ECRB Report on Electricity Transmission and Distribution Tariff Methodologies in the Energy Community

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Content

List of tables

List of Figures

List of Case Boxes

1. Introduction

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

The Energy Community[1] is an international organisation 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. The ECRB is the independent regional voice of energy regulators in the Energy Community. The ECRB's mission builds on three pillars: providing coordinated regulatory positions to energy policy debates, harmonizing regulatory rules across borders and sharing regulatory knowledge and experience.

1.2. Background

The Energy Community acquis, namely Regulation (EU) 2019/943 of 5 June 2019 on the internal market for electricity[4] as adapted and adopted by the Ministerial Council's Decision D/2022/03/MC-EnC (hereinafter: 'Regulation 2019/943') 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. In particular, the 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 Regulation 2019/943 to prepare a best practice report on transmission and distribution tariff methodologies in Energy Community Contracting Parties biannually. In line with this Article, the best practice report shall address at least:

- the ratio of tariffs applied to producers and tariffs applied to final customers;
- the costs to be recovered by tariffs;
- time-differentiated network tariffs;

[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] 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/

- 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 including, where applicable, the characteristics of those groups, forms of consumption, and any tariff exemptions;
- losses in high, medium and low-voltage grids.

Also, Article 18 prescribes that the ECRB should take into account the report developed by the Agency for the Cooperation of Energy Regulators (ACER) under Article 18 of Regulation (EU) 2019/943.

In line with Regulation 2019/943, this report shall be duly taken into consideration by National Regulatory Authorities ('NRAs') in the Energy Community Contracting Parties when fixing or approving transmission tariffs and distribution tariffs or their methodologies in 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').

The present report analyzes the transmission tariff ('T-tariff') and distribution tariff ('D-tariff') methodologies applied in the Contracting Parties, including the regulatory framework for network tariff regulation, methods to ensure transparency in setting tariff methodologies and network tariffs, the composition of allowed revenues and costs, tariff design/structures, etc. This report also provides an overview of the main aspects of setting other network-related charges (e.g., connection charges, reactive charges) in the Contracting Parties. A specific part of the Report is dedicated to the selected provisions of other acts of the Energy Community acquis to be considered when setting the network tariffs in electricity and their application status in current methodologies. Finally, the ECRB recommendations as regards further development of transmission and distribution tariff methodologies in the Contracting Parties are provided with the view to accommodate current practices to the requirements of the Clean Energy Package, where needed.

1.3. Methodology and scope

ACER's *Report on Electricity Transmission and Distribution Tariff Methodologies in Europe* (ACER Tariff Methodologies Report), as well as previous ACER reports on tariff methodologies, namely: *Report on Transmission Tariff Methodologies in Europe (2019)* and *Report on Distribution Tariff Methodologies in Europe (2021),* were taken into account for the preparation of this report, as required by Regulation 2019/943.

Data and analyses provided in the present report are based on information provided by the regulatory authorities of the analysed markets. The questionnaires used for the collection of information are designed taking into account the topics covered in the abovementioned ACER reports, as well as previous ECRB reports[5] related to the electricity network tariff methodologies applicable in the Energy Community Contracting Parties.

[5] *ECRB Report on Evaluation of the annual average transmission charges paid by producers in Energy Community Contracting Parties*, 2019 and *ECRB Report on Distribution tariff methodologies for electricity and gas in the Energy Community*, 2019.

The information in this report reflects the electricity transmission and distribution tariff methodologies and tariffs as well as other electricity network charges applied in 2022. Where other period is covered, it is notified explicitly in the report.

This report covers all nine Energy Community Contracting Parties: Albania (AL), Bosnia and Herzegovina (BA), Georgia (GE), Kosovo* (XK*), Moldova (MD), Montenegro (ME), North Macedonia (MK), Serbia (RS) and Ukraine (UA).

The definitions set by Directive (EU) 2019/944, Regulation (EU) 2019/943 and ACER Tariff Methodologies Report apply in this report.

2. National framework for network tariff setting in the Contracting Parties

2.1. Legal and regulatory framework

Article 59(1)(a) of Directive 2019/944 provides that NRA shall fix or approve, in accordance with transparent criteria, transmission or distribution tariffs or their methodologies, or both.

2.1.1. Transmission

The national legal frameworks on electricity network tariff regulation of the Contacting Parties comprise primary law and methodologies approved by the NRAs. In particular, in most of the Contracting Parties, the type of T-tariff regulation is determined solely by the NRA through the relevant methodologies, while in four Contracting Parties (XK*, ME, RS and UA) the laws define the main principles and/or type of T-tariff regulation. The majority of Contracting Parties have only one TSO in their jurisdiction and a single T-tariff methodology per country applied.

At the same time, in Bosnia and Herzegovina, transmission operator's activities are performed by two entities, Independent System Operator (ISO) BIH and TRANSCO. ISO BIH 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. Therefore, the regulator – the *State Electricity Regulatory Commission of Bosnia and Herzegovina* (SERC) approved the methodology for the calculation of both tariffs for services of electricity transmission and tariffs for ISO, which are applied by those operators. In Ukraine, there is a single TSO with two types of tariffs (and relevant methodologies), the one – for transmission services and the second – for dispatch services (power system management).

A general description of the regulatory framework applied by Energy Community Contacting Parties is presented in Table 1.1 of Annex I. As observed, in all Contracting Parties, NRAs play the key role in tariff setting and approval of T-tariff calculation methodologies. For example, in Kosovo*, the TSO is responsible for T-tariff methodology development based on the principles set by the NRA – *Energy Regulatory Office* (ERO), however, the ERO then conducts a consultation process and after that approves the methodology. In Serbia, the methodology is developed by the regulator – *Energy Agency of the Republic of Serbia* (AERS) in cooperation with the TSO, and subject to approval by the regulator after public consultations.

2.1.2. Distribution

Similar to the T-tariff, the NRAs play a key role in D-tariff regulation and setting. As regards the legal framework for the D-tariff setting, some Contracting Party specifics are observed due to the different number of DSOs and different authorities involved at the national scale. Also, four Contracting Parties reported having closed distribution systems operators[6] (hereinafter: CDSO) and in three of them the NRAs have the authority to approve the tariff methodology and/or review the tariffs of CDSO upon a

[6] An operator of a system which distributes electricity within a geographically confined industrial, commercial or shared services site and does not supply household customers, except for a small number of households with employment or similar associations with the owner of the distribution system, which fulfils conditions set by Article 38 of Directive 2019/944 and which is appointed by a regulatory authority or other competent authority as a closed distribution system operator. Article 38 Directive 2019/944 recognizes the closed distribution systems as a distribution system for the purposes of this Directive.

request of a closed distribution system user or to examine the tariff methodology applied by CDSO (also upon a request).

Albania and Kosovo* reported having one DSO each in their jurisdiction and one methodology in place for D-tariff regulation set by the NRA – *Energy Regulatory Authority* (ERE) – in Albania and by the DSO in Kosovo*. In Kosovo*, DSO develops the D-tariff methodology based on the principles set by ERO, ERO then conducts a consultation process and after that approves the methodology. There are no CDSOs in Albania and Kosovo*.

Bosnia and Herzegovina ('BA') has divided jurisdiction regarding the regulation of the electricity distribution activity between two entity regulatory commissions – *Regulatory Commission for Energy in Federation of Bosnia and Herzegovina* (FERK) and *Regulatory Commission for Energy of Republika Srpska* (RERS) that have jurisdiction in the entities of the Federation of Bosnia and Herzegovina and Republika Srpska, respectively – and the SERC that has jurisdiction in the Brcko District. Each regulatory authority independently determines the methodology and adopts D-tariffs within its jurisdiction. There are 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.

In Georgia, the type of D-tariff regulation is determined by the methodology approved by the NRA – *Georgian national energy and water supply regulatory commission* (GNERC) and it is (legally) required to be applied by all DSOs (there are two DSOs in Georgia).

Similar to Georgia, in Moldova, there are two DSOs to which the same distribution tariff methodology is applied. Also, there are nine CDSOs that have authorization to operate granted by the NRA – *National Agency for Energy Regulation of the Republic of Moldova* (ANRE)[7]. The tariffs for the CDSOs are calculated and set by the CDSOs themselves in accordance with the methodology issued and approved by ANRE. However, upon a request of a closed distribution system user, ANRE will verify the tariff set by the operator and the approved tariff will be published in the Official Gazette.

North Macedonia has two DSOs whose tariffs are calculated in accordance with the D-tariff regulatory framework set by the NRA – *Energy and Water Services Regulatory Commission* (ERC).

Montenegro and Serbia have one DSO each in their jurisdiction. The main provisions regarding the scope and requirements of the D-tariff methodology are prescribed by primary legislation (national laws), while the D-tariff methodology is developed by the respective NRA – *Energy and Water Regulatory Agency of Montenegro* (REGAGEN) in Montenegro and AERS in Serbia.

Also, four CDSOs operate in Montenegro and they are responsible for setting the network tariffs for their users, i.e., the tariff methodology is determined by CDSOs. However, the closed distribution system user can request REGAGEN to examine the tariff methodology or network tariffs applied by CDSO.

In Serbia, there are five CDSOs. According to Article 151 of the Energy Law, AERS adopts a methodology for the calculation of the price for access to the closed distribution system. In accordance with this methodology, CDSO adopts a decision on the price of access to the closed distribution system and publishes it on its website. However, upon a request of a closed distribution system user, AERS should check the method for determining the price of access to that system, and in case that it

[7] See the list on the ANRE website: https://anre.md/registrul-titularilor-de-autorizatii-3-141

finds that the prices have not been determined in accordance with the methodology, AERS will require the CDSO to correct the prices.

In Ukraine, there is by far the highest number of DSOs compared to other Contracting Parties – 32 DSOs. Although the primary legislation[8] and regulatory framework allow for the introduction of incentive regulation for DSOs, the application of the cost-plus regulatory model is allowed for the transitional period. Therefore, currently, out of 32 DSOs, 26 DSOs operate based on the incentive-based regulation, while the cost-plus regulation is applied to six DSOs. Both methodologies are approved by the NRA – *National Energy and Utilities Regulatory Commission* (NEURC). To switch to incentive-based regulation, DSO shall apply to the NEURC and comply with a number of conditions set by the regulatory framework[9]. Also, there are so-called "small distribution system operators"[10] in Ukraine for which provisions of primary legislation provide that the maximum (marginal) fee for their services should not exceed the level of the established D-tariff for DSO, which is the owner of the largest (in terms of the number of conventional units of energy equipment) electricity distribution system in the territory of the relevant region. Therefore, currently, the NEURC has no authority to regulate or review either methodology or tariff values for CDSO.

2.2. Tariff setting principles and types of regulation

Energy Community acquis[11] defines principles as regards the setting of the charges for access to and use of networks. In conjunction with the basic objectives of network tariff regulation of natural monopolies such as cost recovery, non-discrimination and transparency, the recently adopted acquis requires from Contracting Parties to provide the necessary regulatory framework to facilitate energy transition processes. In particular, rooted in the acquis of energy efficiency and the Clean Energy Package, the network tariff shall provide appropriate incentives to TSOs and DSOs over both the short and long run, in order to increase efficiencies, including energy efficiency, to foster market integration and security of supply, to support efficient investments, to support related research activities, and to facilitate innovation in interest of consumers in areas such as digitalisation, flexibility services and interconnection.

To meet these principles, NRAs apply several regulatory tools where one of the most decisive is the type of tariff regulation. Starting from the cost-plus approach that was used at the beginning of the natural monopolies' regulation, the tariff regulation methods evolved to different incentive- and performance-based approaches which aim to accommodate parameters incentivizing network operators to more efficient cost utilization and investment, reliability and quality of service, research and development etc.

2.2.1. Transmission

In six Contracting Parties (AL, GE, XK*, MD, ME and MK), NRAs apply incentive-based T-tariff regulation, mostly the revenue cap approach and only in Albania, the price cap approach is used.

[8] Law of Ukraine "*On natural monopolies*".
[9] NEURC Resolution "*On the application of incentive regulation in the conduct of economic activity on the electricity distribution*".
[10] Analog to CDSO. After recent (in 2023) amendments to the Law on Electricity Market, small DSOs are subject for NEURC license.
[11] Directive 2019/944, Directive 2012/27/EU, Regulation 2019/943.

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:

- capital expenditures are mostly determined using the historic value of the regulatory asset base (RAB), however, the inclusion of the investment plans for the regulatory period is allowed,
- controllable operational costs (OPEX) – most of the operational expenditures are treated with the RPI-X model, except for various taxes,
- uncontrollable OPEX is treated with ordinary cost-plus, and
- goal-setting principles are used towards electricity losses, using the normative loss approach.

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 applied in Bosnia and Herzegovina, Serbia and Ukraine.

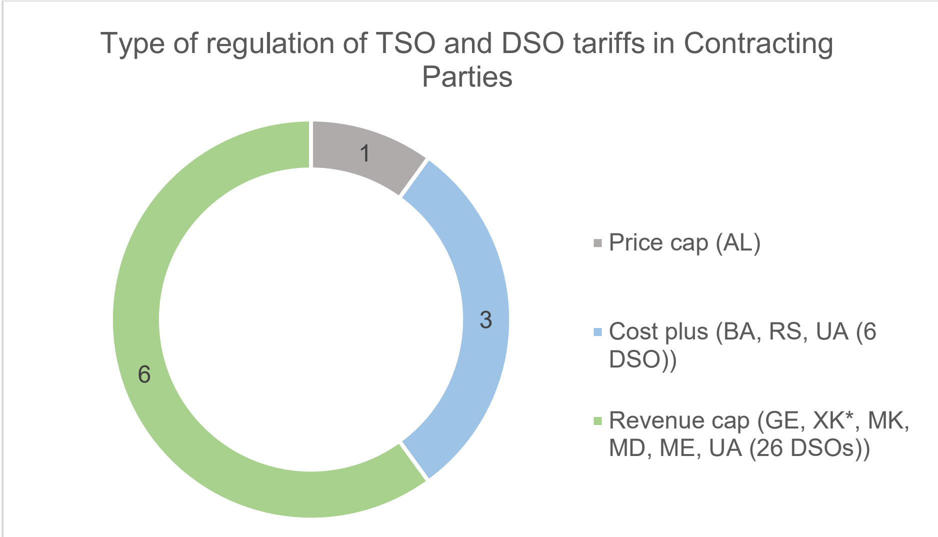
The quality factor is present in T-tariff regulation in Bosnia and Herzegovina, Kosovo* and Montenegro. For example, in Bosnia and Herzegovina, NRA shall examine the justification of an investment from the aspect of improvement of the quality and security of supply, in accordance with the projected increase of demand.

In Montenegro, starting from 2026, the target values for Average Interruption Time (AIT) will be determined for each year of the regulatory period. The model introduced is based on the ex-post assessing if the realized value of AIT is close to the target one, during the process of determination of the regulatory allowed revenue for the next period. Depending on the distance of realized 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.

2.2.2. Distribution

Similar to T-tariff regulation, incentive-based regulation is the most widely used approach for D-tariff calculation in the Energy Community [12] (Figure 1). Along with the application of the revenue cap approach, NRAs also include performance-based indicators (e.g. performance indicators such as efficiency factor, loss reduction target, quality factor[13] etc.). In Ukraine, for most of the DSOs, the incentive-based regulation applies, however, tariffs of six DSOs are regulated on the cost-plus methodology, as already mentioned in Chapter 2.1.

[12] Georgia reported a hybrid type of regulation (Cost-plus and Revenue-cap methods applying to different cost components)
[13] Except in Albania.



**Contracting Parties which reported having a hybrid method of regulation are presented in the revenue cap part of the chart*

Figure 1 *- Type of regulation of T-tariff and D-tariff in the Contracting Parties*

Quality regulation for DSOs is introduced in four Contracting Parties (GE, XK*, ME and UA).

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 Montenegro, similar to the approach applied at the transmission level, starting from 2026, the target values for the *System Average Interruption Duration Index* (SAIDI) will be determined for each year of the regulatory period. When determining the regulatory allowed revenue for the next period, the realized value of SAIDI will be compared with the target value. In that regard, depending on the distance of realized 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 also capped.

In Ukraine, target values of SAIDI are established for DSOs under the incentive-based regulation with the final target to be achieved in the 14th year from the year of application of incentive-based regulation. For each regulatory period, the interim target is also introduced[14].

2.3. Frequency of tariff methodologies' revision and tariff value updates

The regulatory period is a crucial aspect of tariff regulation in terms of its predictability and stability of key regulatory parameters. Setting the performance targets for TSO/DSO requires also adequate time to meet them. This relates to long-lasting measures that require investment planning and network upgrading (e.g. reliability, reduction of the network losses) and optimization of operational processes. On the other hand, the length of the regulatory period shall also consider the national economic developments in order not to become irrelevant, that may impact the financial liquidity of the network

[14] Due to the martial law NEURC does not adjust allowed revenue for incompliance with the quality targets in 2022.

operator in the middle of the period in question. To reflect changes in some non-controllable cost elements, the value of the tariffs shall be updated regularly based on the actual information from network operators.

