PUBLIC CONSULTATION
117

REPORT

Justification of the motivated decision in accordance with Article 27(4) of the Network Code on harmonised transmission tariff structures for gas

GAS SECTOR

March - 2024

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1 INTRODUCTION

This Report corresponds to the justification of the motivated decision based on the terms of article 27(4) of the European network code regarding harmonised tariff structures for gas, closing Public Consultation No. 117, regarding the periodic consultation in accordance with article 26 of the aforementioned network code. The motivated decision on the approval of the methodology for determining reference prices for the transmission tariff for gas is approved through ERSE Directive No. 2/2024, which awaits publication in Series II of *Diário da República* (the Portuguese Official Journal).

Commission Regulation (EU) 2017/460, of 16 March 2017, establishes a network code on harmonised transmission tariff structures for gas (hereafter Tariff Network Code) setting rules on the application of a reference price methodology and on consultation requirements, among others.

Public Consultation No. 117, which took place between 4 October 2023 and 4 December 2023, covered, in addition to the periodic consultation provided for in article 26, the consultation provided for in article 28, regarding discounts, multipliers and seasonal factors. The previous periodic consultation [1] was open between 17 August 2018 and 17 October 2018, with effects from gas year 2019-2020 onwards, and corresponded to the initial implementation of the Tariff Network Code in Portugal. In compliance with the deadlines stipulated in the Tariff Network Code, on 4 January 2024 ERSE published a summary of the comments received, and on 2 February 2024 the European Union Agency for the Cooperation of Energy Regulators (ACER) published its analysis report for ERSE's periodic consultation.

The motivated decision, that is now approved, presents minor differences compared to the previous motivated decision, and will take effect as of gas year 2024-2025. The decision maintains the current reference price methodology, although subject to updated parameters, which affect the resulting tariff structure. Since the tariff decision for gas year 2024-2025 will be approved by ERSE at the end of May 2024, the information presented in this Report on the reference prices for gas year 2024-2025 is indicative.

Compared to the consultation document, this Report includes a new chapter (chapter 2), which presents the analysis of the contributions received and explains the changes compared to the consultation proposal.

[1] Public Consultation No. 66, regarding the Implementation of the network code on harmonised transmission tariff structures for gas.

Chapter 3 gives an overview of the national transmission network and the current transmission tariff structure. The application of the reference price methodology is described in chapter 4, which results in the simplified tariff model available in Excel format, which is part of this consultation. Chapter 5 fulfils with the transparency obligations that refer to the allowed revenues to be recovered by tariffs. Chapter 6 addresses the topics of energy-based transmission tariffs and non-transmission tariffs. In turn, chapter 7 presents the indicative reference prices, which result from the reference price methodology, including the analysis required by the Tariff Network Code, in particular the cost allocation assessment and the comparison with the methodology defined in Article 8 of the Tariff Network Code. The aspects to be consulted under Article 28 are presented in chapter 8, while chapter 9 provides a brief overview of other European documents relevant to tariff-setting.

As a final note, ERSE, together with the national regulatory authority in Spain (CNMC, *Comisión Nacional de los Mercados y la Competencia*), is currently developing a study regarding the role of tariffs in the integration of the gas markets in Spain and Portugal. As mentioned in the work programme of the Southern Regional Gas Initiative, the study shall evaluate a set of options, including the elimination of tariffs at the interconnection point between Portugal and Spain and the application of a common reference price methodology for transmission tariffs in both countries. The next periodic consultation to be carried out by ERSE will benefit from the conclusions of this joint study.

<u>Legal disclaimer</u>

This document is published in Portuguese and English. In case of different interpretations, the Portuguese version prevails.

2 ANALYSIS OF THE CONTRIBUTOS RECEIVED, AND CHANGES TO THE PUBLIC CONSULTATION PROPOSAL

This chapter analyses the contributions received to the proposal presented in the public consultation and summarizes the changes made by ERSE resulting from those responses and also from the recommendations formulated by ACER in its analysis report, prepared in accordance with paragraphs 2 and 3 of article 27 of the Tariff Network Code.

2.1 RESPONSES RECEIVED

At the close data of the public consultation, on 4 December 2023, five entities had sent comments, namely the Tariff Council of ERSE, REN Gasodutos, EDP Comercial, Endesa and EDP Group. ERSE published a summary report of the comments one month after the end of the public consultation, in accordance with article 26(3) of the Tariff Network Code.

Technical comments were also received from the transmission system operator (TSO), in bilateral contacts during the public consultation process, which are described in section 2.1.1. Additionally, after the end of the public consultation, a letter was received from CNMC, the Spanish national regulatory authority, indicating that it had no comments to the consultation.

In order to better understand the changes resulting from the responses received, a Report with the summary of the responses is available [2].

2.1.1 REFERENCE PRICE METHODOLOGY

Although the public consultation proposal was to maintain the reference price methodology, known as the modified capacity-weighted distance methodology, two adaptations were proposed by ERSE, namely (1) the adoption of a complete characterisation of the transmission network for the construction of the distance matrix and (2) the replacement of the physical utilization factor by the commercial utilization factor. As both adaptations only received positive reviews, they are maintained in the motivated decision.

[2] Webpage with the Responses regarding Public Consultation no. 117.

During the final phase of the public consultation, ERSE held bilateral contacts with the TSO, which resulted in two technical comments. The first comment indicated an inconsistency in the input data for the simplified tariff model. Specifically, the TSO identified that the presence of zero values in the use of five GRMS was not coherent [3]. The existence of null values for these five GRMS affected the calculation of average distances, weighted by capacity.

The second comment concerned the network segments to be considered when calculating the distance matrix. Taking into account the clarifications of the TSO, and the correction of a distance in the diagram that characterizes the transmission network, the distance matrix now includes two additional network segments, next to the two interconnection points with Spain, for a total value of 380 metre [4]. Other comments about the information contained in the Simplified Tariff Model were also taken into account [5], without this having any effect on the calculation of the reference prices.

The changes resulting from this analysis impact the distance matrix (section 4.1.4) and the indicative reference prices (chapter 7).

2.1.2 TARIFF STRUCTURE OF THE INDICATIVE REFERENCE PRICES

The change in the tariff structure of reference prices, at entry and exit points, which results from the update of the parameters of the reference price methodology, was commented on by several agents. In particular, the greater differentiation between the prices of entry points from the VIP Iberico and the LNG Terminal, with a relative increase in the latter, was highlighted by the agents, pointing out the situation of security of supply and competition between the Iberian LNG terminals. It was also suggested that the use of these two entry points should be monitored, in order to ensure consistency with the price signals that the methodology produces. The relative increase in the price of the exit point to the VIP Iberico was also

[3] See lines 346 to 350 of worksheet 'Input' of the «Simplified Tariff Model» in Excel, published at the opening of the public consultation. The affected GRMS are: 12609, 12619, 12619B, 12629 and 12809.

[4] In Campo Maior, an additional segment of 240 metre was considered, which connects the CTS Campo Maior point to the RAIA point (pk 0,4). This segment previously had a length of 400 metre. In Valença do Minho, an additional 140 metre segment was considered, which connects the CTS Valença do Minho point to the RAIA point (pk 0,14).

[5] The correction affected the information available in worksheet 'A2.Network segments' of the Simplified Tariff Model in Excel, namely, in relation to GRMS 3359, 3369, 12609, 12619 and 12629.

identified as detrimental to competition between Portuguese and Spanish market agents, harming the integration of the two markets.

In response to the comments received, two arguments are to be presented. Firstly, ERSE will naturally, within the framework of its powers, monitor the use of the various points of the transmission network, in order to ensure the adequacy of the price signals produced by the reference price methodology. The decision to allow for a review of the commercial utilization factor, as analysed in section 2.1.3, will contribute to this objective. Regarding the competitive framework between Portuguese and Spanish market agents, ERSE publishes annually, within the scope of the tariff process, a price comparison analysis regarding the use of gas infrastructures between Portugal and Spain [6]. Secondly, the impact of the changes in the tariff structure that raised the most comments were partially attenuated as a result of the combined effect of the various changes made between the proposal put out for public consultation and the motivated decision. As explained in the following analysis, the relative price between the LNG Terminal and the VIP Iberico at the entry points was smoothed, at the same time that the price at the exit point to the VIP Iberico also decreased, compared to the proposal in Public Consultation No. 117.

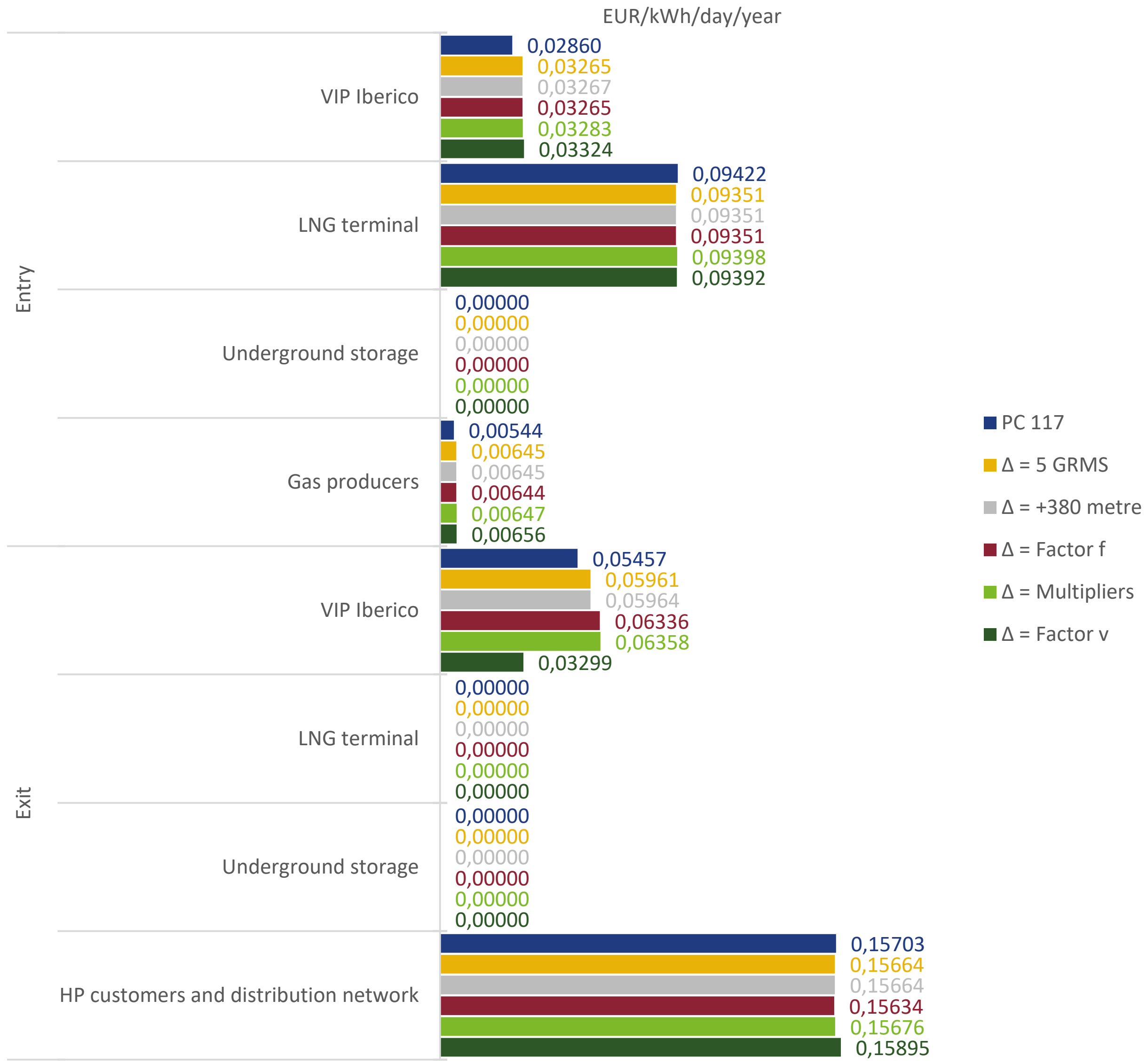
In addition to the values presented at the opening of Public Consultation No. 117, Figure 2-1 also shows the effects of the changes that resulted from the consultation process, which in the figure are carried out incrementally [7], namely:

- Values presented at the opening of Public Consultation No. 117 (**PC 117**)
- Correction in the utilisation of five GRMS (**Δ = 5 GRMS**), presented in section 2.1.1.
- Correction of the distance matrix by 380 metre (**Δ = +380 metre**), presented in section 2.1.1.
- Update of the commercial utilisation factor (**Δ = Factor f**), presented in section 2.1.3.
- Update of the short-term multipliers (**Δ = Multipliers**), presented in section 2.1.4.
- Adaptation of the economic value factor (**Δ = Factor v**), presented in section 2.2.1.

[6] Published annually in the document relating to the tariff structure for each gas year, available on ERSE's webpage dedicated to regulated tariffs and prices in the gas sector (Portuguese only).

[7] That is, the second series, «**Δ = 5 GRMS**», only considers this change, compared to the values presented at the opening of the Public Consultation. However, the last series, «**Δ = Factor v**», includes this change, and all previous ones.

Figure 2-1 - Changes in the indicative reference prices for gas year 2024-2025



Note: Prices assume forecasted capacity and allowed revenues from the tariff decision for gas year 2023-2024.

Figure 2-1 illustrates the incremental effects on the indicative reference prices of the various points of the network, taking as a starting point the values at the opening of the public consultation (PC 117). The correction in the utilisation of five GRMS (Δ = 5 GRMS), presented in section 2.1.1, mainly impacted the VIP Iberico entry and exit prices, with increases of 14,2% and 9,2%, respectively.

The correction of the distance matrix by 380 metre (Δ = +380 metre), presented in section 2.1.1, has a residual impact, with variations of less than ±0,1% in the various prices.

The update of the commercial utilisation factor (Δ = Factor f), presented in section 2.1.3, implies an increase of +6,2% in the price of the exit point to the VIP Iberico, and negligible effects on the remaining points.

The update of the short-term multipliers (Δ = Multipliers), presented in section 2.1.4, has a reduced impact on the structure of the reference prices, referring to the annual capacity, with variations of less than ±0,6% in the various prices.

The adaptation of the economic value factor (Δ = Factor v), presented in section 2.2.1, implies a reduction of -48,1% in the exit price to the VIP Iberico, offset by an increase of +1,4% in the price of domestic exits. There is an increase of +1,2% in the entry price for VIP Iberico.

Overall, the five changes implemented cause the following relative variations, when compared with the reference prices presented at the opening of the public consultation [8]:

– <u>Entry points</u>: VIP Iberico (+16,2%), LNG Terminal (-0,3%), Underground storage (±0,0%), Gas producers (+20,7%),

– <u>Exit points</u>: VIP Iberico (-39,6%), LNG Terminal (±0,0%), Underground storage (±0,0%), HP customers and distribution network (+1,2%).

At entry points, the main change is the increase in VIP Iberico, which is mainly justified by the correction of the utilisation in five GRMS [9]. In the case of price for gas producers, and although its relative increase is higher, it must be taken into account that this is an instrumental price, provisionally calculated on the assumption that gas producers are located close to the underground storage.

At exit points, the main change is the decrease in VIP Iberico, which is mainly justified by the adaptation of the economic value factor. As indicated in ACER's analysis report, the previous value of the economic value factor did not minimize cross-subsidization for the allocation of costs with regional networks.

The set of changes referred to in this analysis impact the parameters of the reference price methodology (chapter 4), the indicative reference prices (chapter 7) and the multipliers (section 8.2).

[8] Comparison, in Figure 2-1, of the series «**Δ = Factor v**» with the series «**PC 117**».

[9] The increase occurs because the five GRMS are located in the south of the country, further away from international interconnection points. By assuming a non-zero utilisation, they contribute to a greater average distance determined for the two interconnection points that constitute the entry point from the VIP Iberico.

2.1.3 COMMERCIAL UTILISATION FACTOR

Given the initial proposal to keep the commercial utilisation factor constant until a new periodic consultation on the reference price methodology, as the other parameters, the agents cautioned that the resulting price signals should be consistent with the utilisation pattern of the transmission network, thus justifying greater frequency in its updating.

Recognizing that the commercial utilisation factor is a crucial parameter, as it indeed reflects the use of entry and exit points, this motivated decision provides for the possibility of the commercial utilisation factor being updated before the next periodic consultation is carried out.

Additionally, and as already mentioned in section 2.1.1, the TSO sent ERSE comments at a technical level. The comment regarding the inconsistency in data on the utilisation by five GRMS not only affects the calculation of average distances, weighted by capacity, as analysed in section 2.1.1, but also affects the commercial utilisation factor, since the five GRMS were disregarded for the purposes of calculating the aggregate technical capacity of the GRMS. The consideration of zero values for the five GRMS mentioned reduced the calculation of the aggregate technical capacity of domestic exits from 653,90 GWh/day to 613,23 GWh/day. With the correction now made, the commercial utilisation factor presented in the public consultation for domestic exit points should have been 46,8%, instead of 49,9%. By affecting the commercial utilisation factor of domestic exit points alone, but bearing in mind that the value of revenue to be recovered at all exit points is set at 72%, the main expected effect [10] of the change is a reduction in the exit price at domestic exits, offset by an increase in the exit price in VIP Iberico.

The changes resulting from this analysis impact the commercial utilisation factor (section 4.1.3), the possibility of updating it (section 4.1.5) and the indicative reference prices (chapter 7).

