CONSULTATION DOCUMENT

381/2026/R/GAS

TARIFF REGULATORY CRITERIA FOR THE NATURAL GAS TRANSMISSION AND METERING SERVICE FOR THE SEVENTH REGULATORY PERIOD (7PRT)

Final guidelines

Consultation document for the formation of rulings within the framework of the proceedings initiated with resolution 16/2026/R/GAS of the Italian Regulatory Authority for Energy, Networks and Environment (ARERA) of 3 February 2026

Markets of incidence: natural gas

22 October 2026

Whereas

This consultation document is part of the proceedings initiated with the resolution of the Italian Regulatory Authority for Energy, Networks and Environment (hereinafter: ARERA) of 3 February 2026, 16/2026/R/GAS, for the formation of rulings on tariffs and quality of the natural gas transmission and metering service, for the seventh regulatory period (7PRT) and, taking into account the outcomes of the consultation document 165/2026/R/GAS of 12 May 2026, sets out ARERA's final guidelines on the determination of revenues and reference prices of the natural gas transmission and metering service for the 7PRT, starting in 2028.

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 ***22 December 2026****.*

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Participants wishing to preserve the confidentiality or secrecy, in whole or in part, of the comments and/or documentation submitted are required to specify which sections are to be considered confidential and may not be disclosed, identifying in separate appendices the parts to be excluded from publication. In such cases, interested parties must also submit, in electronic format, a version with the confidential sections redacted, for publication should ARERA's Offices accept the confidentiality request. A general confidentiality statement included in the communications submitted will not be regarded as a request for anonymous publication or for non-disclosure of the contributions provided. In the absence of requests for confidentiality or secrecy protection and/or where redacted versions are not submitted, comments will be published in their entirety.

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ARERA
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per Energia Reti e Ambiente

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PART I
INTRODUCTION

1. Procedural framework and scope of the consultation

1.1 This consultation document is part of the proceedings initiated with resolution 16/2026/R/gas of 3 February 2026 (hereinafter: resolution 16/2026/R/gas) for the adoption of rulings on tariffs and quality of the natural gas transmission and metering service, for the seventh regulatory period (7PRT), starting on 1 January 2028. Pursuant to point 2 of that resolution, the proceeding is subject to a Regulatory Impact Assessment (RIA), in accordance with the criteria set out in resolution 255/2025/A adopting ARERA's Regulation governing the conduct of RIAs (RIA Regulation), and consistently with the RIA Procedure (Annex 2 to resolution 255/2025/A).

1.2 As part of these proceedings, and following a meeting with associations representing transmission system users held on 11 March 2026, in the consultation document 165/2026/R/gas ARERA outlined presented 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), as well as the regulatory framework governing the quality of the natural gas transmission service.

1.3 Overall, responses to consultation document 165/2026/R/gas showed broad support for the objectives of containing transmission costs, improving efficiency and enhancing regulatory transparency, together with requests for additional quantitative analysis and tariff simulations to support decision-making. Several respondents, particularly transmission operators, also highlighted the need to ensure stability and predictability of the regulatory framework, while at the same time promoting an appropriate allocation of costs and maintaining a balance between the economic sustainability of infrastructure investments and the protection of end users. Stakeholders further stressed the importance of preserving the competitiveness of the Italian market within the European context by strengthening its attractiveness for international gas flows, particularly LNG-related flows, and avoiding regulatory arrangements that could weaken Italy's position relative to other continental hubs. Some contributions also underlined the need to safeguard the security and adequacy of infrastructure through efficiency-oriented incentive mechanisms. Lastly, respondents called for greater stakeholder engagement through technical working groups and structured consultation opportunities throughout the regulatory process.

1.4 Following requests raised as part of the consultation on document 165/2026/R/gas, a thematic meeting with transmission operators (hereinafter also referred to as the focus group) was held on 23 September 2026 to discuss in greater detail the responses received. The discussion focused primarily on:

a) cost recognition criteria under the ROSS (see resolution 163/2023/R/com and Annex) approach;
b) incentive and efficiency mechanisms, regarding particularly the proposals set out in consultation document 165/2026/R/gas on investment selectivity, capital expenditure efficiency and the continued operation of fully depreciated assets;
c) the remuneration of the cost of capital, particularly the remuneration of assets under construction and the end of the measure of increased WACC remuneration to compensate for the regulatory lag;
d) recognition of the costs associated with dual-fuel and fully electric compressor stations;
e) administrative simplifications.

1.5 This consultation document, which has also been prepared in accordance with the RIA Regulation, presents ARERA's final proposals on the criteria for determining reference revenues and on the charges applicable to the natural gas transmission and metering service during the 7PRT.

1.6 In light of the provisions of TAR NC establishing specific requirements for national regulatory authorities with regard to the consultation process (Articles 26 and 28), as well as the provisions governing the review to be carried out by the Agency for the Cooperation of Energy Regulators (ACER) (Article 27), it is necessary to ensure the adoption, by March 2027, of the final resolution setting out the tariff regulation criteria for the natural gas transmission service, effective from 2028. In addition, the information on tariff levels for 2028 required under Articles 29 and 30 of TAR NC must be published by 31 May 2027.

1.7 As regards the timetable for the adoption of tariff regulation criteria for the 7PRT, the schedule set out in Table 1 of consultation document 165/2026/R/gas remains broadly unchanged. Reference is made to that consultation document for a description of the objectives of ARERA's intervention, including for RIA purposes, as well as for a detailed overview of the regulatory and legislative framework, market conditions and outlook, and the initial proposals developed by ARERA.

1.8 Given the breadth and complexity of the issues under discussion, this document provides a detailed rationale only for those topics that attracted the greatest attention during the previous consultation phase. For more details on the guidelines set out by ARERA in consultation document 165/2026/R/gas, 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. Outline of the document

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

a) Part II, in which the final guidelines on the criteria for determining the reference revenues for charges are set out, as well as criteria for incentives and efficiency measures;
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 other relevant aspects.

2.2 An executive summary in English and the document containing the data and information required under TAR NC (Appendix), including simulations of revenue and tariff levels for 2028, are published together with this consultation document.

2.3 In addition, to facilitate the assessment that ACER is required to carry out under Article 27 of TAR NC on the proposals set out in this document, ARERA will send to ACER the template containing the consultation requirements of the TAR NC.

2.4 The main transmission operator will make the simplified tariff model available in a specific section dedicated to stakeholder consultation on regulatory criteria and tariff levels for the 7PRT.

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) general cost recognition criteria and the related implementation arrangements;
d) additional criteria for the recognition of capital costs;
e) incentive and efficiency mechanisms;
f) revenue components covering specific cost items (costs relating to fuel gas, network losses and unaccounted for gas (UFG), costs related to the Emission Trading System, and costs relating to operational balancing), which are excluded from the application of the ROSS methodology;
g) criteria for determining the reference revenues of new transmission system operators;
h) recovery of costs relating to the metering service on the gas transmission network.

4. Start date and duration of the regulatory period

4.1 ARERA confirms the proposal set out in consultation document 165/2026/R/gas to maintain a four-year duration for the seventh regulatory period (7PRT), running from 1 January 2028 to 31 December 2031. This approach is consistent with the duration of the current regulatory period, aligned with the integrated text on expenditure and service-output regulation for regulated electricity and gas infrastructure services for the period 2024-2031 (TIROSS 2024-2031), and reflects the broad consensus expressed by respondents.

5. General cost recognition criteria under the ROSS approach

Structure of reference revenues

5.1 ARERA confirms the current structure of reference revenues, in line with the existing regulatory period and taking into account the broad support expressed by respondents. Reference revenues for the determination of transmission charges would therefore comprise the following revenue components covering:

a) remuneration of the recognized net regulatory asset base;

b) regulatory depreciation;
c) operating costs;
d) incentives granted in previous regulatory periods in the form of an uplift to the rate of return, as well as any new incentive mechanisms;
e) costs relating to fuel gas, network losses and unaccounted for gas (UFG);
f) costs relating to the Emissions Trading System (ETS);
g) costs relating to the system's hourly balancing service.

6. General cost recognition criteria under the ROSS approach

6.1 In consultation document 165/2026/R/gas, ARERA proposed general cost recognition criteria broadly consistent with those applied during the 6PRT, within the framework of the ROSS principles, while also assessing opportunities for administrative simplification.

Scope of application of the ROSS criteria

6.2 With regard to the scope of application of the ROSS criteria, consultation document 165/2026/R/gas presented three alternative options, together with the related RIA assessment. In particular:

a) Scope Option 0 (baseline option) – maintain, for the 7PRT, the same scope of application of the ROSS criteria as under the 6PRT, applying ROSS criteria to all transmission system operators under an evolutionary approach;
b) Scope Option 1 – apply ROSS criteria under an evolutionary approach to the main transmission system operators operating the national transmission network (Snam Rete Gas and SGI), while applying the general TIROSS cost recognition criteria to the other transmission system operators, with a view to administrative simplification and proportionality of regulatory measures (hereinafter also referred to as the simplified ROSS approach);
c) Scope Option 2 – extend the simplified ROSS approach to all gas transmission system operators, representing an evolutionary step compared to the arrangements envisaged for the 6PRT.

6.3 The comments received and the discussions held during the focus group with network operators indicate a prevailing preference for a simplified regulatory approach, with broad support for the adoption of the simplified ROSS model (Scope Options 1 and 2) rather than further development towards a full-Ross framework. At the same time, respondents stressed the need for a gradual implementation process.

6.4 More generally, respondents considered it appropriate either to limit the application of the full ROSS framework to the main transmission system operator or to defer its wider implementation, given that the expected benefits have not yet been sufficiently demonstrated in light of the additional organisational, administrative and managerial burden involved. In this regard, stakeholders noted that, also considering the ongoing experimentation of some aspects of ROSS

regulation, there is still limited evidence as to the actual ability of the full ROSS framework to achieve its intended objectives, namely reducing capex bias, improving overall spending efficiency and strengthening performance incentives. For this reason, some respondents considered it premature to take definitive decisions on its broader application before the completion and assessment of the experimental phase.

6.5 With specific reference to Scope Option 1, some respondents pointed out that applying the full ROSS framework (i.e. the evolutionary application of ROSS criteria) only to a subset of operators could create difficulties in benchmarking performance, raise proportionality concerns and lead to potential competitive distortions, while also reducing the overall consistency of the regulatory framework.

6.6 By contrast, consultation responses showed broad support for the simplified model based on the recognition of actual capitalised expenditure (Scope Option 2), which is considered more closely aligned with actual costs incurred, more transparent and predictable in terms of revenue determination, and less burdensome to manage. Under this approach, efficiency objectives could be pursued through specific incentive mechanisms without introducing the complexity associated with the full ROSS framework.

6.7 Respondents also highlighted the importance of ensuring continuity in efficiency assessment mechanisms across regulatory periods so as to preserve incentives for performance improvements over time.

6.8 Finally, stakeholders called for a broader discussion on the future development of the ROSS framework, noting that the introduction of differentiated rules across operators could represent a significant change in the regulatory model and may also have implications for other regulated infrastructure services. Overall, a clear preference for simplicity, proportionality, regulatory certainty and gradual implementation in the further evolution of the regulatory framework has emerged.

6.9 ARERA confirms its preference for options involving the application of simplified ROSS criteria, at least for smaller transmission system operators, provided that they are accompanied by specific mechanisms aimed at promoting capex efficiency.

6.10 In line with the principle of proportionality in regulatory action, ARERA therefore maintains its preference for Scope Option 1, under which ROSS criteria would continue to evolve for the main transmission system operators operating the national transmission network (Snam Rete Gas and SGI), while the general TIROSS cost recognition criteria would apply to the remaining transmission system operators. This option appears best suited to balancing the trade-offs between administrative simplification and a regulatory framework designed to promote efficiency in service provision while maintaining consistency with the cost recognition principles set out in TIROSS. Under this approach, the evolutionary ROSS framework would apply to operators accounting for approximately 99% of service revenues, while the remaining transmission system operators would be subject to a simplified ROSS approach, aligned with the

principles defined in TIROSS but implemented in a more proportionate manner. The capital efficiency incentive mechanism described in paragraphs 8.1 et seq. would, however, apply to all transmission system operators. In this respect, ARERA considers that the ongoing experimentation does not prevent the adjustment of regulatory tools currently being tested, such as the business plan and cost assessment processes, for the implementation of the regulatory measures envisaged for the 7PRT, including the definition of the operating expenditure baseline, the determination of capitalisation rates and the application of the capital efficiency mechanism. Such adjustments build on the experience gained to date and reflect the opportunities identified for further improvement, while supporting a gradual learning process for both ARERA and network operators.

6.11 About the need for greater stability and predictability of revenue components, ARERA considers that targeted adjustments to specific ROSS parameters, such as the capitalisation rate, could help address the concerns raised during the consultation process.

6.12 Smaller transmission system operators would be subject to a simplified ROSS approach, largely analogous to that applied to larger operators, but characterised by:

a) determination, for each year, of the capitalisation rate on the basis of the actual share of capital expenditure in total expenditure (estimated ex ante and adjusted ex post), with the corresponding allocation of total expenditure between fast money and slow money components in accordance with Section III of TIROSS and the nature of the underlying costs;

b) simplification of the cost assessment obligations set out in Article 45 of TIROSS, focusing only on those elements necessary for the operation of capital efficiency mechanisms;

c) discontinuation of the incentive mechanism for the accurate reporting of capital expenditure provided for in Article 46 of TIROSS.

6.13 The introduction of differentiated criteria for smaller operators is consistent with the approach already applied to electricity distribution through the parametric tariff regime. Furthermore, the introduction of simplified ROSS criteria is consistent with the proposals consulted upon in consultation document 267/2026/R/gas of 23 July 2026 concerning gas distribution (see Chapter 9), in which ARERA assessed different regulatory options regarding the configuration of the ROSS model and expressed a preference for the so-called simplified base ROSS model (Option A.1). This option was considered capable of balancing the objective of mitigating capex bias with the need to avoid introducing additional administrative burdens and complexity for operators and contracting authorities, also taking into account the specific characteristics of the gas distribution service, particularly the award of concessions through competitive tenders.

6.14 As regards the need to ensure continuity in efficiency assessment mechanisms across regulatory periods, ARERA confirms the application to all operators of the criteria set out in TIROSS, including the mechanism allowing efficiencies and inefficiencies to be recognised for up to four years after they have been achieved,

and the determination of a new operating expenditure baseline, as discussed in paragraph 6.28 et seq.

S 1. Comments on the proposed scope of application of the ROSS criteria.

Capitalisation rates and incentives for accurate reporting of expenditure

6.15 In consultation document 165/2026/R/gas, ARERA proposed, for those transmission system operators to which ROSS criteria would continue to apply under an evolutionary approach (Scope Options 0 and 1), to maintain the capitalisation rate methodology established by resolution 390/2025/R/gas for 2026-2027. Under this proposal, the capitalisation rate for the 2028-2029 period would be set as the average of the capitalisation rates for the years 2025-2029, based on historical and forward-looking data supported by the business plan. The proposal also envisaged a cap of 5% on the deviation between the ex-ante expected capitalisation rate for each year and the average capitalisation rate, together with the possibility of a mid-period reopener.

6.16 The comments received during the consultation process and the discussions held with network operators in the focus group revealed opposition to notional capitalisation rates based on a combination of historical and forward-looking data. Respondents generally favoured the use of actual capitalisation rates, on the grounds that these provide a closer alignment between costs incurred and tariff recognition, while avoiding distortions in the allocation of expenditure between fast money and slow money components.

6.17 As an alternative, the main transmission system operator highlighted the need to adopt an approach based on forward-looking data, accompanied, where appropriate, by ex-post adjustment mechanisms to align regulatory parameters with changes in actual expenditure.

6.18 Consistent with its preference for Scope Option 1 (application of simplified ROSS criteria to smaller transmission system operators), ARERA considers it appropriate that, for transmission system operators subject to ROSS criteria under an evolutionary approach, the notional capitalisation rate should be determined taking into account the concerns raised during the consultation process by assigning greater weight to forward-looking information. This would help prevent excessive misalignments in expenditure components resulting from changes in expenditure patterns over time. In particular, ARERA proposes that the notional capitalisation rate for the first two years of the 7PRT be calculated as the average of the capitalisation rates for the years 2027-2029, based on estimated outturn data or forward-looking projections supported by the business plan. The 5% cap on the deviation between the ex-ante expected capitalisation rate for each of the years 2028 and 2029 and the average capitalisation rate would be maintained. The possibility of a mid-period reopener is also confirmed for the years 2030-2031, based on the average capitalisation rates observed over the period 2029-2031.