2.3.1. Transmission

In most of the Contracting Parties, the T-tariff methodologies are approved with no expiry date, i.e., until changed by the relevant NRAs. Only in Kosovo* and Moldova[15], 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 by the methodology and varies from one year in Serbia and Ukraine (that is typical for the cost-plus model) to three years in Albania and North Macedonia and five years in Georgia, Kosovo* and Moldova where incentive-based models applied. In Montenegro, the length of the regulatory period is not predefined by the legislation, but the NRA defines the length of the next regulatory period prior to the end of the ongoing one (therefore, may differ). The length of the few previous regulatory periods was three years and this is the case for the ongoing regulatory period (January 2023 - December 2025).

2.3.2. Distribution

Contracting Parties which apply cost-plus regulation have a one-year regulatory period (RS, UA) or indefinite regulatory period (BA) for which the same D-tariffs are set with a possibility to revise them in case of significant changes in DSOs costs out of their control (e.g., wholesale price, inflation, legal changes., etc.). Among those Contracting Parties that apply incentive-based regulation, in Georgia, NRA is using tariff setting methodology that sets 5-year cost-reflective tariffs with a possibility to revise during the regulatory period; in Kosovo* and Moldova, there is no distinction between the methodology period and regulatory period: the regulatory period is 5-year and it is set in the methodology, hence all regulatory parameters are set for this period. There are also annual adjustments for making corrections between actual and forecasted values for the parameters which are out of the DSO control.

In North Macedonia, the tariff methodology is applied with no time limits, i.e., until it is changed by the NRA. The regulatory period for D-tariff is three years starting from the 1st of January, however, the values of D-tariffs are set once per year and applicable from the 1st of July until the 30th of June next year[16]. In Montenegro, similarly to the transmission, the length of the next regulatory period is defined by NRA before the end of the ongoing regulatory period. The length of the current and few previous regulatory periods was three years. In Ukraine, for DSOs which switched to incentive regulation since 2021, the first regulatory period is three years, while the second and subsequent regulatory periods are five years[17]. Rates are subject to adjustments every year.

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[15] The new methodology for T-tariff which is now developed will not be limited in time and will be applied as is if no modification occurs. For each regulatory period of five years, TSO will present and NRA will approve the baseline costs (for the first year of the regulatory period).

[16] For 2022 tariffs were approved in December 2021 for the period from 1st of January to 30th of June 2022 and in June 2022 for the period from 1st of July to 31st of December 2022.

[17] Due to the martial law, NRA decided to extend the first regulatory period for 1 year.

2.4. Stakeholder involvement

Article 59(9) of Directive 2019/944 prescribes that all interested parties shall be provided with all necessary information and decisions or proposals for decisions concerning transmission and distribution tariffs. Public consultations are proven to be an efficient mechanism to ensure stakeholders' involvement which is also the case for the tariff-setting process. Although some regulatory parameters may be of interest to the network operator (e.g., X-factor), such elements as quality standards, application of tariffs for withdrawal and/or injection to the grid, tariff application basis (e.g., energy- or power-based) etc., have direct impact on various network users. Non-discrimination, relevant incentives and acknowledgement of technological particularities of newly emerging technologies in tariff-setting and design shall be ensured through stakeholders' involvement.

2.4.1. Transmission

All Contracting Parties reported that NRAs conduct public consultations on draft T-tariff methodologies (as a whole). Apart from public consultations, six Contracting Parties also have a consultation of specific party(ies) (e.g., TSO). On top, s*ub-elements* of tariff methodology are consulted in five Contracting Parties through public (three cases) and specific (two cases) consultations. Georgian NRA noted that often international experts are involved to provide more insight in the first stages of the process when the general outlines of the methodology are developed, while the communications with stakeholders get more intensive at the final stages of the process when all the technical details and nuances are determined. TSO and other stakeholders are heavily involved in the process and they provide the necessary data.

Documents and information related to the T-tariffs are also published by most NRAs, although not all publish the public feedback and results of the consultations. The availability of English translation of the consulted documentation is reported only by NRAs of Bosnia and Herzegovina and Kosovo*. This is a positive practice that contributes to transparency for all (including foreign) market participants and stakeholders.

2.4.2. Distribution

D-tariff methodologies are subject to public consultations in all Contracting Parties and most NRAs publish the summary of the public consultation results. On top of this, most Contracting Parties also have a practice of holding additional consultations on methodology or its sub-elements with specific parties. In Serbia, only the draft Methodology as a whole is put on the public consultation, while all necessary data and documentation obtained from energy entities as a base for the development of methodology are not publicly available.

Documents and information related to the public consultations are published in all Contracting Parties except Georgia. In Bosnia and Herzegovina and Kosovo*, the practice of publishing tariff-related documents in English is applied also to D-tariff documentation (e.g., public consultation documents, methodology, etc.).

2.5. Transparency in tariff setting

In line with Article 59(8) and (9) of the Directive 2019/944, the transmission and distribution tariffs or their methodologies shall be published.

2.5.1. Transmission

In all Contracting Parties, the T-tariff calculation methodology is publicly available (e.g., through national legal databases, websites of NRA or TSO)[18], although mostly in national languages. An English version is available only in Bosnia and Herzegovina, Kosovo* and North Macedonia.

Also, in all Contracting Parties, the following information is publicly available:

- information on the transmission cost categories (including detailed information, i.e., provision of OPEX, depreciation, cost of capital, losses, other values) recovered by tariffs,
- information on fixed, energy-related and power-related components of the tariff (where applied),
- information on the transmission costs (amount and/or share) covered by producers (for injection) and by consumers (for withdrawal) and
- transmission charges (values) paid by different grid users are publicly available.

2.5.2. Distribution

As regards D-tariffs, the practice of publishing information in contracting Parties is the same as for T-tariffs and relevant methodologies.

[18] Links to T-tariff and D-tariff national methodologies may be found in Table 1.1 of Annex I.

3. Cost model, cost determination and cost recovery

3.1 Cost model and cost determination

3.1.1. Transmission

In this report, the cost model refers to the model used for the calculation of unitary network tariffs. In the majority of Contracting Parties[19], NRAs apply the average cost model when determining the unit prices for transmission service and allocate the allowed revenue to the forecasted volumes of transmitted electricity, namely average cost per unit, in contrast to the allocation of incremental costs to relevant cost drivers (e.g., marginal losses, peak load etc.). This is very similar to the EU-wide practice where most of the NRAs[20] also currently apply the average model for cost allocation. In case of relatively stable network conditions (e.g., injection/withdrawal volumes), this model ensures that the total revenue is recovered by unitary tariffs by its design, i.e., there shall be no residual costs. In case of some deviations due to unpredictable conditions, TSO may apply for tariff revision.

More details on cost determination aproaches and/or cost models applied in the Contracting Parties are presented in Table 1.

Table 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	By limiting the allowed revenue and application of price caps, incentives for improving cost efficiency are provided. Each cap is calculated based on costs (OPEX and CAPEX) that the operator foresees and predicts for the upcoming regulatory period. The Regulator considers the costs from the test year 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. OPEX refers only to 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. On the other hand, CAPEX is calculated as follows: CAPEX= R + D, where: *R* is a return on the RAB and *D* is the depreciation of the fixed assets and the depreciation of the other assets. For the second year of the tariff review cycle, each component determined for the base year is multiplied by the annual adjustment/correction factor: A = (1 + RPI – X), where: *RPI* is the rate of customer price inflation for the second year according to the forecast of the National Bank of Albania, while *X* is the efficiency improvement factor set by ERE. In each year of the tariff review cycle, the average T-tariff is determined as follows: P average = (OPEX + CAPEX) / E, where *E* is the total energy amount in kWh that shall be shown in transmission system customers' invoices during the year. This method aims to determine a cost-reflective tariff and to cover all those services costs.

[19] Serbia reported the application of another cost model. Details on the approach applied in Serbia are described in Table 1 and Annex I.
[20] ACER Tariff Methodologies Report.

Bosnia and Herzegovina	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 T-tariff is comprised of: the T-tariff paid by customers and the T-tariff paid by generators. The T-tariff paid by customers is comprised of two components: part of the T-tariff pertaining to energy and a capacity component. The T-tariff paid by generators is energy-based, i.e., it applies to the electricity injected by T-generators into the transmission system.
Kosovo*	ERO assesses the costs of services for TSO based on actual costs for certain cost categories. These cost categories mainly come from financial statements and allocation to user groups is based on cost drivers (allocation factors).
Georgia	CAPEX is mostly determined using the historic value of RAB but the inclusion of the investment plans for the regulatory period is allowed. Controllable OPEX, which includes most operational expenditures except various taxes, is treated with the RPI-X model, while uncontrollable OPEX is treated with ordinary cost-plus, and goal-setting principles are used towards electricity losses.
Moldova	In the first year of the regulatory period (out of 5 years), TSO is presenting to ANRE 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 weighted average cost of capital (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 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. The revenue caps consist of the following main components: basic revenue, specified pass-through costs and costs for losses. 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 to the electricity 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 the 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 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 and 5) prevention of mutual subsidization 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).

3.1.2. Distribution

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 its systems and the energy they use to cover energy losses in their systems[21]. 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[22]. The Clean Energy Package and Electricity Integration Package in the Energy Community put additional tasks on TSOs and DSOs.

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. 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[23].

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

As can be seen from Table 2 below, in most of the Contracting Parties, the main cost categories that are recognized in T-tariff relate to CAPEX (investments into the transmission network, depreciation), operational costs (OPEX), costs of purchasing ancillary services and transmission losses. The ITC mechanism cost/incomes are recognized in the methodologies of seven Contracting Parties[24]. Considering the costs not directly related to network operation (e.g., PSO, support schemes), only in Kosovo* and Ukraine[25], T-tariffs serve as a tool to totally or partially collect funds for supporting schemes for renewables. In Bosnia and Herzegovina and Montenegro, a separate (non-transmission) charge is defined on the end-user's bill to cover the costs of the supporting schemes for renewables and cogeneration, therefore, it does not have an impact on transmission tariffs. In the case of Bosnia and Herzegovina, NRA reported that costs of purchasing ancillary services and transmission losses are fully recovered by additional//non-transmission charge - so-called the Tariff for System Service, collected by Independent System Operator (separated from the Tariff for Operation of an Independent System Operator). Similarly, in Ukraine, the costs of ancillary services are covered through the separate tariff for dispatching services collected also by the TSO.

[21] Articles 31, 40 and 46 of the Directive 2019/944.
[22] Article 18 (3) of Regulation (EU) 2019/943
[23] https://www.energy-community.org/dam/jcr:3b0daaa9-73e9-480c-b83f-ef3f292e96e2/Regulation_838_2010_EL.pdf
[24] TSOs of Moldova and Ukraine have not joined the ITC Agreement yet.
[25] 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.

Table 2 *- Recovery of cost categories by T-tariffs in the Contacting Parties*

	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**
a. the remuneration (return on capital) of electricity transmission investments	AL, BA, GE, XK*, MD, MK, RS	ME[26]				UA
b. the deprecation of electricity transmission investments	AL, BA, GE, XK*, MD, MK, RS, UA	ME[26]				
c. the operational expenditures for electricity transmission	AL, BA, GE, XK*, MD, ME, RS, UA	MK[27]				
d. costs (incomes) related to the Inter-TSO compensation mechanism	AL, BA, XK*, MD, ME, MK, RS, UA[28]					GE
e. costs (incomes) related to cross-border cost allocation decisions	BA, XK*, MD, ME, MK, RS		GE			UA
f. costs of purchasing ancillary services	AL, GE, XK*, MD, ME, MK, RS, UA[29]		BA			
g. costs of purchasing transmission losses	AL, GE, XK*, MD, ME, MK, RS, UA		BA			
h. costs of purchasing (another part of) system losses	AL, MD, RS, UA		BA		ME	GE, MK
i. costs of supporting schemes for renewables	XK*	UA	BA, ME		RS	GE, MK, MD
j. costs of supporting schemes for cogeneration of heat and power			BA, ME			GE, XK*, MD, MK, RS, UA
k. costs of supporting schemes for fossil fuels					BA	GE, XK*, MD, ME, MK, RS, UA
l. costs of measures for ensuring adequacy (e. g. strategic reserve power plants)				AL		BA, XK*, MD, ME, MK, RS, UA

26 Only return on capital and deprecation for approved investments is remunerated through T-tariff in Montenegro.
27 Not all operational costs are recognized in T-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.
28 It is in the methodology but TSO has not joined the ITC mechanism yet.
29 Dispatch service tariff of TSO.

3.2.2. Distribution

Similar to transmission, the following cost categories are recovered by D-tariffs in all Contracting Parties: CAPEX, OPEX and cost of distribution losses. It is worth mentioning that in five Contracting Parties, procurement of ancillary or flexibility services for managing the distribution networks and relevant costs are recognized by the NRAs when determining D-tariff. The administration costs related to switching are encompassed in D-tariffs of three Contracting Parties, while in Kosovo*, they are covered through connection charges, not by D-tariff. As in most of the Contracting Parties metering is a regulated activity, relevant costs are recovered by distribution-connected users as part of the D-tariff, and only in Serbia these costs are recovered via a separate tariff. It has to be noted that in Ukraine, metering is a deregulated activity, i.e., a market participant has the right to choose any provider of metering services. However, DSOs are default[30] metering service providers in their networks and the fee for such metering services is calculated in accordance with the methodology approved by the Regulator. For more details on each Contracting Party please see Table 3.

***Table 3** - Recovery of the costs categories by D-tariffs in the Contracting Parties*

	Paid by distribution connected users via tariffs	***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[31], MK, RS, UA[32]		
b. Depreciation of electricity distribution investments	AL, BA, GE, XK*, MD, ME[30], MK[33], RS, UA		
c. Operational expenditures 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, MK, RS	XK*	AL, GE, MD, UA, ME
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[34], MK, RS, UA		
g. metering	AL, BA, GE, XK*, MD, ME, MK, UA (partly)[35]	RS, UA	
e. other (please, specify)			AL, MK, RS

[30] Obliged to provide the service on the user's request.
[31] Only return on capital and deprecation for approved investments is remunerated through D-tariff in Montenegro.
[32] For incentive-based regulation
[33] 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.
[34] Only technical losses are recovered via D-tariff.
[35] 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.

As regards addressing the emergency issues in D-tariff regulation, 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. If there is an estimated positive difference between the realized and approved costs, ERE recognized this difference 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 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, using the weighted average cost of capital as the discount rate. Additionally, during the extraordinary tariff adjustment, its timing and structure should be designed in such way as to reduce the tariff shock to customers (e.g., by smoothing the effect of the extraordinary adjustment over a number of years). In North Macedonia, the D-tariff was set every six months in the emergency situation. Other Contracting Parties have not reported any specific elements in tariff methodology targeted to respond to emergency situations.

In terms of any significant changes regarding the cost model in the D-tariff methodology for the next tariff methodology period, NRA of North Macedonia notified about the discussion to change the base year for cost calculation (from currently applied t-1 to t-2 if appropriate). Georgia intends to introduce fixed charges from the next regulatory period (starts in 2026) in order to make tariffs more cost-reflective in terms of type of the costs and to stabilize DSO revenues and make them less dependent on consumption fluctuations.

3.2.3 Transmission and distribution losses

Due to the technical characteristics of the power lines and transformers, power losses are inevitable phenomena in each electricity grid. Except for so-called technical losses, non-technical losses (e.g., non-metered consumption, theft, hidden losses etc.) are recorded in many countries. In general, power losses represent a substantial share of the electricity transmitted and distributed and the costs of purchasing the electricity for covering them are usually assigned to TSOs and DSOs. In this regard, at least the costs of the technical losses should be recognized when determining the allowed revenues of TSO and DSO. The cost of losses transferred to customers depends highly on how the energy for losses is procured and at which price. To some extent, the volume of losses also may be “controlled” by network operators and even decreased by more efficient network management, renovation and smart grid development.

All Contracting Parties reported that they recognize the costs to cover the TSO and DSO losses in tariff regulation. In most cases, losses are procured through the market-based procedure on the electricity market (DAM/power exchange) or public tender at market price. Only Albania noted that according to the decision of the Council of Ministers[36], the Public Supplier in the Free Market (FTL) is obliged to purchase electricity from RES, after which it sells the purchased electricity at the same price to DSO, in order to cover the losses. In Georgia, DSOs are purchasing electricity for compensating the normative allowed losses at the balancing market price, which is deemed to be the price for allowed losses.

As regards the level of the allowed losses, the different approaches are used by Contracting Parties for their determination, for example:

[36] Decision No 456/2022.

