CONSULTATION DOCUMENT

502/2022/R/GAS

TARIFF REGULATORY CRITERIA FOR THE NATURAL GAS TRANSMISSION AND METERING SERVICE FOR THE SIXTH REGULATORY PERIOD (6PRT)

Final guidelines

Consultation document for the formation of rulings within the framework of the proceedings initiated with resolution 617/2021/R/GAS of the Italian Regulatory Authority for Energy, Networks and Environment (ARERA) of 23 December 2021

Markets of incidence: natural gas

18 October 2022

Whereas

This consultation document is part of the proceedings initiated with a resolution of the Italian Regulatory Authority for Energy, Networks and Environment (hereinafter: ARERA) of 23 December 2021, 617/2021/R/GAS, for the formation of rulings on tariffs and quality of the natural gas transmission and metering service, for the sixth regulatory period (6PRT) and, taking into account the outcomes of the consultation document 213/2022/R/GAS OF 19 MAY 2022, sets out ARERA's final guidelines on the determination of revenues and reference prices of the natural gas transmission and metering service for the 6PRT, commencing in 2024. However, the criteria for determining the revenues recognised to gas transmission service operators as a result of the conclusion of the proceedings initiated with resolution 271/2021/R/COM of 28 June 2021 concerning the alignment of the criteria for recognising costs and the ROSS approach are deferred to a subsequent consultation document.

Interested parties are invited to submit their comments and recommendations to ARERA in written form by filling in the interactive form available on ARERA's website or, alternatively, at the certified e-mail address (protocollo@pec.arera.it) by ***21 November 2022****.*

Reference is made to the Information Notice on Personal Data Processing, regarding the publication and manner of publication of comments. With reference to the publication of comments, as referred to in point 1, letter b) of the same Information Notice, it is further specified that participants in the consultation who wish to safeguard the confidentiality of data and information, other than personal data, must justify this request at the same time as sending their contribution to this consultation, highlighting in appropriate appendices the parts that they intend to withhold from publication. In this case, the interested parties must also send the digital version without the confidential parts, intended for publication, if the request for confidentiality is accepted by the ARERA's Offices.

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INFORMATION NOTICE ON PERSONAL DATA PROCESSING

pursuant to Art. 13 of EU Regulation 2016/679 (GDPR)

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The Data Controller is ARERA, with registered office at Corso di Porta Vittoria 27, 20122 Milan, e-mail: info@arera.it, certified e-mail: protocollo@pec.arera.it, switchboard: +39 02655651.

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Data subjects, where applicable, also have the right to lodge a complaint with the Data Protection Authority, as supervisory authority, or to take legal action.

TABLE OF CONTENTS

PART I
INTRODUCTORY ASPECTS

1. Procedural framework and scope of the consultation

1.1 This consultation document is part of the proceedings initiated with resolution 617/2021/R/gas of 23 December 2021 (hereinafter: resolution 617/2021/R/gas) for the adoption of rulings on tariffs and quality of the natural gas transmission and metering service, for the sixth regulatory period (6PRT), commencing 1 January 2024.

1.2 As part of these proceedings, in the consultation document 213/2022/R/gas of 19 May 2022, (hereafter: DCO 213/2022/R/GAS), ARERA outlined its initial guidelines on the criteria for determining the allowed revenue and reference prices of the natural gas transmission and metering service, within the framework of the provisions of the European legislation on the harmonisation of natural gas transmission service tariff structures set out in Commission Regulation (EU) 460/2017 of 16 March 2017 (TAR NC).

1.3 As part of the proceedings on tariffs and quality of the natural gas transmission and metering service for the 6PRT, ARERA's guidelines on the incentive and efficiency criteria for the transmission service, as set out in the consultation documents 616/2021/R/GAS of 23 December 2021 (hereinafter: DCO 616/2021/R/GAS) and 336/2022/R/GAS of 19 July 2022 (hereinafter: DCO 336/2022/R/GAS), specifically on the subject of incentives for keeping depreciated networks in operation, efficiency criteria for the development of transmission networks in newly methanised areas, and the treatment of revenues from the operation of dual fuel plants. The outcomes of this consultation process will be the subject of specific measures and/or the final ruling on tariff criteria, but are not dealt with in this document except insofar as they are strictly related to the criteria for recognising service costs (such as, for example, the introduction of specific assets or the revision of regulatory lifetimes).

1.4 Also taking into account what emerged as a result of DCO 616/2021/R/GAS, with its resolution 195/2022/R/GAS of 3 May 2022 (hereinafter: resolution 195/2022/R/GAS), ARERA mandated Snam Rete Gas S.p.A. to define a methodology for evaluating the health of the transmission facility, to support decisions to switch obsolete or fully depreciated transmission facilities, based on transparent procedures that can be verified *ex-post*.

1.5 In relation to the development of the transmission network in newly methanised areas, with resolution 470/2022/R/GAS of 4 October 2022, ARERA also initiated proceedings to comply with Council of State ruling no. 4241/2022 on the subject of coordination between transmission and distribution operators and the criteria for evaluating plans for new developments in the transmission network. The results of these proceedings will be considered when adopting the rulings on the efficiency of the development of the transmission network in newly methanised areas, also taking into account the guidelines already expressed in DCO 616/2021/R/GAS and 336/2022/R/GAS and the results of this consultation.

1.6 It is also worth mentioning that ARERA has initiated a proceeding for the definition of general criteria for the determination of the recognised cost according to the ROSS approach, to be applied to all the regulated facility services of the electricity and gas sectors (resolution 271/2021/R/COM of 28 June 2021; hereinafter: resolution 271/2021/R/COM), providing for its conclusion by 31 December 2022. This resolution was followed by the consultation document 615/2021/R/COM of 23 December 2021 (hereinafter: DCO 615/2021/R/COM) and the consultation document 317/2022/R/COM of 12 July 2022 (hereinafter: DCO 317/2022/R/COM), in which guidelines for the development of *ROSS-base* regulation were presented.

1.7 As far as the gas transmission service is concerned, as assumed in DCO 317/2022/R/COM, the first application of the *ROSS-base* criteria is envisaged for the period starting in 2024, i.e. for the 6PRT, and, starting in 2026 (after a two-year experimental application period), the application of the *ROSS-integrale* criteria to the main transmission operator, with the aim, over time, of extending the application of the *ROSS-integrale* to the other transmission operators as well. The precise definition of the criteria for determining the allowed revenue of gas transmission service operators must therefore necessarily take into account the general principles and criteria established as a result of the proceedings initiated with resolution 271/2021/R/COM. ARERA therefore intends to submit possible criteria for the recognition of specific costs for the transmission service to a further consultation document.

1.8 Finally, it is necessary to point out the following rulings that will necessarily have to be taken into account when defining the criteria for tariff regulation of the natural gas transmission service for the 6PRT:

a) with resolution 614/2021/R/COM ARERA approved the "Criteria for determining and updating the rate of return on invested capital for facility services in the electricity and gas sectors for the period 2022-2027 (TIWACC 2022-2027)", which provide, *inter alia*, for an update of the WACC for the years 2023 and 2024 according to a trigger logic; this aspect is particularly relevant for the purposes of estimating the revenues and charges for the year 2024 (see Appendix to this consultation document), which is necessarily made on the basis of the value of the remuneration rate currently in force;
b) with resolution 279/2022/R/COM of 28 June 2022 (hereinafter: resolution 279/2022/R/COM), ARERA initiated proceedings for the implementation of the Prime Ministerial Decree of 29 March 2022 concerning the works and facilities necessary to phase out the use of coal in Sardinia;
c) with resolution 448/2022/R/GAS of 27 September 2022 (hereinafter: resolution 448/2022/R/GAS), ARERA initiated a proceeding to comply with rulings 6096 and 6098 of 2022 of the Council of State, aimed at adopting flexibility and affordability measures for the transmission tariff system for entities with greater natural gas consumption, in application of Decree Law 83/12; as part of this resolution, the assessments on the introduction of further

flexibility measures through the provision of short-term allocations were postponed to the proceeding to revise the tariff criteria for the 6PRT;

d) with resolution 462/2022/R/COM of 29 September 2022 (hereinafter: resolution 462/2022/R/COM), when updating, as from 1 October 2022, the tariff components intended to cover the general charges and additional components of the electricity and gas sectors, ARERA confirmed the guidelines set out in DCO 213/2022/R/GAS on the subject of reducing the time interval between the collection of the revenue from the additional components of the natural gas transmission service – including the additional charge for the recovery of revenues CV_{FC} – and the corresponding payment to CSEA, amending the RTTG with effect from 1 January 2023 in order to provide that the revenue from such components is to be paid, on a monthly basis, by the 15th day of the second month following the month in which the relevant billing took place, with effect from 1 January 2023.

1.9 In this consultation document, ARERA sets out its final guidelines on the criteria for determining reference revenues, as well as on the determination of charges for the natural gas transmission and metering service for the 6PRT. These criteria will be supplemented with the procedures for determining the allowed revenue of operators, as a result of the proceedings initiated with resolution 271/2021/R/com.

1.10 In view of the rules set out in the TAR NC containing specific requirements for national regulators on the consultation process (Articles 26 and 28), as well as the rules relating to the analysis by the Agency for the Coordination of Energy Regulators – ACER (Article 27), it is necessary to ensure the adoption of the final ruling setting out the criteria for the tariff regulation of the natural gas transmission service no later than the first days of April 2023 (with effect from the year 2024), and the publication of the information on the tariff levels for 2024 referred to in Articles 29 and 30 of the TAR NC by 31 May 2023.

1.11 With regard to the timing for the adoption of the tariff regulatory criteria for the 6PRT, the contents of Table 1 of DCO 213/2022/R/GAS are confirmed. Likewise, reference is made in full to that DCO for a description of the objectives of ARERA's intervention, and for a detailed examination of the regulatory and legislative framework, as well as market conditions and prospects.

1.12 The guidelines expressed in this consultation document take into account the comments received on the previous consultation documents within the framework of the proceedings initiated with resolution 617/2021/R/GAS. In view of the breadth and complexity of the topics dealt with, only those topics most discussed in the previous consultation phases will be explained in more detail in this document. The analysis of the issues related to the ROSS approach is instead postponed to the further in-depth analysis and consultation phases envisaged within the framework of the proceedings initiated with resolution 271/2021/R/COM.

1.13 For more details on the guidelines formulated by ARERA in previous consultations, referred to in this document only where indispensable, please refer to the above-mentioned documents in full. Similarly, for more detailed information on the responses of those who participated in the previous consultations, please refer to the comments published on the ARERA's website www.arera.it.

2. Document structure

2.1 In addition to this introductory part, this document includes:

a) Part II, in which the final guidelines on the criteria for determining the reference revenues for charges are set out;
b) Part III, which contains the final guidelines on the determination of transmission service charges;
c) Part IV, in which the final guidelines on the determination of charges for the transmission metering service are set out;
d) Part V, in which the final guidelines on revenue compensation and recovery mechanisms are set out;
e) Part VI, which contains the final guidelines on additional charges.

2.2 Also published in the Appendix to this consultation document are:

a) in English, an executive summary and the template made available by ACER with the consultation requirements of the TAR NC, in order to facilitate ACER's assessments under Article 27 of the TAR NC on the guidelines issued;
b) the document containing the data and information required under the TAR NC, including simulations of the level of revenues and charges for the year 2024.

2.3 ARERA will make an English language version of this document available on its website. The main transmission operator will be in charge of making the simplified tariff model available in a specific section dedicated to stakeholder consultation on regulatory criteria and tariff levels for the 6PRT.

PART II
GUIDELINES ON CRITERIA FOR DETERMINING REFERENCE REVENUES FOR CHARGES

3. Whereas

3.1 This Part deals with the ARERA's final guidelines on the criteria for determining the reference revenues for transmission and metering service charges on the transmission network, in particular on the:

a) duration of the regulatory period;
b) structure of reference revenues for the determination of charges;
c) procedures for the transition towards regulatory criteria by expenditure and service objectives (referred to as ROSS) and decoupling between the reference revenues relevant for the determination of tariff charges and the allowed revenue of each operator;
d) incentive and efficiency criteria;
e) treatment of allowances excluded from the application of the ROSS methodology (costs related to the Emission Trading System, costs related to network losses, fuel gas and unaccounted-for gas (UFG), costs for the operational balancing service).

4. Commencement and duration of the regulatory period

4.1 In relation to the commencement and duration of the new regulatory period, in DCO 213/2022/R/GAS ARERA recommended confirming a duration of 4 years, starting from 1 January 2024, providing that any changes to the duration of the new regulatory period should also be considered in coordination with the proceedings for the reform of the tariff regulatory criteria according to the *ROSS-base* approach.

4.2 In the consultation, one operator recommended a regulatory period of 5 years, which is consistent with the typical durations of the corporate plans of the major operators that would be used in ROSS-type (full) regulation.