2.1.4 SHORT-TERM MULTIPLIERS

In the responses received, REN stated that it considers the new methodology to be a positive change. Some agents recommended that ERSE should evaluate and monitor the impact of the multipliers for Combined Cycle Gas Turbines (CCGT) and for large consumers who contract short-term products.

[10] Due to the nature of the reference pricing methodology, this change also produces second-order effects on entry prices, as the calculation of the average distance, weighted by capacity, is also affected. These effects are not very significant, and are evidenced in the analysis presented in section 2.1.2.

In view of the methodology proposed by ERSE in public consultation, changes were made, which, although not of a methodological nature, impact the level of the multipliers. The main change consists of updating the database with the year 2023, that is, data from the period 2020-2023 is considered in the calculation of the multipliers, with the inclusion of contracted capacity data disaggregated by entry and exit points of the transmission network, available on the ENTSOG Transparency Platform. In addition, changes were made to the aggregation of information from the various years [11].

The combined effect of the aforementioned changes results in a decrease in the level of multipliers for quarterly, monthly and daily (and, consequently, within-day) maturities, compared to what was proposed by ERSE in the public consultation. This decrease is in line with the concern expressed by EDP Group, regarding the increase in daily and within-day multipliers as proposed in the public consultation.

These changes are incorporated in section 8.2 of this report.

2.1.5 TOPICS THAT RESULTED IN NO CHANGES

This section addresses the responses received, within the duration of the public consultation, which did not result in changes to the proposal submitted to public consultation.

On the subject of the **entry-exit split**, the comment to bring it closer to the default split indicated in the Tariff Network Code, that is, a 50/50 entry-exit split, was not accepted. On the one hand, the current split of 28/72 arises from a cost-reflectivity rationale, which is important to preserve, and which was recognized in technical terms by ACER as contributing to avoiding situations of cross-subsidization. On the other hand, the arguments presented in favour of the 50/50 split (maximizing the availability of input capacity, minimizing the need for new capacity) are precisely objectives that are intended to be achieved with the reference price methodology, promoting an efficient utilisation of the national gas transmission network (RNTG).

Participating entities expressed concern about the difference in treatment between the **entry price for producers in RNTG and RNDG**, since only in the case of gas injection at transmission level would an entry

[11] A correction was made to a formula relating to the quarterly maximum capacity, with a residual effect on the results. Additionally, the new calculation now only considers information from a single period of four years, equivalent to the length of the regulatory period, instead of calculating the average of several periods of four years each.

price be applied. As explained in a previous public consultation [12], the absence of an entry price in the distribution network is a direct consequence of having no entry-exit system in the distribution networks. Given that the Tariff Network Code does not allow, in its current wording, the definition of partial or total exemptions for producers injecting into the RNTG, it is not possible to respond to the comments received. Taking into account the future European legislative package for the decarbonisation of gas, changes in this matter are expected in the near future. It is also important to highlight that presently there is a harmonisation of rules at the Iberian level, given that in Spain the same rationale is followed, as there are only entry prices for producers connected to the transmission network.

It was also suggested to **eliminate the VIP Iberico tariff**, with the argument that it would increase liquidity and competition in the Iberian gas market, in addition to contributing to the integration of markets and the security and diversification of supply. In this topic, it is recalled that such tariff change is being studied and considered within the scope of the joint study with the Spanish national regulatory authority, regarding the role of tariffs in the integration of gas markets in Spain and Portugal.

Two topics were also presented that were not the subject of a proposal in the public consultation, and that cannot be included in the motivated decision, as they go beyond its scope. In the case of the suggestion to introduce a **flexible quarterly tariff**, this would have to be discussed with all agents within a regulatory review of the Portuguese Tariff Code. In the case of the proposal to limit the availability of **commercial storage of the underground storage** to short-term products only (e.g., monthly, daily), the change goes beyond the tariff scope of this public consultation. The allocation of underground storage capacity is a matter under the Access to Networks, Infrastructures and Interconnections Code (RARII) and the Manual of Procedures for Access to gas Infrastructures (MPAI), which already provide for the possibility of retaining capacity in the annual and quarterly processes, to ensure the existence of available capacity in the short term. This matter must be evaluated by the Global Technical Manager (GTG) annually and proposed to ERSE, if the GTG considers that short-term contracting should be guaranteed. Offering an annual capacity value lower than the short-term maximum in underground storage has produced an equivalent effect, freeing up capacity in the short term, despite congestion in the annual allocation. In any case, it is recognized that the obligations to create gas reserves cause greater rigidity in the use of high pressure infrastructures, especially in the current context of priority supply via the LNG terminal, for purely commercial reasons.

[12] See section 4.1.2 of Public Consultation Report No. 96, regarding the proposed reformulation of gas regulations (RARII, ROI, RT and MPGTG) (in Portuguese).

2.2 ACER RECOMMENDATIONS

In preparing its analysis report for Public Consultation No. 117, in accordance with article 27(2) and 27(3) of the Tariff Network Code, ACER held bilateral contacts with ERSE, which began on 14 November 2023.

The ACER Report for Portugal, published on 2 February 2024, makes a positive assessment of ERSE's Public Consultation no. 117. In addition to highlighting that all information requirements, under article 26(1) of the Tariff Network Code, were complied with, the Agency highlights the level of detail in ERSE's analysis as a good practice for other regulators and other transmission system operators.

In terms of compliance with the Tariff Network Code, ACER focuses its assessment of the reference price methodology on five criteria that derive from article 7 of the aforementioned European regulation, namely: (a) transparency, (b) volume risk, (c) cost-reflectivity, (d) cross-subsidization and non-discrimination, and (e) cross-border trade. In the first two criteria, ACER understands that the public consultation complies with the Tariff Network Code. In the last three criteria, ACER considers that the motivated decision can be classified as compliant, as long as it implements the recommendation analysed in section 2.2.1 of this document, regarding the allocation of costs with regional networks.

Additionally, ACER requested ERSE to evaluate the cost structure of the allowed revenues, particularly in terms of allocation through the reference price methodology. The answer to this recommendation can be found in section 2.2.2.

2.2.1 ALLOCATION OF COSTS WITH REGIONAL NETWORKS

The topic of regional networks in gas transmission was addressed from a regulatory perspective at European level for the first time by ACER in 2020 [13]. In this report, ACER presented a first definition for regional networks, considering that they are the assets that are part of the TSO's transmission networks and that are dedicated to supplying domestic consumers, and cannot be used to transport gas to points of international interconnections. As mentioned by ERSE at the opening of Public Consultation No. 117, in the Portuguese case, gas pipelines classified as secondary pipelines and GRMS may, according to ACER's definition, be classified as regional networks.

[13] See section 2.2 and chapter 5 of the report «The internal gas market in Europe: The role of transmission tariffs», ACER, April 2020.

Even before this topic began to be discussed by ACER, ERSE had already implemented in its reference price methodology, approved in 2019, elements that contributed to an allocation of costs with regional networks that minimized cross-subsidization between users. These elements are the entry-exit split and the economic value factor, as explained in section 4.4.

In its analysis report on Public Consultation no. 117, ACER recognizes the merit of these elements to mitigate the risk of cross-subsidization related to regional networks. However, ACER also concludes that this mitigation is only partial. In ACER's analysis [14], the proposed methodology results in exit prices at the VIP Iberico that are 92% higher compared to a counterfactual, presented by ERSE in the consultation, which prevents any form of cross-subsidization between domestic exits and the exit to the VIP Iberico.

In the bilateral contacts held with ERSE, ACER shared, in particular, this result. Recognizing the situation, ERSE presented ACER with an amendment proposal that allowed the issue raised to be resolved. The proposed change consisted of adapting the economic value factor, which received ACER's agreement, a fact that was highlighted in its analysis report.

The economic value factor, which reflects the economic value of the transmission network assets, assumes a value greater than 100% for all entry-exit combinations that have HP customers or distribution networks as their exit point (that is, domestic exits), and assumes a value of 100% in the remaining situations. In Public Consultation No. 117, ERSE proposed keeping the value for domestic exits unchanged at the current value, of approximately 132% [15]. The change now made changes this value to approximately 257% [16].

The rationale for this change can be understood as follows. In 2019, when ERSE set the economic value factor at 132% for domestic exits, the objective was to only reflect the assets of regional networks that are not measurable in terms of distance, that is, the GRMS. For other assets belonging to regional networks, given by gas pipelines classified as branches, or secondary pipelines, it was considered that they were already internalized in the analysis through the distance matrix, guaranteeing their allocation to the gas flows that terminate at domestic exit points. However, taking into account ACER's assessment, it is concluded that this assumption was incomplete.

[14] For more information, see section 4.6 of the report «Agency Report - Analysis of the Consultation Document on the Gas Transmission Tariff Structure for Portugal», ACER, 2 February 2024.

[15] The value of 1,32 (= 1 + 24/76) adds the relative weight of GRMS (24%), as a value that is not measured in distance, to the remaining network assets (76%).

[16] The value of 2,57 (= 1 + (20+24)/28) adds the relative weight of secondary pipelines and GRMS (20%+24%), as assets used by domestic exits, to half of the remaining network assets (0,5 x 56% = 28%).

The reason is predominantly related to an underrepresentation of length of the secondary pipelines in the distance matrix. The distances indicated in the distance matrix represent the shortest route between an entry point and an exit point. By its nature, each peripheral gas pipeline tends to serve only one domestic exit, or few domestic exits. For this reason, its length will only be counted in these limited occurrences. In comparison, a central pipeline tends to belong to several routes between different entry and exit points. As a result, there is an underrepresentation of secondary pipelines in the distance matrix, as demonstrated in Table 2-1.

Table 2-1- Contribution of secondary pipelines

	Average distance in the distance matrix, in km	Cost structure, in %
Primary pipelines	245,428 km	56,0 %
Primary pipelines + Secondary pipelines	250,348 km	76,0 %
Increase due to inclusion of secondary pipelines	**+2,0 %**	**+35,7 %**

Note: The average distance in the distance matrix refers to the average value, per cell, of the matrix, not including zero distances.

According to Table 2-1, the inclusion of secondary pipelines increases the average distance in the distance matrix from approximately 245 km to 250 km, which corresponds to an increase of +2,0%. In comparison, the cost structure used in the reference price methodology, which assigns a weight of 20% to peripheral gas pipelines, in addition to the 56% of central gas pipelines, suggested a relative increase of +35,7%.

It follows that, although conceptually peripheral gas pipelines are included in the distance matrix, their underrepresentation means that they are practically absent. This result justifies that the economic value factor is adapted to reflect not only GRMS, but also secondary pipelines, resulting in a value of 257% [17] for domestic exits.

The changes resulting from this analysis impact the economic value factor (section 4.1.2), the discussion on the allocation of costs with secondary pipelines and GRMS (section 4.4) and the indicative reference prices (chapter 7).

[17] See footnote 16.

2.2.2 COST STRUCTURE OF ALLOWED REVENUES

ACER highlights that ERSE's reference price methodology determines prices at entry and exit points based on a cost structure, obtained by an analysis of investments made in primary pipelines, secondary pipelines and GRMS, which determined a structure with weights of 56%, 20% and 24%, respectively [18]. This cost structure directly influences the entry-exit split and the economic value factor. To compare this perspective, based on the investments made, ACER recommends that ERSE evaluates the ability of the reference price methodology to reflect network costs also from the perspective of allowed revenues in each year. In its analysis, ACER highlights the need to distinguish between the (main) transmission network, the regional networks and the autonomous gas units (AGU). Recognizing that the analysis will necessarily have to be based on hypotheses, ACER suggests that they be made explicit.

As preliminary points, before presenting the analysis requested by ACER, the following points stand out. Firstly, ERSE does not have, as of today, information with sufficient granularity to be able to fully subdivide the allowed revenues for each year in accordance with the requirements of the reference price methodology. Second, the Tariff Network Code itself does not suggest using the structure of allowed revenues as a cost driver, since it tends to favour the value of allowed revenues being used in aggregate by the reference price methodology. Third, and no less important, the determination of a cost structure based on the allowed revenues of each year, would result, according to the reference price methodology adopted by ERSE, in a volatile entry-exit split from year to year. Not only would this be contrary to the practice adopted in several Member States, but market agents in the gas sector in Portugal have also shown concern in the past about changes in the entry-exit split. Having presented these preliminary points, an analysis follows, which seeks to respond to ACER's recommendation.

To evaluate the transmission cost structure, the following assumptions were adopted. In the case of the separation of gas pipelines between primary and secondary, instead of adopting the split given by the value of the investments, the distribution based on the total length of each type of gas pipeline was adopted, keeping the relative weight of GRMS constant [19]. In the case of costs with AGU, due to the transport of LNG

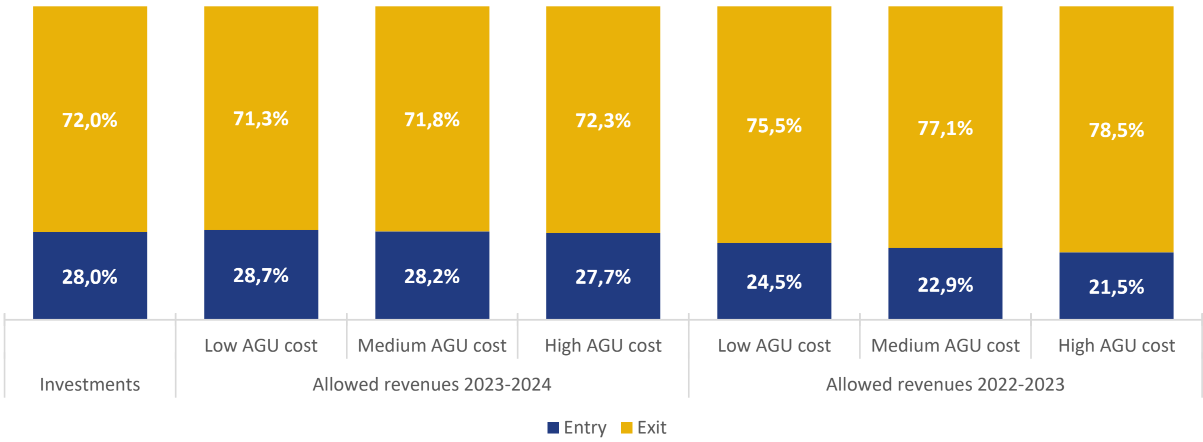
[18] See motivated decision of 2019, published at the Closing of ERSE Public Consultation No. 66.

[19] As previously mentioned, according to the analysis of investments made in primary pipelines, secondary pipelines and GRMS, the relative weights of 56%, 20% and 24%, respectively, were obtained. Reviewing the relative weights of gas pipelines according to their contribution to length, the new relative weights are 61,7%, 14,3% and 24%, respectively.

by road, the values of the tariff processes for the gas years 2021-2022 until 2023-2024 were collected [20]. In the case of allowed revenues of the TSO, the values for the gas years 2022-2023 and 2023-2024 are adopted, with the first value representing a level below the regular revenue level, due to the presence of auction premia that revert in favour of network users, and the second representing a level closer to the regular level [21].

Figure 2-2 presents the entry-exit split that would result from the perspectives of investment and of allowed revenues, in terms of the above assumptions. From an investment perspective, the division is equivalent to the parameter adopted in the reference price methodology. From the allowed revenues perspective, the entry split corresponds to half the weight of the central gas pipelines, with the remaining percentage recovering the remaining costs, including the costs of transporting LNG by road.

Figure 2-2 – Entry-exit split from the perspective of investments and allowed revenues



Notes: The low, medium and high AGU cost scenarios correspond to values of 4,9, 6,2 and 7,3 million euros, respectively, as referred to in footnote 20.

The entry-exit split, when determined from the perspective of allowed revenues, is volatile, and depends on the level of the allowed revenues and the AGU cost. It can also be concluded that in the case of allowed revenues for the gas year 2023-2024, even for different values of the AGU cost, the distribution obtained

[20] In the gas years 2021-2022, 2022-2023 and 2023-2024, the costs of transporting LNG by road were approximately 4,9, 6,2 and 7,3 million euros, respectively.

[21] In the gas years 2022-2023 and 2023-2024, the allowed revenues of the TSO were approximately 23,9 and 70,9 million euros, respectively.

from the investment perspective is aligned with the different distributions from the perspective of allowed revenues.

Finally, it should be noted that this ACER recommendation did not result in changes compared to the proposal presented in the public consultation.

3 CURRENT TARIFF STRUCTURE

Pursuant to the ERSE Gas Tariff Code (RT) [22], the tariff for the use of the transmission network (transmission tariff) must provide the Transmission System Operator (TSO) with allowed revenues from its gas transmission activity, recovering the costs of operation, development and maintenance of the networks [23].

3.1 DESCRIPTION OF THE NATIONAL TRANSMISSION NETWORK

The national gas transmission network (RNTG), presented in Figure 3-1, consists of two axes: a north-south axis that connects the interconnection with Spain at Valença do Minho with the Liquefied Natural Gas (LNG) terminal in Sines, and an east-west axis that connects the interconnection with Spain at Campo Maior with the coast, passing close to the underground storage in Carriço. In 2013, the connection between two sections that ended in Mangualde and Guarda was completed, resulting in a circular section. Table 3-1 characterises the RNTG.

Table 3-1 - Characterisation of the RNTG, as of 31 December 2022

Length of the gas pipelines, in km	1375
Diameter of the gas pipelines, in mm	150 – 800
Gas Regulating and Measurement Stations (GRMS), in no.	86
Block Valve (BV), in no.	44
Custody Transfer Station (CTS), in no.	2
Branch station (ICJCT), in no.	5
Junction Station (JCT), in no.	66

Source: Data Hub (REN).

[22] Approved by Regulation no. 825/2023 of 28 July.