- in Georgia, it is calculated in accordance with the methodology for normative values,
- in Kosovo*, ERO sets a loss reduction target and an allowable loss curve for five-year regulatory period,
- in Montenegro, the level of technical losses is determined according to the Study on losses submitted by TSO/DSO. It has to be noted that this study needs to be reviewed by an independent institution in the energy field,
- in Moldova and Serbia, the level of losses is determined based on historical volumes of losses,
- in North Macedonia, ERC recognizes the costs for procurement of the electricity for covering the approved losses in the transmission and distribution network in accordance with the Plan for decreasing the losses. This plan is approved by the ERC before beginning of each regulatory period, and on annual basis.

Additionally, three Contracting Parties (AL, XK*[37], UA) apply the *reduction factor for losses* to incentivize DSOs to reduce losses in their systems. For more details on transmission and distribution losses recognition in tariff regulation please see Annex I.

3.3 Cost cascading

Allocation of costs among different categories of network users and voltage levels has the main objective to ensure cost reflectiveness in respect of cost drivers – i.e., the costs shall be recovered by the users that cause those costs.

3.3.1. Transmission

As it may be observed from Table 4, in five Contracting Parties, 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. In particular, in Montenegro[38], 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.

[37] In Kosovo for the third regulatory period (2023-2027), a loss target and a loss-sharing factor is applied for the first year. In the previous regulatory periods (2018-2022; 2013-2017) there were applied only targets of losses and not loss sharing factors.
[38] 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.

Table 4 *- Shares of electricity withdrawal by T-connected and D-connected users and shares of T-costs which is covered by T-connected network users and cascaded to network users not directly connected to T-grid*

Contracting Party	*AL*	*BA*	*GE*	*XK**	*MD*	*ME*[39]	*MK*	*RS*	*UA*
Withdrawn by T-connected network users, %	9	10.85	56	7	5	23.28	10.06	11.7	16
Withdrawn by D-connected network users, %	91	89.15	44	93	95	76.72	89.94	88.3	84
T-cost paid by T-connected network users, %	9	10.85	56	33	4.5	51.56	18	12.4	n/a
T-cost paid by D-connected network users, %	91	89.15	44	67	95.5	48.44	82	87.6	9 and 46[40]

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[41]. 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). All other Contracting Parties apply the same T-tariff to all T-connected users[42] regardless of the voltage of connection, therefore, there is no transmission cost-cascading at the transmission level. 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 MK, MD, ME, RS - 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[43]. 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 for the amount of the distribution losses is recovered through the D-tariff.

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

[39] Data for Montenegro refers to the forecasted values (by T-users including the producers) from REGAGEN's decision on tariffs for 2022.
[40] For Ukraine, as there are two tariffs charged by TSO, in Table 4 - 9% refers to the share of transmission service costs covered by D-connected users, and 46% - refers to the share of dispatch service costs covered by the D-connected users in D-tariffs.
[41] TSO operates with three high voltage levels 400kV, 220kV and 110kV.
[42] This is without prejudice to different tariffs for different categories of users (e.g., producers or consumers).
[43] 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).

3.3.2. Distribution

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. In Montenegro, only D-connected producers are exempted from D-cost cascading due to the complexity of defining the allocation key.

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. On the other hand, reverse cost cascading is not applied in any of the observed countries. For more details on the cost-cascading method applied to the D-costs in Contracting Parties, please see Table 5.

***Table 5** - Cost-cascading method applied for the D-costs in the Contracting Parties*

Contracting Party	*D-cost cascading approach*
Bosnia and Herzegovina	The 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 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 recognized, 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 (BAM), C – value of total distribution capacities (BAM), RRd – amount of revenue requirement for the performance of regulated distribution activity, reduced for the value of losses on the distribution network (BAM). 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 (BAM), 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 (BAM), WLi – distribution losses at the voltage level i (kWh), WL – total losses on distribution network (kWh).
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 2 DSO's are approximately as follows - high voltage (1%-4%), medium voltage (21%-24%) and 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.
Kosovo*	The cascading approach is used to reflect 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 share depends on the energy consumption of each voltage group. The share of the cost of losses according to 2022 data is as follow: at 35kV cost of losses are 0.1%, at 10kV 3.4% and for 0.4kV 96.5%. OPEX and CAPEX cost are not subject to the cost cascading, they are allocated to customer categories based on energy and demand sharing factors.
Moldova	There are three distribution voltage levels (High, Medium and Low) in Moldova. The tariff for the HV is calculated by dividing HV cost by total quantity of electricity distributed to (HV, MV, LV) levels. Subsequently the costs at MV are divided by the quantity of electricity distributed to medium and low voltage levels and increased by part of the HV costs. Finally, the costs at LV level are divided by the electricity distributed at this level and increased by MV tariff. In 2022, costs covered by HV users were - 4 %, MV users - 34 % and LV users - 62 %.
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: the capacity charge of a higher voltage level and the share of cost of the concerned voltage level allocated to consumers of this voltage level, calculated by taking into account the capacity of these consumers. Losses charges are calculated as a ratio of costs of losses for voltage level and energy planned to be delivered. Costs of certain voltage level take into account of cost of losses of all higher voltage levels. Detailed calculation formulas are described in the Methodology. In 2022, the shares of use-of-network costs for 35 kV consumers was 22%, for 10 kV 25% and for 0,4 kV 53%. The shares of costs for covering losses were: 2% for 35 kV, 11% for 10 kV and 87% for 0,4 kV voltage level. A different D-tariff allocation approach is being used for D-connected producers. The cost of use-of-network is based on the allocation key which represents the share of costs of connection infrastructure used only by producers in the value of total fixed assets of distribution system. The costs for covering system losses are based on

	the allocation key which represents estimation of impact of producers connected to a certain voltage level on increase/decrease of the system losses.
North Macedonia	D-connected network users at a lower voltage level pay for part of the D-costs of higher voltage levels. Cost cascading applied to all distribution costs per connection category (MV1, MV2, LV1.1, LV1.2, LV2). The share of D-costs cascaded to an appropriate connection category is calculated taking into account consumption of active and reactive energy and active power. Detailed calculation formulas are described in the D-tariff methodology.
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.
Ukraine	D-tariffs are calculated and set per two classes of DSO connected consumers, first class – connected to the DSO network at voltage 27.5 kV and above, and second class – connected to the DSO network at voltage below 27.5kV. Consumers of second voltage class pay for part of DSO-costs of higher level. The ratio of the volumes of the 2nd class customers to the total volumes of TSO is 57%.

To support cost cascading, a certain 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 in all Contracting Parties except Serbia by voltage level and also by CAPEX/OPEX parts. 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. In Serbia, no cost granularity is reported, therefore distribution costs are recognized by the tariff methodology as a total amount.

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, excluding connection and reactive energy charges which are further elaborated in the next chapter. In this regard, 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, while 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 6 *- 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	✓	✓	-	✓

All nine Contracting Parties (BA, GE, XK*, MD, ME, MK, RS and UA) apply transmission and distribution withdrawal network tariffs. On the other hand, out of these nine Contracting Parties, only Montenegro applies transmission and distribution injection charges. Bosnia and Herzegovina, Kosovo*[44] and Ukraine[45] apply transmission injection charge only, while 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. It has to be noted that Ukraine applies so-called dispatch tariff not only for injection but also for withdrawal and import/export[46]. 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 public consultations, consultation with other NRAs, or after carrying out an impact assessment.

In Bosnia and Herzegovina and Montenegro, the transmission injection charge was initially introduced due to the specific nature of their power systems and the fact that part of the total transmission costs is caused by network users that inject into the grid, not only the ones that withdraw from the grid. In particular, Bosnia and Herzegovina is a net exporter of electricity, i.e., a large volume of the electricity produced is not consumed within the country. Montenegro, on the other hand, significantly developed the grid for the purpose of RES integration. It was assessed that around 50% of the 220 kV network in Montenegro is built and used predominantly for the purpose of connection and operation of the largest HPPs. In Ukraine, the producers, among other users[47], pay the tariff for (operational and technological) dispatching 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.

The distribution injection charge in Montenegro was introduced several years after the introduction of the transmission injection charge (in 2020, while the T-injection charge was introduced in 2014). The legal basis for its application is set out in the Energy Law. 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.

In other Contracting Parties (AL, GE, MD, MK and RS) injection charges do not apply at all. 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 2011) 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

[44] It has to be noted that 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.

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

[46] This provision applies until TSO joins ITC mechanism, but no later than 1st January 2024.

[47] It has to be noted that this tariff applies to consumers, DSOs, small DSOs, storages and to all producers of type B, C, D (regardless the network of connection).

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. On the other hand, the introduction of injection charges is under consideration in Georgia. Also, Kosovo* plans to introduce a distribution injection charge in the future.

4.1.2. Allocation of the costs between injection and withdrawal charges

In general, 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.

As Albania, Georgia, Moldova, North Macedonia and Serbia do not apply injection charges, this subsection will focus on allocation of costs in Bosnia and Herzegovina, Kosovo*, Montenegro and Ukraine at transmission level and on the allocation of costs in Montenegro at the distribution level.

- ***Transmission***

In 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. It has to be noted that the costs of Elektroprenos BIH (TRANSCO - Transmission Company) are not allocated to the producers.

In 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.[48] 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.

In 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, while 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.

In Ukraine, the TSO's costs for dispatching services are allocated to producers by taking into account the share of the total electricity produced in the sum of total electricity produced and transmitted, in accordance with the *Approval of the Procedure for Tariff Formation for Services for Dispatching* (operational-technological) Management Resolution of the NEURC of 22.04.2019. The other costs related to transmission of electricity are not allocated to producers.

[48] 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

➢ ***Distribution***

The total costs of DSO (except 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 the technical losses.

4.1.3. Share of injection and withdrawal charges in cost recovery

➢ ***Transmission***

Figure 2 shows the share of injection and withdrawal charges in transmission costs recovery in the Contracting Parties.

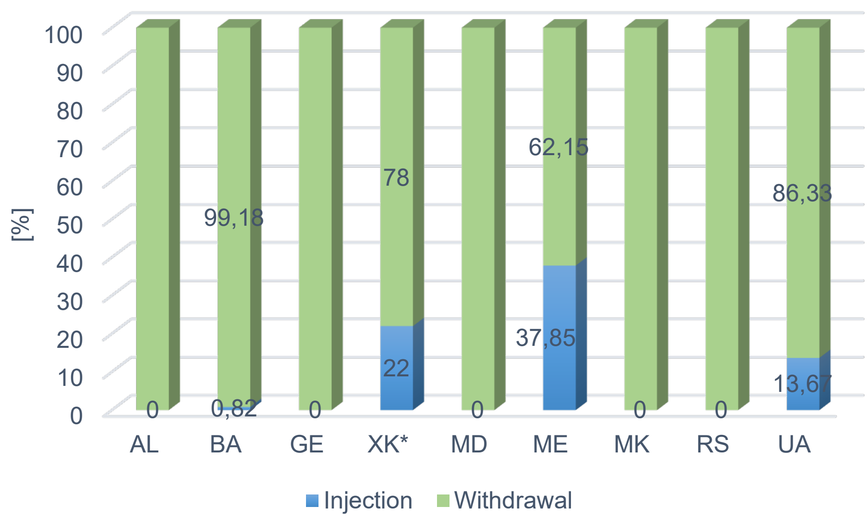


Figure 2 *- Share of transmission costs recovered by injection and withdrawal charges in 2022*[49]

In most of the Contracting Parties, the transmission costs are recovered completely by withdrawal charges only.

In Bosnia and Herzegovina, the share of the transmission costs (ISO BIH and Elektroprenos BIH) covered by injection charge was 0.82%, whereas 9.28% of total ISO's costs were covered by injection tariff and the rest was covered by withdrawal tariff (90.72%). The costs of Elektroprenos BIH were completely covered by the withdrawal tariff.

In Kosovo*, 22% of the TSO's costs are recovered via injection charge. In Montenegro, for 2022 37.85% TSO's costs are allocated to producers, while the rest is allocated to consumers. In Ukraine, 13.67% of the TSO's costs are recovered by producers.

[49] It has to be noted that 2022 data for Montenegro refers to the determined values from the REGAGEN's decision.

- ***Distribution***

In Montenegro, at the distribution level, 0.2% of the DSO's costs are to recovered by the producers connected to the distribution system in 2022[50], while 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 metrics (tariff basis) such as withdrawn energy, peak load, contracted capacity, etc. or the value of the withdrawal charge can be fixed regardless of the withdrawn energy or power - i.e., lump sum charges.

Subsection "Injection charges" is focused on tariff bases in Bosnia and Herzegovina, Kosovo*, Montenegro and Ukraine, while subsection "Withdrawal charges" deals with all nine Contracting Parties. Values of injection and withdrawal charges in 2022 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 is combined, i.e., 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 costs for dispatching services and total electricity produced and transmitted.

In Montenegro, the energy-based component is calculated by diving the part of OPEX allocated to producers (including costs for covering losses) by forecasted transmission producers generation. On the other hand, the power-based tariff is calculated by diving 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 2022, out of the total costs that are allocated to transmission producers, 75.98% is to be recovered by energy based-tariff, while 24.02% is to be recovered by a power-based tariff.

The main goals for selecting the above-mentioned structure and design of transmission injection charges are presented in Table 7 below. In a nutshell, when designing of injection charges, Bosnia and Herzegovina, Kosovo* and Montenegro aimed to achieve fair contribution of all generation facilities to revenue recovery. Also, in Montenegro and Kosovo*, an important requirement was ensuring cost-reflectiveness of injection charges and recovery of transmission costs. Bosnia and Herzegovina, on the other hand, took special care of ensuring level playing field of its injection charge with injection charges of other countries. In Ukraine, the main goal for the design of dispatching tariff

[50] It has to be noted that 2022 data for Montenegro refers to the determined values from the REGAGEN's decision.

was the recovery of TSO costs for power system operation, especially taking into account that substantial part of these costs represents a budget for ancillary services.

Table 7 *- 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 (fair) allocation of transmission revenues across generation facilities	reflecting system use of current transmission assets
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 energy-based. The injection charge is calculated by dividing part of the DSO's costs allocated to producers by the total forecasted production of the producers connected to the distribution system. The design and the calculation of the distribution injection charges are fairly 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, which is not the case in the transmission system which is used by producers for also exporting electricity. Taking this fact into account, 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.

In the new Distribution Tariff Methodology, both power- and energy-based tariffs have been introduced for the producers connected to the distribution system. The energy-based tariff will be used for the recovery of cost of losses, while power-based tariff will be used for the recovery of other costs allocated to producers.

4.2.2. Withdrawal charges

- ***Transmission***

The most frequently used transmission tariff basis in the Energy Community Contracting Parties is a combination of energy and power. Five Contracting Parties (BA, XK*, ME, MK and RS) apply transmission withdrawal tariffs that consist of energy-based and power-based components, while four (AL, GE, MD and UA) apply solely energy-based tariff.

Table 8 *– T-tariff basis in the Energy Community Contracting Parties*

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

In five Contracting Parties (BA, XK*, ME, MK and RS) that apply a two-component charge, 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). In 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. As an initial value, the share of costs allocated to power-based component is 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. In Montenegro, costs of technical network losses are recovered via an energy-based tariff, while the remaining part of TSO's CAPEX and that is not allocated to producers is recovered via a power-based charge. In North Macedonia, power-based tariff mostly covers the fixed costs like OPEX, CAPEX, while remaining costs are recovered via the energy-based component. 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.

The share of energy-based and power-based component in cost recovery in 2022 is presented on the following Figure.

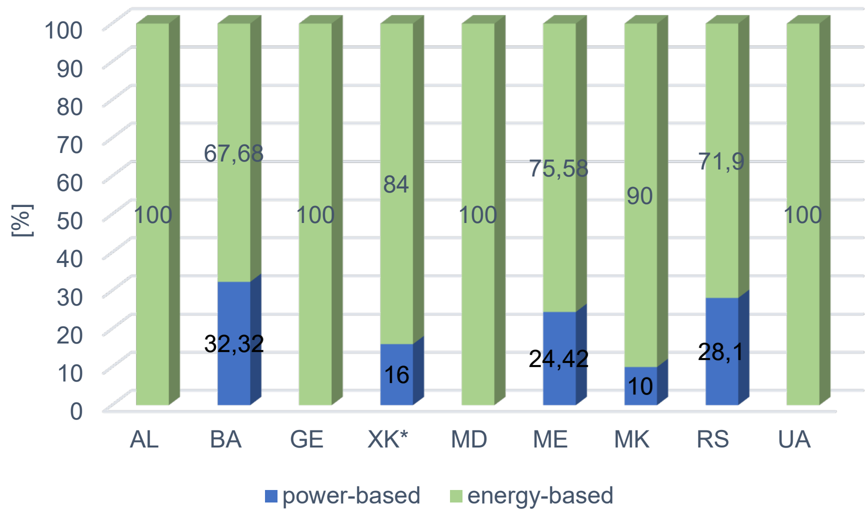


Figure 3 *- Share of transmission withdrawal costs recovered by energy- and power-based tariffs in 2022*[51]

Energy-based withdrawal tariffs are most frequently calculated by using gross withdrawn energy (AL, BA, XK*, ME, MK, RS and UA), while Georgia and Moldova apply net energy. Among Contracting Parties that apply power-based tariffs, peak load is most commonly used for the calculation of withdrawal tariffs (BA, XK*, ME and MK). Contracted power is applied only in Serbia.