4.3 ARERA agrees that extending the duration of the regulatory period to 5 years is a possible option (maximum possible duration under the TAR NC[1]). However, with a view to the transition to the *ROSS-integrale* model, also in consideration of the fact that the final decision on the time horizon of the business plans has not yet been made, it is deemed appropriate to confirm the orientation of defining the duration of the regulatory period as 4 years (from 1 January 2024 to 31 December 2027), in continuity with the current duration of the regulatory period and in line with the regulation of the power transmission service. Any need to revise the

[1] Article 27, paragraph 5 of the TAR NC provides that the final consultation procedure (Article 26) and the resulting decision of the Italian national regulatory authority (Article 27, paragraph 4) must be repeated at least every five years.

duration of the regulatory period, also with a view to aligning tariff regulatory criteria and synchronising them with the timing of the WACC regulatory period (the "PWACC", see chapter 15 of DCO 615/2021/R/COM), may be assessed as a result of the proceedings initiated with resolution 271/2021/R/COM.

S 1.Comments on the length of the regulatory period.

5. Structure of reference revenues

5.1 ARERA intends to confirm that for the 6PRT, the reference revenues for the determination of the transmission service tariff charges will be broken down according to the same revenue shares currently provided for in the 5PRT, i.e. the shares covering:

a) return on recognised net invested capital;
b) economic-technical depreciation;
c) operating costs;
d) incentives recognised in previous regulatory periods as an increase in the return on capital, as well as new incentive mechanisms;
e) costs related to fuel gas, network losses and UFG;
f) costs related to the Emissions Trading System;
g) costs related to the hourly balancing service of the system.

6. Reconciliation with ROSS methodology for capital and operating costs

6.1 The criteria for determining the allowed revenues of the transmission operators, both in relation to future expenditure, managed through the ROSS approach, and in relation to the invested capital existing at 31 December of the year preceding the year of transition to the ROSS approach, will be defined as a result of the proceedings initiated with resolution 271/2021/R/COM, which envisages, *inter alia*, the hypothesis of aligning the cost recognition criteria among the various energy infrastructure services (see Part IV of DCO 317/2022/R/COM).

6.2 Following the publication of the resolution containing the general criteria for tariff regulation according to the *ROSS-base* model, expected by December 2022, ARERA intends to set out the implementation criteria for the transmission service in a further consultation document.

6.3 This consultation document presents the guidelines for the determination of reference revenues relevant only for the definition of transmission charges for the first year of the new regulatory period.

Reconciliation elements with the ROSS methodology

6.4 ARERA, in line with what was envisaged in DCO 317/2022/R/COM, intends to confirm the reconciliation elements proposed in DCO 213/2022/R/GAS, which allow the ROSS criteria to be applied to the expenditure incurred starting from the first year of the 6PRT, i.e. from 2024. Most of the comments received on the reconciliation elements proposed in the DCO 213/2022/R/GAS concern, in fact, implementation aspects of the ROSS methodology which are not dealt with in the present proceedings (e.g. efficiency incentives, determination of the capitalisation rate, criteria for determining depreciation) and/or which relate to the areas of alignment of the regulatory criteria between energy infrastructure services; these aspects will be dealt with in the proceedings initiated with resolution 271/2021/R/COM and, consequently, are not addressed in this consultation document.

6.5 For reconciliation purposes, the recommendation is confirmed whereby:

a) the revenues for the determination of the transmission tariffs are determined according to the principle of "tariff decoupling" (see points 22.19 *et seq.* of DCO 317/2022/R/COM) between:
   i. the reference revenues for the determination of the tariff charges of year *t*, determined on the basis of the information available in year *t-1*;
   ii. the allowed revenue, determined according to the ROSS approach, which also takes into account, *ex-post* (i.e., once actual costs are known), deviations between total expenditure baseline and actual total expenditure and efficiency incentives;
b) the year 2024 is the first year of application of the ROSS methodology;
c) the reference revenues relevant for the determination of the charges for the year 2024 include:
   i. the capital costs relating to asset realised up to the year 2023 ("legacy"), determined according to the criteria in force in the 5PRT and taking into account the guidelines on the treatment of the capital stock at the date of the start of the ROSS (see points 22.10 *et seq.* of DCO 317/2022/R/COM) and the outcome of the proceedings initiated with resolution 271/2021/R/COM;
   ii. the remuneration of work in progress, as set out at point 6.10 *et seq.*;
   iii. the recognised operating costs as set out at point 6.17 *et seq.*;
d) the efficiency incentives deriving from the comparison between the expenditure baseline and the actual total expenditure, according to the mechanisms of the ROSS approach, which will be defined as a result of the proceedings initiated with resolution 271/2021/R/COM, will count for the purposes of determining the allowed revenue of each operator.

S 2.Comments on the reconciliation with ROSS criteria.

<u>Criteria for determining capital costs</u>

<u>General criteria</u>

6.6 As already envisaged in DCO 213/2022/R/GAS, for the sole purpose of determining the reference revenue for the 2024 transmission tariffs, the asset up to the year 2023 are taken into account, confirming the current criteria for determining and updating the regulatory net invested capital pursuant to Article 4 of the RTTG in force in the 5PRT. In particular, it is confirmed that the recognition of the value of fixed assets takes place on the basis of the revalued historical cost principle, with the application of the gross investment deflator surveyed by ISTAT, provided that the related investments are compatible with the efficiency and safety of the system, are carried out according to economic criteria and are included in the Ten-Year Network Development Plan without having received a negative evaluation.

6.7 In addition, the provisions concerning the adjustment accounting items and the incentive treatment of contributions are to be confirmed, while providing for a single incentive treatment in relation to the latter. In particular, for the purpose of calculating depreciation, the value of public capital contributions received during the regulatory period to cover infrastructure costs is not deducted from the gross fixed assets pertaining to the "Pipelines" asset for a period of 5 years from obtaining the contribution (and in any case up to a maximum threshold equal to 10% of the value of the contribution received in the case of allocation to another category of asset).

6.8 The real pre-tax rate of return on net invested capital is determined and updated in accordance with the criteria set out in the 2022-2027 TIWACC (Annex A to resolution 614/2021/R/COM); for investments made after 31 December 2013 and before 31 December 2016, the provision according to which the value of the rate of return is increased by 1% is confirmed.

6.9 The methodologies for determining and updating the regulatory net invested capital for the purpose of determining the allowed revenue of transmission service operators will be defined as a result of the proceedings initiated with resolution 271/2021/R/COM.

Treatment of assets under development

6.10 In DCO 213/2022/R/GAS, ARERA envisaged the introduction of a criterion for the remuneration of assets under development decreasing according to the year in which the expenditure was incurred, based on the criteria for the recognition of assets under development already in force for power transmission. As a result of the consultation, the transmission operators suggested increasing the level of remuneration recognised, increasing the time depth compared to what ARERA had proposed, and applying the new criterion only to new fixed assets. As part of the consultation, one operator also proposed the possibility of recovering costs associated with the alienation of work in progress.

6.11 With regard to the treatment of assets under development, for the purpose of determining the reference revenues for the year 2024, ARERA intends to confirm the proposed guidelines, providing that, for assets under development as at 31 December 2023, the differentiated rates of return will apply as follows:

a) for assets under development relating to expenditure incurred in the years 2022 and 2023, applying a rate equal to the value of the WACC determined in accordance with the 2022-2027 TIWACC, but assuming a debt-to-equity ratio of 4;

b) for assets under development relating to expenditure incurred in the years 2020 and 2021, applying a rate equal to the value of the parameter referred to in paragraph 3.7 of the 2022-2027 TIWACC;

c) for assets under development relating to expenditure incurred in years prior to 2020, applying a rate of return of zero.

6.12 In general terms, ARERA does not consider it appropriate to introduce forms of automatic recovery of the costs associated with the divestment of works in progress: the purpose of the regulatory interventions, including that relating to the decreasing level of remuneration of works in progress depending on the year in which the expenditure was incurred (see point 6.11), is in fact to make transmission operators more responsible with respect to the identification of projects to be developed and to provide adequate incentives for the rapid start-up of investments. ARERA, however, recognises that there may be specific cases in which to assess a possible recognition of such alienations; this is particularly relevant in the case of costs incurred for the drafting of analyses and preliminary studies on projects, in any case included in the Plans and not subject to critical evaluations by ARERA, which are then not realised for reasons not dependent on the transmission operator. In this regard, ARERA intends to provide that transmission operators may submit, within the framework of the presentation of tariff proposals, a request for the recognition of these costs, adequately justifying the reasons that led to the divestment.

6.13 The treatment of assets under development for the purposes of determining the allowed revenue of the operators and the tariff levels for the years after 2024 shall be regulated within the ROSS methodology, taking into account the guidelines expressed in DCO 317/2022/R/COM (see Chapter 16) and the outcome of the proceedings initiated with resolution 271/2021/R/COM.

Depreciation and regulatory useful lives

6.14 For the purpose of determining the reference revenues for the year 2024, ARERA intends to confirm, in substance, the current criteria for determining the economic-technical depreciation, based on the conventional duration for each type of asset as reported in Table 1.

Table 1: Conventional tariff duration of asset categories

Asset category	Conventional duration (years)
Buildings	40
Pipelines (pipelines and shunts)	50
Compressor stations	20
Pressure regulation and reduction stations	20
Meters	20
Final customer meters	20
Information systems	5
Tangible fixed assets (office machines, vehicles, mobile telephones)	5
Other tangible fixed assets	10
Intangible fixed assets	5
Land	-

6.15 As a result of the proceedings initiated with resolution 271/2021/R/COM, any need to revise the regulatory useful lives may be assessed, also with a view to aligning the regulatory criteria (see points 22.29 and 22.30 of DCO 317/2022/R/COM).

6.16 ARERA intends, however, to confirm, as described in DCO 336/2022/R/GAS, (i) the advisability of evaluating an extension of the regulatory useful life of the pipeline asset limited to pipelines that have technical characteristics such as to permit their use for the transmission of hydrogen, and (ii) the introduction of a specific asset, with a regulatory useful life shorter than that of the pipeline asset, dedicated to extraordinary maintenance costs exclusively aimed at keeping the pipeline in operation, which do not entail its switching, even partially (within the limits of a predetermined threshold), to be amortised over 15-20 years. ARERA's guidelines on these issues will be expressed in a specific consultation document, as a result of the proceedings initiated with resolution 271/2021/R/COM.

S 3. Comments on the criteria for determining the capital costs for determining the relevant reference revenues for the 2024 tariffs.

Criteria for determining the operating cost baseline

6.17 For the determination of the operating cost relevant for the purposes of the reference revenues for 2024, ARERA confirms its intention to consider the operating costs actually incurred by the transmission operators and, possibly, a sharing of the greater/lower efficiencies achieved during the 5PRT as also envisaged in DCO 317/2022/R/COM (see point 22.8), on the basis of the outcome of the proceedings initiated with resolution 271/2021/R/COM.

6.18 The actual operating costs comprise the costs actually incurred in the financial year 2021 and attributed to the transmission service, and are determined, within the limits set out in the letter c) of the following point 6.19, on the basis of the separate annual accounts prepared in accordance with the Integrated Accounting Unbundling Text (Annex A to resolution 137/2016/R/COM, TIUC), net of costs attributable to other activities, revenues from internal supplies of goods and services and capitalised costs.

6.19 ARERA also confirms that:

a) if there is an abnormal increase in a specific cost item incurred in 2021 compared to that incurred in previous years, where not clearly justified by the transmission operator, the actual operating costs shall be determined on the basis of an average of the specific allowance in the years 2019-2021;

b) the *ex-post* comparison between the expenditure baseline (as defined as a result of the proceedings initiated with resolution no. 271/2021/R/com) and the actual expenditure relating to 2024, which is relevant for the purpose of determining the allowed revenue, shall take into account any emerging costs, which could not be foreseen at the time the baseline was defined or which arise from extraordinary situations;

c) the calculation of the actual operating costs excludes the allowances attributable to the scope of non-recognisable operating costs (see point 22.22 *et seq.* of DCO 317/2022/R/COM) defined as a result of the proceedings initiated with resolution 271/2021/R/COM, as well as the specific allowances for the transmission service referred to in paragraph 7.4 of the RTTG in force for the 5PRT.

6.20 The modalities for determining and updating the operating cost baseline for the years after 2024 will be defined as a result of the proceedings initiated with resolution 271/2021/R/COM.

S 4.Comments on the criteria for determining operating costs for determining the reference revenues for 2024.

7. **Incentive and efficiency criteria**

<u>Incentives for the development of new transmission capacity</u>

7.1 ARERA intends to confirm the proposal not to apply, in the 6PRT, incentive criteria based on increases in the rate of return, without prejudice to the guarantee of recognition of the additional return for investments that came into operation in previous regulatory periods, pursuant to the respective ARERA resolutions no. 166/05, ARG/gas 184/09, 575/2017/R/GAS and 114/2019/R/GAS.

<u>Incentive for keeping depreciated networks in operation</u>

7.2 In DCO 336/2022/R/GAS, to which reference should be made, ARERA confirmed the introduction of an incentive for keeping in operation fully depreciated pipelines, envisaging, *inter alia*, that the level of the incentive could be periodically updated, especially in cases where significant investments for keeping in operation the asset subject to the incentive were found to have been made during the incentive period.

