.3.2. Distribution

In the vast majority of Contracting Parties, the D-tariff methodologies have no expiry date. In 2025, like in the case of T-tariff, the NRA of Moldova approved the new D-tariff methodology following this approach. In Kosovo*, there is no distinction between the methodology period and regulatory period: the regulatory period is 5 years, and it is set in the methodology; hence, all regulatory parameters are set for this period.

In other Contracting Parties, the approach to the regulatory period for D-tariffs is similar to the T-tariff practices and depends on the type of regulation that is applied: one-year regulatory period in Serbia and Ukraine (for DSO under the cost-plus methodology), three years in North Macedonia and Montenegro[22], and five years in Georgia, Moldova and Ukraine[23].

In Albania, according to the D-tariff methodology, the regulatory period (the duration of the cycle to review the distribution tariff) is three years. If the average distribution tariff ceiling according to the voltage levels for the following reviewed tariff cycle is not approved before the termination of the three-year period, the regulator may approve a decision to extend the cycle of reviewing the tariffs to four years. In April 2022[24], ERE set the regulatory period starting in May 2022, and it lasted until December 2022. This regulatory period has been extended several times. With its decision of December 2024, ERE further extended the regulatory period until the approval of a new decision based on the application submitted by DSO for the year 2025, in accordance with the applicable legal and sub-legal framework.

In Bosnia and Herzegovina, there is no predefined regulatory period; the same D-tariffs are set until revised in case of significant changes in DSOs costs out of their control (e.g., wholesale price, inflation, legal changes, etc.).

In all Contracting Parties, D-tariff values may be revised and in most cases the D-tariff methodologies provide the conditions for such revision. Generally, the primary purpose of revision of D-tariff values is to reflect the changes in DSO's costs or in allowed revenue during the regulatory period. The values of the deviation factor are set in the D-tariff methodologies in Georgia, Moldova, Montenegro and Ukraine, and the revision approach is similar to the one as for revision of T-tariffs. Serbia and Ukraine also reported that revision may result in a decrease of the D-tariff value. In Serbia, it may be the case if DSO' revenues are higher than the justified revenue according to the methodology. In Ukraine, the NRA may decrease (as an enforcement measure) the DSO tariff if the operator does not comply with the requirements regarding the submission and/or implementation

22 The length is not predefined by the legislation but it can be changed before the start of the next regulatory period as defined by the NRA. The length of the few previous regulatory periods was 3 years and this is the case for the on-going regulatory period (2023 - 2025).

23 In Ukraine, for DSOs that switched to incentive regulation in 2021, the first regulatory period is 3 (three) years. Due to martial law, the NRA decided to extend the first regulatory period by the end of 2025, so it will last for 6 years.

24 According to the ERE'S Board Decision No. 73, dated on April 13th 2022

of the investment program or violates license conditions. In total, NEURC may reduce the required income of the licensee by up to 10%.

Rules for D-tariff revision in Contracting Parties are presented in Table 2.3.

Table 2.3 - Rules for D-tariff revision

Contracting Party	Rules for D-tariff revision
Albania	Same tariffs for the whole regulatory period, with a possibility to revise. Even though in the methodology is not specified at what cases the tariff is updated within the regulatory period, if there are circumstances that the operator should be affected with extraordinary costs (for example the energy crisis that happened in 2021-2022), the operator can apply for re-evaluation of the allowed revenues and the tariff revision. If there are no extraordinary circumstances, the methodology, foresees the adjustments in the end of the regulatory period for all the costs of the distribution operator activity.
Bosnia and Herzegovina	Same tariffs for the whole regulatory period, with a possibility to revise. Regulator continuously monitors the effects of applying the determined tariffs, keeping the right to adjust them if deemed necessary. It is within the pure competence of the regulator to monitor, revise, and adjust the tariff, if it deems it necessary.
Georgia	Same tariffs for the whole regulatory period, with a possibility to revise. During the tariff regulation period, tariffs are subject to adjustment based on factors that do not require a regulatory audit of costs: a) The amount of transmitted and distributed electricity; b) The cost of purchasing normative electricity losses; c) Imbalance costs; d) Actual inflation rates; e) Changes in the forecasted values of the factors listed in subparagraphs 'b', 'c', and 'd' of this paragraph; f) Forecasted changes in special operational expenditures (spOPEX); g) Changes were made to the investment plan agreed upon with the Commission. If, during the tariff regulation period, the absolute value of the total adjustment components caused by the factors listed in subparagraphs (a), (b), (c), and (d) of exceeds 7% of the average annual amount of the base of regulated costs defined for the same tariff regulation period, and if the DSO submits a tariff application, the Commission shall adjust the tariffs set, starting from the beginning of the next tariff year. If, during the tariff regulation period, the absolute value of the total adjustment components caused by the factors listed in subparagraphs (e), (f), and (g) exceeds 10% of the average annual amount of the base of regulated costs defined for the same tariff regulation period, and if the DSO submits a tariff application, the Commission is authorized to adjust the tariffs set starting from the beginning of the next tariff year.
Kosovo*	Tariff values are updated annually on the basis of a methodology which remains the same throughout the regulatory period. The revision is allowed during the regulatory period. However, reviews do not include the input values (regulatory parameters) determined at the beginning of the five-year regulatory period, such as losses, WACC,

	efficiency factor, asset lifetime, asset categorisation, except CAPEX and operating and maintenance expenses (where these are beyond operator's control and there are legal or tax changes), etc. It can be triggered by significant deviations in costs or revenues, changes in legal/regulatory framework, or force majeure events.
Moldova	Tariff values are updated annually on the basis of a methodology which remains the same throughout the regulatory period. A 3% (and more) deviation from the calculated regulated annual revenue of the DSO is the trigger for DSO tariff adjustment. The request can be issued by the DSO or the NRA.
Montenegro	Tariffs are set at a different level for each year of the regulatory period (depending on the different forecasted costs and quantities) according to the methodology. There is a possibility to revise them during the regulatory period. The Agency determines revisions during the regulatory period if the deviation in the realisation of certain elements (costs that cannot be controlled, revenues from regulated activities, depreciation and return on assets based on the implementation of investment plans) in relation to the established regulatory allowed revenue that is transposed into prices or fees on an annual basis is cumulatively greater than 10%.
North Macedonia	Tariff values are updated annually on the basis of a methodology which remains the same throughout the regulatory period. Every year, DSO submits a request for the correction of the tariff. The correction is based on the revision of the costs for electricity to cover the losses, the revision of the costs pass-through and checking if the MAR has been reached or not. Consequently, the correction factor is calculated and applied to the calculation of the MAR.
Serbia	Same tariffs for the whole regulatory period, with a possibility to revise. Section XI.1. of D-tariff Methodology prescribes that DSO submits to NRA the information according to Regulatory accounting guidelines and info code tables for regular annual reporting. If DSO is requesting approval of new D-tariff at the end of the regulatory period, it needs to submit to NRA in addition info code tables for tariff calculation and other data on NRA request, accompanying DSO decision on the new tariff. Also, according to Energy Law and art. XI.3. of D- tariff Methodology, if based on the submitted regular reporting data, the NRA performing its duties within its competence determined by the Law, finds that the system operator generates revenues that are higher than the justified revenue obtained by applying this methodology, NRA may request D-system operator to revise tariff within 30 days from the date of receipt of NRA request, (DSO is required to submit a new decision establishing revised tariff to NRA for approval).
Ukraine	Tariff values are updated annually on the basis of a methodology which remains the same throughout the regulatory period. The NEURC has the right to set tariffs on its own initiative in the event of detection of the fact that the licensee provided the NEURC with inaccurate information regarding the performance of the licensed activity and, in accordance with the information available to the NEURC, to reduce the required income of the licensee by up to 10%. NEURC may also initiate, including on the basis of reporting and/or upon the licensee's request, the establishment of tariffs as a means of state regulation in the energy sector, in particular: 1) in the absence of an approved investment program for the forecast year, the costs of which are taken into account when calculating the current tariffs;

2) in case of failure to implement the investment program, provision of unreliable data by the licensee, errors in calculating the required income;
3) in case of change in the volumes of electricity distribution relative to those taken into account in calculating the current tariffs by more than 5%;
4) in case of a deficit or surplus of funds from the provision of services for connecting customers' electrical installations to electrical networks in year t-1, which is confirmed by the licensee's extended report and the results of monitoring compliance with the License Terms;
5) in case of failure of the licensee to submit reports to the NEURC;
6) based on the results of control activities on compliance with the License Terms;
7) in case of failure to submit to NEURC, duly executed and approved changes to the approved investment program for the relevant year by adjusting income (expenses);
8) in case of elimination of the grounds specified in subparagraph 7.
If the decision to establish tariffs based on subparagraphs 1 and 2, the NEURC may reduce/increase the relevant costs of the tariff structure in the amount of the sources of financing of the absent/existing approved investment program.

2.4. Stakeholder involvement and transparency in tariff setting

In all Contracting Parties, the draft T-tariff and D-tariff methodologies are subject to public consultations before approval by NRA. The period of public consultations varies in Moldova and Ukraine - at least 10 working days; in Montenegro - at least two weeks; in Serbia - up to 30 days. The overall procedure includes:

- the publication of the draft methodology by NRA:
- collection of the comments from interested parties,
- analysis of the provided comments by the NRAs,
- adjustment of the draft methodology (if considered relevant),
- adoption of the final act and its publication.

In Albania, after the decision of the Board of ERE to start the procedure of evaluation of tariff and prices application, ERE publishes, for two working days, a notification in two nationally circulated newspapers and on its official website, inviting interested parties or any other stakeholders to review the draft act and submit written comments. ERE also notifies the interested parties directly, providing them with a copy of the draft act for which the procedures have been initiated by a Board Decision. All interested parties may submit their written comments on the draft act within the deadlines specified by ERE in the notification addressed to the subject and in the public notice published in the newspapers. ERE may decide, on a case-by-case basis, to hold public hearings in order to obtain additional input from other stakeholders.

In Bosnia and Herzegovina, the Regulator uses formal hearings in the tariff proceeding[25]. A formal hearing shall include testimonial proceedings with all means necessary for establishing the facts, such as identification documents, testimony of participants in the proceeding, and statements of

25 Regulator set the Rules of Hearing Procedures (Rules) with the purpose to provide transparent, prompt, efficient and economically efficient procedure of public hearings. In accordance with the Rules, the Regulator may conduct several different types of public hearings in the course of the proceedings, including a general hearing, a technical hearing, and a formal hearing.

parties and witnesses, documents, investigations, findings and expert opinions, etc. related to a concrete case under the Regulator's jurisdiction. Also, a technical hearing may be held for the purpose of resolving technical issues in a tariff, licensing or other proceeding held before the Regulator and requires further consideration by discussion with specific experts, parties in the proceeding, interveners, interested persons and/or members of the public.

In the case of Georgia, before adopting any amendments, GNERC publishes the draft amendment on its official website. All interested parties are given a defined period during which they may submit comments or suggestions, or present and discuss their views directly with the Commission.

In Ukraine, NEURC analyses and processes received comments and proposals to the draft decision, and shall conduct open hearings on the received comments to the draft methodologies (Ukraine) with relevant stakeholders. Based on the results of public consultations, NEURC considers the acceptance or rejection of comments and proposals for the final draft. For the period of martial law public consultations on draft decisions concerning the establishment of prices/tariffs are not conducted.

The report on the public consultation process (with reasoning behind why comments sent by each public consultation participant were not accepted/or accepted by NRA) is published by NRAs in Moldova, Montenegro, Serbia and Ukraine.

The information related to the cost recognised for the purpose of calculating the allowed revenue and the tariff values is published in all Contracting Parties and is available in national languages. In Albania and in Bosnia and Herzegovina, tariff-related information is also published in English. The detailed picture with the publicly available information regarding the T-tariffs is presented in Table 2.4.

Table 2.4 - Transparency of T-tariff relevant information

Tariff-related information	Publicly available	Non publicly available[26]
General information (i.e. list) on the transmission cost categories recovered by tariffs	AL(ENG), BA(ENG), GE, XK, MD, ME, MK, RS, UA	
Information on the overall transmission cost (value) recovered by the tariffs	AL(ENG), BA(ENG), GE, XK, MD, ME, MK, RS, UA	
Detailed information on the transmission cost recovered by tariffs (i.e. provision of OPEX, depreciation, cost of capital, losses, other values)	AL(ENG), BA(ENG), GE, XK, MD, ME, MK, RS	UA
Information on fixed, energy-related and power-related components of the tariff	AL(ENG), BA(ENG), XK, MD, ME, MK, RS	
Information on the transmission costs (amount and/or share) covered by producers (or by injection) and by consumers (or by withdrawal)	BA(ENG), XK, MD, ME, RS, UA	

26 Indicates the reply of NRAs as "non publicly available". For other CPs non presented in "publicly available" column the answer is "non applicable".

Transmission charges (values) paid by different grid users	BA(ENG), XK, ME, MK, RS, UA	
Methodology for the calculation of the individual user tariff	BA(ENG), XK, ME, MK, RS	AL
Connection charges (values) paid by different grid users	BA(ENG), GE, XK, ME, MK, RS, UA	
Other charges (values) paid by different transmission grid users	BA(ENG), XK, ME, RS	
Information on the application of locational signals	n/a	n/a
Information on the application of time signals	ME, RS	

As regards D-tariffs, the practice of publication of tariff-related information in Contracting Parties is the same as for T-tariffs and relevant methodologies.

3. Cost model, cost determination and cost recovery

Network tariffs constitute an essential part of the end-user bill for household and non-household customers in Contracting Parties. As of 2024, in two (2) Contracting Parties (Albania and Ukraine), the total share of transmission and distribution tariffs in household bills exceeded 70%, with the largest in Ukraine[27] (76,2%). In Georgia, it accounted for around 63%, in four (4) Contracting Parties (Bosnia and Herzegovina, Kosovo*, North Macedonia and Serbia) it was around 50%; two (2) Contracting Parties (Moldova and Montenegro) reported the smallest share of up to 35%.

The T-tariff has less impact on the end-user bill than D-tariffs in all Contracting Parties. In Ukraine, the share of T-tariff in the household bill is almost 19%, the largest among Contracting Parties. The smallest T-tariff share in HH bill is in North Macedonia (5,2%).

Regarding the D-tariffs, they occupy share in the HH bill to a greater extent. In two (2) Contracting Parties (Albania and Ukraine), the D-tariff share is around 60%, and in five (5) Contracting Parties (Bosnia and Herzegovina, Kosovo*, Moldova, North Macedonia and Serbia), it is in the range from 28% to 43%. In Montenegro, the total share of T-tariff and D-tariff is around 34%.[28]

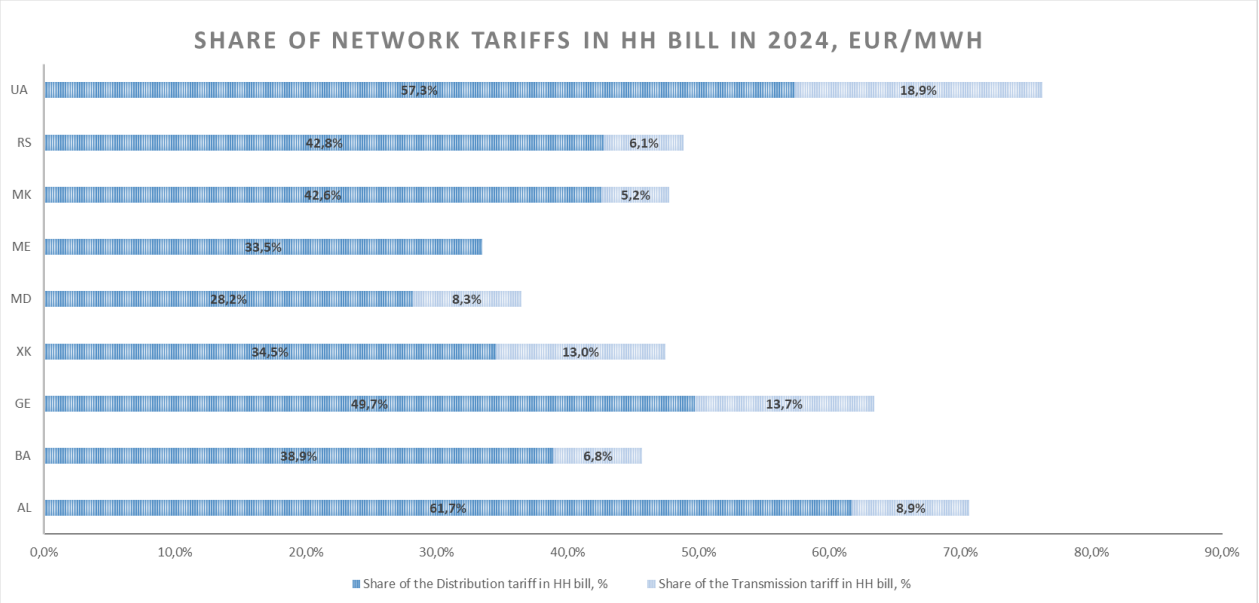
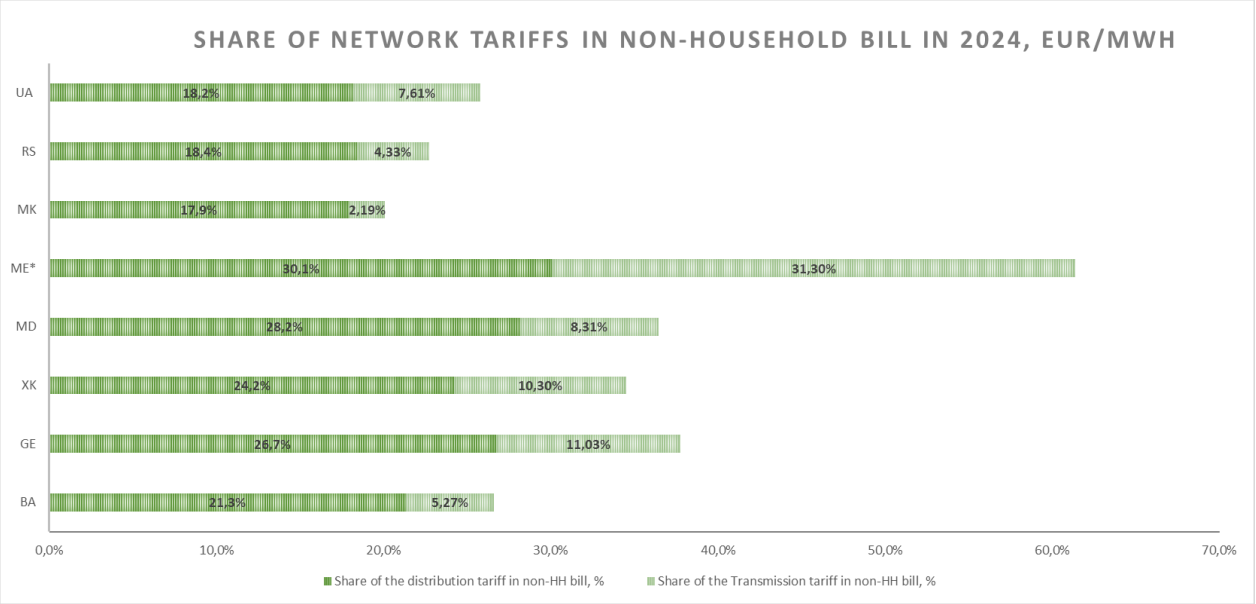


Figure 3.1 – Share of network tariffs in HH bill in Contracting Parties

27 HH end user prices in Ukraine are set via a public service obligation mechanism below total cost recovery level. Representation of a share of network tariffs is represented based on a HH end user price structure.
28 Electricity consumers in Montenegro, connected to the distribution system, are charged capacity fees, without breakdown of the transmission and distribution components. The data in the tables and in the figures represent the share of the capacity charge (including the transmission and the distribution component).



*Electricity consumers in Montenegro, connected to the distribution system, are charged capacity fees, without a breakdown of the transmission and distribution components. Data from the closed distribution system connected to the transmission system is not used for calculating the average share.

Figure 3.2 – Share of network tariffs in non-HH bill in Contracting Parties29

For non-households, the share of network tariffs in electricity bills is notably lower than for households in Bosnia and Herzegovina, North Macedonia, Serbia, and Ukraine, and constitutes between 20% and 26%. The lowest share is reported in North Macedonia at 20,1% total as well as by T and D-components; the largest is in Georgia (37,7%). In Moldova, the share of network tariffs in non-household bills is almost the same as for households (36,5%). For non-household users, the share of D-tariff is greater than that of T-tariff, similar to household users.

The values of the network tariff reflect the allowed revenue of the relevant network operator calculated to recover the efficient and reasonable costs and provide appropriate incentives. In absolute terms, most NRAs reported a moderate T-tariff increase during the last five years. In Kosovo* and Ukraine, T-tariffs have almost doubled since 2020. Only in Serbia, the T-tariff decreased slightly compared to the 2023 value. Montenegro reported a decrease in the capacity-related element of the network tariff compared to 2023. The values of T-tariff and D-tariffs in Contracting Parties as of 2024 are presented in the Figure 3.3 and Annex (Tables A1.2- A1.4)

29 Albania did not provide data

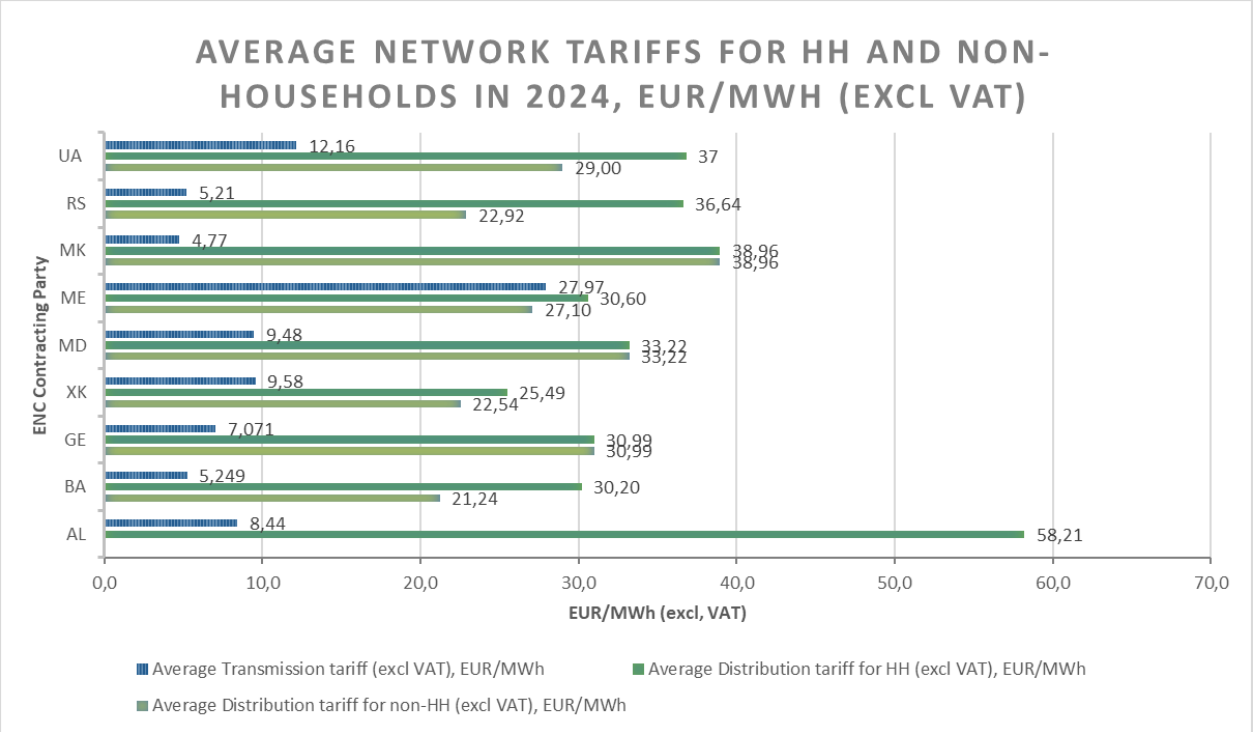


Figure 3.3 – Average network tariffs

The following sections provide an overview of network operators' costs recognised by the NRAs in Contracting Parties of the Energy Community and methods for their allocation for the calculation of the T-tariff and D-tariff.

3.1. Cost model and cost determination

Similar to the previous 2023 ECRB Tariff Report, all NRAs in Contracting Parties reported "an average cost model" for the calculation of unit prices for transmission and distribution services. The allowed revenue is allocated to the forecasted volumes of transmitted/distributed electricity (or capacity where the capacity payment is applied), namely, the average cost per unit. NRA of Ukraine reported the application of a forward-looking approach for some cost items, which are calculated based on the forecast balance data. No NRA reported any assessments or considerations regarding introducing incremental or forward-looking cost model. Table 1 in Annex presents more details on cost determination approaches and/or cost models applied in the Contracting Parties.

Similar to T-tariff cost allocation, in most of the Contracting Parties NRAs apply the average cost model for D-tariff calculation.

3.2. Costs to be recovered by tariffs

Tasks of network operators are defined by different acts of the Energy Community acquis. In particular, TSOs and DSOs are responsible for ensuring the long-term ability of the system to meet reasonable demands for the transmission and distribution of electricity, for operating, maintaining and developing under economic conditions a secure, reliable and efficient electricity transmission and distribution system in its area with due regard for the environment and energy efficiency. In performing their tasks, TSOs and DSOs (where applicable) shall procure the ancillary services needed for their systems and the energy they use to cover energy losses in their systems[30]. Where appropriate, the level of the tariffs applied to producers or final customers, or both shall […] take into account the amount of network losses and congestion caused, and investment costs for infrastructure[31]. The Clean Energy Package and Electricity Integration Package in the Energy Community put additional tasks on TSOs and DSOs. Particularly, stronger regional and pan-EU cooperation of TSOs is to be exercised through, e.g. participations in RCCs and CCRs, implementation of single Day-Ahead and Single Intraday Coupling, participation in European balancing platforms, etc. Reasonable, efficient and proportionate costs of such activities shall be recovered through ..., network tariffs or other appropriate mechanisms as determined by the NRAs[32]. Additionally, TSOs shall participate in the inter-transmission system operator compensation mechanism in accordance with Regulation (EU) 838/2010 and contribute to the ITC fund[33].

Increased role of DSOs under the CEP in integrating to their networks RES producers, distributed generation, active customers and citizens energy communities requires recognition of relevant costs, e.g. for flexibility services, to ensure system resilience and operational security.

At the same time, according to Article 18 of the Electricity Regulation, network charges shall not include unrelated costs supporting unrelated policy objectives.

Directive 2019/944 requires that TSOs and DSOs shall be equipped with all human, technical, physical and financial resources necessary for fulfilling their obligations and carrying out the activity of electricity transmission and distribution.

Considering the natural monopoly status of the network operators, justified and reasonable costs of TSOs and DSOs for the performance of their tasks and responsibilities shall be recovered through relevant network charges.

3.2.1. Transmission

Since 2022, the basic list of cost categories recognised by NRAs in T-tariffs has not changed substantially (Table 3.2). Ukraine reported developments related to costs associated with the TSO

30 Articles 31, 40 and 46 of the Directive 2019/944.

31 Article 18 (3) of Regulation (EU) 2019/943

32 CACM (Article 75), EB GL

33 https://www.energy-community.org/dam/jcr:3b0daaa9-73e9-480c-b83f-ef3f292e96e2/Regulation_838_2010_EL.pdf

participation in the ITC mechanism. During 2022–2023, implementing the Regulation (EU) No 838/2010, NEURC improved its regulatory framework (Transmission System Code and procedures for setting (forming) tariffs for electricity transmission and dispatching (operational and technological) control services) to enable the participation of Ukraine's TSO in the ITC mechanism. Starting from January 1, 2024, no additional payments are charged by the TSO from electricity market participants for import or export operations, except the perimeter transmission service charge as defined by ENTSO-E. Receivable/payments under the ITC Fund are recognised in the T-tariff methodology.

Thus, in all Contracting Parties, except Albania and Georgia (has no interconnection with Continental Europe), the ITC mechanism cost/incomes are recognised in the T-tariff methodologies[34] .

Following the 2025 ACER Tariff Report, ECRB investigated among Contracting Parties the additional cost categories in T-tariff, like costs related to inter TSOs cooperation on the pan-EU and regional level, costs related to market operations, informational exchange (including data hubs) and re-dispatching. It is noticeable, that currently relevant costs are mostly not recognised in T-tariffs among the Contracting Parties (as presented in Table 3.1):

Table 3.1 - Cost category of T-tariff

Cost category	Not recognised in T-tariff	Recovered by other non-transmission charge
Contributions to ENTSO-E35	Albania, Kosovo*, Moldova	-
Market operations29 (e.g. CCRs, regional projects, cost sharing)	Albania, Kosovo*, North Macedonia, Serbia, Ukraine	-
Re-dispatching and countertrading	Albania, Georgia, Kosovo*, Moldova, North Macedonia, Ukraine	Bosnia and Herzegovina

In North Macedonia, new Energy Law tasks NRA (ERC) to develop and adopt in 2026 the separate methodology for sharing costs between TSO and NEMO for market coupling operations. The re-dispatching and countertrading costs of TSO should be elaborated in the new methodology in 2026 as well.

34 TSOs of Moldova has not joined the ITC Agreement yet.

TSO activities related to information exchange in the electricity market, e.g. datahub, are reported to be in place and recovered through T-tariffs in four (4) Contracting Parties (Bosnia and Herzegovina, Montenegro, Serbia and Ukraine).

The research and development costs constitute a part of T-tariff only in three (3) Contracting Parties (Bosnia and Herzegovina, Montenegro and Serbia). In case of Bosnia and Herzegovina, the research and development costs are treated like any other costs and are within the competence of the Regulator. Following the basic principle that tariffs will be just and reasonable, non-discriminatory, based on objective criteria and justified costs and set in a transparent manner to the maximum extent possible, SERC considers relevant costs while considering the tariff application in the tariff proceedings. In Montenegro, research and development costs are not recognised as a separate cost category. However, research costs for development purposes, costs of services related to various development-oriented studies, and salary costs for employees engaged in research and development are part of the costs determined by the regulator on the basis of the TSO request. These costs are part of the controllable costs subject to efficiency incentives.