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 is either the same as at the transmission level or higher, except for Kosovo* which applies only energy-based tariffs at the distribution level in contrast to the application of both energy- and power-based at the transmission level. Apart from Kosovo*, Albania, Georgia, Moldova and Ukraine apply only energy-based distribution withdrawal tariffs, North Macedonia and Serbia apply both energy- and power-based, while Bosnia and Herzegovina and Montenegro apply energy-, power-based and lump sum tariffs.

Table 9 *- D-tariff basis in the Energy Community Contracting Parties*

	AL	*BA*[52]	*GE*	*XK**	*MD*	*ME*	*MK*	*RS*	*UA*
Energy-based	✓	✓	✓	✓	✓	✓	✓	✓	✓
Power-based	-	✓	-	-	-	✓	✓	✓	-
Lump sum	-	✓	-	-	-	✓	-	-	-

[51] It has to be noted that 2022 data for Montenegro refers to the determined values from the REGAGEN's decision.
[52] In Bosnia and Herzegovina, only BA's entity Federation of Bosnia and Herzegovina applies energy-, power-based and lump-sum tariffs, while BA's entity Republika Srpska and Brčko District apply only energy- and power-based tariffs.

In Bosnia and Herzegovina, as a rule, all fixed distribution costs are allocated to the power component, and variable costs to the energy component. For some DSOs, in addition to the two components mentioned above, there is also a fixed amount that is charged to each customer as a lump sum tariff. In Montenegro, distribution network tariff for MV consumers and LV consumers with metered power consists of two components – power-based and energy-based. Only costs for covering network losses are recovered via energy-based tariff, while all the other costs are recovered by power-based tariffs. However, for LV consumers without metered power, part of OPEX (material costs and costs of services) is recovered via fixed tariff (lump sum), while all other remaining costs are recovered via energy-based tariff. In North Macedonia and Serbia, some categories of consumers pay only energy-based charge, while others pay both power-based and energy-based charges.

Figure 4 shows the shares of different tariff basis in DSOs' revenue recovery in the Contracting Parties in 2022. Even though power-based and lump sum tariffs are applied in some Contracting Parties, the major part of the DSOs' costs is recovered via energy-based tariffs.

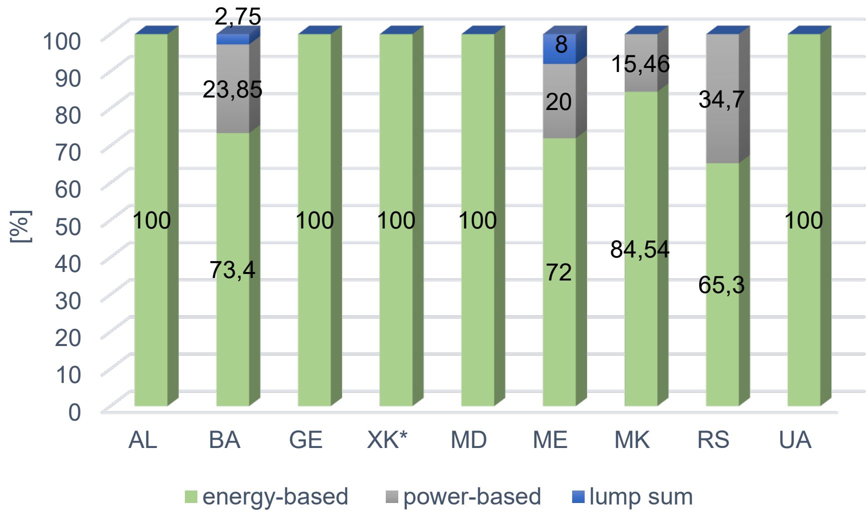


Figure 4 *- Share of distribution withdrawal costs recovered by energy-, power-based and lump-sum tariffs in 2022*[53][54]

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[55]). 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 2022 are shown in Annex III, while the main goals for designing the distribution withdrawal charges in the Contracting Parties is presented in Annex IV.

[53] It has to be noted that 2022 data for Montenegro refers to the determined values from the REGAGEN's decision.
[54] The shares presented in Figure 4 are calculated as the weighted averages for Bosnia and Herzegovina. Realized shares of energy-, power-based and lump sum tariffs in DSOs' cost recovery were 78.63%, 16.72% and 4.65%, respectively in BA's entity Federation of Bosnia and Herzegovina, 66.04%, 33.96% and 0%, respectively in BA's entity Republika Srpska, while in Brčko District, planned recovery by energy- and power-based charges was 62.37% and 37.63%. It has to be noted that the part of the distribution costs recovered by reactive energy charges was excluded from the calculation of the presented shares.
[55] There is the first and the second voltage class in Ukraine.

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 5 shows the level of G-charge paid by producers in 2020, 2021 and 2022 in Bosnia and Herzegovina, Montenegro[56] and Ukraine[57]. It can be concluded that the G-charge levels in Bosnia and Herzegovina, Montenegro and Ukraine are within the ranges prescribed by adapted Regulation (EU) 838/2010.

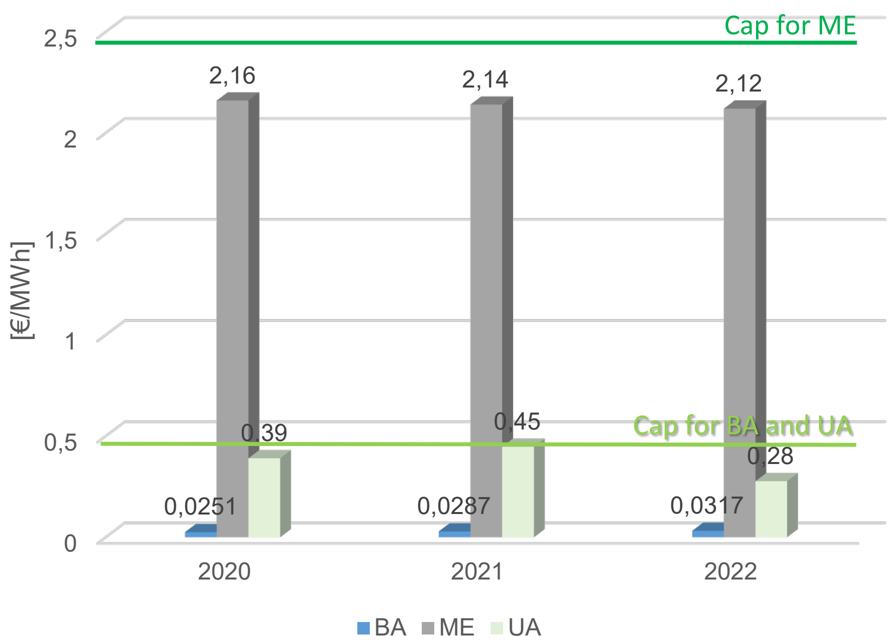


Figure 5 *- Level of G-charge in Bosnia and Herzegovina, Montenegro and Ukraine in 2020, 2021 and 2022*

Not Bosnia and Herzegovina, nor Montenegro and Ukraine faced difficulties during tariff setting due to the ceiling prescribed in 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.

56 It has to be noted that data for 2022 for Montenegro refers to the determined values from the REGAGEN's decision.
57 For Kosovo*, annual G-charge level could not be obtained from the injcetion charge which includes costs of losses and costs of ancillary services.

4.4. Groups of network users subject to tariffs

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

- network users that only inject into the grid[58] (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.

4.2.1. Transmission

Table 10 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 10 *- 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	W	W	n/a	n/a	n/a	n/a	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	n/a	-	W
T-connected producers: Auxiliary services of generators[59]	-	W	W	n/a	-	W	W	W	W

[58] Excluding supply of auxiliary equipment of generators.
[59] 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).

D-connected RES producers	-	-	-	I	-	-	-	-	I[60]
D-connected non-RES producers	-	-	-	I	-	-	-	-	I[55]
D-connected consumers	W	W_i	W	W_i	W	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
D-connected non-storage network users that both inject into and withdraw from the grid (e.g., prosumers)	W	W_i	W	n/a	W_i	W_i	W_i	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	n/a	n/a	n/a	-	-

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 (BA, XK*, ME and UA), 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 that both inject and withdraw from the grid usually pay the charge only for withdrawing. However, in Bosnia and Herzegovina, PHES pays only the injection charge. In Ukraine, battery storages are subject to withdrawal tariff for netted withdrawn energy.

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 seven Contracting Parties (AL, BA, GE, XK*, MD, ME, MK, RS and UA) there are no power to gas facilities connected to the transmission system.

[60] Producers of type B, C, D connected to the distribution network.

4.2.2. Distribution

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

***Table 11** - 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[61]	-	W	W	n/a	W	W	W	-	W
D-connected consumers	W	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	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	-	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 CP 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 to net withdrawn energy by prosumers, i.e., in the difference between withdrawn and injected energy, while in Albania the net billing principle applies. In Ukraine, prosumers also pay withdrawal network

[61] 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).

tariff for netted withdrawn energy. However, as in the most cases such consumers sell electricity to their suppliers, the network services are paid by supplier to TSO/DSO (not by the prosumer directly).

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 and reactive energy charges

5.1. 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.

5.1.1. Transmission

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 12 shows the types of 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 12 *- Type of T-connection charges applied in the 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 Moldova, new network users are obliged to pay a lump sum connection charge whose value depends on the individual actual connection costs. 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.

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 Kosovo*, the connection charge for each new user is calculated by applying the table of the indicative costs for new transmission assets and potential infrastructure reinforcement assets from the Annex of the Methodology. In North Macedonia, a new user is subject to the network connection cost calculations based on certain cost categories that are in correlation with the connection methodology. At this point, also individual costs arising from physical construction of the network connection are taken in consideration. In general, these costs include also the costs of the grid reinforcements needed for the connection of the concerned user. In Ukraine, the value of the connection charge is individual (non-standard) 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 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 concerned user and then purchased by the TSO. Otherwise, the part of the connection infrastructure that is not going to be used by more users represents part of users' internal infrastructure for connection and it has to be built by the concerned user.

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.

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).

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

In general, in order to foster RES integration, different charging approaches can be applied to the connection of RES producers. However, 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 a nutshell, 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, in the case of the non-standard connection, the energy storage facilities pay only a linear connection component, i.e., the component for the construction of the linear part of the connection. This approach is introduced as an incentive for the integration of the battery storage facilities and its application is limited in time, i.e., it applies until January 1, 2025, in accordance with the Law "*On Certain Issues of Use of Vehicles equipped with Electric Motors and Amendments to Certain Laws of Ukraine Regarding Overcoming Fuel Dependency and Development of Electrical Infrastructure and Electric Vehicles*".

5.1.2. Distribution

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

Table 13 *- Type of T-connection charges applied in the Energy Community Contracting Parties*

	AL	*BA*	*GE*[62]	*XK**	*MD*	*ME*	*MK*	*RS*	*UA*[63]
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. Moldova applies a lump sum connection charge based on the actual individual connection costs. In Serbia, the consumer’s connection to the distribution system can be standard or individual depending on the connection complexity, technical conditions for connection, type of consumer’s facility, its distance from the system, and the connection method. In the case of the standard connection, the consumer pays a standard lump sum per connection, a standard unit charge per distance and a unit charge per capacity, while if the connection is individual, the consumer pays individual actual costs of the connection and a unit charge per capacity.

In Bosnia and Herzegovina, a connection to the distribution system can be standard or non-standard. The charge for the standard connection consists of two components: a fixed component for the construction of the connection of each type of standard connection and a component for ensuring the connection conditions for the respective connection capacity, which is obtained by multiplying the unit price with the connection capacity. On the other hand, a charge for a non-standard connection to the distribution network consists of three components: 1) a fixed component for the construction of a typical measuring point for each type, 2) a component for the construction of a typical connection line for each type according to the length of the connection line, and 3) a component for ensuring the conditions for connection capacity, which is obtained by multiplying the unit price with connection capacity. In Kosovo*, connection charges are set on a unit basis (unit charge per capacity and unit charge per distance) and lump-sum bases for the services that cannot be included in unit charges. These charges are applied to concerned new users depending on the services required. A new user is obliged not only to cover the costs of the assets required for connection to the existing distribution system but any upstream costs for reinforcement, expansion, or reconfiguration of the existing network which are caused as a direct consequence of connection.

[62] For demand shallow connection charge applies, while small power plants pay either shallowish or deep connection charge
[63] For standard connection – shallow connection charge, while for non-standard connection deep connection connection charge.

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. The connection charge aims to cover the upstream 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. 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 6 km 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 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 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). 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.

In Bosnia and Herzegovina and Montenegro, there are similar mechanisms for compensation of the users whose connection infrastructure is going to be used by new users as the ones applied for the transmission users. In particular, in Bosnia and Herzegovina, if a new user is going to be connected via the non-standard connection infrastructure of an existing user, it is obliged to pay compensation for the part of the non-standard infrastructure to the existing user. The level of the compensation is calculated by the DSO. In Montenegro, DSO is obliged to purchase the part of the connection infrastructure built and owned by the user (internal infrastructure for connection).

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).

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. In a nutshell, 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.

5.2. Reactive energy 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.

5.2.1. Transmission

Due to the recent market developments, only Bosnia and Herzegovina and Montenegro 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 neighbouring 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. Finally, in the framework of the periodic review, with the aim of avoiding overvoltages, ERO approved investment projects such as shunt-variable reactor 100 MVAr, 400 kV in SS Ferizaj 2.

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 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, transmission 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"[64], approved by the Ministry of Energy.

Figure 6 shows the level of reactive charges for excessive reactive withdrawal in Kosovo*, Montenegro, North Macedonia[65] and Serbia[66] in 2022. A single reactive tariff applies in these 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).

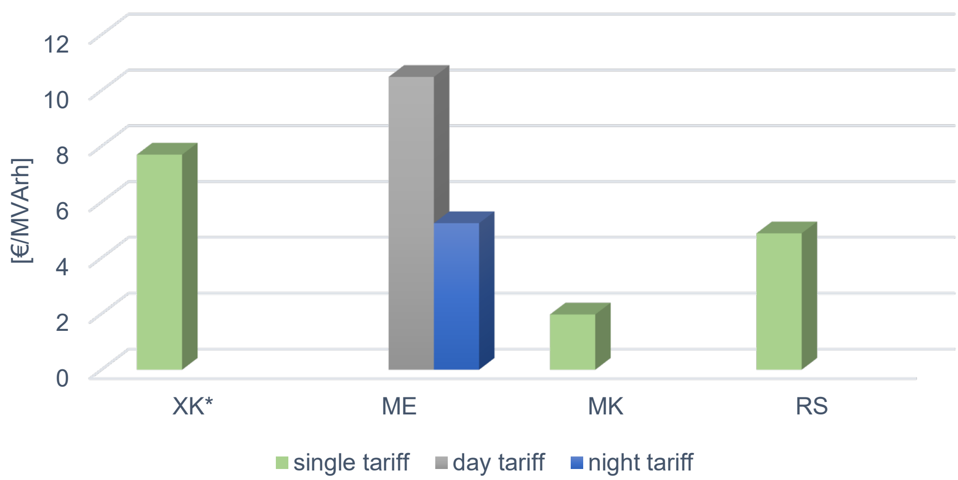


Figure 6 *- The level of unit charges for reactive withdrawal in 2022*[67]

5.2.2. 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 apply also 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

[64] https://zakon.rada.gov.ua/laws/show/z0392-18#Text
[65] Please note that in North Macedonia one value of unit charge was applied from January 1st, 2022 until June 30th, 2022: 0,1206 MKD/kVArh (1,96 €/MVArh), while the other one applied from July 1st, 2022 until December 31st, 2022: 0,1227 MKD/kVArh (1,99 €/MVArh)
[66] In Serbia, the tariff for reactive energy withdrawal up to the power factor of 0,95 (ind) was 2,44 €/MVArh in 2022.
[67] The information for Ukraine is not available.

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 $\cos\varphi$ 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 $\cos\varphi$ 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 Contracting Parties, 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"[68], approved by the Ministry of Energy

Figures 7 and 8 show the value of reactive charges (€/MVArh) applied to medium voltage and low users in Albania, Bosnia and Herzegovina, Kosovo*, Moldova[69], Montenegro, North Macedonia[70] and

[68] https://zakon.rada.gov.ua/laws/show/z0392-18#Text

[69] Values shown for Moldova are for the total reactive withdrawal and injection.