7.3 ARERA intends to reiterate the desirability of a periodic review, with a frequency in line with the evidence of possible average useful life extension found today, i.e. after 5 years.

7.4 The incentive criteria for keeping tariff-depreciated networks in operation, taking into account the guidelines consulted so far and the results of the consultations, may be the subject of a specific resolution, which will regulate their effective date as of 2023.

S 5.Comments on the incentive and efficiency criteria of the transmission network.

8. **Costs related to the Emissions Trading System**

8.1 In DCO 213/2022/R/GAS, ARERA envisaged the maintenance of the criteria in force in the 5PRT, which envisage, by means of specific reconciliation mechanisms on the tariff levels of year *t+2*, the recognition of a quantity of ETS certificates determined on the basis of the gas used for the operation of the compressor stations (net of any quotas obtained free of charge), valued on the basis of the average prices of the certificates recorded in the final balance. ARERA has also put forward the opportunity to induce transmission operators to limit CO_2 emissions into the atmosphere as much as possible, through the adoption, within the framework of the *ROSS-integrale*, of a virtuous path of emission reduction, identified by the transmission network operator and proposed within the business plan.

8.2 The comments received in the consultation generally agreed with this, emphasising the need to postpone the necessary actions until the entry into force of the ROSS approach.

8.3 ARERA intends to confirm for the 6PRT the criterion for the recognition of ETS allowances currently in force, providing, however, that the reconciliation of the difference between the actual revenues from the pro-forma charge CV_{ETS} (see paragraph 16.7) and the actually recognised costs recalculated to take account of the gas actually used for the operation of the compressor stations is to be settled with CSEA in year *t+1* (see Chapter 22).

8.4 ARERA also intends to provide that the transmission network operator shall define a virtuous path to reduce CO_2 and methane gas emissions into the atmosphere, representing the necessary actions and investments in a specific section of the Ten-Year Network Development Plan referred to in Article 16 of Legislative Decree no. 93 of 1 June 2011. This is also consistent with objective "SO.6" of the 2022-2025 Strategic Framework, which calls for regulation to be oriented towards social, economic and environmental sustainability objectives.

8.5 In addition, as part of the *ROSS-integrale* approach and the sharing of the business plan, an Environmental Sustainability Plan could be prepared at the beginning of the regulatory period, which identifies the objectives of reducing CO_2 emissions and the relative actions, to which a bonus/penalty mechanism could be associated (without prejudice to the mechanism for recognising network losses as set forth in the following Chapter); this also taking into account ARERA's provisions set forth in DCO 336/2022/R/GAS on the subject of incentives for the operation of dual fuel compression stations and the benefits that the use of such stations entails with respect to the reduction of fuel gas and the consequent need to use ETS certificates.

8.6 In particular, an effective model could be similar to what has been adopted in the UK's RIIO2, where companies are required to submit an Environmental Action Plan (EAP) in year *t*, containing a plan of actions to reduce emissions and the environmental impact of the network, with the aim of reducing emissions to zero. Annually, companies then submit a dedicated report (the "Annual Environmental Report" or "AER") presenting the progress made against the submitted EAP and the efforts undertaken to reduce the environmental impact of the networks.

S 6. Comments on the treatment of costs related to the Emission Trading System and the provision of an Environmental Sustainability Plan.

9. Treatment of network losses, fuel gas and unaccounted-for gas

9.1 In DCO 213/2022/R/GAS, ARERA envisaged a simplification of the application modalities for the recovery of costs relating to fuel gas, losses and unaccounted-for gas (UFG), as well as of efficiency mechanisms, where applicable. In particular, ARERA envisaged:

a) the confirmation of the approach whereby transmission operators, through the balance responsible entity (RdB), supply the quantities of gas needed to cover fuel gas, network losses and UFG within the centralised natural gas market;
b) a simplification of the administrative procedures for the management of the aforementioned cost recovery mechanisms for companies, with:
    i. the monthly payment to the CSEA of the entire tariff revenue;
    ii. monthly coverage by CSEA of the costs actually incurred by the RdB, with *ex-post* application, where provided for, of incentive mechanisms (in particular for losses and UFG);
c) the advisability of assessing any need to revise the emission factors, taking into account the results of the metering campaigns carried out by the main transmission operator;
d) the desirability of ensuring that transmission operators share more of the risk of UFG fluctuations;
e) the desirability of applying a single incentive mechanism to reduce physical losses and unaccounted-for gas (UFG), because of the close interdependence between the two parameters.

9.2 The consultation revealed a general agreement with the outlined guidelines, with particular reference to the increased sharing of UFG risk by transmission operators. On the other hand, the transmission operators, and the main transmission operator in particular, expressed opposition to increased UFG risk-sharing and the introduction of a single incentive mechanism for physical losses and UFG, and also demanded that:

a) the costs of electricity self-consumption from electric or dual-fuel compressor stations are considered as pass-through costs;
b) also for transmission operators other than the main transmission operator, the financial transactions relating to fuel gas, losses and UFG are managed on a monthly basis.

9.3 Below are ARERA's final guidelines for the 6PRT, which confirm in substance what was outlined in DCO 213/2022/R/gas, structured according to the following topics:

a) quantities of gas recognised to cover fuel gas, losses and UFG;
b) criteria for pricing of fuel gas, losses and UFG;
c) mechanism for hedging price and quantity risks;
d) reconciliation and efficiency mechanisms.

Quantities of gas recognised to cover fuel gas, losses and UFG

Fuel gas

9.4 ARERA, as outlined in DCO 213/2022/R/GAS, intends to confirm the current regulation, which provides for an *ex-ante* estimate (for the purpose of determining tariffs) by transmission operators of the quantities of gas required to cover their fuel gas needs.

9.5 With reference to the consumption of electricity for the operation of electric or dual-fuel compressor stations, it is considered that the relevant costs can be covered within the commodity-based charge to cover fuel gas, losses and UFG, as envisaged in point 5.12, letter b) of DCO 336/2022/R/GAS, which, on the basis of the mechanisms envisaged, is paid in full to CSEA. As in the case of fuel gas, the transmission operators determine *ex-ante* the quantities of electricity required for the operation of electric compressor stations.

Network losses

9.6 ARERA intends to confirm the determination of the recognised level of losses through the application of efficient emission factors for each relevant component of the transmission network, following the guideline of DCO 213/2022/R/GAS to proceed with a revision of the emission factors with the aim of further incentivising the reduction of methane emissions into the atmosphere.

9.7 On the basis of the data and information gathered in the course of the proceedings, there is a commitment on the part of the transmission operators to adopt actions to contain emissions, such as valve replacement, Leak Detection and Repair (LDAR) programmes, switching of pneumatic gas instruments with air and/or electro-hydraulic-actuated instruments, and the adoption of gas recompression systems when working on the network. The emission factors reported by the main transmission operator "*on the basis of the current losses as found as a result of the reduction measures*" deviate, in some cases significantly, from the emission factors in force today for regulatory purposes; overall, the application of these actual emission factors to the plant consistency of the transmission network would result in a significantly lower value of recognised losses than that approved on the basis of the emission factors established by ARERA.

9.8 With respect to the methodology adopted, the main transmission operator notes that:

a) fugitive and pneumatic emissions of natural gas are estimated as the product of emission factors[2] (average emission of natural gas dispersed into the atmosphere by the individual constituent element of the gas system, or by the individual operation that has occurred) and activity factors (numerical consistency of a particular constituent element of the gas system, or the frequency with which a certain operation is carried out);

b) vented and unburned emissions are basically quantified by engineering calculations.

9.9 Taking this evidence into account, ARERA intends to realign the value of losses recognised for regulatory purposes with that resulting from the most recent evidence, passing on to service users the efficiencies achieved by transmission operators through the actions taken to reduce emissions (see Table 2). In particular:

a) for network elements with a pressure above 12 bar, it is deemed appropriate to use the values as resulting from the metering campaigns carried out by Snam Rete Gas; in this regard, it is noted that the emission factors reported are significantly reduced compared to those in force in the 5PRT, with the exception of that associated with pipelines, the value of which was determined, in 2013, on the basis of literature data, while it is now estimated on the basis of meterings carried out in the field;

b) for network elements with a pressure below 12 bar, it is considered appropriate to confirm – in continuity with previous regulatory periods – the adoption of a simplified approach that provides for alower valuation criterion for emission factors than for network elements with a pressure greater than 12 bar.

[2] For fugitive emissions, the emissions factor is associated with the specific element type, while for pneumatic emissions, the element model and manufacturer are also considered.

Table 2: Emission factors

	Emission Factor P<12 bar	Emission Factor P>12 bar	Unit
Fugitive emissions			
Pipeline	4,3	43	Smc/km/y
Nodes	-	12.050	Smc/source/y
PIG Stations	-	3.382	Smc/source/y
R&R[1] Stations	-	6.156	Smc/source/y
Compressor stations	-	1.425	Smc/MW/y
Regulation and Metering Stations (REMI)[1,2]	102,8	1.028	Smc/source/y
Pneumatic emissions			
Network (pneumatically actuated valves)	13,6	136	Smc/source/y
R&R Stations	-	8.053	Smc/source/y
Compressor stations	-	390	Smc/MW/y
Plant for measuring the gas composition	157,0	1.570	Smc/source/y
Vented emissions			
Network, R&R and REMI	11,9	119	Smc/km/y
Plants	-	1.148	Smc/MW/y

[1] *In the case of regulation and reduction (R&R) and regulation and metering (REMI) stations, the pressure to be considered is the pressure at the system inlet.*

[2] *The value indicated refers to the part of the system within the network perimeter: in the case of redelivery points the part "upstream" of the meter, for input points the part of the plant "downstream" of the meter.*

9.10 Methane emissions targets may be affected by any obligations arising from future European legislation; the European Commission's recommendation for a Regulation dated 15 December 2021 envisages, among other things, a new EU legal framework to ensure stricter rules on the measurement, verification and reporting of methane emissions, which envisages significant commitments by regulated companies towards losses measurement (with respect to which a careful balancing of costs and benefits for the system is appropriate). The costs of these commitments, according to the same recommendation, are to be recognised by the regulators to the extent that they correspond to those of an efficient and structurally comparable operator. In this regard, it is also considered appropriate that the results of the activities of transmission operators in relation to losses measurement can also be used for further revisions of efficient emission factors.

<u>*Unaccounted-for gas*</u>

9.11 With regard to unaccounted-for gas (UFG), ARERA intends to confirm the criterion for determining the recognised quantity in force in the 5PRT, which is equal to the average of the UFG quantities recorded in the last four available years.

Criteria for pricing fuel gas, losses and UFG

9.12 As far as the *ex-ante* pricing of the quantities recognised to cover fuel gas, losses and UFG is concerned, ARERA intends to confirm the *ex-ante* criterion on the basis of the available quotations of forward products with delivery at PSV in the tariff year, taking into account the time profile with which these resources are needed.

9.13 With reference to the quantities of electricity required for the operation of electric compressor stations, similarly to the criterion provided for fuel gas, it is considered appropriate to provide a pricing on the basis of the available quotations of forward electricity products in the tariff year.

Price and quantity risk hedging mechanisms

9.14 ARERA intends to confirm what was outlined in DCO 213/2022/R/GAS with regard to the advisability of proceeding with a simplification of the price and quantity risk hedging mechanisms currently in force (operating in part under tariff regulation, in part through the neutrality mechanism of the network balancing rules), through the recognition to the RdB of the costs actually incurred during the year and the application of *ex-post* reconciliation and efficiency incentive mechanisms.

9.15 In particular, the following guidelines are confirmed:

a) definition of a pro-forma commodity-based charge CV_{APG}, as a share of the CV_U charge, determined as the ratio between the *ex-ante* pricing of the gas quantities recognised to cover fuel gas, network losses and UFG, and the reference volumes for the determination of the CV_U charge (see also paragraph 16.7);

b) monthly payment to CSEA (into the fund for the coverage of charges related to the gas balancing system referred to in Article 8 of the TIB), by the transmission operators, of their share of the revenue deriving from the application of the CV_U charge determined as the product between the pro-forma charge CV_{APG} and the volumes delivered at the exit points of the transmission network;

c) recovery, within the framework of the neutrality mechanisms set forth in paragraph 8.6 of the TIB duly modified, of the entire cost incurred by the RdB for the supply of the gas volumes necessary to cover fuel gas, losses and UFG (and not only, as is currently the case, the difference between the purchase price and the price established *ex-ante*);

d) application, in year $t+1$ with reference to year t, of the reconciliation and efficiency incentive mechanisms, through a compensation with CSEA that occurs at the same time as the compensations arising from the other revenue compensation and recovery mechanisms.

9.16 The framework outlined above presupposes not only a modification of the neutrality mechanism in the TIB, but also a different application of the operational balancing agreements (or "OBAs"). In the new design, in fact, all transmission operators would pay CSEA the pro-forma revenue to cover the costs of fuel gas, losses and UFG; consequently:

a) operators other than the main one would no longer be obliged to pay to/receive from the RdB, within the limits set by the balancing account defined in the agreements referred to in paragraph 4.2 of the TIB, resources to cover the supply costs of fuel gas, losses and UFG;
b) the main transmission operator would also obtain from CSEA the resources to cover the cost of supplying fuel gas, losses and UFG accruing to the other transmission operators (which, therefore, would not incur any costs and would not retain any revenue in relation to fuel gas, losses and UFG during the year).