[23] The current methodology for determining the annual value of the allowed revenues of the TSO is described in the document "Parameters for the regulatory period 2024-2027" (only in Portuguese). The determination of the allowed revenues for the gas year 2023 2024 is provided in the document "Allowed revenues and adjustments for the gas year 2023-2024 for the regulated companies of the gas sector" (only in Portuguese).

The RNTG, which operates with a pressure level above 20 bar [24], currently has a length of 1 375 km, has gas pipelines with diameters between 150 and 800 mm and includes 86 Gas Regulating and Measurement Stations, among other network assets.

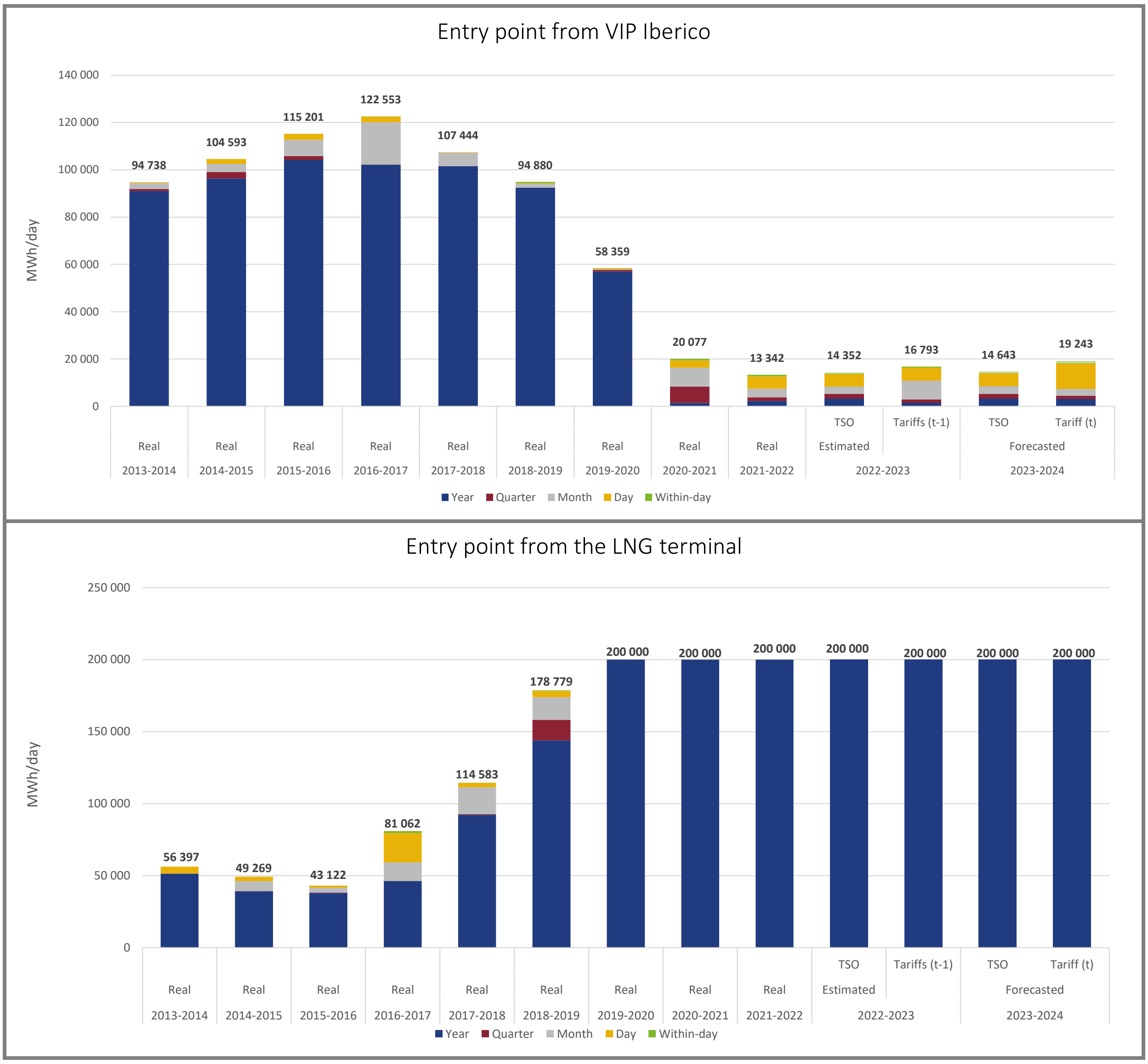
[24] Pursuant to the "Manual of Procedures for the Global Technical Management of the National Gas System" (only in Portuguese), the maximum operational pressure in the RNTG is 84,0 barg.

Figure 3-1 - Diagram of the national gas transmission network

Source: Data Hub (REN). Information presenting the situation as of end-2022.

Figure 3-2 shows the booking of firm capacity at the entry points from the Iberian Virtual Interconnection Point (VIP Iberico) and the LNG terminal, highlighting the change in the gas import profile, with the LNG terminal taking on a more important role since gas year 2018-2019.

Figure 3-2 - Booking of firm capacity in the RNTG, by entry point



Source: [Characterisation of gas demand for the gas year 2023-2024](#) (ERSE, only in Portuguese), June 2023. Includes real data until gas year 2021-2022.

At the beginning of September 2023, ERSE issued its opinion [25] on the indicative ten-year development and investment plan for the National Transmission Network, Storage Infrastructures and LNG Terminals for the period 2024-2033 (PDIRG 2023) presented by the operator of the national gas transmission network. ERSE's opinion was preceded by a public consultation and should be considered in the final version of PDIRG 2023, to be approved by the member of the Government responsible for the energy sector, in line with Article 87 of Decree-Law no. 62/2020 of 28 August, in the current wording.

It is not expected that any significant investments will be made within five years (the deadline set by the Tariff Network Code for a new periodic public consultation process) that will have an impact on the analysis carried out in the present document.

[25] https://www.erse.pt/media/eb1k0u0a/parecer-%C3%A0-proposta-de-pdirg-2023-hp.pdf (only in Portuguese).

3.2 TRANSMISSION TARIFF

The transmission tariff is applied by the TSO and distribution system operators (DSOs).

The transmission tariff applied by the TSO has an **entry-exit structure**, that is, users of the transmission network pay one price for the gas that enters the transmission network and pay another price for the gas that exits it [26]. The transmission tariff is applied by the DSOs to customers connected to the Medium Pressure (MP) and Low Pressure (LP) distribution networks. They must pay the transmission tariff since they use the RNTG upstream: the gas that reaches customers in MP and LP passes through the RNTG before entering the national gas distribution network (RNDG).

Table 3-2 summarises the application of the transmission tariff to the various RNTG users.

Table 3-2 - Summary on the application of the transmission tariff

<table>
<tr><th></th><th>User of the transmission network</th><th>Applied by the TSO</th><th>Applied by the DSOs</th></tr>
<tr><td rowspan="4">Entry to the RNTG</td><td>VIP Iberico</td><td rowspan="3">Paid by market agents</td><td rowspan="11">Not applicable</td></tr>
<tr><td>LNG terminal in Sines</td></tr>
<tr><td>Underground storage</td></tr>
<tr><td>Gas producers</td><td>Paid by gas producers</td></tr>
<tr><td rowspan="6">Exit from the RNTG</td><td>VIP Iberico</td><td rowspan="3">Paid by market agents</td></tr>
<tr><td>LNG terminal in Sines</td></tr>
<tr><td>Underground storage</td></tr>
<tr><td>Distribution system operators</td><td>Value to be reflected in the clients at Medium Pressure and Low Pressure</td></tr>
<tr><td>Clients at High Pressure</td><td rowspan="2">Paid through the network access tariff</td></tr>
<tr><td>AGU (private ownership)</td></tr>
<tr><td rowspan="2">Exit from the RNDG</td><td>Clients at Medium Pressure</td><td rowspan="2">Not applicable</td><td rowspan="2">Paid through the network access tariff</td></tr>
<tr><td>Clients at Low Pressure</td></tr>
</table>

[26] The entry-exit tariff structure has been applied in Portugal since the 2010-2011 tariff period.

3.2.1 APPLICATION BY THE TSO

The transmission tariff is applied by the TSO to its users at entry and exit points of the RNTG. Table 3-3 indicates for each point the billing variables of the transmission tariff applied by the TSO, as well as additional observations.

Table 3-3 - Transmission tariff applied by the TSO

	User of the transmission network	Billing variable (price unit)	Observation
Entry to the RNTG	VIP Iberico	Contracted capacity (EUR/kWh/day/day) or (EUR/kWh/h/h)	▪ Subject to capacity allocation processes (transmission tariff represents the reserve price) ▪ Price depends on the type of product (firm or interruptible capacity) and the time horizon (multi-year, annual, quarterly, monthly, daily or within-day)
	LNG terminal in Sines		
	Underground storage		
	Gas producers	Used capacity at injection (EUR/kWh/day/day)	▪ Not subject to capacity allocation processes
Exit from the RNTG	VIP Iberico	Contracted capacity (EUR/kWh/day/day) or (EUR/kWh/h/h)	▪ Subject to capacity allocation processes (transmission tariff represents the reserve price) ▪ Price depends on the type of product (firm or interruptible capacity) and the time horizon (multi-year, annual, quarterly, monthly, daily or within-day)
	LNG terminal in Sines		
	Underground storage		
	Distribution system operators	Used capacity (EUR/kWh/day/day)	▪ The DSO passes on the transmission tariff through the network access tariff to customers connected at MP and LP
	Clients at High Pressure		▪ Included in the network access tariff ▪ Available in different tariff options [27]
	AGU (private ownership)		▪ Included in the network access tariff applied to AGU (private ownership) [28]

In the case of the **contracted capacity** variable, the price approved by ERSE for the transmission tariff corresponds to the reserve price in the capacity allocation processes, in the form of capacity auctions. Depending on the demand and supply conditions of these auctions, a final price equal to or higher than the reserve price may result. The difference between the final price and the reserve price is called the auction

[27] In the tariff options, the billing variable is a concept similar to capacity used.

[28] Due to restrictions in measuring the used capacity of these customers, the used capacity price is converted to an energy price, in euros per kWh.

premium. It should also be noted that the value of capacity reserved by the market agent constitutes a right to use capacity with binding payment, regardless of actual use, for the annual, quarterly, monthly, daily and within-day time horizons. Use rights are also called capacity products, and are divided into firm capacity products and interruptible capacity products.

In the case of the variable **used capacity at injection**, the price approved by ERSE for the transmission tariff is applied to the value measured at the gas producer's installation as capacity at injection into the transmission network, applying to the maximum daily injection, measured in kWh/day, recorded in the last twelve months.

In the case of the variable **used capacity**, the price approved by ERSE for the transmission tariff is applied to the value measured at the consumer's installation (or at the RNTG's border points with the RNDG) for the use of the transmission network's exit capacity, applying as a default the maximum daily consumption, measured in kWh/day, recorded in the last twelve months. Exceptions to this application occur in additional tariff options for customers at High Pressure and in the case of Autonomous Gas Units (AGU) under private ownership[29]. The **tariff options** available to customers at High Pressure are characterised in Table 3-4 , with the “long usage” option corresponding to the default option.

[29] For deliveries to facilities supplied by AGU owned by customers, due to the impossibility of having a measurement for the concept of used capacity, ERSE converts the price of used capacity, applicable to customers at High Pressure, to an energy price, in EUR/kWh, according to a modulation factor published by ERSE.

Table 3-4 - Billing variables in the transmission tariff for clients at High Pressure, by tariff option

Tariff option	Billing variable	price unit
Long usage	Used capacity Maximum daily consumption, measured in kWh/day, recorded in the last twelve months, measured at the delivery point of the transmission network.	EUR/(kWh/day) per day
Annual flexible option	Annual base capacity The annual base capacity must be greater than or equal to the maximum daily consumption recorded in the winter months (from October to March) of the last twelve months, including the month to which the invoice refers.	
	Monthly additional capacity The monthly additional capacity for the summer months (April to September) corresponds to the difference between the maximum monthly capacity determined in the billing month and the annual base capacity.	
Monthly flexible option	Monthly capacity Maximum daily consumption, measured in kWh/day, recorded in the month of the invoice. Prices differ between the summer season (April to September) and the winter season (October to March).	
Daily flexible option	Daily capacity Daily consumption, measured in kWh/day, recorded in the month of the invoice. Prices differ between the summer season (April to September) and the winter season (October to March).	

The capacity prices for **flexible tariff options** are obtained by applying multiplicative factors[30] to the capacity price of the long usage tariff.

AUTONOMOUS GAS UNITS OWNED BY CUSTOMERS

Autonomous Gas Units (AGU) are storage systems (cryogenic reservoirs) for storing liquefied natural gas, other gases or gas mixtures, which can supply distribution networks or dedicated customers (customer-owned AGU) in areas of the country where there is no gas network. The AGU are supplied by road using tanker trucks that fill up at the Sines LNG terminal.

[30] In the case of the annual flexible option, a multiplicative factor of 1,5 is applied to the monthly additional capacity. In the case of the monthly flexible option, multiplicative factors of 3,0 and 1,5 apply to the monthly capacity billed in the periods [October to March] and [April to September], respectively. In the case of the daily flexible option, multiplicative factors of 10,0 and 6,0 apply to the daily capacity billed in the periods [October to March] and [April to September], respectively.

The costs of tanker transport to supply customer-owned AGU are transferred by the AGU owner to the transmission network operator and are included in the calculation of the transmission network tariff. This results in a transmission tariff that is the same for all consumers, whether they are supplied via a network interconnected with the transmission network or via a customer-owned AGU.

Customer-owned AGU are considered a delivery point for the transmission network, and access is billed using a simplified billing rule that consists of applying a price in EUR/kWh to the quantity of energy delivered to the AGU, determined on the basis of the quantities of gas discharged. The quantity of energy delivered can be calculated on the basis of the weight or volume of the quantities discharged, without the need to install cryogenic measuring equipment.

The price in EUR/kWh of the network access tariff to be applied to installations supplied by customer-owned AGU results from the sum of the price of the use of the transmission network tariff and the price of the global use of the system tariff. The average price of the Transmission Network Use tariff results from the conversion of the respective capacities into energy, conditioned by a modulation factor published by ERSE.

3.2.2 APPLICATION BY THE DSOS

The payment to the DSOs of the transmission tariff by customers at MP and LP is neutral for the DSOs, as they transfer the entire value to the TSO through the payment of the transmission tariff applied by the TSO to the DSOs. Table 3-5 indicates the billing variables in the transmission tariff applied by the DSOs, as well as additional observations.

Table 3-5 - Transmission tariff applied by the DSOs

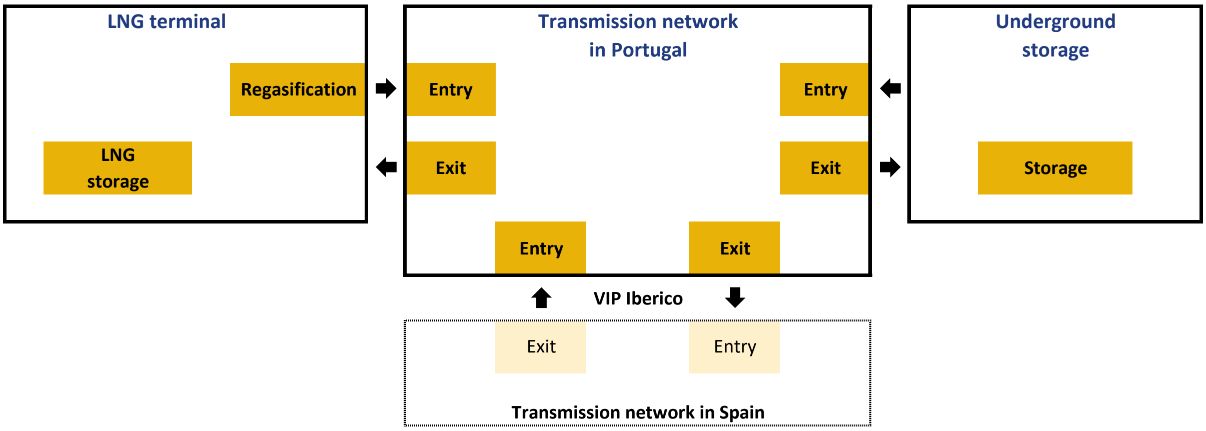
	User of the transmission network	Observation	Billing variable
Exit from the RNDG	Clients at Medium Pressure	▪ Included in the network access tariff ▪ Available in different tariff options	Energy EUR/kWh
	Clients at Low Pressure		

As can be seen in Article 75 of the ERSE Gas Tariff Code, the transmission tariffs to be applied by the DSOs to deliveries to customers result from the conversion, by applying adjustment factors for losses and selfconsumption and are based on consumption profiles. For this reason, the price of the transmission tariff, in EUR/kWh, is different between MP and LP [31].

3.3 CAPACITY PRODUCTS

In the high pressure infrastructure of the national gas system (SNG) (LNG terminal, underground storage, entry and exit points of the transmission network to these infrastructures and international interconnection points), there is a capacity allocation model with binding reservation, through market mechanisms, subject to payment, regardless of its use. Figure 3-3 illustrates the capacity products in Portugal that arise from capacity allocation processes.

Figure 3-3 - Illustration of capacity products in Portugal



Legend: Capacity product in Portugal, whose reserve prices are approved by ERSE

Capacity product in Spain, whose reserve prices are approved by CNMC

At the LNG terminal, the two capacity products refer to LNG storage and regasification. In underground storage, the only capacity product is storage. In transmission, capacity products concern the entry and exit points of the RNTG with binding reservation, namely at the interface with the VIP Iberico, the LNG terminal and underground storage. As a complement, the figure also indicates the capacity products on the Spanish side of VIP Iberico, referring to the transmission network in Spain.