[70] Please note that in North Macedonia the value of unit reactive charge was not the same during the whole year:

- from January 1 st, 2022 until June 30th, 2022: category MV1: 0,0230 MKD/kVArh (0,374 €/MVArh), MV2: 0,0680 MKD/kVArh (1,106 €/MVArh),
- from July 1st, 2022 until December 31st, 2022: category MV1: 0,0295 MKD/kVArh (0,48 €/Mvarh), MV2: 0,0838 MKD/kVArh (1,363 €/Mvarh).

Serbia[71]. Only Bosnia and Herzegovina, North Macedonia and Serbia apply different tariffs for medium and low voltage users.

In Montenegro, there is a day and night unit reactive energy charge, while the other Contracting Parties apply a single unit charge. as shown in Graph xx, 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). The values applied by the DSO in Bosnia and Herzegovina are divided in four categories (DSO_1 and DSO_2 – *two DSOs operating in BA's entity Federation of Bosnia and Herzegovina*, DSO_3 – *five DSOs operating in BA's entity Republika Srpska* and DSO_4 – *DSO operating in Brcko District*), whereas the highest value of the reactive tariff for each category is shown, as different reactive tariff is applied for different voltage levels and consumer categories.

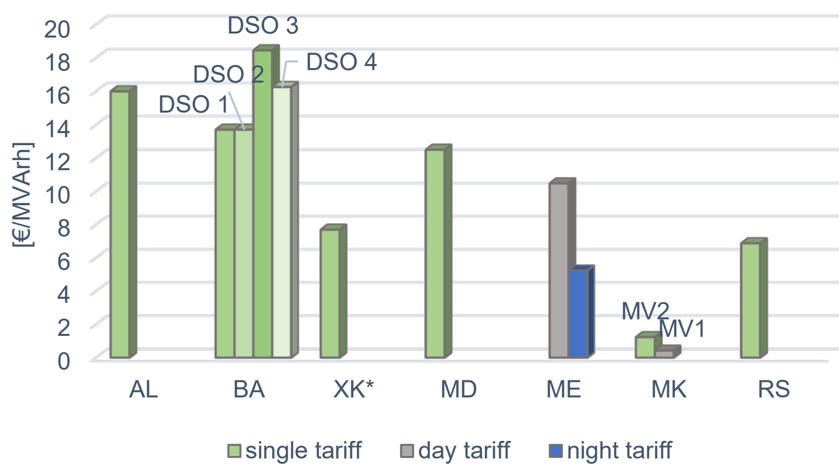


Figure 7 *- The level of unit charges for reactive withdrawal at MV in 2022*[72]

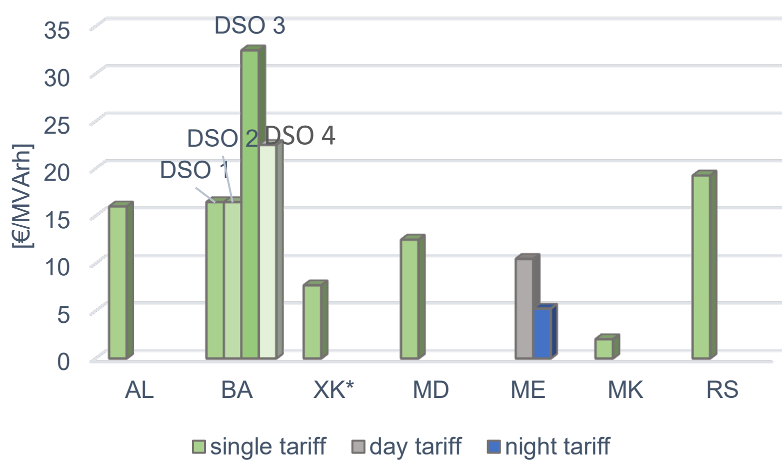


Figure 8 *- The level of unit charges for reactive withdrawal at LV in 2022*[70]

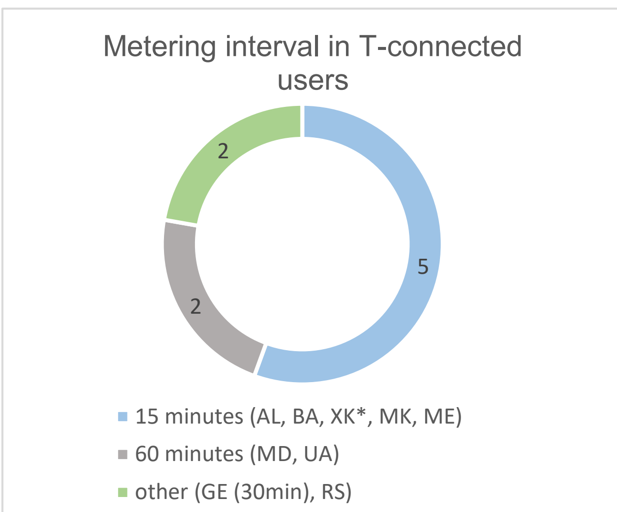
[71] In Serbia, the MV tariff for reactive energy withdrawal up to the power factor of 0,95 (ind) was 3,44 €/MVArh in 2022.
[72] The information for Ukraine is not available.

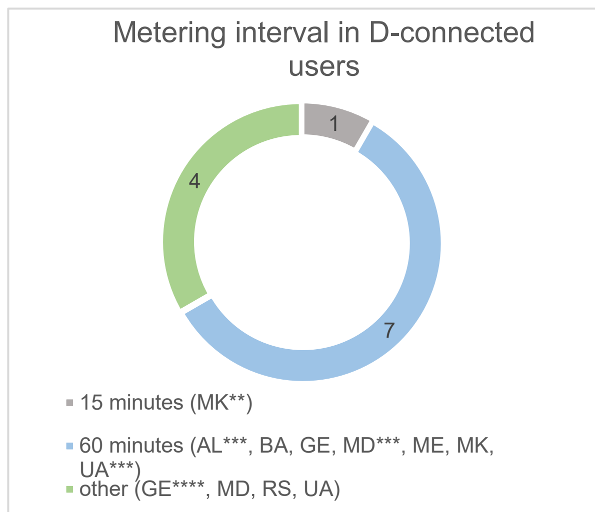
6. Time-differentiation and locational signals

6.1. 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 (see also Figure 9) a sufficient level of penetration of meters capable to record time-of-use, and in five 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. It is worth mentioning that in North Macedonia, out of 803,204 active metering devices at the distribution level, 88,000 are capable of measuring withdrawal with 15-minute time intervals (that represents around 11%).





***In Albania, Moldova and Ukraine, two intervals are used for D-connected users, where 60 minutes interval is applied to those who are equipped with the interval meters, the consumption of other users is metered monthly.*
****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.*

Figure 9 *- Metering intervals applied in the Contraction Parties*

6.1.1. 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 *Case Box 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 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).

Case Box 1 *– Time-of-use T- tariffs in Montenegro and Serbia*

Contracting Party	***Application of time-differentiated T-tariffs***
Montenegro	*In Montenegro 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).* *A low tariff (night tariff) applies also on Sunday (namely, from 11 p.m. (or 12 p.m. DST) on Saturday till 7 a.m. (or 8 a.m. DST) on Monday.* *The tariff methodology defines that ratio between day/night tariff cannot be higher than 3:1. Currently applied ratio (in 2023) is 2:1.* *All network users connected to the transmission system do have smart meters capable of recording time-of-use with 15 minutes interval.* *Time-of-use tariffs are mandatory for all transmission connected consumers; but not available for producers connected to the transmission system.* *As day/night tariffs are introduced a long time ago, their impact on the consumption pattern can be hardily assessed. However, currently, around 35% of annual consumption is consumed during periods of low tariff application.*
Serbia	*In Serbia, 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.* *The value of the day T-tariff is twice higher than the value of the night one. Time-of-use network tariffs are available and mandatory for all transmission connected users.* *Based on NRA's assessment the main outcomes from application of time-of-use T-tariff are reduction of the system or local peak, congestion costs, grid losses and as a result reduction of network development cost. It also contributed to the reduction of loss of load cost as it decreases (due to the load shifting) the need for additional injection to the system by marginal units in order to maintain the security of supply.*

6.1.2. Distribution

Time-of-use D-tariffs are reported only in Bosnia and Herzegovina (seasonal time signals, day/night and weekends tariffs – see details in Case Box 2), Montenegro (day/night applied similar to T-tariff approach) and Serbia. It needs to be noted that in Serbia there are three areas defined (in geographical scope) in which the “start-time” of the period of the off-peak tariff (night tariff) is different in order to “shift” start of “lower tariff” period within three consecutive hours, from 22 CET till 24 CET, and therefore to avoid instant increase of consumption in only one hour. In the first area, the period is from 22:00 to 6:00, in the second from 23:00 to 7:00 and in the third from 24:00 to 08:00. 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 – 8%, Georgia – below 10%) and in others from 75% (Serbia) to 100% (Bosnia and Herzegovina, North Macedonia, 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*, Moldova).

Case Box 2 *- Time-of-use D- tariffs in Bosnia and Herzegovina*

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.*

6.2. 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. 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[73], 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[74] 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[75].

Regulation (EU) 347/2013 on guidelines for trans-European energy infrastructure (TEN-E Regulation) provides for a specific regulatory regime for Projects of Energy Community Interest (hereinafter, PECI), in order to foster refurbishment of existing energy infrastructure and the deployment of new energy infrastructure in Energy Community to support climate policy objectives, market integration in the region, reducing greenhouse gas emissions and increasing the share of renewable energy in final energy consumption, achieving increase in energy efficiency whereby energy efficiency gains may contribute to reducing the need for construction of new infrastructure. In particular, according to Article 13 of the TEN-E Regulation Contracting Parties and national regulatory authorities shall ensure that appropriate incentives are granted to the PECI if its promoter incurs higher risks for the development, construction, operation or maintenance compared to the risks normally incurred by a comparable infrastructure project.

Again, Regulation 2019/943 prescribes that tariff methodologies shall […] provide appropriate incentives to TSOs and DSOs over both the short and long run, in order […] to support related research activities and to facilitate innovation in the interest of consumers in areas such as digitalisation, flexibility services and interconnection.

7.1 PECI

Only the NRA of Montenegro reported that the tariff methodologies envisaged the rules for anticipatory investment for PECI in order to provide incentives for the development of these projects. In Kosovo*, NRA drafted the Methodology for PECI/PMI projects but such methodology has not been approved yet because so far there has not been such a project in the country. All other Contracting Parties do not provide any specific incentives to PECI/PMI.

[73] Decision 2022/02/MC-EnC of the Energy Community Ministerial Council of 15 December 2022.
[74] Directive 2012/27/EC on energy efficiency, as amended by Directive (EU) 2018/2002
[75] Annex XI and Annex XII to the Directive 2012/27/EC

7.2 Energy efficiency

Five NRAs (GE, XK*, MD, ME and RS) from Contracting Parties 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 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.

ANRE informed that *Law No 139/2018* for energy efficiency transposes partially the Directive 2012/27/EU in Moldova. In this regard, ANRE considers the investments made by the DSO when approving the distribution tariffs.

In Montenegro, when planning the development of the transmission and distribution system, TSO and DSO should take into account 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. 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. In these investment plans, the operators shall present the expected increase in the efficiency of the operation of the transmission system and distribution system as a result of the investments foreseen, by reducing the losses of electricity and improvement of the quality of the delivered electricity from the subsequent networks. For each investment, a resume with indicators on the economic efficiency, return period, current net value, internal rentability rate and profitability index should be submitted, except for the separate investment with a value lower than 100,000 euro, for which no resume with the indicators on economic efficiency should be submitted. Thereby, the regulated company cannot show another identical separate investment (with the same purpose, same or similar technical characteristics, i.e., for which the same depreciation rate is calculated) in the same calendar year. At the request of the ERC, the regulated company is obliged to submit additional information, data, and clarifications regarding the benefits of the planned investment.

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/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 realized and approved income for the previous regulatory period(s).

7.3 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[76] 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[77], 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[78]. All other Contracting Parties currently do not have and do not plan any activities in this regard. Research and Development activities of TSOs/DSOs are not supported by any targeted incentivizing component in tariff methodologies in all analyzed countries.

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.

7.4 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

[76] Article 3, Article 51, Article 59;

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

[78] 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.

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.

8. 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.

Although the primary law may provide for main guiding principles and objectives of network tariff regulation, **it is recommended that solely NRAs determine the regulatory method and relevant regulatory parameters** to ensure smooth development of regulatory practices from one regulatory period to another, cost-reflectivity of tariffs, network development as well as relevant incentives for TSOs, DSOs and network users. Finally, this shall also contribute to the harmonization of regulatory approaches among the Contracting Parties and the EU Member States and facilitate market integration.

In most of the Contracting Parties, NRAs develop and approve T-tariff and D-tariff methodologies and also approve the values of T-tariff and D-tariffs. At the same time, not all NRAs reported powers as regards regulation of CDSO. As Directive 2019/944 in Article 38 (2) considers CDSO to be DSO for the purposes of the Directive, **NRAs shall have the power to approve tariffs for CDSO, or the methodologies underlying their calculation, prior to their entry into force**. Alternatively, where an exemption is granted, the applicable CDSO tariffs, or the methodologies underlying their calculation, shall be reviewed and approved by the NRA upon request by a user of the closed distribution system.

Tariff setting principles and type of 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 introduction of new performance indicators (e.g. quality, energy efficiency) than cost plus methodology which provides limited incentives to increase efficiency of activity. Therefore, **it is recommended to introduce the incentive-based regulation for T-tariff and D-tariff in all Contacting Parties.**

It is also observed that in most of the Contracting Parties NRAs still[79] do not include incentives for quality in T-tariff and D-tariff regulation (compared to status in 2019). **ECRB recommends to the NRAs of the Contracting Parties to include incentives for quality of service in the transmission and distribution tariff methodologies** with the aim to maintain the quality of service levels or improve them[80].

[79] Based on the findings of the ECRB report "Distribution tariff methodologies for electricity and gas in the Energy Community" in 2019;
[80] 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.

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. Most of the NRAs also set the regulatory period for T-tariffs and D-tariffs between three and five years.

The NRAs are recommended to revise the network tariff methodologies in order to accommodate new developments in network operation, introduce incentives (for both network operators and users) in areas where performance improvements are evidently required, to reflect market developments, including new types of users and specifics of their operation. It is not recommended to revise network tariff methodologies 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) and tariff setting period (the period for which the tariff value calculated[81]). 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.

Stakeholder involvement

In all Contracting Parties, tariff methodologies for network operators are subject to public consultations. **It is recommended that all documents and information related to the public consultations are published in a timely manner.**

Several NRAs introduced a positive practice to publish the tariff related documents in English. The role of stakeholders in designing of network tariff methodologies is growing. Energy transition and energy efficiency measures also provide for some specifics in network operation and regulation. The modern network accommodates emerging network users, which are capable both to inject and to withdraw electricity, to trade energy or provide services on the market or flexibility services to network operators. To meet all these requirements, **it is recommended for NRAs to set up an appropriate mechanism of stakeholders' involvement (e.g., stakeholder expert group) at the stage of tariff methodology revision, to take into account evolving circumstances while preserving the principles of network tariff regulation.**

Transparency in tariff setting

When setting network tariffs, NRAs in all Contracting Parties make publicly available the methodology and 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 consolidated version of network tariff methodologies, in local languages and in English,** in order to increase transparency for market participants from other markets as well as to support benchmark and harmonization of regulatory approaches between the Energy Community Contracting Parties and the EU Member States. This also benefits the investment decisions in network development.

[81] Normally regulatory period with the duration of more than 1 year contains several tariff periods

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 recognized in T-tariff and D-tariffs relate to investments into transmission and distribution networks, operational costs, costs of cross-border issues and purchasing ancillary services (TSO), network losses, metering (DSO). These categories shall be monitored by NRAs including effect of each category on the tariff value for each type of network user. Specific **cost drivers in each category shall be reviewed regularly** to take into account new developments (e.g., costs related to market integration and regional cooperation shall be recognized). At the same time, **TSO and DSO tariffs shall not include any non-TSO/DSO tasks related costs (e.g., 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 though the separate non-transmission (non-distribution) charges.