9.17 With regard to the costs of electricity for the operation of the electric compressor stations, it is considered that the price and quantity risks must be covered for the transmission operator. In particular, it is considered appropriate for CSEA to compensate the difference between:

a) any revenue from the provision of balancing services for the electricity grid, which the operator is obliged to return to the system pursuant to the incentive mechanism set out in DCO 336/2022/R/GAS (see point 5.13);
b) the costs incurred in supplying the electricity needed to operate the electric compressor stations.

Reconciliation and efficiency incentive mechanisms

9.18 The framework outlined above makes it possible to recognise to the RdB, in the course of the year, the costs actually incurred for the supply of fuel gas, losses and UFG, even on behalf of other transmission operators. It is therefore necessary to provide, with reference to the costs in relation to which it is not considered appropriate to guarantee full recovery (i.e., in continuity with the current regulatory framework, costs relating to losses and UFG), specific reconciliation mechanisms that send economic signals to each transmission operator providing incentives to take action to make these costs more efficient.

9.19 As far as self-consumption (both fuel gas and electricity) is concerned, it is considered that the regulatory framework must guarantee full recovery of the costs incurred, in continuity with the regulation in force; this is because this allowance is to a large extent independent of the choices made by the transmission operators, since it is attributable to network configurations which are a consequence of the network users' injection and withdrawal schedules. Consequently, the guideline of not providing any reconciliation or incentive mechanism with reference to this allowance is confirmed. Also with regard to electricity self-consumption, the monthly adjustment of the amounts to be paid or received by the operator from the system does not require the definition of any reconciliation mechanism. In any case, ARERA intends to pursue mechanisms that stimulate the overall efficiency of fuel gas on the transmission network through technological innovation, also by sharing, within the framework of the *ROSS-integrale* approach, fuel gas reduction targets and instruments to pursue these targets.

9.20 As far as losses and UFG are concerned, it is deemed appropriate to confirm the introduction of specific efficiency incentive mechanisms, operating simultaneously, without, however, following-up on the hypothesis of defining a single incentive mechanism for the two components of losses (physical and UFG) envisaged in DCO 213/2022/R/GAS. In this regard, it is in any case deemed appropriate to apply a single pricing for deviations between the actual and the allowed levels of UFG and losses, ensuring the same incentive force of the two mechanisms in order to avoid opportunistic behaviour by operators (e.g. concentrating efficiency efforts on one component to the detriment of the other). It is believed that the definition of two separate but simultaneous mechanisms may allow for a more accurate modulation of the associated risks related to (physical) losses and UFG, in respect of which the transmission operators have a different ability to control, while also providing an incentive to reduce overall (physical and UFG) losses on the network.

9.21 With regard to physical losses, it is considered appropriate to confirm the recognition of the level of losses determined on the basis of efficient emission factors; therefore, it is necessary to introduce a specific reconciliation mechanism that provides for each transmission operator to compensate with CSEA, in year *t+1*, the difference between the losses accounted for in the network balance (supplied by the RdB) and the losses allowed for tariff purposes, priced on the basis of a fixed unit value for the entire regulatory period, equal to the unit charge for UFG pricing (see point 9.27 below). This reconciliation, therefore, operates as an incentive mechanism to reduce emissions, pushing transmission operators to take all actions deemed appropriate to reduce losses below the regulatory level, with the possibility of retaining, as an incentive, any resulting difference.

9.22 With regard to UFG (unaccounted-for gas), the intention is to confirm the current mechanism of making the transmission operators responsible for deviations between the allowed UFG and the actual UFG, by defining a unit charge for the companies, fixed for the entire 6PRT, for the pricing of this deviation. Therefore, it is intended to confirm the UFG reconciliation mechanism (see Article 30*bis* of the RTTG), whereby the transmission operators compensate with CSEA, in year *t+1*, the deviation between the actual and allowed UFG quantities, suitably adapted to the new framework; in particular:

a) if the actual UFG is greater than the allowed UFG, the transmission operator, which has already received from CSEA all the resources to supply UFG, returns to CSEA the charge it bears on the deviation, within a threshold;

b) conversely, if the actual UFG is lower than that allowed, CSEA, which has recognised the company less resources than those recognised *ex-ante* on a tariff basis in the pro-forma charge CV_{APG}, recognises the deviation, valued on the basis of the unit charge, to the company, within a threshold.

9.23 The in-depth studies and analyses conducted by the main transmission operator to identify the possible determinants of the level and dynamics of UFG confirm – albeit without arriving at the identification of unambiguous causes and envisaging further investigations with the use of advanced analytics tools – an impact deriving from "*incorrect or obsolete design of the metering lines and/or their non-*

optimal management", with particular reference to the age of the plants and limited rangeability, as well as the relevance of the failure/delayed updating of gas quality parameters in the flow computers installed at the metering stations.

9.24 ARERA, therefore, taking into account the results of the consultation, the results obtained so far from the in-depth studies on the determinants and dynamics of UFG, as well as the tools that transmission operators will have from 2024 to ensure the efficiency and accuracy of the metering service (see resolution 512/2021/R/GAS), intends to confirm the proposal of providing for a greater co-participation of transmission operators in the risks of UFG fluctuations.

9.25 In this regard, it is noted how:

a) using the same criteria for defining the unit charge and the maximum exposure threshold adopted in resolution 569/2020/R/GAS, updated to take account of the parameters in the 2019-2022 period[3], the result would be an estimated unit charge of approximately € 3.57/MWh (instead of the € 3.33/MWh currently in force) and a maximum exposure threshold (for each transmission operator, equal to their respective $RM_{CAPITAL}$ allowance) that would tend to be higher than those currently in force;

b) when the parameter of € 3.33/MWh was set by resolution 569/2020/R/GAS, the gas price was on average (for 2020) around € 10/MWh.

9.26 In view of the above, ARERA intends to determine a unit exposure and a maximum exposure threshold that do not exceed the share of the allowed costs for the metering service, achieving the objective of a greater co-participation of the transmission operators in the risks associated with UFG fluctuations. It is considered that this increased risk co-participation can be achieved by referring no longer to the remuneration of the metering service, but to the operating costs associated with that service, as, *inter alia*, initially envisaged in the consultation document 437/2020/R/GAS of 3 November 2020.

9.27 Compared to an estimated unit charge on the basis of the current criteria of approximately € 3.57/MWh, the redetermined unit charge taking into account the allowance covering operating costs is estimated to be about € 6.95/MWh, and the maximum exposure for each transmission operator would be about twice as high as at present. ARERA intends to determine the unit charge when defining the criteria for the 6PRT, taking into account for the year 2022 the final UFG data, reserving the right to intervene, even during the regulatory period, to ensure a redistribution between operators and users of any benefits deriving from a reduction in gas prices.

S 7.Comments on the treatment of network losses, fuel gas and unaccounted-for gas.

3 The actual UFG for the year 2022 was assumed to be 310 MSm^3, based on the preliminary data provided by Snam Rete Gas.

10. Recovery of network operational balancing service costs

10.1 ARERA is inclined to confirm the current provisions on the methods for recovering costs relating to the network operational (physical) balancing service, which call for the recognition, to the companies that perform transmission activities on the national natural gas pipeline network, of an allowance for the recovery of the costs relating to the storage service necessary to the hourly balancing of the transmission system.

S 8.Comments on revenue for the balancing service.

11. Criteria for determining reference revenues for new transmission operators

New transmission operators

11.1 ARERA intends to confirm the provisions for the determination of the reference revenues of transmission operators starting operations during the regulatory period, which stipulate that:

a) the determination of the reference revenues for the first year of operations shall be based on the value of assets relating to the assets in operation in the balance sheet of the financial year preceding the year in which the tariff proposal is submitted;

b) any pre-operating costs incurred in the start-up phase are taken into account only to the extent that such costs have been capitalised;

c) any interest expense during construction incurred up to the year in which the commercial provision of the transmission service is started are included, provided that they have been capitalised;

d) for the first two years of operations (or, in any case, until the availability of final data relating to the actual operating costs that can be deduced from a balance sheet representative of an entire financial year), in the absence of data on the extent of the recurring costs deriving from the performance of the activity of transmission and balancing, the operating costs are proposed by the operators and subjected to verification by ARERA; such proposals must be supported by a comparison with comparable operators or by evidence of procedures for minimising costs;

e) the allowed revenue is rescaled by applying the *pro-die* criterion on the basis of the period during which the service is actually made available during the year.

New transmission operators established following the reclassification of distribution network sections

11.2 ARERA intends to confirm the existing provisions for cases in which a new transmission operator is established as a result of a reclassification of distribution network sections. In particular, it is considered appropriate to safeguard the principle of cost invariance for users of the natural gas system: any reclassification of existing networks may not lead to an increase in the costs covered by natural gas tariffs at the time when such reclassification becomes operational. Existing distribution network sections reclassified as regional transmission will therefore not be recognised in the transmission tariff, unless there is an equivalent cost-covering waiver from the distribution tariff.

11.3 ARERA also intends to confirm the principle that system users should not be burdened with the costs arising from the mere reclassification of networks; if it can be demonstrated that the reclassification of networks leads to an increase in the operator's profitability, ARERA reserves the right to reduce the rate of return recognised in order to ensure the same profitability that the operator had before the reclassification.

S 9.Comments on the criteria for determining the revenue constraint for new operators.

12. Recovery of costs relating to the transmission network metering service

12.1 ARERA intends to confirm the recommendations set out in DCO 213/2022/R/GAS, providing in particular that the criteria for the recovery of costs and determination of reference revenues for the metering service on the natural gas transmission network shall follow the general criteria provided for the transmission service, as described above, including the mechanisms for the reconciliation with the ROSS methodology.

12.2 As regards deviations between revenue for 2024 determined on the basis of preliminary data and final revenue, the guideline is confirmed of considering such amounts within the metering service revenue recovery factor (see point 22.15 *et seq.*).

PART III
DETERMINATION OF TRANSMISSION SERVICE CHARGES

13. Identification of the services performed by transmission operators for tariff purposes

13.1 Pursuant to Article 4 of the TAR NC, the reference price methodology is applied to the share of revenue relating to the transmission service, i.e. the service whose costs are caused by the cost drivers of both technical or forecasted contracted capacity and distance, and are related to the investment in and operation of the infrastructure which is part of the net invested capital for the provision of transmission services.

13.2 In line with the 5PRT, ARERA is inclined to define the transmission service, thereby meaning transmission on both the national and regional natural gas pipeline networks, as a transmission service pursuant to the TAR NC, and therefore to allocate the relative revenue according to the reference price methodology.

13.3 In order to guarantee the operational (physical) balancing service of the network, the balance responsible entity (RdB) is required to acquire the necessary resources in terms of storage capacity. In continuity with previous regulatory periods, and in accordance with Article 4, paragraph 1 of the TAR NC, ARERA considers it appropriate to include this allowance within the scope of the revenues related to the transmission service to be recovered through transmission tariffs applied to capacity.

13.4 ARERA is inclined to confirm the proposal of classifying the transmission metering service as a non-transmission service, as it is not dependent on the cost driver of distance. The criteria for allocating the costs of this service to users are explained in Part IV below.

13.5 As far as auxiliary services are concerned, as identified in the Network Codes of the transmission operators (such as, for example, the allocation and transfer of capacity, billing, physical balancing of the network, gas allocation, management of transmission data, management of meter data, management of quality data, management of service emergencies, etc.), ARERA considers that these services – although not dependent on the cost drivers of capacity and distance – are closely associated with the transmission service and as such are offered to service users together with this service. Therefore, ARERA considers it appropriate to confirm the inclusion of the costs of these services in the transmission service, and thus to recover their costs through transmission tariffs.

13.6 ARERA is of the opinion that any further services provided by the transmission operators, referred to as “optional services” (see chapter 3, paragraph 4 of the Network Code of the main transmission operator) or further services offered by the operator as part of its core business (see Article 22 RTTG), which are provided in accordance with the provisions of the Network Code approved by ARERA and the costs of which are not recognised in the transmission tariff, must be classified as non-transmission services and be provided under conditions consistent with the requirements of the TAR NC. Therefore, the tariffs for such services must reflect the underlying costs of providing the service and be determined objectively, transparently and applied in a non-discriminatory manner directly to the beneficiaries of the service.

13.7 As part of the consultation on DCO 213/2022/R/GAS, one operator pointed out that, as with the metering service, services such as blending, gas quality analysis and the possible temporary storage of hydrogen to be injected into the network, are assimilated to the non-transmission services carried out today by operators and managed as regulated services, and the corresponding costs being recovered through specific charges. However, ARERA considers that, with reference to the services mentioned, these either (i) do not present natural monopoly characteristics such as to justify regulation, or (ii) are services not yet materially offered by transmission operators for which it would be premature to define a specific regulatory framework. However, ARERA considers it appropriate to monitor developments in the supply of these services so as to possibly adjust the regulation in the future.