[31] The price of the transmission tariff is the same for all tariff options and consumption thresholds within the same pressure level.

In addition to the individual capacity products in Figure 3-3 there are also '*bundle*' products, i.e., capacity products allocated jointly, called harmonised or grouped capacity products:

- '*Bundle*' products in VIP Iberico, which involve an entry point and an exit point for the transmission networks in Portugal and Spain, in both directions of gas transmission.
- '*Bundle*' product at the border of the transmission network with the LNG terminal, which involves the terminal's regasification service and entry into the transmission network.

Table 3-6 presents capacity products, of a firm and interruptible nature, in the RNTG.

Table 3-6 - Capacity products for the RNTG

Infrastructure	RNTG point		Capacity product
RNTG	Entry to the RNTG	VIP Iberico	Firm: A, Q, M, D, WD Interruptible: D, WD
		LNG terminal	Firm: A, Q, M, D, WD Interruptible: WD
		Underground storage	Firm: D, WD Interruptible: WD
	Exit from the RNTG	VIP Iberico	Firm: A, Q, M, D, WD Interruptible: D, WD
		LNG terminal	Interruptible: D, WD
		Underground storage	Firm: D, WD Interruptible: WD

Legend: A – annual, Q – quarterly, M – monthly, D – daily and WD – within-day.

The last column of Table 3-6 identifies the booking horizons (annual, quarterly, monthly, daily, within-day) available for firm and interruptible capacity products.

4 REFERENCE PRICE METHODOLOGY

Pursuant to the Tariff Network Code, transmission tariffs must be based on a reference price methodology.

The Tariff Network Code defines «**reference price methodology**» as the methodology applied to the part of the transmission services revenue to be recovered from capacity-based transmission tariffs with the aim of deriving reference prices (Article 3(2)). In turn, the network code defines as a «**reference price**» the price for a capacity product for firm capacity with a duration of one year, which is applicable at entry and exit points and which is used to set capacity-based transmission tariffs (Article 3(1)).

The reference price methodology used in gas year 2023-2024 to determine entry and exit prices, as well as the pre-scaling prices that the methodology determines, were kept constant and the same as in the previous regulatory period, which covered the gas years 2019-2020 to 2022-2023.

With the implementation of the Tariff Network Code in 2019, ERSE began to determine the tariff for the use of the transmission network, to be applied by the transmission system operator, in accordance with the modified capacity weighted distance methodology, under the terms of Directive no. 8/2019, of 4 April. This methodology determines, each year, the prices for the transmission tariff at the entry and exit points of the transmission network. These prices result from the application of a multiplicative scaling factor to the pre-scaling prices at the entry points and a multiplicative scaling factor to the pre-scaling prices at the exit points in order to ensure that the allowed revenues are recovered, based on the forecasted capacity. Pre-scaling prices were held constant during the regulatory period (Article 2(9) of Directive no. 8/2019).

4.1 REFERENCE PRICE METHODOLOGY

The reference price methodology currently adopted and which ERSE continues to propose is called the **modified capacity-weighted distance methodology** (modified CWD [32] methodology). The designation of the methodology reflects the proximity to the capacity-weighted distance methodology (CWD methodology), defined in Article 8 of the Tariff Network Code, whose application is optional, but which must be presented for comparison purposes (in line with Article 26(1)(a)(vi) of the Tariff Network Code).

[32] Abbreviation for 'capacity weighted distance' (CWD).

There are two main reasons why ERSE introduced modifications to the CWD methodology described in the Tariff Network Code. On the one hand, the CWD methodology is restrictive, as it does not adequately reflect the economic value of the transmission network assets, using mainly distance as a cost driver. On the other hand, the use of forecasted capacity for the next tariff period disconnects the tariff calculation from the use of the technical capacity of the transmission network, making it impossible to define price signals for situations of capacity shortage. ERSE incorporates these two concerns through two parameters, namely the economic value factor and the commercial utilisation factor.

The **economic value factor** reflects for each entry-exit combination the use of transmission network assets from the economic point of view, by weighting the distances between an entry point and an exit point. In particular, a gas flow leaving the transmission network at a consumption exit point uses primary and secondary pipelines, measured in kilometre, and the Gas Regulation and Metering Stations (GRMS). The economic value factor, which corresponds to a multiplicative factor, assumes a value greater than 100% for entry-exit combinations that use regional network assets [33], in order to reflect the economic value of secondary pipelines and GRMS, and assumes a value equal to 100% for the remaining entry-exit combinations.

The **commercial utilisation factor** reflects, for each entry point and each exit point, the proximity of the commercial capacity to the respective technical capacity. The closer the commercial capacity is to the technical capacity for a given point in the transmission network, the more likely it is that congestion situations will occur. The commercial utilisation factor, which corresponds to a multiplicative factor, will be determined by the ratio between the commercial capacity and the technical capacity of a given point.

The two factors described are used to adjust the two cost drivers of the CWD methodology, distance and forecasted capacity. These adjustments give rise to two new concepts, namely effective distance and effective capacity.

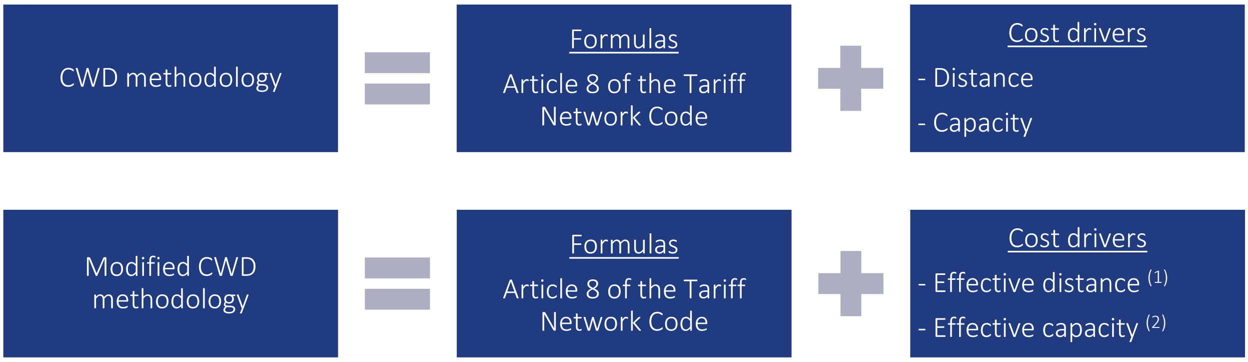
The concept of effective distance allows reflecting investments in regional networks (secondary pipelines and GRMS), which are only used by gas flows destined for HP customers and distribution networks. On the other hand, the concept of effective capacity makes it possible to identify points whose commercial use is closer to the technical capacity, allowing the price signal to be increased at these points and consequently identifying a higher probability of congestion situations.

[33] See discussion on the cost allocation of regional networks in section 4.4.

4.1.1 CALCULATION METHODOLOGY

The modified CWD methodology consists in applying the concepts of effective distance and effective capacity [34] to the formulas of the CWD methodology, defined in Article 8 of the Tariff Network Code. Figure 4-1 presents, in a simplified illustration, the comparison between the CWD methodology and the modified CWD methodology. While both methodologies use the formulas in Article 8 of the Tariff Network Code, they are distinguished by the cost drivers used, namely by the fact that the modified CWD methodology uses effective distance and effective capacity as cost drivers.

Figure 4-1 - Illustration of the CWD and the modified CWD methodologies



Notes: (1) The effective distance (D^e) corresponds to the product between the distance (D) and the economic value factor (v), that is, $D^e=D\times v$. (2) The effective capacity (K^e) corresponds to the product between the capacity (K) and the commercial utilisation factor (f), that is, $K^e=K\times f$.

This section details the mathematical formulas for applying the modified CWD methodology.

The effective distance is equivalent to the distance between two points in the network, adjusted by a multiplicative factor that will be greater than 100% if the gas flow between these two points uses regional network assets. The multiplicative factor will be greater than 100% for all entry-exit combinations that have HP clients or distribution networks as their exit point [35]. This multiplicative factor is called economic value factor. The expression to determine the effective distance is:

$$D^e_{i,j}=D_{i,j}\times v_{i,j}$$

[34] With the exception of the expression for determining pre-equalisation prices, which will continue to use forecasted capacity, and not effective capacity.

[35] And equal to 100% in all other situations.

Where:

$D_{i,j}^{e}$ – effective distance, measured in km, between an entry point i and an exit point j

$D_{i,j}$ – distance, measured in km, between an entry point i and an exit point j

$v_{i,j}$ – economic value factor, to be set by ERSE, for the path between an entry point i and an exit point j, to reflect the economic value of the assets of the transmission system being used

The effective capacity is equivalent to the forecasted capacity for each entry point and each exit point, corrected by a multiplicative factor that measures the utilisation of that point. For a point that is permanently utilised at its technical capacity, the multiplicative factor, known as the commercial utilisation factor, will be equal to 100%. For points whose utilisation is less than their technical capacity, the commercial use factor will be less than 100%, and determined by the ratio between commercial utilisation and technical capacity. The expressions to determine the effective capacity at entry points and exit points are:

$$K_i^e = K_i \times f_i$$

$$K_j^e = K_j \times f_j$$

Where:

K_i^e – effective capacity, measured in kWh/day, at entry point i

K_i – forecasted capacity, measured in kWh/day, at entry point i

f_i – commercial utilisation factor, to be set by ERSE, at entry point i

K_j^e – effective capacity, measured in kWh/day, at exit point j

K_j – forecasted capacity, measured in kWh/day, at exit point j

f_j – commercial utilisation factor, to be set by ERSE, at exit point j

Based on the values of the effective distance and effective capacity, the weighted average distances are determined for each entry point and for each exit point, using the following formulas, equivalent to the formulas used by the CWD methodology of the Tariff Network Code:

$$AD_i=\frac{\sum_{j=1}^{J} K_j^e \times D_{i,j}^e}{\sum_{j=1}^{J} K_j^e}$$

$$AD_j=\frac{\sum_{i=1}^{I} K_i^e \times D_{i,j}^e}{\sum_{i=1}^{I} K_i^e}$$

Where:

AD_i – weighted average distance, measured in km, for entry point i

K_j^e – effective capacity, measured in kWh/day, at exit point j

$D_{i,j}^e$ – effective distance, measured in km, between an entry point i and an exit point j

AD_j – weighted average distance, measured in km, for exit point j

K_i^e – effective capacity, measured in kWh/day, at entry point i

J – total number of exit points j

I – total number of entry points i

Once the weighted average distances have been calculated, the weight of cost for each entry point and each exit point is calculated. The weight of cost determines the proportion of revenue to be recovered at each entry and exit point. Here, it is also worth mentioning that the formulas presented are equivalent to the formulas of the CWD methodology of the Tariff Network Code. The expressions to determine the weight of cost at entry points and exit points are:

$$W_{c,i}=\frac{K_i^e \times AD_i}{\sum_{i=1}^{I} K_i^e \times AD_i}$$

$$W_{c,j}=\frac{K_j^e \times AD_j}{\sum_{j=1}^{J} K_j^e \times AD_j}$$

Where:

$W_{c,i}$ – weight of cost for entry point i

K_i^e – effective capacity, measured in kWh/day, at entry point i

AD_i – weighted average distance, measured in km, for entry point i

I – total number of entry points i

$W_{c,j}$ – weight of cost for exit point j

K_j^e – effective capacity, measured in kWh/day, at exit point j

AD_j – weighted average distance, measured in km, for exit point j

J – total number of exit points j

Given the values for the weight of cost for each network point, and given the entry-exit split between entry and exit points, the pre-equalisation prices for each point are determined. The expressions for determining pre-equalisation prices at entry points and exit points are:

$$T_i = \frac{W_{c,i} \times S_I \times R_{total}}{K_i}$$

$$T_j = \frac{W_{c,j} \times S_J \times R_{total}}{K_j}$$

Where:

T_i – pre-equalisation price resulting from the reference price methodology for entry point i

$W_{c,i}$ – weight of cost for entry point i

S_I – proportion of allowed revenues to be recovered across all entry points i

R_{total} – allowed revenues of transmission services, measured in euros, to be recovered from capacity-based transmission tariffs

K_i – forecasted capacity, measured in kWh/day, at entry point i

T_j – pre-equalisation price resulting from the reference price methodology for exit point j

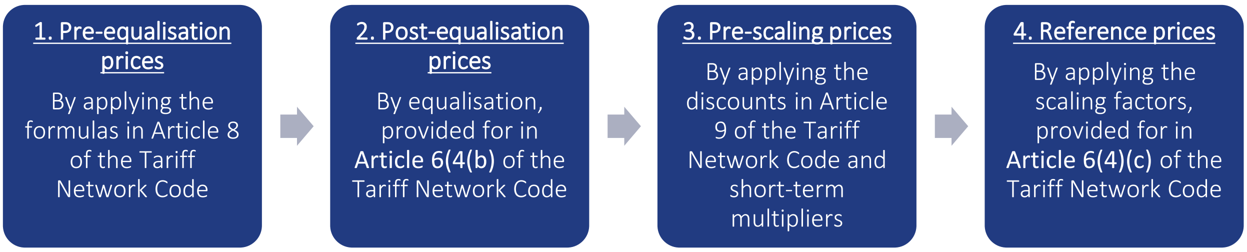
$W_{c,j}$ – weight of cost for exit point j

S_J – proportion of allowed revenues to be recovered across all exit points j

K_j – forecasted capacity, measured in kWh/day, at exit point j

Finally, the adjustments referred to in Article 6(4), the discounts provided for in Article 9 of the Tariff Network Code and the multipliers applicable to capacity products with a period other than the annual horizon apply to pre-equalisation prices. Firstly, the price equalisation resulting from Article 6(4)(b) is applied, which allows the equalisation of prices between points belonging to a homogeneous group of points. In this specific case, equalisation applies to the two interconnection points, forming VIP Iberico, and to the exit points for customers connected to the transmission network and to distribution networks. The resulting prices are called post-equalisation prices. Secondly, the discounts provided for in Article 9 and multipliers for a non-yearly capacity apply. The prices obtained are called pre-scaling prices. Finally, a multiplicative scaling factor is applied to the pre-scaling prices of the entry points and another multiplicative scaling factor to the pre-scaling prices of the exit points, in order to ensure that the allowed revenues are recovered, based on the forecasted capacities, maintaining the entry-exit split. The application of scaling factors is provided for in Article 6(4)(c) of the Tariff Network Code. Figure 4-2 summarises the different steps to determine reference prices in the modified CWD methodology.

Figure 4-2 – Steps for determining references prices according to the modified CWD methodology



4.1.2 DATA INPUT

This section presents the data input used to determine the indicative reference prices presented in section 7.1. The reference prices are indicative, as some of the information will necessarily be updated at the time of setting the transmission tariff for the gas year 2024-2025, which will be the first gas year in which the methodology will be applied under the terms of the motived decision now approved. Table 4-1indicates the source and year of the modified CWD methodology input data.

Table 4-1 – Input data to determine the indicative reference prices

Input data	Source of the information	Year of the information
Allowed revenues	Gas Tariffs	Gas year 2023-2024
Forecasted capacity (1)	Gas Tariffs	Gas year 2023-2024
Multipliers for non-yearly capacity products	ENTSOG TP and ERSE calculations	2020-2023
Discounts	Gas Tariffs	Gas year 2023-2024
Entry-exit split	Motivated decision from 2019	Years 2010 to 2022
Economic value factor	Motivated decision from 2024	Years 2010 to 2022
Commercial utilisation factor	ENTSOG TP, TSO information and computations by ERSE	Years 2019 to 2022
Distance matrix	TSO information and calculations by ERSE	RNTG diagram of 31 December 2022
Capacity structure by domestic exit point	TSO information and calculations by ERSE	Years 2019 to 2021

Notes: (1) Includes products with firm and interruptible capacity and capacity used at domestic exit points.

The allowed revenues, the forecasted capacity and the discounts are the values available in the gas tariffs defined for the gas year 2023 2024 [36]. For the purposes of applying the reference price methodology, capacity values are calculated using an equivalent capacity reference, in which the capacity value is multiplied by the respective multiplier, whenever a multiplier other than 1 is applicable [37].

The multipliers for short-term capacity products, to be applied as of gas year 2024-2025, are determined in section 8.2 of this report.

The entry-exit split corresponds to the value defined in ERSE's 2019 motivated decision [38]. Since the RNTG has not presented investments expanding the network, this parameter was kept unchanged.

The economic value factor is updated, with this motivated decision, to a value of approximately 257% [39] for domestic exists, under the terms explained in section 2.2.1.

[36] Information available at ERSE's webpage (only in Portuguese).

[37] This procedure ensures that the reference price to be determined by the reference price methodology does not depend on the structure of the capacity products.

[38] Information available at ERSE's webpage.

[39] See footnote 30.

The commercial utilisation factor resulted from a new analysis by ERSE, based on information from the ENTSOG Transparency Platform (ENTSOG TP) and the actual and forecast information of the TSO submitted within the scope of the information provision rules established by the regulator. The determination of the commercial utilisation factor is described in section 4.1.3.

The distance matrix and capacity structure per domestic exit point were determined based on information requested from the TSO. Compared to the 2019 motivated decision, instead of using a simplified RNTG diagram, the distance matrix is now based on the complete characterisation of the network, with four entry points and 89 exit points. Additionally, in order to accommodate the possibility of connections to the RNT by gas producers, the reference price methodology determines a reference price for these entry points assuming, in the absence of real information, that these producers are located close to underground storage [40].