Cost cascading

Most of the NRAs of the Contracting Parties reported no cascading of transmission costs between the users of transmission grid, namely all T-users regardless the voltage of connection pay the same T-tariff value set for particular customer category (where relevant) in all Contracting Parties. Only in Kosovo*, T-connected network users at a lower voltage level pay for part of the T-costs of higher voltage levels. Distribution costs (in total or partly[82]) cascade between different voltage levels in all Contracting Parties. **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 apply to the most cost-driving voltage levels compared to the adjacent one, considering also the density of network users connected to each of the voltage levels. At the same time, **it is recommended to NRAs to collect information on costs by each voltage level, to proper monitor and propose revisions of cascade levels where reasonable.**

Injection and withdrawal tariffs

Only several Contracting Parties have introduced injection network charges at the transmission level, while Montenegro is the only Contracting Party that applies distribution injection charges. 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 a single user should reflect the costs caused by this user, **NRAs are invited to consider assessing the impact of network users that inject electricity into the grid on the costs of TSO and DSO and, in line with the assessment**

[82] In Kosovo* only cost of losses are subject to cascading among the distribution voltage levels.

results, to reconsider 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 apply 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, while there are more Contracting Parties that apply energy-based withdrawal tariffs for distribution system use. 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. Therefore, following the ACER's recommendation, **capital/infrastructure costs should not be covered via energy-based tariff – these costs are correlated mainly with power, while some costs such as costs of losses or some operational costs should be recovered by energy-based tariffs, as the injected/withdrawn energy is the cost driver. Finally, for the costs that are not correlated with either energy or power, the lump-sum charges should be used.**

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. 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, while also accounting for the cost-offsetting effect of these users. In this context, **the application of withdrawal charges to netted energy is not recommended due to the cross-subsidization of these users by other network users that only inject into or withdraw from the grid.**

Connection charges

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, in many Contracting Parties the distribution connection charge is defined as either 'standard' or 'non-standard', meaning that the costs for 'non-standard' connections mainly represent deep or "shallowish" connection charges. **In case the 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 some Contracting Parties, new producers are subject to lower connection charges than consumers. Also, in one Contracting Party (Ukraine), there is a different approach for the connection of energy storage facilities and EV charging stations – lower connection charge by January 2025 – to incentivize their penetration. Even though introducing a different approach for the connection of some categories of network users (new technologies) is good for incentivizing 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, the consumers that withdraw the reactive energy excessively (above a certain threshold) are charged with reactive energy charge. Except for reactive charge for withdrawal, some Contracting Parties also apply the charge for reactive energy injection. 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 costs of active energy or more complex calculation methods are applied. Only a few Contracting Parties reported that they faced increased costs of compensating reactive exchanges due to the recent market developments. Nevertheless, in these cases, NRAs should consider adapting reactive charging methods to reflect increased costs and send appropriate signals to network users.

Time-differentiation and locational signals

Time-of-use T-tariffs apply only in two Contacting Parties and one more NRA applies also time-of-use for D-tariff regulation. As the market prices may still vary among the hours of the day (reflecting not only time of use but other conditions influencing the supply/demand balance, such as outages), the time-of-use network tariffs provide for more predictable demand behavior. **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[83]. 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, in order to support 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 the smart meter.**

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. All other Contracting Parties do not provide any specific incentives to PECI/PMI.

The TEN-E Regulation requires the NRA to recognize the potential additional risks of PECI project promoters in the tariff methodologies. **The ECRB recommends to the 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 neighbouring countries, especially, when it is a cross border project with the request for cost sharing, may be useful. It is of utmost importance also in light of the expected adoption in the Energy Community of Regulation (EU) 2022/869 on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013. The ECRB shall investigate the regulatory practice on risk assessment and incentives

[83] Every 2 years.

applied to PECI by NRAs in the Contracting Parties in a separate report, following the practice and approach of ACER[84].

Half of the 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 potentials 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, and concrete measures and investments are identified for the introduction of cost-effective energy efficiency improvements in the network infrastructure, with a timetable for their introduction.

The NRAs are recommended to assess the introduction of incentives for innovation and R&D for network operators that may contribute to energy efficiency and network flexibility, including integration of newly emerging system users. This requires also setting clear criteria for projects (investments) falling under the term "innovation".

[84] ACER Report on Investment Evaluation, Risk Assessment and Regulatory Incentives for Energy Network Projects, 2023, https://acer.europa.eu/Publications/ACER_Report_Risks_Incentives.pdf

Annex I: Tariff Practices

Table 1.1: General description of the T-tariff and D-tariff regulatory framework

Country	T-tariff and D-tariff regulation
Albania	*According to the Law no. 43/2015 "On Power Sector", ERE is the responsible authority for drafting and approving the methodologies on determining the transmission and distribution network tariffs. After preparing the draft methodologies, ERE publishes an announcement in two national newspapers within two working days and invites the interested groups or public to be informed with the draft-methodology and to send their opinions/comments in a written form. ERE shall inform the affected parties by providing a copy of the draft-methodology. ERE will decide in a case-by-case basis to organize hearing sessions to have the opinion of the other parties. After the interested parties sent their comments within the deadline defined in announcement, ERE Board approves the methodology. The final act is published on the ERE website and a copy is sent to all the interested groups.* *Transmission and distribution tariff methodologies are based on the principles of costs transparency, non-discriminatory access, avoiding cross subsidies, favourable investments conditions, reducing costs and improving efficiency. Also, the transmission tariff should not be used to liquidate the cost of electricity imports, or capacity charges related with imported energy, or any other costs by suppliers and the users under bilateral agreements. The transmission tariff shall consider the electricity purchase costs to cover the electricity losses in the transmission system and to ensure the balancing ancillary services procured in the market.* *The T-tariff methodology applied to the current regulatory period (May 2022 – December 2024) has been approved by the decision of ERE Board No.180, dated November 8th 2017[85], while the D-tariff methodology applied to the current regulatory period has been approved by the decision of ERE Board No.182, dated November 11, 2017. According to the ERE's Board Decision No. 73, dated on April 13, 2022, the regulatory period started in May 2022 and it lasted until December 2022. With the Decision No. 324, dated December 14, 2022, ERE's Board decided to extend the legal force of the Decision No. 73, until the approval of a decision based on DSO application or the determination of cost changes.* *T- and D-tariff regulation based on the price cap approach. The tariffs set for the whole regulatory period, with a possibility to revise.* *While the methodologies determine the model and elements of costs taken into consideration for the calculation of tariffs, the Regulation for "ERE organization, operation and procedures" defines the relevant documents, form and timing of the TSO/DSO application as well as the application review procedures steps. After the evaluation process of the application, in accordance with the output of the methodology, Regulator approves the T-tariff and D-tariff.*
Bosnia and Herzegovina	*T-tariff regulatory framework is solely set by SERC in Tariff Pricing Methodology[86] for services of Electricity Transmission, Independent System Operator and Ancillary Services, the Rule on Tariff Proceedings and Forms for Submitting Data. In accordance with the Rulebook on Public Hearings, the draft tariff methodology prepared by SERC is sent to a public hearing (session)*

[85] https://www.ere.gov.al/doc/Electricity_Transmission_Methodology.pdf
[86] https://www.derk.ba/DocumentsPDFs/Metodologija_za_izradu_tarifa-precisceni_tekst_4Nov2021-en.pdf

	with the aim of obtaining comments and suggestions from all interested parties and the general public. After processing the comments and suggestions preparing the report of the Public hearing, SERC adopts the Tariff Methodology. The same procedure is applied when changing and supplementing the tariff methodology. If there is a need, certain parts of the methodology can be considered through a Technical (specific) discussion with a limited number of experts. *T-tariff methodology is based on the cost-plus type of regulation. 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: part of the transmission tariff pertaining to energy and part - to capacity.* *The transmission tariff paid by generators on active electric energy injected by them in the transmission network.* *Regarding the regulation of the electricity distribution activity, Bosnia and Herzegovina has divided jurisdiction between: two entity regulatory commissions – Regulatory Commission for Energy in Federation of Bosnia and Herzegovina[87] and Regulatory Commission for Energy of Republika of Srpska[88] that have jurisdiction in the entities of the Federation of Bosnia and Herzegovina and Republika Srpska, respectively – and the State Electricity Regulatory Commission of Bosnia and Herzegovina that has jurisdiction in the Brcko District[89]. Each regulator independently determines the methodology and adopts D-tariffs within its jurisdiction.* *The D-tariff methodology is based on the cost-plus method of regulation through which the special revenue requirement is set on an annual basis, that is, the price that enables coverage of justified business costs as well as an appropriate rate of return for licensed assets is determined for an energy facility that performs the activities of electricity distribution.* *The revenue requirement for an energy entity is allocated to tariff elements based on:* *a) the planned energy values, structure and value of power facilities, and* *b) the proportion of variable and fixed costs to the total costs of the energy entity.*
Georgia	*At the moment, for both TSO and DSO, GNERC is using tariff methodologies that set 5-year fully volumetric cost-reflective tariffs. TSO tariff is uniform for all its customers, while each DSO has different tariffs for three different voltage levels. The T-tariff methodology[90] represents a hybrid model of Cost-Plus and Revenue Cap - utilizing 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 (with X is 1.5% annual), while Uncontrollable OPEX*

[87] https://www.ferk.ba/_hr/images/stories/2013/tarifna_metodologija_2013_hr.pdf
[88] https://reers.ba/wp-content/uploads/2022/11/Methodologies-for-determining-the-fee-for-the-use-of-the-distribution-network-and-calculation-of-the-price-of-using-the-closed-distribution-system.pdf
[89] https://www.derk.ba/DocumentsPDFs/Tarifna_metodologija-Brcko_DBiH-26Okt2011-en.pdf and https://www.derk.ba/DocumentsPDFs/Odluka-o-izmjenama-Tarifne-metodologije-za-distribuciju-Brcko-Distrikt-6Nov2014-en.pdf
[90] https://gnerc.org/ge/tariffs/tariff-el-energy/tariff-methodology

	is treated with ordinary cost-plus, and goal-setting principles are used towards electricity losses, using normative loss approach. *D-tariff methodology[91] is based on the same principles.* *The core of the current D-tariff methodology was developed within the scope of the EU Twinning project about 10 years ago (2011-2013) while another Twinning project (2021-2023) supported the development of methodology which introduces Fixed Charges. It is planned to have new methodology ready for the next regulatory period that starts in 2026.*
Kosovo*	*T-tariff and D-tariff regulatory framework includes the primary law and methodology.* *T-tariff methodology[92] determines the charges by means of which the maximum allowed revenues of TSO will be covered through charges for the given regulatory period which is 5 years) (revenue cap and performance-based regulation as regulator sets the performance indicators (X-factor is 1,5% per year)). They include Capital Costs (in the form of depreciation and return), Maintenance, Operation and Loss Costs of TSO in order to meet the demands of consumers connected to the medium and low voltage level. The methodology is developed by the TSO in line the Principles set by the ERO. First step is to allocate cost to transmission activities such are: Transmission System Operator, System Operator and Market Operator, next step is to classify these costs in order to determine if they are fixed or variable, and after it the allocation to customer categories is performed based on allocation factors. Cost of RES are directly allocated to MO.* *The ERO then conducts a consultation process and after that approves the methodology. Charges for the connection to the transmission system will be covered through the Charges Methodology for Connections, issued by TSO and approved by ERO.* *DSO methodologies are drafted by DSO according to the Principle for Determination of Tariffs, and ERO role is to approve those after public consultation. The purpose of D-tariff methodology[93] is to determine the charges by means of which the maximum allowed revenues of DSO will be covered through charges for the given regulatory period (revenue cap). They include Capital Costs (in the form of depreciation and return), Maintenance, Operation and Loss Costs of DSO in order to meet the demands of consumers connected to the medium and low voltage level. OPEX and CAPEX cost are allocated to customer categories based on energy and demand sharing factors. Charges for Connection to the distribution system will be covered through the Charges Methodology for Distribution Connections, issued by DSO and approved by ERO.* *The regulatory period is 5-year, and it is set in the regulation, hence all regulatory parameters are set for this period. There are as well annual adjustments for making correction between actual and forecasted values for the parameters which are out of the DSO control, such are: wholesale price, inflation, or any other changes that may imply impact on DSO cost due to the legal changes, etc.*

91 https://gnerc.org/ge/tariffs/tariff-el-energy/tariff-methodology
92 https://kostt.com/Home/TransmissionAndConnection
93 https://www.keds-energy.com/Uploads/Data/Docs/Metodologjiaengarkesavepershfryteziminesistemitteshperndarjes-2-_pYDkHjbaNe.pdf; http://ero-ks.org/2017/Rregullat/DSO_Pricing_Rule.pdf

Moldova	*The methodology for calculation, approval and application of regulated tariffs for the electricity transmission was approved by ANRE Decision No.486/2017[94] of 13.12.2017.* *The methodology is developed by the ANRE in accordance with the requirements of the Law No.100 regarding the normative acts from 2017 and the Law regarding transparency in the decisional process No.239 of 2008. The draft of the methodology is made public and proposals from the interested parties are received. The draft is being amended if reasonable. Also, the draft methodology is sent for opinion to the Ministry of Justice, National Anticorruption Center and Ministry of Energy. All the proposals from the interested parties are compiled in a table of synthesis, with the resolution regarding the ANRE decision on each proposal made (approved/rejected). If the proposal is rejected ANRE specifies the reason to do so. The final draft of the methodology is placed on ANRE website 5 days before the approval by ANRE Administration Council.* *The T-tariff methodology is set for 5 years as well as the regulatory period (2018-2023). At the moment ANRE is working on the next methodology, which will be approved in the near future. The new methodology will not be limited in time.* *The methodology is a cost based one, having a regulation period of 5 years. For the first year of the methodology ANRE approves the base costs (i.e., asset depreciation and OPEX) of the TSO which 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.* *According to the methodology TSO received a unique tariff for all the electricity which is being transmitted through the TSO network. Subject to these payments are the suppliers who are paying to TSO according to the quantities of electricity supplied to the final consumers and DSOs who purchase electricity to cover technological consumption and distribution network losses. If during the year there are conditions that caused a deviation of more than 5% from the amount of revenues that TSO expects to receive in that year, TSO can issue a request to ANRE in order to revise the T-tariff during the year. The deviations occurred in the previous period of that year are considered then adjusting the T-tariff.* *The applied D-methodology[95] is also cost based one, thus the revenue which DSO will get is considered to cover all justified costs as well as a rate of return on investment component. The regulatory period is 5 years, for the first year DSO is providing the costs according to the methodology, further this are indexed each year taking in account growth and inflation factors.* *For the first year of the regulatory period, DSO are presenting to the ANRE the annual base costs which are examined and approved by the regulator. For each subsequent year these costs are revised. In case of 5% deviation of the calculated revenues and real expected revenues the annual tariff may be revised by the request of the operator or ANRE.*
Montenegro	*The main provisions regarding the scope of the T-tariff[96] and D-tariff[97] methodologies and requirements are prescribed by the Energy Law, so the methodologies are developed taking into account those requirements. The draft methodologies are then submitted for public consultation for at least two weeks, after which the final version of the Methodology with incorporated changes (after the public consultation) is adopted by the NRA'a Board.*

[94] https://www.legis.md/cautare/getResults?doc_id=103990&lang=ro
[95] https://www.legis.md/cautare/getResults?doc_id=103739&lang=ro
[96] https://regagen.co.me/wp-content/uploads/2021/12/2022.07.05_Metodologija-CGES.pdf
[97] https://regagen.co.me/publikacije/cedis-metodologija-za-rdp-precisceni-tekst/

	Currently, the hybrid regulatory model (mix of the incentive-based and performance-based regulatory models) applies for T-tariff and D-tariff regulation in Montenegro. This regulatory model aims to incentivise TSO and DSOs to reduce its operational costs (revenue cap), increase its efficiency and improve the quality of service provided by the TSO and DSOs. *In general, OPEX of TSO is divided into three categories: operational costs that can be controlled, operational costs that can be partially controlled (costs for covering network losses), and costs that cannot be controlled. CAPEX consists of depreciation and return on assets. After applying adjustments from the previous regulatory period and deducing TSO's incomes from determined OPEX and CAPEX in accordance with the Methodology, the regulatory allowed revenue is determined. Then, in order to calculate T-tariffs, the determined regulatory allowed revenue is allocated to the producers and consumers by using specific keys (keys are not predetermined but calculated taking into account the assessed impact of producers and consumers on the TSO's cost). T-tariffs for producers and consumers are calculated by applying the average cost model, i.e., the specific part of the revenue is divided by forecasted production/consumption or forecasted maximum power of generators/consumers. 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. The length of the next regulatory period is defined by NRA prior to the end of the on-going regulatory period.* *In general, the same level of tariff is paid by the network users connected to the transmission system (but the tariff is not the same for producers and consumers), regardless of the voltage level of their connection. In that regard, there is no actual cost cascading at the transmission level - all transmission system users pay for the costs of all transmission voltage levels.* *For D-tariff the same regulatory approach is used. For the calculation of D-tariffs for producers, the total costs of DSO that are assigned to the producers by using specific key (key depends on the value of the assets used by producers only) is divided by the total production. On the other hand, for the calculation of D-tariffs for consumers, the remaining part of DSO's costs is divided by forecasted maximum engaged power/ electricity withdrawal of the distribution consumers.*
North Macedonia	*T-tariff and D-tariff regulatory framework is solely set by the ERC in transparent procedure involving all stakeholders and affected parties. The procedure includes public and expert discussion, preparatory session discussion and adoption on the session of the commissioners. ERC adopts Rulebook of the manner and conditions for determining maximum allowed revenue and regulated average tariffs for electricity transmission, electricity market organization and management and electricity distribution with the methodology. The Rulebook aims to provide:* *1) Interest balance of regulated companies and system users, as well as system user protection from all kinds of abuse of dominant position in the market.* *2) Creation of stable and predictable working conditions for regulated companies while performing the regulated activities,* *3) Creation of measures for efficient operation of regulated companies,* *4) Compensation of justified operating costs by the regulated companies as well as acquisition of adequate return on equity,* *5) Financing and maintenance and development of the existing and construction of new electricity transmission and distribution capacities, as well as provision of their sustainable and secure functioning,*