In North Macedonia, the Energy Law stipulates that methodologies should support related research activities and implementing innovations in the interest of consumers in areas such as digitalization, flexibility and interconnectivity services, as well as the development of smart grids and smart metering systems. Those elements will be elaborated in the new methodology.

Unrelated to transmission activity costs are still a part of the T-tariff in two (2) Contracting Parties, Kosovo* and Ukraine[36]. In Kosovo* T-tariff serves as a tool to collect funds for supporting schemes for renewables, while in Ukraine, as part of the renewable support scheme, T-tariff methodology also recognises costs of all PSOs (including RES PSO) imposed on TSO according to the law. In this regard, NEURC reported the ongoing activities in developing the new financing scheme for winners of RES support quota allocation auctions starting from July 1, 2026. This scheme will be funded through a separate surcharge for renewable energy sources, collected by the TSO independently of the electricity transmission tariff. Costs of support granted before July 1, 2026, will be collected through the current mechanism during the transitional period until 31 December 2029.

Ancillary services are recognised by all Contracting Parties and, in most cases, are recovered through the T-tariffs.

Albania reported that the costs of measures for ensuring adequacy (e.g. strategic reserve power plants) are only recovered by additional, non-transmission charges.

Table 3.2 - Recovery of the cost categories by T-tariffs in Contacting Parties

36 In Ukraine T-tariff also includes costs from other PSOs, introduced on the electricity market (e.g., financing of budget of supplier of last resort.

	Fully recovered by T-tariff	*Partially recovered by T-tariff*	*Fully recovered by additional/ /non-transmission charges*	*Partially recovered by additional /non-transmission charges*	*Not recovered by any tariffs or charges*	*Not applicable*	*Recovered by injection/withdrawal/both (indicate one)*
a. the remuneration (return on capital) of electricity transmission investments	AL, BA, GE, XK*, MD, MK, ME[37], RS					UA	N/A GE; withdrawal MK; both ME;
b. the deprecation of electricity transmission investments	AL, BA, GE, XK*, MD, MK, ME[26], RS, UA						N/A GE; withdrawal MK; both ME;
c. the operational expenditures for electricity transmission	AL, BA, GE, XK*, MD, ME, RS, UA	MK[38]					N/A GE; withdrawal MK; both ME;
d. costs (incomes) related to the Inter-TSO compensation mechanism	BA, XK*, MD, ME, MK, RS, UA					GE, UA, AL	N/A GE; withdrawal MK; both ME;
e. costs (incomes) related to cross-border cost allocation decisions	BA, XK*, MD, ME, MK, RS		GE			AL	N/A GE; withdrawal MK; both ME;
f. costs of purchasing ancillary services	AL, GE, XK*[34], MD, ME, MK, RS, UA[39]		BA				N/A GE; withdrawal MK; both ME;
g. costs of purchasing transmission losses	AL, GE, XK*, MD, ME, MK, RS, UA		BA				N/A GE; withdrawal MK; both ME;
h. costs of purchasing (another part of) system losses	AL, XK*, MD, RS, UA		BA		ME	GE, MK	N/A GE;

37 Only return on capital and deprecation for approved investments is remunerated through T-tariff in Montenegro.

i. costs of supporting schemes for renewables	XK*, UA	BA, ME		RS	GE, MK, MD, AL	N/A GE;
j. costs of supporting schemes for cogeneration of heat and power		BA, ME			GE, XK*, MD, MK, RS, UA, AL	N/A GE;
k. costs of supporting schemes for fossil fuels				BA	GE, XK*, MD, ME, MK, RS, UA, AL	N/A GE;
l. costs of measures for ensuring adequacy (e.g. strategic reserve power plants)			*AL*		*BA, XK*, MD, ME, MK, RS, UA*	*N/A GE;*
m. stranded costs of phased-out power plants					*BA, XK*, RS, UA,* AL	*N/A GE;*
n. fees that system operators contribute to the European Network of Transmission System Operators for Electricity (ENTSO-E)	*BA, ME, MK, RS, UA, MK*				AL	*N/A GE; both ME;*
o. costs related to market operation (e.g. nominated electricity market operators, regional projects under CCR, cost Sharing with NEMOs/TSOs)	*BA, MD, ME*				*RS*	*N/A GE; both ME;*
p. research and development costs	*BA, ME, RS*				*MD,* AL	*N/A GE; both ME;*

q. costs related to data hub activities	*BA, ME, RS, UA*[40]		*MD,* AL	*N/A GE; both ME;*
r. costs of re-dispatching and counter trading	*ME, RS*	*BA*		*N/A GE; both ME;*

Note: For North Macedonia costs mentioned in "o", "p", "r" will be part of cost for TSO according to the new methodology, that will be elaborated in 2026.

The value of selected cost categories recovered by T-tariffs in some Contracting Parties is presented in Table 3.3.

Table 3.3 – Value of recovered costs by T-tariffs in Contacting Parties in 2024 (by cost categories)

Value of recovered costs (mln EUR)	*GE*	*MK*	*ME*	*UA*[41]
the remuneration (return on capital) of electricity transmission investments	52.8	7.9	13.2	-
the deprecation of electricity transmission investments	19.4	8.2	7.9	29.04
the operational expenditures for electricity transmission	18.4	13.6	21.9	
costs (incomes) related to the Inter-TSO compensation mechanism		0.1	0.9	-16.36
costs (incomes) related to cross-border cost allocation decisions		26.2	23.97	
costs of purchasing ancillary services		23.2	3.9	253.94
costs of purchasing transmission losses	13.4	11.3	13.8	343.81
fees that system operators contribute to the European Network of Transmission System Operators for Electricity (ENTSO-E)			0.3	

3.2.2. Distribution

In all Contracting Parties, CAPEX, OPEX and cost of distribution losses are recovered by D-tariffs. In 5 (five) Contracting Parties, cost of procurement by DSOs of the ancillary or flexibility services for managing the distribution networks are recognised by the NRAs when determining D-tariff. In 2 (two) Contracting Parties (Bosnia and Herzegovina and Serbia) D-tariffs include administration costs related to switching.

In most Contracting Parties, D-tariffs include costs for metering as metering is a regulated activity of DSOs.

41 For Ukraine values are according to the approved T-tariff structure and Dispatch Tariff structure for 2025 according to the NEURC Resolutions No.2200 and No.2201 of 19.12.2024

In Serbia metering costs of DSO are paid by distribution connected users as part of a single distribution and metering tariff.

Only in Ukraine, metering is a deregulated activity, i.e., a market participant has the right to choose any provider of metering services, while DSOs are default [42] metering service providers in their networks. Metering costs of DSOs are recovered through a separate fee for metering services, which is calculated in accordance with the methodology approved by the Regulator. However, the costs of replacing conventional meters in residential buildings are recovered through the distribution tariff of the relevant DSO. Thus, metering costs are recovered partially through D-tariffs paid by all users and partially by metering fees.

R&D costs of DSOs are not widely recognised by NRAs in the distribution tariff, namely only in three (3) Contracting Patries: Albania, Bosnia and Herzegovina and Montenegro.

Data-hub costs of DSO are recovered in the distribution tariff in Serbia, and partially in Albania. In other Contracting Parties, such costs are not related to DSO activity.

For more details about cost categories and their values recovered by D-tariffs of each Contracting Party, please see Tables 3.4 and 3.5.

Table 3.4 - Recovery of the cost categories by D-tariffs in Contracting Parties

	Paid by distribution connected users via tariffs	*Partially paid by distribution connected users via tariffs and partially covered by other means*	*Covered by other means and not by distribution tariffs*	*Not applicable (there is no such cost for DSO)*
a. Return on capital of electricity distribution investments	AL, BA, GE, XK*, MD, ME[43], MK, RS, UA[44]			
b. Depreciation of electricity distribution investments	AL, BA, GE, XK*, MD, ME[30], MK[45], RS, UA			
c. Operational expenditure for electricity distribution (not including losses)	AL, BA, GE, XK*, MD, ME, MK, RS, UA			
d. Costs of managing the switching between suppliers (e.g. related administration costs)	BA, RS		XK*	AL, GE, MD, UA, ME, MK

43 Only return on capital and deprecation for approved investments is remunerated through D-tariff in Montenegro.

44 For incentive-based regulation

45 Not all operational costs are recognized in D-tariff but only the costs of the company's operations and the maintenance costs of the regulated basic assets, with which the company performs the regulated activity, in accordance with valid laws, regulations, standards and technical norms that are applied in the Republic of North Macedonia, as well as the obligations contained in the issued licenses.

e. Costs of purchasing ancillary and /or flexibility services by the DSO	AL, BA, GE, MD, MK			XK*, RS, UA, ME
f. Costs of distribution losses	AL, BA, GE, XK*, MD, ME[46], MK[47], RS, UA			
g. research and development costs	AL, BA, ME			XK*, MD, MK,
h. costs related to data hub activities	BA, ME, RS	AL		XK*, MD, MK,
g. metering	AL, BA, GE, XK*, MD, ME, MK, RS, UA (partly)[48]		UA	
e. other (please, specify)				AL, MD, MK, RS

The value of selected cost categories recovered by D-tariffs in some Contracting Parties is presented in Table 3.5.

Table 3.5 – Value of recovered costs by D-tariffs in Contacting Parties (by cost categories)

Value of recovered costs (mln EUR)	GE	XK*	MK	ME
Return on capital of electricity distribution investments	39.9	17.3	22.2	16.1
Depreciation of electricity distribution investments	16.1	20.6	28.8	15.2
Operational expenditure for electricity distribution (not including losses)	56.7	30.3	49	70.3
Costs of distribution losses	44	65.4	86.3	27.3
other (please, specify)			2.1[49]	

Most of the Contracting Parties reported no changes in tariff methodology targeted to respond to emergency situations. Only Albania and Kosovo* have specifics in considering the cost of uncertain and unforeseen events. In Albania, NRA doesn't consider the cost of uncertain and unforeseen events proposed by the DSO for the calculation of the requested revenues for the base year, however, realised and approved costs may be recognised by ERE as a reserve fund, in order to cover the unforeseen costs for the upcoming regulatory period. In Kosovo*, in the case of the emergency situation, the extraordinary tariff adjustment is performed in such a manner that the net present value of the forecast change is equal to the net present value of the financial impact of the extraordinary event. An extraordinary review (according to ERO rules) takes place when unforeseen

46 Only technical losses are recovered via D-tariff.

47 In North Macedonia not all costs of losses are recognized, but the recognised costs are paid by system users.

48 In Ukrainian DSOs, annually, on the basis of the investment programs approved by the NEURC, the old meters are planned to be replaced with multifunctional (zone) in order to implement the program of the automated system of commercial electricity metering (ASCME). ASCME for households is installed in a residential building for all residents at the same time and provides for the replacement of conventional means of electricity metering with multifunctional (zone) in all apartments. This replacement is free for consumers and is covered through the D-tariff costs. At the same time, decisions on the terms and conditions of the above-mentioned replacement are regulated only by the approved plans of DSO for replacing metering facilities. All other cases are at the expense of the consumer.

circumstances occur that have a significant impact on the costs or revenues of regulated operators — for example: natural disasters, major economic or legal changes, energy crises, or other situations beyond the operator's control. In such cases, the ERO may conduct an extraordinary review to adjust the approved tariffs or allowed revenues. One of the criteria that may trigger such a review is when there is a deviation greater than 5% between the approved and actual values of financial.

In terms of any significant changes regarding the cost model in the D-tariff methodology, the NRA of North Macedonia notified about the amendments to the D-tariff regulatory framework in 2023. With the adopted changes, the base year calculation was set to t-2. Also, a new distribution fee was introduced as a lump sum for access to the grid.

3.2.3. Transmission and Distribution investments

Network operators are responsible for ensuring the long-term ability of their systems to meet reasonable demands for the transmission and distribution of electricity, for operating, maintaining and developing under economic conditions a secure, reliable and efficient electricity transmission and distribution system. Network development is now also driven by the need to integrate numbers of RES producers, recharging points, storages and active customers. To ensure better market integration and security of supply, investments are needed to develop the cross-border infrastructure within the region and with the EU. Investments shall be efficient, justified, and timely to catch up with energy and economic development. They shall go with due regard to the environment and energy efficiency.

Treatment of investments in network tariff methodologies gives the signal to network operator on the priorities, planning horison, available/recognised financial resources, remuneration and reward. At the same time, investments shall bring relevant measurable benefits (e.g. increase capacity, lower losses etc.)

Energy transition requires sufficient infrastructure, not only for today's needs but also for prospects. In this regard, in the EU, strong attention is paid to the grid's developments, including by means of forward-looking (anticipatory) investments. In 2025, the Commission issued the guidance on anticipatory investments for developing forward-looking electricity networks[50]. According to this guidance, anticipatory investments understood as an investments into grid infrastructure assets that proactively address network development needs beyond the ones corresponding to reinforcements relating to currently existing grid connection requests by generation or demand projects. Anticipatory investments are forward-looking network investments based on identified medium- and long-term network needs, justified in network development plans, based on scenarios that project plausible trajectories of generation and demand capacities that support energy, climate and industrial policies, including the National Energy and Climate Plans. Anticipatory investments

50 https://eur-lex.europa.eu/eli/C/2025/3179/oj/eng

are not a new investment 'class', as they consist of identical network assets as all other types of network investments, such as reactive investments.[51]

Investments shall go through several regulatory processes, e.g., planning, regulatory assessment, cost recognition in allowed revenue and network tariffs, depreciated, etc.

Investments planning

In all Contracting Parties, transmission investments are planned through the long-term network development plans and/or investment programmes. Ten-Year Network Development Plans (TYNDP) are prepared by TSOs in four (4) Contracting Parties (Kosovo*, Montenegro, Serbia and Ukraine). TSOs also submit the detailed investment programmes developed based on the TYNDP, in Kosovo* (for 5 years), Montenegro (for 1 year) and Ukraine (for 1 year).

Transmission investment projects require Cost-Benefit Analysis (CBA) in four (4) Contracting Parties (Kosovo* (major investment projects), Georgia (grid extension projects), Montenegro (for each investment project) and North Macedonia (projects value above EUR 100 000). In Montenegro, the CBA template is predefined by the law and differs for infrastructure and non-infrastructure projects. For infrastructure projects, the CBA template is based on the ENTSO-E CBA template, and the main benefits that are analysed include social-economic welfare, RES integration, stability, flexibility, etc. While for non-infrastructure investments, these benefits include, inter alia, avoided operational costs.

In Bosnia and Herzegovina, investments in the fixed assets are estimated and recognised based on the maintenance of the required scope and standard quality of services in the regulated activity. With a view to determining justification of every single investment in the fixed assets, which is performed within the regulated activity, Regulator: a) examines justification of an investment from the aspect of improvement of the quality and safety of supply, in accordance with the projected increase of demand; b) examines harmonization of investments with the existing development programs (plans).

In Moldova, the investments are submitted by TSO only in the annual investment plan based on three criteria (i.e. necessary, mandatory, efficient). If the operator proposes an investment project based on efficiency criteria, it should demonstrate that the financial savings are higher than overall project costs over its lifetime.

In terms of anticipatory investments in transmission, where anticipatory investments are recognised, they mostly relate to PECI/PMI or projects of national interest. In this regard, four (4) Contracting Parties reported the following practices and developments:

51 Investment reacting on the need for network refurbishment or on existing connection requests.

Table 3.6 – Categories of recovered costs by D-tariffs

Contracting Party	Categories of recovered costs
Kosovo*	Forward-looking (anticipatory) investments are supported especially for RES integration and system adequacy. Cross-border capacity investments enhance regional connectivity and market integration. Digitalisation investments include SCADA system upgrades, automation of substations, and deployment of advanced monitoring tools, aimed at improving operational efficiency and system flexibility.
Moldova	With regard to the anticipatory investments, the recent amendment to the Law on electricity no. 107/2016, state that when determining and approving the regulated tariffs for the provision of the electricity transmission service, the Agency shall take into account the project value of the investments in the construction works of the electricity transmission network objects, declared works of public utility of national interest, from the moment of disbursement of the financial means for financing the project. When transmitting into operation the electricity transmission network objects, the construction works of which were declared works of public utility of national interest, the necessary recalculations shall be carried out.
Montenegro	The different treatment is provided only for PECI and PMI projects, which are included in the regulatory asset base in advance, depending on when these projects are planned to be put into operation. Other approved investments (regardless of their category) are included in the regulatory asset base only after their realisation.
North Macedonia	Anticipatory investments are considered. Anticipatory as new investments that should come in the future, beyond the regulatory period, are recognised as part of the RAB, Return on Assets and depreciated.

When it comes to distribution investments, long term planning of development of distribution grid is introduced in three (3) Contracting Parties. In Montenegro DSO identifies the needs for the distribution infrastructure development in the TYNDP. In North Macedonia, ERC approves five-year distribution network development plan that is submitted by the DSO every year (practice until 2025). As of 2026, this plan should be submitted every two years. in Ukraine DSOs are tasked to prepare their Five-Year Distribution Network Development Plans and submit them to NEURC for approval.

In evaluation of the distribution investment projects, NRAs applied simplified requirements for CBA:

a) in Kosovo* the inclusion of a distribution investment project in the calculation of allowed revenues requires the completion of pre-feasibility and feasibility studies. For projects above 1 million EUR, a CBA is mandatory, while for smaller projects or groups of small projects valued at less than €1 million, ERO may require the licensee to carry out a CBA on a case-by-case basis. Exemptions from these studies are only possible upon a justified request by the licensee and formal approval by the Regulator.

b) In Montenegro, DSO should submit a techno-economic analysis for each individual investment with a value greater than EUR 200,000, according to the template predefined by the bylaw.

c) In North Macedonia the CBA is performed for the investments above EUR 100.000, and it does not have all elements but basic information.

In other jurisdictions, the distribution projects mostly required to be supported by justification of an investment from the aspect of improvement of the quality, safety of supply and efficiency.

Anticipatory investments in the distribution grid are rarely recognised by NRAs of the Contracting Parties, and distribution investments are included in the D-tariff only after commissioning. The distribution projects are mostly associated with grid renovation or modernization projects. Only NRA of Kosovo* indicated that forward-looking investments enable future grid needs (e.g., EVs, renewables) and are gradually supported by the Regulator via planning scenarios and cost allowances.

Financing of investments

The main sources of financing of transmission investments are equity, loans (mostly provided by International Financial Organisations), and grants. Specifically, loans and grants are widely used to invest into cross-border infrastructure, while less presented in case of financing the distribution system projects. In Ukraine important sources of financing of investments are also revenues from reactive power flows.

Table 3.7 – Recovering of investments

		Transmission	Distribution
Main financial resources for investment projects	Allowed revenue	XK, UA	XK, MK
	Equity	GE, XK, ME, MK, RS[52]	GE, XK, ME, RS, UA[53]
	Depreciation	BA, MD, UA	MD, UA
	Loans	BA, GE, XK[54], MD[55], ME, MK, RS[56], UA	GE, XK, ME, RS
	Grants	GE, XK[57], MD, ME, RS, UA	XK, ME, RS,
	Other	UA[58]	UA[59]
How investments recovered through granted funds are recognised in the tariff methodology	Not recognised in tariffs	AL, GE, XK, MD, RS	AL, GE, MD, RS
	Not included in the RAB	BA, XK, MK, RS	BA, XK, MK, RS
	Included in RAB	GE	GE
	No return on investment	ME, MK	ME, MK
	Only depreciated in tariff	ME, MK, UA	ME, MK, UA

52 The Main financial resource for the national infrastructure is equity

53 50% of revenue from return on investments (for old RAB) shall be reinvested. Due to martial law, the RoR was decreased to 3% and to 0% (for some DSOs). For 2024, the main financing of investments came from depreciation and revenue from reactive power flows.

54 Loans from IFIs (e.g., KfW, EBRD), .

55 In case of significant projects e.g. „Vulcanesti - Chisinau 400 kV OHL" the financial sources are generally from loans and grants from foreign development partners

56 for cross-border infrastructure differs from project to project (grants, credits, equity, etc.)

57 EU/WBIF grants for cross-border projects or donor funds under regional initiatives

58 revenues from reactive power flows; funds received from the allocation of cross-border transmission capacity

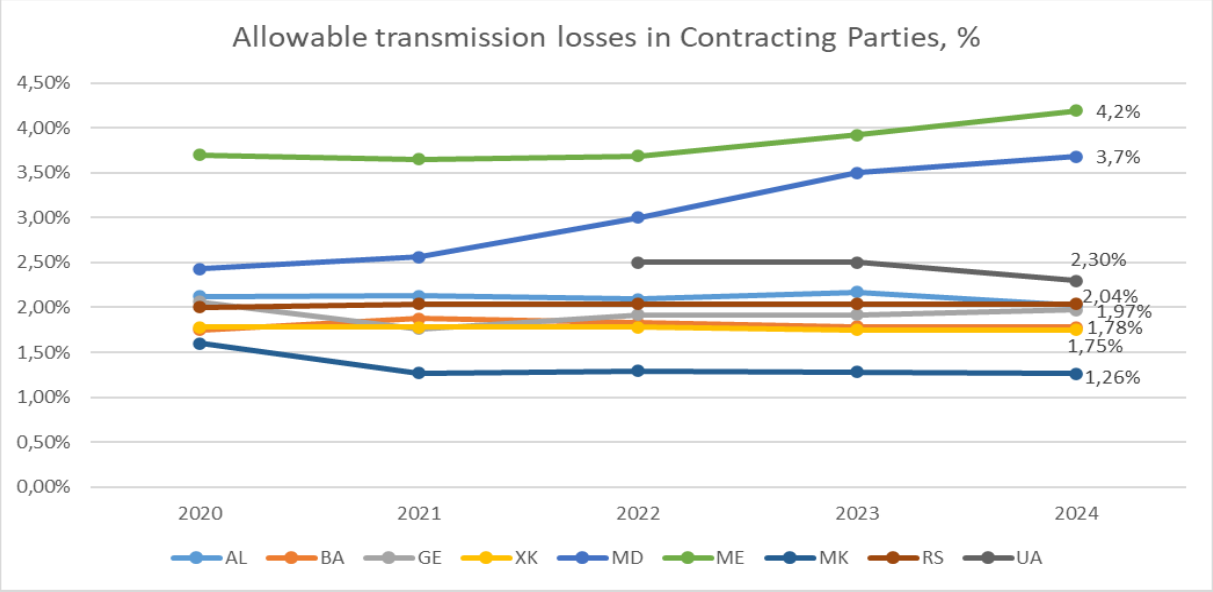
59 revenues from reactive power flows, profit (additional reinvestments), connection fees, funds received from activities related and unrelated to electricity distribution; a portion of the planned profit related to the reduction of losses in distribution network (for DSOs subject to the "cost +" tariff-setting methodology).

How investments financed through loans are recognised in the tariff methodology	Recognised in tariffs	XK[60], MD, ME, MK, UA	XK, MD, ME, MK, UA
	Included in RAB	GE, XK, MD, ME, MK, RS[61]	XK, MD, ME, MK, RS, UA

Treatment of investments from loans and grants is similar across the Contracting Parties: investments financed through loans are recognised in the tariff methodologies (in RAB and tariffs), while investments recovered through granted funds do not benefit from return on investments and are not recognised in network tariffs.

3.2.4. Transmission and Distribution Losses

The power losses represent a substantial share of the electricity transmitted and distributed, and the costs of purchasing the electricity covering them are usually assigned to TSOs and DSOs through the network tariffs.

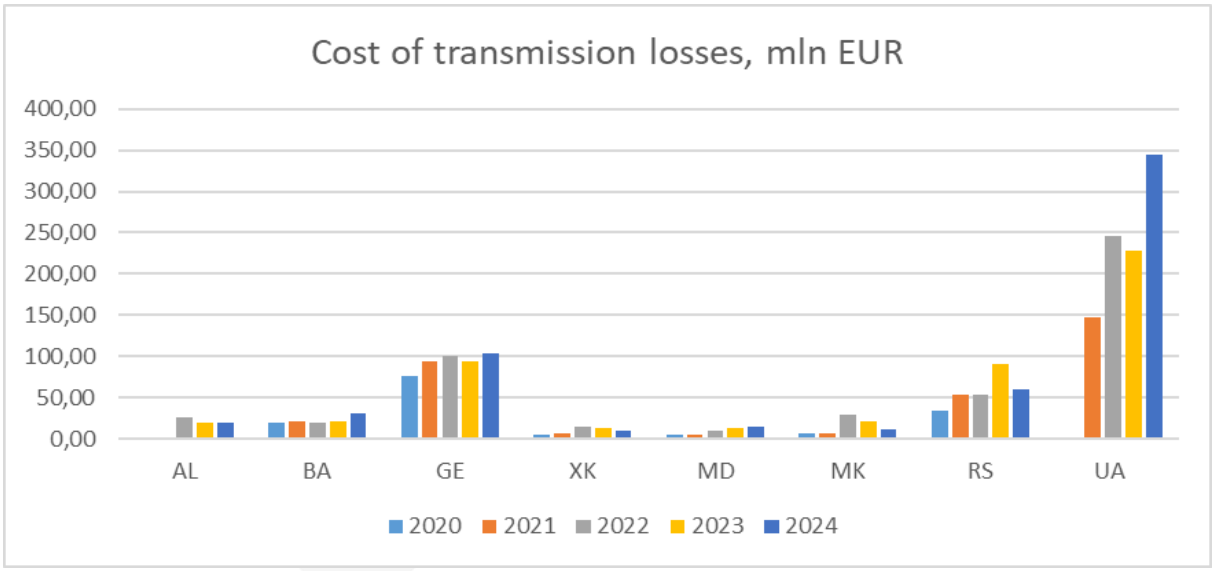


For Ukraine data for 2024 are from the NEURC Bulletin to the 2024 Annual Report and for 2022/2023– from the Bulletin to the 2023 Annual Report.

Figure 3.4 – Allowable transmission losses in Contracting Parties, %

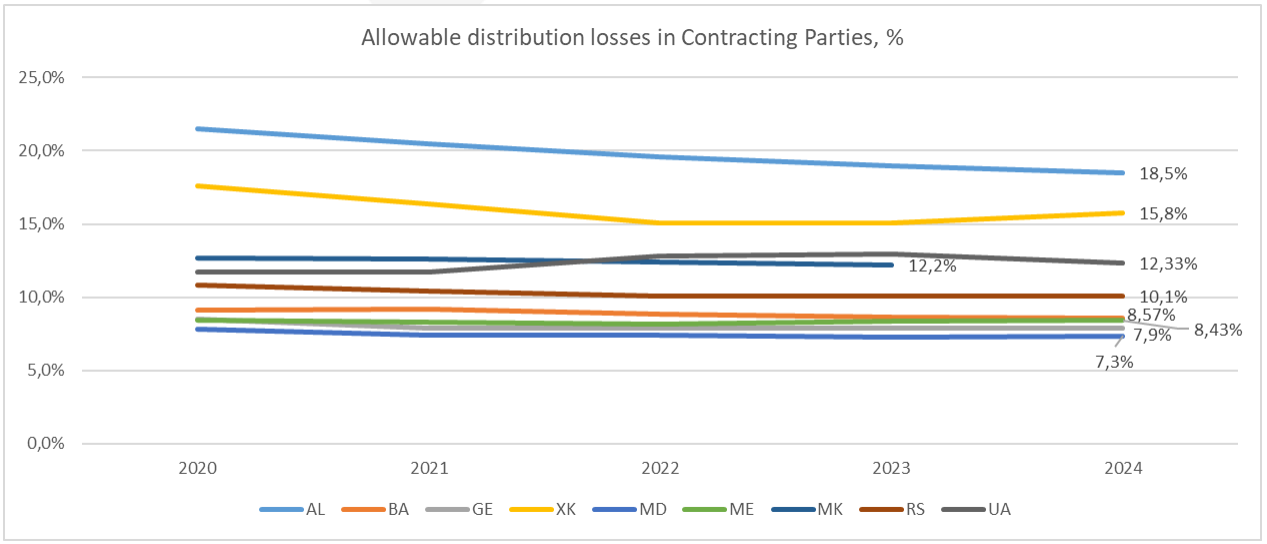
60 Loan interest and principal repayments are considered as allowable costs, and these costs are recovered over the loan period via T-tariffs.