4.1.3 COMMERCIAL UTILISATION FACTOR

As previously mentioned, the commercial utilisation factor reflects for each entry point and for each exit point the proximity of commercial capacity to the respective technical capacity, allowing the price signal to be increased at points where commercial utilisation is closer to technical capacity. The commercial utilisation factor is determined using the following expression:

$$f_k = K_k \div K_k^T$$

Where:

- f_k – commercial utilisation factor at the point of entry or exit k
- K_k – commercial capacity, in kWh/day, at the point of entry or exit k
- K_k^T – technical capacity, in kWh/day, at the point of entry or exit k

At points subject to capacity allocation processes, commercial capacity K_k corresponds to the contracted capacity in a firm capacity product. In the remaining points, without capacity allocation processes, the commercial capacity K_k corresponds to the used capacity, which is the billing variable for the network

[40] With a post-equalisation price equivalent to the equivalent price, on an annual horizon, at the entry from underground storage.

access tariff. Table 4-2 presents, for the two types of RNTG points, the sources of information used to determine commercial capacity K_k. In both cases, commercial capacity corresponds to the average value for the years 2019 to 2022.

Table 4-2 - Source of information for commercial capacity

Type of network point	Point of the RNTG	Source of information
Points subject to capacity allocation processes	Entry: VIP Iberico, LNG terminal, Underground storage Exit: VIP Iberico, LNG terminal, Underground storage	Average value of booked firm capacity in the years 2019 to 2022. Information available on the ENTSOG Transparency Platform.
Points not subject to capacity allocation processes	Exit: HP customers, DSOs	Average value of used capacity in the years 2019 to 2022. Information reported to ERSE within the reporting requirements, based on actual and forecasted information.

Table 4-3 and Table 4-4 detail the calculation of the commercial utilisation factor at the entry and exit points, respectively. In addition to presenting the value for the period from 2019 to 2022, the value for each of these years is also presented.

Table 4-3 - Computation of the commercial utilisation factor at entry points

	VIP Iberico	LNG terminal	Underground storage
	Technical capacity GWh/day		
Years 2019-2022	**144,00**	**200,00**	**85,68**
	Commercial capacity GWh/day		
Year 2019	85,95	189,31	8,58
Year 2020	51,92	200,00	13,24
Year 2021	16,79	200,00	14,61
Year 2022	18,69	200,00	8,55
Years 2019-2022	**43,34**	**197,33**	**11,25**
	Commercial utilisation factor %		
Year 2019	59,7%	94,7%	10,0%
Year 2020	36,1%	100,0%	15,5%
Year 2021	11,7%	100,0%	17,1%
Year 2022	13,0%	100,0%	10,0%
Years 2019-2022	**30,1%**	**98,7%**	**13,1%**

Table 4-4 - Calculation of the commercial utilisation factor at exit points

Exit points	VIP Iberico	LNG terminal	Underground storage	Domestic exits
Technical capacity (GWh/day)				
Years 2019-2022	80,00	0,00	24,00	653,90
Commercial capacity (GWh/day)				
Year 2019	7,08	0,00	11,27	288,06
Year 2020	8,77	0,00	10,49	298,47
Year 2021	12,72	0,00	17,32	334,93
Year 2022	17,67	0,00	11,63	303,66
Years 2019-2022	11,56	0,00	12,68	306,28
Commercial utilisation factor (%)				
Year 2019	8,9%	0,0%	47,0%	44,1%
Year 2020	11,0%	0,0%	43,7%	45,6%
Year 2021	15,9%	0,0%	72,2%	51,2%
Year 2022	22,1%	0,0%	48,4%	46,4%
Years 2019-2022	14,5%	0,0%	52,8%	46,8%

Table 4-5 presents the values of the commercial utilisation factor adopted in the modified CWD methodology, by entry point and exit point, based on the results for the period from 2019 to 2022.

Table 4-5 - Commercial utilisation factor at entry and exit points

	Entry	Exit
VIP Iberico	30,1%	14,5%
LNG terminal	98,7%	0,0%
Underground storage	13,1%	52,8%
Produtores de gás	13,1%	-
Domestic exits	-	46,8%

Notes: Based on the average value of commercial capacity in the years 2019 to 2022.

Finally, the arguments that led ERSE to replace the physical utilisation factor[41] with the commercial utilisation factor in the modified CWD methodology are presented below. Both parameters correspond to

[41] The physical utilisation factor, in the 2019 motivated decision, corresponded to the ratio between a measure for the most relevant physical gas flows and the respective technical capacity, both measured in kWh/day. Specifically, the measure of physical flows corresponded to the average value of daily natural gas flows on the 10% of days with the highest value for a period of 3 years. More information can be found in section 3.2 of Motivated Decision of 2019.

a ratio whose denominator is technical capacity: while the first used a measure of physical gas flows in the numerator, the second uses the concept of commercial capacity. There are two arguments for the change.

Firstly, the use of commercial capacity represents a methodological improvement, as it uses the two concepts of capacity [42] used for billing the transmission tariff in Portugal, which ultimately will be used to determine the capacity-based prices of the tariff. The previous parameter, when considering physical gas flows, is closer to an energy concept. Secondly, the change improves the coherence of the effective capacity variable. As the effective capacity is now equal to the product between the forecasted capacity, which necessarily corresponds to the commercial dimension, and the commercial utilisation factor, the effective capacity now has a solely commercial nature. Previously, the effective capacity variable simultaneously combined commercial and physical perspectives, thus making its interpretation more difficult.

It is also worth noting that the measure used in the numerator of the commercial use factor corresponds to the average value for the years 2019 to 2022, which is equivalent to the duration of the regulatory period in Portugal. The use of the average value over a period of four years proves to be less volatile, and therefore more suitable for guaranteeing tariff stability, than a concept oriented towards a certain percentile, as was the case with the 2019 motivated decision. This has become particularly evident in recent years with the change in the dominant entry point from VIP Iberico to the LNG terminal.

4.1.4 DISTANCE MATRIX

The distance matrix was determined based on information requested from the TSO, namely on the lengths of the various gas pipelines and on the existence of unidirectional gas pipelines. Based on this information, ERSE classified the various network segments into primary and secondary gas pipelines, in addition to identifying gas pipelines that should not be included in the calculation of the distance matrix, as they are beyond the GRMS. Table 4-6 presents a summary of the classification of gas pipelines.

[42] At points subject to capacity allocation processes, commercial capacity corresponds to the booked capacity in a firm capacity product. In the remaining points, without capacity allocation processes, commercial capacity is equivalent to the used capacity used, which is the billing variable for the network access tariff.

Table 4-6 – Classification of the gas pipelines of the RNTG

Primary pipelines	1 117,506 km
Secondary pipelines	242, 137 km
Pipelines beyond the GRMS	15,850 km
TOTAL	1 375,493 km

Primary pipelines correspond to segments required to transport gas to and from interconnection points, the LNG terminal, underground storage and other possible entry points, with all of these pipelines classified by the TSO as bidirectional pipelines. Secondary gas pipelines correspond to the segments that transport gas from central gas pipelines to GRMS, with all of these pipelines classified by the ORT as unidirectional gas pipelines.

Therefore, for the purposes of the reference price methodology, the distance matrix was determined exclusively from the primary and secondary gas pipelines, totalling 1 359,643 km in length. To obtain the distance matrix, an algorithm [43] was applied to minimise the distance required for each route between an entry point and an exit point [44].

4.1.5 Update frequency of the reference prices

For each gas year, reference prices will be recalculated according to updated information on allowed revenues, forecasted capacity and the distance matrix. Additionally, reference prices may also vary depending on applicable multipliers and discounts. Therefore, each gas year the various prices indicated in Figure 4-2 will be updated.

Some input data will be kept constant until a new periodic consultation on the reference price methodology, namely the following parameters: entry-exit split and economic value factor. As discussed in section 2.1.3, the commercial utilisation factor can be updated before a new periodic consultation if there are relevant changes in the utilisation of the entry and exit points of the transmission network.

[43] Applied through the statistical programme R.

[44] To execute the algorithm, it was necessary to include instrumental distances of 1 meter at some overlapping points. The lengths presented in Table 4-6 include a total of 13 meters of instrumental distances. More specifically: the primary gas pipelines include 6 segments of instrumental distances, totalling 6 meters; secondary gas pipelines include 7 segments of instrumental distances, totalling 7 meters.

4.2 COMPLIANCE OF THE REFERENCE PRICE METHODOLOGY WITH THE EUROPEAN REGULATORY FRAMEWORK

This section assesses whether the reference price methodology to be applied in the calculation of transmission tariffs in Portugal complies with the requirements of Article 7 of the Tariff Network Code and of Article 13 of Regulation (EC) 715/2009.

Pursuant to Article 7 of the Tariff Network Code, a set of requirements must be met, namely: (i) to enable network users to reproduce the calculation of reference prices; (ii) to take into account the actual costs incurred for the provision of transmission services (considering the level of complexity of the transmission network); (iii) to ensure non-discrimination and to prevent undue cross-subsidisation; (iv) to ensure that significant volume risk related to gas transits is not assigned to final customers; and (v) to ensure that the resulting reference prices do not distort cross-border trade.

Pursuant to Article 13 of Regulation (EC) 715/2009, which concerns tariffs for access to networks in the natural gas sector (or the methodologies used to calculate them), thus covering transmission tariffs, shall be "(i) transparent, take into account the need for system integrity and its improvement and reflect the actual costs incurred;" (ii) shall be "applied in a non-discriminatory manner;" (iii) shall "facilitate efficient gas trade and competition, while at the same time avoiding cross-subsidies between network users and providing incentives for investment and maintaining or creating interoperability for transmission networks;" and (iv) "shall neither restrict market liquidity nor distort trade across borders of different transmission systems".

In ERSE's understanding, the reference price methodology adopted meets the above requirements. Firstly, the reference price methodology is simple enough and well documented to be transparent, allowing users to reproduce calculations by the system users. The availability of a simplified tariff model in Excel contributes to this objective and allows estimating the evolution of transmission tariffs until the end of the regulatory period.

On the other hand, the methodology considers the real costs of the transmission activity, by taking into account the complexity of the transmission network. Compared to the 2019 motivated decision, which was based on a simplified diagram of the transmission network, this decision applies the reference price methodology to the actual network diagram[45]. This change contributes to the definition of cost drivers based on the actual characterisation of the network, therefore constituting an improvement.

Secondly, the use of a single methodology to allocate all allowed revenues of the TSO contributes to non-discrimination and the absence of cross-subsidisation. The results of the cost allocation assessment confirm the absence of cross-subsidisation between intra-system and cross-system uses[46].

Thirdly, although the allocation of the volume risk of gas transits to final consumers is not a real concern for Portugal when compared to other Member States, since cross-border flows represent residual values for Portugal, this requirement is met. The cost allocation assessment determines that revenues from cross-system use represent 4,1% of the TSO's allowed revenues, considering the indicative reference prices in chapter 7 [47].

Lastly, cross-border trade is promoted through reference prices that encourage an efficient use of the transmission network, through the price signal applied at each entry and exit point, particularly in the case of VIP Iberico. Taking into account the analysis of the indicative reference prices in chapter 7, the following observations can be made regarding the reference prices applicable to VIP Iberico:

- Compared to other possible approaches [48], the update of the reference price methodology ensures lower prices in both directions at VIP Iberico, avoiding the risk of contributing to the 'tariff pancaking' [49] issue. The adoption of any of the other methodologies presented would always increase reference prices in the VIP Iberico, in both directions, contradicting the objective of greater integration of the Portuguese and Spanish markets, requiring a gradual reduction in tariffs at the interconnection of the two countries.

[45] While the simplified network diagram, used since 2019, considered a total of seven clusters of exit points for national consumption, the current network diagram, used now and reflected in the distance matrix, considers a total of 85 exit points for national consumption.

[46] Based on the result obtained for the case in which capacity and distance are used as cost drivers. See section 7.4.

[47] The information published within the scope of transmission tariffs transparency shows that this value has been lower in the past, assuming values of 0,7% and 2,9% for gas years 2021-2022 and 2022-2023, respectively.

[48] The other approaches analysed are: CWD methodology with a 50/50 entry-exit split; CWD methodology with a 28/72 entry-exit split; and, postage stamp methodology with a 28/72 entry-exit split.

[49] 'Tariff pancaking' refers to the accumulation of transmission tariffs paid by cross-border flows of natural gas: since gas flows pay entry and exit tariffs each time it moves across entry-exit systems, a cross-border flow has to pay entry and exit tariffs of the various transmission networks it crosses. Several market players consider this accumulation excessive.

- Compared to the tariffs approved for the gas year 2023-2024, the update of the reference price methodology increases the reference prices applicable at the point of exit to VIP Iberico and at the point of entry from the LNG terminal, contradicting arguments that the tariff structure seeks to favour the export of gas to Spain from the LNG terminal [50].

4.3 INJECTION OF RENEWABLE OR LOW-CARBON GASES

Decree-Law 62/2020 of 28 August introduced, among other changes, a new activity in the gas sector, requiring a regulatory review [51] of the ERSE Gas Tariff Code [52] to ensure the adaptation of the tariff rules for the injection of renewable or low-carbon gases into the gas transmission and distribution networks.

As a result, the ERSE Tariff Code was revised to define the tariff system applicable to the injection of renewable gases into the gas transmission and distribution networks. In gas year 2021-2022, a price applicable to gas producers' deliveries to the transmission network was published for the first time, in EUR/(kWh/day)/day, applied to the utilised injection capacity [53], i.e., the maximum daily injection over the last twelve months.

In fact, the use of the transmission network tariff applied by the TSO presents entry and exit prices for the transmission network. Entry points include VIP Iberico, the LNG terminal at Sines, underground storage at Carriço and gas producers connected to the transmission network.

Since the tariff structures applied to transmission (entry-exit model) and distribution (exit model) are objectively different, no price is applied to the injection of renewable or low-carbon gases when the injection takes place in the distribution network.

[50] The sum of the reference prices applied at the entry point from the LNG terminal and at the exit point to VIP Iberico changes with the update of the reference price methodology from 0,1040 to 0,1269 EUR/kWh/day/year. This variation represents a relative increase of 22,0% compared to the price structure in force in the gas year 2023-2024.

[51] ERSE's public consultation No. 96.

[52] Regulation no. 368/2021, Of 28 April.

[53] The billing variable is the capacity used for injection, since the intention is not to apply a capacity reservation system to the injection of these gases.

In Spain, entry prices are also applied to gas producers only when injection takes pl ace in the transmission network. The injection of renewable or low-carbon gases into local networks [54] in Spain benefits from a tariff exemption, via Circular 6/2020 of 22 July.[55]

Taking into account the future European package on gas decarbonisation, which addresses tariff issues for the injection of gas from renewable or low-carbon sources, namely related to tariffs discounts, it is advisable to wait for the new European legislation to be published to revisit this issue (see section 9.1).

4.4 ALLOCATION OF COSTS FROM SECONDARY PIPELINES AND GRMS

In ERSE's public consultation No. 66, the investments in the transmission network between 2010 and 2022, at constant prices of year 2019, resulted in the following average structure by type of network asset: primary pipelines (56%), secondary pipelines (20 %) and GRMS (24%).

Considering that secondary pipelines and GRMS are assets that can potentially be considered as regional network assets, which are only intended for intra-system use, the ERSE methodology introduced two modifications to address this situation.

Firstly, the choice of the entry-exit split of 28/72 reflects an equal distribution of the value equivalent to primary gas pipelines between entry and exit points and an allocation exclusively to exit points of the value equivalent to secondary gas pipelines and GRMS. Primary gas pipelines represent the main infrastructure of the transmission network, connecting the various entry points directly to GRMS or secondary gas pipelines in HP. Since any entry point or exit point uses primary gas pipelines, it is considered that these must be allocated in equal proportions to the entry points and exit points, resulting in weights of 28% for each set of points. The remaining assets of the transmission network (secondary gas pipelines and GRMS), which represent on average 44% of investments in the transmission network, are assets that must be allocated exclusively to exit points. Therefore, a proportion of 44% of the allowed revenue to be recovered each year must be attributed exclusively to exit points. Therefore, this rationale results in the entry-exit split of 28/72.

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[54] The concept of "local networks" in Spain is equivalent to the concept of "distribution networks" in Portugal, since local networks in Spain cover networks that are not subject to the application of Commission Regulation (EU) 2017/460 of 16 March.

[55] https://www.cnmc.es/sites/default/files/3074982_6.pdf

Secondly, the application of the economic value factor aims to allocate the value equivalent to regional network assets exclusively to exit points for national consumption. The economic value factor of approximately 257%, to be applied to combinations of entry-exit points that use regional networks, results from the fact that secondary pipelines and GRMS represent, on average, 44% of investments in the national transmission network. Therefore, compared to the parcel corresponding to primary gas pipelines to be supported by exit points in general, which represents 28%, the use of regional networks parcel represents an additional value of approximately 157% (44% ÷ 28%) [56].