6.19 It should be noted that, for transmission system operators subject to ROSS criteria under an evolutionary approach, expenditure forecasts continue to play a

significant role in determining the capitalisation rate and, consequently, the related tariff recognition. For this reason, the incentive mechanism for the accurate reporting of capital expenditure provided for in Article 46 of TIROSS would continue to apply, also with a view to preventing opportunistic behaviour by network operators. ARERA considers that this mechanism helps ensure greater accountability in the preparation of expenditure forecasts used to calculate the capitalisation rate, while limiting incentives for strategic behaviour aimed at influencing the allocation of expenditures between slow money and fast money components.

S 2. Comments on the proposed capitalisation rate methodology and on the incentive mechanism for the accurate reporting of expenditure.

Determination and update of the operating expenditure baseline and X-factor

6.20 Pursuant to Article 41 of TIROSS, consultation document 165/2026/R/gas proposed that the 2028 operating expenditure baseline should be determined based on:

a) the actual level of operating expenditure in 2027, taking into account estimated or provisional outturn values;

b) an adjustment of the individual operating expenditure items or categories estimated for 2027 to reflect the productivity improvement expected for 2028, determined based on the average productivity gains observed in previous years. Where a given operating expenditure item or category showed a reduction over the period 2024-2026 (in real terms), the estimated 2027 expenditure would be adjusted by applying the average annual decrease recorded during the period 2024-2026.

6.21 Consultation document 165/2026/R/gas also proposed:

a) the recognition, through the ex-post Z-factor mechanism provided for under TIROSS from 2026 onwards, of any incremental operating costs incurred in 2028 compared to the 2027 test year;

b) the calculation of the 2028 operating expenditure baseline once the 2026 unbundled annual accounts become available, as part of the determination of the 2026 allowed revenue, by the end of 2027. This exercise would also take account of the best available estimate of 2027 operating expenditure based on the latest provisional data available at that time;

c) for the purposes of the 2028 transmission tariffs, the use of the most recently determined 2027 operating expenditure baseline, updated to 2028 to reflect forecast inflation.

6.22 With regard to the annual reduction factor applied to recognised operating expenditure (X-factor) for the purpose of updating the baseline, and taking into account the provisions of TIROSS, ARERA proposed:

a) for transmission system operators subject to ROSS criteria under an evolutionary approach:

i. to determine the X-factor under the low-powered incentive option (SBP) referred to in Article 10 of TIROSS as the average annual change in actual operating expenditure observed over the period 2024-2026, where such change is negative. Where the average annual change is positive, the X-factor would instead be set so as to align the baseline in the final year of the new regulatory period (2031) with the 2027 baseline;

ii. to determine the X-factor under the high-powered incentive option (SAP) referred to in Article 11 of TIROSS upon specific request by the operator, provided that it is not lower than either the SBP X-factor or the value applied during the 6PRT (0.5%, see Article 3 of resolution 497/2023/R/com);

b) for transmission system operators subject to the simplified ROSS approach, to determine the X-factor according to the same criteria, but without the possibility of adopting the SAP option.

6.23 Responses to the consultation and comments made during the focus group held on 23 September 2026 raised some concerns regarding ARERA's proposals. Respondents considered it preferable:

a) not to impose productivity targets based on historical data, since efficiencies achieved in the past do not necessarily imply structurally achievable future efficiencies and could effectively sterilise future efficiency improvements;

b) in order to provide ex-ante certainty regarding the level of reference revenues, to incorporate any incremental costs eligible for tariff recognition, whether through the Y-factor or Z-factor mechanisms, directly into the baseline on an ex-ante basis using the best available estimates, particularly in cases involving regulatory or legislative changes with a lasting impact;

c) not to determine the X-factor on the basis of past efficiency gains, as this would amount to a double penalty for operators and would be inconsistent with the incentive logic underpinning the ROSS framework, thereby discouraging further efficiency improvements. One operator also noted that, after more than twenty years of incentive-based regulation, residual efficiency potential in operating expenditure is now limited, if not exhausted.

6.24 More generally, one operator argued that the SAP option is effectively unworkable and that the incentive mechanisms established under TIROSS are less effective than the previous framework in rewarding efficient behaviour and generating benefits shared between operators and the system as a whole. Transmission system operators, together with some network users, also stressed the desirability of maintaining continuity with the current regulatory period.

6.25 ARERA considers the observations concerning the difficulty of replicating past efficiency gains and the need to ensure ex-ante certainty regarding reference revenues to be well founded. However, consistently with the changes introduced by resolution 390/2025/R/com to the Z-factor framework, ARERA considers that incremental costs can be more effectively captured on an ex-post basis once they have actually materialised. This approach promotes administrative simplification,

provides greater certainty regarding the genuinely incremental nature of such costs and mitigates the regulator's exposure to information asymmetries.

6.26 Accordingly, taking account of the comments received and the objective of administrative simplification, ARERA considers it appropriate, for all transmission system operators, irrespective of whether they are subject to simplified ROSS criteria or to the evolutionary ROSS approach, to:

a) confirm the proposal to determine the operating expenditure baseline on the basis of actual operating expenditure in 2027, taking into account estimated or provisional values submitted by operators for the purpose of redetermining the 2027 reference revenues as part of the 2028 tariff-setting process, without including any incremental costs expected to arise in 2028, which may instead be addressed through the Y-factor and Z-factor mechanisms established under TIROSS;

b) discontinue the adjustment of individual operating expenditure items or categories estimated for 2027 based on reductions observed over the period 2024-2026;

c) determine the X-factor used to update the baseline during the 7PRT on a fixed-rate basis, consistently with the approach adopted for the 6PRT, rather than through the predefined methodology proposed in consultation document 165/2026/R/gas. In particular:

   i. the X-factor under the SBP option would be set below the level applicable under the SAP option, but above zero, taking into account both the efficiency gains already achieved through the efficiency-sharing mechanism applied during the 6PRT and the desirability of establishing a minimum efficiency target unrelated to individual operators' past performance and independent of incremental cost dynamics addressed through the Y-factor and Z-factor mechanisms. For this purpose, an X-factor of 0.1% could be adopted as a conservative estimate of expected productivity growth, supported by historical ISTAT data on total factor productivity in Italy, particularly over a period representative of a full business cycle, namely 2010-2019, from the years following the global financial crisis up to the period immediately preceding the COVID-19 pandemic;

   ii. the X-factor under the SAP option would remain unchanged at 0.5%;

d) apply this minimum productivity target also in the first year of the regulatory period, for the purpose of updating 2027 operating expenditure to 2028 in the determination of the baseline.

6.27 The operating expenditure baseline for the 7PRT would therefore be determined based on estimated or provisional data relating to 2027. In addition, ARERA intends to retain the possibility of redetermining the 7PRT baseline once actual 2027 operating expenditure data become available, as part of the determination of the allowed revenue for that year, by the end of 2028, should material deviations emerge compared to the provisional estimate, whether positive or negative, and exceeding a threshold of 3% to 5%.

S 3. Comments on the proposed criteria for determining and updating the operating expenditure baseline and recognised operating expenditure.

7. Other criteria for determining capital costs

Allowed regulatory asset base

7.1 In consultation document 165/2026/R/gas, ARERA proposed confirming the general criteria applied during the sixth regulatory period (6PRT) for the determination and updating of the recognised regulatory asset base (RAB), based on:

a) investment costs, provided that the relevant investments are consistent with the efficiency and security of the system, carried out in accordance with principles of economic efficiency, and within the limits of quantifiable and measurable benefits, while also taking into account minimum development requirements for projects in newly gasified areas;

b) the revaluation of the historical cost of asset additions through the Capital Revaluation Index, equal to 1 in year t-1 relative to the tariff year, determined on the basis of the Harmonised Index of Consumer Prices for Italy (HICP Italy), using the overall index published by Eurostat[1].

7.2 ARERA also clarified that, under no circumstances, may investment costs relating to projects that have received a negative or suspended assessment following ARERA's evaluation of the Ten-Year Network Development Plan be eligible for tariff recognition. An exception would apply to investment costs associated with projects already included in previous editions of the Development Plans and not subject to adverse assessment, insofar as such costs were incurred before ARERA issued its negative or suspended assessment.

7.3 Respondents broadly supported ARERA's proposals. However, TSOs asked to:

a) revalue asset additions commissioned in a given year but developed and constructed over previous years;

b) clarify in the regulatory framework that expenditure incurred up to the point at which ARERA issues a negative or suspended assessment continues to be recognised, thereby mitigating regulatory risks for projects characterised by lengthy development timelines;

c) explicitly state that costs incurred for projects initiated in compliance with legal or regulatory obligations but subsequently abandoned, are recognised consistently with the principle already established by resolution 191/2026/R/gas.

7.4 Considering the comments received, ARERA intends to confirm the proposals set out in consultation document 165/2026/R/gas.

[1] See resolution 130/2025/R/com. Historical cost revalued on the basis of the Harmonised Index of Consumer Prices for Italy (HICP Italy), using the overall index published by Eurostat.

7.5 With specific regard to the revaluation of new assets commissioned in a given year but developed and constructed over previous years, ARERA considers that there are no grounds for revising the general criteria governing the eligibility of capital expenditure, which apply across all regulated services and are set out in TIROSS (Article 4). These criteria are based on the historical cost principle, whereby an asset is recognised at its acquisition cost at the time of first use or at its construction cost. It should also be noted that the introduction of the ROSS framework established the principle of revaluing assets under construction (see Article 22 of TIROSS), which partially mitigates the issue highlighted in relation to the implementation phase of an investment project. However, this does not provide a basis for revaluing asset additions when they become operational.

7.6 With regard to regulatory risks associated with projects characterised by lengthy development timelines, ARERA intends to confirm the proposal set out in consultation document 165/2026/R/gas to clarify that, under no circumstances, may investment costs relating to projects that have received a negative or suspended assessment following ARERA's evaluation of the Ten-Year Network Development Plan be eligible for tariff recognition. An exception would apply to investment costs associated with projects already included in previous editions of the Development Plans and not subject to adverse assessment, provided that such costs were incurred before ARERA issued its negative or suspended assessment.

7.7 Lastly, ARERA considers it appropriate to clarify that expenditure incurred in relation to projects initiated in compliance with legal or regulatory obligations but subsequently abandoned may be eligible for tariff recognition. Depending on their nature, such costs may be included under Intangible Assets or Other Tangible Assets, subject to a specific request being submitted as part of the tariff proposal.

S 4. Comments on the criteria for determining the recognised regulatory asset base (RAB).

Rate of return and gearing

7.8 In consultation document 165/2026/R/gas, taking into account the provisions of TIWACC 2022-2027 (Article 7), under which the gearing ratio, defined as the ratio of debt capital (D) to total capital (D+E), is normally updated as part of the tariff review of each regulated service, ARERA noted that leverage levels in the transmission sector exceed the notional gearing currently embedded in the regulatory framework and have increased over time. At the same time, ARERA recognised the need for further assessment of a possible revision of the general criteria used to determine the gearing parameter, while ensuring consistency across regulated services and with the broader framework governing the rate of return on invested capital. Consequently, any revision of the gearing parameter was deferred to the process for reviewing the criteria for determining and updating the rate of return on invested capital applicable to electricity and gas infrastructure services, also considering that both the third WACC period (3PWACC) and the seventh transmission regulatory period (7PRT) will commence in 2028.

7.9 The consultation revealed broad support among network users for ARERA's proposal. Respondents generally agreed that the current gearing level no longer adequately reflects the sector's actual financing structure. Some stakeholders advocated bringing forward the review of the parameter to 2027, while others supported postponing any revision until the forthcoming TIWACC review. By contrast, the main TSOs and the transmission system operator, although supporting the decision to defer the review, questioned both ARERA's analysis and the proposal to align the parameter more closely with observed leverage levels. Similar views were reiterated during the focus group held on 23 September 2026. Respondents argued that:

a) accounting-based indicators do not adequately reflect the actual financing structure of regulated operators; the gearing parameter should instead be determined on the basis of metrics consistent with the regulatory framework, taking into account the RAB[2], in line with financial market practice and the methodologies adopted by rating agencies for regulated utilities. Alternatively, market capitalisation could be used, as it more accurately reflects the level of risk perceived by investors and rating agencies;

b) increasing the notional gearing parameter would reduce the share of equity recognised in the WACC and, consequently, the return allowed to investors. This could encourage operators to rely more heavily on debt financing, increasing the financial risk perceived by the market and potentially resulting in a higher cost of capital;

c) the gearing parameter should retain its notional and benchmark nature, reflecting the financing structure of an efficient operator rather than the leverage actually observed for individual companies, while supporting the maintenance of an adequate credit profile;

d) the gearing value currently recognised by ARERA, equal to 0.5, is already broadly aligned with European regulatory practice for network infrastructure, where notional gearing levels typically range between 40% and 60%.

7.10 ARERA intends to maintain its proposal to defer any assessment of a possible revision of the gearing parameter to the 3PWACC review process, also to consider the comments received during the consultation.

Additional remuneration to compensate for the regulatory lag

7.11 In consultation document 165/2026/R/gas, ARERA proposed phasing out the application of the 1% premium on the rate of return granted to compensate for the regulatory lag for new investments undertaken between 2014 and 2016. In ARERA's view, the additional remuneration recognised to date (amounting to approximately EUR 20 million per year since 2017) can be considered sufficient to offset the impact of the regulatory lag on tariff recognition.

[2] Accounting values reflect historical figures that are influenced by depreciation policies and accounting valuation criteria, whereas the WACC is applied to a revalued asset base.

7.12 The main TSOs (both in their consultation responses and during the focus group held on 23 September 2026) and the electricity transmission system operator strongly objected to ARERA's proposal on the grounds that:

a) the early removal of the measure would retroactively alter the remuneration conditions applicable to investments that have already been undertaken and are still far from the end of their regulatory useful life, thereby undermining the principles of regulatory certainty, stability, predictability and credibility;

b) a retroactive revision of the remuneration framework would increase the level of risk perceived by investors and could translate into higher returns required by investors, as well as a higher cost of debt and equity, ultimately producing adverse effects;

c) discontinuing the premium for assets that have not yet reached the end of their regulatory useful life would be inconsistent with the objective of ensuring a net present value of investments aligned with the recognised WACC and would also be at odds with the need to preserve regulatory stability.

7.13 In response to these concerns, it should be noted that the proposal to discontinue the additional remuneration cannot in any way be regarded as undermining the principles of regulatory certainty, stability, predictability, credibility and inter-temporal consistency. Given the time that has elapsed since the introduction of the measure designed to compensate for the regulatory lag, the proposal essentially consists in reassessing the measure in order to verify whether its original objective has been achieved, namely to compensate for the reduced remuneration resulting from the recognition of investments with a two-year, rather than one-year, regulatory lag (see resolution 514/2013/R/gas[3] and consultation document 164/2013/R/gas[4]). In this regard, it should be emphasised that, when introducing the measure, ARERA did not specify its duration but merely set out its purpose, which, based on the analysis carried out, can now be considered fulfilled. Consequently, as already explained in the consultation, the proposal to discontinue the additional remuneration designed to compensate for the regulatory lag is based on the finding that the additional remuneration granted to date has already offset the impact of the regulatory lag in the tariff recognition of investments undertaken between 2014 and 2016.

7.14 This conclusion is also supported by an analysis of the tariff data of the main TSO. In particular, two different internal rates of return (IRRs) were compared: (i) the IRR resulting from the current regulatory framework, which combines a two-year regulatory lag with a 1% premium on the rate of return for investments undertaken between 2014 and 2016, applied until and including 2027; and (ii) the theoretical IRR under a counterfactual scenario in which those investments are recognised with a one-year regulatory lag and no compensatory premium. The analysis shows

[3] In particular, resolution 514/2013/R/gas introduced "the recognition of a 1% premium on the recognised cost of invested capital, in line with the approach adopted in the electricity sector, in order to compensate for the regulatory lag in the recognition of new investments".

[4] In particular, consultation document 164/2013/R/gas specified that the objective of the measure under consultation was to "neutralise the reduction in effective remuneration resulting from the regulatory lag in the recognition of new investments".

that, over the period 2016-2027, the current regulatory framework has resulted in an additional IRR of approximately 0.5 percentage points. Furthermore, over the full regulatory life of the assets, maintaining the additional remuneration on the WACC would result in an IRR approximately 0.3 percentage points higher than under the counterfactual scenario, implying a level of remuneration exceeding the original purpose of the measure.