61 Investments that are financed from the loans in the year when activated are becoming part of RAB, interest rate is recognized through the WACC calculation (return on debt)



For Ukraine values are according to the approved T-tariff structures for 2021, 2022, 2023 and 2024 according to the NEURC Resolutions № 2353 of 09.12.2020, № 2454 of 01.12.2021, № 1788 of 21.12.2022 and No.2200 of 19.12.2024 respectively

Figure 3.5 – Cost of transmission losses, mln EUR



For Ukraine data for 2024 are from the NEURC Bulletin to the 2024 Annual Report and for 2022/2023– from the Bulletin to the 2023 Annual Report. Data reflect the allowable (normative) values, while the actual losses are lower

Figure 3.6 – Allowable distribution losses in Contracting Parties, %

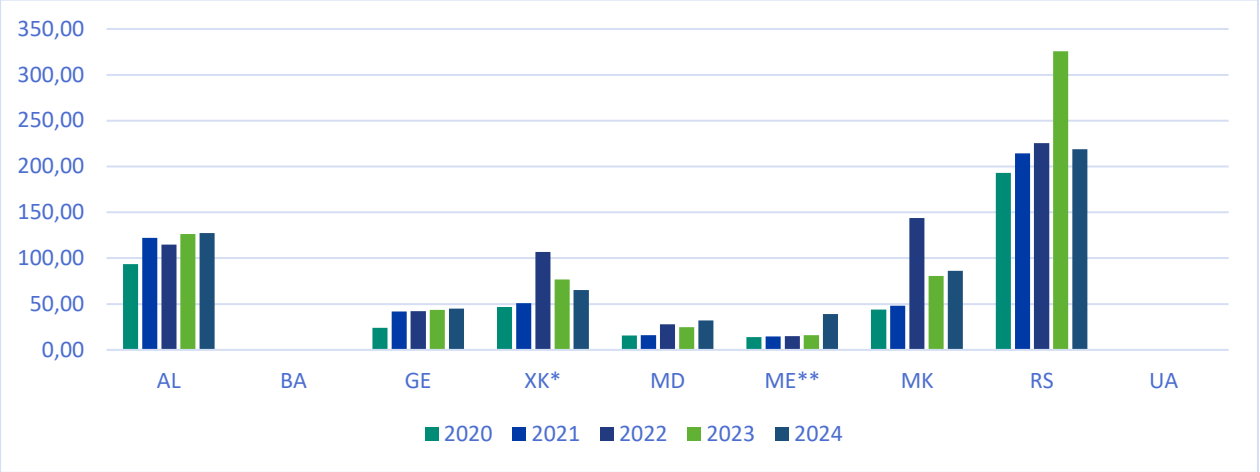


Figure 3.7 – Cost of distribution losses, mln EUR

All NRAs in Energy Community recognise the costs of the technical losses when determining the allowed revenues of TSO and DSO. In Bosnia and Herzegovina, the cost of losses is recovered through the Tariff for System Services (not the T-network tariff) of the Independent System Operator.

NRAs usually define rules regarding the volumes of losses to be recognised, how the allowed volumes of energy for losses are procured, and at what price. There are also differences in the treatment of transmission and distribution losses, particularly, related to the recovery of technical and non-technical losses, defining the allowed (target) values, etc. Details of practices regarding the recognised losses in Contracting Parties are presented in Table 3.8.

Table 3.8 – Recognised losses and target values

Contracting Party	Recognised losses		Target values	
	Transmission	Distribution	Transmission	Distribution
AL	Only technical losses.	No split for technical and non-technical losses.		Set in %. The allowed percentage of losses is determined by governmental decision.
BA	Only technical losses.	Only technical losses.	Set in kWh. Estimated by Independent System Operator when determining the annual Electricity Balance.	Set in %. Benchmarking based on available data on similar distribution companies inside or outside the country.
GE	No split for technical and non-technical losses.	No split for technical and non-technical losses.	Set in %. Normative losses calculated according to the methodology approved by NRA based on actual data from the past few	Set in %. Normative losses calculated according to the methodology approved by NRA based on actual data from the past few

			years in combination of reduction target.	years in combination with reduction target.
XK	No split for technical and non-technical losses. The loss-sharing factor of 50% will be implemented by TSO only in the first year of the regulatory period.[62]	No split for technical and non-technical losses. The loss-sharing factor of 50% will be implemented by DSO only in the first year of the regulatory period	Set in %. Allowed losses are the same for each year of the regulatory period. Targets based on benchmarking, historical performance, and regional best practices. NRA applies the comparative analysis and efficiency benchmarks.	Set in %. Loss reduction target for each year of the regulatory period. Based on historical data, the Investment Plan, benchmarking with regional utilities, and expected efficiency improvements.
MD	Only technical losses. Revenue decreases if real losses are lower than projected. Revenue increase for the normative value of losses if an increase in actual losses is justified by a relevant study.	No split for technical and non-technical losses. Economy is splited between the DSO and consumers in 50/50 share.	Set in %. Benchmark method. Average % for the last 5 years and forecasted volume of transmission.	Set in %. Based on real values and decrease trajectory from previous period
ME	Only technical losses.	Only technical losses.	Set in % for each year of the regulatory period. Based on a study performed by TSO and audited by an independent institution. Investment measures are considered.	Set in % for each year of the regulatory period. Based on a study performed by DSO and audited by an independent institution.
MK	No split for technical and non-technical. Until 2024, ERC has been approving the plan for decreasing the losses in the transmission system for each regulated period. Currently, all losses are recognized in the transmission system.	No split for technical and non-technical	Set in %. The losses are set as a percentage of the electricity input into the system. The percentage was set after the analysis prepared by the TSO and the implementation of the proposed measures.	Set in kWh. Losses reduction plan after previous analysis and results of the measures to be undertaken by DSO.

62 https://www.ero-ks.org/zrre/sites/default/files/Publikimet/Vendimet/Vendimet%202022/V_1636_2022_Decision_Input%20Values%20_Losses%20PRR3_2023_%20FINAL.pdf

RS	There is no split between technical and non-technical losses. The NRA evaluates allowed losses according to historical data and investment plans.	There is no split between technical and non-technical losses. The NRA evaluates allowed losses according to historical data and investment plans.	Set in %.	Set in %
UA	The projected volume of technological costs of electricity for its transmission for the year t (with a breakdown by quarters), which is determined taking into account the Forecasted Electricity Balance of the Unified Power System of Ukraine for the relevant year (if available) and the Methodological Recommendations for Determining the Volumes of Electricity Transmission via Main and Interstate Networks and the Costs of Its Transmission, approved by the Ministry of Fuel and Energy.	Economic coefficients of projected technological electricity costs for voltage classes 1 and 2, established in accordance with the Regulations on the procedure for submitting, determining and approving economic coefficients of normative and projected technological electricity costs, approved by NEURC.	In MWh	Set in %

The cost of losses shall be distributed among the network users according to the principles of cost-reflectiveness, non-discrimination, and transparency. To ensure this, the impact of different end-users (such as loads, producers, and storage facilities) on network losses shall be assessed.

Three (3) Contracting Parties reported the performance of analysis to determine the impact of network users on the volume and patterns of the losses in transmission and distribution networks.

In Kosovo*, the impact of loads, producers, and storage units on network losses is assessed through power flow analysis. Their location, capacity, and operational behavior influence the extent to which they increase or reduce the losses in the grid. Loads located far from generation typically increase losses, while producers close to demand help reduce losses.

In Montenegro, the keys for allocation of the cost of transmission losses to producers are determined based on the ratio of losses on the transmission system elements in Montenegro that are mostly used by the producers. The remaining costs are allocated to consumers. Regarding the distribution losses the approach is similar: at first, the portion of the allowed losses caused by producers connected to the distribution system is calculated. Consumers (load) cover the difference between the total losses and those covered by producers. Electricity consumers in Montenegro, connected to the distribution system, are charged losses without breakdown of the transmission and distribution components.

In North Macedonia, such an assessment is performed only for distribution losses. This is done through analysis and studies, based on which the distribution tariff system allocates the implications of the costs for losses in the different connection categories.

All NRAs reported on market-based procurement of transmission losses. In most cases, TSOs procure losses in the electricity market. In North Macedonia, TSO procures losses through the public tender in accordance with the rules approved by NRA and Power Exchange. Cost for transmission losses includes the costs for purchasing of electricity, including the costs for the market operator.

Market-based price of distribution losses is recognised in most of the Contracting Parties. However, in Albania, the distribution losses are partially covered by producers at regulated price under the Public Service Obligation, and the rest of the volume is purchased in the market. Three (3) Contracting Parties (Moldova, North Macedonia and Serbia) recognise also the concomitant costs associated with the market procurement. E.g. in Moldova the procurement price includes price of energy, cost of transmission service, cost of using interconnection capacities and the cost of imbalances. In North Macedonia, costs for distribution losses cover costs for purchasing of electricity, costs for market operation, costs for transmission and imbalance costs.

Losses are mostly driven by the volume of consumption/injection into the grid per time period. Therefore, the cost of losses is usually allocated to the energy-based element of the end-user network charge. In two (2) Contracting Parties, where the injection charge is in place, the cost of losses is also paid by producers (transmission in Kosovo*, transmission and distribution in Montenegro).

For more details on transmission and distribution losses in network tariff regulation, please see Annex I.

Country case: Allowed cost of transmission and distribution losses in Moldova

Transmission

Commercial losses are not recognized in the allowed revenue. To determine target loss indicators, benchmark is applied. The technological consumption and electricity losses in each regulatory year "j" are determined as the product of the average value for five years preceding the management year, in relative units, %, and the quantity of electricity planned to be injected into the electricity transmission network in the management year "j".

If the technological consumption and losses of electricity in the electricity transmission networks actually recorded in the management year are lower than the value applied to determine the tariff for the electricity transmission service in the year "j", the effective value will be applied when updating the tariff for the electricity transmission service.

If the technological consumption and losses of electricity in the electricity transmission networks actually recorded in the management year, in relative units, are higher than the value applied to determine the tariff for the electricity transmission service, the TSO determines the normative value of the technological consumption and losses of electricity in accordance with the Instruction for calculating the technological consumption of electricity in the electricity networks, approved by ANRE decision no. 190/2005 and submits to the Agency information regarding the factors that influenced the exceeding of the technological consumption and losses of electricity in the management year "j".

The Agency verifies the correctness of the calculations submitted by the TSO and, if they comply with the provisions of the Instruction for calculating the technological consumption of electricity in electrical networks, will accept for tariff purposes the minimum value between the amount of technological consumption and losses of electricity actually recorded and those determined according to the Instruction.

The effective value of technological consumption and losses of electricity in electrical transmission networks is determined as the difference between the amount of electricity measured at the entry points into electrical transmission networks and the amount of electricity measured at the exit points from electrical transmission networks.

For the purpose of calculation of the allowed revenue of TSO, the average purchase price, in year "j", of electricity to cover technological consumption and electricity losses in the electricity transmission networks, lei/kWh, is used. The TSO purchases the electricity necessary to cover technological consumption and electricity losses in the electricity transmission networks according to the provisions of the Electricity Market Rules, approved by ANRE Decision no. 283/2020, in compliance with the principle of maximum efficiency at minimum costs.

Distribution

Technological consumption and electricity losses in the electricity distribution network (PDnt) represent the product of the quantity of electricity injected into the distribution networks and the relative value of technological consumption and losses of electricity for the respective year accepted by the Agency, which is calculated according to the formula:

$$PD_{nt} = \frac{ED^n}{1 - [P_{2024} \times (1 - \alpha)^{n-2024}]} \times [P_{2024} \times (1 - \alpha)^{n-2024}]$$

where:

EDn – the amount of electricity distributed in year (n), kWh;

P2024 – the level of technological consumption and electricity losses recorded in the distribution network of the licensee in 2024;

α – the average annual rate of decrease in the relative value of technological consumption and total electricity losses per distribution system operators recorded in the period 2018-2024. For the period 2025-2029 its value is 0.018.

The target set for the period 2025-2029 was determined by the real values of losses registered by the DSOs in 2018-2024. If the real technical losses are lower than the target values established by the Methodology, the economy is splited between the DSO and consumers in 50/50 share.

The price for allowed losses, CEn – average cost of electricity used in year "n" by the DSO to cover technological consumption and electricity losses in the electricity distribution networks, lei/kWh. The average cost of purchased electricity is determined at the entry bars in the electricity distribution networks, taking into account: the cost of purchased electricity, the cost of electricity transmission service, the cost of using interconnection capacities and the cost of imbalances caused as a participant in the electricity market, according to the formula:

$$CE_n = \frac{CCB_n + CST_n + CAC_n + RFD_n}{PD_{ef,\,n}}$$

where:

CCBn – costs incurred in year "n" by the DSO for electricity purchased based on notifications, lei;

PDef, n – technological consumption and electricity losses in the electricity distribution network, actually recorded, in year "n", expressed in kWh;

CSTn – costs related to the provision of the electricity transmission service intended to cover technological consumption and losses in the electricity distribution networks, lei;

CACn – expenses incurred by the DSO related to the use of the interconnection capacities of the national electricity system with neighboring systems, lei;

RFDn – costs for imbalances caused by the DSO as a participant in the electricity market, lei.

3.3. Cost cascading

Allocating costs among different categories of network users and voltage levels has the main objective of ensuring cost reflectiveness in respect of cost drivers—i.e., the costs shall be recovered by the users who cause those costs.

All Contracting Parties reported no substantial changes in terms of cost-cascading practices since 2022.

3.3.1. Transmission

As it may be observed from Table 3.9, in four (4) Contracting Parties, which provided information, T-connected users cover the share of T-cost proportionally to their share in electricity withdrawal. In Kosovo* and Montenegro, a share of the transmission costs allocated to T-connected users is larger than the share of their withdrawal compared to D-connected users that may witness some additional cost allocation keys between users, which are not solely related to withdrawn electricity. Particularly, in Kosovo* and Montenegro[63], T-connected users are subject to injection charges, so the cost covered by these users is not proportional to the withdrawal, but also to the injection.

Table 3.9 - Shares of electricity withdrawal and T-costs

Contracting Party	*AL*	*BA*	*GE*	*XK*	*MD*	*ME*[64]	*MK*	*RS*	*UA*[65]
Withdrawn by T-connected network users, %	7.3	8.2	56	5.3	7.9	6.2	7,9	11.25	n/a
Withdrawn by D-connected network users, %	92.7	91.8	44	94.7	92.1	93.80	92,1	88.75	n/a
T-cost paid by T-connected network users, %	7.3	8.2	56	38	7.9	39.21[66]	18	12.8	n/a
T-cost paid by D-connected	92.7	91.8	44	62	92.1	60.79	82	87.2	n/a

63 If the T-costs covered by injection charges were excluded, the ratio would be 22,06% (TSO network users) and 77,94% (DSO network users), which is quite comparable with the data on withdrawal from transmission and distribution systems.

64 Data for Montenegro refers to the forecasted values (by T-users including the producers) from REGAGEN's decision on tariffs for 2022.

65 information was not provided

66 The data on costs covered by all network users (including producers). The data for withdrawal refer only to electricity withdrawal, so these data cannot be compared. If the T-costs covered by producers would not be included, the ratio would be 7.87% (T-consumers): 92.13% (D-consumers).

network users, %

In Albania, Bosnia and Herzegovina, Kosovo* and North Macedonia, the share of withdrawal by T-connected users in 2024 decreased by roughly 2 % compared to 2022. In Kosovo* it reflected in the increase of share covered by T-connected users, while in Albania and Bosnia and Herzegovina the relevant shares are adjusted accordingly. In North Macedonia the share of costs covered by T-connected users remained unchanged compared to 2022.

When it comes to the cost cascading at the transmission level, only in Kosovo* T-connected network users at a lower voltage level (110 kV) pay for part of the T-costs of higher voltage levels[67]. The allocation of allowed revenue between 400 kV/220 kV and 110 kV voltage levels is based on the value of assets at each voltage level, and it is levied on expected maximum demand at the time of system peak (per kW). OPEX and CAPEX costs are not subject to cost cascading; instead, they are allocated to customer categories based on energy and demand sharing factors. All other Contracting Parties have no transmission cost-cascading at the transmission level and apply the same T-tariff to all T-connected [68]OBJ regardless of the voltage of connection. To some extent, this might be explained by the fact that most Contracting Parties have relatively small energy systems with all customers connected to the same voltage level (e.g., in Moldova, Montenegro, North Macedonia and Serbia - to high voltage transmission level).

As regards transmission cost cascading to D-users, in all Contracting Parties transmission costs are borne by both T- and D-connected network users. In most Contracting Parties, these costs are included in the D-tariff, namely, DSO pays the T-tariff and these costs are then included in the D-tariff paid by D-connected users[69].

In Albania and Georgia, the T-tariff is shown as a separate item on the bill and paid by customers directly. In Moldova, the final consumer covers the costs for both TSO and DSO through electricity supply prices. In North Macedonia and Montenegro, users of small DSOs/consumer-connected users also pay part of the T-costs. In Ukraine, the T-tariff is mostly paid by suppliers of D-connected users, while only a share of the transmission costs paid by DSOs in respect to the distribution losses and is recovered through the D-tariff.

Only Montenegro reported having producers connected to the distribution system fully exempted from the T-costs cascading.

Despite the cost cascading not being widely presented among Contracting Parties, NRAs require some level of cost granularity for transmission costs, as an input to the tariff calculation methodology to allocate cost between groups of users (generation or load) or between the elements

67 TSO operates with three high voltage levels 400kV, 220kV and 110kV.

68 This is without prejudice to different tariffs for different categories of users (e.g., producers or consumers).

69 In Bosnia and Herzegovina, DSOs transfer T-costs to the final customers. These costs related to the T-tariff, System Service tariff and ISO operation tariff are shown separately on the final customer's bill (not tariff element, just cost/amount).

of the allowed revenue calculation (CAPEX, OPEX). Overall, the cost granularity supports the transparency and cost-reflective nature of the network tariffs.

Table 3.10 - Granularity required for the transmission costs

Granularity required for the transmission costs	Contracting Parties
No granularity. Transmission costs enter the tariff methodology as an overall amount.	MD, MK, RS
Transmission costs separated by voltage level.	XK
Transmission costs separated according to a Generation-Load split.	BA, XK, ME
Transmission separated at least into CAPEX and OPEX.	AL, BA, GE, XK, ME,
Cost categories other than CAPEX and OPEX need to be individualized.	BA, GE, XK, ME
Other	UA[70]

3.3.2. Distribution

In all Contracting Parties distribution cost cascading refers to the situation when the D-connected network users at a lower voltage level pay for part of the D-costs of higher voltage levels. This concept is present in all Contracting Parties. Reverse cascading is not used at the distribution level.

Most Contracting Parties apply cost cascading to all distribution costs. However, Georgia reported that some D-cost categories are not cascaded between voltage levels as they are already allocated to the customers (e.g., billing costs). In Kosovo*, only the costs of losses are subject to cascading between the distribution voltage levels. For more details on the cost-cascading method applied to the D-costs in Contracting Parties, please see Table 3.4.

Table 3.11 - Cost-cascading method applied for the D-costs in Contracting Parties

Contracting Party	*D-cost cascading approach*
Albania	"Price-cap" regulation based on the General rules and the basic principles of the methodology are applied for the average revenues permitted for the electricity distribution service. The DSO should provide the data and propose the share of D-costs per each voltage level, and ERE evaluate if the method is appropriate and can be implemented by evaluating historic cost based on actual data when the cost can be divided for each voltage level. The regulator approves the average distribution tariff. If the average distribution tariff ceiling for any voltage level defined according to the historic data for one of the years in the tariff review cycle exceeds the average permitted distribution tariff ceiling set by ERE for each voltage level, DSO shall reduce the average distribution tariff in the next year for that voltage level so that the customer and the distribution system users in a defined voltage level receive a refund of the amount of excess revenues collected (over-repayment amount).
Bosnia and Herzegovina	D-tariff rates for different voltage levels are determined according to a cumulative principle, which means that the tariff for a customer that receives energy at a lower voltage level includes the associated part of distribution costs at higher voltage levels. The basis for the

70 Transmission tariff is calculated separately for system users (excluding "green" electrometallurgy enterprises) and for "green" electrometallurgy enterprises. In the tariff for "green" electrometallurgy enterprises, the costs related to RES PSO are deducted from the required revenue.

	determination of relative relationships between tariff rates by voltage levels is the total costs occurred up to the delivery point. Such costs include the distribution costs and losses in the distribution network. The transmission costs cascaded to the distribution level, ISO costs and ancillary services costs shall be recognised, unless the market arrangement for the procurement of electricity is specified differently. The allocated part of the revenue requirement for the voltage level i (RRi) is proportional to the ratio of distribution capacity at the associated voltage level and the total distribution capacities, taking into account the cumulative principle: RRi=RRd*(Ci/C) Where: Ci – value of distribution network capacities for voltage level i, C – value of total distribution capacities, RRd – amount of revenue requirement for the performance of regulated distribution activity, reduced for the value of losses on the distribution network. For tariff element billing demand on voltage level i, the average price is: pWi=RRWi/Wi RRi where: RRWi – allocated part of revenue requirement to voltage level i, Wi – total annual non-coincident peak load for all customers connected to voltage level i (kW). The value of losses on the distribution network is allocated to the voltage level and proportional to the ratio of losses at the voltage level and total losses: RRWi=CL*(WLi/WL) Where: CL – value of losses on the distribution network, WLi – distribution losses at the voltage level i (kWh), WL – total losses on distribution network (kWh). The consumption split per each distribution voltage level: 35kV - 401.48 GWh (4.03%); 10 kV - 2071.95 GWh (20.79%); 1 kV and below - 7494.62 GWh (75.18%).
Georgia	The percentages are determined based on the energy flows (e.g., if high voltage customers consume only 5% of the energy delivered through the high voltage network, then they only pay 5% percent of the cost allocated to high voltage network). Last time, shares were calculated based on forecasted volumes of 2021-2025 period and the resulting cascaded shares for the two (2) DSO's are approximately as follows: high voltage (1%-4%), medium voltage (21%-24%) low voltage (about 75%). D-cost categories that are already allocated to the customers instead of being allocated to the voltage levels, are not subject to cascading. For example, the billing costs - any shared billing costs are distributed according to the number of customers on various voltage levels, so they are already allocated to customers who should pay for those. The consumption split (in %) per each distribution voltage level: HV - 0.9 TWh; MV - 2.5 TWh; LV - 4.9 TWh

*Kosovo**	The cascading approach is used to reflect the cost of losses. Hence, the share of losses at 35kV is allocated to 35kV, 10kV and 0.4kV; losses at 10kV are allocated to 10kV and 0.4kV; and 0.4kV network losses are directly allocated to 0.4kV. The allocation method is used based on energy consumption of each voltage group. The share of the cost of losses according to 2024 data is as follows: at 35kV cost of losses are 0.1%, at 10kV - 3% and for 0.4kV - 96.9% The consumption split per each distribution voltage level: 35kV - 0.056TWh (1.09%); 10kV - 0.494TWh (9.42%) 0.4kV - 4.691 TWh (89.49%).
Moldova	Each lower voltage level is paying also the higher D-tariff, i.e. the consumers at medium voltage level are paying high voltage tariff plus medium voltage tariff. Subsequently, the low voltage consumers are paying medium (which already includes high voltage) + low voltage tariff. The consumption split per each distribution voltage level: HV – 1.3 %; MV – 27.1%; LV - 72 %
Montenegro	D-costs cascading is used for calculating use-of-network and losses charges. Use-of-network charges for a certain voltage level are calculated as a sum of ratio of the cost and capacity of that voltage level, and a capacity charge of a next higher voltage level. Losses charges are calculated as quotient of costs of voltage level and energy planned to be delivered. Costs of certain voltage level take into account cost of losses of all higher voltage levels. Detailed calculation formulas are located in tariff methodology. The shares of use-of-network costs for 35 kV consumers is 20%, for 10 kV is 30% and for 0,4 kV is 50%. The shares of costs for covering losses are: 1% for 35 kV, 8% for 10 kV and 91% for 0,4 kV voltage level. Consumption split per each distribution voltage level: 35 kV – 0.11 TWh, 10 kV – 2.21 TWh, 0,4 kV – 2.21 TWh
North Macedonia	DSO costs are attributed to the different voltage level in accordance to the different connection categories. Cascading is not only on the voltage level but also on the connection categories meaning the connection points in the network. Consumption split (in %) per each distribution voltage level: MV1: 5.85% MV2: 16.46% LV1.1: 1.19% LV1.2: 6.53% LV2: 69.97%
Serbia	Share of D-costs of a higher voltage level cascaded to a lower voltage level is calculated taking into account consumption of active and reactive energy, metered and contacted active power of users connected to the different voltage levels of D-network. The costs related to the low-voltage network are not included in the cascade and they are reimbursed only from users connected to the low/voltage network. Consumption split (in %) per each distribution voltage level Households -- 13,23 TWh (49,05%)

	35kV - 1,218 TWh (4,51%); 10 -20 kV - 6,876 TWh (25,49%) 0,4kV - 5,65 TWh (20,95%)
Ukraine	The electricity distribution tariff is calculated for consumers and operators of energy storage facilities based on two voltage classes: Class 1 – 27.5 kV and above, including those connected to power plant busbars; and Class 2 – below 27.5 kV. The tariff calculation for Class 2 voltage includes the tariff level of Class 1 voltage, adjusted by an economic coefficient that accounts for forecasted technical electricity losses at the Class 2 voltage level and the volume of generation delivered directly to Class 2 voltage.

Example of cascades applied for DSO costs in North Macedonia is presented in the table below.

Country case: cascades applied for DSO costs in North Macedonia

DSO costs are attributed to the different voltage levels in accordance with different connection categories. Cascading is not only on the voltage level but also on the connection categories, meaning the connection points in the network.

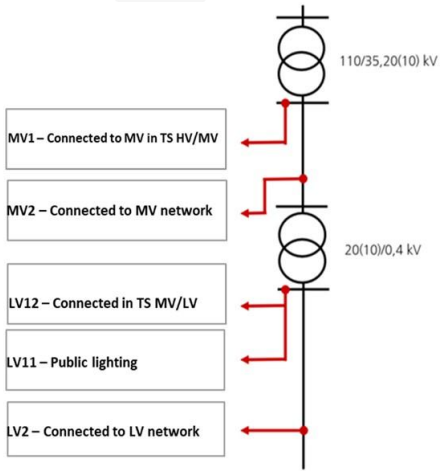
MV1 and MV2 are (35, 20,10kV) and LV12, LV11 and LV2 are on the 0,4kV.

MV1 - Connected to MV in TS HV/MVMV2 - Connected to the MV network

LV12 - Connected to TS MV/LV

LV 11 - Public lighting

LV2 - Connected to LV network



To support cost cascading, a relevant granularity of the distribution costs is required to allocate them to the network users. Where the Contracting Party has more than one DSO, relevant costs are determined for each DSO separately. The distribution costs are separated by voltage level and CAPEX/OPEX costs in most Contracting Parties. Cost categories other than CAPEX and OPEX are individualized in Georgia, Kosovo*, Moldova and Ukraine, and only in Montenegro distribution costs

are separated according to a Generation-Load split reflecting the relevant tariff design (e.g. application of injection charge). In Serbia, no cost granularity is reported, therefore distribution costs are recognised by the tariff methodology as a total amount.

Table 3.12- - Granularity required for the distribution costs

Granularity required for the transmission costs	Contracting Parties
No granularity. Distribution costs enter the tariff methodology as an overall amount.	RS
Distribution costs separated by DSO.	BA, GE, XK, MD
Distribution costs separated by voltage level.	AL, BA, GE, XK, MD, ME, MK, UA
Distribution costs separated according to a Generation-Load split.	ME
Distribution costs separated at least into CAPEX and OPEX.	BA, GE, XK, MD, MK
Cost categories other than CAPEX and OPEX need to be individualized.	GE, XK, MD

4. Injection and withdrawal network charges

4.1. General overview

This Chapter deals with the network charges levied on users connected to transmission and distribution system for the use of the network. This excludes connection and reactive energy charges which are elaborated in the next chapter.

The injection network charge refers to the charge paid by transmission/distribution network users for injecting into or for the possibility of injecting into the grid. The withdrawal network charge refers to the transmission/distribution network charges levied on the network users for withdrawing from the grid or the possibility to withdraw. In general, injection and withdrawal network charges aim to proportionally recover the costs of the transmission/distribution system operators for operating and building the network to meet the needs of network users. Also, these charges should reflect the impact of relevant activity (injection/withdrawal) on network operator costs.

Table 4.1 - Type of transmission and distribution network charges applied in the Contracting Parties

	Transmission		Distribution	
	Injection	*Withdrawal*	*Injection*	*Withdrawal*
AL	-	✓	-	✓
BA	✓	✓	-	✓
GE	-	✓	-	✓
XK	✓	✓	-	✓
MD	-	✓	-	✓
ME	✓	✓	✓	✓
MK	-	✓	-	✓

RS	-	✓	-	✓
UA	✓[71]	✓	✓[72]	✓

All Contracting Parties apply transmission and distribution withdrawal network tariffs.

None of the Contracting Parties reported introduction of injection charges compared to the status of 2022. At the same time, two (2) Contracting Parties reported intention to introduce injection charges. Thus, Georgian NRA considers the injection charge for transmission level, and Kosovo* plans to introduce a distribution injection charge in the future according to the approved in November 2024 Rule on Principles for Determining Distribution Use of System Charges and Connection Charges.

As of now, only Montenegro applies transmission and distribution injection charges. [73] [74] apply transmission injection charge only. At the same time in Ukraine, for storage facilities, including installed by active customers, the T-tariff, dispatch tariff and distribution tariff shall be paid for absolute value of difference between monthly injection and withdrawal from the grid. Thus, in case the monthly injection from storage exceeds the withdrawal from the grid, the relevant tariffs are applied to such volume.

North Macedonia used to apply distribution injection charge to the prosumers connected to the distribution system, but this charge was phased-out in July 2022. Ukraine applies so-called dispatch tariff not only for injection but also for withdrawal. However, the network users that withdraw from the grid are subject also to the tariff for transmission services, so in the following text the transmission withdrawal charge in case of Ukraine will refer to payment in relation to dispatch and transmission services tariff for withdrawal (gross or netted) and transmission injection charge will refer to the payment in relation to dispatch tariff for injection.

4.1.1. Reasons behind the introduction or non-introduction of injection charges

Injection charges in Bosnia and Herzegovina, Kosovo*, Montenegro and Ukraine were put in place either after consultations with system or network operator, consultations with concerned network users or after carrying out an impact assessment.

In Bosnia and Herzegovina and Montenegro, the transmission injection charge was introduced to reflect the situation, that part of the total transmission costs is caused by network users that inject into the grid, not only those withdrawing it. Bosnia and Herzegovina, as a net exporter of electricity, produces more electricity than it consumes, while Montenegro expanded its grid mainly for RES integration – about 50% of its 220 kV network serves large HPP connections. The allocation of TSO costs to producers reflects their impact on the system, within the limits of the G-charge cap (up to 2,5 €/MWh for Montenegro under the adapted Regulation 838/2010). In Ukraine, the producers,

71 Paid by producers of B, C, D type regardless of connection voltage

72 only for storages in case the monthly injection volume exceeds monthly withdrawal, applies to the netted volume

73 Kosovo* applies transmission (system operation) injection charges not only to producers connected to the transmission system but also to producers connected to the distribution system.