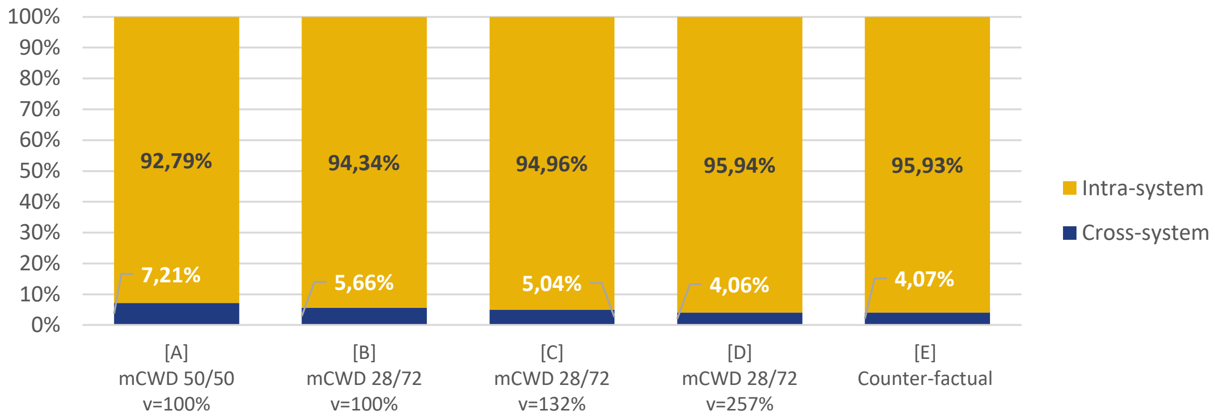
Figure 4-3 illustrates the distribution of revenues between intra-system and cross-system uses [57], for different methodological approaches. The first approach [A] corresponds to the case in which the reference price methodology does not reflect the two previously mentioned modifications to improve the allocation of costs of regional network assets, that is, it corresponds to a case in which the entry-exit split is 50/50 and the economic value factor assumes a neutral value, that is, a value that is always 100%. The second approach [B] corresponds to the case in which the reference price methodology reflects only one of the two modifications mentioned, namely the entry-exit split of 28/72. The third approach [C] corresponds to the case in which the reference price methodology reflects both modifications, that is, with an entry-exit split of 28/72 and the economic value factor reflecting the GRMS value for the combinations of entry-exit points using GRMS, according to the value approved in the 2019 motivated decision. The fourth approach [D] corresponds to the case in which the reference price methodology reflects the two modifications, i.e., with an entry-exit split of 28/72 and the economic value factor reflecting the value of the regional networks for the combinations of entry-exit points supplying national consumption, according to the value approved in the 2024 motivated decision. Finally, the fifth approach [E] corresponds to the counter-factual, in which the reference price methodology only applies to 56% of the allowed revenues [58], the value corresponding to the primary gas pipelines, and the remaining value is allocated through a uniform capacity price applied only to the exit points to national consumption.

[56] See also analysis in section 2.2.1.

[57] This separation follows the assumptions adopted in the cost allocation assessment, in accordance with Article 5 of the Tariff Network Code.

[58] In this case with an entry-exit split of 50/50 and the economic value factor assuming a neutral value, that is, a value that is always equal to one.

Figure 4-3 - Distribution of revenues between intra-system and cross-system uses, for different approaches



Notes: [A] Modified CWD methodology with a 50/50 entry-exit split and unitary values for the economic value factor. [B] Modified CWD methodology with an entry-exit split of 28/72 and unitary values for the economic value factor. [C] Modified CWD methodology with an entry-exit split of 28/72 and the economic value factor equal to 132% for entry-exit point combinations using GRMS. [D] Modified CWD methodology with an entry-exit split of 28/72 and the economic value factor equal to 257% for entry-exit point combinations supplying national consumption. [E] Counter-factual, where the modified CWD methodology is applied to only 56% of the allowed revenues, with the remaining amount allocated to exit points for national consumption through a uniform capacity price.

Approach [E] thus reflects an outcome in which the reference price methodology is only applied to assets that are not considered to be regional network assets, with the remaining value being allocated separately through a uniform capacity price. As can be seen, the two modifications introduced in the modified CWD methodology, in approaches [C] and [D], help to bring the distribution of revenues between intra-system and cross-system uses closer to the distribution suggested by approach [E], the counter-factual, especially with the new economic value factor from approach [D]. Hence, the methodology approved by ERSE in this decision, in approach [D], which incorporates the two aforementioned modifications, represents a reasonable approximation to the distribution that could be obtained by separating regional network assets.

5 ALLOWED REVENUES FOR THE TRANSMISSION SYSTEM OPERATOR

The gas transmission activity consists of transporting gas through the interconnected high-pressure network, connecting the SNG entry points to the SNG exit points, namely to large customers directly connected to the transmission network (power stations and industrial customers) and to the distribution networks that are interconnected to the high-pressure network.

The RNTG is operated by REN Gasodutos, under a public service regime and is subject to regulation by ERSE. Revenues from the gas transmission activity are recovered by applying the tariff for use of the transmission network under the terms defined in the ERSE Gas Tariff Code.

The information presented in this chapter is based on the values set by ERSE for gas tariffs in force in the gas year 2023-2024. This gas year marks the beginning of a new regulatory period for this sector, which runs from 2024 to 2027. The regulation parameters and methodologies[59] reflect the objectives set out in the ERSE Gas Tariff Code, namely ensuring the economic sustainability of regulated activities in the gas sector, in a context of decarbonisation of economic sectors and energy transition.

5.1 ALLOWED REVENUES FOR THE GAS TRANSMISSION SYSTEM OPERATOR

The transmission system operator's (TSO) allowed revenues[60] for the gas year 2023-2024 and the percentage variation compared to the previous gas year are shown in the table below.

Table 5-1 - Revenues to be recovered by the Transmission System Operator

Art. 30 (1)(b)(i) Allowed or target revenue, or both, of the transmission system operator	70 874 364 € (revenues recovered)
Art. 30 (1)(b)(ii) Information related to changes in the revenue referred to in point (i) from one year to the next year	196,4% (change of annual revenues recovered compared with gas year 2022/2023)

[59] Presented in «Regulatory parameters for the period 2024 to 2027» (ERSE, only in Portuguese), June 2023.

[60] Article 30 (1)(B)(I,II) Commission Regulation (EU) 2017/460 of 16 March 2017.

The large variation that occurred when comparing the level of revenues for 2023-2024 with the allowed revenues for 2022-2023 was due to the lower level of adjustments that occurred in the allowed revenues for 2021 and 2022, which according to the ERSE Gas Tariff Code integrate the allowed revenues for each year. The final adjustments to the allowed revenues for year s-2 are taken into account in tariffs two years after they occur. These adjustments represent the difference between the operator's invoiced revenues in year s-2 and the allowed revenues calculated with audited real values. The estimated adjustment for year s-2 that was taken into account in the previous year's tariffs is deducted from this value. The s-1 adjustments are taken into account in the following tariffs and represent the difference between estimated invoicing and the best estimate of allowed revenues[61], both for the year s-1. The adjustments considered in the TSO allowed revenues for the gas year 2023-2024 are around 0,8 million euros in favour of consumers, while in the previous year they were 38,5 million euros, also in favour of consumers. This high level of adjustments was due to the reimbursement to the tariff of amounts received by the TSO relating to premiums received from a capacity allocation auction[62]. It should be noted that the s-1 adjustments are not included in 2023-2024 allowed revenues.

5.2 ALLOWED REVENUE PARAMETERS

This chapter presents the parameters applied to the calculation of the allowed revenues for the gas transmission activity, as established in Article 30 (1)(b)(iii) of Commission Regulation (EU) 2017/460 of 16 March. The structure of the information, which follows the ACER Recommendation[63], is divided in the following topics:

1. Description of the methodology for calculating the allowed revenues
2. Values and parameters
3. Values and costs of expenses used to calculate allowed revenues or the forecast of allowed revenues.

Table 5-5 (Annex A) and Table 5-6 (Annex B) also provide detailed information on asset depreciation.

[61] The inclusion of the provisional adjustments for year s-1 in the allowed revenues for gas year t is subject to prior annual assessment of the resulting tariff impacts.

[62] Further detailed in section 5.3.

[63] «The internal gas market in Europe: The role of transmission tariffs», ACER, April 2020, page 71.

Table 5-2 - Methodology for regulating the gas transmission activity in the 2024 to 2027 regulatory period

Art. 30 (1)(b)(iii) **(1) A description of the methodology, including at least a description of:**	
(a) The overall methodology, such as revenue-cap, hybrid, cost-plus or tariff benchmarking;	A price cap methodology is applied to operational expenditures, with a fixed part and a variable amount indexed to the evolution of physical variables. For CAPEX, a rate-of-return type methotodology is applied. Allowed revenues are adjusted every two years, based on real audited values of the costs and the incomes.
(b) The methodology to set the regulated asset base;	The regulated asset base consists of the average value of assets net of investment subsidies and amortisations and depreciations. The value of works in progress are not considered in the regulated asset base.
i. Methodologies to determine the initial (opening) value of the assets;	For the first regulatory period (2007) the RAB was re-evaluated by the government (ICR).
ii. Methodologies to re-evaluate the assets;	No revaluation of assets (ICR).
iii. Explanations of the evolution of the value of the assets;	Assets grow annually by the addition of new assets and the deduction of asset write-offs and subsidies.
(c) The methodology to set the cost of capital;	In the gas year 2023-2024, the new regulatory period 2024-2027 begins. Gas TSO WACC is a pre-tax nominal. The calculation methodology for the cost of equity is the Capital Asset Pricing Model (CAPM) and the methodology for the cost of debt is the default spread. The WACC to be applied in the regulatory period 2020-2023 is indexed to the Portuguese 10 year bond benchmark and depends, in each year, on its evolution, with a cap (8,80%) and a floor (4,50%). The WACC to be applied in the regulatory period 2024-2027 is indexed to the Portuguese 10 year bond benchmark and depends, in each year, on its evolution, with a cap (7,40%) and a floor (3,10%).
(d) The methodology to determine the TOTEX or, if applicable, OPEX and CAPEX;	For OPEX, a price cap methodology is applied, with a fixed part and a variable part indexed to the evolution of physical variables (used exit capacity based on the daily maximum over a 12 month period and an annual efficiency target of 3% in 2023 and 2% for regulatory period 2024-2027). At the OPEX level, LNG transport costs by road are also considered. CAPEX is determined by the remuneration of the regulated asset base (WACC x RAB), plus amortisations and depreciation net of investment subsidies. Works in progress are not remunerated.
(e) The methodology to determine the efficiency of the cost, if applicable.	In order to set parameters for the gas transmission activity, the evolution of OPEX over the last few years is analysed. Based on this evolution, the regulatory cost base is reviewed, which aims to share efficiency performance with consumers. Based on the analysis carried out, it is also assessed whether the efficiency targets imposed on the company in the previous regulatory period are in line with the level of costs achieved, and depending on the result, the efficiency factors may be revised (for the regulatory period 2024-2027 the efficiency target to be applied to the gas transmission activity is 2% per year. In the regulatiory period 2020-2023 it was 3% per year). Finally, the relative position of the transmission system operator compared to other European peers in terms of efficiency, with emphasis on the work done to define the parameters for the 2024-2027 regulatory period, in collaboration with the CNMC. The position of the Portuguese operator compared to other operators is also assessed and monitored through participation in European benchmarking studies.

Table 5-3 - Parameters for calculating the gas transmission activity revenues for the gas year 2023-2024

(2) The values of the parameters:	
(a) Cost of equity and cost of debt or weighted average cost of capital in percentages;	Weighted average cost of capital: 2023: 5,69% 2024: 5,30% Values are revised ex-post, taking into account the evolution of the Portuguese 10-year bonds, as explained above - paragraph 1 c)
(b) Depreciation periods in years;	Depreciation rates have remained stable since gas year 2018/2019 . See table below (Annex A with average rates of depreciation by type of asset).
(c) Efficiency targets in percentages;	2023: 3% 2024: 2%
(d) Inflation indices;	2023: 5,8% 2024: 2,3%

Table 5-4 - Values of costs and expenditures that are used for setting the allowed revenues of the gas transmission activity for the gas year 2023-2024

Art. 30 (1)(b)(iii) **(3) The values of costs and expenditures that are used for setting the allowed or target revenue in the local currency and in Euro**	
(a) The regulated asset base per asset type;	503 103 479 € (net weighted average asset value)
(b) The depreciation per asset type;	See table below (Annex B with annual depreciation amounts by type of asset).
(c) The cost of capital;	56 539 319 €
(d) Operational expenditures.	21 606 016 €

Table 5-5 - Annex A: average depreciation rate by asset type

Asset type	**Average rate of depreciation**
Industrial property	5,26%
Linepack	4,94%
Land and Natural Resources	2,52%
Buildings and Other Construction	1,68%
Basic Equipment	2,84%
Transporte Equipment	13,90%
Tools and Utensils	6,38%
Office Equipment	6,63%
Other tangible fixed assets	1,65%

Table 5-6 - Annex B: annual depreciation values by assets type

Asset type	Average annual values of depreciation by assets type (gas year)
Industrial property	1 526 316 €
Linepack	668 286 €
Land and Natural Resources	1 951 515 €
Buildings and Other Constructions	342 513 €
Basic Equipment	29 991 886 €
Transporte Equipment	334 879 €
Tools and Utensils	100 811 €
Office Equipment	591 155 €
Other tangible fixed assets	27 510 €

5.3 CAPACITY ALLOCATION AUCTION PREMIA

The mechanisms for allocating capacity on the National Transmission Network's infrastructure are set out in the ERSE Access to Networks, Infrastructures and Interconnections Code (RARII) [64] and the details of the allocation procedures are published in the ERSE Manual of Procedures for Access to Infrastructures (MPAI) [65]. Revenues obtained through premiums to the allocation of capacity are part of the remuneration for the use of infrastructure provided for in the ERSE Gas Tariff Code, namely revenues from the allocation of infrastructure capacity as a result of the application of capacity auction premiums.

The amounts relating to the capacity auction premiums received by the LNG Terminal, Underground Gas Storage and Gas Transmission operators are returned to the tariff [66].

The adjustment to the 2021 allowed revenues included in the calculation of the gas year 2023-2024 allowed revenues for the Gas Transmission activity includes a value of 25 424 000 euros in auction premiums for the allocation of capacity at the interface between the LNG Terminal and the transmission network. A significant part of this amount, corresponding to 24 504 000 euros, has already had an impact on the 2022-2023 tariffs, through the provisional adjustments for 2021 considered in the allowed revenues for that gas year.

Overall, the value of the capacity allocation premiums received by the gas TSO between 2020 and 2022, and which have already been returned via the tariff, totalled 34 494 000 euros.

[64] Approved by Regulation no. 407/2021, of 12 May.

[65] Approved by Directive no. 7/2020 of 21 April. (In Portuguese)

[66] According to the ERSE Gas Tariff Code in force.

Table 5-7 -Value of capacity allocation auction premiums received by the TSO that benefited tariffs

Unit: 10^3 EUR

	Year of receipt			Total 2020-2022
	2020	2021	2022	
REN Gasodutos	**8 227,2**	**25 424,1**	**842,9**	**34 494,1**
Interface				
entry LNG Terminal	8 227,2	24 431,5	323,1	**32 981,8**
entry Underground Storage		0,1		**0,1**
exit LNG Terminal		0,8		**0,8**
exit Underground Storage		991,7	519,7	**1 511,4**

A new capacity allocation auction took place in 2023, which again resulted in an auction premium at the interface between the LNG terminal and gas transmission.

6 ENERGY-BASED TRANSMISSION TARIFFS AND NON-TRANSMISSION TARIFFS

According to ERSE's 2019 motivated decision, the transmission tariff applied by the TSO no longer has energy-based transmission tariffs[67].

Under the Tariff Network Code “transmission services” means the regulated services that are provided by the transmission system operator within the entry-exit system for the purpose of transmission (Article 3(12)). Furthermore, a given service shall be considered a transmission service where both of the following criteria are met (Article 4):

a) the costs of such service are caused by the cost drivers of both technical or forecasted contracted capacity and distance;

b) the costs of such service are related to the investment in and operation of the infrastructure which is part of the regulated asset base for the provision of transmission services.

If any of the criteria in points (a) and (b) are not met, a given service may be allocated to non-transmission related services or to transmission related services, subject to the conclusions of the periodic consultation by the TSO(s) or the national regulatory authority and the decision of the national regulatory authority, as provided for in Articles 26 and 27.

In contrast, according to the Tariff Network Code, “non-transmission services” means the regulated services other than transmission services and other than services regulated by Regulation (EU) No 312/2014 that are provided by the TSO (Article 3(15)). Non-transmission services, under the terms of the Tariff Network Code, may apply "non-transmission tariffs", i.e., charges payable by network users for non-transmission services provided to them.

Pursuant to the Tariff Network Code, revenue from non-transmission services will be recovered through non-transmission tariffs applicable to a given non-transmission service. These tariffs will be (Article 4(4)):

a) cost-reflective, non-discriminatory, objective and transparent;

b) Charged to the beneficiaries of a given non-transmission service with the aim of minimising cross-subsidisation between network users within or outside a Member State, or both.

[67] With the exception of the value applied to customer-owned Autonomous Gas Units (AGU), since in this case there is no measurement of a capacity value due to measurement restrictions. In this case, the capacity-based price determined using the reference price methodology is converted into an energy-based price.

Where according to the national regulatory authority a given non-transmission service benefits all network users, the costs for such service shall be recovered from all network users.

Considering the information released by ACER regarding the evaluation of the reports on the application of reference price methodologies in the Member States, it can be seen that 11 countries do not report non-transmission services[68] while 13 countries[69] report the existence of specific tariffs for non-transmission services. The services most frequently identified as not related to transmission are the pressure reduction, odourization, the provision of non-standard information, services and connection to the network, market area conversion rates, biogas injection rates and the use of regional networks.