	6) *Nondiscriminatory treatment of companies, and implementation of objective criteria and transparent methods and procedures for adequate tariff regulation,* 7) *Provision and improving supply safety, as well as safe, continuous, and quality electricity transmission and distribution,* 8) *Prevention of revenues and cost redistribution while performing the regulated and/ or other activities,* 9) *Compensation of costs for electricity purchase designated for covering the losses in the adequate energy system, taking into consideration the plans and the dynamics for reducing the losses that the system operators deliver to the Energy Regulatory Commission for approval,* 10) *Advancing energy efficiency, energy-saving, efficient energy use and* 11) *Environment protection and enhancement while performing the regulated activities.* *Revenue cap type of regulation is applied for T-tariff methodology*[98] *and D-tariff methodology*[99]*. The regulatory period for electricity transmission and distribution is 3 years starting from 1st of January. The transmission and distribution tariffs are set once per year and applicable from 1st of July until 30th of June next year.* *Only justified operational cost are covered by tariffs. The justification of the operating costs is determined by the ERC, according to the:* 1) *Type of cost;* 2) *Necessity of cost and the possibility for it to be controlled by the enterprise;* 3) *Comparative analysis with previous periods;* 4) *Manner of price formation of the purchased materials or services if for the same, no transparent purchase procedure is carried out;* 5) *Comparative analysis with other regulated companies in case of compatible costs.* *For the purpose of the next tariff methodology period ERC is considering to use t-2 for the base year (currently it is t-1).*
Serbia	*In accordance with Article 50, paragraph 1 of the Law on Energy, the Energy Agency of the Republic of Serbia adopts a methodology for determining the price of access to the electricity transmission system*[100] *and the methodology for determining the price of access to the electricity distribution system*[101]*. Both Methodologies are developed by the NRA in cooperation with relevant operators (TSO or DSOs). Afterwards first Draft of Methodology is put on the public consultation which lasts 30 days. Once public consultation is finished final version is the subject of NRA's approval.* *Both T-tariff and D-tariff methodology is based on the costs-plus method of regulation, which determines the maximum amount of income for the regulatory period. T-tariff methodology enables:*

98 https://www.erc.org.mk/odluki/2019.05.10%20PRAVILNIK%20ZA%20TARIFI%20ZA%20ELEKTRICNA%20ENERGIJA%20ZA%20GS-SL.VES%20ENG.pdf

99 https://www.erc.org.mk/odluki/2019.05.10%20PRAVILNIK%20ZA%20TARIFI%20ZA%20ELEKTRICNA%20ENERGIJA%20ZA%20GS-SL.VES%20ENG.pdf

100 https://www.aers.rs/Files/Metodologije/Preciscen/2022_12_28%20Metodologija%20prenos%20EE%20SG%2093-12,123-12,116-14,109-15,98-16,99-18,4-19,158-20,71-21,141-22,5-23.pdf

101 https://www.aers.rs/FILES/Odluke/OCenama/2021-10-01_ED%20Cenovnik%20-%20distribucija.pdf

	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 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;* 5) *prevention of mutual subsidization between individual activities performed by the transmission system operator and between individual users of the system.* *Tariffs are equal for all system users of the same system operator within the same category and groups of users. Producers connected to distribution system for injection are exempted.* *Similarly, D-tariff methodology ensures:* 1) *covering justified costs, and the corresponding return on effectively invested funds in the performance of electricity distribution and distribution system management activities, which ensure short-term and long-term security of supply, i.e. sustainable development of the system;* 2) *security of system operation;* 3) *encouraging economic and energy efficiency;* 4) *non-discrimination, i.e. equal position of the same category and group of system users;* 5) *prevention of mutual subsidization between individual activities performed by the system operator and between individual system users.* *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.*
Ukraine	*The methods of network tariff regulation which may be applied by the Regulator are defined by the Law "On natural monopolies".* *In pursuance of the Law of Ukraine "On the Electricity Market" to ensure full-scale functioning of the electricity market, the NEURC adopted a resolution "On Approval of the Procedure for Establishment (Formation) of the Tariff for Electricity Transmission Services"*[102] *and "Approval of the Procedure for Forming the Tariff for Services of Dispatch (operational-technological) Management"*[103]*. Therefore, there are two types of tariffs charged by the TSO: for transmission service (covers mostly network investments and losses) and dispatch service tariff (covers mostly ancillary services).* *The regulatory framework takes into account legislative changes, determines the procedure for providing the licensee with materials for setting tariffs, including revision, clarification and adjustment of tariffs for the transmission of electricity and dispatching (operational-technological) management, the procedure for reviewing the NEURC of these materials and a detailed mechanism for calculating the predicted necessary income from the implementation of activities for the transmission of electricity and from dispatching (operational-technological)*

102 https://zakon.rada.gov.ua/laws/show/v0585874-19#Text
103 https://zakon.rada.gov.ua/laws/show/v0586874-19#Text

management, with decryption of all components, as well as the mechanism for calculating the relevant tariffs.

Also, the resolution of the NEURC of April 22, 2019, 585 provides for the possibility of determining the income from the transmission of electricity and calculating the tariff for the transmission of electric energy to the licensee, subject to the application of incentive regulation. Currently T-tariff regulation is based on the cost-plus type of regulation. The regulatory period is 1 year.

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).

The plan for the development of the transmission system is approved by the Regulator each year for the next 10 years, on its basis, the transmission system operator develops an appropriate investment program for 1 calendar year, which is also approved by the NEURC.

Law of Ukraine "On the Electricity Market" and Law on the NEURC provide for the creation of favorable conditions for attracting investments in the development of markets in the energy and utilities sectors, as well as that the methods (orders) of setting (forming) tariffs for electricity distribution services should ensure fair rates of profit on the invested capital, as well as short-term and long-term incentives for distribution systems operators to increase efficiency. In 2013, the regulatory framework of NEURC was adopted, which allows for the introduction of incentive regulation for DSOs.

In accordance with the requirements of the Electricity Market Law, a resolution of the NEURC of 05.10.2018 dated 05.10.2018 1175 "On Approval of the Procedure for Establishing (Formation) Tariffs for Electricity Distribution Services"[104], which defines the procedure for setting the tariff for electricity distribution services, provided the transition to incentive-based regulation (however, the use of the methodology of costs-plus is allowed for the transitional period). Currently both methodologies applied.

The NEURC Resolution dated 23.07.2013 № 1009 "On the establishment of parameters of regulation having a long-term validity for the purposes of stimulating regulation"[105], established the parameters of incentive regulation.

The specified regulatory framework made changes in connection with the improvement of legislation, as well as in connection with the introduction of martial law in Ukraine. All changes were made in compliance with the requirements of the Procedure for conducting an open discussion of draft decisions of the NEURC, approved by the NEURC resolution of June 30, 2017.

For DSO under cost-plus methodology: 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 on the basis of forecast data.

For DSO under the RAB-regulation methodology approaches to determining each component of the tariff structure are determined by Procedure 1175. Also, different rate of return set for

[104] https://zakon.rada.gov.ua/laws/show/v1175874-18#Text%0A
[105] https://zakon.rada.gov.ua/laws/show/z1266-13#Text

	RAB created before application of incentive regulation and after it (with the higher value for the new RAB). *Plans for the development of distribution systems are approved by NEURC each year for the next 5 years, on their basis, the distribution system operators develop an appropriate investment program for 1 calendar year, which are also approved by NEURC.*

Table 1.2. 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[106] 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.*

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

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 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* *Based on wholesale cost forecast*
	DSO	*DSO* *Based on wholesale cost forecast.*

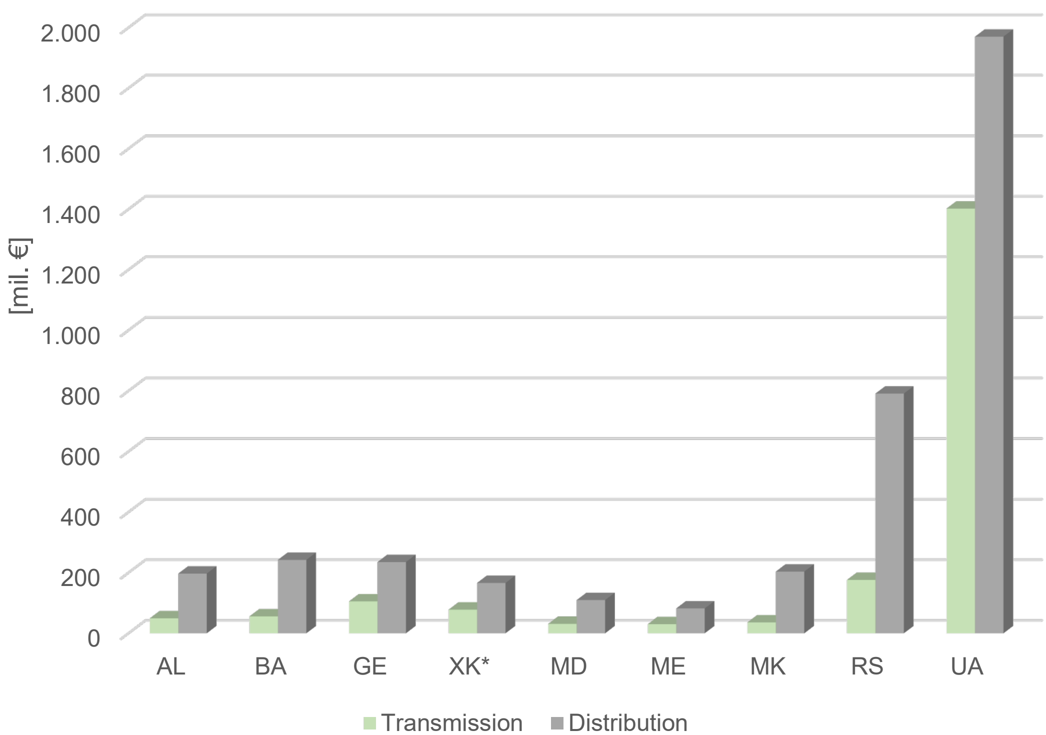
	The allowed cost of losses shall be the forecast cost of losses to be recovered from the DSO to compensate for losses on the Distribution System, calculated using the Loss Allowance which shall be set at Periodic Reviews. Details can be found in the Article 12 of the DSO Pricing Rule	
Moldova	*TSO* *Only 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 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.*	*TSO* *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.*
	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 a percentage of the losses set in the Plan for reduction of the losses approved 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 percentage 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.* *DSO* *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 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*	*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).*

	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.	
	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 2022

Figure 2.1: Collected TSO's and DSO's revenue in 2022 in mil. €[107][108]



[107] TSO's revenue for Kosovo* includes also RES Fund.
[108] It has to be noted that data for 2022 for Montenegro refers to the determined values from the REGAGEN's decision.

Annex III: Value of injection and withdrawal charges in 2022

Transmission

Table 3.1: T-injection and T-withdrawal charges in the Contracting Parties in 2022

<table>
<tr><th></th><th colspan="4">Withdrawal charges</th><th colspan="2">Injection charges</th></tr>
<tr><td rowspan="3">AL[109]</td><td colspan="4">Energy-based (€/kWh (ALL/kWh))</td><td colspan="2" rowspan="3">-</td></tr>
<tr><td colspan="3">Jan-Apr</td><td>May-Dec</td></tr>
<tr><td colspan="3">0.0063 (0.75)</td><td>0.071 (0.85)</td></tr>
<tr><td rowspan="3">BA[110]</td><td colspan="3">Elektroprenos BiH</td><td>NOSBIH (ISO)</td><td colspan="2">NOSBIH (ISO)</td></tr>
<tr><td>Energy-based (cent€/kWh)</td><td colspan="2">Power-based (€/kW)</td><td>Energy-based (cent€/kWh)</td><td colspan="2">Energy-based (cent€/kWh)</td></tr>
<tr><td>0.296</td><td colspan="2">0.753</td><td>0.045</td><td colspan="2">0.0037</td></tr>
<tr><td rowspan="2">GE[111]</td><td colspan="4">Energy-based (c€/kWh (tetri/kWh))</td><td colspan="2" rowspan="2">-</td></tr>
<tr><td colspan="4">0.95 (2.664)</td></tr>
<tr><td rowspan="4">XK*[112][113]</td><td colspan="3">Supply</td><td>DSO</td><td>T-connected generation</td><td>D-connected generation</td></tr>
<tr><td rowspan="2">Energy-based (€/MWh)
SO; MO; RES</td><td colspan="2">Power-based (€/kW/year)</td><td rowspan="2">Energy-based (€/MWh)
SO; MO</td><td rowspan="2">Energy-based (€/MWh)
SO; MO</td><td rowspan="2">Energy-based (€/MWh)
SO; MO</td></tr>
<tr><td>400/220 kV</td><td>110 kV</td></tr>
<tr><td>5.141; 0.026; 0.732</td><td>4.745</td><td>9.675</td><td>1.726; 0.023</td><td>1.965; 0.025</td><td>0.104; 0.025</td></tr>
</table>

[109] Links to the Decisions: https://www.ere.gov.al/images/files/2022/02/18/Tarifat_dhe_cmimet_2022_18022022.pdf, https://www.ere.gov.al/images/files/2022/05/11/Tarifat_dhe_cmimet_2022.pdf, https://www.ere.gov.al/images/files/2022/12/22/Tarifat_dhe_cmimet_202222122022.pdf and https://www.ere.gov.al/images/files/2023/04/12/Tarifat_dhe_cmimet_2023.pdf

[110] 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

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

[112] Link to the Decision: https://www.ero-ks.org/zrre/sites/default/files/Publikimet/Vendimet/Vendimet%202023/V_1712_2023_Decision%20for%20Tariffs_2023_FINAL_TSO_MO.pdf

[113] The tariff values are presented as sum of several components: Transmission Use of System Tariffs, System Operation and Market Operation tariffs, as presented in the Decision.

<table>
<tr><th></th><th colspan="4">Withdrawal charges</th><th colspan="2">Injection charges</th></tr>
<tr><td rowspan="2">MD[114]</td><td colspan="4">Energy-based (€/kWh (bani/kWh))</td><td colspan="2" rowspan="2">-</td></tr>
<tr><td colspan="4">0.007 (14.5)</td></tr>
<tr><td rowspan="2">ME[115]</td><td colspan="2">Energy-based
(cent€/kWh)</td><td colspan="2">Power-based (€/kW/month)</td><td>Energy-based (€/MWh)</td><td>Power-based (€/MW/month)</td></tr>
<tr><td colspan="2">0.1470</td><td colspan="2">2.0351</td><td>2,4636</td><td>213.8034</td></tr>
<tr><td rowspan="3">MK[116]</td><td colspan="2">Jan-Jun</td><td colspan="2">Jul-Dec</td><td colspan="2" rowspan="3">-</td></tr>
<tr><td>Energy-based (MKD/kWh)</td><td>Power-based (MKD/kW)</td><td>Energy-based (MKD/kWh)</td><td>Power-based (MKD/kW)</td></tr>
<tr><td>0.3015</td><td>19.8515</td><td>0.3067</td><td>17.3319</td></tr>
<tr><td rowspan="3">RS[117]</td><td colspan="2">Energy-based (c€/kWh (RSD/kWh))</td><td colspan="2">Power-based (c€/kW (RSD/kW))</td><td colspan="2" rowspan="3">-</td></tr>
<tr><td>High tariff</td><td>Low tariff</td><td>Contracted power</td><td>Exceeded power</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)</td></tr>
<tr><td rowspan="3">UA[118]</td><td colspan="2">Transmission services</td><td colspan="2">Dispatching management services</td><td colspan="2">Dispatching management services</td></tr>
<tr><td colspan="2">Energy-based (€/MWh (UAH/MWh))</td><td colspan="2">Energy-based (€/MWh (UAH/MWh))</td><td colspan="2">Energy-based (€/MWh (UAH/MWh))</td></tr>
<tr><td colspan="2">10,17 (345.64)</td><td colspan="2">1,82 (62.13)</td><td colspan="2">1,82 (62.13)</td></tr>
</table>

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

[115] Links to the Decisions: 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

[116] Links to the Decisions: https://www.erc.org.mk/odluki/231.12.2021%20MEPSO%20PRENOS%202022.pdf and https://www.erc.org.mk/odluki/29.06.2022%20MEPSO%20PRENOS%202022.pdf