74 Dispatch tariff applies to all producers of type B, C, D including those connected to the distribution system.

among other users[75], pay the tariff for dispatching (operational and technological) services for injection into the grid, which is introduced to provide compensation for the TSO's reasonable costs for carrying out activities of dispatching of the UES of Ukraine (including ancillary services).

When it comes to D-injection charge, in Bosnia and Herzegovina in the past period, the purpose and development of the distribution network was exclusively related to the supply of electricity to customers. At this moment, distribution generation is not at such a level that its impact on the needs of development of the distribution network can be considered. The costs caused by distributed generation are still negligible. In order to stimulate investments in distributed generation (closer to customers), no D-tariffs or D-fees for generators were introduced.

In Montenegro the Energy Law prescribes that tariff methodologies shall contain principles of allocation of regulatory allowed revenue of the TSO and DSO to network users, while the definition of the network users refers also to the producers. The T-injection charge was introduced in 2014, while the distribution injection charge has been in place since 2020.

In Albania, Georgia, Moldova, North Macedonia and Serbia injection charges do not apply. In North Macedonia, a distribution injection charge was applied until July 2022, but it was removed due to the change of tariff system for the electricity distribution. On the other hand, the main reason for the non-introduction of transmission injection charge in North Macedonia are limitations of the legislative framework, i.e., the Energy Law (from 2018) explicitly states which network users pay the transmission network tariffs. Similarly, in Moldova, the legislative framework in place does not allow for the application of injection charge. In Albania, the non-application of injection charges serves as an incentive to increase investments in energy production, by ensuring a lower price of the generated energy, as well as by reducing the risk of competition disadvantages for the national producers. In Serbia, injection charge is not introduced mainly due to the fact that producers' costs resulting from the payment of injection into the system would be included in the price of electricity, which is finally paid by the customers. When it comes to pump-storage and storage facilities, the injection charge is not applied in Serbia due to their importance in maintaining the security of supply.

4.1.2. Allocation of the costs between injection and withdrawal charges

Allocation of the transmission/distribution costs between injection and withdrawal charges can be done by assigning specific costs to injection or withdrawal or by applying allocation keys to total costs, or a combination of these two. Keys value can be predetermined (fixed in advance) or they can be calculated depending on the impact of injection/withdrawal on a certain cost category.

This subsection will focus on allocation of costs in Contracting Parties, which apply injection charges, namely Bosnia and Herzegovina, Kosovo*, Montenegro and Ukraine at transmission level and on the allocation of costs in Montenegro at the distribution level.

75 Dispatch tariff applies to consumers, DSOs, small DSOs, storages and to all producers of type B, C, D (regardless the network of connection).

– *Transmission*

Bosnia and Herzegovina - up to 10% of the approved ISO (NOSBIH) revenue is allocated to the producers connected to the transmission network. There is no fixed formula for determining the percentage, but the regulator determines the value based on all planned quantities from the energy balance. The costs of Elektroprenos BiH (TRANSCO - Transmission Company) are not allocated to the producers.

Kosovo* - the TSO's OPEX is allocated to the producers connected to the transmission and distribution system by applying specific cost allocation keys on costs of system services and costs of market operation.[76] However, it has to be noted that the costs for recovering transmission losses and costs for ancillary services are not levied on the producers connected to the distribution system.

Montenegro - the TSO's OPEX and CAPEX are allocated to the producers by using keys that are calculated based on the assessed impact of producers on the TSO's costs. The key for OPEX (excluding costs for covering transmission losses) depends on the share of electricity production in the sum of the total electricity production and consumption. The costs of transmission losses are allocated to producers by assessing how much certain transmission elements are used by producers. On the other hand, the keys for allocating CAPEX to producers depend on the asset value of infrastructure used mostly by producers compared to the total asset value of TSO's infrastructure.

Ukraine - the TSO's costs for dispatching services are allocated to producers by taking into account their share (in terms of produced electricity) in the sum of total electricity produced and transmitted. All costs categories covered by dispatch tariff are allocated to producers (e.g. ancillary services, market operation costs, etc.). The other costs related to transmission of electricity (e.g. infrastructure costs, cost of losses) covered by T-tariff are not allocated to producers.

– *Distribution*

In Montenegro, the total costs of DSO (except for the costs of technical losses in the distribution system) are assigned to the producers by using keys whose value depends on the value of assets used by distribution producers solely. The costs of distribution losses allocated to producers depend on the assessed impact of distributed generation on technical losses.

4.1.3. Share of injection and withdrawal charges in cost recovery

– *Transmission*

Figure 4.1 shows the share of injection and withdrawal charges in transmission costs recovery in the Contracting Parties[77].

76 The details can be found on the following link:
https://kostt.com/Content/ViewFiles/TransmissionAndConnection/DT_KO_006_Methodology_on_Determination_of_System_Operator_Tariffs_SO_ver2_0_Eng.pdf

77 Ukraine did not provide information



Figure 4.1 - Share of transmission costs recovered by injection and withdrawal charges in 2024[78]

In most of the Contracting Parties, the transmission costs are recovered completely by withdrawal charges only. Compered to 2022, the share of injection charge has slightly increased in Bosnia and Herzegovina and Kosovo*, while decreased in Montenegro. Overall, the shares reflect the cost categories which are allocated between different users, thus, where all costs (including CAPEX) are redistributed between users injecting and withdrawing from the grid, the injection charge has sufficient role in cost recovery.

In Bosnia and Herzegovina, the share of the transmission costs (ISO BIH and Elektroprenos BIH) covered by injection charge was 1.04%, whereas 8.79% of total ISO's costs (11.66% of total transmission costs) were covered by injection tariff and the rest was covered by withdrawal tariff (91.21%). The costs of Elektroprenos BIH were completely covered by the withdrawal tariff (88.34% of total transmission costs).

In Kosovo*, 25% of the TSO's costs are recovered via injection charge. In Montenegro, for 2024 34% TSO's costs are allocated to producers, while the rest is allocated to consumers.

– *Distribution*

In Montenegro, at the distribution level, 0.16% of the DSO's costs are to recovered by the producers connected to the distribution system in 2024[79]. For the other Contracting Parties, total revenue of the DSOs is recovered by withdrawal charges.

4.2. Tariff basis

Injection and withdrawal network charges can be calculated by using different tariff basis, such as withdrawn/injected energy, peak load, contracted capacity, etc. or the value of the

78 It has to be noted that 2024 data for Montenegro refers to the determined values from the REGAGEN's decision.

79 Data for 2024 for Montenegro refers to the determined values from the REGAGEN's decision.

withdrawal/injection charge can be fixed regardless of the withdrawn energy or power - i.e., lump sum charges. The tariff design may also include the combination of above-mentioned metrics.

In the following part the subsection "Injection charges" is focused on tariff bases in Bosnia and Herzegovina, Kosovo*, Montenegro and Ukraine, while subsection "Withdrawal charges" deals with all Contracting Parties. Values of injection and withdrawal charges in 2024 are shown in Annex III.

4.2.1. Injection charges

– *Transmission*

In Bosnia and Herzegovina, Kosovo* and Ukraine, the transmission injection charge is energy-based, while in Montenegro it consists of two components: energy-based and power-based component.

The injection charges in Bosnia and Herzegovina and Kosovo* are calculated by dividing the part of the transmission costs allocated to producers by the forecasted electricity production. However, in Kosovo* the electricity production at the distribution level is taken into account for the calculation of injection charges (except for costs for recovering transmission losses and costs for ancillary services). In Ukraine, the dispatching tariff calculated by dividing the allowed costs for dispatching services by total electricity produced by producers of type B, C, and D, and transmitted (consumed) volumes.

In Montenegro, the energy-based tariff is calculated by dividing the OPEXp (the part of OPEX allocated to producers, including costs for covering losses) by the forecasted electricity production by producers connected to the transmission system. On the other hand, the power-based tariff is calculated by dividing the part of CAPEX allocated to producers by the sum of the *maximum* generation power of producers connected to the transmission system. It has to be noted that the energy-based component plays pivotal role in the recovery of TSO's costs allocated to producers. For 2024, out of the total costs that are allocated to transmission producers, 84.20% is to be recovered by energy based-tariff, while 15,80% is to be recovered by a power-based tariff.

The main objectives behind the design of transmission injection charges are summarized in the table below. Bosnia and Herzegovina, Kosovo* and Montenegro aimed to ensure a fair contribution from all generators to revenue recovery. In Montenegro and Kosovo*, cost-reflectiveness and recovery of transmission costs were key priorities, while Bosnia and Herzegovina, focused on aligning its charges with those of neighboring countries. In Ukraine, the main goal for the design of dispatching tariff was the recovery of TSO costs for power system operation, especially considering that substantial part of these costs represents a budget for ancillary services.

Table 4.2 - Primary and secondary goals for the determination of the design of injection charges

	Primary goals	Secondary goals
Bosnia and Herzegovina	ensuring level playing field of injection charges with other countries, providing an equitable	reflecting system use of current transmission assets

	(fair) allocation of transmission revenues across generation facilities	
Kosovo*	recovery of transmission costs, reflecting system use of current transmission assets, and providing an equitable (fair) allocation of transmission revenues across generation facilities	-
Montenegro	recovery of transmission costs, reflecting system use of current transmission assets, providing an equitable (fair) allocation of transmission revenues across generation facilities	price signal to postpone new network reinforcements, price signal to postpone the reinforcement of the interconnection capacity, price signal to avoid congestion in the transmission grid, ensuring level playing field of Injection charges with other countries
Ukraine	recovery of TSO costs for power system operation (dispatch), mainly ancillary services	-

– *Distribution*

The distribution injection charge in Montenegro is combination of energy-based and power-based for all users. The injection charge is calculated by dividing part of the DSO's costs allocated to producers by the total forecasted production and connection capacity of the producers connected to the distribution system. The design and the calculation of the distribution injection charges are different to the one applied at the transmission level, mainly due to the specificities of the use of the distribution system by the producers and consumers. Electricity injected in the distribution system is dominantly consumed at the D-level. This is not the case in the transmission system which is used by producers for also exporting electricity. Thus, the share of covering costs is much higher for producers connected to the transmission system.

So, when defining structure of injection charges, Montenegro was mainly led by incentivising the connection of generation that contributes to a more efficient system use, recovery of the distribution costs, reflecting system use of current distribution assets and providing an equitable (fair) allocation of distribution revenues across generation facilities.

4.2.2. Withdrawal charges

– *Transmission*

Five (5) Contracting Parties (Bosnia and Herzegovina, Kosovo*, Montenegro, North Macedonia and Serbia) use both, energy and power-based transmission tariffs for withdrawal, while four (4) Contracting Parties (Albania, Georgia, Moldova and Ukraine) apply solely energy-based tariffs. None of the Contracting Parties applies the lump-sum element in the transmission tariff.

Table 4.3 – T-tariff basis in the Energy Community Contracting Parties

	AL	BA	GE	XK	MD	ME	MK	RS	UA
Energy-based	✓	✓	✓	✓	✓	✓	✓	✓	✓
Power-based	-	✓	-	✓	-	✓	✓	✓	-
Lump sum	-	-	-	-	-	-	-	-	-

Energy-based withdrawal tariffs are most frequently calculated by using gross withdrawn energy (Albania, Bosnia and Herzegovina, Kosovo*, Montenegro, North Macedonia, Serbia and Ukraine[80]), while Georgia and Moldova apply net energy. In Ukraine net energy approach is applied in case of storages.

Among Contracting Parties that apply power-based tariffs, metered capacity is most commonly used for the calculation of withdrawal tariffs (Bosnia and Herzegovina, Kosovo*, Montenegro, and North Macedonia). In Serbia metered power and contracted power are considered.

Where two-component transmission charge applies, the allocation of the transmission costs to be recovered by energy- or power-based tariffs is done either by applying keys to the total transmission costs or by assigning different cost categories to power and energy component (e.g., variable and fixed costs).

Bosnia and Herzegovina - the key is determined on the basis of a share of the base load in an annual load diagram for the previous year. Please see the relevant country case.

Calculation of T-withdrawal charge (energy and power-based components) in Bosnia and Herzegovina

Part of the transmission tariff pertaining to energy pLE which represents the ratio of the revenue requirement of the component for energy k*RRL and energy withdrawn by customers WC is calculated as follows:

$$pLE = k*RRL / WC$$

where:

[80] except storages

RRL – part of the revenue requirement pertaining to network fees paid by customers;

WC – active electric energy withdrawn by customers;

k – the ratio of the revenue requirement of the component for energy and total revenue requirement pertaining to customers.

Part of the transmission tariff pertaining to capacity pLC, which represents the ratio of the revenue requirement of the component for capacity (1– k)* RRL and peak load PC measured at customers is calculated as follows:

$$pLC = (1 - k)^* RRL / PC$$

where:

PC – peak load measured at customers, which represents an annual summation of all monthly maximum capacities measured at customers.

The ratio of the energy component and the capacity component shall be determined on the basis of a share of constant energy in an annual load diagram for the previous year. As an initial value, the share of capacity element shall be determined at 35%.

In Kosovo*, the TSO's costs are allocated to different activities of the TSO: transmission system operation (CAPEX – infrastructure costs), system operation (OPEX - system service costs) and market operation. Transmission system operation costs are recovered via a power-based tariff, while system and market operation costs are recovered via an energy-based tariff. Network users in Kosovo*, when the power-based element is applied, can access detailed information about their capacity usage.

In Montenegro, costs of technical network losses are recovered via an energy-based tariff, while the remaining part of TSO's CAPEX (that is not allocated to producers) is recovered via a power-based charge that is based on *metered (actual) capacity*. In Montenegro, specific allocation keys are applied to distribute the TSO's costs between injection and withdrawal charges. These keys vary depending on the category of the TSO's costs. Operating expenditures (OPEX), excluding the costs of transmission losses, are allocated based on a ratio determined by the forecasted volumes of electricity production and consumption. Network users, when the power-based element is applied, can access detailed information about their capacity usage.

In North Macedonia, power-based tariff mostly covers the fixed costs like OPEX, CAPEX, while the remaining costs are recovered via the energy-based component. The power-based component is applied to *the metered (actual) capacity at a specified time (e.g. system peak periods)*. Network users, when the power-based element is applied, can access detailed information about their measured capacity usage.

In Serbia, variable costs and a smaller part of fixed costs are allocated to energy, while the remaining larger part of fixed costs is allocated to power. There are different power-based tariff rates, which apply to the metered (actual) capacity. The lower rate applies if the actual capacity of the network

user is within the contracted capacity. In case the actual capacity of network users exceeds their contracted capacity, they pay an excess (higher) capacity tariff. Customers have access to detailed information regarding their capacity usage.
The share of energy-based and power-based T-tariff components in cost recovery in 2024 is presented in the following Figure 4.2.

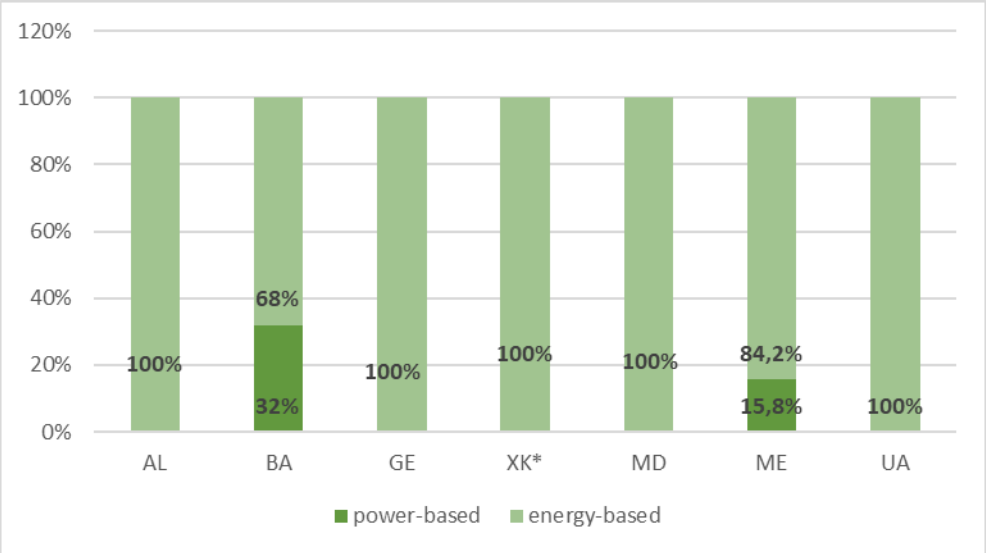


Figure 4.2 - Share of transmission withdrawal costs recovered by energy- and power-based charges in 2024[81]

Main goals for designing the transmission withdrawal charges in Contracting Parties is presented in Annex IV.

– *Distribution*

At the distribution level, the diversity of application of different tariff basis in Contracting Parties is either the same as at the transmission level or higher. In Kosovo*, while having the energy and power-based components for T-tariff, at the distribution level only the energy-based tariff is applied to network users.

Compared to 2022, North Macedonia made amendments to the D-tariff methodology, introducing a new lump-sum element of the distribution fee for access to the grid.

Thus, most of the Contracting Parties (Albania, Georgia, Kosovo*, Moldova and Ukraine) still apply only energy-based distribution withdrawal tariffs. Serbia applies energy- and power-based components. And, Bosnia and Herzegovina, Montenegro and North Macedonia apply energy-, power-based and lump sum tariffs.

Table 4.4 - D-tariff basis in the Energy Community Contracting Parties

	AL	BA	GE	XK	MD	ME	MK	RS	UA

81 It has to be noted that 2024 data for Montenegro refers to the determined values from the REGAGEN's decision.

Energy-based	✓	✓	✓	✓	✓	✓	✓	✓	✓
Power-based	-	✓	-	-	-	✓	✓	✓	-
Lump sum	-	✓	-	-	-	✓	✓	-	-

In Bosnia and Herzegovina, fixed distribution costs are allocated to the power component, and variable costs to the energy component, with some DSOs also applying a fixed lump-sum charge per customer. The contracted capacity is limited by a fuse/limiter so that the customer cannot exceed the contracted capacity. There are no consequences if a network user underuses their contracted capacity, other than paying for the contracted capacity. At the same time, customers do not have access to detailed information regarding their capacity usage.

In Montenegro, MV consumers and LV consumers with metered power pay both power and energy-based tariffs - only network losses are recovered the energy component. For LV consumers without metered power, part of OPEX (material costs and costs of services) is recovered via fixed tariff, while the rest is covered by the energy charge. The

In North Macedonia some consumer categories pay only energy-based tariffs, while others pay energy-based, power-based and/or lump-sum. The power-based component applies compared to the metered (actual) capacity at a specified time (e.g., system peak periods). If actual capacity exceeds contracted, customers should adjust their actual situation in eight (8) days and request changes of the contract with different contracted maximum power (higher). If they exceed their contracted power and do not ask for changes of the contract they could be disconnected.

In Serbia the combination of energy-based and power-based D-tariff component applies for all users. In case the user exceeds the contracted capacity, it pays an excess capacity tariff.

Figure 4.3 shows the shares of different tariff basis in DSOs' revenue recovery in the Contracting Parties in 2024. Even though power-based and lump sum tariffs are applied in some Contracting Parties, the major part of the DSOs' costs is still recovered via energy-based tariffs. Compared to 2022, there is a slight increase in share of power-based components in Montenegro and North Macedonia. In North Macedonia, the share of energy-based component decreased by around 20% (from 84,54% reported for 2022), mainly resulting from the redistribution of relevant costs to the newly introduced lump-sum component.

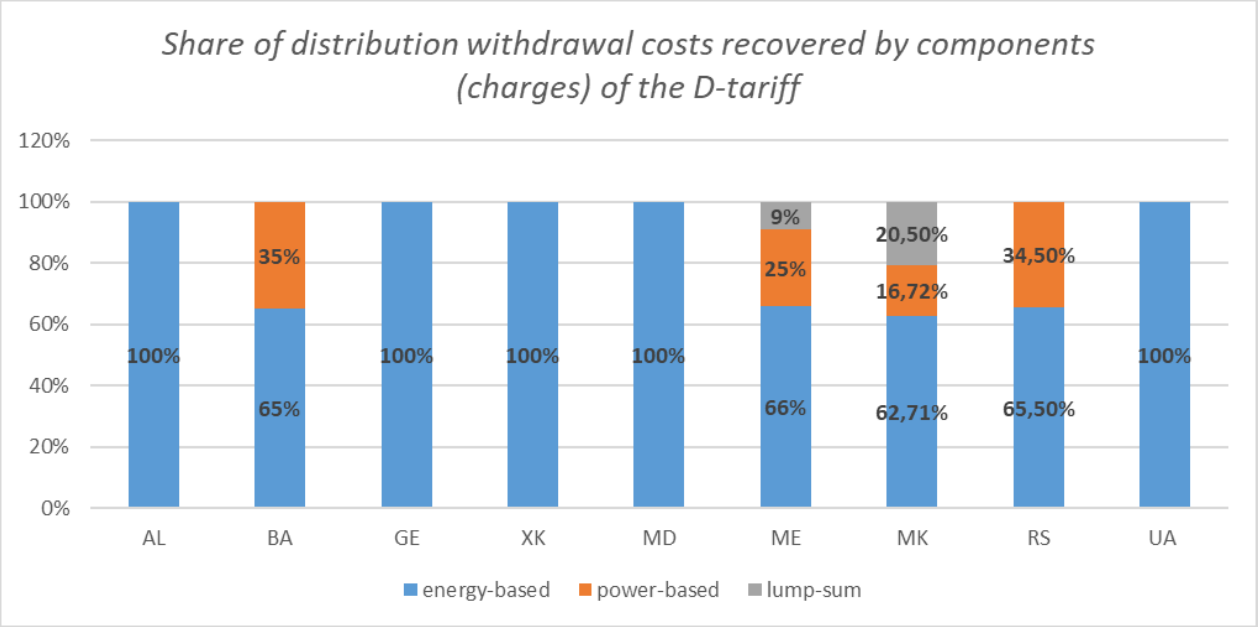


Figure 4.3 - Share of distribution withdrawal costs recovered by energy- and power-based charges in 2024[82]

In most of the Contracting Parties, the tariff value varies depending on the voltage level of the connection (AL, BA, GE, XK*, ME, MK, RS and UA[83]). In Bosnia and Herzegovina, Montenegro and Serbia, tariff value depends also on the time of use (high and low tariff). The values of the distribution withdrawal tariffs in 2024 are shown in Annex III, while the main goals for designing the distribution withdrawal charges in the Contracting Parties are presented in Annex IV (Table A4.2).

4.3. G-charge

Annex B of Regulation (EU) 838/2010, as adapted and adopted by Decisions 2013/01/PHLG-EnC and 2021/01/PHLG-EnC, sets the maximum value(s) of the annual average transmission charges paid by producers in the Contracting Parties. In the context of this provision, the annual average transmission charge (G-charge) does not include charges paid for the connection or the upgrade of connection, charges for ancillary services, and specific system loss charges levied on producers. Accordingly, the G-charge should not be higher than 0.5 €/MWh in all Contracting Parties, except for Montenegro, where the G-charge cap is 2.5 €/MWh.

Figure 4.4 shows the level of G-charge paid by producers in 2023 and 2024 in Bosnia and Herzegovina and Montenegro[84] [85]. It can be concluded that the G-charge levels in Bosnia and Herzegovina and Montenegro are within the ranges prescribed by adapted Regulation (EU) 838/2010. When it comes to the share of the revenue generated by G-charge from total transmission revenues, in Bosnia and Herzegovina, it constitutes around 1%, while in Montenegro,

82 The ration for Bosnia and Herzegovina is estimated to be close to 65%:35% energy-based/power-based. The fixed amount charged is practically negligible in this statistic.

83 There is first and second voltage class in Ukraine.

84 It has to be noted that data for 2024 for Montenegro refers to the determined values from the REGAGEN's decision.

85 For Kosovo*, annual G-charge level could not be obtained from the injection charge which includes costs of losses and costs of ancillary services.

G-charge covered around 30,35% % (in 2023) and 26,93% (2024) of the transmission revenue (excluding the costs of ancillary services and the cost of losses)[86].

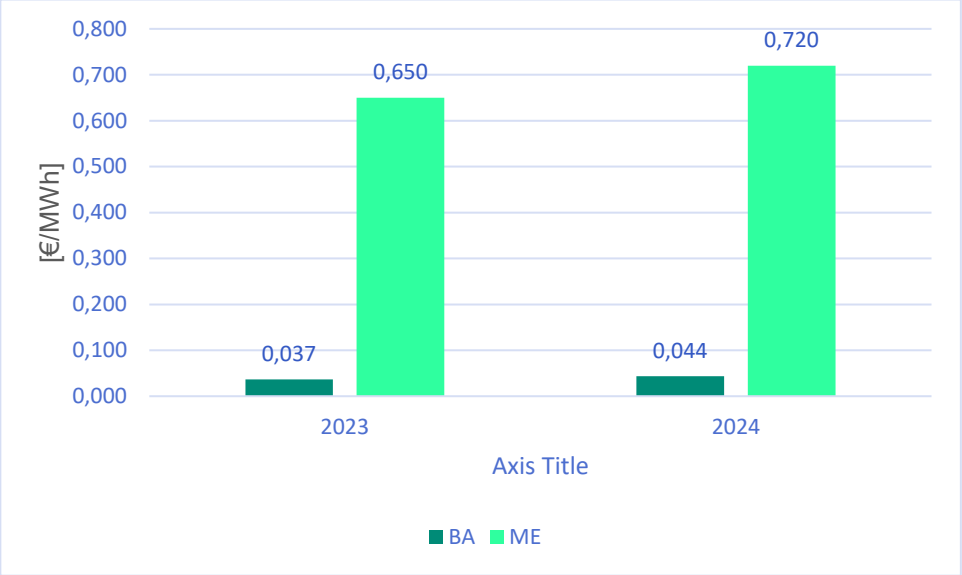


Figure 4.4 - Level of G-charge in Bosnia and Herzegovina and Montenegro in 2023-2024

Neither Bosnia and Herzegovina nor Montenegro faced difficulties during tariff setting due to the ceiling prescribed in the adapted Regulation (EU) 838/2010. In particular, Bosnia and Herzegovina has introduced the maximum level of the revenue allocated to producers so that this ceiling cannot be exceeded. On the other hand, methodology for cost allocation to producers applied in Montenegro did not lead to exceeding this limit so far.

4.4. Groups of network users subject to tariffs

In general, network users subject to tariffs can be categorised into three main groups:

- network users that only inject into the grid[87] (RES and non-RES producers),
- network users that only withdraw from the grid (consumers, unidirectional EV charging stations, power to gas (P2G), etc.), and
- network users that both inject into and withdraw from the grid (prosumers, pumped-hydro energy storages (PHES), battery storages, bidirectional EV charging stations, etc.).

The categories of network users subject to transmission and distribution tariffs are shown in the following subchapters.

86 The data provided for 2023 and 2024 refer to the determined (projected) values from REGAGEN's decision. The realised values will be officially determined during the next process of determination of T-tariffs for the next regulatory period.

87 Excluding supply of auxiliary equipment of generators.

4.4.1. Transmission

Table 4.5 shows the groups of network users that are directly or indirectly subject to transmission tariffs, i.e., network users that participate in recovering transmission costs.

Table 4.5 - Categories of network users subject to injection and withdrawal charges for recovering transmission costs

	AL	BA	GE	XK*	MD	ME	MK	RS	UA
T-connected RES producers	-	I	-	I	-	I	-	-	I
T-connected non-RES producers	-	I	-	I	-	I	-	-	I
T-connected consumers	W	W	W	W	W	W	W	W	W
DSOs whose systems are connected to the transmission system	W	W	-	W	W	W	W	W	W
CDSOs whose systems are connected to the transmission system	W	n/a	n/a	n/a	W	W	W	W	W
T-connected non-storage network users that both inject into and withdraw from the grid (e.g., prosumers)	W	n/a	W	n/a	n/a	n/a	I, W	W	W
T-connected storage network users that both inject into and withdraw from the grid (e.g., PHES, battery storage, etc.)	n/a	I	n/a	n/a	n/a	n/a	W	-	W
T-connected producers: Auxiliary services of generators[88]	-	W	W	n/a	-	W	W	W	W
D-connected RES producers	-	-	-	I	-	I	-	-	I[89]
D-connected non-RES producers	-	-	-	I	-	-	-	-	I[55]
D-connected consumers	W	W_i	W	W_i	W	I	W_i	-	W
D-connected producers: Auxiliary services of generators	-	W_i	W	n/a	-	W_i	n/a	-	W
CDSOs whose systems are connected to the distribution system	W	n/a	n/a	n/a	W_i	W_i	n/a	-	W

[88] An equipment at the electric plant site that provides power for the operation of the electric plant, when the plant is not generating (self-consumption of producers).
[89] Producers of type B, C, D connected to the distribution network.

D-connected non-storage network users that both inject into and withdraw from the grid (e.g., prosumers)	*W*	*n/a*	*W*	*n/a*	W_i	W_i	*n/a*	-	*W*
D-connected storage network users that both inject into and withdraw from the grid (e.g., PHES, battery storage, etc.)	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*W*	-	-

Legend:

I	*Subject to injection charge*	*W*	*Subject to withdrawal charge*	-	*Not subject to any network charge*
n/a	*Not applicable*	W_i	*Subject to withdrawal charge for T-costs that is integrated into distribution tariff*		

In all Contracting Parties, the treatment of RES and non-RES producers is the same – either both categories pay the transmission injection charge (Bosnia and Herzegovina, Kosovo*, Montenegro and Ukraine), or none of them. Only in Kosovo* and Ukraine, the producers connected to the distribution system cover transmission costs, i.e., pay transmission injection charge. In six Contracting Parties, producers connected to the transmission system pay withdrawal charges for supplying auxiliary equipment needed for the operation of the power plant.