In Portugal, all the services provided by the TSO are transmission-related services. With regard to connection to the transmission network, connection costs are the result of an agreement between the applicant and the TSO, with ERSE's approval, under the terms of the ERSE´s Commercial Relations Code. In the case of the connection of gas producers, payment is due for the connection elements, but no prices have yet been approved by ERSE. As in both cases there are no predetermined prices, it is considered that these are not yet included in the tariffs for non-transmission services.

[68] In particular, Austria, Bulgaria, Slovakia, Spain, Estonia, Northern Ireland, Latvia, Lithuania, the Netherlands, Poland (OGP Gaz-System S.A.), Czechia. Information available at https://acer.europa.eu/gas/network-codes/tariffs/acer-reports-national-tariff-consultations/acer-analysis-national-tariff-consultation-documents.

[69] In particular, Germany, Belgium, Croatia, Denmark, Finland, France, Germany, Greece, Hungary, Italy, Ireland, Romania, Slovenia, Sweden. Information available at https://acer.europa.eu/gas/network-codes/tariffs/acer-reports-national-tariff-consultations/acer-analysis-national-tariff-consultation-documents.

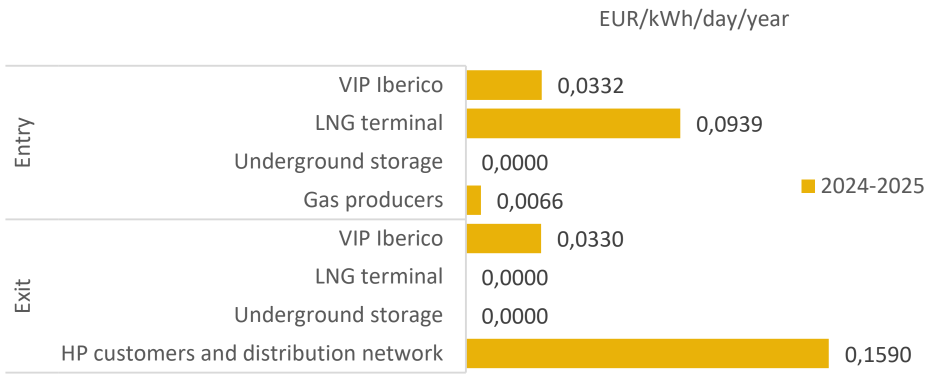
7 ANALYSIS OF THE INDICATIVE REFERENCE PRICES

This chapter presents indicative reference prices, determined in accordance with the reference price methodology presented in section 4.1.

7.1 INDICATIVE REFERENCE PRICES FOR GAS YEAR 2024-2025

The indicative reference prices for the gas year 2024-2025, in the definition of the Tariff Network Code [70], are presented in Figure 7-1. These prices were determined based on the reference price methodology in section 4.1, which will be applied as of gas year 2024-2025, based on information on the forecasted capacity and allowed revenues that were the basis for the decision on gas tariffs for the gas year 2023-2024, of 1 June 2023 [71].

Figure 7-1 - Indicative reference prices for gas year 2024-2025



Notes: Prices assume forecasted capacity and allowed revenues from the tariff decision for the gas year 2023-2024.

At entry points, the LNG Terminal price is higher than the VIP Iberico price by a factor of 2,8x. Additionally, the price of underground storage is zero, due to the 100% discount [72], and the price from gas producers represents approximately 20% of the VIP Iberico price.

[70] Price for a capacity product for firm capacity with a duration of one year, which is applicable at entry and exit points and which is used to set capacity-based transmission tariffs.

[71] Information available at ERSE's webpage (only in Portuguese).

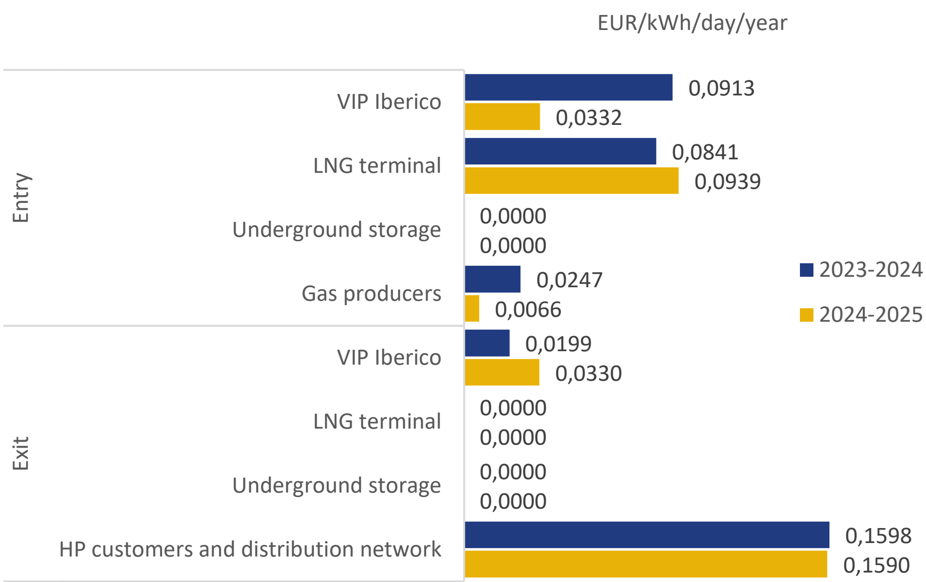
[72] See section 8.1.

At exit points, the price of VIP Iberico represents approximately 21% of the price for customers in HP and distribution networks. Furthermore, the price of underground storage is zero, due to the 100% discount, and the price of the LNG Terminal, applicable to virtual counter-flow booking, is zero.

7.2 COMPARISON WITH THE REFERENCE PRICES OF GAS YEAR 2023-2024

As previously mentioned, the indicative reference prices, presented in section 7.1, use the forecasted capacity and allowed revenues that were the basis for the gas tariff decision for the gas year 2023-2024. For this reason, they can be compared with the reference prices approved for the gas year 2023-2024, which were determined with the reference price methodology current in place. This comparison is shown in Figure 7-2.

Figure 7-2 - Comparison with the reference prices for gas year 2023-2024



Notes: (1) Prices for the gas year 2023-2024 correspond to the prices approved for that gas year. (2) Prices for the gas year 2024-2025 correspond to the indicative reference prices presented in section 7.1.

The reference prices approved for the gas year 2023-2024 present some structural differences compared to the indicative reference prices for the gas year 2024-2025.

At entry points, considering the gas year 2023-2024, the LNG terminal price is lower than the VIP Iberico price by approximately 8%. This situation is reversed with the reference prices determined for 2024-2025, with the entry price from the LNG terminal being almost three times the entry price from the VIP Iberico. This change results from a high capacity booking at the entry point from the LNG terminal [73]. The price of underground storage is zero, due to the 100% discount, and the price from gas producers represents approximately 27% of the VIP Iberico price.

At exit points, considering the gas year 2023-2024, the price of VIP Iberico represents approximately 12% of the price for customers in HP and distribution networks. Considering the reference prices for the gas year 2024-2025, the price of VIP Iberico would represent 21% of the price for customers and distribution networks. Furthermore, the prices for underground storage and counter-flow booking at the LNG terminal are zero.

In summary, compared to the methodology in force in the gas year 2023-2024, the main changes in the decision for the updated reference price methodology are: (1) at VIP Iberico, a relative reduction in the entry price and a relative increase in the exit price; (2) at the LNG terminal, a relative increase in the entry price.

7.3 COMPARISON WITH THE CWD METHODOLOGY

Whenever the reference price methodology is different from the capacity-weighted distance methodology (CWD methodology), defined in Article 8 of the Tariff Network Code, its comparison with the latter is mandatory [74].

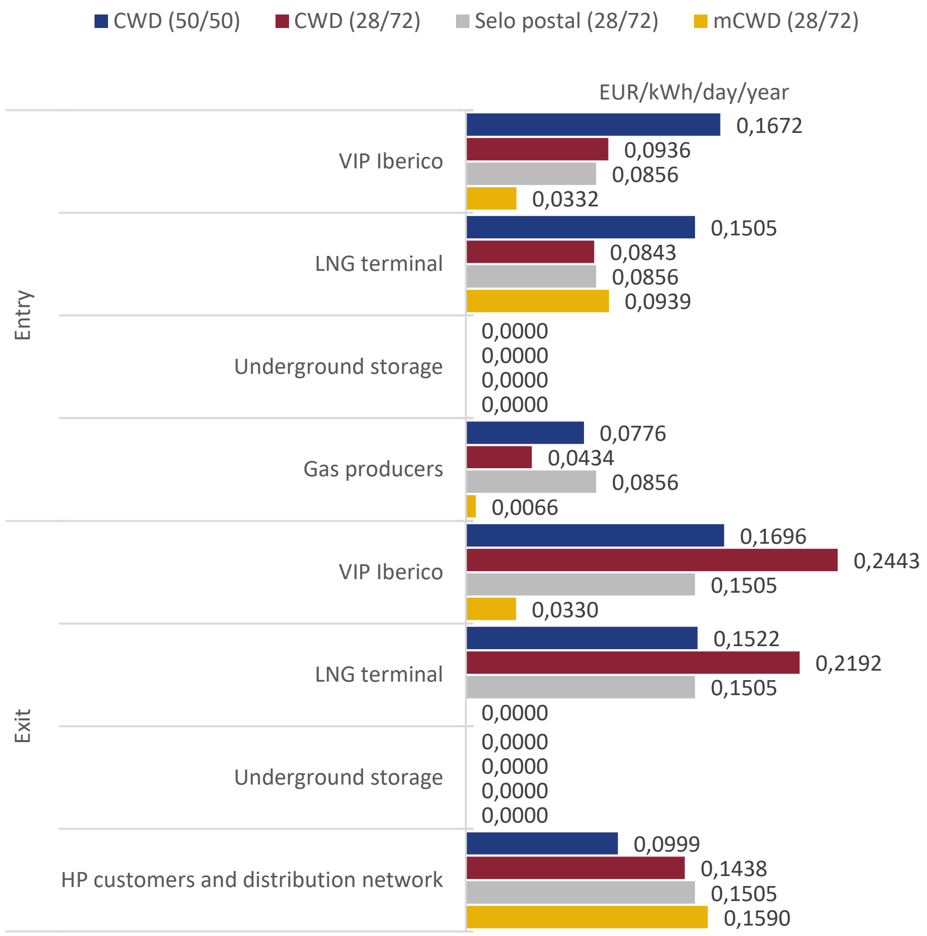
In addition to presenting the results of the CWD methodology with an entry-exit split of 50/50, as provided for in the Tariff Network Code, the comparison that follows also presents the results of the CWD methodology with an entry-exit split of 28/72, in order to be more comparable with the relative prices of entry and exit points. Additionally, the results for the postage stamp methodology [75] with an entry-exit split of 28/72 and the results of the modified CWD methodology (mCWD) were also included, as presented in section 4.1. The comparison of indicative reference prices for the gas year 2024-2025, determined using the various methodologies, is shown in Figure 7-3.

[73] In the reference price methodology, this high utilisation is reflected in a commercial utilisation factor of 98,7%, according to the Table 4-5.

[74] Article 26(1)(a)(vi) of the Tariff Network Code.

[75] Methodology according to which prices are the same at the various entry points and the same at the various exit points.

Figure 7-3 - Comparison with the CWD methodology and other methodologies



Notes: **CWD (50/50)** – CWD methodology with a 50/50 entry-exit split; **CWD (28/72)** – CWD methodology with an entry-exit split of 28/72; **Postage stamp (28/72)** – Postage stamp methodology with an entry-exit division of 28/72; **mCWD (28/72)** – Modified CWD methodology with an entry-exit split of 28/72. The indicative reference prices for the gas year 2024-2025, of the various methodologies, assume the forecasted capacity and the allowed revenues that were the basis for the gas tariff decision for the gas year 2023-2024.

The CWD methodology, with an entry-exit split of 50/50, produces a pricing structure that is less comparable to the other methodologies presented. On average, prices are higher at entry points and lower at exit points, due to the different distribution of revenues between entry points and exit points.

Comparing the three methodologies with an entry-exit split of 28/72, the conclusions are as follows for the entry points:

– The CWD methodology and the postage stamp methodology produce a similar pricing structure between the VIP Iberico and the LNG terminal. In the price applicable to VIP Iberico, the three methodologies produce different prices, with the following hierarchy, from the highest price to the lowest price: CWD > Postage stamp mCWD. In the price applicable to the LNG terminal, the three methodologies produce different prices, with the following hierarchy, from the highest price to the lowest price: mCWD > Postage stamp > CWD.

- When comparing the CWD and mCWD methodologies, the latter produces a greater differentiation between VIP Iberico and the LNG terminal, with the two methodologies producing a price ratio between the LNG terminal and VIP Iberico of 0,90 and 2,83, respectively.
- In the price applicable to gas producers, the three methodologies produce very different prices, with the following hierarchy, from the highest price to the lowest price: Postage stamp > CWD > mCWD. However, it should be remembered that the price applicable to this case is being determined provisionally, as there is still no information on connection of gas producers to the transmission network.

In the case of exit points, the comparison of the three methodologies with an entry-exit split of 28/72 results in the following conclusions:

- In the price applicable to VIP Iberico, the three methodologies produce very different prices, with the following hierarchy, from the highest price to the lowest price: CWD > Postage stamp > mCWD.
- In the price applicable to the counter-flow to the LNG terminal, the CWD and postage stamp methodologies result in positive prices, equal or higher to the corresponding price applicable to customers in HP and distribution networks. The mCWD methodology results in a zero price.
- In the price applicable to customers in HP and distribution networks, the three methodologies produce a hierarchy inverse to the hierarchy at the exit point to VIP Iberico (from the highest price to the lowest price): mCWD > Postage stamp > CWD.

7.4 COST ALLOCATION ASSESSMENT

In accordance with Article 5 of the Tariff Network Code, a cost allocation assessment must be carried out to assess whether there is cross-subsidisation between the use of the network at a cross-system level (gas transits that cross the country) and at an intra-system level (gas flows intended for national consumption). If there are only capacity-based prices, the capacity cost allocation comparison index (CACI) must be calculated to assess whether the recovery of revenue for cross-system and intra-system uses is proportional to the cost drivers of those uses. The indicator for the presence of cross-subsidisation varies between the values 0% and 200%, where 0% indicates the absence of cross-subsidisation and 200% indicates the situation of maximum cross-subsidisation. Article 5(6) establishes that if the calculated indicator exceeds the value of 10%, the national regulatory authority must justify these results in its motivated decision referred to in Article 27(4).

To calculate the capacity CACI, it is necessary to establish which cost driver to use, among the four options indicated in Article 5(1)(a). Since the modified CWD methodology uses effective capacity and effective distance as cost drivers, the calculation of the capacity CACI applies the cost factor that uses forecasted contracted capacity and distance, referred to in subparagraph (iv).

Since the Tariff Network Code does not present formulas to determine the cost driver when it combines the forecasted contracted capacity and the distance, ERSE´s calculation uses directly the weight of cost resulting from the reference price methodology formulas, which corresponds to the variables $W_{c,i}$ and $W_{c,j}$ for the entry and exit points [76,77], respectively, multiplied by the percentage of revenue to be recovered at the entry and exit points, respectively.

Table 7-1 presents the result for the capacity CACI for four different methodologies, namely the CWD methodology, the CWD methodology with an entry-exit split of 28/72 (CWD 28/72), the postage stamp methodology with an entry-exit split of 28/72 and the modified CWD methodology, the latter corresponding to the reference price methodology approved by ERSE.

[76] The variables for the weight of cost ($W_{c,i}$, $W_{c,j}$) reflect the product between capacity and the average distance of a given point.

[77] In intersystem use: the weight of cost for the exit points corresponds to the value $W_{c,j}$ of the exit point for VIP Iberico, while the weight of cost for the entry points corresponds to the value of the entry point from the LNG terminal, in the proportion that the exit value at VIP Iberico represents in the total entry from the LNG terminal. For intra-system use: the weight of cost for entry and exit points is calculated to add up to 100% when added to the respective value for cross-system use.

Table 7-1 - Cost allocation assessment for capacity-based prices

		CWD 50/50	CWD 28/72	Postage stamp 28/72	mCWD 28/72
Revenues					
Cross-system	million €	7,26	7,45	5,35	2,88
Intra-system	million €	63,61	63,42	65,52	68,00
Cost driver					
Cross-system	%	9,98%	10,22%	4,03%	4,03%
Intra-system	%	90,02%	89,78%	95,97%	95,97%
Ratio = Revenues ÷ Cost driver					
Cross-system	million €	72,75	72,92	132,69	71,32
Intra-system	million €	70,67	70,64	68,28	70,86
Capacity cost allocation comparison index		**(-) 2,9%**	**(-) 3,2%**	**(-) 64,1%**	**(-) 0,7%**

Note: The cost driver is calculated based on the weight of cost, multiplied by the percentage of revenue recovered at the entry and exit points. The sign in parentheses in the capacity CACI result indicates the direction of cross-subsidisation: a positive sign (+) indicates that cross-system uses are being subsidised; a negative sign (-) indicates that intra-system uses are being subsidised.

Given the selected cost driver, all methodologies present values below the 10% threshold indicated in the Tariff Network Code, with the exception of the postage stamp methodology. A low value for the capacity CACI was expected to result in the CWD and modified CWD methodologies, since these precisely use capacity and distance as cost drivers [78].

The cost driver determined for the mCWD methodology follows the formulas presented in section 4.1.1, which means that its value reflects the effective capacity and effective distance variables.