7.15 If the additional remuneration (a 1% premium on the WACC) for the regulatory lag were removed from the beginning of the next regulatory period (7PRT), the IRR of these investments over the regulatory life of the assets would be broadly equivalent to the theoretical IRR that would have been achieved under the counterfactual scenario in which the regulatory lag applicable to those investments was one year and no compensatory premium was granted.

7.16 As the objective of ensuring a net present value of investments consistent with the recognised WACC can therefore be considered achieved, ARERA intends to confirm its proposal to discontinue the additional remuneration designed to compensate for the regulatory lag.

S 5. Comments on the proposal to discontinue the additional remuneration designed to compensate for the regulatory lag.

Return on assets under development

7.17 In consultation document 165/2026/R/gas, ARERA proposed maintaining the recognition of financing costs associated with capital tied up during the construction phase. At the same time, ARERA considered the possibility of adopting a rate of return that more closely reflects the recognised cost of debt (real Kd) included in the WACC, rather than a rate derived from a WACC calculated assuming a debt-to-equity ratio of 4. This approach would also be broadly consistent with the regulatory frameworks applied in other European countries, such as France, where assets under construction are remunerated at the cost of debt, and Spain, where no remuneration is granted during the construction phase.

7.18 The consultation revealed diverging views. Network users generally supported the principle of a more conservative remuneration of assets under construction, given that such assets do not yet generate benefits for the system. By contrast, TSOs (and the electricity transmission system operator) strongly opposed ARERA's proposal, also during the focus group held on 23 September 2026, arguing that assets under construction should be remunerated at the full WACC during the 7PRT. Respondents raised the following concerns:

a) the timely completion and commissioning of infrastructure projects should not be incentivised through the application of different rates of return to assets under construction and assets included in the RAB. Moreover, under the current framework, operators are already incentivised to bring new investments into operation as quickly as possible, given both the lower remuneration of assets under construction and the commencement of depreciation allowances only once the assets become operational;

b) from an economic perspective, it is not correct to assume that assets under construction are financed almost exclusively through debt, as this would result in an under-remuneration of invested capital;

c) assets under construction are exposed to the same systematic risks as the activities to which they relate and, during the construction phase, such risks may even be higher;

d) remunerating assets under construction primarily based on the cost of debt could encourage greater reliance on debt financing, increasing the level of risk perceived by investors and ultimately increasing the overall cost of capital;

e) under the ROSS framework, revenues should be determined based on capital expenditure rather than by reference to new assets becoming operational;

f) the regulatory frameworks applied in France and Spain represent particularly restrictive cases. In most major European jurisdictions, including the United Kingdom, Ireland, Germany, Austria, Luxembourg and, albeit through different approaches, the Netherlands, investments under construction are remunerated based on WACC or by taking into account an equity component.

7.19 Considering both the comments received and the evidence collected regarding debt levels and the effective financial leverage of transmission operators, ARERA considers it appropriate to confirm the principles underlying the current remuneration framework for assets under construction. Under the existing regime, assets under construction are remunerated at a rate below the WACC for a construction period of up to four or six years, with the objective of strengthening economic incentives for the timely commissioning of infrastructure projects characterised by long development timelines, to the benefit of the system.

7.20 In this regard, it should be noted that any rate of return applied to assets under construction that is lower than the WACC must nonetheless ensure the recovery of financing costs incurred during the pre-operational phase. Against this background, the proposal set out in consultation document 165/2026/R/gas to assess a higher weighting of debt in the formula used to calculate the rate of return for assets under construction is consistent with the regulatory treatment already applied in other contexts. These include activities for which no remuneration of assets under construction is provided, such as gas storage and LNG regasification, the recognition of interest rate during construction (IRDC) in years in which assets under construction are no longer remunerated in relation to gas transmission and electricity transmission activities (i.e. after the fourth or sixth year following the incurrence of capital expenditure), and the treatment of new TSOs, which are allowed to capitalise IRDC incurred before the start of commercial operations[5].

7.21 Finally, regarding comparisons with other countries, it is important to note that there is no uniform approach across European gas transmission regulatory frameworks with respect to the treatment of assets under construction. Regulatory regimes that grant full WACC remuneration on assets under construction, as cited by some operators in their responses, coexist with others where no remuneration

[5] See, for example, Articles 5.5(a) and 5.9-bis of RTTG 6PRT.

is granted or where remuneration may be allowed only in exceptional circumstances, for example for investments forming part of Projects of Common Interest and assessed on a case-by-case basis.

7.22 Against this background, and consistently with the proposal set out in consultation document 165/2026/R/gas, ARERA considers it appropriate to confirm the current regulatory framework for assets under construction. This framework provides for a rate of return equal to the WACC recalculated based on a D/E ratio of 4 (corresponding to a gearing ratio of 0.8), considering the actual contribution of debt financing to new investments.

7.23 Based on the WACC currently applicable for 2026, the resulting rate of return for assets under construction would therefore be 4.2%.

S 6.Comments on the rate of return applicable to assets under construction.

Depreciation and regulatory useful lives

7.24 Regarding economic and technical depreciation, in consultation document 165/2026/R/gas, ARERA proposed to broadly maintain the framework in force during the 6PRT, including asset categories, asset lives and the incentive mechanism for obtaining public contributions. The only proposed change concerns the asset category relating to extraordinary maintenance exclusively aimed at keeping gas pipelines in operation extending their useful life, for which ARERA considered extending the regulatory asset life from 15 to 20 years and, in case the incentive mechanism for fully depreciated networks be discontinued (Option Depreciated Networks-2), removing the 10% threshold of revalued historical cost.

7.25 The consultation revealed broad support for ARERA's proposals.

7.26 With specific regard to the extension of the regulatory asset life applicable to extraordinary maintenance activities, respondents expressed differing views, including among TSOs. Some supported the proposal on the grounds that it would encourage the continued use of existing assets without promoting premature replacement, while others considered the proposal inappropriate as it could reduce incentives to favour maintenance and life-extension interventions over the replacement or refurbishment of gas pipelines.

7.27 In addition, the main TSO proposed introducing a new asset category for information systems with an economic and technical life of three years, reflecting the increasingly rapid replacement cycles of certain devices and software applications driven by technological developments.

7.28 ARERA intends to confirm the proposals presented in consultation document 165/2026/R/gas, including the extension from 15 to 20 years of the regulatory asset life applicable to extraordinary maintenance interventions exclusively aimed at keeping gas pipelines in operation and extending their useful life. Evidence arising from the incentive mechanism for fully depreciated networks indicates a significant proportion of assets remaining in operation beyond 65 years.

Furthermore, with a view to encouraging life-extension interventions, discouraging premature replacement and simplifying administrative procedures, ARERA intends to remove the 10% threshold of revalued historical cost applicable to extraordinary maintenance interventions, irrespective of the outcome of the impact assessment concerning the incentive mechanism for fully depreciated networks.

7.29 As regards the proposal to introduce a specific asset category for information systems with an economic and technical life of three years, ARERA considers this to be a cross-sectoral issue affecting all energy infrastructure services. The matter should therefore be more appropriately assessed as part of the revision of the common tariff methodologies following the expiry of TIROSS.

7.30 Consequently, for the 7PRT, ARERA intends to maintain the asset categories and economic and technical asset lives set out in Table 1 below.

7.31 Finally, it should be noted that, in consultation document 302/2026/R/gas, ARERA presented its proposals for reforming the framework governing the connection of biomethane production facilities to the natural gas network. Within that context, reverse-flow facilities, which increase the capacity of the gas network serving a biomethane plant by allowing excess gas to be re-injected into the upstream gas network (typically the national transmission network), were identified as being exclusively related to biomethane production requirements. Pursuant to Article 1, paragraph 933, of Law No. 199 of 30 December 2025 (Law 199/25), the associated costs are borne by network operators and allocated to network users through nationally uniform charges. Similarly, the share of connection costs assigned to network operators under Law 199/25 (equal to 70%) is also borne by network operators and allocated to users through nationally uniform charges. The consultation document further proposes that:

a) investment costs incurred by network operators for the construction of reverse-flow facilities should be recognised through network tariffs and attributed to the operators that have actually incurred those costs, through the introduction of dedicated asset categories designed to keep such investments separate from other investments (see paragraph 2.17);

b) the share of connection costs borne by network operators (70%) should be recognised through network tariffs and attributed to the operators that have actually incurred those costs, through the introduction of dedicated asset categories designed to distinguish such investments from other connection-related investments (see paragraph 2.19). This asset category would include the full investment cost of the connection facility, while the share borne by the biomethane producer (30%) would be treated as a capital contribution.

7.32 Consequently, to ensure separate accounting treatment for these costs and to allow their specific characteristics, where relevant, to be distinguished from other assets already included in the RAB, two new asset categories need to be introduced within the gas transmission regulatory framework. These asset categories would have asset lives consistent with those applicable to equivalent assets not associated with biomethane facilities, namely 20 years for reverse-flow facilities,

in line with compressor stations, and 50 years for connection facilities, in line with gas pipelines. Furthermore, following consultation document 302/2026/R/gas, it will be necessary to assess the treatment of both investment and operating and maintenance costs associated with metering and gas quality control systems, as well as biomethane compression systems used for subsequent injection into the gas network.

Table 1: Conventional tariff duration of asset categories (in bold, the proposed modifications with respect to 6PRT)

Asset category	Conventional duration (years)
Buildings	40
Pipelines (pipelines and shunts)	50
Biomethane connection plants	**50**
Extraordinary maintenance to extend useful life	**20**
Compressor stations	20
Biomethane reverse-flow 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	-

S 7.Comments on the criteria for determining depreciation.

8. Incentive and efficiency criteria

Incentive for Capital Cost Efficiency

8.1 In order to address the challenges associated with assessing the efficiency of investments resulting from the information asymmetry between the regulator and the operator, in consultation document 165/2026/R/gas ARERA outlined the proposal to introduce an incentive mechanism applicable to a subset of projects (70% of development and maintenance investments subject to cost assessment). The mechanism would provide for a symmetrical reward/penalty scheme, with a sharing factor equal to 30% of the difference between the reference cost (based on unit costs benchmarked against relevant benchmarks) and the actual investment cost. Compared with the capex efficiency sharing mechanism under the TIROSS, this mechanism is based on the ex-post assessment of the costs of specific projects rather than on the evaluation of total annual expenditure.

8.2 Responses received during the consultation, including those submitted during the focus group held on 23 September 2026, showed interest in the proposed mechanism. Specifically, some respondents suggested to adopt asymmetric

sharing schemes, providing greater retention of inefficiencies and lower participation in benefits. Conversely, the main transmission system operator noted that any asymmetry should operate in the opposite direction, with operators retaining 70% of the savings achieved relative to the reference cost while limiting to 10% the share of additional costs borne by them. The operator also suggested updating the reference cost for inflation and exogenous factors and expanding the use of the Y-factor.

8.3 The need to ensure appropriate regulatory safeguards regarding the quality of ex ante cost estimates has also been emphasized, with reference to project maturity, robustness of the assessments and consistency with reliable benchmarks, "to support the proper functioning of the mechanism. Other respondents raised concerns regarding the use of international benchmarks considered insufficiently comparable and proposed, as an alternative, using tender award prices.

8.4 Concerning the scope of application of the incentive mechanism, respondents highlighted the opportunity to limit its application to projects included in the first Ten-Year Network Development Plan adopted after the entry into force of the new integrated regulatory texts, thereby safeguarding investments already planned under the current regulatory framework. Respondents also noted the risk of significant financial exposure for operators whose portfolios are concentrated in a limited number of large projects and argued that output-based mechanisms could be more effective in promoting efficiency and benefits for the system. Finally, it was observed that the proposed mechanism is sufficiently innovative to warrant a comprehensive revision of the ROSS framework.

8.5 About the request for asymmetric sharing arrangements, ARERA considers that the mechanism should pursue the objective of improving capital-cost efficiency without allocating risks asymmetrically between operators and users. Consequently, the Authority confirms the application of symmetrical sharing of investment cost overruns and underruns. In addition, ARERA considers it appropriate to maintain the use of the international benchmarks referred to above to support the verification of the reliability of reference investment costs. In the Authority's view, these benchmarks represent an effective safeguard for the proper functioning of the mechanism by ensuring objective, stable and transparent assessments of the cost estimates submitted by operators and by mitigating the information asymmetry between regulator and operator. Conversely, ARERA does not consider tender award prices to be an appropriate reference parameter, as they reflect contingent market dynamics influenced by the degree of competition and the commercial strategies of economic operators and are therefore not necessarily aligned with the rationale of the proposed mechanism.

8.6 With regard to the request to limit the application of the incentive mechanism to projects included in the first Ten-Year Network Development Plan adopted after the start of the next regulatory period, ARERA considers that such a limitation would not be consistent with the purpose of the mechanism, which is to assess the efficiency of the capital costs of projects implemented during the next regulatory period. Restricting the mechanism to projects included in the new Ten-Year Plan would create an unjustified discontinuity in regulatory treatment and could

exclude projects already planned and characterized by comparable levels of project maturity, despite being implemented during the period in which the mechanism applies.

8.7 ARERA therefore considers it appropriate to confirm the introduction of the incentive mechanism as proposed in consultation document 165/2026/R/gas, applying it to all TSOs, regardless of whether simplified or evolutionary ROSS criteria apply. In particular, ARERA considers it appropriate to:

a) apply the incentive mechanism to the subset of development projects and maintenance or asset renewal works subject to cost assessment within business plans, as specified in Chapter 22, that are expected to become operational during the next regulatory period. For complex projects consisting of several individually assessable works with different implementation schedules, the incentive mechanism shall apply to each individual work when it becomes operational;

b) provide that the efficiency assessment shall be carried out when the asset becomes operational;

c) introduce a symmetrical reward/penalty scheme with a sharing factor equal to 30% of the difference between the ex-ante reference investment cost and the actual investment cost recorded in the year in which the project becomes operational. For the sake of simplification, ARERA does not consider it appropriate to provide for any adjustment of the reference cost to reflect actual infrastructure quantities, since, for the same project or work, once the reference expenditure has been established following the authorization process, when construction activities can reasonably be forecast, any changes in plant quantities may be attributable to changes in the efficiency conditions of project implementation. This approach also takes into account the possibility of applying ex post corrections for estimation errors resulting from events that could not reasonably be foreseen ex ante or from changes in the regulatory framework, provided that such events are duly documented by the operator (the capital Y-factor referred to in Article 46 of TIROSS);

d) define the ex-ante reference investment cost on the basis of the investment cost estimate submitted by the operator and subject to cost assessment within the first business plan containing the forecast start date of construction works. For projects or works already included in the 2026-2027 business plan, where construction has already commenced or is underway during that two-year period, the reference investment cost shall be defined on the basis of the estimate already submitted in that business plan. In any event, operators shall be required to submit to ARERA, in future business plan editions, a comparison between the unit cost indicators used for cost assessment purposes (see Article 45.3(c) of TIROSS) and the unit cost benchmarks identified pursuant to Regulation (EU) 2024/1789 or, alternatively, the Unit Investment Cost Indicators published by ACER under the TEN-E Regulation. ARERA reserves the right to revise the reference investment cost in the event of inconsistencies in the comparison or failure to provide it, based on its own

assessments and taking into account the estimated investment costs of similar projects identified in the Plan;

e) introduce a deadband with no rewards or penalties where the deviation between the reference cost and actual cost is less than 3%;

f) provide that rewards or penalties shall be determined as part of the approval of allowed revenue and settled through CSEA, including over a multi-year period.

S 8.Comments on the incentive for capital cost efficiency.

Incentive to enhance investment selectivity

8.8 In consultation document 165/2026/R/gas ARERA set out proposals to introduce regulatory mechanisms aimed at enhancing the selectivity of investment decisions by gas network operators, with a view to moderating the upward investment trend projected in the TYNDP. Specifically, ARERA proposed a reduced rate of return for certain categories of investments through a reduction in the WACC of approximately 15-20% (equivalent, at 2026 values, to around 80-110 basis points). The proposal targeted investments in new capacity development, the extension of gas infrastructure to new areas, and pipeline replacement projects not strictly justified by safety requirements, while excluding connections, security-of-supply investments, and projects supporting biomethane and other renewable gases.

8.9 Stakeholders expressed divergent views during the consultation process. Supporters of the measure highlighted the importance of granting remuneration for new investments only where demonstrable benefits can be identified. They also argued that the scope of the measure should be sufficiently broad to ensure a meaningful impact.