13.8 Similar considerations apply with respect to the request formulated by an operator to provide, by analogy with the provisions of the current regulation of the electricity sector, that any revenues deriving from the use of the gas facility for purposes other than the gas service may be the subject of symmetrical allocation between the transmission system operator and the final customers. In this regard – without prejudice to the general principle according to which revenues deriving from services and activities based on the use of the regulated facility, the costs of which are recognised at tariffs, are in any case passed back to the system –, ARERA intends to monitor the development in the offer of these services in such a way as to envisage, if necessary, specific forms of regulation.

S 10. Observations on the identification of the services performed by transmission operators for tariff purposes

14. Transmission service tariff structure

14.1 ARERA is inclined to confirm the current structure of the tariff for the transmission service, which is divided into capacity charges (*CPe* and *CPu*) and commodity charges (CV_U and CV_{FC}), and in particular to define the transmission tariff *T* for the continuous transmission service on an annual basis on the basis of the following formula:

$$T = K_e \cdot CP_e + K_u \cdot CP_u + V \cdot CV_U + V_{FC} \cdot CV_{FC}$$

where:

- K_e is the capacity allocated to the user at the entry point *e* of the national gas pipeline network (i.e., cross-border point, entry from LNG terminals, entry from storage, entry from national production), expressed in cubic meters/day;

- CP_e is the capacity unit charge for transmission related to the entry point *e* of the national gas pipeline network, expressed in euros/year/cubic meter/day;
- K_u is the capacity allocated to the user at exit point *u* of the network (i.e., cross-border point, exit to storage, redelivery), expressed in cubic meters/day;
- CP_u is the capacity unit charge for transmission related to the exit point *u* of the network, expressed in euros/year/cubic meter/day;
- *V* is the quantity of gas withdrawn from an exit point *u* in the network, expressed in cubic meters;
- V_{FC} is the quantity of gas withdrawn from an exit point *u* of the network, with the exception of cross-border exit points, expressed in cubic meters;
- CV_U is the commodity-based charge, expressed in euros/cubic meter;
- CV_{FC} is the complementary revenue recovery charge for revenue recovery, expressed in euros/cubic meter.

14.2 Unit charges forming part of tariff *T* are expressed with reference to a *standard* cubic meter of gas at an absolute pressure of 1.01325 bar and a temperature of 15 °C.

14.3 As part of the consultation, the main transmission operator pointed out that it was best to:

a) express tariff charges in energy terms;

b) express the volumes used for the calculation and billing of CV_U and CV_{FC} charges in *standard* cubic meters with an energy content of 38.1 MJ/Sm^3 instead of physical cubic meters.

14.4 In general terms, ARERA considers it appropriate to maintain the definition of charges in units of volume rather than in units of energy, also in order to ensure greater consistency with legal metrology and to adopt a consistent approach across the entire perimeter of the transmission network and across the entire natural gas supply chain (where billing to final customers is typically carried out in units of volume). However, this is without prejudice to the current obligations of the main transmission operator to publish the charges in units of energy at the interconnection points for information purposes only.

14.5 With respect to the volumes expressed at 38.1 MJ/Sm^3, it is considered that such a change would still require a precise metering of the calorific value at the exit points of the transmission network, which is, however, currently only possible for a few of these points. In this regard, it is believed that the minimum plant and functional requirements laid down in resolution 512/2021/R/GAS of 23 November 2021, reorganising the metering activity at the entry and exit points of the transmission network, may lay the foundations for a more timely metering of gas quality at all points of the transmission network, possibly making it easier in future years to adopt reference units that presuppose the metering of energy content.

S 11. *Comments on the tariff structure for the transmission service.*

15. Duration of the tariff period

15.1 The tariff period, i.e. the period for which the charges approved by ARERA are in force, is currently 1 year.

15.2 As part of the consultation on DCO 213/2022/R/GAS, one party recommended keeping the transmission charges fixed for the regulatory period (similarly to what ARERA recommended for the CM^{CF} metering charge) by managing the deviations between the revenues actually achieved and the reference revenues within the revenue recovery factor, i.e. by means of the CV_{FC} charge (which would continue to be on an annual basis). With respect to this recommendation, ARERA considers that:

a) whereas for the CM^{CF} the variability and magnitude of revenues are small, in the case of the transmission service such a choice could result in significant deviations between the revenues actually achieved and the reference revenues, failing the principles also referred to in the TAR NC (Article 17, paragraph 1) according to which: (i) the recovery of sums under or in excess of transmission service revenues should be kept to a minimum; (ii) the level of transmission tariffs should ensure that revenues covering transmission service costs are recovered by the transmission system operator in a timely manner;

b) in relation to the revenues of the transmission operators, it is noted that some relevant parameters are updated annually (the deflator and inflation parameters, the prices of commodities for the quantification of the revenues recognised to cover losses, fuel gas and UFG, as well as the rate of return, if there is an update with the so-called trigger logic) and, particularly in a phase of macroeconomic discontinuity and tension in the energy markets such as the current one, this would risk significantly increasing the gap between actual and allowed revenues;

c) in relation to actual revenues, it is pointed out that expectations of a substantial change in import dynamics also complicate the forecasting of forecasted contracted capacity at individual points, contributing to the variability of actual revenues achieved.

15.3 For these reasons, ARERA considers it preferable to maintain the duration of the tariff period at one year.

16. **Allocation of transmission service costs between capacity and variable tariff components (capacity-commodity split)**

16.1 In DCO 213/2022/R/gas, ARERA recommended keeping the capacity-commodity split unchanged, essentially based on the distinction between capital and operating costs (see below).

16.2 In this regard, one party pointed out the need to adopt a split that would make the transmission service more flexible and economic to the benefit of those with greater natural gas consumption, as established by Article 38, paragraph 2*bis*, of Decree Law no. 83 of 22 June 2012 and confirmed by the rulings of the Council of State, Sixth Section, no. 6096 and 6098 of 18 July 2022. On this point, ARERA initiated a specific compliance proceeding (resolution 448/2022/R/GAS) in the context of which a number of solutions were put forward which, in this document, are referred to in the following Chapter 19 with regard to greater flexibility with the introduction of short-term allocations, and in Part VI below with regard to additional charges. However, it is necessary to clarify, on a preliminary basis, how the administrative law judge clarified that the regulations set forth in Article 38, paragraph 2*bis*, of Decree Law no. 83/2012 do not, *per se*, impose an intervention on the capacity/commodity and entry/exit split – which, on the contrary, were deemed to be matters subject to the discretionary power attributed to ARERA, and which, moreover, were deemed to be reasonable, legitimate and in line with the provisions of the TAR NC.

<u>Revenues from transmission services to be recovered by capacity-based transmission charges</u>

16.3 Consistent with the 5PRT, ARERA intends to confirm the principle according to which capacity-based transmission tariffs are aimed at recovering the following items that contribute to the determination of reference revenues:

a) adequate return on the regulatory net invested capital, including any increased return recognised as an incentive for new investments incurred as from the second regulatory period;
b) economic-technical depreciation;
c) costs incurred for the operational balancing service of the system.

16.4 Furthermore, ARERA intends to confirm the provision whereby, for the purposes of determining the share of revenue to be recovered through capacity tariffs, the reference revenues are considered net of the *RSC* revenues deriving from the application of overrun charges at the entry and exit points of the gas pipeline network in the year *t*-2, including the penalties paid in the same year pursuant to paragraph 10.1 of resolution no. 168/06 of 31 July 2006, within the limits of a threshold equal to 5% of the revenues to be recovered by capacity-based charges. Also included in the *RSC* component is the reconciliation of overrun charges revenues pertaining to previous years determined as a result of the settlement sessions under the TISG. *RSC* revenues in excess of the 5% threshold would be taken into account when determining the capacity charges for year *t+1*.

Revenues from transmission services to be recovered by commodity-based transmission charges

Commodity-based charge

16.5 With reference to the commodity-based charge (CV_U), it is deemed appropriate to confirm the application of a tariff component applied to transported volumes that is:

a) allocated to cover recognised operating costs, the Emission Trading System costs and costs for the supply of quantities of gas to cover fuel gas, losses and UFG;

b) applied to the transmission network exit points (and that is, at redelivery points, at exit points towards storage facilities and at export interconnection points).

16.6 ARERA also intends to confirm the provision that the driver for the calculation of the commodity-based charge is defined as equal to the quantities of natural gas withdrawn from the network at the exit points towards storage facilities, at cross-border exit points, and at redelivery points. In order to ensure consistency with the quantities of gas invoiced, it is necessary for the driver to take into account the quantities of natural gas allocated to the transmission service users (instead of those metered), objectively verifiable from the service billing documents. ARERA, in continuity with the existing criteria, also intends to consider:

a) for the purpose of determining the charges for the year 2024, the volumes for the year 2022;

b) for the purpose of determining the charges for each subsequent year *t*, the volumes for the year *t-2*.

16.7 For the sole purpose of the management of the commodity recovery factor (see point 22.7 *et seq.*) and the reconciliation and efficiency incentive mechanisms, it is deemed appropriate to split the CV_U charge into three *pro-forma* charges:

a) CV_{COR}, to cover the revenue share of operating costs;

b) CV_{ETS}, to cover the revenue share for covering costs related to the Emission Trading System;

c) CV_{APG}, to cover the revenue share for covering the costs of supply for fuel gas, losses and UFG.

Complementary revenue recovery charge

16.8 ARERA intends to confirm the application of a complementary revenue recovery charge CV_{FC} aimed at revenue recovery. Due to the recommended changes in Part V on recovery and reconciliation mechanisms, it is considered that this charge should be:

a) earmarked to cover the sums, pertaining to year *t-2*, related to:

i. the recovery factor of the capacity revenues of the transmission service (see point 22.4 *et seq.*);

ii. the recovery factor of the commodity revenues of the transmission service (see point 22.7 *et seq.*);

iii. the reconciliation of items related to fuel gas, losses, UFG, and ETS charges (see point 22.14 *et seq.*);

b) applied to the quantities withdrawn from the network at the points of exit from the transmission network corresponding to redelivery points and points of exit towards storage facilities, as an increase (if positive) or reduction (if negative) of the variable CV_U charge.

16.9 ARERA intends to provide that the driver for the calculation of this charge is defined as equal to the quantities of natural gas withdrawn from the network at the exit points towards storage facilities and at redelivery points, as actually allocated to the users of the transmission service. Similar to what was recommended under point 16.6 above for the commodity-based charge, ARERA intends to update this value annually.

S 12. Comments on the capacity-commodity split and the scope of application of variable charges

17. Allocation of costs to be recovered with capacity-based components between entry and exit points (entry-exit split)

17.1 In DCO 213/2022/R/GAS, ARERA recommended keeping the entry-exit split of 28/72 unchanged from the 5PRT.

17.2 One party recommended adopting an allocation based on the level of utilisation of transmission capacities at entry points, whereby the costs actually required to serve the national market are allocated to entry points, while security costs are recovered at all exit points. The same party also recommended a change to the methodology for determining reference prices, recommending in particular the use of technical capacity instead of the forecasted contracted capacity at entry points as the driver for calculating charges at entry points, recovering the lost revenue by applying charges at exit points[4]. On this point, it is noted that:

a) the two recommendations (modification of the entry-exit split and utilisation of technical capacity at entry points) are intended to serve the same purpose through separate instruments;

b) however, while the modification of the entry-exit split is a regulatory option, the use of technical capacity and the recovery of lost revenues at all exit points is not feasible under the TAR NC, as:

4 It should be noted that, in the recommended methodology, the parameter of the planned capacity to be allocated is used in three distinct moments: a) in the definition of the relative weights among the charges; b) in the calculation of the individual unit charges, starting from the revenues to be recovered and taking into account the relative weights; c) in the rescaling as a result of the application of discounts. In the subject's recommendation for consultation, the reference is to the use of technical capacity in points b) and c).

i. the mechanism would generate a systematic underestimation of the charges in relation to the revenue to be recovered, thus failing to comply with the principle referred to in Article 17, paragraph 1 of the TAR NC according to which the under- or over-recovery of the transmission services revenue shall be minimised and that revenues covering transmission service costs are recovered by the transmission system operator in a timely manner;

ii. in any event, pursuant to Article 4, paragraph 3, letter b) of the TAR NC, the complementary revenue recovery charge is applied to points other than interconnection points; therefore, it would not be possible to recover the so-called security costs from the users benefiting from it in foreign countries;

c) regarding the entry-exit split:

i. with resolution 575/2017/R/gas defining the criteria for the 2018-2019 transitional period, ARERA allocated a 40% share of national network revenues to entry points and 60% to exit points;

ii. for the determination of the 40% share, ARERA had referred to the level of infrastructure utilisation, based on the maximum daily capacity utilised at each entry point of the national gas pipeline network, excluding storage sites, recorded in the 2014-15 and 2015-16 gas years;

iii. this choice was confirmed for the 5PRT, also on the basis of the transmission capacity utilisation rate, understood as the maximum daily capacity utilised at each entry point of the national gas pipeline network (excluding storages), recorded in the last 3 gas years; the application of a single tariff methodology on the national network and on the regional network, and the allocation of 100% of the regional network revenues to the exit points, resulted in the 28/72 split;

iv. in recent gas years, both due to the effect of reduced demand for natural gas and the entry into operation of the new entry point of Melendugno, the load factor at entry points has decreased; applying the same criterion as in the transitional period and the 5PRT, this would result in a share of national network revenues to be attributed to the entry points of between 30% and 35%, which would lead to the attribution to the entry points of a share of total revenues indicatively between 20% and 25%, instead of the current 28%.