7.5 INDICATIVE EVOLUTION OF THE REFERENCE PRICES

Given the great volatility in the use of the transmission network in the recent past, and which continues in the face of the war in Ukraine, a forecast of reasonable reference prices until the last gas year of the current regulatory period would be challenging, leading ERSE to not present a particular forecast for the various gas years. However, the simplified tariff model that is made available allows users to introduce demand and revenue forecasts in order to determine a trajectory of reference prices.

[78] If there were no discounts when applying the reference price methodology, it is possible to show that the CWD methodologies and the mCWD methodology would result in a capacity CACI value equal to 0,0%.

8 DISCOUNTS, MULTIPLIERS AND SEASONAL FACTORS

This section responds to Article 28(1) of the Tariff Network Code, which establishes the need to consult, on the one hand, the national regulatory authorities of all directly linked Member States and, on the other hand, relevant stakeholders on the level of multipliers, the level of seasonal factors and the discounts provided for in Articles 9 and 16.

8.1 DISCOUNTS AT POINTS OF INTERFACE WITH UNDERGROUND STORAGE

According to Article 9(1) of the Tariff Network Code, a discount of at least 50 per cent must be applied to the reference prices applicable at the entry points to the transmission network from storage facilities and at the exit points from the transmission network to storage facilities (unless the storage facility connected to more than one transmission or distribution network is used to compete with an interconnection point).

This discount, which has been 100% in Portugal since the gas year 2019-2020, is intended to make it easier for suppliers to balance the use of underground storage, taking advantage of the flexibility that this infrastructure can provide and thus better contributing to the system's balance.

A comparison of the level of discount applied in various European countries with underground storage facilities, in Figure 8-1, shows that around half apply a 100% discount and all apply a percentage of 50% or more.

Figure 8-1 - Discounts at entry/exit points from/to storage facilities, by Member State

100%	100%	100%	100%	100%	100%	100%	90%/100% *	90%/100% *	80%	80%	80%	75%	60%	50%	50%	50%	50%
Spain	Austria	Latvia	Belgium	Portugal	Denmark	Sweden	Croatia	Hungary	Bulgaria	France	Poland	Germany	The Netherlands	United Kingdom	Italy	Czechia	Romania

* Entry / Exit

Source: ACER report on Member States consultation documents

The granting of these discounts thus helps to encourage agents to contract and use storage capacity, which contributes to the proper implementation of EU Regulation 2022/1032 on emergency storage measures, which requires member states to adopt minimum filling measures and trajectories (90% as of 1 November 2023).

8.2 MULTIPLIERS

The Tariff Network Code establishes rules for multiplier levels (Article 13), applicable to standardised firm capacity products at interconnection points. The multipliers, applied to the annual reserve prices, make it possible to find the respective non-annual reserve prices, namely at the quarterly, monthly, daily and intraday horizons.

Pursuant to Article 13(1) of the Tariff Network Code, the level of the multiplier must not be less than 1 or more than 1,5 for quarterly and monthly standardised capacity products. For daily and intraday standardised capacity products, the level of the respective multiplier must not be less than 1 or greater than 3. In duly justified cases, it may be greater than 3 and less than 1, but greater than zero.

Table 8-1 shows the multipliers in force for the 2023-2024 gas year, applicable to VIP Iberico, LNG terminal and Carriço underground storage. The multipliers shown in this table comply with the limits set out in Article 13(1).

Table 8-1 - Multipliers in force for the 2023-2024 gas year

	Transmission network Entry point			Transmission network Exit point		
	Iberian VIP	LNG Terminal	Underground Storage	Iberian VIP	LNG Terminal	Underground Storage
Quarterly	1,3	1,3	-	1,3	1,3	-
Monthly	1,5	1,5	-	1,5	1,5	-
Daily	2,0	2,0	1,0	2,0	2,0	1,0
Intradaily	2,2	2,2	1,1	2,2	2,2	1,1

The multipliers applied to the quarterly, monthly and daily products in the 2023-2024 gas year have remained unchanged since the 2013-2014 gas year. From the 2015-2016 gas year, reference prices were also established for the intraday capacity product in the VIP Iberico. From the 2016-2017 gas year, the existence of intraday products was also extended to entry and exit through the LNG Terminal and entry through Underground Storage. The multiplier for intraday products has been constant since the 2016-2017 gas year.

Article 28(3)(a) of the Tariff Network Code mentions five criteria to be taken into account when approving multipliers by the national regulator, namely: i) the balance between facilitating short-term gas trade and providing long-term signals for efficient investment in the transmission network; ii) the impact on transmission service revenues and income recovery; iii) the need to avoid cross-subsidisation between network users and increase the reflection of costs in reserve prices; iv) situations of physical and contractual congestion; and v) the impact on cross-border flows.

The first criterion, a balance between short-term gas trade and long-term signals for efficient investment, is considered to be met insofar as the multipliers in force have not prevented market agents from reserving capacity in the VIP Iberico at the various horizons of the capacity products according to their commercial supply strategy: in the VIP Iberico there has been a transfer from contracting annual capacity to capacity in shorter maturity products since the 2020-2021 gas year (see Figure 3-1), together with a total contracting of the LNG terminal's technical regasification capacity through the annual product, since the 2019-2020 gas year. Given the permanence of the multipliers, this change in the supply strategy of market agents is essentially the result of the price relationship between LNG and natural gas and the long-term contracts held by agents operating in the Iberian Peninsula and, in particular, in Portugal. The value of the multipliers in capacity products with a term of less than one year must ensure that, on the one hand, long-term reserves are not discouraged in order to justify long-term investments in infrastructure and the fair recovery of revenues by infrastructure operators and, on the other hand, that barriers to short-term contracting are not created, jeopardising tariff flexibility and the entry of new agents into the market. In addition, the multipliers should increase as the maturity of the product decreases, encouraging capacity contracting that gives greater predictability to system management.

The second criterion, the impact on revenue recovery, is ensured through the stability of the multipliers, which has allowed ERSE to estimate the use of the VIP Iberico over the various time horizons with greater certainty, mitigating the risk of revenue deviations due to the multipliers[79].

With regard to the third criterion, cross-subsidisation between network users is avoided as the same multipliers are applied to the two supply points in the Portuguese system, represented by the VIP Iberico and the LNG terminal in Sines.

[79] The main reason for the volatility of the revenues recovered at the points in the transmission network is the demand for gas from the power stations, which depends on the dynamics of the wholesale electricity market, as well as weather conditions. The level of the multipliers applied in VIP Iberico does not contribute to this volatility.

Regarding the fourth criterion, on situations of physical and contractual congestion, this situation is not applicable to Portugal since there have not yet been situations of physical congestion in the VIP Iberico, nor the application of risk premiums in the respective capacity auctions.

Finally, for the criterion relating to cross-border flows, it is considered that the current multipliers are neutral for cross-border flows, since the same multipliers apply in both directions of the VIP Iberico and both entry points to the Portuguese system.

The defined multipliers condition the behaviour of users, since each market agent will adopt a temporal use in order to minimise their bill.

Considering that the level of multipliers for short-term capacity products must ensure that revenues are recovered without constituting a barrier to short-term contracting, an exercise was carried out to calculate the level of multipliers for short-term products, ensuring that the revenues obtained from short-term products, for each quarterly, monthly and daily maturity, are equivalent to the revenues provided by the annual product.

The exercise was carried out on the basis of daily contracted capacity data extracted from the ENTSOG Transparency Platform[80], for the period between 1 January 2020 and 31 December 2023, for two of the entry points into the RNTG (VIP Iberico and LNG terminal) and the same two exit points from the RNTG (VIP Iberico and LNG terminal). No information was analysed for the entry or exit points of underground storage, since the price is zero, as discussed in section 8.1.

Table 8-2 shows the level of multipliers obtained considering the aforementioned methodology of equivalence between the invoicing of the annual product and the short-term product.

Table 8-2 - Short-term multipliers for the 2024-2025 gas year

	Transmission network Entry point			**Transmission network Exit point**		
	Iberian VIP	LNG Terminal	Underground Storage	Iberian VIP	LNG Terminal	Underground Storage
Quarterly	1,18	1,18	-	1,18	1,18	-
Monthly	1,35	1,35	-	1,35	1,35	-
Daily	1,94	1,94	1,00	1,94	1,94	1,00
Intradaily	2,13	2,13	1,10	2,13	2,13	1,10

Source: ERSE calculations

[80] https://transparency.entsog.eu/#/zones/data?zones=

The comparison between the multipliers in force and those now approved is shown in Table 8-3.

Table 8-3 – Comparison between current and new multipliers

	Portugal (Entry = Exit)	
	Current	Proposed
Quarterly	1,3	1,18
Monthly	1,5	1,35
Daily	2	1,94
Intradaily	2,2	2,13

Multiplier values similar to those currently in force are obtained, though slightly inferior in all time horizons

Although the multipliers now approved are similar to those in force, they derive from the application of a new quantifiable methodology and are therefore more robust and justifiable. ERSE believes that the change, although small, is in line with the comments made by agents on previous occasions [81], which favour the stability of multipliers.

8.3 SEASONAL FACTORS

The Tariff Network Code also establishes rules for the levels of seasonal factors in Article 13(2), applicable to standardised firm capacity products at interconnection points. ERSE informs that it intends to continue not applying seasonal factors to standardised firm capacity products at interconnection points [82].

[81] For example, in the responses to ERSE's public consultation No. 66.

[82] It should be noted that there is a definition of seasonal factors, which vary with the month, applicable to the capacity used in the flexible tariff options, which are intended exclusively for exit points for customers at HP. As these seasonal factors do not apply to interconnection points with Spain, they fall outside the scope of the public consultation provided for in Article 28(1).

9 RELATION TO OTHER EUROPEAN LEGISLATION

This chapter provides a general description of the most relevant legal and regulatory elements that have a direct influence on the decision regarding gas transmission tariff structures.

9.1 HYDROGEN AND GAS DECARBONISATION PACKAGE

Natural gas (fossil methane) makes up around 95% of the gaseous fuels currently consumed in the European Union (EU). Gaseous fuels account for around 25% of the EU's total energy consumption, including around 20% of electricity production and 39% of heat production [83]. As well as being an energy carrier, gaseous fuels are also a fundamental raw material for industrial processes and are one of the sources of flexibility for an energy system that is increasingly based on renewable energy sources.

As part of the second batch of proposals under the Fit-for-55" measures [84], on 15 December 2021, the Commission presented proposals to amend Gas Directive 2009/73/EC on common rules for the internal markets in natural gas and renewable gases and hydrogen and Regulation (EC) No 715/2009 on the hydrogen and decarbonised gas market (via COM/2021/803 final and COM/2021/804 final, respectively).

On 28 March 2023, the European Council reached a general approach on proposals to amend Gas Directive 2009/73/EC[85] and Regulation (EC) No 715/2009 [86]. On 27 November 2023, the Council and the European Parliament reached a provisional agreement on the regulation establishing common rules for the internal markets in natural gas, renewable gases and hydrogen [87]. The regulation is part of the package on hydrogen and decarbonised gas markets, which also includes a directive. Both the regulation and the directive are part of the Fit-for-55 package. The Council and Parliament reached a provisional agreement on the directive on 27 November 2023[88]. The final versions are expected to be published in the Official Journal in May 2024.

[83] Source: https://ec.europa.eu/commission/presscorner/detail/pt/qanda_21_6685 and https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52021PC0803&qid=1640002501099.

[84] Package Fit-for-55 - https://www.consilium.europa.eu/en/policies/green-deal/fit-for-55-the-eu-plan-for-a-green-transition/

[85] Available at: https://data.consilium.europa.eu/doc/document/ST-7911-2023-INIT/en/pdf.

[86] Available at: https://data.consilium.europa.eu/doc/document/ST-7909-2023-INIT/en/pdf.

[87] Available at: https://data.consilium.europa.eu/doc/document/ST-16522-2023-INIT/en/pdf.

[88] Available at: https://data.consilium.europa.eu/doc/document/ST-16516-2023-INIT/en/pdf.

In the general approach reached on the amendments to Regulation (EC) No 715/2009, the Council clarified the rules on tariffs and tariff discounts for hydrogen and renewable gases requesting connection to the gas network and gave Member States more flexibility in setting them. In addition, it differentiated the tariff discounts for renewable gases (100%) and for low-carbon gases (75%) in the natural gas system.

Regarding the certification of storage system operators, the provisions of the Gas Storage Regulation adopted in June 2022 are integrated and introduce a 100% discount on capacity-based transmission and distribution tariffs for underground gas storage facilities and LNG facilities. The general approach also establishes levels for hydrogen blending in the natural gas system of up to 2% by volume (instead of 5%) in order to ensure harmonised gas quality.

It is worth highlighting, with respect to the general approach, the Council's proposed extension until 2035 of the transition phase for the application of detailed rules to hydrogen and the addition to the definitions of "low carbon" of the reference to the fossil fuel comparison parameter established in the Renewable Energy Directive, in order to guarantee a level playing field in the assessment of the total greenhouse gas emissions footprint of the different gases.

9.2 EU Gas Storage Regulation

Gas storage plays an important role in guaranteeing the security of supply of the European Union (EU), covering, in a normal winter, 25% to 30% of the gas consumed throughout the EU [89].

Given their relevance to the security of energy supply and other essential security interests, both at national and European Union level, underground gas storage facilities are considered critical infrastructure within the meaning of Council Directive 2008/114/EC. In this context, Member States are encouraged to take into account the measures introduced by Regulation (EU) 2022/1032 of the European Parliament and of the Council amending Regulations (EU) 2017/1938 and (EC) No 715/2009 as regards gas storage in their national energy and climate plans and in the progress reports adopted pursuant to Regulation (EU) 2018/1999 of the European Parliament and of the Council.

[89] Source: https://commission.europa.eu/strategy-and-policy/priorities-2019-2024/european-green-deal/eu-action-address-energy-crisis_pt. For up-to-date data on storage levels by member state, see: https://agsi.gie.eu/#/.

Based on the European Commission's analysis, in particular on the adequacy of measures to secure gas supply and the enhanced risk-preparedness analysis at Union level carried out in February 2022, each Member State should ensure, in principle, that underground gas storage facilities located on its territory and directly connected to a market area of that Member State are filled to at least 90% of their capacity at Member State level by 1 November each year (filling target), with a series of intermediate targets (filling trajectory) the following year.

From 2023, the monitoring of gas storage levels is mandatory in order to avoid the sudden withdrawal of gas from underground gas storage facilities in the middle of winter. In order to avoid unjustified gas price increases in the phase of mandatory gas procurement for filling, under Regulation (EU) 2022/1032, regulators will be able to apply a discount of up to 100% to capacity-based transmission and distribution tariffs at the entry and exit points of storage facilities, both for underground gas storage facilities and LNG facilities, making storage more attractive to market participants.

In order to guarantee the EU's energy supply at affordable prices, the European Commission and the Member States have set up an EU platform for the common procurement of gas, LNG and hydrogen[90]. This is a voluntary coordination mechanism, which supports the purchase of gas and hydrogen for the Union [91].

To strengthen the mechanisms for action at Union level, Regulation (EU) 2022/1369, of 5 August 2022 on coordinated measures to reduce gas demand, laid down rules to deal with a situation of serious difficulties in gas supply, in a spirit of solidarity [92]. This Council Regulation defines a set of rules, namely a voluntary reduction in gas demand in the period between 1 August 2022 and 31 March 2023 of, at least 15%, compared to the average gas consumption during the previous five consecutive years in the same period [93].

[90] Approved by Regulation (EU) 2022/2576.

[91] More information at: https://energy.ec.europa.eu/topics/energy-security/eu-energy-platform_en. EU countries are obliged to aggregate demand for gas volumes equivalent to 15% of their respective storage filling obligations. Beyond 15%, aggregation will be voluntary, but based on the same mechanism.

[92] It should be noted that the solidarity mechanism as an instrument to mitigate the effects of a major emergency situation was introduced by Regulation (EU) 2017/1938 of the European Parliament and of the Council.

[93] Demand reduction monitoring is carried out by the Directorate-General for Energy and Geology. More information at: https://www.dgeg.gov.pt/pt/areas-setoriais/energia/planeamento-energetico-e-seguranca-de-abastecimento/seguranca-de-abastecimento/monitorizacao-da-reducao-do-consumo-de-energia/

Following the adoption of this Regulation, Member States reduced their gas demand by 19% between August 2022 and January 2023, compared to the average of the last five years [94].

The European Commission's analysis [95] concluded that, despite the observed reduction, a continuous 15% reduction in demand over a 12-month period until the end of March 2024 is necessary to ensure that Member States can meet the 90% storage target set out in Regulation (EU) 2017/1938, which is imperative for security of gas supply and to avoid any supply deficit in the winter of 2023-2024. These measures were approved by Council Regulation (EU) 2023/706 of 30 March 2023 amending Regulation (EU) 2022/1369 which extended the gas demand reduction measures by one year and strengthened the reporting and monitoring of its implementation. In March 2024, a new political agreement was reached between the European Union's energy ministers to maintain the demand reduction measures until 31 March 2025. EU Member States are encouraged to reduce their gas consumption by at least 15% compared to their average gas consumption in the period from 01 April 2017 to 31 March 2022. These measures were proposed by the European Commission in its report on the review of Regulation 2022/1369 [96].

[94] According to the Report from the Commission to the European Parliament and the Council on certain aspects of gas storage based on Regulation (EU) 2017/1938 of the European Parliament and of the Council (COM/2023/182 final), of 27 March 2023.

[95] Report from the Commission to the Council on the review of Regulation (EU) 2022/1369 on coordinated measures to reduce gas demand (COM/2023/173 final), of 20 March 2023.

[96] COM/2024/88 final.

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