8.10 Conversely, stakeholders opposing the proposal, including TSOs during the focus group discussions, argued that the measure would be redundant, as investment selectivity is already ensured through the CBA underpinning the TYNDP. They also maintained that the measure would increase regulatory risk, undermine the financeability of investments, and be inconsistent with the energy transition, given that gas networks are expected to play a role in transporting biomethane and hydrogen.

8.11 Regarding these concerns, ARERA notes that the measure proposed in consultation could operate as a complement to the CBA. While the CBA is intended to assess whether a project is socially desirable by comparing its costs with the expected benefits for the system, the proposed mechanism would introduce an opportunity cost for the operator's use of capital, thereby promoting greater investment selectivity. This is particularly relevant in a context characterised by increasing uncertainty regarding the future utilisation of natural gas infrastructure as a result of decarbonisation policies. The measure would also support greater neutrality between decisions to expand, replace, or maintain existing assets in operation, while ensuring that the level of remuneration remains

sufficient to preserve the financeability of investments considered necessary. From this perspective, the modulation of the rate of return affects the economic attractiveness of capital allocation decisions by the operator, whereas the CBA assesses the value of the investment for the system as a whole.

8.12 ARERA nevertheless acknowledges the observation that investment selectivity should primarily be addressed through the planning process. It therefore intends to revise the approach originally proposed in the consultation. Rather than introducing a generalised selectivity mechanism based on investment categories, ARERA proposes linking the reduced rate of remuneration directly to CBA outcomes, thereby providing a signal that prioritises investments delivering the greatest value to the system. To this end, ARERA proposes establishing a benefit-to-cost (B/C) ratio threshold below which the reduced rate of remuneration would apply. This approach also reflects the fact that uncertainty regarding future infrastructure utilisation and future natural gas demand under decarbonisation policies inevitably affects the reliability of CBAs, which are based on forward-looking energy consumption scenarios. Accordingly, a more prudent approach to investment appraisal is warranted, which may also be achieved by assigning operators an opportunity cost in their capital allocation decisions.

8.13 Consequently, ARERA confirms the proposal of an incentive to enhance investment selectivity in the form of a WACC reduction. On a prudential basis, the reduction will be set at 10% upon initial implementation, compared with the 15-20% reduction proposed in consultation. The measure will apply to projects becoming operational from 2028 onwards and included in the TYNDP (starting with the 2027 Plan) where the B/C ratio is less than or equal to 2 under the most conservative scenario.

S 9.Comments on the incentive to enhance investment selectivity.

Incentive for keeping fully depreciated networks in operation

8.14 In consultation document 165/2026/R/gas, ARERA presented three alternative options (RetiAmm.0, RetiAmm.1 and RetiAmm.2), together with the related impact assessment (RIA), as follows:

a) RetiAmm.0 (BAU) – retain for the 7th regulatory period the incentive mechanism for depreciated networks currently in force;

b) RetiAmm.1 – limit the scope of the incentive mechanism based on the evidence gathered during the trial phase, with a more targeted application aligned with the objectives of the mechanism and aimed at ensuring efficient resource allocation, namely by excluding from the incentive scheme those assets exhibiting critical Asset Health indicators and those already scheduled for replacement in the relevant Plans and, for assets with low utilisation rates, by proportionally adjusting the incentive according to the corresponding utilisation rate;

c) RetiAmm.2 – phase out the incentive while, at the same time, strengthening the regulatory treatment of extraordinary maintenance expenditure aimed at

keeping fully depreciated networks in operation through the removal of the expenditure cap.

8.15 The consultation responses showed divergent views. Some respondents highlighted the desirability of revising the incentive mechanism and introducing a degree of discontinuity with the current approach, while others, including the TSOs, both in the responses and during the focus group held on 23 September 2026, argued that the incentive should not only be retained, but also strengthened, as it is necessary to avoid unnecessary replacement investments. The TSOs also raised concerns regarding the criteria proposed by ARERA to narrow the scope of the mechanism under RetiAmm.1, arguing that: all assets eligible for the incentive mechanism are infrastructures that, in the operator's assessment, can continue to operate safely; an asset that is already scheduled for replacement nevertheless continues to generate positive economic value for the system until such replacement takes place; and a low utilisation rate does not imply that an asset cannot perform functions essential to continuity of service and should therefore not justify a lower level of incentive. Some respondents also noted that RetiAmm.2, while potentially facilitating the recovery of certain maintenance expenditures, would not address the economic advantage of replacement over continued operation and could instead lead to higher recognised revenues, particularly as a result of bringing forward the replacement of certain assets. Finally, one respondent considered it difficult to express a view in the absence of an impact assessment and suggested that such analysis should be provided in a second consultation document.

8.16 With regard to the impact assessment, ARERA already provided, in consultation document 165/2026/R/gas, an analysis of incentivised assets by Asset Health category and of the corresponding incentive amounts received. ARERA also noted that the incentive for keeping depreciated networks in operation was expected to amount to approximately EUR 53 million in 2026, and that restricting its scope in line with RetiAmm.1 would reduce that amount by around 35%. For assessment purposes, it may also be noted that the total incentive recognised to TSOs in 2027 amounts to approximately EUR 62 million, reflecting both asset revaluation dynamics and the addition of further assets that became eligible upon reaching the end of their regulatory useful life. In addition, considering the main transmission system operator alone, the revalued historical cost of pipelines kept in operation amounted to approximately EUR 8.1 billion as of 31 December 2025, with a further EUR 3.2 billion (at 2026 prices) of pipelines expected to complete their regulatory useful life by 2030. Consequently, if the incentive were discontinued under RetiAmm.2, the revalued historical cost of the network potentially subject to replacement would represent approximately 50% of the total transmission RAB (see Table 3 attached to resolution 191/2026/R/gas establishing gas transmission tariffs for 2027).

8.17 In light of the above considerations, the comments received during the consultation process and the focus group discussions, as well as the risk that additional replacement investments could ultimately result in higher service costs for consumers, ARERA is inclined to favour RetiAmm.1. This option would

preserve the incentive mechanism while refining its scope, thereby ensuring greater selectivity by limiting eligibility to assets that are effectively utilised and can continue to operate safely, consistently with the results of the Asset Health methodology developed by the operator and approved by ARERA for this purpose.

8.18 ARERA also intends to confirm the exclusion from the incentive mechanism of assets already scheduled for replacement in the relevant development Plans. While acknowledging that such assets continue to generate benefits until they are replaced, ARERA considers that an incentive mechanism should not create distorted signals encouraging the continued operation of infrastructure that, having been scheduled for replacement and not challenged by ARERA, has already been identified by the operator itself as critical from a safety perspective. Such signals could also delay the commissioning of replacement assets, thereby increasing risks for the system. With regard to pipelines exhibiting low utilisation rates, while recognising that infrastructure may provide value beyond its actual level of use, ARERA does not intend to proceed with its proposal to adjust the amount of the incentive according to utilisation rates where the utilisation rate falls below the 60% threshold. However, in order to avoid incentivising the continued operation of entirely unused infrastructure, ARERA intends to exclude from the scope of the mechanism those assets that have recorded a zero-utilisation rate throughout the three years preceding the year in which the application is submitted.

S 10. Comments on the incentive for keeping fully depreciated networks in operation.

Incentive for dual-fuel compressor stations

8.19 In consultation document 165/2026/R/gas, ARERA proposed postponing the assessment of the incentive mechanism for the operation of dual-fuel compressor stations until after the first facilities become operational, so as to gather evidence on their performance and on the potential effects of the mechanism itself.

8.20 The consultation responses, including those expressed during the focus group held on 23 September 2026, highlighted a number of technical and operational challenges associated with the operation of such facilities. These include the fact that frequent switching between gas-driven and electrically driven operation may be incompatible with start-up times and equipment constraints, potentially affecting both operational efficiency and compliance with environmental requirements. According to respondents, these factors make it difficult to take advantage of price signals from the electricity and gas markets, particularly given that market price formation does not allow sufficiently timely decisions and may expose operators to costs that are not recognised. Respondents nevertheless emphasised the need to recognise electricity consumption costs and to introduce a mechanism allowing operators to retain a share of the benefits effectively generated through the use of electric compressors rather than gas turbine compressors. Such benefits should be assessed ex post on the basis of actual

operating hours and the benefits generated for the system. The main transmission system operator also highlighted the desirability of retaining the incentive for the provision of flexibility services to the electricity sector, in a sector coupling perspective.

8.21 In light of the above, ARERA intends to confirm the current incentive mechanism while deferring the definition of the related operational arrangements to subsequent assessments, also taking into account the procedures for participation in the Dispatching Services Market (MSD) that the relevant operators will be required to submit, as already provided for under the RTTG 6PRT (Article 6.4). In this regard, ARERA considers it appropriate to exclude revenues from white certificates from the incentive mechanism, given that such facilities are not eligible to participate in the white certificates scheme.

8.22 With regard to the criteria for recognising electricity consumption costs and the possible recognition of a share of the benefits, in terms of lower system costs, arising from the use of electric compressors instead of gas turbine compressors, reference is made to the arrangements for recognising costs relating to fuel gas, discussed in Section 9.3 et seq.

S 11. Comments on incentives for dual-fuel compressor stations.

New methanisation projects

8.23 With regard to new methanisation projects, in consultation document 165/2026/R/gas, ARERA proposed confirming the current minimum development requirements and the cap on recognised investments, while updating their values to reflect the most recent data available.

8.24 Most consultation responses supported ARERA's proposals. One respondent, however, argued that the existing indicators, namely the minimum capacity index and the maximum cost index, are redundant in light of the investment assessment process carried out within the TYNDP, where projects are already subject to a CBA, which is considered sufficient to determine their usefulness on the basis of the benefits delivered to the system.

8.25 Regarding the scope of application of the updated indicators, one respondent suggested excluding from the minimum development requirements those projects linked to distribution development plans already approved by ARERA through gas distribution tenders, as well as projects requiring joint assessment of transmission and distribution infrastructure.

8.26 ARERA intends to confirm the current minimum development requirements and cap on recognised investments for transmission network developments in newly methanised areas, while revising their values to enhance selectivity and efficiency in network expansion. In this regard, ARERA notes that a positive CBA within the TYNDP demonstrates the usefulness of a development project but does not assess its efficiency relative to projects of a similar nature. By contrast, the minimum development requirements and investment cap are intended to ensure that, in the case of new gasification projects, at least the efficiency standards

achieved by the majority of existing networks are met, also taking into account the decarbonisation objectives established for 2050. Furthermore, ARERA notes that, even where gas distribution tenders have already been approved or gas distribution networks are under construction, the development of the transmission network cannot be regarded as necessary irrespective of considerations of usefulness and efficiency. As already required under the TYNDP requirements (see Annex A to resolution 170/2025/R/gas, Article 9.4), operators must always submit, for transmission network developments in newly methanised areas, a counterfactual scenario assuming no transmission network expansion and alternative solutions for supplying the distribution network.

8.27 ARERA therefore confirms the proposals set out in consultation document 165/2026/R/gas and sets the new indicator values within the ranges consulted upon, at their respective average values. In particular:

a) the minimum capacity index for transmission network development will be set at 0.45 Smc/day per metre of network constructed (consultation range: 0.35-0.55 Smc/day), compared with the current value of 0.3 Smc/day per metre of network constructed;

b) the cap on recognised investments for transmission network development in newly methanised areas, where the minimum capacity index is not met, will be set at EUR 1,100 per Smc/day (consultation range: EUR 700-1,400 per Smc/day), compared with the current value of EUR 2,800 per Smc/day.

8.28 Finally, ARERA intends to confirm that the new indicators will apply from the 2027 TYNDP onwards, with reference to new projects that have not yet been assessed and to existing projects that have not yet received a positive assessment from ARERA. To this end, ARERA intends to amend, at the first available opportunity, the TYNDP Minimum Requirements set out in Annex A to resolution 468/2018/R/gas, as amended by resolution 170/2025/R/gas.

S 12. Comments on efficiency criteria for network developments in newly methanised areas.

Incentive for aggregation

8.29 Concerning incentive mechanisms, in its response to consultation document 165/2026/R/gas, the main transmission system operator highlighted the desirability of introducing an incentive for aggregation among operators, with a view to reducing administrative costs for the system and taking into account the large number and significant differences in scale among gas transmission operators, similarly to what is already provided for in the electricity sector.

8.30 ARERA considers the proposals emerging from the consultation worthy of further assessment. In particular, also with a view to administrative simplification, ARERA considers that a one-off incentive could be established equal to a percentage, consistent with the level adopted in other aggregation mechanisms already defined by ARERA, of the net fixed assets transferred by the company disposing of the assets. The incentive would apply to aggregations between gas

transmission operators resulting in one or more operators ceasing their gas transmission activities. The incentive would not apply to companies belonging to the same corporate group.

8.31 Recognition of the benefit could be requested by the undertaking resulting from the aggregation process through a specific application and would be granted by means of a dedicated ARERA decision.

S 13. Comments on incentives for the aggregation of transmission operators.

9. Revenue components covering specific cost items

9.1 Considering the broad support expressed during the consultation process, ARERA intends to proceed with the proposals set out in consultation document 165/2026/R/gas and substantially confirm the existing ad hoc tariff recognition mechanisms for revenue components covering specific cost items excluded from total expenditure relevant for ROSS purposes and recognised on top of the fast-money component, namely:

a) fuel gas;
b) network losses;
c) unaccounted for gas (UFG);
d) Emission Trading allowances;
e) operational network balancing.

9.2 In consultation document 165/2026/R/gas, while maintaining a broadly stable regulatory framework, ARERA also proposed a number of targeted refinements to the current arrangements. The outcomes of the consultation regarding these proposals are discussed in the following sections.

Fuel gas, network losses and unaccounted for gas (UFG)

9.3 Consistently with the 6PRT, ARERA confirms its proposal to determine, for the purpose of calculating the revenue component to be reflected in tariff levels:

a) fuel gas volumes, as well as electricity volumes associated with the consumption of dual-fuel or electric compressor stations, approved by ARERA on the basis of proposals submitted by the TSOs, taking into account the expected network configuration for the following year and historical data, where available;
b) network loss levels on the basis of efficient emission factors for individual network components (such as pipelines, nodes, PIG stations, R&R stations, compressor stations and REMI stations);
c) UFG volumes equal to the average quantities of UFG recorded over the most recent four-year period available;

and to value such gas quantities on the basis of the weighted average price of forward products delivered at the PSV during the relevant tariff year, taking into

account the profile according to which such quantities are required throughout the year.

9.4 ARERA also confirms the application of the mechanism for recognising the above cost components, under which:

a) a) the share of tariff revenues collected through the pro forma variable charge covering such items (the so-called CVAPG charge) is transferred in full by the TSOs to CSEA;

b) b) CSEA reimburses the Balancing Operator in full, on a monthly basis, for costs incurred in procuring on the market the resources required across the transmission network to cover fuel gas consumption (both gas and electricity), through the neutrality mechanism established under the Integrated Balancing Code (TIB);

c) c) with regard to network losses and UFG, specific ex post reconciliation mechanisms are applied in year t+1 in respect of the relevant year, with the objective of ensuring a degree of risk sharing by TSOs while at the same time providing incentives to reduce network losses and UFG levels.

9.5 One TSO highlighted the importance of clarifying that, from 2024 onwards, the share of revenues covering system gas requirements (fuel gas, network losses and UFG), although included in the tariff proposals submitted by individual TSOs, does not fall within their responsibility. This is because the main TSO procures gas for all transmission service requirements and is subsequently reimbursed by CSEA under the TIB neutrality mechanism, except for the specific incentive arrangements relating to network losses and UFG. While ARERA agrees with the observation raised by the TSO, it considers that this clarification is already implicit in the operation of the relevant tariff mechanisms and can therefore be appropriately reflected in the related accounting documentation.

9.6 In consultation document 302/2026/R/gas, ARERA proposed that operating costs associated with compressors installed at reverse-flow facilities be recognised through network tariffs in favour of the network operators that actually incur those costs. To this end, provisions have been introduced requiring such costs to be separately identified in accounting records from other operating costs, also for the purposes of implementing the provisions of Law No. 199/2025 concerning the allocation of such costs to consumers on a national basis (see paragraph 2.18). Accordingly, the fuel gas category should also include the consumption of compressors associated with biomethane reverse-flow facilities, with separate disclosure of the relevant quantities. Allocation of the related costs to consumers at national level is already ensured through the current tariff mechanisms covering such costs.

9.7 Consultation document 302/2026/R/gas also provides that ARERA should define specific transitional arrangements relating to costs incurred during 2026 and 2027. In this regard, within the tariff methodology for the 7PRT, ARERA intends to allow the reconciliation of any operating costs associated with reverse-flow compressors that have not already been covered through tariffs.