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

[118] 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/tarif-na-poslugi-z-peredachi-elektrichnoyi-energiyi-shcho-diye-z-01-sichnya-2022-roku and https://www.nerc.gov.ua/sferi-diyalnosti/elektroenergiya/promislovist/tarifi-na-elektroenergiyu-dlya-nepobutovih-spozhivachiv/tarif-na-poslugi-z-dispetcherskogo-operativno-tehnologichnogo-upravlinnya/tarif-na-poslugi-shcho-diye-z-01-sichnya-2022-roku

Distribution

Table 3.1: D-injection and D-withdrawal charges in the Contracting Parties in 2022

<table>
<tr><th>CP</th><th>DSO</th><th colspan="6">Withdrawal charges</th><th>Injection charges</th></tr>
<tr><td rowspan="4">AL [119]</td><td rowspan="4">Operatori i Shpërndarjes së Energjisë Elektrike Sh.A</td><td colspan="2">Consumers categories</td><td colspan="4">Energy-based tariff (€/kWh (ALL/kWh))</td><td rowspan="4">-</td></tr>
<tr><td colspan="2">35 kV</td><td colspan="4">0.013 (1.55)</td></tr>
<tr><td colspan="2">20/10/6 kV</td><td colspan="4">0.033 (3.99)</td></tr>
<tr><td colspan="2">0.4 kV</td><td colspan="4">0.054 (6.42)</td></tr>
<tr><td rowspan="12">BA</td><td rowspan="12">Javno preduzeće Elektroprivreda Bosne i Hercegovine d.d. - Sarajevo[120]</td><td colspan="2" rowspan="2">Consumers categories</td><td colspan="2">Energy-based (pfenig/kWh)</td><td rowspan="2">Power-based (BAM/kWh)</td><td rowspan="2">Lump sum (BAM)</td><td rowspan="12">-</td></tr>
<tr><td>high</td><td>low</td></tr>
<tr><td colspan="2">35 kV</td><td>1.33</td><td>0.67</td><td>5.08</td><td>11</td></tr>
<tr><td colspan="2">10 kV</td><td>1.58</td><td>0.79</td><td>7.24</td><td>9.35</td></tr>
<tr><td rowspan="2">HH</td><td>I TG</td><td colspan="2">6.82</td><td>-</td><td>1.75</td></tr>
<tr><td>II TG</td><td>8.53</td><td>4.26</td><td>-</td><td>1.75</td></tr>
<tr><td rowspan="4">commercial</td><td>I TG</td><td>6.89</td><td>3.45</td><td>6.52</td><td>4.15</td></tr>
<tr><td>II TG</td><td>8.91</td><td>4.45</td><td>-</td><td>2.6</td></tr>
<tr><td>III TG</td><td colspan="2">6.82</td><td>-</td><td>1.75</td></tr>
<tr><td>IV TG</td><td>8.53</td><td>4.26</td><td>-</td><td>1.75</td></tr>
<tr><td colspan="2">Public lighting</td><td colspan="2">7.73</td><td>-</td><td>1.7</td></tr>
</table>

[119] Link to the Decision: https://www.ere.gov.al/images/files/2022/05/11/Tarifat_dhe_cmimet_2022.pdf
[120] Link to the Decision: https://www.ferk.ba/_en/images/stories/2017/decision_epbih_distribution_network_fee_90_2014.pdf

CP	DSO	Withdrawal charges								Injection charges
BA	Javno poduzeće „Elektroprivreda Hrvatske zajednice Herceg Bosne“ dioničko društvo Mostar[121]	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	
			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[122][123]			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				

121 Link to the Decision: https://www.ferk.ba/_en/images/stories/2017/decision_ephzhb_distribution_network_fee_90_2014.pdf

122 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

123 *МХ „Електропривреда Републике Српске“ МП а.д. Требиње ЗП „Електрокрајина“ а.д. Бања Лука, МХ „Електропривреда Републике Српске“ МП а.д. Требиње ЗЕДП „ЕлектроБијељина“ а.д. Бијељина, МХ „Електропривреда Републике Српске“ МП а.д. Требиње, ЗП „Електро Добој“ а.д. Добој, МХ „Електропривреда Републике Српске“ МП а.д. Требиње ЗП „Електродистрибуција“ а.д. Пале and МХ „Електропривреда Републике Српске“ МП а.д. Требиње ЗП „ЕлектроХерцеговина“ а.д. Требиње*

CP	DSO	Withdrawal charges					Injection charges
BA		0.4 kV – other consumption	I TG	0.0305	0.0153	18.2444	-
		0.4 kV – other consumption	II and VI TG	0.0502		6.5334	
		0.4 kV – other consumption	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	
		0.4 kV - HH	II TG	0.0669	0.0335	3.1668	
	Javno preduzeće „Komunalno Brčko" d.o.o., Brčko[124]			Energy-based (pfenig/kWh)		Power based (BAM/kW/month)	
				high	low		
		35 kV		0.96	0.48	3.5	
		10 kV		1.73	0.87	7.48	
		0.4 kV – public lighting		6.57		-	
		0.4 kV – other consumers	I TG	2.34	1.17	11.5	
		0.4 kV – other consumers	II TG	3.88		3.08	
		0.4 kV – other consumers	III TG	7.53	3.77	3.08	
		0.4 kV HH	I TG	3.91		1.85	
		0.4 kV HH	II TG	5.42	2.71	1.85	

124 Link to the Decision: https://www.derk.ba/DocumentsPDFs/Tarifa-Brcko-distribucija-16feb2023-en.pdf

CP	DSO	Withdrawal charges		Injection charges
GE [125]	JSC Telasi		Energy-based (c€/kWh (tetri/kWh))	-
		110-35 kV	0.86 (2.411)	
		10/6/3.3 kV	1.54 (4.324)	
		0.4 kV	2.91 (8.172)	
	JSC Energy Pro Georgia		Energy-based (c€/kWh (tetri/kWh))	
		110-35 kV	1.16 (3.257)	
		10/6/3.3 kV	1.94 (5.453)	
		0.4 kV	4.26 (11.979)	
XK* [126]	KEDS JSC		Energy-based tariff (cent€/kWh)	-
		35 kV	1.14	
		10 kV	1.77	
		0.4 kV	2.84	
MD [127]	Î.C.S. „Premier Energy Distribution" S.A.		Energy-based tariff (c€/kWh (bani/kWh))	-
		HV 35-110 kV	0.104 (2)	
		MV 6-10 kV	0.99 (19)	
		LV 0.4 kV	3.22 (62)	
	S.A. „RED Nord"		Energy-based tariff (c€/kWh (bani/kWh))	
		MV 6-10 kV	1.25 (24)	
		LV 0.4 kV	5.93 (144)	

[125] Link to the Decision: https://gnerc.org/en/tariffs/tariff-el-energy/distribution
[126] Link to the Decision: https://www.ero-ks.org/zrre/sites/default/files/Publikimet/Vendimet/Vendimet%202023/V_1714_2023_Decision%20for%20tariffs_2023_FINAL_DSO.pdf
[127] Links to the Decisions: https://anre.md/energie-electrica-3-290

<table>
<tr><th>CP</th><th>DSO</th><th colspan="8">Withdrawal charges</th><th colspan="2">Injection charges</th></tr>
<tr><td rowspan="12">ME[128]</td><td rowspan="12">LLC “Crnogorski elektrodistributivni sistem” Podgorica</td><td colspan="4" rowspan="2">Category of consumer</td><td colspan="2">Energy-based component (cent€/kWh)[129]</td><td rowspan="2">Power-based component (€/kW)</td><td rowspan="2">Fixed charge (€/month)</td><td rowspan="2">Producer category</td><td rowspan="2">Energy-based (€/kWh)</td></tr>
<tr><td>high</td><td>low</td></tr>
<tr><td colspan="4">35 kV</td><td>0.3283</td><td>0.1641</td><td>3.3454</td><td>-</td><td>35 kV</td><td>0.737</td></tr>
<tr><td colspan="4">10 kV</td><td>0.5416</td><td>0.2708</td><td>7.3585</td><td>-</td><td>10 kV</td><td>0</td></tr>
<tr><td rowspan="7">0.4kV</td><td colspan="3">Measuring power</td><td>0.8094</td><td>0.4047</td><td>17.8964</td><td>-</td><td rowspan="7">0.4 kV</td><td rowspan="7">0</td></tr>
<tr><td rowspan="6">Not-measuring power</td><td rowspan="2">0 kW ≤ approved CC[130] ≤ 8 kW</td><td>Dual tariff</td><td>4.5901</td><td>2.2947</td><td rowspan="2">-</td><td rowspan="2">0.7034</td></tr>
<tr><td>Single tariff</td><td colspan="2">3.7833</td></tr>
<tr><td rowspan="2">8 kW < approved CC ≤ 16 kW</td><td>Dual tariff</td><td>4.5901</td><td>2.2947</td><td rowspan="2">-</td><td rowspan="2">1.4067</td></tr>
<tr><td>Single tariff</td><td colspan="2">3.7833</td></tr>
<tr><td rowspan="2">16 kw < approved CC ≤ 34,5 kW</td><td>Dual tariff</td><td>4.5901</td><td>2.2947</td><td rowspan="2">-</td><td rowspan="2">3.0332</td></tr>
<tr><td>Single tariff</td><td colspan="2">3.7833</td></tr>
</table>

128 Link to the Decision: https://regagen.co.me/elektricna-energija/regulacija-cijena/operator-distributivnog-sistema/odluke-operator-distributivnog-sistema/odluka-o-utvrdjivanju-privremenih-cijena-za-koriscenje-distributivnog-sistema-elektricne-energije/ and https://regagen.co.me/wp-content/uploads/2022/01/20211202_CGES_Odluka_o_korekcijama_KONACNA.pdf

129 Energy-based components for 0.4 kV – not measuring power consist of two components: component for losses and component for capacity usage which are shown as a sum in the table.

130 CC: approved connection capacity

CP	DSO	Withdrawal charges						Injection charges
MK [131]	Elektrodistribucija Skoplje DOOEL Skoplje			Energy-based (MKD/kWh)		Power-based (MKD/kW)		-
				Jan-Jun	Jul-Dec	Jan-Jun	Jul-Dec	
		MV1		0.3983	0.4144	145.03	165.84	
		MV2		0.5108	0.5502	299.99	331.43	
		LV1.2		0.6269	0.6774	453.63	537.61	
		LV1.2		2.2607	2.4907	-	-	
		LV2		2.8232	3.3742	-	-	
RS [132]	Elektrodistribucija Srbije d.o.o. Beograd			Energy-based (c€/kWh (RSD/kWh))		Power-based (c€/kWh (RSD/kW))		-
				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)	0.97 (0.8258)	-	-	
			Controllable demand	2.8069 (3.297)	0.824 (0.7015)	-	-	
		Public lighting		3.0708 (3.607)		-	-	

[131] Links to the Decisions: 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
[132] Link to the Decision: https://www.aers.rs/FILES/Odluke/OCenama/2021-10-01_ED%20Cenovnik%20-%20distribucija.pdf

CP	DSO	Withdrawal charges		Injection charges
UA[133]			Energy-based (€/MWh (UAH/MWh))	-
	JSC "Vinnitsiaoblenergo"	Voltage class 1	5.87 (199.47)	
		Voltage Class 2	37 (1,257.26)	
	PRIVATE LIMITED Volynyoblenergo	Voltage class 1	4.25 (144.47)	
		Voltage Class 2	32.44 (1,102.19)	
	JSC "DTEK Dniprovski Electromerezhi"	Voltage class 1	3.38 (114.90)	
		Voltage Class 2	23.05 (783.32)	
	JSC "DTEK Donetski Electromerezhi"	Voltage class 1	7.68 (260.92)	
		Voltage Class 2	37.85 (1,286.28)	
	JSC Zhytomyroblenergo	Voltage class 1	7.28 (247.28)	
		Voltage Class 2	39.24 (1,333.43)	
	PRIVATE LIMITED "Zakarpattyaoblenergo"	Voltage class 1	9.62 (326.79)	
		Voltage Class 2	43.57 (1,480.39)	

[133] 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-2022-roku

CP	DSO	Withdrawal charges		Injection charges
	PJSC "Zaporizzhyaoblenergo"	Voltage class 1	3.27 (110.98)	
		Voltage Class 2	28.33 (962.56)	
	PJSC "DTEK Kyiv Electrical Networks"	Voltage class 1	3.05 (103.75)	
		Voltage Class 2	12.91 (438.72)	
	PJSC "DTEK Kyiv Regional Electric Networks"	Voltage class 1	6.31 (214.91)	
		Voltage Class 2	25.86 (878.60)	
	PRIVATE LLC "Kirovogradoblenergo"	Voltage class 1	9,39 (284.99)	
		Voltage Class 2	38.12 (1,295.31)	
	LLC "Luhanske Energy Association"	Voltage class 1	13.23 (415.49)	
		Voltage Class 2	48.44 (1,645.84)	
	PRIVATE LLC "Lvivoblenergo"	Voltage class 1	5.15 (175.04)	
		Voltage Class 2	30.55 (1,038.18)	
	JSC "Mykolaivoblenergo"	Voltage class 1	6.25 (212.46)	
		Voltage Class 2	31.06 (1,055.58)	

CP	DSO	Withdrawal charges		Injection charges
	JSC "DTEK Odesk Electromerezhi"	Voltage class 1	4.96 (168.47)	
		Voltage Class 2	30.22 (1,026.95)	
	JSC "Poltavaoblenergo"	Voltage class 1	3.91 (132.79)	
		Voltage Class 2	31.14 (1,058.27)	
	JSC Prikarpattyaoblenergo	Voltage class 1	6.13 (208.20)	
		Voltage Class 2	40.39 (1,372.37)	
	PRIVATE LLC "Rivneoblenergo"	Voltage class 1	4.98 (169.12)	
		Voltage Class 2	30.77 (1,045.71)	
	JSC "Sumioblenergo"	Voltage class 1	5.59 (190.03)	
		Voltage Class 2	37.92 (1,288.61)	
	JSC "Ternopiloblenergo"	Voltage class 1	6.42 (217.99)	
		Voltage Class 2	27.07 (1,312.21)	
	JSC “Kharkivoblenergo”	Voltage class 1	6.43 (218.41)	
		Voltage Class 2	27.07 (919.98)	

CP	DSO	Withdrawal charges		Injection charges
	JSC “Khersonoblenergo”	Voltage class 1	11.08 (376.59)	
		Voltage Class 2	35.35 (1,201.22)	
	JSC "KHMelnytskoblenerGO"	Voltage class 1	6.99 (237.47)	
		Voltage Class 2	37.21 (1,264.42)	
	PJSC "Cherkasyoblenergo"	Voltage class 1	3.76 (127.66)	
		Voltage Class 2	29.83 (1,013.49)	
	JSC "Chernivtsioblenergo"	Voltage class 1	4.12 (140.04)	
		Voltage Class 2	33.59 (1,141.53)	
	JSC "Chernigivoblenergo"	Voltage class 1	7.20 (244.61)	
		Voltage Class 2	39.6 (1,345.70)	
	DPEM PRAT “AtoMSERVIS”	Voltage class 1	0.64 (21.73)	
		Voltage Class 2	38.42 (1,305.43)	
	SE "Regional Electric Networks"	Voltage class 1	3.37 (114.63)	
		Voltage Class 2	11.49 (390.32)	

CP	DSO	Withdrawal charges		Injection charges
	PJSC "Dtek Pem-Energy Coal"	Voltage class 1	0,83 (28.16)	
		Voltage Class 2	8.7 (295.66)	
	"Naftogaz Teplo" LLC (Noviy Rozdil)	Voltage class 1	5.26 (178.80)	
		Voltage Class 2	30.03 (1,020.52)	
	"Naftogaz Teplo" LLC (Novoyavorivsk)	Voltage class 1	6.85 (232.92)	
		Voltage Class 2	24.93 (847.29)	
	LLC “Dtek High Voltage Networks”	Voltage class 1	2.01 (68.21)	
		Voltage Class 2	58.51 (1,988.22)	
	JSC “Ukrzaliznytsya”	Voltage class 1	5.73 (194.60)	
		Voltage Class 2	26.18 (889.59)	
	PRAT «Sing «Cek»	Voltage class 1	2.97 (101.08)	
		Voltage Class 2	24.18 (821.57)	

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

Transmission

Table 4.1: 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	providing price signal to postpone new network reinforcements and price signal to postpone the reinforcement of the interconnection capacity
GE	recovery of transmission costs	-
XK*	recovery of transmission costs	-
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	ensure level playing field of Injection charges with other countries and 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	reflect system use of current transmission assets

Distribution

Table 4.2: 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 and 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, reflecting system use of current distribution assets and providing an equitable (fair) allocation of distribution revenues	-
MD	recovery of distribution costs, reflecting system use of current distribution assets and provide an equitable (fair) allocation of distribution revenues across generation facilities	-
ME	recovery of distribution costs	reflecting system use of current distribution assets and providing an equitable (fair) allocation of distribution revenues across
MK	recovery of distribution costs	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	recovery of distribution costs and reflecting system use of current distribution assets	-