On the other hand, the network users, who both inject and withdraw from the grid, usually pay the charge only for withdrawing. However, in Bosnia and Herzegovina, PHES pays the system services charge for electricity withdrawed from the transmission system and the injection charge. In Ukraine, battery storages are subject to withdrawal tariff for netted withdrawn/injected energy. At the same time, in most of the Contracting Parties, there is no battery storage in place. In five (5) Contracting Parties, the T-tariff system does not recognise storages (e.g. battery storages) as a separate type of grid users and does not apply network tariffs to them.

No storage capacities are in place yet in Moldova. With the new law on electricity that transposes the EIP, there will be new activities like electricity storage. In this regard, NRA will amend its methodologies in order to ensure that this type of activity is charged for the grid usage as it should be. In Montenegro, until only recently, the legal framework did not allow for prosumers to be connected to the transmission system, but only to the distribution system. The current T-tariff methodology does not deal with the prosumers and storages as the potential transmission system users. However, due to the changes introduced by the Law of cross-border exchanges of electricity and natural gas, T-tariff methodology will be revised to take into account also this type of users.

In many Contracting Parties, the consumers and prosumers connected to the distribution system are either directly or indirectly subject to the transmission withdrawal charge.

Regarding the treatment of new categories of network users, T-connected EV charging stations in Georgia and Moldova are subject to the same tariff as other network users. In other Contracting Parties (AL, BA, XK*, ME, MK, RS and UA) there are no public EV charging stations. In all Contracting Parties there are no power to gas facilities connected to the transmission system.

4.4.2. Distribution

The categories of network users subject to distribution injection and withdrawal charges are presented in the next Table.

Table 4.6 - Categories of network users subject to injection and withdrawal charges for recovering distribution costs

	AL	BA	GE	XK*	MD	ME	MK	RS	UA
D-connected RES producers	-	-	-	-	-	I	-	-	-
D-connected non-RES producers	-	-	-	-	-	I	-	-	-
D-connected producers: Auxiliary services of generators[90]	-	W	W	n/a	W	W	W	-	W
D-connected consumers	W	W	?	W	W	W	W	W	W
CDSOs whose systems are connected to the distribution system	W	n/a	n/a	n/a	W	W	n/a	W	W
D-connected non-storage network users that both inject into and withdraw from the grid (e.g., prosumers)	W	W	W	-	-	W	W	W	W
D-connected storage network users that both inject into and withdraw from the grid (e.g. PHES, battery storage, etc.)	-	n/a	n/a	-	n/a	n/a	W	-	W

Legend:

I *Subject to injection charge*

W *Subject to withdrawal charge*

\- *Not subject to any network charge*

n/a *Not applicable*

Montenegro is the only Contracting Party in which RES and non-RES producers are subject to injection charge for recovering distribution costs). In seven Contracting Parties (BA, GE, MD, ME, MK, RS and UA), producers pay withdrawal charges for supplying auxiliary equipment needed for the operation of the power plant.

When it comes to charges applied to prosumers, in all Contracting Parties prosumers are subject to charges for withdrawal from the grid. In Bosnia and Herzegovina, Kosovo*, North Macedonia and Serbia, the withdrawal charge is applied to the total withdrawn energy without taking into account the injected energy. On the other hand, Moldova, Montenegro and Georgia apply withdrawal charge

[90] An equipment at the electric plant site that provides power for the operation of the electric plant, when the plant is not generating (self-consumption of producers).

to net withdrawn energy by prosumers, i.e., the difference between withdrawn and injected energy. In Albania and in Ukraine, the net billing principle applies. In case the active customer in Ukraine installs energy storage, the network tariff is paid separately for the consumed (withdrawn) volume of customer installations, and for net injected/withdrawn energy by storage.

EV charging stations are already connected to the distribution system in all Contracting Parties. For grid-to-vehicle charging, Albania, Bosnia and Herzegovina, Kosovo*, Moldova, Montenegro, North Macedonia, Serbia and Ukraine apply the same withdrawal charge as for any other network user.

5. Connection charges

In general, in order to be connected to the transmission or distribution grid, new users are subject to a charge that aims to cover the total or part of the TSO/DSO costs related to the connection to the grid, i.e., to a connection charge. Depending on the level of the coverage of the connection costs, the connection charge can be shallow, deep, or mixed (so-called "shallowish"). In this regard, a shallow connection charge covers only the costs needed for the physical connection to the transmission/distribution grid, not the upstream costs of needed grid reinforcements. In contrast, a deep connection charge covers not only the costs of the infrastructure for the connection to the grid but also all upstream costs associated with the connection. Finally, "shallowish" network charge is similar to the "deep" connection charge, however, it covers only part of the upstream costs associated with the connection.

5.1. Transmission

5.1.1 Recovery of connection costs

Approached to recovery of connection costs in the Contracting Parties[91] are as follows:

Albania: The transmission tariff shall cover the following costs: a) Ownership, construction, operation, and maintenance of transmission assets, including lines, cables, substations, dispatch centers, and related facilities. b) Ancillary services, including payments to neighboring TSOs for emergency electricity, reserves, and frequency or voltage regulation. c) Reactive power compensation, allocated to the reactive power charge. d) Market operation costs, including those arising from the legal separation of the MO from the TSO and subsequent monthly payments. All revenue resources of TSO are paid by the transmission system users.

Bosnia and Herzegovina - connection costs are recovered through a connection charge paid by the user.

Kosovo* - Connections in the transmission network are, in principle, deep connections. All costs related to network extensions are covered by the applicant/customer.

Moldova - All connection costs are recovered through a charge paid by the system user who requests the connection, connection costs are not recovered through the tariff.

Montenegro - Each new user is required to pay a connection charge to the TSO, calculated by multiplying the unit connection charge (applicable to the respective voltage level) by the requested connection capacity. The unit charge is identical for all new users connecting at the same voltage level. If additional infrastructure must be built for a specific user's connection, the portion of that infrastructure serving multiple network users shall be constructed by the TSO or by the consumer and subsequently acquired by the TSO. In accordance with the Energy Law, revenues received by

[91] Georgia did not provide information

the TSO from connection charges are deducted from its allowed regulatory revenue, thereby reducing transmission tariffs. Consequently, connection costs are recovered through both the connection charge and the transmission tariff.

North Macedonia - For connection to the transmission system, the costs are divided into three categories: the cost of preparing the analysis, the cost of preparing the connection study, and the actual construction costs of the connection. All these costs are borne by the user and are not recovered by the tariff.

Serbia - Connection costs are recovered through a connection charge paid by the user whose facility is connected to the T-network.

Ukraine - The costs of establishing the technical capability to transmit or receive the corresponding capacity to the transmission system's electrical networks, up to the connection point of the customer's installation, are covered by the customer through the connection fee.

5.1.2. Connection charges setting principles

In most Contracting Parties, the main principles for the calculation of the connection charge are set by the primary legislation and/or the regulator's act (BA, GE, XK*, MD, RS and UA), while in Albania and Montenegro, the methodology for the calculation of the connection charge is drafted by TSO and approved by the regulator. Similarly, in North Macedonia, connection methodology is part of the transmission/distribution network codes that are prepared by the relevant network operator and approved by the ERC.

Table 5.1 shows the types of transmission connection charges applied in the Contracting Parties. Shallow connection charges are applied in Albania, Georgia, Moldova and Serbia, deep in Bosnia and Herzegovina, Kosovo*, North Macedonia and Ukraine, while „shallowish" connection charge is applied only in Montenegro.

Table 5.1 - Type of T-connection charges applied in Energy Community Contracting Parties

	AL	BA	GE	XK*	MD	ME	MK	RS	UA
Shallow	✓	-	✓	-	✓	-	-	✓	-
Deep	-	✓	-	✓	-	-	✓	-	✓
Shallowish	-	-	-	-	-	✓	-	-	-

In Albania, a unit connection charge per capacity applies (kVA) to the required connection capacity. This charge aims to cover costs related to project technical control and assessment, construction, supervision, testing, and commissioning of the connection/modification. Georgia applies the lump sum connection charge whose value depends on the type of connection to the grid, i.e., if the network user is connecting to the TSO's substation or to the transmission line.

In Bosnia and Herzegovina, the connection charge consists of two components: a fixed and a variable component. The fixed component aims to cover the costs of upstream interventions in the

network and to provide the conditions for connection. It is calculated by multiplying the unit connection charge per capacity to the approved connection capacity. On the other hand, the variable component aims to cover the associated specific connection costs. For the connection to the 110 kV or higher voltage level, these specific costs include:

- the costs of preparation (including the possible purchase of land) and construction of a high voltage connection line, from the point in the network which is defined by the Project Analysis to the metering device, as well as the equipment of transmission line feeder bay with accompanying busbars at the facilities of the Transmission Company, in line with the technical solution specified in the Project Analysis for specific user;
- the costs of the instalment of the measurement and protection system
- the costs for the instalment of devices required for the system operation and control after connecting the user's facilities to the network.

The payment is based on the calculated (estimated) variable costs, unless the difference between these costs and the real ones is higher than ±5%. In this case, the payment is done on the basis of the actual costs.

In terms of deep connection, if a new user connects via the same line or uses infrastructure for which an existing user has already paid a connection fee, the existing user is entitled to partial compensation, to be determined by a separate agreement. If no agreement is reached, the Transmission Company will decide the amount upon request. For each subsequent connection, all previous users who paid the fee or received compensation are entitled to compensation. This right is valid for ten years from the connection date.

In Kosovo*, the connection charge for each new user is calculated as the combination of the fix reserve capacity fee + actual construction cost. As it is deep connection all costs related to network extensions are covered by the applicant/customer.

In Moldova, new network users are obliged to pay a lump sum connection charge whose value depends on the individual actual connection costs. According to the Law through the issued connection notice, the applicant may be obliged to bear only the construction costs of a connection installation that corresponds to the requested electrical power.

In Montenegro, the "shallowish" connection charge applies which reflects the standard average costs that the TSO will have for the connection of new network users. The unit charge is the same for all new users that want to connect to a specific voltage level. When it comes to the infrastructure that needs to be built for the connection of the specific user, the part of the infrastructure that will be used by more than one network user can be built by the TSO or by a consumer and then purchased by the TSO. In line with the Energy Law, TSO's revenues arising from the collection of connection charges are deducted from the regulatory allowed revenue of TSO, hence, it leads to the reduction of T-tariffs.

In North Macedonia, for the connection to the transmission system the user should pay for the real connection construction and costs for creation of technical condition in the existing network. If the creation of technical conditions for upgrading the existing network are part of the Transmission Network Development Plan approved by ERC, then these costs are beared by the TSO.

In Serbia, the connection charge is set on the basis of the actual individual costs associated with the connection of the new users to the transmission grid. The part of system costs incurred by connecting a facility is set for the customer, whereas no charge for these costs for connecting a producers' facility.

In Ukraine, there are two types of connections: standard and non-standard. The connection charge for a standard connection is fixed and determined by the Regulator. The value of the connection charge for non-standard is individual for each new user and it depends on the estimated costs defined in the project documentation. Non-standard connection charge consists of two components: a capacity component that represents the product of the unit rate for the non-standard connection and connection capacity, and the component for the construction of the linear part of the connection. In case of connection to transmission grid, the non-standard connection applies. The fee for connection to the electrical networks of the TSO is determined according to the cost estimate, which is an integral part of the respective design documentation. That is, the connection fee to the transmission system is individual for each customer and depends on the technical parameters of the connection.

In Bosnia and Herzegovina and Montenegro, there is a mechanism to „compensate" the user that paid deep/"shallowish" connection charge in case the concerned connection infrastructure (or part of it) is going to be used by new users. In particular, in Bosnia and Herzegovina, the existing user that paid the variable connection charge for the infrastructure that is going to be used partially or fully by the new user is entitled to financial compensation by that new user for a part of the variable connection charge in line with a separate mutual agreement. In case the existing and new users cannot reach an agreement on the value of compensation, it will be determined by the Transmission Company upon the request of one of the users. It is important to note that all connected users who have paid the connection charge and/or compensation are entitled to compensation when the next new user that wants to use the connection infrastructure appears. In Montenegro, if part of the connection infrastructure built and owned by the user (internal infrastructure for connection) becomes necessary for the connection of other users, TSO is obliged to purchase it.

5.1.3. Variation of the level of the transmission connection charge

The connection charges in the Contracting Parties vary depending on the distance of the connection point from the existing grid (BA, XK, MD, MK and RS), voltage level (GE, MD, ME and RS), and/or the geographic location (RS).

5.1.4. Charging for the connection of producers, RES producers and battery storage facilities

In some Contracting Parties, there are some differences in connection charges for different network users.

In Albania the components of connection charge: tariff for covering costs related to project technical control and assessment, construction supervision, testing, and commissioning of the connection/modification will be variable, depending on the maximum capacity by demand required by the user. It will have a value of 50 Leke/kVA, but in all cases, it will not exceed the maximum limit of 2,500,000.00 Leke

In Kosovo*, some differences between producers and consumers (demand) are related to the procedural timeline between demand and generation, while others are due to differences in engineering costs. In Georgia different connection charges apply to prosumers and consumers.

In many Contracting Parties, the RES producers are subject to the same connection charging method as other transmission users or producers. Only in Bosnia and Herzegovina, RES producers have different treatment compared to other transmission users as an incentive for the construction of generation facilities using RES. In particular, RES producers pay only 50% of the fixed connection charge. This approach applies also to HPPs with the installed capacity of up to 10 MW.

Apart from Bosnia and Herzegovina, Serbia applies a different charging approach for the connection of all producers (not only RES) compared to the connection of customers. In accordance with the connection methodology, the customer is charged with part of the system costs arising from connecting a facility, whereas there is no charge for these costs for connecting a producer's facility.

On the other hand, in Ukraine, the cost of connecting energy storage installations are defined as follows: in the case of a standard connection (up to 50 kW and up to 300 m in a straight line from the nearest point in the DSO's existing in-service electrical networks) — the product of the requested connection capacity and the standard connection fee rate.

In the case of a non-standard connection, as the sum of:

- the capacity-connection fee component (taking into account the capacity being created), determined as the product of the requested connection capacity and the average between the fee rate for non-standard connection of power installations intended for generation and the fee rate for non-standard connection of power installations intended for consumption;
- the component of the fee for constructing the line section of the connection networks:
    - for a "turnkey" service — as the product of the fee rate for the line section of the connection and the length of that line section (distance in a straight line from the nearest point(s) in the existing in-service electrical networks);

ii. for a service where the line section is designed by the customer — according to the cost estimate, which is an integral part of the relevant design documentation developed by the customer and agreed with the distribution system operator (DSO).

In Moldova and North Macedonia, there is no differences among system users for calculation of the connection charges.

5.2. Distribution

5.2.1 Connection charges setting principles

Similar to transmission connection charges, in the Contracting Parties, the main principles for the calculation of the distribution connection charge are set either by the primary legislation and/or the regulator's act (BA, GE, XK*, MD, MK, RS and UA) or by primary law and the DSO's methodology approved by the regulator.

Table 5.2 shows the types of distribution connection charges applied in the Contracting Parties. Most of CPs (Albania, Georgia, Moldova, North Macedonia, Serbia and Ukraine) apply shallow connection charges, Bosnia and Herzegovina, Georgia, Kosovo* and Ukraine apply deep charges, while Georgia and Montenegro apply „shallowish" charge for the connection to the distribution system. Georgia and Ukraine apply different types of charges depending on the type of the connection.

Table 5.2 - Type of D-connection charges applied in Energy Community Contracting Parties

	AL	BA	GE[92]	XK*	MD	ME	MK	RS	UA[93]
Shallow	✓	-	✓	-	✓	-	✓	✓	✓
Deep	-	✓	✓	✓	-	-	-	-	✓
Shallowish	-	-	✓	-	-	✓	-	-	-

In Albania, the connection charge consists of four components:

1) the tariff for carrying out the study and the evaluation of project approvals,
2) the tariff for distance,
3) the power (capacity) tariff, and
4) the service tariff for the realization of the new connection and the metering.

Different tariffs are applied for each voltage level (MV, LV), depending on the distance and power between producers, households and other users.

In Bosnia and Herzegovina, connections to the distribution system can be standard or non-standard. Standard connections are charged via two components: a fixed fee for constructing the connection and a capacity-based fee (unit price × connection capacity). Non-standard connections include three

92 For demand shallow connection charge applies, while small power plants pay either shallowish or deep connection charge

93 For standard connection – shallow connection charge, while for non-standard connection deep connection connection charge.

components: a fixed fee for a typical measuring point, a length-based fee for the connection line, and a capacity-based fee (unit price × connection capacity).

Georgia applies the shallow connection charge whose value depends on the voltage level and distance of a demand facility from the distribution grid. For connection of the new 0.4 kV or 6/10 kV demand facility within the 600 m and 6km radius from the 0.4 or 6/10 kV distribution network owned by the system operator, the connection charge is set by GNERC in the distribution network rules. In this case, the connection charge is set as a standard lump sum connection fee per connection, whose value depends also on capacity ranges (e.g., for requested capacity from 1kW to 10kW, 10kW-30kW; 30kW-50kW; 50kW-80kW, etc.). However, any demand facility owner beyond the voltage mentioned above and radius covers the connection costs based on the technical conditions issued by the relevant DSO.

In Kosovo*, connection charges are set on a unit basis and apply to new users according to the services required. A new user must cover not only the costs of assets needed for connection to the existing distribution system but also any upstream costs for reinforcement, expansion, or reconfiguration directly caused by the connection.

In Moldova the connection costs are covered by the network users.

In Montenegro, a new user is subject to the connection charge that corresponds to the product of unit charge per capacity and the approved connection capacity. There are two types of connections to the distribution network: standard and non-standard - determined by the location and voltage level of the connection point. The connection charge aims to cover the costs at the voltage level of the connection and the cost for the next higher transformation. Similar to the approach at the transmission level, the part of the connection infrastructure that will be used by more users can be built by the DSO or by a concerned user and then purchased by the DSO. However, the part of the connection infrastructure that serves only the concerned user has to be built by this user.

In North Macedonia, a type of the connection to the distribution system can be standard or non-standard. If the connection is standard, the user pays the connection charge per capacity required. On the other hand, if the connection is non-standard, the user pays for the connection and provision of technical conditions in the network.

In Serbia, consumer's connection to the distribution system can be either standard or individual, depending on factors such as connection complexity, technical conditions, facility type, distance from the system, and the connection method. For a standard connection, the consumer pays a fixed lump sum per connection, a standard unit charge per distance and a unit charge per capacity. In the case of an individual connection, the consumer covers the actual costs and pays a unit charge per capacity.

In Ukraine, the legislation also defines two types of connection to the distribution system: standard connection and non-standard connection. However, in this case, the type of connection depends on the connection capacity and distance from the existing grid: standard – connection capacity of up

to 50 kW and distance of up to 300 meters, and non-standard – connection capacity of more than 50 kW and/or distance of more than 300 meters. For the standard connection, the new user pays the capacity connection charge which represents the product of the unit rate for the standard connection and connection capacity (shallow charge). In Ukraine, the standard connection charge is calculated based on consolidated cost indicators for the construction of substations with voltages from 6 kV to 150 kV and power transmission lines with voltages from 0.38 kV to 150 kV, e.g. norms approved by the Ministry of Energy, e.g. not on real costs of connection. The justified difference between the amount of revenue from the provision of standard connection and actual connection costs is recovered through the D-tariff. The charge for a non-standard connection consists of two components: a capacity component that represents the product of the unit rate for the non-standard connection and connection capacity, and the component for the construction of the linear part of the connection (deep connection charge). The latter is determined according to an estimation that is an integral part of the relevant project documentation.

5.2.2. Variation of the level of distribution connection charge

The level of the connection charges in the Contracting Parties varies mostly based on the voltage level and the distance of new user's facility from the connection point in the distribution system (AL, BA, XK*, MD and RS). In addition, in Serbia, only for customers, connection charge varies based on the connection capacity. In Georgia, connection charge varies based on voltage level of the connection and connection capacity. In Montenegro, the value of the unit connection charge varies between the different voltage levels, while in North Macedonia, the connection charge varies based on the distance from distribution network and the connection capacity.

Except for varying based on the voltage level, the distance from the distribution and geographical location, the charge for standard and non-standard connection in Ukraine is differentiated based on categories of reliability of power supply in accordance with the "*Rules of installation of electrical installations declared by the customer* and on the electrical supply schemes" (single-phase or three-phase). Apart from that, the charge for non-standard connection varies depending on the type of connected electrical installation (production, consumption, storage) and on the party that designs the linear part of the connection (customer, distribution system operator).

5.2.3. Charging for the connection of producers, RES producers and EV charging stations

In Albania, Georgia, North Macedonia and Serbia, there is a difference in the calculation of connection charges for producers compared to the other network users. Albania applies different connection and distance unit tariffs for producers. In Georgia, the small power plants (installed capacity up to 15 MW) pay deep or "shallowish" connection charges, depending on the connection type and on the costs of the connection works that DSO shall carry out to complete the grid connection works. However, a micro-powerplant (installed capacity of 500 kW) pays the shallow connection charge, the same one as for the standard connection of consumers (as described above). In North Macedonia, in contrast to consumers, producers are not charged with costs for

providing technical conditions for connection. In Serbia, the connection of producers to the distribution system is always categorized as individual, but in this case, producers do not pay a unit charge per capacity, while all consumers have to pay this charge. However, none of these Contracting Parties introduced different approach for RES producers, compared to other producers.

Ukraine applies a different approach to the non-standard connection of electric vehicle charging stations as an incentive for their integration into the grid. By January 1st, 2025, the operator of the electric vehicle charging station or the business entity engaged in the provision of services for charging electric vehicles does not pay a capacity component for non-standard connection, but just a component for the construction of the linear part of the connection (remaining part of the cost are covered through the DSO tariff). The same incentive is introduced for battery storage facilities (until January 1, 2025). On the other hand, in Georgia, the same conditions for the connection of EV charging stations apply as for other consumers, however, EV charging station pays 50% of the connection fee applied for the connection of the final consumers.

6. Reactive energy charges and other network charges

In general, the reactive charges can be levied on the network users for the injection and/or withdrawal of reactive energy. A well-designed reactive charging and voltage control mechanism plays an important role in sending adequate price signals to network users that affect reactive energy flows. In the light of energy transition which led to the change of the generation mix in many countries, the design of reactive charges gained even more importance. The following subchapters elaborate the reactive charging mechanisms present in the Contracting Parties.

6.1. Transmission

Due to the recent market developments, only Bosnia and Herzegovina, Montenegro and North Macedonia experienced an increase in the costs of compensating reactive exchanges. In particular, the transmission networks of Bosnia and Herzegovina and Montenegro faces problems with overvoltages during the hours of low demand, which became more frequent due to the reduction of demand at the national level and in neighboring power system and phasing out the TPPs in the region. To tackle this problem, BIH TRANSCO is planning to install 3-4 shunt reactors into the network – these investments are approved and urged by regulator. Also, Montenegrin TSO (CGES) proposed the investment "Installation of shunt reactor in SS Lastva" to address the problem with overvoltages, which was approved by the REGAGEN. TSO of North Macedonia has already purchased shunt reactor that should be installed in TS Dubrovo 400/110 kV.

Most the Contracting Parties have introduced charges for reactive withdrawals from the transmission system (BA, XK*, ME, MK, RS and UA). However, as the transmission network of Bosnia and Herzegovina experiences the problem of high voltages due to underloading, reactive charging is not applied to withdrawals at the transmission level in this Contracting Party. Other previously-mentioned Contracting Parties (XK*, ME, MK, RS and UA), apply reactive charges for

withdrawals, which are presented separately from other network charges on the bill as the reactive-energy-based charges. Ukraine also applies a reactive energy charge for injection.

In Kosovo* and Montenegro, all transmission-connected consumers are subject to the reactive charge. In North Macedonia, apart from transmission-connected consumers, also DSO connection points, closed distribution systems and producers connected to the transmission system are subject to charge for withdrawn reactive energy. In Serbia, all system users that only withdraw from the grid, DSOs, CDSOs and prosumers are subject to reactive energy charge. In Ukraine, non-domestic electricity consumers with an authorized capacity of 50 kW or more are subject to the reactive charges. The exception are the alternative energy facilities with an approved capacity of 50 kW or more and the generating units of type B, C and D.

In Kosovo*, Montenegro and North Macedonia, this charge applies only to excessively withdrawn reactive energy, i.e., to the difference between withdrawn reactive energy and reactive energy that corresponds to the power factor of 0,95. On the other hand, in Serbia, reactive charges apply to any reactive energy withdrawal. However, for a power factor of up to 0.95, one tariff applies, while the double tariff applies for the reactive energy consumption for lower power factors (excessive consumption). In Ukraine, the reactive energy charge applies to the above-mentioned consumers whose injection or withdrawal of reactive energy is 1000 kVAr or more.

In Kosovo*, the reactive charge is not set based on any costs but it is set administratively with the purpose of changing customer behaviour, not to cover the specific cost. Similarly, in Montenegro, reactive charge is set as a percentage of the active electricity price (20%), while in North Macedonia, unit reactive charge corresponds to 40% of energy-based network tariff. On the other hand, in Serbia, the reactive charge is set on basis of costs linked to the impact of reactive injection/withdrawals on transmission losses and costs linked to the infrastructure solutions to compensate reactive energy. In Ukraine, the value of the reactive charge depends on many complex factors. The calculation of the unitary charge is prescribed in the "Methodology of calculation of reactive electricity flow fees"[94], approved by the Ministry of Energy.

A single reactive tariff applies in Contracting Parties except in Montenegro, where there is a day and night tariff for reactive charges (as there is a day and night tariff for active electricity).

Figure 6.1 shows the level of reactive charges for excessive reactive withdrawal in Albania, Moldova and North Macedonia in 2024.

94 https://zakon.rada.gov.ua/laws/show/z0392-18#Text

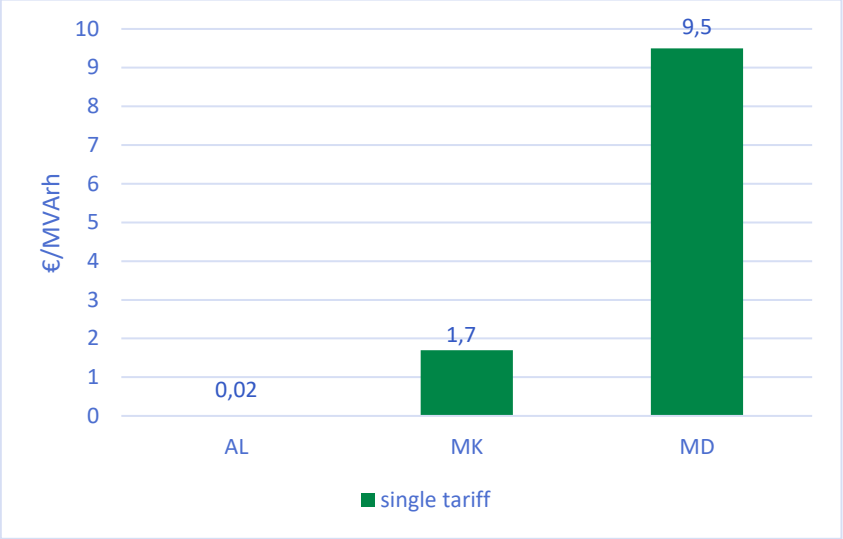


Figure 6.1 - The level of unit charges for reactive withdrawal in 2024

6.2. Distribution

Compared to the application of reactive charges at the transmission level, more Contracting Parties (AL, BA, XK*, MD, ME, MK, RS and UA) apply reactive charges to the distribution users. All these /Contracting Parties apply charges for the reactive energy withdrawn from the grid, which is presented separately on the bill, while Moldova and Ukraine also apply a charge for reactive energy injections.

In all these Contracting Parties, reactive charges apply on distribution-connected consumers. However, in some Contracting Parties not all distribution consumers pay for this charge. To be specific, in Kosovo*, only big commercial and industrial consumers are charged for reactive energy withdrawals, while in Serbia, reactive charge do not apply to households and public lighting, but it applies to prosumers, self-consumption of TSO and DSO and on CDSOs. In North Macedonia, the same as at the transmission level, reactive charge apply to producers for reactive energy withdrawal. In Ukraine, this charge applies to non-domestic electricity consumers with an authorized capacity of 50 kW or more, except for the apartment buildings that consume electricity for communal needs or technical purposes (e.g., the operation of elevators, pumps, intercoms, lighting of courtyards, stairs and license plates, etc.). The exception are also the alternative energy facilities with an approved capacity of 50 kW or more and the generating units of type B and C.

In Albania, Bosnia and Herzegovina, Kosovo*, Montenegro and North Macedonia, only excessive reactive energy withdrawal (reactive withdrawal that is larger than the reactive withdrawal that corresponds to power factor of 0.9 for AL, and 0.95 for other four Contracting Parties) is charged. In Albania, all reactive withdrawals regardless of the power factor are charged. On the other hand, in Serbia, both reactive withdrawals of up to $cos\ cos\ \varphi$ 0.95 and excessive reactive withdrawal are priced. Price for excessive reactive energy withdrawal is two times higher than the price for reactive power withdrawal of up to $cos\ cos\ \varphi$ 0.95. In Moldova, reactive charge for withdrawal and injection

applies to consumers with installed capacity of above 50 kVA and consumption of active electricity of more than 10000 kWh per month. In Ukraine, the reactive energy charge applies to the above-mentioned consumers whose injection or withdrawal of reactive energy is 1000 kVAr or more.