Evaluation of electricity consumption

9.8 In consultation document 165/2026/R/gas, ARERA proposed discontinuing the current approach whereby electricity consumption at compressor stations is valued on the basis of the lower of the daily gas price for system gas procurement (PAGS) determined within the Day-Ahead Gas Market (MGP-GAS); and the daily average electricity price (average PUN), appropriately adjusted to reflect the ratio between the average efficiency of gas-driven compressors and that of electrically driven compressors. In particular, having regard to the concerns expressed by the TSOs regarding the current mechanism, notably the operational constraints affecting dual-fuel compressor stations (including start-up and stabilisation times) and the timing and price formation dynamics of electricity and gas markets, ARERA consulted on the possibility of:

a) for the purposes of calculating the revenue component covering fuel gas costs reflected in tariffs, valuing electricity consumption on the basis of the gas price (weighted average price of forward products delivered at the PSV during the relevant tariff year), multiplied by the ratio between the average efficiency of electric compressors and that of gas-driven compressors;

b) for the purposes of recognising costs incurred by operators, and also taking into account the suspension of incentives for dual-fuel compressor stations proposed in consultation document 165/2026/R/gas, providing for all energy consumption costs, both gas and electricity, to be recognised through the TIB neutrality mechanism to the Balancing Operator (and subsequently allocated among the TSOs[6]), with electricity consumption valued on the basis of the gas price multiplied by the ratio between the average efficiency of electric compressors and gas-driven compressors;

c) introducing a sharing mechanism for any efficiency gains, ensuring an equal allocation between operators and the system of any cost savings actually achieved ex post through the use of electric compressors instead of gas-driven compressors, thereby ensuring operational flexibility and encouraging the use of electric compressors whenever they result in genuine system-wide efficiencies;

d) introducing monitoring of the operation, energy consumption and costs of electrically powered compressor stations in order to assess their actual technical and economic efficiency relative to gas fuel consumption, also for the purpose of reviewing the suspended incentive mechanism applicable to dual-fuel compressor stations (see paragraph 8.19).

9.9 The consultation responses and the discussions held during the focus group highlighted, in particular by the main TSOs, the need to revise the arrangements for recognising electricity consumption costs. According to respondents, the mechanisms in force during the 6PRT do not ensure full recovery of electricity costs and therefore create unequal treatment compared with gas-fuelled

[6] The balancing operator may aggregate, in addition to gas own-consumption volumes, electricity consumption incurred by other transmission operators and, upon receipt of the corresponding payments from CSEA, allocate such payments among the other transmission operators.

compressor stations, despite the fact that electric compression is fully aligned with European and national decarbonisation objectives. In particular, respondents noted that reliance solely on electricity prices does not reflect the actual cost of electricity supply because it excludes significant components such as network charges and system charges, thereby leaving part of the costs to be borne by operators. Consequently, the TSOs requested the introduction in the 7PRT of a dedicated mechanism ensuring that electric compression benefits from the same cost-recovery principle already applicable to gas compression, through recognition of all costs effectively incurred under electricity supply contracts, subject to reporting to CSEA under the TIB neutrality mechanism.

9.10 Taking into account the observations received, ARERA intends to introduce arrangements for recognising electricity consumption costs that both ensure recovery of network and system charges associated with electricity supply and preserve an incentive for the efficient use of electrically powered compressor stations relative to gas-driven alternatives. In particular, ARERA intends to provide that:

a) for the purposes of determining the revenue component covering fuel gas costs reflected in tariffs and for recognising costs through the TIB neutrality mechanism, electricity consumption should be valued on the basis of electricity prices rather than, as proposed in the consultation document, on the basis of the gas price multiplied by the ratio between the average efficiency of electric compressors and gas-driven compressors;

b) an ex-post reconciliation/sharing mechanism should be introduced for electricity supply costs, which:

   i. ensures full recovery of network charges and system charges associated with electricity supply;

   ii. verifies whether electric compression has actually delivered the system cost savings expected when the facilities were planned. Specifically, where the total cost of electricity supply for electric compressors exceeds the cost of equivalent gas compression, defined as the electricity consumed by electric compressors multiplied by the annual average gas price and by the ratio between the average efficiency of electric compressors and gas-driven compressors, plus the ETS cost associated with equivalent gas compression, a sharing mechanism shall apply under which operators return 20% of the additional cost incurred to the system.

9.11 This approach ensures full recovery of electricity supply costs while maintaining a safeguard mechanism for the system where the cost of equivalent gas compression, including ETS costs and determined on the basis of the relative efficiency of the respective technologies, proves to be more efficient. ARERA also considers it appropriate to establish a monitoring framework covering the operation of electrically powered compressor stations and the related consumption and costs through the collection of data and information within the reconciliation mechanism. Such monitoring will also support any future review of the mechanism during the regulatory period.

S 14. Comments on the valuation of electricity consumption.

Network losses

9.12 In consultation document 165/2026/R/gas, ARERA proposed a further revision of efficient emission factors, in addition to that already implemented for the 6PRT, in order to align those factors with the levels actually observed across the transmission network and with the efficiency improvements envisaged under Regulation (EU) 2024/1787[7]. In particular:

a) for network components operating at pressures above 12 bar, ARERA highlighted the opportunity to align emission factors with the most efficient values observed in practice;

b) for network components operating at pressures below 12 bar, ARERA confirmed, consistently with previous regulatory periods, the adoption of a simplified approach whereby emission factors are assumed to be one order of magnitude lower than those applicable to network components operating above 12 bar;

c) for vented emissions only, ARERA proposed the introduction of a linear downward trajectory which, starting from the levels currently in force, would reduce emission factors to zero by the end of the regulatory period.

9.13 ARERA also highlighted the importance of taking into account the total cost of network losses when assessing the additional costs arising from the implementation of Regulation (EU) 2024/1787 on methane emissions reduction, in order to ensure proportionality between the costs borne by the system and the resulting emission-reduction benefits.

9.14 In response to the consultation, the main TSO suggested that efficient loss levels should be determined on the basis of average values observed over recent years rather than the minimum value recorded, which was considered potentially unrepresentative of normal operating conditions. The main TSO also noted that the complete elimination of vented emissions is not realistically achievable under all operating conditions and argued that, if such an objective were pursued, both the costs of mitigation measures and the costs associated with technically unavoidable emissions, as well as all costs incurred in complying with regulatory obligations, should be fully recognised. Other respondents also emphasised that compliance with the obligations imposed on infrastructure operators by Regulation (EU) 2024/1787 is expected to result in a significant increase in costs while delivering only limited benefits, and therefore argued that such costs should be fully recognised.

9.15 ARERA intends, in general, to confirm the proposals set out in consultation document 165/2026/R/gas. In particular, ARERA considers that emission factors, as benchmarks of efficiency, should be determined on the basis of the minimum value recorded rather than the average observed value. The minimum value is

[7] ARERA also noted that the new coefficients would result in a reduction of the recognised cost for the coverage of gas losses of approximately 37% (based on 2026 tariff levels, from around €12.6 million to around €7.9 million).

considered representative of the level of technical and operational performance already achieved by the main TSO and therefore provides an appropriate efficiency reference. Furthermore, the network losses reconciliation mechanism, which requires operators to share part of the costs arising from deviations between actual losses and efficient benchmark levels, already provides partial coverage of costs when actual losses exceed efficient reference levels.

9.16 With specific reference to vented emissions, ARERA acknowledges the observation that complete elimination is not realistically achievable in all operating circumstances, particularly given that the costs of complying with Regulation (EU) 2024/1787 may not be proportionate to the benefits achieved. Accordingly, ARERA intends to confirm the linear reduction path for emission factors during the 7PRT, while revising the end target such that efficient emission factors are reduced by 50% relative to the levels applied during the 6PRT by 2031. Consistently with this approach, ARERA reiterates that the assessment of additional tariff-recognised costs arising from Regulation (EU) 2024/1787 will be based on a proportionality principle balancing the costs borne by the system against the benefits achieved in terms of emission reductions.

Table 5 – Emission factors

	Emission factor		Unit
	P<12 bar	P>=12 bar	
Fugitive emissions			
Pipeline	1.9	19	Smc/km/y
Nodes	-	3860	Smc/source/y
PIG stations	-	1019	Smc/source/y
RR stations[1]	-	2208	Smc/source/y
Compression stations	-	632	Smc/MW/y
Regulation and Metering stations (REMI)[1,2]	102.8	1028	Smc/source/y
Pneumatic emissions			
Network (pneumatic actuated valves)	1.5	15	Smc/source/y
RR stations[1]	-	2877	Smc/source/y
Compression stations	-	120	Smc/MW/y
Plants for measuring gas composition	171.1	1711	Smc/source/y
Vented emissions			
Rete, RR and REMI	*	*	Smc/km/y
Plants	-	*	Smc/MW/y

1 For regulation and reduction (R&R) stations and regulation and metering (REMI) stations, the pressure to be considered is the inlet pressure.
2 The value indicated refers to the portion of the facility located within the network perimeter: for delivery points, the portion upstream of the meter; for entry points, the portion downstream of the meter.
** Values decrease over the regulatory period as shown in the table below. For pipelines, R&R stations and REMI stations operating at pressures below 12 bar, emission factors are assumed to be one order of magnitude lower than those applicable to the same component operating above 12 bar.*

S 15. Comments on the recognition of efficient network loss levels.

Reconciliation and efficiency mechanisms for network losses and UFG

9.17 With regard to the reconciliation mechanisms for network losses and UFG, in consultation document 165/2026/R/gas ARERA proposed increasing the unit charge applied to deviations between recognised and actual quantities from EUR 6.86/MWh to EUR 9/MWh. This proposal was intended to strengthen the participation of TSOs in the risks associated with deviations and to provide stronger incentives to reduce network losses and UFG levels. The proposed increase reflects updated estimates of the underlying costs of gas metering activities on the transmission network and is consistent with the approach adopted in the 6PRT, where the charge is linked to the share of revenue covering operating costs associated with the metering service[8]. Pursuant to resolution 386/2022/R/gas, the same value would also apply to the regulation of Delta In-Out on distribution networks, subject to any future review by ARERA.

9.18 In response to the consultation, the main TSO proposed introducing an asymmetric loss- and UFG-sharing mechanism that would provide stronger rewards for reductions achieved beyond recognised benchmark levels. Other respondents noted that increasing the unit charge from EUR 6.86/MWh to EUR 9/MWh, based on costs, risks and physical phenomena specific to gas transmission, could have significant consequences for gas distribution operators. In particular, they argued that the increase would materially reduce the benefits obtainable from technical measures aimed at reducing Delta In-Out levels. Respondents therefore highlighted the need to revise the penalty applied under the accountability mechanism for gas distribution operators established by Article 3(2) of resolution 386/2022/R/gas[9]. They also observed that limitations in the current data set, together with uncertainties surrounding both loss quantification and compliance with Regulation (EU) 2024/1787, could unduly amplify the economic effects of the mechanism for gas distributors.

9.19 Having considered the observations received, ARERA intends to confirm the proposals set out in the consultation document. In particular, ARERA considers that the introduction of an asymmetric loss- and UFG-sharing mechanism would not be consistent with the objective of increasing TSO participation in deviation risks and strengthening incentives to reduce network losses and UFG levels. Likewise, ARERA intends to confirm the proposal to apply, from 2028 onwards, the unit cost of EUR 9/MWh within the accountability mechanism for gas distribution operators established by Article 3(2) of resolution 386/2022/R/gas. This approach is considered appropriate because, based on estimated operating costs for the metering service and average Delta In-Out quantities observed during the 2022-2025 period, the resulting unit charge would still be more than twice the value proposed.

[8] Based on metering service operating costs for the period 2022-2025, amounting to approximately €22 million, and average CNG volumes over the same period of around 243 MScm (approximately 2.5 TWh), the unit charge to be set for the 7PRT would amount to approximately €9/MWh.

[9] In particular, through parameter α, which represents the average of the values established under the gas transmission tariff regulation for the reconciliation of gas losses and CNG for each year of the relevant three-year period.

S 16. Comments on the reconciliation and efficiency mechanism for network losses and UFG.

Costs related to the Emissions Trading System

9.20 Regarding the recognition of Emission Trading allowance costs, and taking into account the broad support expressed during the consultation process, ARERA intends to proceed with the proposal set out in consultation document 165/2026/R/gas and confirm the arrangements applied under the 6PRT, whereby:

a) the quantity of Emission Trading allowances eligible for tariff recognition is determined as the product of a unit quantity of allowances associated with a reference driver (e.g. fuel gas volumes) and the estimated value of that driver for the relevant tariff year, net of any allowances received free of charge;

b) eligible allowances are valued on the basis of the average price recorded during the most recent year available in the European public auctions for such allowances;

c) a reconciliation mechanism is applied to compensate for the difference between the tariff revenues arising from the pro forma CVETS charge and the recognised cost covering the related obligation, recalculated on the basis of the actual value of the reference driver used and the actual price of the allowances.

9.21 With regard to biomethane used for fuel gas by the main TSO[10], for which the purchase of Emission Trading allowances is not required and where guarantees of origin under Ministerial Decree No. 224 of 14 July 2023 are reflected in the transfer price of the gas, ARERA considers it appropriate that such costs receive the same tariff treatment as Emission Trading allowance costs[11]. To this end, the main TSO may report such costs as part of the reconciliation mechanism referred to in paragraph 1.20(c), consistently with the approach already adopted in the certification of 2025 revenues.

S 17. Comments on the mechanism for recognising Emission Trading allowances and guarantees of origin.

[10] Within the framework of resolution 140/2023/R/gas, concerning the recertification of Snam Rete Gas S.p.A. as an ownership-unbundled natural gas transmission operator, Snam Rete Gas S.p.A. is required, pending the implementation of the structural measures, to prioritise the use for own consumption, without sale to third parties, of the biomethane produced by the Group company. The TIB provides, under the neutrality mechanism, for the recovery only of the commodity-related component, including with respect to biomethane own consumption, since the recovery of ETS costs, and, by analogy, Guarantees of Origin (GOs), is governed separately through a dedicated charge.

[11] Guarantees of origin for biomethane have characteristics that allow them to be functionally assimilated to emissions-pricing instruments similar to ETS allowances. Indeed, both mechanisms incorporate an economic value that is implicitly linked to the carbon intensity of the underlying energy carrier: while the ETS internalises the cost of CO_2 through a cap-and-trade mechanism, guarantees of origin for biomethane monetise the positive environmental attributes of biomethane (namely reduced or neutral emissions), thereby conveying a market-based price signal consistent with decarbonisation objectives.

Coverage of the costs of operational network balancing services

9.22 Also taking into account the broad support expressed for the proposals presented in consultation document 165/2026/R/gas, ARERA intends to confirm the arrangements in force during the 6PRT concerning the recovery of costs associated with the provision of operational (physical) network balancing services. These arrangements provide for the recognition, to companies carrying out transmission activities on the national gas transmission network, of a revenue component covering the cost of storage services used for the hourly balancing of the system.

10. Criteria for determining reference revenues for new transmission operators

10.1 Also taking into account the broad support expressed for the proposals set out in consultation document 165/2026/R/gas, ARERA intends to confirm the arrangements in force under the 6PRT for determining the revenues of transmission operators commencing operations during the regulatory period. In particular:

a) during the initial years of operation, until actual data become available, operating costs shall be estimated by the operator and submitted for ARERA's approval, together with a comparison with similar operators, evidence of procedures aimed at minimising costs, or a consistency assessment against a benchmark based on average national operating costs;

b) in the case of transmission operators established following the reclassification of sections of gas distribution networks, the reclassification shall ensure cost neutrality for users of the natural gas system.

10.2 ARERA also intends to confirm the proposals set out in consultation document 165/2026/R/gas regarding:

a) the application of an operating cost efficiency mechanism during the initial years of operation, based on the symmetrical sharing between the operator and the system of any efficiencies or inefficiencies achieved relative to the estimated operating cost level;

b) the non-application, due to the absence of historical data, of the capitalisation-rate provisions under the ROSS framework, with possible application deferred until the regulatory period following the start of operations or, in any event, once historical operating cost data become available.