17.3 In view of the above, it is deemed appropriate to ensure regulatory continuity with respect to the criterion adopted in resolution 575/2017/R/gas and, at the same time, to avoid significant tariff changes with respect to the 5PRT. Therefore, it is deemed appropriate to change the entry-exit split from the 5PRT by adopting a 25/75 split that reflects the utilisation rate of transmission infrastructures recorded in the most recent gas years.

18. **Reference price methodology**

Reference price methodology based on capacity-weighted distance

18.1 The reference price methodology identifies the criteria for determining the transmission charges applied to the booked capacity. In order to ensure stability and certainty in the evolution of tariff charges over time, ARERA intends to confirm for the 6PRT the adoption of the Capacity-Weighted Distance (or "CWD") methodology as described in Article 8 of the TAR NC, using an entry/exit split of 25/75.

18.2 With regard to the capacity cost driver, ARERA intends to confirm the utilisation of the forecasted contracted capacity in a given tariff year, determined as a weighted average of the forecasted contracted capacity in the two gas years relevant for that year. The estimate is made by the transmission operators on the basis of the best information available at the time the tariff proposal is submitted, and is subject to approval by ARERA. This estimate must also include forecasts for allocations:

a) of short-term capacity, taking into account the re-proportioning on an annual basis as well as the level of multipliers (see point 19.4 *et seq.*);
b) of interruptible capacity, taking into account the relevant discount applied (see point 19.15).

18.3 In relation to the cost driver of distance, ARERA intends to use

a) for the national network, the physical length of the pipelines connecting, by the shortest route, an entry point and an exit point;
b) for the regional network, the average distance from the national network of the redelivery points underlying an exit area, weighted by the forecasted contracted capacity at the same redelivery points.

18.4 On the possibility of grouping entry and/or exit points, similar to the criteria currently in force, it is considered appropriate that:

a) the entry points from national production are grouped into 10 entry points from production hubs; for each hub, the distance to the exit points is determined by considering the distance to the most representative production point in terms of input volumes;
b) the redelivery points are grouped into 12 exit points, determined on the basis of the 6 withdrawal areas[5] and 2 clusters according to the distance from the national gas pipeline network (within/beyond 15 kilometres); the distance from each entry point to each group of redelivery points is determined as the sum of:
    i. a national network distance, determined as the average distance from the entry point to the important interception and diversion points (PIDIs) of the group of redelivery points, weighted for each PIDI

5 In the case of the inclusion of the facilities relating to the methanization of the Region of Sardinia (see point 18.17 *et seq.*), there would be 14 exit points determined on the basis of 7 withdrawal areas.

according to the forecasted contracted capacity at the points underlying each PIDI;

ii. a regional network distance, determined as the average – for the PIDIs related to the redelivery point group – of the PIDI-distances to the redelivery point, weighted by the forecasted contracted capacity at the redelivery points.

S 13.	*Comments on the reference price methodology*

Adjustments of transmission charges under the TAR NC

18.5 With respect to the charges as resulting from the reference price methodology based on the capacity-weighted distance, ARERA intends to confirm the application of certain adjustments to the transmission charges, in the following order.

Equalisation of charges to and from storage, and of exit charges to redelivery points

18.6 At entry points from and exit points to storage facilities, by analogy with the criteria currently in force and in line with the provisions of Article 6, paragraph 4, letter b) of the TAR NC, ARERA intends to confirm the application of an equalisation mechanism which, starting from the specific charges per storage facility, determines:

a) a single entry charge, applied to all entry points from storage facilities;

b) a single exit charge, applied to all exit points to storage facilities.

18.7 Moreover, in order to avoid excessive misalignments in the levels of charges of the national exit points, ARERA considers it appropriate to confirm the adjustment of the charges resulting from the application of the methodology in line with the provisions of Article 6, paragraph 4, letter b) of the TAR NC, equalising the redelivery points belonging to each cluster (within/over 15 kilometres). This adjustment concerns two homogeneous groups of points as defined pursuant to Article 3, paragraph 10 of the TAR NC.

Adjustments related to charges from and for storage, and from LNG plants

18.8 In the 5PRT, ARERA applied a discount to transmission charges related to storage facilities of 50%, in accordance with Article 9 of the TAR NC, and did not apply any discount to entry points from LNG terminals.

18.9 As part of DCO 213/2022/R/GAS, ARERA recommended:

a) in the interests of greater transparency, and also in view of the European Commission's recommendation of 23 March 2022, revising Regulation (EU) 2017/1938, to apply a discount to transmission tariffs to and from storage equal to 100%;

b) in consideration of the extraordinary provisions for the use of regasification capacity set forth in resolution 632/2021/R/GAS of 28 December 2021 (which set transmission capacity charges equal to zero in the event of actual LNG delivery), as well as to increase the competitiveness of gas supply sources through LNG, to introduce a 50% tariff discount for entry points from LNG terminals.

18.10 Most of the consultation participants do not agree with ARERA's recommendations, in particular because of the expected increase these would have on other capacity charges. On this point, several parties demand that the missing revenues from these discounts should not be recovered by an increase in capacity charges but rather should be recovered through the additional commodity-based charges CRV_{FC} and CRV_{OS}, applied at exit points.

18.11 Due to the strong opposition that emerged during the consultation, ARERA intends to confirm the level of discounts currently in force, i.e. 50% for points to and from storage, and zero for entry points from LNG terminals. The recommendation to structurally recover the costs of higher discounts through the additional charges CRV_{FC} and CRV_{OS} is deemed to be infeasible as it is not compatible with the provisions of the TAR NC; nevertheless, it is worth noting that the two charges are already used, where necessary, to recover revenue for interventions aimed at maximising the use of storage and regasification capacities for security and market reasons.

Rescaling of capacity charges to cover reference revenues

18.12 In order to ensure the recovery of the reference revenues related to the capacity charges, ARERA intends to confirm the rescaling mechanism as provided for in Article 6, paragraph 4, letter c) of the TAR NC, by means of which the reference prices, as resulting from the methodology based on the capacity-weighted distance and from the application of the adjustments referred to in point 18.6 above, are scaled up by multiplying the respective values by a constant, in order to ensure the recovery of the reference revenues in relation to the planned capacities to be allocated.

18.13 On this point, a number of parties requested in the consultation that this rescaling be done by applying an additive rather than a multiplicative constant, an option provided for under the TAR NC. With a view to regulatory continuity and stability, however, ARERA considers it preferable to maintain the current rescaling criterion, as it does not see sufficient grounds for adopting a different approach.

Discount at future exit point at Gela

18.14 Within the framework of DCO 213/2022/R/GAS, ARERA recommended applying a 50% discount to the future exit point at Gela for interconnection between Italy and Malta, a possibility expressly provided for under Article 9, paragraph 2 of the TAR NC with regard to exit points to facilities developed with the purpose of ending the isolation of Member States.

18.15 In response to the consultation, some parties disagreed with this discount recommendation, partly because of the supposed unequal treatment with respect to other export points (in particular the reverse flow exit point at Passo Gries), which would not benefit from similar discounts. In this regard, it is noted that:

a) under the TAR NC, it would not be possible to apply a similar discount to other exit points because only that point in Gela would meet the requirements of Article 9, paragraph 2, and in particular the fact that it would serve to end the isolation of a Member State;

b) as recalled in the previous consultation, the realisation of the project would entail, for the Italian system, investment costs of negligible entity, against the possibility of a greater use of the existing transmission facilities; the estimates of the impact on the other charges show how there would be a reduction in such charges even in the hypothesis of a discount applied to the exit point at Gela: it is therefore unquestionable that there is an interest for the Italian system for such a project to be realised, whereas an excessively high exit charge would instead risk making the project economically unsustainable.

18.16 For these reasons, ARERA intends to confirm the recommendation to apply a 50% discount at the future exit point at Gela. Refer to the Appendix to this document for simulations on the tariff impact of the entry into operation of the Gela point.

<u>Tariff treatment of transmission facilities for the methanization of the Region of Sardinia</u>

18.17 With regard to the criteria for the recognition of the costs associated with the virtual pipeline between the Region of Sardinia and the mainland, ARERA postponed the assessments to a specific proceeding initiated with resolution 279/2022/R/com, in which the modalities for the realisation of this connection and the relative entity will be assessed in detail, also in view of the expected development of gas demand on the island.

18.18 In relation to cost allocation methodologies for investments to be included in the national transmission network, in DCO 213/2022/R/gas ARERA expressed its intention to consider:

a) the related operating costs within the recognised operating costs to be recovered through the commodity-based charge CV_U;

b) capital costs as part of the costs to be recovered through capacity charges and thus allocated to the entry and exit points of the transmission network according to the reference pricing methodology.

18.19 With regard to the allocation of capital costs, ARERA has recommended that the inclusion of costs in the reference price methodology should take place according to the following criteria:

a) creation of two new exit points, grouping together the withdrawal points located in the Region of Sardinia subdivided according to distance from the national gas pipeline network (within/beyond 15 kilometres);

b) calculation of the distance from each entry point to the exit points in the Region of Sardinia using a simplified approach, as the sum of:

i. a “Mainland” national network distance, determined as the average of the distances from the entry point to the virtual exit points at the Panigaglia and OLT Livorno terminals;
ii. a “Sardinia” national network distance, determined as the average of the distances from the terminal entry points to the exit points relative to the consumption basins;
iii. a potential regional network distance, determined as the average – for the PIDIs related to the redelivery point group – of the PIDI-distances to the redelivery point, weighted by the forecasted contracted capacity at the redelivery points;

c) confirmation of the provision to determine, from the exit charges towards withdrawal areas (including the exit charges of the Region of Sardinia), a single exit charge at national level.

18.20 No specific comments were received in the consultation on how the transmission costs of methanization in Sardinia should be allocated.

18.21 Given the uncertainties relating to the commissioning date of some investments, and the lack of cost data relating to some investments, the simulations of revenues and charges for the year 2024 set out in the Appendix to this consultation document are carried out without considering the costs relating to the methanization of the Sardinia Region in the scope of the allowed revenue. However, a separate Chapter in the Appendix containing simulations is devoted to this aspect, in which an estimate of the main tariff impacts is given.

S 14. Comments on the tariff treatment of investments attributable to the methanization of the Sardinia Region.

Assessment of the reference price methodology

18.22 The reference price methodology must comply with the provisions of Article 13 of Regulation (EC) no. 715/2009, as well as with the following requirements of Article 7 of the TAR NC:

a) enable network users to reproduce the calculation of reference prices and their accurate forecast;
b) take into account actual costs incurred for the provision of transmission services considering the level of complexity of the transmission network;
c) ensure non-discrimination and prevent undue cross-subsidisation;
d) ensure that the network users within an entry-exit system are not assigned a significant volume risk, particularly in relation to transports across an entry-exit system;
e) ensure that the resulting reference prices do not distort cross-border trade.

18.23 It is considered that the methodology represented in this consultation document is consistent with the requirements of transparency and replicability of the tariff as set out in the TAR NC, as already stipulated – in substance – in the ACER Report of 14 February 2019, entitled “Analysis of the Consultation Document on the Gas

Transmission Tariff Structure for Italy”, evaluating consultation document 512/2018/R/gas for the 5PRT. With reference to the aspects that distinguish the methodology recommended in this consultation from the methodology consulted for the 5PRT:

a) the change in the entry-exit split does not entail any variations in the relative ratios of tariff charges and therefore on the allocation of costs between the various entry and exit points; moreover, since the Italian system is characterised by a limited share of exports, the change in the entry-exit split does not entail any significant variations on the revenue shares recovered at the cross-border exit points, and therefore has an impact on cross-border trade that is deemed negligible;
b) the discount at the exit point to Malta does not entail significant changes in the charges, also considering that the entry into operation of this point would be associated with an increased use of the existing transmission facilities and therefore, on the whole, with a reduction in the exit charges even in the presence of the tariff discount;
c) with respect to the inclusion of the transmission facilities for the methanization of the Region of Sardinia, it should be noted that the recommended methodology does not entail significant changes in the weights attributed to the existing entry and exit points, and therefore to the relative ratios between the entry and exit charges.

18.24 For a more analytical discussion of the effects of points b) and c) on the level of transmission charges, see the Appendix to this document.

19. Consultation on discounts, multipliers and seasonal factors under Article 28 of the TAR NC

19.1 Pursuant to Article 28 of the TAR NC, at the same time as the final consultation carried out in accordance with Article 26, paragraph 1 of the TAR NC, the Italian national regulatory authority is obliged to conduct a consultation with its counterparts of all directly connected Member States and relevant stakeholders on the following aspects: (a) the level of multipliers; (b) where applicable, the level of seasonal factors and the calculations referred to in Article 15 of the TAR NC; (c) the level of discounts referred to in Articles 9, paragraph 2 and 16 of the TAR NC.