In all these CP, except for Albania, Kosovo* and Ukraine, reactive charges setting principle is prescribed in NRA's methodologies. Reactive charges in the Contracting Parties are calculated based on the costs arising from reactive exchanges and/or voltage control (AL, BA and RS) or their value is administratively set (XK*, MD, ME and MK) or they depend on many factors summarised in the relevant methodology (UA). In Albania, the reactive charge reflects the impact of reactive energy flows on the distribution system losses. In particular, the reactive charge is determined by dividing the estimated costs caused by the reactive energy flows by measured reactive energy withdrawal for the power factor of less than 0.9. In Bosnia and Herzegovina, costs linked to the impact of reactive injection/withdrawals on distribution losses, costs linked to the use of infrastructure or to the need for additional network infrastructure, costs linked to the infrastructure solutions to compensate reactive energy and costs linked to the supply of voltage control services from network users, are taken into account for the calculation of reactive charge. In Serbia, reactive charge value is based on costs linked to the impact of reactive injection/withdrawals on distribution losses and on costs linked to the infrastructure solutions to compensate reactive energy. On the other hand, in Kosovo* reactive charge is administratively set with the purpose of changing customer behaviour, not to cover the specific cost. In Moldova, the price for reactive energy is 10% from the regulated electricity price supplied to the consumer. Finally, in Montenegro and North Macedonia, reactive charge is determined as a percentage (20% in ME, 40% in MK) of the active electricity price (ME) or energy-based network tariff (MK). In Ukraine, the value of the reactive charge depends on many complex factors. The calculation of the unitary charge is prescribed in the "Methodology of calculation of reactive electricity flow fees"[95], approved by the Ministry of Energy

Figures 6.2 and 6.3 show the value of reactive charges (€/MVArh) applied Albania, Moldova[96] and North Macedonia.

North Macedonia applies different tariffs for medium voltage consumers directly connected to MV busbar in SS HV/MV (MV1) and other medium voltage consumers (MV2).

95 https://zakon.rada.gov.ua/laws/show/z0392-18#Text

96 Values shown for Moldova are for the total reactive withdrawal and injection.

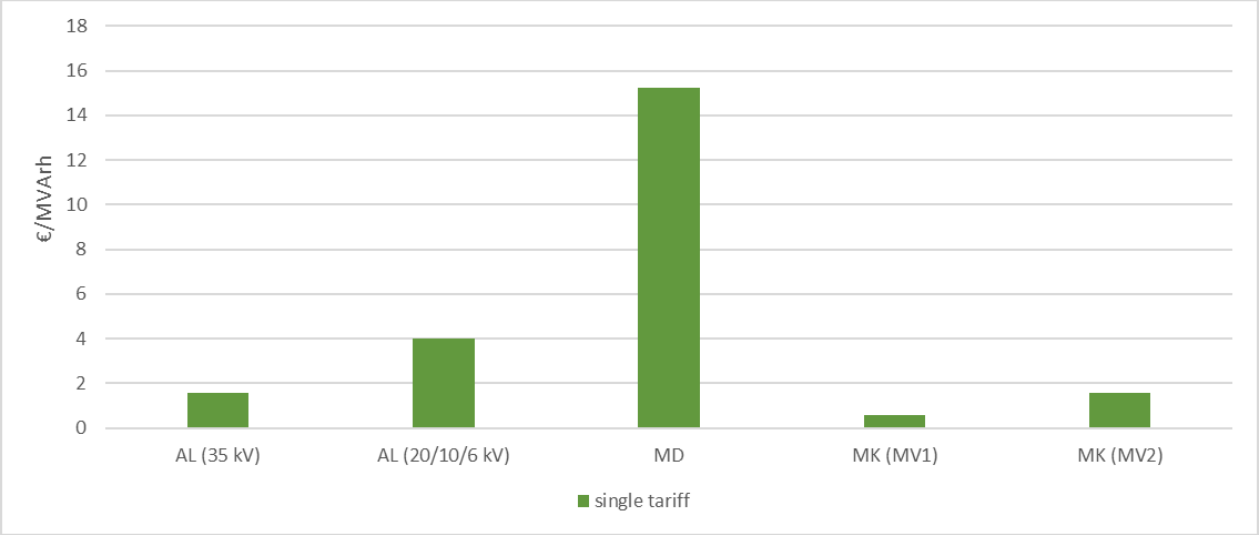


Figure 6.2 - The level of unit charges for reactive withdrawal at MV in 2024

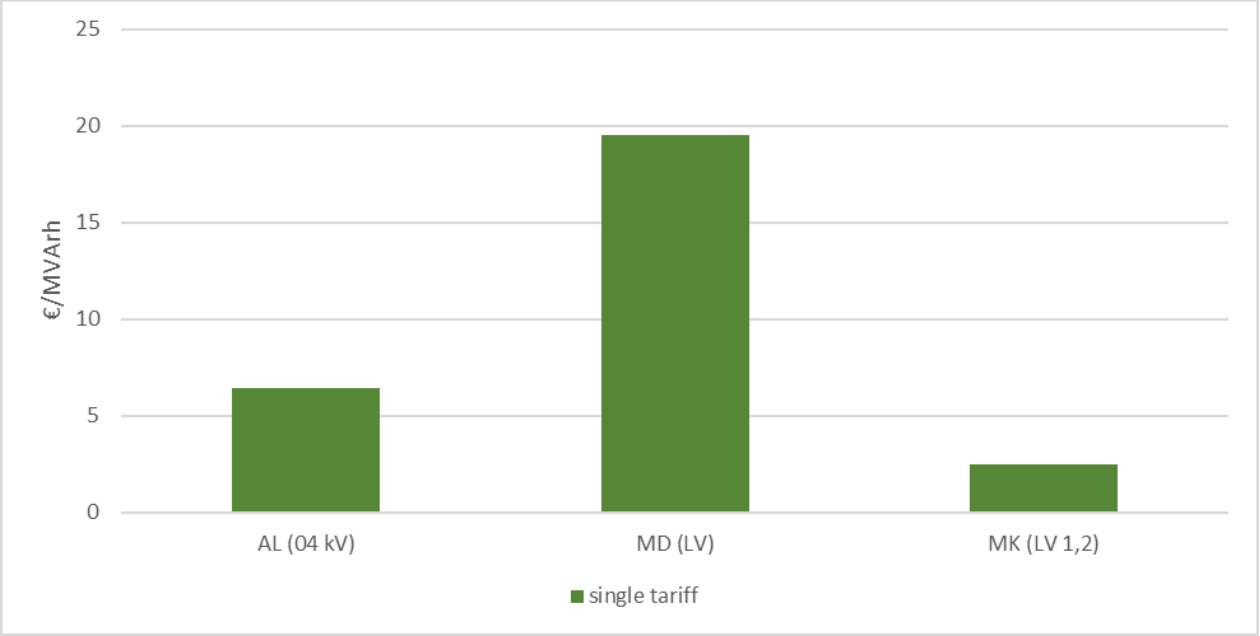


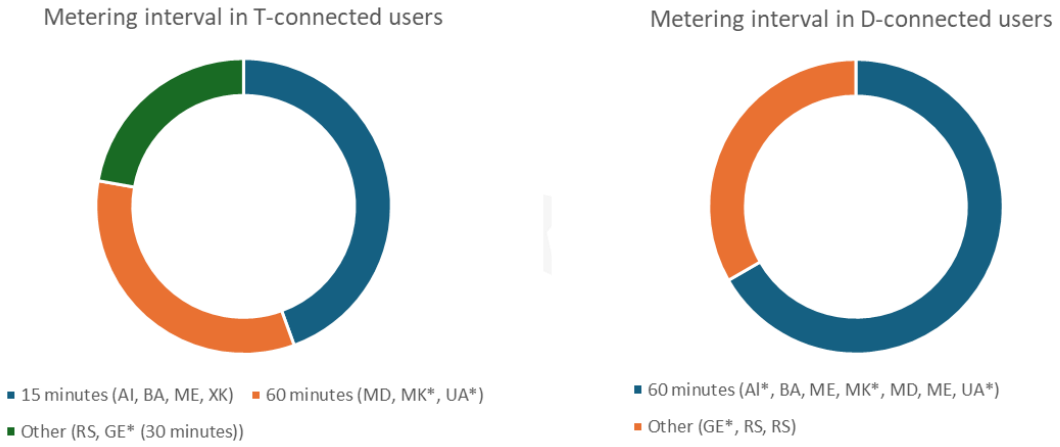
Figure 6.3 - The level of unit charges for reactive withdrawal at LV in 2024

7. Time-differentiation and locational signals

7.1. General overview of time-of-use network charges

Article 18 of Regulation 2019/943 provides that where Contracting Parties have implemented the deployment of smart metering systems, regulatory authorities shall consider time-differentiated network tariffs when fixing or approving transmission tariffs and distribution tariffs or their methodologies and, where appropriate, time-differentiated network tariffs may be introduced to reflect the use of the network, in a transparent, cost-efficient and foreseeable way for the final customer.

For the purposes of this report, most Contracting Parties reported a sufficient level of penetration of meters capable to record time-of-use, and in four countries, the metering interval is already 15 minutes for T-connected network users. As regards D-connected users, six Contracting Parties apply 60-minute metering intervals. In other jurisdictions, hourly metering is applied in parallel with integral metering.



**Country-specific features*
** In Albania for T-connected users meters have a 15-minute interval, while for D-connected users there are two metering intervals: 60 minute interval and 15 minute interval when consumers are equipped with interval metering.*
I
In Ukraine usually meters have a 60-minute interval, but the DSO strives to reduce it to 30-minutes, especially for large consumers.
In Georgia, three metering intervals are applied to D-connected users: the month period for users with conventional meters, 60-minute period for retail consumers with smart meters and 30-minute for consumers trading electricity at the wholesale market. However, all smart meters shall have the capability to record metering data in 15-minute interval.
In North Macedonia meters are able to measure in 15 minutes however data are submitted for 60-minutes intervals.

Figure 7.1 - Metering intervals applied in Contraction Parties

7.1.1. Transmission

Currently, time-of-use T-tariffs are not widely applied among Contracting Parties and it is reported they are not planned to be introduced by the NRAs in the near future. The existence of different T-tariffs (low and high) during the day and days of the week is reported only by Montenegro and Serbia (for more details please see *Table 7.1*).

As noted by NRA of Bosnia and Herzegovina, the transmission network in the country is not overloaded and there is no congestion in the network therefore there is no justification for the introduction of time-of-use tariffs.

In three (3) Contracting Parties, one of the obstacles to the application of time-of-use T-tariffs is the low penetration of *smart meters/meters able to record time-of-use* in transmission and/or distribution level. Finally, most of the NRAs consider that the complexity of designing such tariffs does not outweigh the benefits and that load-shifting signals to the consumers may be ensured by other (market-based) signals (e.g. supplier's price for electricity).

Table 7.1 – Time-of-use T- tariffs in Montenegro and Serbia

Contracting Party	Application of time-differentiated T-tariffs
Montenegro	The day/night T-tariff applied. In line with the Transmission tariff methodology, the periods during which day and night tariffs apply are: – day tariff (high tariff) applies from 7 a.m. to 11 p.m. (or from 8 a.m. to 12 p.m. DST); – night tariff (low tariff) applies from 11 p.m. till 7 a.m. (or from 12 p.m. to 8 a.m. DST).
Serbia	The day/night T-tariff is applied during the following periods: – day tariff – from 7 a.m. to 23 p.m.; – night tariff – from 23 p.m. to 07 a.m.

7.1.2. Distribution

Time-of-use D-tariffs are reported only in Bosnia and Herzegovina (seasonal time signals, day/night and weekends tariffs, Montenegro (day/night applied similar to T-tariff approach) and Serbia (day/night) – see details in Table 7.2.

In some other Contracting Parties (e.g., in Kosovo*, Ukraine), time-of-use signals are applied to the retail tariffs, but not to the DSO tariffs. The introduction of time-of-use D-tariffs requires a sufficient level of smart meter penetration among D-connected users. From reported information it may be observed that some Contracting Parties are in the early stage of introduction of time-of-use meters on distribution level (e.g. Albania, Moldova and Georgia – below 10%) and in others from 50% Ukraine and 75% (Serbia) to more than 90% (Bosnia and Herzegovina, Montenegro) of D-connected users are equipped with meters which are capable of measuring withdrawal from the grid for different time-of-use. It also noted that no information on smart meters penetration in D-level is available for some NRAs (e.g. Kosovo*, North Macedonia).

Table 7.2 - Time-of-use D- tariffs in Bosnia and Herzegovina, Montenegro, Serbia

Contracting Party	Application of time-differentiated D-tariffs
Bosnia and Herzegovina	Seasonal time signals are applied by only one DSO (Elektroprivreda HZHB) in Bosnia and Herzegovina. The higher (winter) season lasts from 1st January until 28th/29th February and from 1st November to 31st December, and the lower (summer) season lasts from 1st March until 31st October. Seasonal time signals are applied to all categories of consumption and are present in the tariff elements of active energy and power. Day/night tariffs are applied to all categories of consumption and are present in the tariff element of active energy. Tariff rates for active energy are applied according to the time of day, namely: a) higher daily tariffs (VT) from 6 a.m. to 10 p.m. during winter time, or from 7 a.m. to 11 p.m. during summer time, b) lower daily tariffs (MT) from 10 p.m. to 6 a.m. during winter time, or from 11 p.m. to 7 a.m. during summer time. Exceptionally, for the category of household consumption, the tariff rates for active energy are applied according to the time of day, namely: a) higher daily tariffs (VT) from 7 a.m. to 1 p.m. and from 4 p.m. to 10 p.m. during winter time, or from 8 a.m. to 2 p.m. and from 5 p.m. to 11 p.m. during summer time, b) lower daily tariffs (MT) from 1 p.m. to 4 p.m. and from 10 p.m. to 7 a.m. during winter time, or from 2 p.m. to 5 p.m. and from 11 p.m. to 8 a.m. during summer time, and on weekends. Time-of-use D-tariffs are a historical legacy.
Montenegro	The periods during which day and night tariffs apply are prescribed in the special methodology. The day tariff (high tariff) applies from 7 a.m. to 11 p.m. (or from 8 a.m. to 12 p.m. DST). The night tariff (low tariff) applies from 11 p.m. (or 12 p.m. DST) on Saturday till 7 a.m. (or 8 a.m. DST) on Monday.
Serbia	The day tariff (high tariff) applies from 7 a.m. to 11 p.m. The night tariff (low tariff) applies from 11 p.m. to 7 a.m.

7.2. Locational signals in tariff design

All Contracting Parties reported that currently they don't apply locational signals in T-tariff and D-tariff regulation.

7.3. Potential significant changes in the tariff methodology (tariff structure)

Two countries (North Macedonia and Georgia) noted that they have plans to change their tariff methodologies. Georgia stated that it intends to introduce Fixed Charges starting from the next Regulatory Period (beginning in 2031) in order to make tariffs more cost-reflective in terms of cost types, stabilize DSO revenues, and make them less dependent on consumption fluctuations. North

Macedonia noted that a new tariff methodology should be adopted by the end of February 2026, as required by the Energy Law[97].

7.4. Locational connection charges and use of network charges

At the TSO level, no NRA has established specific rules for the allocation of connection charges based on the location of the connection point.

Georgia and Montenegro reported that they have no specific features. All other countries stated that connection charges depends on the distance to the connection point in the DSO grid. In addition, Ukraine reported that the connection charges also depends on geographic location (urban or rural areas).

It should be noted that the locational use of network charges is not applied in any Contracting Party.

97ERC adopted new tariff system for electricity transmission in which lump sum fee is added for connection points to the transmission grid at the end of November 2025. This will be reflected in more details in the next report.

8. Addressing the Energy Community acquis and energy transition

A number of Energy Community legal acts explicitly or implicitly influence network tariff regulation in Contracting Parties. With the adoption of the 2030 energy and climate targets[98], Energy Community Contracting Parties stepped on a path towards achieving climate neutrality of their economies by 2050 and decreasing dependence on fossil fuels in the shorter term. This shall be supported by RES development, energy efficiency measures, introduction of new innovative technologies and their integration into the electricity market.

In particular, Article 15 of the Energy Efficiency Directive [99] requires that NRAs pay due regard to energy efficiency in carrying out the regulatory tasks regarding their decisions on the operation of the gas and electricity infrastructure. Further, the Energy Efficiency Directive sets the energy efficiency criteria for energy network regulation and for electricity network tariffs as well as for energy efficiency requirements for TSOs and DSOs[100].

In 2023, the Regulation (EU) 2022/869 of 30 May 2022 on guidelines for trans-European energy infrastructure, incorporated and adapted by Ministerial Council Decision 2023/02/MC-EnC of 14 December 2023, became a part of Energy Community acquis with the transposition deadline by 31 December 2024 (hereinafter 'Energy Community TEN-E Regulation').

Energy Community TEN-E Regulation' contributes to ensuring climate change mitigation, in particular achieving the Energy Community 2030 targets for energy and climate and the climate neutrality objective by 2050 at the latest, and to ensuring interconnections, energy security, market and system integration and competition that benefits all Contracting Parties, as well as affordability of energy prices. Particularly, Article 16 provides, that efficiently incurred investment costs, which exclude maintenance costs, related to a PECI falling under the energy infrastructure categories set out in point (1)(a), (b), (c), (d) and (f) of Annex II, and PECI falling under the energy infrastructure category set out in point (3) of Annex II, where they fall under the competence of NRAs in each Contracting Party concerned, shall be borne by the relevant TSO or the project promoters of the transmission infrastructure of the Contracting Parties to which the project provides a net positive impact, and, to the extent not covered by congestion rents or other charges, be paid for by network users through tariffs for network access in that or those Contracting Parties. Article 17 provides for regulatory incentives for PECI if the risks of this project are higher compared to risks normally incurred by a comparable infrastructure project. Such incentives may include:

(a) the rules for anticipatory investment;

98 Decision 2022/02/MC-EnC of the Energy Community Ministerial Council of 15 December 2022.

99 Directive 2012/27/EC on energy efficiency, as amended by Directive (EU) 2018/2002

100 Annex XI and Annex XII to the Directive 2012/27/EC

(b) the rules for recognition of efficiently incurred costs before commissioning of the project;

(c) the rules for providing additional return on the capital invested for the project;

(d) any other measure deemed necessary and appropriate.

The Energy Community TEN-E Regulation introduces changes to the projects, eligible for PECI and PMI status, and particularly, in electricity, extended for the following categories, to support grid digitalization and flexibility:

Concerning electricity:

- any equipment or installation essential for the systems to operate safely, securely and efficiently, including protection, monitoring and control systems at all voltage levels and substations;

- smart electricity grids: any equipment or installation, digital systems and components integrating information and communication technologies (ICT), through operational digital platforms, control systems and sensor technologies both at transmission and medium and high voltage distribution level, aiming to ensure a more efficient and intelligent electricity transmission and distribution network, increased capacity to integrate new forms of generation, energy storage and consumption and facilitating new business models and market structures, including investments in islands and island systems to decrease energy isolation, to support innovative and other solutions involving at least two Contracting Parties with a significant positive impact on the Energy Community 2030 targets for energy and climate and the 2050 climate neutrality objective, to contribute significantly to the sustainability of the Energy Community.

8.1. PECI and innovation support

NRA of Montenegro reported that draft law on cross-border energy infrastructure projects is in the final stages of development, and its adoption is expected in the near future. In addition, Georgia indicated that the working group, which includes representatives from GNERC, is in the process of developing a methodology that duly takes PECI/PMI projects into consideration.

8.2. Energy Efficiency

Seven NRAs from Contracting Parties (AL GE, XK, MD, ME, MK and RS) reported that they recognize the energy efficiency measures, including the investments identified by TSOs/DSOs for the introduction of cost-effective energy efficiency improvements in the network infrastructure.

In Albania, the impact of energy efficiency is reflected as a decrease of the total energy consumption.

In Georgia, based on the Investment Appraisal Rules, approved by the GNERC in 2021, one of the categories of investments to be approved by the NRA is the investment project contributing the

energy efficiency. The DSOs are obliged to provide the annual report on implementing the investment plan to the GNERC.

In Kosovo, ERO applies TSO and DSO methodology that encourages network operators to reduce losses and implement a cost-efficient and energy-efficient infrastructure investment, but no incentives for flexibility have been introduced yet. In addition to this during the global crisis, the government also implemented measures to incentivize efficient electricity consumption. Also an efficiency factor is applied to the DSO's OPEX, which in turn affects its revenues. Energy efficiency measures reduce distributed volumes, thereby impacting DSO revenues through an applied efficiency factor in the DSO's OPEX.

In Moldova D-tariff is calculated for a year, based on projected electricity distributed volume and costs that are to be recovered by the DSO. In the next year the NRA compares the real value of revenue and the one that it should have been received. This deviation is addressed in the new DSO tariff.

In Montenegro, when planning the development of the transmission and distribution system, TSO and DSO should consider the measures to increase energy efficiency in the transmission and distribution infrastructure and should assess the impact of investments on the reduction of transmission and distribution losses. Also, to address the impact of energy efficiency measures (on the customer's side) in case the consumption is lower than the forecasted one, the T-tariff and D-tariffs are reviewed.

In North Macedonia, the TSO and DSO shall prepare and submit for approval to the ERC investment plans in the transmission system and distribution system for each regulatory period. Also, TSO and DSO submit Network Development Plans that, besides other issues, should contain measures that support the implementation of NECP and achieving national goals and an indicative trajectory for renewable energy sources, energy efficiency, reducing greenhouse gas emissions and increasing security of electricity supply.

In Serbia, any investment which is identified for the introduction of cost-effective energy efficiency improvement in the network infrastructure is treated as justified. The impact of energy efficiency measures on TSO and DSO revenue can be adjusted by changing the participation of active power (fixed cost). In addition, there is a correction element which may reduce or increase approved income for the amount of deviation between the realised and approved income for the previous regulatory period(s).

8.3. Innovation/ R&D/smart grids/smart metering

Clean energy transition with more intense RES penetration (including on the consumer level), customer empowerment regarding participation in the electricity market and balancing/flexibility services provision, demand response etc. requires the reconsideration of concept of power system development and a high level of digitalization. The role of network operators in this respect is crucial as they possess relevant infrastructure and technical knowledge, have direct relations with main

stakeholders (producers, customers, suppliers, aggregators, etc.) and it is their interest to increase the efficiency of their networks in order to obtain additional revenue. Therefore, Directive 944/2019[101] tasks TSOs and DSOs to develop a smart grid that promotes energy efficiency and the integration of energy from renewable sources, based on a limited set of indicators, and NRAs to monitor and assess their performance in this respect and publish a national report every two years, including recommendations.

In 2020 CEER presented a progress report on regulatory frameworks for innovation in electricity transmission[102], according to which it was summarized that regardless of the lack of a unified definition of innovation, NRAs recognize activities of TSO as regards developments that increase grid efficiency and benefits for consumers at the same (or at even lower) cost as innovation. It is mostly promoted indirectly via the general regulatory framework and/or via specific features regarding incentives for network performance (output-based regulation), there are also examples where specific activities for innovation have been or are being adopted (e.g. additional incentive multiplier to the investments with innovative solutions).

Among Contracting Parties, only Albania reported that although so far in the D-tariff methodology there is no special methodology element to support/incentivise innovation, NRA is planning to add it in the near future[103]. Innovation describes the development, introduction and dissemination of new processes, products and services. It involves new technologies such as smart grid, electromobility or decentralized energy storage. Innovation can also be of a socio-cultural-nature such as new forms of solar energy communities.

Montenegro reported, that some changes might be introduced when preparing the new T-tariff methodology by the end of 2025.

All other Contracting Parties currently do not have developments in this regard. Research and Development activities of TSOs/DSOs are not supported by any targeted incentivising component in tariff methodologies in all analysed countries. In North Macedonia, research and development, and digitalisation will be included in the new Methodology that should be adopted in 2026.

In Georgia, the Distribution Network Rules (DNR), approved in 2021, oblige DSOs to install smart meters in all new multi-store buildings connecting to the network. Besides, existing final consumers have the right to apply to the DSO to install smart meters. The DNR determine the smart meter installation fee and the timeframe for providing the service by the DSO. With the consent of the NRA, the DSO is authorized to install smart meters in any building.

101 Article 3, Article 51, Article 59;

102 CEER Status Review Report on Regulatory Frameworks for Innovation in Electricity Transmission Infrastructure, https://www.ceer.eu/documents/104400/-/-/8c2aace7-5601-8723-4d45-337073af38d5

103 Although there is no definition of innovation in the legal acts of Albania, ERE considers innovation as the development, introduction and dissemination of new processes, products and services. It involves new technologies such as smart grid, electromobility or decentralized energy storage. Innovation can also be of a socio-cultural nature such as new forms of solar energy communities.

8.4. Emerging network users

Directive 2019/944 calls for regulatory framework to facilitate the connection and operation of newly emerging categories of network users in the course of clean energy transition, e.g. participants offering energy from renewable sources, market participants engaged in demand response, operators of energy storage facilities and market participants engaged in aggregation, publicly accessible and private recharging points.

In this regard, only NRA of Albania informed that ERE published a study "Regulatory and legal framework aimed at the utilization of new technologies for electric vehicle charging stations, including the regulation of tariff structure for this service" but currently there are no specific rules introduced regarding the T-tariffs and D-tariffs approach applicable to (public) EV charging. All other NRAs from Contracting Parties reported no activities and developments in this regard.

Georgia reported, that the DSO Connection Fee for setting up an EV Charging station is half the usual fee. In Moldova, renewable energy communities applied a 30% discount of normal D-tariff.

8.5. EV charging, power-to-gas, storage and other energy transition activities

In Albania, after the approval of Law No. 24/2023 "For the Promotion of Renewable Energy Usage," ERE has to develop and approve the methodology for determining the charge for renewable energy, which will be paid by end-consumers of electricity network.

In Macedonia, in accordance to the Energy Law, new T-tariff methodology should take into consideration the impact of all new market entrants like distributed generation, storages, aggregators. Also application of the D-tariffs to storages will be considered as well as for other market participants as defined by the new Energy law like active consumers, energy communities etc.

In Moldova, considering the implementation of EiP, and the new law on electricity that will soon enter into force, most probably some changes in regard with the regulation of new types of activities like electricity storage and trading will be introduced in the secondary legislation.

In Montenegro, the draft T-tariff methodology is going to be prepared by the end of 2025. The new methodology has to be adopted in order to align this methodology with the new Energy Law. It is expected that the public consultation for this methodology will also be initiated in 2025.

In Georgia, currently are transposing the EIP and activities will be based on the implementation of the mechanisms provided in the package. NRA with TSO is already working on implementation of the regulatory framework for storage facilities.

In Serbia, NRA activities are conditioned by previous adoption of by-laws defining in more detail energy community status.

8.6. Renewable energy communities, citizen energy communities

Moldova reported, that according to the Regulation on renewable energy communities issued and approved by the NRA, the D-tariff is applied in the following way, depending on the type of energy community, namely, local[104] or regional[105]. For shared electricity, the supplier will charge a distribution service fee corresponding to the voltage level to which the installation of the consumption point of the respective member or associate is connected, reduced by 30% in the case of the local community and reduced by 15% in the case of the regional community. In the case of the application of capacity tariffs, the supplier will charge a distribution service fee, reduced by 30% in the case of the local community and reduced by 15% in the case of the regional community.

104 **local community** – renewable energy community whose members or associations own the facilities for using the consumption sites and one or more power plants that produce/produce electricity from renewable sources, connected to the low-voltage electricity network of the distribution system operator related to the same medium/low voltage transformer station

105 **regional community** – renewable energy community whose members or associations own at least one consumption site where the usage facility and/or the power plant/power plants that produce/produce energy from renewable sources owned/owned is/are connected to the medium-voltage electricity network of the distribution system operator, provided that all connection points are downstream of the same 10 kV busbar system within the high/medium voltage or medium/medium voltage transformer station, in the normal operating scheme;

9. Conclusions and recommendations

Legal and regulatory framework

In all Contracting Parties, network tariffs are calculated and set based on the methodologies approved by the NRAs. At the same time, in some Contracting Parties the method of T-tariff and D-tariff regulation is defined by the primary legislation. In several Contracting Parties NRA shall agree on network tariff methodologies or method of regulation with other state authorities. There is also a practice in one Contracting Party that the network tariff methodology is developed by network operator according to the rules and principles provided by the NRA and shall be approved by the NRA.

Although the primary law may provide for main guiding principles and objectives of network tariff regulation, according to the Electricity Directive, solely NRAs are tasked to approve the network tariff methodologies, including the type of regulation, relevant regulatory parameters, and tariff design. In performing its tasks NRA shall take autonomous decisions and act independently from any political body as required by Article 57 (4). That requirement is without prejudice to close cooperation with other relevant national authorities, and may be realised in a way of consultations.

Tariff setting principles and type of regulation

Since 2022, there have been no significant changes in Contracting Parties regarding the methods applied to network tariff regulation. The incentive-based methods of T-tariff and D-tariff network regulation (with performance-based indicators such as X-factor) prevail among the Contracting Parties. Such methods ensure basic incentives for network operators in terms of cost efficiency and return on investment. To be more precise, incentive-based methods are more flexible for the introduction of new performance indicators (e.g. service quality, energy efficiency, and total cost optimisation).

Following the ECRB recommendations, the status of quality regulation through the D-tariff methodology has progressed since 2022 and is now present in five (5) Contracting Parties (Albania, Georgia, Kosovo*, Montenegro and Ukraine). While in transmission, the quality factor is practically applied only in Bosnia and Herzegovina and Kosovo*.

Other NRAs reported some developments planned to be done in this regard. Thus, one Contracting Party (Montenegro) informed about application of quality factors in T and D tariff calculation starting from 2027, and in North Macedonia, the NRA shall develop the Rulebook on monitoring technical and performance (business) indicators and regulating the quality of electricity delivery and supply in the course of 2026.

Following the EIP transposition in the Contracting Parties, the network tariff methodologies may require revision in the coming years in a way to provide appropriate incentives to TSOs and DSOs over both the short and long run, in order to increase operating efficiency, (including energy

efficiency), foster market integration and security of supply, promote efficient investments, support related research activities, and facilitate innovation in the interest of consumers in areas such as digitalisation, flexibility services and interconnections. This may include revision of approaches to the calculation of allowed revenues and, particularly, to the suitable application of incentives between the CAPEX and OPEX to avoid CAPEX/OPEX bias.