10.3 The two main TSOs argued that Enura, the joint venture established by the same operators to develop and operate the new gas transmission infrastructure in Sardinia, should be subject to a dedicated regulatory framework in light of the island context and the unique characteristics of the project. In particular, the operators:

a) consider the use of average national operating costs as a benchmark to be inappropriate, arguing that such values are not representative of actual costs;

b) request full remuneration of work in progress, including the application of a higher WACC during the development and construction phases to reflect the greater risks involved, with subsequent convergence towards ordinary values;

c) consider it appropriate not to apply the ROSS framework or operating cost efficiency mechanisms during the initial years of operation, preferring instead an ex-ante estimation of costs combined with full ex post reconciliation until steady-state operations are reached.

10.4 While recognising the specific characteristics of the Enura initiative, ARERA considers that the regulatory framework proposed for new transmission operators already incorporates sufficient flexibility and can be applied to all new transmission operators, including Enura. ARERA also sees no need to provide different remuneration arrangements for work in progress relating to investments carried out in Sardinia, given that neither the regulatory framework nor capital markets for infrastructure financing are affected by the specific local characteristics of the areas where the investments are undertaken.

S 18. Comments on the criteria for determining the revenue cap for new transmission operators.

11. **Recovery of costs relating to the transmission network metering service**

11.1 Also taking into account the broad support expressed for the proposals set out in consultation document 165/2026/R/gas, ARERA intends to confirm the current arrangements governing the recognition of costs and the determination of reference revenues for the gas transmission metering service.

PART III
DETERMINATION OF TRANSMISSION SERVICE CHARGES

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

12.1 Considering the broad support expressed for the proposals set out in consultation document 165/2026/R/gas, ARERA intends to confirm the inclusion within the transmission service of both transmission on the national gas pipeline network and transmission on regional networks, allocating the corresponding revenues through the reference price methodology for the determination of entry and exit capacity charges on the transmission network and:

a) including the costs associated with the procurement of storage capacity resources for operational network balancing and ancillary services (e.g. billing and physical balancing);

b) classifying the metering service on the transmission network as a non-transmission service;

c) confirming the treatment of additional services (the so-called optional services) currently applied under the 6PRT.

12.2 Concerning transmission services included within the scope of the so-called virtual pipeline for the Sardinia Region under the Prime Ministerial Decree of 10 September 2025, some respondents to the consultation document proposed recognising the virtual pipeline as a service distinct from traditional transmission. As regards the possible options for excluding virtual pipeline costs from the reference price methodology, reference should be made to consultation document 135/2026/R/gas and to the outcome of the proceedings established for the implementation of the above decree.

13. Transmission service tariff structure

13.1 Also given the broad support expressed for the proposals set out in consultation document 165/2026/R/gas, 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}), with unit charges forming part of the tariff 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. Allocation of transmission service costs between capacity and variable tariff components (capacity-commodity split)

14.1 In general, respondents to consultation document 165/2026/R/gas expressed support for ARERA's proposal to maintain the current allocation of costs between capacity charges (the capacity component, covering the return on recognised RAB, depreciation and operational balancing costs) and commodity charges (the

commodity component, covering operating costs, corresponding to the fast-money component under the ROSS framework, as well as costs relating to fuel gas, network losses, UFG and ETS charges), based on the nature of the underlying costs of the service, with annual updates reflecting the composition of recognised revenues for each tariff year.

14.2 Some respondents, mainly network users and their associations, nevertheless highlighted the increasing weight of the capacity component in recent years and the difficulty of forecasting its future evolution. They therefore proposed maintaining the ratio between the capacity and commodity components within a predefined range throughout the regulatory period. In particular, respondents suggested introducing an upper limit (cap), in the range of approximately 4 to 4.5, on the capacity-to-commodity ratio to limit further increases in the fixed component and improve tariff predictability without significantly undermining the principle of cost reflectivity.

14.3 While recognising the concerns underlying this proposal regarding the containment of capacity charges, ARERA considers that this objective can be pursued more effectively and appropriately through greater selectivity and efficiency in capital expenditure (see Sections 8.8 et seq. and 8.1 et seq., respectively) and through greater predictability of operating expenditure (see Chapter 6 concerning the application of simplified ROSS criteria and the methodology for determining the capitalisation rate), rather than by introducing rigidity into the relationship between the capacity and commodity components. The introduction of a cap would in fact create a risk of unjustified increases in variable charges. Furthermore, ARERA's analysis of the evolution of the capacity-to-commodity ratio does not indicate a trend towards a greater incidence of the capacity component in recent years. On the contrary, the average ratio during the 6PRT was 80%-20%, compared with an average ratio of 83%-17% during the 5PRT (see Table 3).

14.4 ARERA therefore considers it appropriate to confirm the proposals set out in consultation document 165/2026/R/gas.

Table 3 – Evolution of the capacity-to-commodity ratio

(mln €)	2020	2021	2022	2023	2024	2025	2026	2027	Average
Transmission service revenues to be recovered through capacity charges	1.780	1.831	1.927	1.791	1.958	2.284	2.400	2.542	
Transmission service revenues to be recovered through the CV_u charge	323	299	296	576	615	607	562	462	
Total	**2.103**	**2.130**	**2.223**	**2.367**	**2.573**	**2.891**	**2.962**	**3.004**	
Capacity component	*85%*	*86%*	*87%*	*76%*	*76%*	*79%*	*81%*	*85%*	*82%*
Commodity component	*15%*	*14%*	*13%*	*24%*	*24%*	*21%*	*19%*	*15%*	*18%*

S 19. Comments on the allocation between capacity and commodity components.

15. **Determination of variable charges**

Variable charge CV_U

15.1 Regarding the methodology for determining the CV_U variable charge, in consultation document 165/2026/R/gas ARERA proposed confirming CV_U as the tariff component applied to transported volumes and intended to recover recognised operating costs, namely the fast-money component under the ROSS framework and other variable costs (ETS, fuel gas, network losses and UFG). The component is applied to volumes allocated to users at exit points from the transmission network, at exits towards storage facilities and at interconnection points with neighbouring systems. For determining the charge, the relevant driver is represented by gas volumes withdrawn (measured) at the same points in year t-2. Accordingly, the 2028 tariffs will be based on 2026 volumes and, under the standard regime, tariffs for each year t will be based on the corresponding volumes recorded in year t-2.

15.2 The main TSO highlighted the need to provide a clearer description of the arrangements governing tariff recognition of the difference between volumes measured at interconnection points (used to determine the charge) and volumes allocated to transmission users (effectively invoiced), clarifying the operational arrangements underlying Article 18.3 of the RTTG 6PRT, under which this item is allocated to the Balancing Operator. The main TSO proposed that this item should instead be managed through the commodity revenue recovery factor, increasing or decreasing the reconciliation amount calculated on the basis of measured volumes.

15.3 ARERA does not consider it appropriate to manage this item through the commodity recovery factor. Rather, it considers it preferable to confirm the current arrangements, under which any revenues associated with differences between withdrawn (measured) volumes and volumes allocated to users are assigned to the Balancing Operator and covered by CSEA through the "Settlement Charges Account" established under the TISG.

15.4 With regard to requests for greater transparency and predictability concerning the tariff driver used for the CV_U charge, ARERA notes that the driver is represented by quantities withdrawn from the network, measured at actual gross calorific value (GCV). It further notes that the network balance published by the main TSO already constitutes a source of information allowing this parameter to be reconstructed with a sufficient degree of reliability. In particular:

a) the network balance expresses physical volumes using a conventional GCV of 38.1 MJ/Smc. The GCV value required to convert quantities into actual GCV terms is available only for interconnection points and LNG entry points, while it is not available for storage facilities and delivery points, which represent a large number of individual points. For these categories of points, the daily weighted average GCV of entry points can be used as a reasonable approximation for estimating physical volumes;

b) for bidirectional points, such as interconnections and storage facilities, the network balance reports net flows, even where entry and exit components are

separately identified for interconnection points. Although this value may not exactly coincide with the measured value used for determining the tariff driver, any deviations are minimal;

c) the network balance does not provide a breakdown of quantities withdrawn from the networks of TSOs other than the main TSO, but only a breakdown of deliveries made by the main TSO to such networks. Also in this case, deviations compared with the data used for the tariff driver are negligible.

Complementary charge for CV_{FC} revenue recovery

15.5 In consultation document 165/2026/R/gas, ARERA confirmed the application of the complementary CV_{FC} variable charge under the arrangements currently in force, while proposing adjustments aimed at limiting excessive annual tariff fluctuations and stabilising the level of the charge over time.

15.6 Overall, the consultation responses expressed support for measures aimed at reducing the volatility of the CV_{FC} component and mitigating its tariff impacts, including through mechanisms that spread the most significant increases over time. However, respondents stressed the need for substantially greater transparency and predictability in the methodology used to determine the charge, particularly regarding clear disclosure of the calculation drivers, cost components and revenue recovery requirements taken into account, so that operators can understand the evolution of the charge both ex-ante and ex post. Respondents also noted that the discretionary interventions adopted in recent years to modulate revenue recovery, while contributing to limiting tariff increases, have reduced the predictability of the component. At the same time, the need was highlighted to strike an appropriate balance between tariff stability and the timely recovery of recognised revenues by infrastructure operators, including through the evaluation of alternative solutions for recovering specific categories of costs.

15.7 In light of the consultation responses received, ARERA considers it appropriate to confirm the introduction of measures aimed at limiting excessive annual fluctuations in the CV_{FC} charge and stabilising its level over time. In particular, ARERA intends to:

a) make available, within the tariff update process, all data and parameters used in determining the CV_{FC} charge;

b) adopt a broader perspective when quantifying revenue recovery requirements, including estimates relating to compensations and reconciliations that can already be reasonably forecast for subsequent years;

c) evaluate, in each tariff year, whether compensation requirements leading to a positive or negative variation of more than 30% in the CV_{FC} charge compared with the previous year should be spread over a two-year or three-year period.

15.8 In this regard, ARERA notes that the predictability of the charge in recent years has been undermined by the exceptional magnitude of the amounts to be recovered through the complementary charge, rather than by discretionary interventions by ARERA. Those interventions were aimed solely at limiting fluctuations in the charge, consistently with the requirements for predictability

and stability highlighted during the consultation process. With regard to transparency, ARERA notes that the actual amount of the items to be recovered through the complementary charge can only be disclosed once those items have been identified as part of the charge approval process, in line with ARERA's established practice.

15.9 The main TSO also observed that the treatment of differences between allocated volumes and measured volumes does not apply to the CV_{FC} charge, as currently stated in Article 19.2 of the RTTG 6PRT, because the revenues generated by that charge are paid directly to CSEA pursuant to Article 19.3. Accordingly, unlike revenues arising from the CV_U charge, there is no need to reconcile ex post any allocated-versus-measured volume differences, since all revenues collected through the charge are transferred to CSEA on a monthly basis during the year.

S 20. Comments on the determination of transmission charges.

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

16.1 In consultation document 165/2026/R/gas, ARERA proposed defining the entry-exit split consistently with the 6PRT by allocating:

a) to entry points, a share of revenues of 50% of national network revenues;

b) to exit points, a share of revenues equal to the sum of 50% of national network revenues, the share of revenues associated with overcapacity at entry points, determined on the basis of the utilisation rates recorded in recent years for the transmission capacity associated with those points, which typically have maximum capacities exceeding actual utilisation levels, and 100% of regional network revenues.

16.2 Based on the above methodology, while also seeking to ensure tariff stability and avoid excessive increases in exit charges, ARERA proposed an entry-exit split of 23/77. ARERA also recalled that certain proposals presented in consultation document 135/2026/R/gas regarding the allocation of costs associated with the virtual pipeline would imply a modification of that split (see paragraph 10.14), resulting in a larger share of revenues being allocated to exit points.

16.3 The consultation responses did not show a clear consensus regarding the entry-exit split. Some respondents supported maintaining the current 25/75 allocation to avoid further increases in exit charges and the resulting impacts on consumers, industrial users and thermoelectric plants. Other respondents highlighted the opportunity to move towards a 20/80 allocation, considering it more consistent with the principle of cost reflectivity, the declining utilisation of entry capacity and the objective of enhancing security of supply, market liquidity and Italy's role as a gas hub.

16.4 Some respondents nevertheless emphasised the need to limit the impact on cross-border exit points to avoid adversely affecting exports, international transit flows and the utilisation of national infrastructure.

16.5 Furthermore, although this issue falls outside the scope of the present consultation document, respondents broadly agreed on the need to coordinate any increases in exit tariffs with the capacity market. In particular, the need to adjust the premiums granted to thermoelectric plants has been highlighted, to offset higher transmission costs and to achieve greater alignment between capacity market timelines and gas capacity booking procedures, including through the introduction of multi-year bookings at predetermined tariffs.

16.6 As discussed in consultation document 165/2026/R/gas, ARERA considers it necessary to balance the principle of cost reflectivity with the need to mitigate tariff impacts on exit points. Accordingly, ARERA considers it appropriate to confirm its proposal to modify the entry-exit split by adopting a 23/77 allocation instead of the current 25/75 split, without prejudice to any further adjustments that may arise from the options under consideration for including virtual pipeline costs within the reference price methodology following the outcome of consultation document 135/2026/R/gas.

S 21. Comments on the entry-exit split.

17. **Reference price methodology for determining capacity charges**

The reference price methodology in 6PRT

17.1 In consultation document 165/2026/R/gas, ARERA proposed maintaining for the 7PRT the Capacity-Weighted Distance (CWD) methodology described in Article 8 of the TAR NC, taking into account the amendments introduced by Regulation (EU) 2024/1789, particularly regarding the possible application of discounts at LNG entry points and additional transparency requirements, as well as the outcome of consultation document 135/2026/R/gas concerning the tariff treatment of the virtual pipeline for the methanisation of the Sardinia Region.

17.2 In summary, the CWD methodology allocates costs on the basis of both the distances travelled by gas within the network and the capacity booked by users. The capacity currently used as the cost driver is the capacity estimated by the TSOs on the basis of expected capacity bookings, including appropriately weighted short-term and interruptible capacity.

17.3 For the distance component, the methodology considers:

a) the physical length of the national network between entry and exit points;
b) for the regional network, the average distance between delivery points and the national network.

17.4 The methodology also includes some aggregations designed to simplify the tariff structure, notably:

a) entry points associated with domestic production, which are grouped into ten production hubs;
b) delivery points, which are aggregated into twelve exit points obtained by combining six withdrawal areas and the distance of the delivery point from the national network (within or beyond 15 km).

17.5 Some adjustments are subsequently applied to the charges resulting from the CWD methodology:
a) equalisation of exit tariffs for delivery points, resulting in only two distinct tariffs based on the distance from the national network;
b) equalisation of entry and exit tariffs at storage facilities;
c) a 50% discount on transmission charges applicable to storage facilities;
d) a 50% discount at the Gela exit point;
e) a multiplicative rescaling mechanism, whereby the same scaling factor is applied to all charges to ensure recovery of recognised revenues.

17.6 As no objections have been raised in this regard, ARERA confirms that, except as otherwise specified below and without prejudice to the outcome of consultation document 135/2026/R/gas concerning the tariff treatment of the virtual pipeline for the methanisation of the Sardinia Region, the current arrangements established under the RTTG 6PRT remain unchanged.

Proposed adjustments for the 7PRT

17.7 In consultation document 165/2026/R/gas, ARERA consulted on some possible adjustments to the CWD methodology for the 7PRT, in particular:
a) introducing, at LNG terminal entry points, an equalisation mechanism whereby a unique entry charge would be derived from the individual charges applicable to each regasification terminal and applied across all LNG terminal entry points, consistently with Article 6(4)(b) [12] of the TAR NC;
b) evaluating the introduction of a discount at LNG entry points, considering the implications for the level of other entry charges;
c) assessing whether the rescaling of unit capacity charges used to recover reference revenues should be performed through the application of an additive constant[13], notwithstanding the preliminary finding that such an option would reduce cost reflectivity and could be detrimental to the system as a whole, since it would increase charges at entry points through which gas most relevant to price formation at the PSV flows, namely gas imported from European hubs and LNG, as well as at storage entry points, which are essential for system flexibility.

[12] That is, the possibility of applying equalisation, whereby the same reference price is applied to some or all points belonging to a homogeneous group of points.
[13] Calculated as the ratio between the difference of the total revenues to be recovered and the revenues that would be recovered by applying the relevant adjustments (under the current rules, only the storage discount), and the total forecast booked capacity.