19.2 Concerning the level of discounts referred to in Article 9, paragraph 2, i.e. discounts applied to entry points from LNG plants, see point 18.8 above.

19.3 Below are the ARERA’s recommendations on the level of multipliers, seasonal factors, and the discount applied to interruptible capacity.

Multipliers

Cross-border entry and exit points

19.4 ARERA is inclined to confirm the multiplier levels at the cross-border entry and exit points regulated by the RTTG, also in order to offer incentive for longer-duration allocations and favour the use of the facility even during non-peak consumption periods.

19.5 As part of the consultation responses, a request was made for a change in the multipliers (in particular the quarterly one) so that, in the event that the allocation of products is carried out for the entire gas year, the total cost borne by the transmission user is the same as it would have been for transmission capacities on an annual basis. This request is not considered to be related to the definition of multipliers in the strict sense (which, by their nature, are defined *ex-ante* and apply indiscriminately to all users on a given point) but rather, possibly, to *ex-post* reimbursement modalities, to some specific users, of part of the cost incurred for capacity reservation (not the subject of this ruling). In any case, ARERA considers that the multiplier also serves the purpose of enhancing the flexibility provided by the possibility of booking capacity on an infra-annual basis and, as such, should be applied in all cases of infra-annual booking (including cases where the user uses this flexibility in such a way as to cover, *de facto*, the entire gas year).

Redelivery points at city gates

19.6 In relation to the redelivery points feeding distribution networks (city gates) and the recommendation of DCO 213/2022/R/GAS to introduce, on these points, capacity allocations on a daily basis, also on an implicit basis, as a result of the consultation, requests for clarification were received in particular on the relationship between this recommendation and the reform of the capacity allocation processes, in relation to which the final guidelines were consulted with DCO 157/2022/R/GAS, and which was postponed to 1 October 2023 with resolution 225/2022/R/GAS.

19.7 With regard to this point, it should be noted that the possibility of short-term allocations, even on a daily basis, at the city gate redelivery points would be an alternative solution to the one envisaged in DCO 157/2022/R/GAS. In particular:

a) taking into account the provisions of resolution 147/2019/R/GAS that provide for the allocation to each distribution redelivery point (hereafter: DRP) of a conventional transmission capacity, DCO 157/2022/R/GAS recommended the recovery of the transmission cost, with reference to the DRPs identifiable within the settlement as those belonging to the types referred to in paragraph 1.1, letters q) and r) of the TISG[6], through the application of a variable charge to the withdrawn volumes equal for all the aforementioned DRPs and defined

[6] In paragraph 1.1. of the TISG: letter q) defines monthly metered DRPs or MM DRPs as the redelivery points for which the metering attempts are defined in Article 14, paragraph 14.1, letter d) of the TIVG; letter r) defines non-monthly metered DRPs or daily detailed DRPs or MY DRPs as the redelivery points for which the metering attempts are defined in Article 14, paragraph 14.1, letters a) to c) of the TIVG.

on the basis of the overall capacity allocated to them and the relative tariff cost;

b) the recommendation set forth in DCO 213/2022/R/GAS, on the other hand, presupposes a modification of the regulations of resolution 147/2019/R/GAS, providing for the allocation at the redelivery points to the distribution networks, in relation to the DRPs served as identified by DCO 157/2022/R/GAS referred to in the previous point, of a conventional capacity, on a daily basis, determined *ex-post* equal to the sum of the volumes withdrawn in the same DRPs; the capacity transmission tariff would be applied to this daily capacity, re-proportioned on a daily basis, taking into account a multiplier; there would therefore be no need for the specific mechanism for the variability of transmission costs referred to in DCO 157/2022/R/GAS; furthermore, the methods for determining conventional transmission capacities defined in resolution 147/2019/R/GAS for the DRPs other than those identified by DCO 157/2022/R/GAS would remain unchanged.

19.8 The recommendation would therefore represent, in effect, a substantial commoditisation of the cost of transmission in the spirit of the allocation reform, but without prejudice to the criteria for determining the charges, also with a view to greater adherence to the provisions of the TAR NC.

19.9 The transmission tariff approved by ARERA would then be applied to this daily capacity, taking into account an indicative multiplier of 4.

19.10 With respect to the above, ARERA intends to confirm the guidelines expressed in DCO 213/2022/R/GAS, while reserving the right to carry out more in-depth assessments on the implications of the recommendations that emerged as a result of DCO 157/2022/R/GAS[7]. For the purpose of the simulations in this document, the short-term multipliers as set out at Table 3 were taken into account.

Thermoelectric redelivery points and industrial customers

19.11 With resolution 448/2022/R/GAS, ARERA initiated proceedings to comply with the rulings 6096 and 6098 of 2022 of the Council of State, aimed at adopting flexibility and affordability measures for the transmission tariff system for entities with higher natural gas consumption, in application of Article 38, paragraph 2*bis*, of Decree Law 83/2012. In the same resolution, assessments on the introduction of further flexibility measures through the provision of short-term allocations for these gas-intensive users were postponed to the revision process of the tariff criteria for the 6PRT. The main transmission operator was also requested to provide, for the purpose of impact assessments, the gas withdrawal data of all final customers directly connected to the transmission network for the years 2018-2021, no later than 31 October 2022.

[7] It is noted that, in response to DCO 157/2022/R/GAS, some entities recommended a solution involving the allocation of a fixed annual capacity share, determined in a conventional manner, effectively eliminating the need to make the capacity charge variable.

19.12 The need to introduce daily multipliers for industrial customers was also pointed out in the replies to DCO 213/2022/R/GAS.

19.13 ARERA considers it appropriate to introduce the possibility of short-term capacity allocations for redelivery points serving industrial customers, in particular monthly and daily capacity allocations. Based on the analysis of the transmission capacity load factors at these points, it is considered appropriate to adopt a multiplier of 1.3 for monthly capacity products, and 1.7 for daily capacity products.

Table 3: Level of multipliers

Short-term capacity product	Multiplier					
	Entry points	Cross-border exit points	Thermoelectric delivery points	Industrial delivery points	City gates	Other exit / delivery points
Quarterly	1,2	1,2	-		-	-
Monthly	1,3	1,3	2 (1)	1,3	-	-
Daily	1,5	1,5	7 (1)	1,7	around 4 (2)	-
Intra-day	1,5	1,5	-		-	-

(1) Regulated under resolution 512/2017/R/GAS, point 1, letters b) and c)
(2) Without prejudice to further assessments as a result of DCO 157/2022/R/GAS

Seasonal factors

19.14 ARERA, in continuity with the criteria currently in force and taking into account the results of previous consultations, does not consider the introduction of seasonal factors to be necessary.

Interruptible capacity

19.15 Interruptible transmission capacity is made available by the main transmission operator at entry and exit cross-border points, according to the modalities defined in its Network Code, applying reduced capacity charges compared to those applied to firm transmission capacity. The reduction currently applied is 15%, and is determined by the main transmission operator in order to reflect the probability of interruption.

S 15. Comments on multipliers and seasonal factors.

PART IV
DETERMINATION OF TRANSMISSION METERING SERVICE CHARGES

20. **Tariff structure of the metering service**

General criteria

20.1 The current tariff structure of the metering service provides for two charges:

a) the CM^T charge covering the meter reading and metering activities under the direct responsibility of the transmission operator, applied to the allocated capacity at the redelivery points of the transmission network;

b) the CM^{CF} charge to cover the metering activity at final customers' redelivery points, applied to the allocated capacity at redelivery points that supply final customers, whose ownership of the metering system is held by the transmission operator; as of the year 2022, to the redelivery points in the ownership of the transmission operators for which the ownership has been acquired, as of the year 2022, through assignment by the final customers, the CM^{CF} charge is applied at a rate of 50% for a period of 4 years from the time of the assignment.

20.2 In DCO 213/2022/R/gas, ARERA recommended:

a) a differentiation of the CM^{CF} charge on the basis of two or three distinct classes of Qero, also taking into account the costs associated with the different classes of meters, to be assessed on the basis of specific investigations;

b) the definition of these fixed CM^{CF} charges for the entire regulatory period, managing any deviations between the revenue recognised for the metering service and the actual tariff revenue within the revenue compensation mechanism for the metering service.

Differentiation of CM^{CF} charge

20.3 Within the scope of the consultation responses, no particular criticism was expressed with regard to the possible differentiation of the metering charge. One party recommended, instead of a capacitive charge, a fixed charge per redelivery point of the transmission network (again differentiated by flow class).

20.4 On the basis of the data collected, there is, on the one hand, a wide heterogeneity in the cost and allocated capacity data of redelivery points with meters falling in class A (up to 100 Sm^3/h) and, on the other hand, a limited number of plants falling in higher classes. This makes it complex to define specific charges according to the different classes (or possibly sub-classes) of *Qero*, which are, over time, a timely expression of the underlying costs of the service; this is all the more important in view of the recommendation (see point 20.7 *et seq.*) to define the CM^{CF} charge as stable for the entire regulatory period.

20.5 Having said this, it can be seen that installation (reported on an annual basis) and maintenance (on an annual basis) costs increase as the class of the meter increases, but less than proportionally to the average capacity allocated. It follows that, assuming that a capacitive charge is maintained, the charge applied to higher class meters should be lower than that applied to lower class meters in order to reflect the effects of economies of scale.

20.6 In this regard, taking into account the data on average installation and maintenance costs and allocated capacities as provided by the transmission operators, and with the aim of avoiding excessive differences compared to the value of the CM^{CF} charge applied in the years of the 5PRT, ARERA considers it appropriate to introduce at least a twofold differentiation of the CM^{CF} charge, recommending:

a) applying two separate CM^{CF} charges to meters with a *Qero* up to and including 4,000 Sm^3/h (CM_A^{CF}), and to meters with a *Qero* greater than 4,000 Sm^3/h (CM_B^{CF});
b) defining the two charges on the basis of a ratio between the charge applied to higher class meters and the charge applied to lower class meters, kept fixed for the duration of the 6PRT;
c) setting this ratio at 15%, a value that is deemed to strike a balance between the need to reflect the effects of economies of scale in installation and maintenance costs and the need to ensure adequate stability compared to the value in force in the 5PRT.

Stability of CM^{CF} charge

20.7 With respect to the possibility of defining the CM^{CF} charge as stable for the entire regulatory period, it should be noted that the recommendation arises from the need to ensure greater certainty with respect to the evolution of the charge and to facilitate the decisions to alienate the metering plants: there is in fact the risk of a high volatility in the valuation of the charge, due to the transition underway from a system where most of the plants are owned by the final customers, to a system where a significant part of these plants could be sold to the transmission operators for the purposes of an optimised management of the service (see the reform of the metering system regulated by resolution 512/2021/R/GAS). The value of the forecasted contracted capacity and the costs associated with these plants can therefore also vary significantly from year to year.

20.8 In order to ensure greater stability, certainty and predictability in the development of the differentiated CM^{CF} charges as set out above, ARERA is inclined to provide that these are defined for the first year of the regulatory period, and are subsequently updated annually, taking into account only the percentage change in the gross investment deflator used for the purpose of updating the regulatory invested capital.

S 16.	*Comments on the tariff structure of the metering service.*

PART V
REVENUE COMPENSATION AND RECOVERY MECHANISMS

21. Transfers and compensations of tariff revenues

21.1 The application of nationally defined charges makes it necessary to confirm specific revenue compensation and recovery mechanisms aimed at ensuring that each transmission operator receives a revenue consistent with its reference revenue.

21.2 With regard to capacity charges, application of the following is to be confirmed:

a) a transfer of the national network revenues associated with exit charges, aimed at enabling each TSO carrying out the activity of gas transmission on the national gas pipeline network to receive its share of the revenue covering the costs of this service from the regional transmission operators (which collect the revenue from the exit charges, covering the costs of the transmission service both on the regional network and on the national network, at the redelivery points);

b) a revenue compensation for the regional network, aimed at ensuring that each regional transmission operator receives a tariff revenue commensurate with the amount of revenue recognised to cover its costs, rather than the average costs of the sector.

21.3 For the purposes of the management of the mechanisms mentioned in the previous point, the guideline to divide the CP_u charge into the *pro-forma* charges CP_u^R and CP_u^N is confirmed, where:

a) the *pro-forma* charge CP_u^R, referring to regional network revenues, is defined as the ratio of regional network revenues (net of the share of *RSC* revenues and penalties attributable only to redelivery points) to the forecasted contracted capacity to redelivery points;

b) the *pro-forma* charge CP_u^N, referring to national network revenues, is defined as $CP_u^N = (CP_u - CP_u^R)$.

21.4 For the purpose of the management of the revenue compensation mechanism for the regional gas pipeline network, a company-specific *pro-forma* charge $CP_{u,i}^R$ is defined for each regional transmission operator *i*, determined as the ratio between the revenue component $RT_i^{CAP,R}$ of each transmission operator *i* and the forecasted contracted capacity to the redelivery points attributable to each transmission operator *i*.