The new network tariff methodologies shall ensure that network charges do not include unrelated costs supporting unrelated policy objectives. Particularly, one Contracting Party (Ukraine) has already started implementation of the relevant roadmap aiming to separate the RES PSO costs from the transmission system costs currently embedded in transmission service tariffs.

ECRB also recommends NRAs of the Contracting Parties to introduce quality regulation in the transmission and distribution tariff methodologies, to provide incentives to network operators to maintain or improve the quality of service levels[106].

Frequency of tariff methodologies revision and of tariff value updates

In most of the Contacting Parties, the tariff methodologies are approved by the NRAs for an indefinite term and may be revised if needed. As of 2025, NRA of Moldova switched to this approach from the previous practice. Only in Kosovo*, the new methodology for each new regulatory period is developed and approved, defining the regulatory parameters for this period.

The regulatory period in most of the Contracting Parties is fixed within the methodology. Most of the NRAs also set the regulatory period for T-tariffs and D-tariffs between three and five years, while the practice of a one-year regulatory period is also present in both transmission and distribution tariffs (Serbia and Ukraine).

Tariff methodologies in all Contracting Parties allow for tariff value adjustments during the regulatory period, but methodologies do not always define clear conditions/criteria for tariff review (Albania, Bosnia and Herzegovina). The regular revision is usually done for the next year during the regulatory period, while in some Contracting Parties (for example, Serbia and Ukraine) adjustments are also possible during the year. Usually, the tariff update accommodates changes in allowed revenue due to changes in conditions outside the operators' control. Some Contracting Parties also apply a tariff decrease in case the revenue is higher than projected (Serbia) or decrease the allowed revenue in case the operator violates the requirements of the regulations or licensing conditions (Ukraine).

With transposition of the EIP, NRAs are tasked to update and approve network tariff methodologies complying with the principles of the Energy Community acquis.

106 Status of quality of service monitoring and regulation in Contracting Parties as well as more detailed recommendations on this issues presented in the 7th CEER-ECRB Benchmarking Report on the Quality of Electricity and Gas Supply.

It is recommended for NRAs to set the regular process of revision of network tariff methodologies (e.g. each 5-6 years) in order to accommodate new developments in network operation, to introduce incentives (for both network operators and users) in areas were performance improvements are evidently required, to reflect market developments, including new types of users and specifics of their operation.

The network tariff methodologies and/or regulatory parameters shall not be revised often, particularly not within the regulatory period, in order to ensure predictability for regulated companies and users in terms of tariff structure and application. It is also important to distinguish between the regulatory period (the period for which regulatory parameters, targets and incentives are set typically 5-6 years) and tariff setting period (the period, typically of one year, for which the tariff value is calculated[107]). The regulatory period shall reflect the reasonable time required for TSOs and DSOs to adjust their operation in a way that will allow them to meet regulatory targets and to realize efficient investment decisions. The tariff setting period shall allow for timely consideration (and recovery) of non-controllable costs incurred by TSOs and DSOs within the regulatory period.

The tariff value update is a needed measure to presume the cost-reflectiveness of network tariffs influenced by factors outside the operator's control. It is recommended that network tariff methodologies include clear criteria and conditions for such tariff review/update, to ensure predictability and transparency for network operators. Such revision shall reflect the reasonable changes in costs, while NRAs shall avoid reviewing (decreasing) the allowed revenue as an enforcement measure for operators' non-compliance.

Stakeholder involvement

The role of stakeholders in designing network tariff methodologies is growing. Energy transition and energy efficiency measures create the need to integrate specific aspects in network operation and regulation, which stakeholders can provide via public consultation. In all Contracting Parties, tariff methodologies for network operators are subject to public consultations to achieve the objective. The period of public consultations on network tariffs methodologies varies among the Contracting Parties, from 10 working days to 30 days.

Several NRAs introduced a positive practice to publish the tariff related documents in English to reach out to international stakeholders as well.

Tariff design shall not be a barrier for network users to operate efficiently in the energy system and provide services to the system. It shall reflect the costs driven by different types of users without undue complexity and reflect their specific needs. To meet all these requirements, it is recommended that NRAs to set up an appropriate mechanism of stakeholders' involvement (e.g., stakeholder expert group) when designing and revising tariff methodologies, to take into account

107 Normally regulatory period with the duration of more than 1 year contains several tariff periods

views and circumstances of external stakeholders while preserving the principles of network tariff regulation.

It is recommended that all documents and information related to public consultations are published in a timely manner. The rationale behind acceptance or rejection of the stakeholders' comments shall be transparently communicated by NRAs to market participants, e.g., by publishing the response in the materials under the public consultation.

Public consultations on network tariff methodologies shall allow reasonably enough time for stakeholders to react and provide their feedback. Specifically, if changes to the methodology and/or tariff design are crucial, the consultation period is recommended to last at least one month, supported by the relevant information campaign.

Transparency in tariff setting

When setting network tariffs, NRAs in all Contracting Parties make publicly available the methodology and the relevant cost information used in tariffs calculation. Also, the tariff values for injection and withdrawal (as applied) are published. It is recommended to NRAs to publish also the consolidated version of network tariff methodologies reflecting all amendments in force, in national languages and in English.

Cost model

Most of the NRAs reported the use of average cost model in calculating the unit value of tariff. In terms of cost allocation, this model is the simplest and does not require additional measure to cover residual costs. NRAs are invited to consider other cost models (forward looking or incremental) in terms of better cost reflectivity (by cost driver).

Cost recovery

In most of the Contracting Parties, main cost categories recognised in T-tariff and D-tariffs relate to investments into transmission and distribution networks, operational costs, costs of cross-border operations and purchasing ancillary services (TSO), network losses, metering (DSO).

Anticipatory investments are not recognised in most Contracting Parties. At present they are mainly limited to transmission investment (including cross-border) projects of high importance(Kosovo*, Moldova, Montenegro and North Macedonia).

In relation to the EIP, the costs related to inter-TSOs cooperation and market integration on the pan-EU and regional level recognised currently in T-tariff methodologies only in three Contracting Parties (Bosnia and Herzegovina, Moldova and Montenegro), while costs of redispatching recovered by T-tariff only in Montenegro and Serbia. At the same time, most Contracting Parties do not recognise

relevant costs in the T-tariff methodologies at this moment, while planning to do so in the new tariff methodologies developed following the EIP transposition.

Cost of losses constitute a significant part of the allowed revenue, which may be impacted by their volume and price. During the energy crisis 2021-2022, in some CPs the increased value of losses due to high market prices mainly caused the increase of network tariffs. Most CPs recognise the losses in the network tariffs in % of the transmitted or distributed volume of electricity. Since 2022, one CPs switched to another approach by recognising the absolute volume of distribution losses in kWh. The rationale of such decision is to recognise the reality when the distribution volumes drop from year to year due to the high share of RES.

The main financial resources for transmission investments are equity, loans and grants. Specifically, loans and grants are widely used to invest into cross-border infrastructure, while they are less used in case of distribution system projects. In some Contracting Parties investment funds rely mostly on depreciation and other income (e.g. revenues from reactive power flows).

Cost categories shall be monitored by NRAs, including the effect of each category on the tariff value for each type of network user.

NRAs are invited to constantly monitor the performance of network operators and changes in their operational parameters, e.g. distributed volumes of energy, as a result of energy efficiency measures and RES penetration and operation of active customers, to timely and properly reflect the new patterns in tariff regulation.

TSO and DSO networks shall not include any costs not related to transmission and distribution activities (e.g., different support schemes) as required by the Article 18(1) of Regulation 2019/943. Therefore, where TSOs or DSOs are tasked to collect relative funds for any support scheme, they shall do this through the separate non-transmission (non-distribution) charges.

Transmission system tariff methodologies shall consider the costs of TSOs for performing their tasks under the EIP, subject to their assessment by NRA. For example, this relates to TSO's share in the common costs referred to in Article 80(2)(a), regional costs referred to in Article 80(2)(b) and national costs referred to in Article 80(2)(c) of CACM, Article 23 of EB GL, etc. assessed as reasonable, efficient and proportionate, and to be recovered in a timely manner (if not recovered through other mechanisms).

Demand for network development and modernisation may exceed the available financing for investments. While transmission investments are widely supported by international financial organisations, facilitated by State guarantees, investments by DSOs, often privately owned, are more reliant on their own resources and/or depreciation. The energy transition and the need to integrate more RES, active customers and distributed generation technologies at the distribution network level, may require more regulatory attention in terms of distribution network development

to meet the relevant demand for new connections. In this respect, recognition of new, flexible solutions that may defer the network developments and still accommodate the new capacities is highly recommended. NRA also are recommended to consider anticipatory investments in the distribution grid (where reasonable) to timely meet the expected demand for capacity according to national development plans and strategies (e.g. NECP). Regulatory support mechanisms for DSOs to attract additional capital for investments need to be explored, e.g. in the case of grants (e.g. for PECI).

ECRB invites NRAs to investigate relevant approaches and provide their findings in the next ECRB reports on the best practices on tariff methodologies.

Cost cascading

Most of NRAs of the Contracting Parties reported no cascading of transmission costs between the users of transmission grid. At the same time, cascading of distribution costs, when D-connected network users at a lower voltage level pay for part of the D-costs of higher voltage levels, are present in all Contracting Parties. In most cases, the cascading reflects the main voltage levels in the distribution grid (35kV, 10kV, 0,4 kV), while in some CPs, the cascades also depend on other criteria contributing to additional cascades, such as connection points in the network in North Macedonia. Reverse cascading is not applied in any CP.

To support principles of cost reflectivity and non-discrimination between network users in terms of cost recovery, it is recommended that NRAs apply cost cascading among the network voltage levels. The number of cascades may not necessarily reflect the whole range of voltage levels used in the power network but they should reflect the most cost-driving voltage levels , considering the density of network users connected to each of the voltage level.

Overall, the cost granularity supports the transparency and cost-reflective nature of the network tariffs. NRAs are recommended to introduce cost granularity at least by voltage level and by types of customers, and regularly monitor the contribution of each category to the overall costs. This shall create a proper basis for further developments in network tariffs' design to ensure their cost-reflectiveness.

Injection and withdrawal tariffs

Only several Contracting Parties have introduced injection network charges at the transmission level, while distribution injection charge applies only in Montenegro. One of the main reasons for the introduction of injection charges in these Contracting Parties was the fact that certain shares of network costs are caused by network users injecting into the grid, not only the ones that withdraw from it.

Bearing in mind that the network charge level of network users should reflect the costs caused by these users, NRAs are invited to assess the impact of network users that inject electricity into the

grid on the costs of TSO and DSO and, in line with the assessment results, to consider the introduction of injection charges. In this context, NRAs shall also ensure that the annual average transmission charges paid by producers shall comply with ranges provided in the *Regulation 838/2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging*. When designing injection network tariffs, there should be neither positive nor negative discrimination between production connected at the distribution level and production connected at the transmission level, unless certain differences in approach are justified for network efficiency reasons.

Injection network tariffs applied in Contracting Parties are mostly energy-based, i.e., only one Contracting Party applies the combination of energy- and power-based injection tariff. On the other hand, the most frequently used transmission tariff basis for withdrawal is a combination of energy and power. When it comes to withdrawal tariffs for distribution system most Contracting Parties apply only energy-based component. . One Contracting Party (North Macedonia) introduced the fixed (lump sum) charge to the D-tariff in 2023. Several NRAs plan the introduction of capacity charge (Kosovo*) and fixed charge (Georgia) in the near future. Considering the fact that TSO's and DSO's costs are associated with different cost drivers, special care should be taken when designing the network tariffs in order to make them more cost-reflective and to send appropriate signals to network users. Following ACER's recommendation, capital/infrastructure costs should be covered primarily via capacity (or power) based tariff charges, reflecting the costs of network assets that provide available capacity, , while variable costs such as costs of losses or some operational costs, should be recovered via energy-based charge, reflecting the costs of injected/withdrawn energy. Finally, for the costs that are not correlated with either energy or power, the fixed (lump-sum) charges per connection or metering point should be used. Furthermore, in view of fluctuating transmission and distribution volumes resulting from the expansion of RES, active customers and distributed generation, NRAs are recommended to consider introducing distribution tariff methodologies that include network connection capacity elements, in accordance with Article 18(7) of Regulation (EU) 2019/943 on the internal market for electricity.

In most Contracting Parties, the network users that both inject and withdraw from the grid are subject to charges for withdrawal. When it comes to the prosumers connected to the distribution system, they are subject to withdrawal charges either for the total withdrawn electricity or for netted energy (withdrawal minus injection) – net-metering. In this context, the application of withdrawal charges to netted energy leads to the cross-subsidiation of these users by other network users that only inject into or withdraw from the grid.

NRAs are advised to take into account the impact on the costs of both injection and withdrawal of these users when setting the network tariffs. Existing schemes that do not account separately for the electricity fed into the grid and the electricity consumed from the grid for the purpose of network tariffs are recommended to be phased out gradually. While, as of 1 January 2027, such schemes shall not be granted to new users in Contracting Parties, bearing in mind the requirements of Article

15 (4) of the Electricity Directive. When designing network tariffs, EnC NRAs are invited to consider the specifics of some network users, such as storage and its positive impact on system flexibility, which supports network stability and the security of supply. In this regard, the tariff design may support the operation of storage in a system-needs-oriented mode or location. Following the cost-reflectiveness principle, NRAs shall carefully analyse the impact of such users on network costs, and if any specific treatment is granted, it shall be justified with regular revision to avoid undue cross-subsidisation.

Connection charges

In all Contracting Parties connection costs are covered by the relevant applicant for connection through the connection charge. In most of the Contracting Parties, except for covering costs of physical connection to the transmission system, the new network users cover also part or all upstream reinforcement costs needed for their connection. These costs are mainly set as actual individual costs of connection. On the other hand, the distribution connection charge in most Contracting Parties is based on the "shallow" approach (six CPs), while four CPs apply "deep" connection charge. In one CP (Georgia) connection charge may represent deep, shallow and shallowish fee, which depends on the type of connection. The distribution connection charges in some CPs are defined as either 'standard' or 'non-standard'. The "standard" connection charge is paid for the required capacity (Bosnia and Herzegovina, North Macedonia, Serbia and Ukraine) and in some CPs (Bosnia and Herzegovina and Serbia) also for construction of the connection (e.g. unit charge for distance). While 'non-standard' connection charge reflects the costs of individual connections and may also include component for provision of technical conditions in the network (North Macedonia) or for the construction of the linear part of the connection (Ukraine). . Where deep/"shallowish" connection charge is applied, the introduction of a certain cost-sharing "compensation mechanism" should be considered in case the infrastructure concerned serves also the future network users. In Ukraine, the standard connection charge is calculated based on normative values, defined by the Ministry of Energy, e.g. not on real costs of the individual connection. The justified difference between the amount of revenue from the provision of standard connection and the actual connection costs is recovered through the D-tariff.

In some Contracting Parties, new producers are subject to lower connection charges than consumers.

Even though introducing a different approach for the connection of some categories of network users (new technologies) may facilitate their integration into the grid, the application of this approach should be limited in time, i.e., until the specific goals for their integration are achieved.

Reactive charges

Most of the Contracting Parties have introduced charges for reactive withdrawal from the transmission and distribution system. In most cases, consumers that withdraw the reactive energy excessively (above a certain threshold) are charged with reactive energy charges. E Some

Contracting Parties also apply the charge for reactive energy injection in addition to the reactive charge for withdrawal.

Different approaches for the calculation of reactive charge apply in the Contracting Parties. In some Contracting Parties, the reactive charge level is calculated based on estimated costs associated with reactive energy flows, while in others this charge is set administratively based on the costs of active energy or more complex calculation methods are applied. Only three Contracting Parties (Bosnia and Herzegovina, Montenegro and North Macedonia) reported that they faced increased costs of compensating reactive exchanges due to the recent market developments. In particular, the transmission networks of Bosnia and Herzegovina and Montenegro face problems with overvoltages during the hours of low demand, which became more frequent due to the reduction of demand at the national level and in neighboring power system and phasing out the TPPs in the region]. We recommend that NRAs consider adapting reactive charging methods to reflect the associated increased costs and send appropriate signals to network users.

Time-differentiation and locational signals

Time-of-use T-tariffs and D-tariffs apply only in two Contacting Parties, and one more NRA applies also time-of-use D-tariffs only. As the market prices may still vary among the hours of the day (reflecting not only time of use but also other conditions influencing the supply/demand balance, such as outages), the time-of-use network tariffs provide additional signals for demand response. Where Contacting Parties have introduced the time-of-use metering (as reported, it is the case at transmission level for most of Contacting Parties), NRAs shall evaluate the advantages and disadvantages of applying time-of-use network tariffs and report the results to the ECRB for the preparation of the next ECRB Tariff Report[108]. Where application of time-of-use network tariffs is positively assessed, NRAs are recommended to consider introducing them in the framework of the nearest tariff methodology review, supporting more efficient network utilization together with other tools of demand response and management. The lack of smart metering should not be an obstacle for introduction of regulatory framework for time of use tariffs (as an option for customers) and may serve as a driver for consumers to opt for smart meters.

Renewable energy communities, citizen energy communities

Most Contracting Parties reported no specific in terms of network tariffs for renewable energy communities and citizen energy communities. Only NRA of Moldova reported reduced distribution tariff for shared electricity by 30% in the case of the local community and by 15% in the case of the regional community.

With the transposition of EIP and further development of the citizen energy communities in Contracting Parties, NRAs shall consider relevant network users when developing the network tariff methodologies. Network charges applied shall be transparent, non-discriminatory and cost-

[108] Every 2 years.

reflective, ensuring that they contribute in an adequate and balanced way to the overall cost sharing of the system. Network charges at the connection points between the network of the citizen energy community and the distribution network shall account separately for the electricity fed into the distribution network and the electricity consumed from the distribution network by the citizen energy community in accordance with Article 59(7) of the Electricity Directive.

Addressing the Energy Community acquis and energy transition

Only in one Contracting Party (Montenegro) NRA recognizes in the T-tariff methodology the incentives for PECI. Georgia indicated that it is in the process of developing a methodology that duly takes PECI/PMI projects into consideration. All other Contracting Parties do not provide any specific incentives to PECI/PMI.

The TEN-E Regulation requires NRAs to recognize the potential additional risks of PECI project promoters in the tariff methodologies. The ECRB recommends to NRAs to provide the regulatory framework for such projects (including risk specific incentives, if any), in order to increase transparency and clarity for project promoters regarding the incentives they may apply for. Also, the benchmark with the neighboring countries, especially, when it is a cross border project with the request for cost sharing, may be useful. This is of utmost importance in light of the adoption in the Energy Community of Regulation (EU) 2022/869 on guidelines for trans-European energy infrastructure with the transposition deadline for Contracting Parties as of 31 December 2024. Following the EIP transposition, the ECRB may further investigate the regulatory practices on risk assessment and incentives applied to PECI by NRAs in the Contracting Parties.

The majority of NRAs of the Contracting Parties reported that they recognized the energy efficiency measures and investments identified by TSOs/DSOs for the introduction of cost-effective energy efficiency improvements in the network infrastructure. In this regard, the ECRB recommends to NRAs to pay due attention to energy efficiency through the development of network tariffs and regulations, taking into account the costs and benefits of each measure, as well as to provide incentives for grid operators to make available system services to network users permitting them to implement energy efficiency improvement measures in the context of the continuing deployment of smart grids, as required by the Directive 2012/27/EU. For this purpose, the Contracting Parties shall ensure an assessment is undertaken of the energy efficiency potential of their electricity infrastructure, in particular regarding transmission, distribution, load management and interoperability, and connection to energy generating installations, including access possibilities for micro energy generators. Concrete measures and investments shall be identified for the introduction of cost-effective energy efficiency improvements in the network infrastructure, with a timetable for their introduction.

NRAs are also recommended to assess the introduction of incentives for innovation and R&D for network operators that may contribute to the energy efficiency and network flexibility, including integration of newly emerging system users. NRAs may adopt regulatory sandboxes or similar innovation schemes that enable energy market participants to test new approaches and solutions

and draw “lessons learned” for further development of the energy market design and the associated regulatory framework. This typically include requires also setting clear criteria for projects (investments) falling under the term “innovation” and defining the key goals and priorities as well as the incentives and timeframes of such schemes.

Annex I: Description of the cost determination and tariffs

Table A1.1 - The description of the cost determination and/or cost models applied in the Energy Community Contracting Parties

Country	*Cost determination and/or cost models*
Albania	Allowed revenues and tariffs for the use of the electricity transmission system are determined by a hybrid regulatory method that basically considers the price-cap principles. Through the limit of the allowed revenues, a price cap is provided and also incentives for improving cost efficiency. Each cap is calculated based on costs (OPEX and CAPEX) that the operator foresees and predicts for the upcoming regulatory period. To provide the data for the base year, ERE consider the costs from the test year, which is used as a basis for defining the required revenues for the base year. Revenue requirements for the base year are calculated as follows: RR = OPEX + CAPEX. As OPEX are considered only the operational expenditures related to the transmission activities: C operating = C metering + C maintenance + C payment + C losses + C ancillary services + C third party services + C tax. The transmission tariff should not be used to liquidate the cost of electricity imports, or capacity charges related to imported energy, or any other costs by suppliers and the users under bilateral agreements. CAPEX is calculated as follows: CAPEX= R + D, where R- return on the regulated asset base and D – depreciation of the fix assets and the depreciation of the other assets. For the second year of the tariff review cycle, each component of tariff to use the transmission network for the base year is multiplied with the annual adjustment/correction factor: A = (1 + RPI – X), where: RPI is rate of customer price inflation for the second year according to the forecast of the National Bank of Albania. X is the efficiency improvement factor set by ERE. In each year of the tariff review cycle, the average transmission tariff equals: P average = (OPEX + CAPEX) / E, where E is total energy amount in kWh that shall be shown in transmission system customers invoice during the year. This method aims to determine a cost-reflective tariff and to cover all those services costs.
Bosnia and Herzegovina	When determining tariffs, the following goals and principles are taken into account: a) impartiality, transparency, and prevention of discrimination; b) incentive for efficiency of the regulated entities and transmission network users; c) incentive for mechanisms for the increase of the energy efficiency; d) establishment of stable relationships on the electricity market and stable conditions for investors into the energy sector; e) incentive for transmission network development in order to continuously maintain or increase the quality of supply. In order to achieve goals and principles referred to in the previous paragraph, tariffs shall be established on justified costs of business, operation, maintenance,

	replacement, construction or reconstruction of facilities and equipment, including a reasonable amount of return on investment, depreciation and taxes and taking into consideration the environmental protection. The non-transaction method of postage stamp is used to determine the transmission tariff. The method is applied to all voltage levels and all types of users with single tariff rates on the territory of the entire Bosnia and Herzegovina. The transmission tariff is comprised of the transmission tariff paid by customers and the transmission tariff paid by generators. The transmission tariff paid by customers is comprised of two components: a) Part of the transmission tariff pertaining to energy (pLE), which represents the ratio of the revenue requirement of the component for energy k*RRL and energy withdrawn by customers WC : pLE = k*RRL /WC where: RRL – part of the revenue requirement pertaining to network fees paid by customers; WC – active electric energy withdrawn by customers; k – the ratio of the revenue requirement of the component for energy and total revenue requirement pertaining to customers. b) Part of the transmission tariff pertaining to capacity (pLC), which represents the ratio of the revenue requirement of the component for capacity (1− k)* RRL and peak load PC measured at customers: pLC = (1− k)* RRL /PC where: PC – peak load measured at customers which represents an annual summation of all monthly maximum capacities measured at customers. The ratio of the energy component and the capacity component shall be determined on the basis of a share of constant energy in an annual load diagram for the previous year. As an initial value, the share of capacity shall be determined in the amount of 35%. The transmission tariff paid by generators shall be: pG = RRG/WG where: RRG – part of revenue requirement pertaining to network tariff paid by generators WG – active electric energy injected in the transmission network by generators connected to the transmission network. Part of the revenue requirement pertaining to network tariffs paid by generators can range from 0 to 10% of the revenue requirement for performance of the regulated activity of the Transmission Company RRTR.
Georgia	Capital Expenditures are mostly cost-based using historic value of RAB, but allows inclusion of the investment plans for the regulatory period. Controllable OPEX, that includes most of operational expenditures except various taxes, is treated with RPI-X model, while Uncontrollable OPEX is treated with ordinary cost-plus, and Goal-

	Setting principles are used towards Electricity Losses, using Normative Loss approach.
*Kosovo**	The cost model used for tariff setting aims to ensure cost-reflectivity, transparency, and efficiency in recovering allowed revenues for network operators. Objective: align tariffs with actual costs, incentivize efficient operation, and maintain financial sustainability. Cost Drivers: include capital expenditures, operational costs, energy losses, and network maintenance.
Moldova	On the first year of the regulation period (of 5 years) TSO is presenting to NRA the base costs (i.e. asset depreciation and OPEX). These costs are indexed each subsequent year using national and international references. Also, the revenue is capped, taking into account the undepreciated asset base and the WACC.
Montenegro	The average cost model is used for determining T-tariffs. The main objective of using this approach is to ensure that all cost categories are assigned to specific cost drivers, such as volume of electricity or maximum power, and that the total regulatory allowed revenue is recovered by design. For the calculation of T-tariffs for producers, the OPEXp (the part of OPEX that is allocated to producers, including the costs for covering transmission losses) is divided by the total forecasted electricity production, while the CAPEXp (the part of OPEX that is allocated to producers) is divided by the sum of the maximum generation power. On the other hand, for the calculation of T-tariffs for consumers, the remaining part of CAPEX and OPEX (excluding the costs for covering network losses) is divided by the sum of the forecasted peak demand, while the costs for covering losses allocated to consumers are divided by the forecasted electricity withdrawal from the transmission system.
North Macedonia	The Rulebook on the manner and conditions for determining maximum allowed revenue and regulated average tariffs of electricity transmission, electricity market organization and management and electricity distribution regulates the conditions and manner of tariff formation, approval, and control that provide maximum allowed revenue which is necessary for performing the energy activities of the electricity transmission, electricity market organization and management and electricity distribution. The average tariff and the tariffs are regulated through the determination of revenue cap that the regulated company is allowed to achieve during one calendar year. The average tariff for the regulated activities for each year of the regulated period, represents a unique tariff obtained as a quotient of the maximum allowed revenue determined for the adequate year of the regulated period divided by the adequate quantity of transmitted or distributed electricity in the same year, as well as electricity that is delivered through physical nominations. The regulated period comprises the period of one or more calendar years for which maximum allowed revenue is determined to the regulated company, necessary for performing the regulated activities. In the first year of the regulatory period, the ERC sets the base revenue for all three years of the regulatory period and the maximum revenue for the first year of the regulatory period. In the second and third year of the regulatory period, ERC sets the maximum revenue for the relevant year. The data from the base year are used in the calculations of the components contained in the base revenue. Starting from 2023, the base year for calculation was set to be t-2. The revenue caps consist of the following main components: basic revenue,

	specified pass-through costs, costs for losses , and correction factor. Revenue for distribution additionally takes into account liquidity assets. The basic revenue, which consists of operational cost, depreciation, return on assets is set at the beginning of the regulatory period for each year of the period and is not adjusted during the regulatory period.
Serbia	The methodology is based on the "costs plus" method of regulation, which determines the maximum amount of income for the regulatory period, i.e. the price of access, for the transmission system operator to the electrical energy transmission system, which provides: 1) covering justified costs, and the appropriate return on effectively invested funds in the performance of electricity transmission and transmission system management activities, which ensure short-term and long-term security of supply, i.e. sustainable development of the system, taking into account income and expenses related to the allocation of cross-border capacities and implementation of a compensation mechanism for electricity transit and other revenues; 2) security of system operation; 3) encouraging economic and energy efficiency; 4) non-discrimination, i.e. equal position of the same category of system users i 5) prevention of mutual subsidisation between individual activities performed by the transmission system operator and between individual users of the system.
Ukraine	Most expenditure items are determined at the level of actual expenditures of the previous year, taking into account the inflation index (or the consumer price index). Some items of expenditure are calculated based on the forecast balance sheet data. In some cases, the level of the item of costs is determined at the level proposed by the TSO (for example, the cost of repairs during martial law).

Table A1.2 - Average Transmission tariff (excl VAT) in 2020-2024, EUR/MWh

	2020	2021	2022	2023	2024
AL	6,06	6,12	7,15	7,81	8,44
BA	4,967	5,030	5,019	5,144	5,249
GE	5,853	5,473	6,789	7,324	7,071
XK	5,37	4,67	7,56	9,56	9,58
MD	7,43	7,43	10,3	10,3	9,48
ME**	29,99	30,49	29,72	30,01	27,97
MK	2,86	3,17	5,54	4,2	4,77
RS	4,25	4,76	5,28	5,29	5,21
UA	6,46	9,10	10,17	11,25	12,16

**Electricity consumers in Montenegro, connected to the distribution system, are charged capacity fees, without a breakdown of the transmission and distribution components. Here, the average value for non-households is presented.