Equalisation of entry charges at regasification terminals

17.8 Consultation responses revealed diverging views regarding the introduction of a mechanism for equalising entry charges at regasification terminals:

a) some respondents supported ARERA's proposal, considering that a single charge could facilitate more integrated terminal management, support the development of pooling services, increase operational flexibility and contribute to competitiveness, security of supply and tariff stability. Some respondents also noted that such an approach would be consistent with the evolution of Italy's natural gas supply strategy;

b) other respondents considered it preferable to retain differentiated entry charges, noting that the current arrangements have not hindered the allocation of regasification capacity and preserve tariff signals that are more closely aligned with underlying costs. According to these respondents, equalisation would mainly produce redistributive effects, generating benefits for some terminals and disadvantages for others without delivering significant gains in allocative efficiency.

17.9 Among the comments received, ARERA considers particularly relevant the observation that equalisation would concern terminals that are already largely covered by long-term contracts or are fully booked, thereby limiting its ability to influence allocation decisions and generate pro-competitive effects. Furthermore, such a measure would increase the charge applicable to the Ravenna terminal, which is still under development.

17.10 Table 4 illustrates the charge that would result from the creation of a possible LNG hub, reproducing the analysis presented in consultation document 165/2026/R/gas alongside a simulation based on the tariffs approved for 2027 through resolution 191/2026/R/gas. The analysis highlights a redistribution effect to the detriment of Adriatic terminals, which are already characterised by higher logistical and operational costs than Tyrrhenian terminals. As already clarified in consultation document 165/2026/R/gas, equalisation of LNG charges would affect only LNG entry charges.

Table 4 – Simulation of a single charge at LNG entry points compared with approved charges

CP_e (euro/y/Smc/d)	Charges 2026	With equalisation	**CP_e (euro/y/Smc/d)**	Charges 2027	With equalisation
LNG Panigaglia	1,346334		LNG Panigaglia	1,379357	
LNG Cavarzere	1,213708		LNG Cavarzere	1,243716	
LNG OLT Livorno	1,580487	1,352253	LNG OLT Livorno	1,649641	1,405888
LNG Ravenna	1,141894		LNG Ravenna	1,171327	
LNG Piombino	1,603790		LNG Piombino	1,677503	
Average	*1,377243*		*Average*	*1,424309*	

17.11 In light of the above considerations, ARERA considers that the proposed equalisation mechanism could generate effects that are not necessarily pro-competitive and may not support the efficient use of infrastructure. ARERA further considers that such a measure would only become meaningful as part of a broader reform of LNG entry-point allocation arrangements involving the pooling

of LNG terminals, which is not currently under consideration. Accordingly, ARERA does not intend to proceed with the proposal put forward in consultation document 165/2026/R/gas.

Discount on LNG entry charges

17.12 The consultation responses broadly supported the possible introduction of a discount on LNG entry charges. Respondents generally considered that such a measure could strengthen the competitiveness of Italian terminals, enhance security of supply and improve the attractiveness of the Italian market relative to other European markets. Different views were expressed regarding the value and scope of the discount. Some respondents supported a general measure, while others favoured targeted interventions limited either to specific terminals or to capacity not yet allocated. Regarding the latter approach, some respondents argued that any discount should also apply to capacity already allocated under long-term contracts, to avoid discriminatory effects and ensure continuity in the economic conditions applicable to operators.

17.13 As highlighted in consultation document 165/2026/R/gas, while such a measure would improve the competitiveness of LNG supplies for the Italian system, it would at the same time increase all other entry charges. Table 5 illustrates the increase that would affect the entry charges approved for 2027, with results substantially similar to those obtained using 2026 tariffs, under different discount levels ranging from 30% to 100%.

Table 5 – Increase in each entry charge under different discount levels at LNG entry points. The increase in entry charges is uniform.

	30% Discount	50% Discount	100% Discount
Increase in entry tariffs other than LNG entry points	5%	8%	17%

17.14 All above considered, ARERA deems that the application of a discount may still be appropriate. Although, under current market conditions, the Italian market is primarily influenced by transmission costs along supply routes from Northern Europe and an LNG discount may therefore not necessarily benefit all sources of supply, ARERA notes that the simultaneous introduction of the proposed 23/77 entry-exit split (see paragraph 16.6) would partially offset the increase in other entry charges resulting from an LNG discount. Accordingly, ARERA considers it appropriate to introduce a discount at LNG entry points with the objective of maintaining broad stability in other entry charges across the Italian system while reducing LNG entry charges. This would increase both the likelihood and the number of days in which LNG supplies become the marginal source of gas in the Italian market, thereby promoting greater alignment between Italian prices and those observed in Northern European markets.

17.15 Regarding capacity already allocated under long-term contracts, the discount would be internalised within the reference price methodology, which would therefore generate charges already reflecting both the LNG discount and the consequent rescaling of all entry charges. Accordingly, the arrangements normally applicable to the pass-through of transmission costs to regasification service users, as well as the contractual provisions agreed at the time capacity was awarded, would remain unchanged.

17.16 ARERA further considers that the introduction of such a discount could contribute to security of supply, consistently with Article 17(3) of Regulation (EU) 2024/1789. Specifically, lower charges at LNG entry points could encourage greater diversification of supply sources and routes, reducing dependence on specific suppliers and pipeline import corridors and improving the resilience of the national system to supply disruptions. Moreover, increased utilisation of regasification infrastructure may generate broader system benefits, insofar as additional revenues arising from higher capacity utilisation contribute to reducing deviations from recognised revenues and, consequently, reliance on revenue adjustment mechanisms, thereby limiting the associated costs for the system and its users.

17.17 A 30% discount appears to represent a proportionate measure in relation to these objectives, as it would strengthen the potential contribution of LNG to diversification and security of supply while encouraging greater utilisation of existing infrastructure, preserving appropriate tariff signals and limiting redistributive effects on other network points.

Rescaling mechanism for unit charges

17.18 Regarding the rescaling mechanism, most respondents favoured maintaining the current approach based on a multiplicative constant, citing the need for regulatory continuity and the preservation of tariff cost reflectivity. Some respondents nevertheless supported the introduction of an additive constant to mitigate the redistributive effects associated with the application of discounts.

17.19 Respondents also highlighted the desirability of making available quantitative and sensitivity analyses relating to different combinations of equalisation, discounts and rescaling approaches.

17.20 In this regard, ARERA reiterates that rescaling through an additive constant does not preserve the relative relationship between charges and tends to reduce the differences among them, particularly by lowering charges at Southern entry points, thereby reducing the cost reflectivity of the tariff methodology. Furthermore, such an approach could be detrimental to the system as a whole because it would increase charges at entry points through which has the greatest influence on price formation at the PSV flows, namely imports from European hubs and LNG, as well as at storage entry points that provide system flexibility.

17.21 In light of the above, ARERA intends to maintain for the 7PRT the current rescaling methodology based on the application of a multiplicative constant.

Stability, transparency and predictability of charges

17.22 As part of the measures aimed at reducing tariff variability, consultation document 165/2026/R/gas considered the possibility of adopting, for capacity charges, a driver different from forecast booked capacity, which currently contributes to variability in both the level of charges and their relative relationships. The options considered were:

a) technical capacity;

b) maintaining forecast booked capacity from the first year fixed throughout the regulatory period;

c) actual booked transmission capacity recorded in the most recent available year (t-2), consistently with the volume driver used for the variable charge.

17.23 In consultation document 165/2026/R/gas, ARERA underlined the importance of maintaining sufficient flexibility within the tariff methodology to ensure that transmission costs are allocated according to actual network utilisation, while also recognising the need for greater transparency and supporting evidence regarding forecasts of booked capacity.

17.24 Consultation responses highlighted a shared need for greater transparency and earlier availability of the information used to determine tariff charges, as well as for quantitative simulations and tools enabling stakeholders to assess the effects of different regulatory options, including their combined application.

17.25 With regard to the use of technical capacity as the tariff driver, several respondents recognised its potential benefits in terms of increased tariff stability and reduced volatility, while stressing the need for further analysis of its practical implications, clearer implementation arrangements and an assessment of the trade-off between tariff stability and reduced methodological flexibility.

17.26 Some respondents also noted that the use of drivers based on fixed or technical capacity could reduce the ability of the system to reflect actual network utilisation and the evolution of demand, potentially distorting cost allocation among different network points. For this reason, respondents stressed the importance of preserving an adequate degree of flexibility within the methodology and of making more comprehensive information available before reaching definitive conclusions. The main TSO, in particular, suggested introducing an obligation requiring commercial operators to provide the main TSO with information on the expected utilisation of individual entry and exit points in the following year, to be used when estimating booked capacity.

17.27 As already highlighted in consultation document 165/2026/R/gas, ARERA considers it preferable to adopt a tariff methodology capable of allocating transmission costs in accordance with actual network utilisation. This consideration excludes the use of both technical capacity and fixed capacity, as these would be entirely disconnected from actual network usage.

17.28 With regard to the request for further simulations, ARERA notes that the use of technical capacity[14] presents significant limitations at points where forecast booked capacity is very low and where specific corrective measures would therefore be required. Technical capacity would assign a certain weight, and consequently a certain amount of recoverable revenue, to such points despite their very limited booked capacity, resulting in disproportionately high unit tariffs. This would be the case, for example, for Tarvisio, where the resulting tariff would be approximately EUR 135/Smc/day/year.

17.29 As with additive rescaling, this approach would generate outcomes that are inconsistent with the principle of cost reflectivity and potentially anti-competitive at system level, namely a significant reduction in charges at Southern entry points and a significant increase in charges at Passo Gries. Concerning exit points, the approach would result in higher charges at cross-border exit points and storage facilities and lower charges at delivery points.

17.30 In light of the above considerations, ARERA considers it appropriate to maintain booked capacity as the relevant driver rather than technical capacity, while assessing the possibility of using the transmission capacity booked in the most recent available calendar year in place of forecast booked capacity. The main TSO would retain the possibility of proposing duly justified adjustments for individual network points.

17.31 In any event, even if forecast booked capacity were retained as the tariff driver, ARERA confirms its intention to improve the transparency and predictability of the tariff driver by publishing:

a) the assumptions underlying forecasts of entry and exit capacity;
b) further details regarding short-term capacity bookings and the multipliers applied, which are relevant for determining the driver;
c) information regarding any interruptible capacity and the corresponding discount levels;
d) the data and forecasting model underlying the capacity estimates, including forecasts covering the four years following the relevant tariff year.

17.32 ARERA also considers it appropriate to confirm that the model submitted and published by the main TSO should be expanded to include, for the following four years:

a) more refined forecasts of the capacities used as the tariff driver, which should be consistent with the assumptions underpinning the scenario analyses used for the TYNDP and include a justification of those assumptions;

[14] In this respect, it should be noted that technical capacity data are not available in a unique, comprehensive and readily usable form for regulatory analyses. It is therefore necessary to adopt an indicator that is as representative as possible of technical capacity, while relying on a number of methodological assumptions that inevitably introduce a degree of approximation (for example, by considering only firm capacity and excluding interruptible capacity), given the challenges associated with reconstructing the relevant data. A reliable application of technical capacity for tariff-setting purposes would require the availability of more granular, complete and transparent data, preferably provided directly by the network operator, in order to reduce reliance on assumptions and discretionary estimates.

b) the projected evolution of regulated revenues determined in accordance with the applicable regulatory framework and based on the investments included in the TYNDP, distinguishing between revenues to be recovered through capacity charges and revenues to be recovered through variable charges.

Assessment of the reference price methodology

17.33 The reference price methodology must comply with Article 17 of Regulation (EU) 2024/1789 and with the requirements set out in Article 7 of the TAR NC, namely that it:

a) enables network users to reproduce the calculation of reference prices and obtain accurate forecasts thereof;

b) takes account of the actual costs incurred in providing transmission services, having regard to the level of complexity of the transmission network;

c) ensures non-discrimination and prevents undue cross-subsidisation;

d) ensures that final customers within an entry-exit system are not exposed to significant volume risk, particularly in relation to transportation within an entry-exit system;

e) ensures that the resulting reference prices do not distort cross-border trade.

17.34 ARERA considers that the methodology presented in this consultation document, which remains substantially aligned with the current framework, is consistent with the transparency and tariff replicability requirements established by the TAR NC, as already recognised, in substance, by the ACER report of 17 February 2023 entitled Analysis of the Consultation Document on the Gas Transmission Tariff Structure for Italy, which assessed consultation document 502/2022/R/gas for the 6PRT. As regards the elements that distinguish the proposed methodology from that currently applied during the 6PRT:

a) the modification of the entry-exit split responds to the need for a cost allocation that is more consistent with the principle of cost reflectivity, while at the same time limiting increases in exit charges;

b) the discount applied to transmission tariffs at LNG regasification entry points is intended to promote security of supply and the competitiveness of import sources, consistently with Regulation (EU) 2024/1789;

c) the proposed modification of the driver used for capacity charges, through the use of transmission capacity booked in the most recent available calendar year, is intended to improve the predictability and transparency of transmission charges for network users.

S 22. Comments on the proposed adjustments to the reference price methodology, regarding the equalisation of LNG entry points and the application of discounts at such points.

S 23. Comments on the proposals relating to the stability, transparency and predictability of transmission charges.

18. **Multipliers, seasonal factors and interruptible capacity**

18.1 In consultation document 165/2026/R/gas ARERA proposed substantially maintaining the multiplier framework currently in force, while highlighting the opportunity to introduce revisions to ensure consistency with the short-term capacity products currently offered or that may be introduced in the future following the implementation of new European capacity allocation rules. Specifically, ARERA proposed:

a) the possible introduction of a multiplier of 1.4 for the Balance of the Month (BoM) product, should such a product be included in the revised CAM NC;

b) the extension of short-term capacity products to additional entry points, as proposed in consultation document 118/2026/R/gas;

c) a possible review of the multipliers applied at industrial and thermoelectric delivery points, to be assessed through further analysis;

d) confirmation of the methodology for determining the coefficient k applied to daily capacity bookings at delivery points supplying distribution networks, while also providing greater transparency through the publication of the data and information used to determine that coefficient, in line with the transparency requirements established under the TAR NC.

18.2 The consultation responses included, in particular, the following comments:

a) respondents welcomed the introduction of a multiplier of 1.4 for the BoM product. It was also proposed that the product be extended to all entry and exit points on the national network and offered on a bundled basis together with foreign TSOs;

b) some stakeholders supported the proposed review of multipliers applied to short-term products, particularly at thermoelectric and industrial delivery points, with a view to increasing system flexibility and reflecting the changing requirements of the electricity sector. In particular, they proposed a reduction in the multipliers applied to thermoelectric delivery points and the introduction of additional short-term products;

c) with regard to the methodology for determining coefficient k:

   i. several respondents requested greater transparency, highlighting the need for more detailed information and for an assessment of the effects on tariff stability;

   ii. stakeholders also proposed simplifying the process for calculating capacity-booking parameters at city-gates, noting that the complexity of the current mechanism and the timing of the information required, particularly the forecast booked-capacity data approved as part of tariff proposals and necessary for calculating parameter z, are not consistent with operational timelines;

   iii. respondents also requested clarification regarding the effects of the derogation relating to the zcg component, highlighting potential distortions arising from the lack of updating of that parameter and its

implications for the calculation of CTC_{PdR} and, consequently, forecast booked capacity;

d) the main TSO did not support proposals for further transparency requirements, considering that the level of information currently provided under the regulatory framework is already adequate;

e) with regard to reverse-flow points (bi-directional REMI stations), several respondents highlighted concerns about treating such points in the same way as production points directly connected to the transmission network. In their view, utilisation of these points is unpredictable and cannot be fully controlled by transmission users. They therefore proposed a dedicated regulatory approach, possibly through the creation of a separate cluster distinct from other entry points, in order to avoid imposing inappropriate obligations and risks on transmission users;

f) one respondent proposed postponing the deadlines for monthly and quarterly capacity bookings applicable to thermoelectric users and introducing the possibility of revising previously communicated capacity values at the time capacity bookings are confirmed;

g) respondents also highlighted the need to coordinate any changes to multipliers with other market mechanisms, particularly the Capacity Market, including through a revision of the cap applicable to the premiums recognised thereunder.

18.3 With specific regard to reverse-flow points, in resolution 220/2026/R/gas ARERA concluded that the challenges associated with capacity booking and balancing, arising from the unpredictability of gas quantities injected into the network by users, can be addressed through appropriate amendments to settlement procedures. Such amendments would enable balancing users to determine with certainty the quantities to be allocated as injections into the transmission network, based on the volumes of biomethane injected into the distribution network and on parameters defined ex ante. ARERA has therefore launched a dedicated proceeding aimed at identifying the most appropriate arrangements for allocating gas quantities at bi-directional REMI delivery points in order to optimise and improve the efficiency of balancing activities.