21.5 Compensation mechanisms similar to that of the revenues relating to the regional network, aimed at enabling each company to obtain a tariff revenue consistent with its specific allowed revenue, must also be applied with reference to the share of the commodity-based charge CV_U to cover operating costs (CV_{COR}) and to the CM^T and CM^{CF} metering charges. For the sake of administrative simplicity, these compensation mechanisms are left to specific inter-TSO compensation agreements.

21.6 Consistent with the mechanisms currently in place, it is therefore considered appropriate:

a) that revenue comepnsation for the regional network be managed by the "Cassa per i Servizi Energetici e Ambientali" (the clearing and settlement agency for the energy sector, hereinafter: CSEA), from the "Conto squilibri perequazione trasporto", and carried out on an annual basis;

b) to refer to specific inter-TSO compensation agreements:

i. the transfer of revenue to cover the transmission service provided on the national gas pipeline network;

ii. the compensation of the *pro-forma* revenue associated with the CV_U commodity-based charge to cover operating costs (CV_{COR});

iii. the compensation of revenue from the application of metering charges.

S 17.	*Comments on revenue compensation mechanisms.*

22. Revenue recovery and reconciliation

22.1 ARERA intends to confirm the application of the following revenue recovery mechanisms:

a) coverage of the risk associated with changes in transmission capacity allocated with respect to that forecasted (transmission service capacity revenue recovery factor);

b) coverage of the risk associated with changes in gas volumes actually withdrawn from the network with respect to those used for the calculation of the CV_U variable charge (transmission service commodity revenue recovery factor);

c) metering service revenue recovery factor.

22.2 Furthermore, due to the amendments recommended on the criteria for recognising network losses, fuel gas and UFG and the associated reconciliation mechanisms (see Chapter 12), the introduction of specific mechanisms for reconciling such items is confirmed.

22.3 The mechanisms described below could be subject to revision/supplementation in order to take into account the need to reconcile revenues following the application of the ROSS approach.

<u>Transmission service capacity revenue recovery factor</u>

22.4 ARERA is inclined to confirm the current application modalities of the recovery factor of the capacity revenue of the transmission service, determined, for each transmission operator, as the difference between:

a) the revenue component used to determine the capacity unit charges, net of the portion relating to overrun charges revenue;

b) the sum of:

i. the revenues actually achieved from the application of the capacity charges CP_e and CP_u, gross of any reductions made by the company and any penalties paid by the transmission operator, net of the compensation mechanisms between transmission operators;

ii. the difference between the revenue component used to determine the capacity unit charges and the same component redetermined on the basis of the final balance sheet data and any updates of the *WACC* pursuant to the TIWACC.

22.5 In calculating the actual revenue, account is also taken of any additional revenue collected by the transmission operator for the supply of additional services pursuant to provisions laid down in the Network Code, the costs of which have not been separated from the recognised costs of the transmission and metering service.

22.6 For the purpose of calculating the actual revenue, with regard to the amount of early termination of long-term transmission contracts, the amounts actually collected shall be taken into account instead of the amounts invoiced, without prejudice to the company's obligation to take all steps to reduce or limit the insolvency risk, in accordance with the principle of utmost diligence.

<u>Transmission service commodity revenue recovery factor</u>

22.7 In DCO 213/2022/R/GAS, ARERA recommended confirming the current modalities of application of the recovery factor for the commodity revenues of the transmission service, which provide the operator with a hedge against the risk of deviation between reference and actual volumes, taking into account a 4% threshold. On this aspect, one operator asked for the Emission Trading System (ETS) costs to be excluded from the share of the variable charge subject to volume risk (within the limits of the allowance).

22.8 ARERA considers that, like the allowance for fuel costs, losses and UFG, the allowance of the commodity recovery factor leaves a risk for the transmission operators (which may result in lower or higher revenues for the company depending on whether the volumes actually delivered by the transmission network are lower or higher than the reference volumes) that varies according to the price of ETS certificates, which is outside the control of the transmission operators. For this reason, similarly to what has already been regulated for the revenue share covering fuel costs, losses and UFG, it is considered appropriate to exclude the revenue share covering ETS costs from the calculation of the commodity recovery factor. Refer to Chapter 8 for the reconciliation modalities of tariff revenues to cover ETS costs.

22.9 Taking the above into account, ARERA is geared to determine the recovery factor of the commodity revenues of the transmission service as the difference between:

a) the revenue component used to determine the commodity-based charge CV_U, excluding the portion of revenue covering fuel gas, losses and UFG (RT_{APG}), and the portion of revenue covering costs related to the Emission Trading System (RT_{ETS});

b) the revenue actually earned from the application of the CV_U charge, gross of any reductions made by the company, the portions of variable charge to cover fuel gas, losses and UFG (CV_{APG}) and the costs relating to the Emission Trading System (CV_{ETS}), and taking into account a 4% allowance.

22.10 The recovery factor is determined for the main transmission operator, which settles the sums with the other transmission operators within the framework of the revenue sharing agreements.

Reconciliation of items related to fuel gas, losses, UFG, and ETS costs

Reconciliation of items relating to fuel gas

22.11 As recalled at point 9.19, the regulatory framework guarantees full recovery of the costs incurred by the RdB to cover fuel gas, in continuity with the regulation in force; consequently, no reconciliation or incentive mechanism is envisaged with reference to this item.

Reconciliation of items related to physical network losses

22.12 In relation to the physical network losses, as recalled in point 9.21, ARERA intends to introduce a mechanism whereby each transmission operator compensates with CSEA, in year *t+1*, the deviation between the actual losses as accounted for in the network balance (supplied by the RdB) and the losses allowed for tariff purposes, valued at the average purchase price by the RdB recorded in the tariff year.

Reconciliation of items relating to UFG

22.13 In relation to UFG, as recalled in point 9.22, the intention is to confirm, in substance, the current mechanism of making transmission operators responsible for deviations between the recognised and the actual UFG, but to adapt it to the new regulatory framework that ensures that the RdB fully covers the costs incurred for UFG, and to modify the parameters of unit exposure and maximum exposure (see point 9.26).

Reconciliation of costs related to the Emissions Trading System

22.14 In relation to the revenue share to cover ETS costs, as mentioned at point 8.3, and due to the changes made to the recovery factor for commodity revenues, it is deemed appropriate to introduce a specific reconciliation of the difference between the actual revenue associated with the *pro-forma* charge CV_{ETS} (company-specific) and the revenues restated to take into account the gas actually used for the operation of the compressor stations, to be settled with CSEA in year *t+1*.

Metering service revenue recovery factor

22.15 ARERA is inclined to confirm, in substance, the current method of determining the recovery factor for metering revenues. With respect to the modalities of recovery of the relative sums, ARERA intends to confirm what was recommended in DCO 213/2022/R/GAS, and in particular to provide that the recovery should take place in analogy to the modalities of recovery of the sums for the transmission service, i.e. by means of adjustment with CSEA in year *t+1* with respect to the tariff year.

22.16 The recovery factor would therefore be determined, for each transmission operator, as the difference between:

a) the metering service reference revenues;

b) the sum of:

   i. the revenue actually earned from the application of the CM^{T} and CM^{CF} metering charges, gross of any reductions made by the operator and net of the compensation mechanisms between transmission operators;

   ii. the difference between the revenue component used to determine the metering charges and the same component restated on the basis of the final balance sheet data.

22.17 In calculating the actual revenue, account is also taken of any additional revenue collected by the transmission operator for the supply of additional services pursuant to provisions laid down in the Network Code.

S 18. Comments on revenue recovery factors.

PART VI
ADDITIONAL CHARGES

23. Additional charges to cover system costs

23.1 Table 4 presents a summary of the additional charges to the transmission tariff to cover the system costs (today governed by Title VIII of the RTTG), specifying their destination, application methods and the relevant account set up with CSEA.

Table 4: Additional charges to the transmission tariff

Component	What covers	Applied to	Account
GS_T	Compensazione delle agevolazioni tariffarie ai clienti del settore gas in stato di disagio	Domestic delivery points other than distribution (exit points excluding cross-border points, storage exits, exits to distribution networks).	Conto per la compensazione delle agevolazioni tariffarie ai clienti del settore gas in stato di disagio
RE_T	Oneri per misure ed interventi per il risparmio energetico e lo sviluppo delle fonti rinnovabili nel settore del gas naturale nonché degli oneri derivanti dalle disposizioni di cui all'articolo 22 e all'articolo 32 del decreto legislativo 3 marzo 2011, n. 28		Fondo per misure ed interventi per il risparmio energetico e lo sviluppo delle fonti rinnovabili nel settore del gas naturale
UG_{3T}	Importi di morosità riconosciuti ai fornitori transitori ai sensi dell'articolo 3 della deliberazione dell'Autorità 12 settembre 2012, 363/2012/R/gas		Conto oneri per il servizio dei fornitori transitori sulla rete di trasporto
CRV^{FG}	Oneri derivanti dall'applicazione del fattore di copertura dei ricavi per il servizio di rigassificazione del Gnl	Domestic delivery points (exit points excluding cross-border points, storage exits).	Conto oneri impianti di rigassificazione
CRV^{I}	Oneri per il contenimento dei consumi di gas di cui alla deliberazione n. 277/07		Fondo per la promozione dell'interrompibilità del sistema gas
CRV^{OS}	Oneri derivanti dall'applicazione del fattore correttivo dei ricavi di riferimento per il servizio di stoccaggio, volto ad assicurare la parziale copertura dei costi riconosciuti per tale servizio anche in caso di una sua valorizzazione al di sotto del ricavo tariffario ammissibile, nonché del conguaglio dei costi di ripristino		Conto oneri stoccaggio
CRV^{BL}	Oneri connessi al sistema del bilanciamento del sistema gas		Fondo per la copertura degli oneri connessi al sistema del bilanciamento del sistema del gas
CRV^{ST}	Oneri connessi al *settlement* gas	Exit points to distribution networks	Fondo per la copertura degli oneri connessi al sistema di settlement gas
CRV^{CS}	Costi per la disponibilità di stoccaggio strategico di cui all'articolo 22 del RAST		Conto oneri stoccaggio

Structure of additional charges for gas-intensive users

23.2 As mentioned at point 19.11, with resolution no. 448/2022/R/GAS ARERA initiated proceedings to comply with the rulings of the Council of State, Sixth Section, nos. 6096 and 6098 of 18 July 2022, aimed at adopting flexibility and affordability measures for the transmission tariff system for gas-intensive users, in application of Article 38, paragraph 2*bis* of Decree Law no. 83/2012.

23.3 With regard to the affordability measures for gas-intensive users that can be taken, the resolution stipulated that:

a) where it is not possible to have recourse to general taxation, it is appropriate that the application of a principle of affordability of the system of natural gas transmission tariffs for gas-intensive users may possibly be assessed with exclusive reference to the additional charges to cover system costs attributable to the regulatory power of ARERA, i.e. the charges aimed at recovering the system costs not covered by the users of the relative services (e.g. the additional charges to cover storage and regasification costs);

b) in order to avoid administrative complexity, it is appropriate that the identification of the potential beneficiaries of the intervention should take place according to criteria not dissimilar to those identified in consultation document 385/2022/R/GAS of 2 August 2022, implementing the MiTE Decree of 21 December 2021, suitably modified to take into account the different scope of application;

c) any further affordability measures may be constructed according to the same application methods already in force for the tariff relief that will be defined in implementation of the MiTE Decree of 21 December 2021, which provide for reimbursements by CSEA of the higher amounts paid by the beneficiaries.

23.4 Any measures affecting the tariff structure of the additional charges are deferred to the proceedings initiated by the aforementioned resolution.

Timing of payment

23.5 With regard to the timing for the payment of the additional charges, with resolution 462/2022/R/COM ARERA ordered, already as from 2023, that the revenue from the additional charges be paid, on a monthly basis, by the 15th day of the second month following the month in which the billing of the charges took place. ARERA considers it appropriate to confirm this provision for the 6PRT.

Credit risk hedging instruments for additional charges

23.6 As part of the replies to DCO 213/2022/R/GAS, some transmission operators pointed out the need to pay only the revenue collected, instead of the revenue invoiced, or alternatively to extend the system of guarantees against the risk of insolvency of the transmission tariff also to the additional charges, also in consideration of the fact that the time compression for payment would in fact make it impossible to carry out debt collection actions for unpaid bills.

23.7 On this point, ARERA considers that in the case of uncollected and otherwise non-recoverable credits relating to the additional charges of the natural gas transmission service, a reintegration mechanism substantially similar to that governed by resolution 119/2022/R/EEL may be applied, which may be activated at the request of the transmission operator. In particular, it is deemed appropriate to provide that the transmission operator shall in any event pay the invoiced revenue but, at a later date, may ask CSEA to repay the financial transactions in respect of which the company, taking into account the outcome of the legal actions taken, is able to prove that the claim is unable to be collected, giving evidence of the relevant causes and demonstrating that it has taken all appropriate and reasonable action to recover the sums in question.

S 19.	*Comments on additional charges.*