Table A1.3 - Average Distribution tariff for HH (excl VAT) in 2020-2024, EUR/MWh

	2020	2021	2022	2023	2024
AL	38,69	39,13	49,27	53,89	58,21
BA	28,75	28,18	29,31	29,59	30,20
GE	19,54	25,07	32,10	33,55	30,99
XK	25,24	23,27	36,23	31,67	25,49
MD	27,00	20,61	24,48	32,87	33,22
ME	35,76	35,54	35,17	35,12	30,60
MK	25,03	24,7	41,93	34,37	38,96
RS	30,19	32,83	36,01	36,50	36,64
UA	22	27	29	32	37

Table A1.4 - Average Distribution tariff for non-HH (excl VAT) in 2020-2024, EUR/MWh

	2020	2021	2022	2023	2024
AL	-	-	-	-	-
BA	15,66	16,73	16,97	21,68	21,24
GE	12,80	16,26	20,18	21,77	30,99
XK	22,32	20,61	33,09	27,57	22,54
MD	27,00	20,61	24,48	32,87	33,22
ME	31,25	31,24	30,98	31,15	27,10
MK	25,03	24,7	41,93	34,37	38,96
RS	20,35	21,17	22,99	23,12	22,92
UA	16,00	20,00	23,00	26,00	29,00

Table A1.5. - Transmission and distribution losses recognition in tariff regulation

Contracting Party	*Procedure and criteria for recognizing losses in the allowed revenue for TSO and DSO*	*Price for allowed losses of TSO and DSO*
Albania	TSO The costs to cover and procure the electricity to cover power losses are recognized as a component of OPEX.	TSO The costs to cover and procure the electricity losses in the transmission network is calculated based on the market prices: C losses = E losses * P h E losses, where E losses are the electricity losses in the

		transmission network during the base year and Ph is the electricity average price that shall be purchased in the market to cover the losses during the base year.
	DSO Based on the methodology, the costs of losses are considered as a component of OPEX. The energy losses are calculated using the formula below: The amount of lost energy = Distributed quantity * Losses target (%) The allowed percentage of losses is determined by government decision.	DSO According to the law of the power sector, based on the public service obligation, the Government obliged[109] Public Supplier in free market (FTL) to buy the whole energy amount produced by the Priority Producers (RES) with the price approved by ERE. The Public Supplier in free market (FTL) sells this energy amount to the DSO at the same price in order to cover the losses. The remaining energy quantity of loses is purchased on free market. The costs of purchasing losses are calculated and allocated for each producer based on the forecasts of the public service obligation and the respective prices of each source for the year For the remained quantity which is purchased in the free market, the market price is considered.
BA	TSO There are only technical T-network losses. The procurement of the T-network losses is market-based. The realized results of the market procurement of losses provide input values for the calculation of the Tariff for the System Service (not the T-network tariff).	TSO Market based procurement
	DSO Only technical D-network losses are considered by the regulator. The procurement of the D-network losses is based on the DSO assessment and planning.	DSO Mainly, DSOs negotiate energy price with the generators (there are no market procurements).
Georgia	TSO A specific methodology exists, which sets normative losses and based on this methodology, normative losses are included in the revenue of TSO for each tariff period.	TSO The TSO purchase the electricity for compensation of the actual losses at the balancing market price, while only the allowed volume of losses at the same price is recovered via tariff. After launching the day-ahead and intraday markets, the price of

109 There is a supporting mechanism approved by the Council of the Ministers (Decision no. 456/2022).

		allowed losses in tariffs will be set at the day-ahead market price.
	DSO The NRA approves the methodology for calculating the normative losses, and based on this methodology and the historical data, the GNERC determines the normative allowed losses for each DSOs, which is paid through tariffs by the consumers.	DSO The DSOs purchase the electricity for compensation of the actual losses at the balancing market price, while only the allowed volume of losses at the same price is recovered via tariff. After launching the day-ahead and intraday markets, the price of allowed losses in tariffs will be set at the day-ahead market price.
Kosovo*	TSO The allowed cost of losses shall be the forecast cost of losses to be recovered from the TSO to compensate for losses on the Transmission System, calculated using the Loss Allowance which shall be set at Periodic Reviews. Details can be found in the Article 13 of the TSO/MO Pricing Rule.	TSO During the regular annual revenue adjustments, this cost is corrected based on the actual realized energy prices.
	DSO The allowed cost of losses shall be the forecast cost of losses to be recovered from the DSO to compensate for losses on the Distribution System, calculated using the Loss Allowance which shall be set at Periodic Reviews. Details can be found in the Article 12 of the DSO Pricing Rule	DSO During the regular annual revenue adjustments, this cost is corrected based on the actual realized energy prices.
Moldova	TSO Only technical transmission losses are included in the allowed revenue. According to the legislation the level of losses considered for tariff calculation in the year "n" can't exceed the real measured losses in the previous year "n-1".	TSO The price for the allowed losses is taken considering the realized data for the previous period. In the same time the realized cost is inputted when available and the difference (positive or negative) is reflected when calculating the tariff for the next year.
	DSO According to the provision of the Law on electricity (art. 87) the recognized technical losses in the allowed revenue cannot exceed the real losses registered in the previous year.	DSO The price for the losses reflects the realized price for the electricity bought by the DSOs. When calculating the distribution tariff for the year „n" NRA is using an estimated prices considering the available information in the contracts. When establishing the tariff for year n+1 NRA is considering the realized and estimated values.
Montenegro	TSO When submitting the request for determining the regulatory allowed revenue, the TSO is obliged to	TSO The price of allowed losses that is used for the assessment of costs

	submit also the Study of Losses, which is audited by an independent institution. This Study shall assess the percentage of the (technical) transmission losses, which is then taken into account when assessing costs for covering transmission losses.	for covering network losses is calculated by taking into account the price achieved by the dominant trader in the Montenegrin wholesale market and the price of futures on HUDEX (the closest liquid market). When determining the adjustments to determined regulatory allowed revenue, the actual price that is achieved on the market when purchasing electricity for covering losses is used.
	DSO Only technical losses are recognized as justified by NRA. Technical losses are calculated and presented in Study on losses in distribution system submitted by DSO and audited by an independent institution.	DSO The price of allowed losses that is used for the assessment of costs for covering network losses is calculated by taking into account the price achieved by the dominant trader in the Montenegrin wholesale market and the price of futures on HUDEX (the closest liquid market). When determining the adjustments to determined regulatory allowed revenue, the actual price that is achieved on the market when purchasing electricity for covering losses is used.
North Macedonia	TSO The allowed revenue of TSO includes costs for the losses set by ERC. Losses are procured on the tender, after which TSO signs bilateral agreement with the bidders with the best offers. Also, TSO may procure the necessary quantities and sell excess of electricity on the power exchange.	TSO The price achieved on the tender/power exchange price.
	DSO The allowed revenue of DSO includes a quantities of the losses set in the Plan for reduction of the losses approved by ERC. Losses are procured on the tender, after which DSO signs bilateral agreement with the bidders with the best offers. Also, DSO may procure the necessary quantities and sell excess of electricity on the power exchange.	DSO Price is obtained on the public tenders and the price achieved is power exchange price.
Serbia	TSO The allowed losses are evaluated by NRA according to the historical data and investment plans.	TSO The price of electricity for loss compensation is the weighted average justified purchase price of electricity, including all justified dependent costs of electricity procurement.

	DSO The allowed losses are evaluated by NRA according to the historical data and investment plans.	DSO The price of electricity for loss compensation is the weighted average justified purchase price of electricity, including all justified dependent costs of electricity procurement.
Ukraine	TSO The costs associated with the purchase of electric energy in order to compensate transmission (technical) losses are determined in accordance with the Procedure for establishing (forming) the tariff for electricity transmission services (NEURC Resolution of 22.04.2019 № 585). According to this procedure, the projected amount of transmission technical losses of electricity per year t (with a breakdown by quarters) is determined taking into account the approved (by the Ministry of Energy) forecast balance of electricity of the united power system of Ukraine for the corresponding year.	TSO TSO price is calculated based on the level of prices of electricity purchased under bilateral contracts at electronic auctions, balancing market and on the day-ahead market (in the established ratio).
	DSO The costs associated with the purchase of electric energy in order to compensate distribution losses are determined in accordance with the Tariff Establishment Procedure (NEURC Resolution No.1175 of 05.10.2018). The forecasted amount of distribution losses is considered taking into account the economic coefficients of predicted technical losses of electricity for 1st and 2nd voltage classes respectively.	DSO The price is calculated based on the level of prices of electricity purchased under bilateral contracts at electronic auctions, balancing market and on the day-ahead market (in the established ratio).

Annex II: TSO's and DSO's revenue in 2024

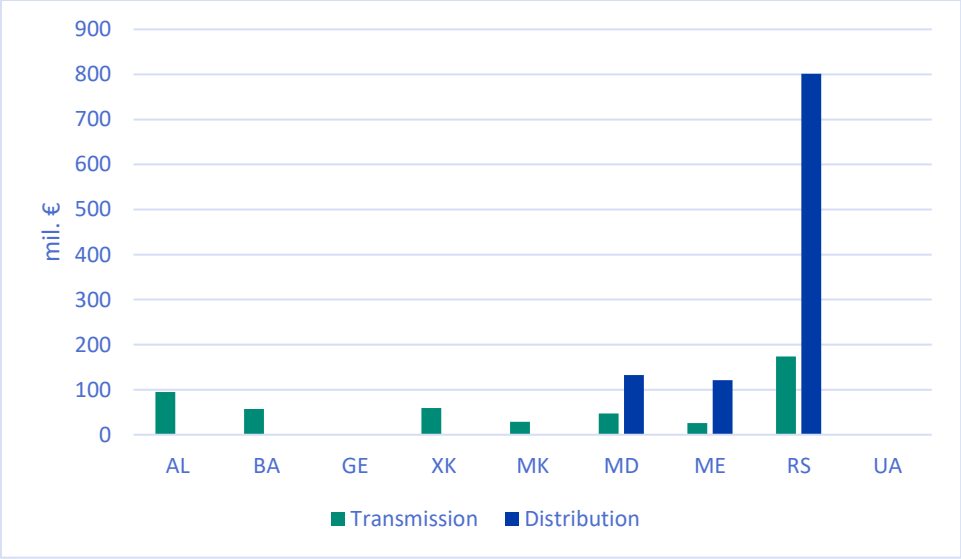


Figure A2.1 - Collected TSO's and DSO's revenue in 2024 in mil. €

Annex III: Value of injection and withdrawal charges in 2024-2025

Transmission

Table A3.1 - T-injection and T-withdrawal charges in Contracting Parties

	Withdrawal charges			*Injection charges*
AL[110]	Energy-based (€/kWh (ALL/kWh))			-
			May 2022-Dec 2024	
			0.85	
BA[111]	Elektroprenos BiH		NOSBIH (ISO)	NOSBIH (ISO)
	Energy-based (cent€/kWh)	Power-based (€/kW)	Energy-based (cent€/kWh)	Energy-based (cent€/kWh)
	0.296	*0.753*	*0.0558*	*0.0043*
GE[112] *(on 2025)*	Energy-based (c€/kWh (tetri/kWh))			-
	1.04 (3.298[113]*)*			

110Links to the Decisions: https://www.ere.gov.al/doc/Metodologjia_e_llogaritjes_se_tarifave_te_transmetimit_te_energjise_elektrike-2.pdf

111 Links to the Decisions: https://www.derk.ba/DocumentsPDFs/Odluka-o-tarifi-za-prenos-03-04-2017-en.pdf https://www.derk.ba/DocumentsPDFs/Odluka-o-produz-vazenja-Odluke-o-tarifi-prijenosa-8mar19-en.pdf and https://www.derk.ba/DocumentsPDFs/Odluka-o-tarifi-za-NOS-28-12-2022-en.pdf

112 Link to the Decision: https://gnerc.org/en/tariffs/tariff-el-energy/gadatsema

113 Excahge rate: 1 GEL = 0.317849 EUR, 09/10/2025

XK[114]* *(on 2025)*	*Supply*			*DSO*		T-connected generation	D-connected generation
		Power-based (€/kW/year)		Energy-based (€/MWh)		Energy-based (€/MWh)	Energy-based (€/MWh)
		400/220 kV	*110 kV*	SO; MO		SO; MO	SO; MO
	4.644; 0.018; 2.924	*2.087*	*4.939*	*4.644; 0.018*		*5.682; 0.022*	*0.157; 0.022*
MD[115]	Energy-based (€/kWh (bani/kWh))					-	
	0.0009						
ME[116]	Energy-based (€/MW)		Power-based (€/MWh)		Reactive electricity (€/MVarh)	-	
	222.26		4.32		1.73		
MK[117]	Energy-based (c€/kWh)		Power-based (€/kW/month)		Reactive electricity (€/rVar)	-	
	0.004		*0.222*		*0.0017*		
	Withdrawal charges					*Injection charges*	

114 Link to the Decision: https://www.ero-ks.org/zrre/sites/default/files/Publikimet/Vendimet/Vendimet%202025/1.%20Decision%20on%20Tariffs_2025_TSO_MO-FINAL.pdf

115 Link to the Decision: https://www.legis.md/cautare/getResults?doc_id=134854&lang=ro

116: https://regagen.co.me/wp-content/uploads/2021/12/20191202_CGES_Odluka_RDP_2020-2022.pdf and https://regagen.co.me/wp-content/uploads/2022/01/20211202_CGES_Odluka_o_korekcijama_KONACNA.pdf https://regagen.co.me/wp-content/uploads/2022/12/2022.11.30_CGES_Odluka-RDP-2023-2025.pdf

117 https://www.erc.org.mk/odluki/2023.12.22%20ODLUKA%20-%20MEPSO%20PRENOS%202024.pdf

<table>
<tr><td rowspan="3">RS[118]

(on 2021 but without changes)</td><td colspan="2">Energy-based (c€/kWh (RSD/kWh))</td><td colspan="2">Power-based (c€/kW (RSD/kW))</td><td>-</td></tr>
<tr><td>High tariff</td><td>Low tariff</td><td>Contracted power</td><td>Exceeded power</td><td></td></tr>
<tr><td>0.4037 (0.4742)</td><td>0.2019 (0.2371)</td><td>50.5366 (59.3603)</td><td>202.146 (237.4412)[119]</td><td></td></tr>
<tr><td>UA[120]</td><td colspan="2">Transmission services</td><td>Dispatching management services</td><td>Dispatching management services</td></tr>
<tr><td colspan="4">For the period from 1 January 2024 through 31 December 2024 (inclusive)</td><td></td></tr>
<tr><td>Electricity transmission service tariff for system users (except for “green electrometallurgy” enterprises)*.</td><td>Transmission tariff for enterprises of “green electrometallurgy.”</td><td></td><td></td></tr>
<tr><td>Energy-based (€/MWh (UAH/MWh))</td><td>Energy-based (€/MWh (UAH/MWh))</td><td>Energy-based

(€/MWh (UAH/MWh))</td><td>Energy-based

(€/MWh (UAH/MWh))</td></tr>
</table>

118 Link to the Decision: https://www.aers.rs/media/FILES/Odluke/OCenama/2021-10-01_EMS%20Cenovnik%20-%20prenos.pdf

119 Exchange rate: 1 RSD = 0.00853503 EUR, 09/10/2025

120 Links to the Decisions: https://www.nerc.gov.ua/sferi-diyalnosti/elektroenergiya/promislovist/tarifi-na-elektroenergiyu-dlya-nepobutovih-spozhivachiv/tarif-na-poslugi-z-peredachi-elektrichnoyi-energiyi
https://www.nerc.gov.ua/sferi-diyalnosti/elektroenergiya/promislovist/tarifi-na-elektroenergiyu-dlya-nepobutovih-spozhivachiv/tarif-na-poslugi-z-dispetcherskogo-operativno-tehnologichnogo-upravlinnya

	12,16 (528,57[121])	*8,39 (104,57)*	*2,41 (104,57)*	*2,41 (104,57)*
	*including, for 2025, support for electricity producers from renewable energy sources (RES) *4,40 (191,36)*			

121 Exchange rate: 43,4504 UAH = 1 EUR, 09/10/2025

Distribution

Table A3.2 - D-injection and D-withdrawal charges in Contracting Parties

CP	DSO	Withdrawal charges					Injection charges
AL[122]	Operatori i Shpërndarjes së Energjisë Elektrike Sh.A	Consumers categories	Energy-based tariff (€/kWh (ALL/kWh))				-
		35 kV	*0.016 (1.55)*[123]				
		20/10/6 kV	*0.041 (3.99)*				
		0.4 kV	*0.066 (6.42)*				
BA	Javno preduzeće Elektroprivreda Bosne i Hercegovine d.d. - Sarajevo[124]	Consumers categories	Energy-based (pfenig/kWh)		Power-based (BAM/kWh)	Lump sum (BAM)	-
			high	low			
		35 kV	1.33	0.67	5.08	11	

122 Link to the Decision: https://www.ere.gov.al/doc/Electricity_Distribution_Methodology-1.pdf

123 Excahge rate: 1 ALL = 0.0103378 EUR, 09/10/2025

124 Link to the Decision: https://www.ferk.ba/_en/images/stories/2017/decision_epbih_distribution_network_fee_90_2014.pdf (page 2 a

		10 kV		1.58		0.79	7.24	9.35	
		HH	I TG	6.82			-	1.75	
			II TG	8.53		4.26	-	1.75	
		commercial	I TG	6.89		3.45	6.52	4.15	
			II TG	8.91		4.45	-	2.6	
			III TG	6.82			-	1.75	
			IV TG	8.53		4.26	-	1.75	
		Public lighting		7.73			-	1.7	
	Javno poduzeće „Elektroprivreda Hrvatske zajednice Herceg Bosne“ dioničko društvo Mostar[125]	season		Energy-based (pfenig/kWh)			Power-based (BAM/kWh)		-
				higher		lower	higher	lower	
				high	low	high	low		
		35 kV		2.05	1.02	1.57	0.79	7.73	5.94
		10 kV		2.47	1.24	1.9	0.95	8.71	6.7
		HH	I TG	7.61		5.85		6.64	5.11
			II TG	9.51	4.75	7.31	3.66	6.64	5.11
		comercial	I TG	7.98	3.99	6.14	3.07	11.12	8.56

125 Link to the Decision: https://www.ferk.ba/_en/images/stories/2017/decision_ephzhb_distribution_network_fee_90_2014.pdf (page 2 and 3)

			II TG	11.31	5.65	8.7	4.35	11.12	8.56	
			III TG	9.05		6.96		11.12	8.56	
		Public lighting		10.69		8.22		1.8	1.38	
	DSOs in BA's entity Republika Srpska[126] *(on 2022)*			Energy-based (BAM/kWh)		Power based (BAM/kW/month)				
				high	low					
		35 kV		0.023	0.0115	4.3362				
		10 kV		0.0235	0.0117	10.8243				
		0.4 kV – other consumption	I TG	0.0305	0.0153	18.2444				-
			II and VI TG	0.0502		6.5334				
			III and VII TG	0.0637	0.0318	6.5334				
		0.4 kV – public lighting		0.1303		-				
		0.4 kV - HH	I TG	0.0509		3.1668				
			II TG	0.0669	0.0335	3.1668				
	Javno preduzeće „Komunalno Brčko" d.o.o.,			Energy-based (pfenig/kWh)		Power based (BAM/kW/month)				
				high	low					
		35 kV		1.15	0.58	4.2				

126 Link to the Decision: https://reers.ba/wp-content/uploads/2022/12/Odluka-o-utvrdjivanju-tarifnih-stavova-za-korisnike-distributivnih-sistema-u-Republici-Srpskoj-decembar-2022.-godine-cirilica-1.pdf (local no english version - page 2)

	Brčko[127] *(on 2025)*	10 kV		2.08	1.04	8.98
		0.4 kV – public lighting		7.88		-
		0.4 kV – other consumers	I TG	2.81	1.41	13.80
			II TG	4.66		3.70
			III TG	9.04	4.52	
		0.4 kV HH	I TG	4.37		2.22
			II TG	6.56	3.28	
GE[128]	JSC Telasi			Energy-based (c€/kWh (tetri/kWh))		-
		110-35 kV		0.17 (0.544[129])		
		10/6/3.3 kV		0.94 (2.961)		
		0.4 kV		1.96 (6.184)		
	JSC Energy Pro Georgia			Energy-based (c€/kWh (tetri/kWh))		
		110-35 kV		0.59 (1.851)		
		10/6/3.3 kV		1.57 (4.950)		
		0.4 kV		2.99 (9,427)		
XK*[130]	KEDS JSC			Energy-based tariff (cent€/kWh)		-

127 Link to the Decision: https://www.derk.ba/DocumentsPDFs/Tarifa-Brcko-distribucija-11feb2025-en.pdf (page 1)

128 Link to the Decision: https://gnerc.org/en/tariffs/tariff-el-energy/distribution

129 Excahge rate: 1 GEL = 0.317645 EUR, 09/10/2025

130 Link to the Decision: https://www.ero-ks.org/zrre/sites/default/files/Publikimet/Vendimet/Vendimet%202025/2.%20Decision%20on%20Tariffs_2025_DSO-Final.pdf

(on 2025)		35 kV	1.74					
		10 kV	2.33					
		0.4 kV	3.46					
MD[131]	Î.C.S. „Premier Energy Distribution" S.A.		Energy-based tariff (c€/kWh (bani/kWh))			-		
		HV 35-110 kV	0.123 (2.4)					
		MV 6-10 kV	1.09 (21.4)					
		LV 0.4 kV	3.56 (69.5)					
	S.A. „RED Nord"		Energy-based tariff (c€/kWh (bani/kWh))					
		MV 6-10 kV	1.41 (27.5)					
		LV 0.4 kV	6.27 (122.4)					
ME [132]	LLC "Crnogorski elektrodistributivni sistem" Podgorica	Category of consumer	Energy-based component (cent€/kWh)	Power-based component (€/kW)	Fixed charge (€/month)	Producer category	Energy-based (€/kWh)	Power-based (€/M

131 Links to the Decisions: https://anre.md/energie-electrica-3-290

132 Link to the Decision: https://regagen.co.me/publikacije/cedis-metodologija-za-rdp-precisceni-tekst/

											W/ month)
					high	low					
		35 kV					2,6552		35 kV		110 ,85 69
		10 kV					6,7982		10 kV		164 ,85 99
		0.4kV	Measuring power				15,4233		0.4 kV		272 ,53 69
			Not-measuring power	0 kW ≤ approved CC[133] ≤ 8 kW	Dual tariff	3,2555	3,2555	-	0,7030		
					Single tariff	2,6695					
				8 kW < approved CC ≤ 16 kW	Dual tariff	3,2555	3,2555	-	1.4060		
					Single tariff	2,6695					

133 CC: approved connection capacity

				16 kw < approved CC ≤ 34,5 kW	Dual tariff	3,2555	3,2555	-	3.0332			
					Single tariff	2,6695						
CP	DSO	Withdrawal charges								Injection charges		
MK [134]	Elektrodistribucija Skoplje DOOEL Skoplje									-		
						Power-based (EUR/kW)	Energy-based (EUR/kWh)	Reactive electricity (EUR/kVarh)	Access to the network (EUR /month)			
		MV1				3.02	0.0062	0.0006	24.4			
		MV2				6.11	0.0087	0.0016	24.4			
		LV1.2				10.07	0.0110	0.0025	24.4			
		LV1.2				-	0.0543	-	0			
		LV2				-	0.0374	-	3.25			
RS[135] (on 2021	Elektrodistribucija Srbije d.o.o. Beograd					Energy-based (c€/kWh (RSD/kWh))		Power-based (c€/kWh (RSD/kW))		-		

134 Links to the Decisions provided by NRA aren't work: https://www.erc.org.mk/odluki/231.12.2021%20ELEKTRODISTRIBUCIJA%202022.pdf, and https://www.erc.org.mk/odluki/29.06.2022%20ODLUKA%20-%20ELEKTRODISTRIBUCIJA%202022.pdf

135 Link to the Decision: https://aers.rs/media/FILES/Odluke/OCenama/2021-10-01_ED%20Cenovnik%20-%20distribucija.pdf

but no changes)				high	low	Contracted power	Exceeded power	
		Medium voltage		0.9152 (1.075)	0.3048 (0.358)	92.3855 (108.516)	369.543 (434.065)	
		Low voltage		2.1045 (2.473)	0.7015 (0.824)	147.817 (173.626)	591.269 (694.504)	
		Wide consumption	Single tariff	2.8895 (3.394)		46.1927 (54,258)	-	
			Dual tariff	3.3024 (3.879)	0.8258 (0.97)	-	-	
			Controllable demand	2.8069 (3.297)	0.7015 (0.824)	-	-	
		Public lighting		3.0708 (3.607)		-	-	

CP	DSO	Withdrawal charges	Injection charges
UA[136]			-

№	Distribution System Operators (DSOs)	Energy-based (UAH/MWh)		Energy-based (€/MWh)	
		Voltage class 1	Voltage Class 2	Voltage class 1	Voltage Class 2
1	JSC "VINNYTSIAOBLENERHO"	344.82	2028.18	7.94	46.68
2	PrJSC "VOLYNOBLENERHO"	256.27	1722.53	5.90	39.64
3	JSC "DTEK DNIPROVSKI ELEKTROMEREZHI"	226.41	1328.03	5.21	30.56
4	JSC "DTEK DONETSKI ELEKTROMEREZHI"	394.34	1808.6	9.08	41.62
5	PrJSC "ZAKARPATTSAOBLENERHO"	474.95	2152.21	10.93	49.53

136 Link to the Decision:
https://www.nerc.gov.ua/sferi-diyalnosti/elektroenergiya/promislovist/tarifi-na-elektroenergiyu-dlya-nepobutovih-spozhivachiv/tarifi-na-poslugi-z-rozpodilu-elektrichnoyi-energiyi/tarifi-na-poslugi-z-rozpodilu-elektrichnoyi-energiyi-shcho-diyut-z-01-sichnya-2024-roku

6	PJSC "ZAPORIZHZhIAOBLENERHO	177.78	1333.19	4.09	30.68
7	PrJSC "DTEK KYIVSKI ELEKTROMEREZHI"	194.35	767.97	4.47	17.67
8	PrJSC "DTEK KYIVSKI REHIONALNI ELEKTROMEREZHI"	402.65	1601.47	9.27	36.86
9	PrJSC "LVIVOBLENERHO"	311.75	1631.03	7.17	37.54
10	JSC "MYKOLAIVOBLENERHO"	460.44	1995.58	10.60	45.93
11	JSC "DTEK ODESKI ELEKTROMEREZHI"	304.92	1872.98	7.02	43.11
12	JSC "POLTAVAOBLENERHO"	250.87	1748.69	5.77	40.25
13	JSC "PRYKARPATTIAOBLENERHO"	330.44	2131.79	7.60	49.06
14	JSC "SUMYOBLENERHO"	316.88	2243.43	7.29	51.63
15	JSC "TERNOPILOBLENERHO"	400.33	2126.05	9.21	48.93
16	JSC "KhARKIVOBLENERHO"	438.67	1818.79	10.10	41.86
17	JSC "KHMELNYTSKOBLENERHO"	423.93	2019.05	9.76	46.47
18	PJSC "CHERKASYOBLENERHO"	242.03	1709.11	5.57	39.33
19	JSC "CHERNIHIVOBLENERHO"	435.25	2147.25	10.02	49.42
20	LLC "DTEK VYSOKOVOLTNI MEREZHI"	102.57	2630.87	2.36	60.55
21	PrJSC "PEEM "TSEK"	201.57	1387.91	4.64	31.94
22	LLC "LUHANSKE ENERHETYCHNE OBIEDNANNIA"	556.28	2140.52	12.80	49.26
23	DPEM PrJSC "ATOMSERVIS"	91.36	1411.45	2.10	32.48
24	SE "REHIONALNI ELEKTRYCHNI MEREZHI"	181.01	545.02	4.17	12.54
25	PrJSC "DTEK PEM-ENERHOVUHILLIA"	61.91	619.19	1.42	14.25
26	LLC "NAFTOGAZ TEPLO" (NOVYI ROZDIL)	316.01	1844.35	7.27	42.45
	LLC "NAFTOGAZ TEPLO" (NOVOIAVORIVSK)	286.48	1476.01	6.59	33.97
27	JSC "UKRZALIZNYTSIA"	388.59	1730.19	8.94	39.82
Electricity distribution service tariffs applicable from 1 January 2024					
1	JSC"ZHYTOMYROBLENERHO"	327.86	1643.05	7.55	37.81
2	PrJSC "KIROVOHRADOBLENERHO"	397.24	1605.49	9.14	36.95
3	PrJSC "RIVNEOBLENERHO"	243.49	1344.41	5.60	30.94
4	JSC "KHERSONOBLENERHO"	491.28	1439.92	11.31	33.14
5	JSC "CHERNIVTSIOBLENERHO"	187.81	1462.19	4.32	33.65

Annex IV: main goals for designing the structure of withdrawal charges

Transmission

Table A4.1 - Primary and secondary goals for the determination of the design of T-withdrawal charges

	Primary goals	Secondary goals
AL	N/I	N/I
BA	recovery of transmission costs and reflecting system use of current transmission assets	-
GE	-	-
XK*	-recovery of transmission costs reflect system use of current transmission assets Provide an equitable (fair) allocation of transmission revenues across generation facilities	-
MD	recovery of transmission costs	-
ME	recovery of transmission costs and reflecting system use of current transmission assets	Providing price signal to postpone new network reinforcements and to postpone the reinforcement of the interconnection capacity
MK	recovery of transmission costs	reflect system use of current transmission assets
RS	recovery of transmission costs, providing price signal to postpone new network reinforcements and reflecting system use of current transmission assets	providing price signal to postpone the reinforcement of the interconnection capacity and to avoid congestion in the transmission grid
UA	recovery of transmission costs	-

Distribution

Table A4.2 - Primary and secondary goals for the determination of the design of D-withdrawal charges

	Primary goals	Secondary goals
AL	recovery of distribution costs, requiring a fair contribution towards stranded distribution assets, reflecting system use of current distribution assets and providing an equitable (fair) allocation of distribution revenues across	-
BA	recovery of distribution costs, reflecting system use of current distribution assets and providing an equitable (fair) allocation of distribution revenues	-
GE	Recovery of distribution costs	-
XK*	recovery of distribution costs, requiring a fair contribution towards stranded distribution assets, incentivizing the connection of generation that contributes to a more balanced system use and providing an equitable (fair) allocation of distribution revenues across generation facilities	-
MD	recovery of distribution costs	-
ME	-	-
MK	recovery of distribution costs and reflecting system use of current distribution assets	-
RS	recovery of distribution costs, providing price signal to postpone new network reinforcements and reflecting system use of current distribution assets	providing price signal to avoid congestion in the distribution grid
UA	-	-

Energy Community
Regulatory Board

Energy Community Secretariat
Am Hof 4, Level 5, 1010 Vienna, Austria

energy-community.org
info@energy-community.org
0043 (0)1 535 2222