18.4 ARERA intends to confirm the introduction of the BoM product with a multiplier of 1.4 at interconnection points with foreign systems, subject to its inclusion in the revised CAM NC. Regarding thermoelectric and industrial delivery points, ARERA does not consider it appropriate to introduce the BoM product, given that the current portfolio of capacity products already provides sufficient flexibility for network use.

18.5 Regarding the possible revision of multipliers applied at industrial and thermoelectric delivery points, ARERA intends to retain the current values, as these ensure an appropriate balance between flexibility in capacity utilisation and cost allocation. As regards thermoelectric delivery points in particular, a reduction in multiplier levels would result in significant increases in exit charges for all users of the gas transmission network, while generating potential benefits for the

electricity sector. Any such intervention should therefore be accompanied by measures ensuring that the resulting additional costs are recovered from the sector benefiting from the change, without adversely affecting gas-sector users.

18.6 Regarding coefficient k, and in light of both the need for greater transparency highlighted during the consultation and the objectives of tariff stability and simplification, ARERA considers that the parameter could be stabilised at the levels applied over the last two gas years. The k coefficient applied to implicitly booked daily capacity was introduced as part of the reform of capacity allocation processes at transmission-network delivery points (see resolution 72/2023/R/gas) and was designed to ensure equivalence between the transmission charges applied to annual capacity booked explicitly and those applied to daily capacity booked implicitly. Three years after the implementation of the reform, ARERA considers that administrative simplification may appropriately take precedence over strict revenue neutrality relative to the previous framework. Consequently, the coefficient could be fixed on the basis of updated annual consumption values and revised wkr and zcg parameters. Preliminary assessments indicate a value of 3.2.

18.7 Regarding the need to coordinate any changes to multipliers with other market mechanisms, particularly the Capacity Market, ARERA notes that such matters fall outside the scope of transmission tariff regulation addressed in this consultation document and will be considered, where appropriate, in future proceedings.

18.8 Lastly, ARERA recalls that resolution 220/2026/R/gas extended, with effect from 1 January 2027, the availability of short-term capacity products, with quarterly, monthly and daily durations according to the procedures and timelines set out in Chapter 5 of the Network Code, to all entry points, including:

a) domestic production entry points;
b) biomethane production entry points;
c) LNG storage facilities falling within the scope of Article 10 of Legislative Decree No. 257/2016, for the injection into the national transmission network of boil-off gas generated by such facilities;
d) LNG storage facilities referred to in Article 1.3 of resolution 168/2019/R/gas, which do not provide regasification as their primary and prevailing activity, for the injection into the national transmission network of regasified LNG and/or boil-off gas generated by the facility;
e) distribution-network and other transmission-network entry points (reverse flow), provided that at least a minimum amount of annual capacity is booked at the relevant point, thereby allowing the balancing user (UdB) responsible for injections into the network to be identified.

Table 7: Level of multipliers

	Multiplier

Short-term capacity product	Entry points	Cross-border exit points	Thermoelectric delivery points	Industrial delivery points	*City gates*	Other exit/ delivery points
Quarterly	1.2	1.2	1.85	1.2	*n.d.*	*n.d.*
Monthly	1.3	1.3	2[(1)]	1.3	*n.d.*	*n.d.*
BoM	1.4	1.4	n.d.	*n.d.*	*n.d.*	*n.d.*
Day	1.5	1.5	7 [(1)]	1.7	3.2	*n.d.*
Intra-day	1.5	1.5	*n.d.*	*n.d.*	*n.d.*	*n.d.*

[(1)] Regulated under resolution 512/2017/R/GAS, point 1, letters b) and c)
The coefficients shall also be applied, in the case of intra-year capacity bookings at transmission network exit points, to the daily pro rata share of the CM_T charge.

18.9 Consistently with the framework currently in force, ARERA also intends to confirm:

a) the non-application of seasonal factors;

b) the application of reduced capacity charges for interruptible capacity, in order to reflect the risk associated with service interruption while ensuring transparency and equal treatment among network users. The main TSO publishes the criteria used to determine interruptible and firm capacity.

S 24. Comments on multipliers and seasonal factors.

PART IV
DETERMINATION OF TRANSMISSION METERING SERVICE CHARGES

19. Tariff structure of the metering service

19.1 In consultation document 165/2026/R/gas, ARERA proposed to substantially confirm the tariff structure of the metering service, providing in particular for the definition of two charges:

a) the CM_T charge, covering meter reading and metering activities under the direct responsibility of the transmission company, expressed in euro/year/standard cubic metre/day and applied to capacity booked at transmission network redelivery points; this charge is determined as the ratio between:

   i. the sum of the components covering metering costs, net of capital costs associated with metering installations at final customers' premises;

   ii. forecast capacity bookings at transmission network redelivery points;

b) the charge covering metering activities at final customer redelivery points, expressed in euro/redelivery point/year and applied to redelivery points serving final customers where ownership of the metering installation lies with the transmission company; this charge is differentiated according to metering installation Qero classes.

19.2 ARERA also proposed to confirm the application, to redelivery points for which ownership of the metering installation was acquired by the transmission company from 2022 onwards through transfer from final customers, of a charge equal to 50% of the applicable amount for a period of four years from the date of transfer.

19.3 Regarding the methodology for determining the charges, ARERA expressed its proposal to:

a) determine their value for the first year of the regulatory period (2028) by updating the charges approved for 2027, in light of the change in the capital revaluation index;

b) revise their values on the basis of new classes, in particular by splitting each of the two classes with a Qero above 200 Smc/h into two additional classes.

19.4 In response to the consultation:

a) there was broad support for the revision of the charges, while highlighting the need to ensure appropriate cost reflectivity. In particular, one respondent considered the estimated charge for the 200-1,200 Smc/h class, amounting to EUR 5,050/year/redelivery point, to be excessive and proposed setting it at EUR 1,550/year/redelivery point, consistent with the estimated costs of managing the installations. Accordingly, the respondent proposed reducing to EUR 1,550 both the security deposit required by the network operator in cases where ownership of the installation is transferred and the cap applicable to charges for non-compliance with metering service quality standards; alternatively, the respondent proposed a comprehensive review of the charges;

b) several respondents raised concerns regarding the revision of the classes, mainly due to the potential operational challenges associated with adapting IT systems. Concerns were also raised regarding the need to carry out a new census of installations in order to align the relevant information with the new classes, particularly given that several parties had never provided the information required during the original census exercise;

c) there was broad support for ARERA's other proposals, in particular the confirmation of the methodology for determining and applying the CMT charge, and the confirmation of the 50% discount for four years in the event of transfer of ownership of the metering installation to the transmission company.

19.5 About the level of charges for the new classes:

a) the available data on installation costs do not show a marked difference in costs between the classes with Qero between 200 and 1,200 Smc/h and those with Qero between 1,200 and 4,000 Smc/h. Furthermore, the charge of EUR 1,550/year/redelivery point is consistent solely with annual operation and maintenance costs, based on the available data on the average annual cost of meters with capacities above 200 Smc/h, and does not reflect installation costs. In light of these costs, and considering the need to ensure recovery of the corresponding share of metering revenues associated with such meters,

two separate charges could be established at EUR 4,400/year/redelivery point and EUR 5,800/year/redelivery point respectively;

b) for the current Qero class above 4,000 Smc/h, it is considered appropriate to confirm the proposal to split installations into two separate classes (between 4,000 and 30,000 Smc/h, and above 30,000 Smc/h), with the application of two distinct charges derived from the charge approved for 2027 and reflecting the different average installation and maintenance costs.

19.6 With regard to the operational challenges, ARERA considers that approval of the criteria for the 7PRT by the first quarter of 2027 would provide operators with sufficient time to adapt their IT systems and gather the information required for implementation from 1 January 2028, also in light of the contractual arrangements between the transmission company and the final customer directly connected to the transmission network under metering agreements.

19.7 ARERA therefore considers it appropriate to confirm the revision of the CM_{CF}^{pdr} charges, reflecting both the need to ensure greater proportionality among the charges, consistent with the responses received during the consultation, and the desirability of avoiding excessive fluctuations in tariff levels compared with those currently in force, particularly for meters with capacities above 4,000 Smc/h. To this end, ARERA confirms its proposal to split the Qero class between 200 and 4,000 Smc/h into two classes, namely 200-1,200 Smc/h and 1,200-4,000 Smc/h, revising the level of the charges with a view to ensuring greater proportionality while maintaining recovery of both operating and installation costs associated with the metering installation. In particular, for the purpose of determining the charges: i. a single average annual maintenance cost was assumed for all installations with capacities above 200 Smc/h; ii. for meters with capacities above 4,000 Smc/h, given the limited size of the sample and the heterogeneity of the available cost data, separate charges were defined for the two classes so as to ensure both proportionality with the underlying costs and consistency with the current level.

19.8 Table 8 presents an estimate of the CM_{CF}^{pdr} metering charges for 2027, redetermined according to the class structure proposed in consultation document 165/2026/R/gas, which ARERA intends to confirm, and reflecting estimates of the costs underlying the service based on the data available from transmission companies, as well as the need to ensure greater proportionality in the charges applicable to Qero classes between 200 and 4,000 Smc/h and above 4,000 Smc/h.

Table 8: *metering* charges CM_{CF}^{pdr}

	2027	2027 new classes
Qero ≤ 16 Scm/h	31 €	31 €
16 Scm/h < Qero ≤ 65 Scm/h	209 €	209 €
65 Scm/h < Qero ≤ 200 Scm/h	470 €	470 €

200 Scm/h < Qero ≤ 1.200 Scm/h	5.332 €	4.400 €
1.200 Scm/h < Qero ≤ 4.000 Scm/h		5.800 €
4.000 Scm/h < Qero ≤ 30.000 Scm/h	8.364 €	6.700 €
Qero > 30.000 Scm/h		10.500 €

S 25. Comments on the tariff structure of the metering service.

PART V
REVENUE COMPENSATION AND RECOVERY MECHANISMS

20. **Transfers and compensations of tariff revenues**

20.1 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. In consultation document 165/2026/R/gas, ARERA proposed maintaining the revenue reconciliation mechanisms currently in force under the 6PRT.

20.2 Regarding capacity charges, ARERA proposed to confirm the application of:

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); such reconciliation is managed through specific revenue-sharing arrangements among TSOs;

b) the reconciliation of revenues associated with the regional gas pipeline network, aimed at ensuring that each TSO operating a regional gas pipeline network receives revenues commensurate with its recognised revenues; this reconciliation is managed by CSEA through a dedicated account and is carried out on an annual basis.

20.3 ARERA also proposed confirming the specific revenue-sharing arrangements among TSOs relating to:

a) revenues from the national network, among TSOs owning national transmission infrastructure;

b) revenues arising from the application of the variable charge CV_U;

c) revenues arising from the application of metering charges.

20.4 One operator highlighted the desirability of further simplifying existing processes, which currently give rise to a complex and potentially redundant set of bilateral and multilateral relationships among market participants. It therefore proposed moving towards a system more closely aligned with that already adopted for electricity and natural gas distribution activities, where CSEA acts as the sole central counterparty for network operators. More specifically, it was proposed that CSEA should manage the allocation among operators of both transmission revenues, including capacity and variable revenues, and metering revenues, combining these activities with the management of the reconciliation mechanism for revenues associated with the regional transmission network. According to this proposal, CSEA could also manage, with separate accounting treatment, the mechanism covering the risk associated with differences between

actual gas volumes withdrawn and the volumes used for determining the level of the variable charge

20.5 During the focus group held on 23 September 2026, this proposal was welcomed by the other TSOs, provided that monthly management of the reconciliation mechanisms is maintained.

20.6 ARERA considers the views expressed during the consultation in favour of further simplification of reconciliation processes to be well founded and intends to carry out further discussions with CSEA to assess the feasibility of centralising the management of all reconciliation mechanisms. This would be without prejudice to the need to maintain monthly settlement arrangements for reconciliation mechanisms other than those relating to revenues from the regional transmission network.

S 26. Comments on revenue compensation mechanisms.

21. **Revenue recovery and reconciliation**

21.1 In consultation document 165/2026/R/gas, ARERA confirmed the application of the recovery factors relating to capacity revenues for the transmission and metering services, as well as the commodity revenue recovery factor for the transmission service, while proposing certain changes to their implementation arrangements.:

a) the recovery factor relating to transmission capacity revenues would be determined, for each TSO, as the difference between the allowed revenue component definitively approved by ARERA and allocated to the capacity component, and the revenues actually collected through the application of capacity charges, gross of any reductions applied by the operator and net of any additional revenues collected by the TSO for the provision of additional services and of any revenue-sharing arrangements among TSOs;

b) the recovery factor relating to metering revenues would be determined, for each TSO, as the difference between the allowed revenue for the metering service and the revenues actually collected through the application of CMT metering charges, gross of any reductions applied by the operator and net of any additional revenues collected by the TSO for the provision of additional services and of any revenue-sharing arrangements among TSOs;

c) the commodity revenue recovery factor for the transmission service would be determined, for each TSO (and no longer only for the main TSO), as the difference between the allowed revenue component definitively approved by ARERA, on the basis of the proposal submitted by the relevant TSO, and allocated to the commodity component, excluding costs relating to fuel gas, network losses and UFG, and the revenues actually collected through the application of the TSO-specific CV_U charges. In addition, ARERA proposed reducing the threshold for activation of the commodity revenue recovery factor from 4% to 3%.

21.2 Given the broad support expressed for the proposed arrangements governing the determination of recovery factors, in particular the proposal to determine the commodity revenue recovery factor for each individual TSO (with the resulting balances being settled directly with CSEA) and to reduce the activation threshold, ARERA confirms the proposals set out in the consultation document, also in light of the procedural simplifications described in paragraphs 21.3 et seq.

Procedure for revenue approval and determination of recovery factors

21.3 To mitigate the administrative complexity arising from the introduction of the ROSS framework, primarily as a consequence of tariff decoupling, namely the difference between the revenues relevant for tariff-setting purposes (approved in year t-1) and the allowed revenues for year t (approved at the end of year t+1), ARERA proposed in consultation document 165/2026/R/gas to streamline the tariff approval process. Under the proposed approach:

a) transmission charges would be approved on the basis of reference revenues determined using preliminary expenditure data for year t-1 and forecast expenditure data for year t, in May of year t-1;

b) only where the WACC trigger mechanism is activated, the reference revenues for year t would be redetermined during year t, with the consequent activation of the interim settlement mechanism relating to tariff decoupling reconciliations;

c) a single adjustment of tariff revenues against allowed revenues would be carried out in December of year t+1, comparing allowed revenues with the tariff revenues actually recovered by operators, net of revenue-sharing arrangements among TSOs (thus taking into account TSO-specific capacity and variable charges), and determining the capacity, commodity and metering recovery factors, which would be settled with CSEA together with the reconciliations relating to UFG, network losses and ETS (see paragraphs 21.1 and 21.2);

d) revenue-sharing arrangements would continue to operate during year t in accordance with the current regulatory framework, with the objective of ensuring that each operator receives revenues consistent with its reference revenues, while also considering the involvement of CSEA in the administration of all revenue-sharing mechanisms;

e) the CV_{FC} charge would continue, as a general rule, to be determined in May of year t+1 and applied from year t+2, in accordance with the criteria described in paragraph 15.7.

21.4 The consultation responses and discussions during the focus group generally supported the objective of simplifying revenue determination and settlement mechanisms. Respondents nevertheless highlighted the need to preserve an appropriate temporal allocation of costs and to limit cross-subsidisation effects between users in different periods. Against this background, the main operators considered it appropriate for updates and reconciliations to be carried out as soon as the underlying information becomes available, in order to ensure a closer alignment between costs incurred and their tariff recovery. The main TSO also

raised concerns regarding potential impacts on operators' liquidity positions and on the proper economic representation of costs. To mitigate liquidity impacts, one operator proposed the introduction of an advance payment mechanism, activated upon request by the TSO whenever the expected difference between tariff revenues and allowed revenues exceeds a materiality threshold equal to 5% of the year's allowed revenues. In such cases, the advance payment would be granted automatically, without further regulatory assessment.

21.5 With a view to limiting cross-subsidisation among users, ensuring operators' liquidity and, at the same time, rationalising revenue approval procedures, ARERA considers it appropriate to confirm the proposals described in paragraph 21.3. In particular, ARERA proposes that activation of the advance settlement mechanism relating to tariff decoupling reconciliations should take place upon proposal by the relevant TSO and be subject to a materiality principle. Specifically, the mechanism would be activated where the difference between the reference revenues for year t (approved in year t-1) and their redetermination during year t exceeds, in aggregate across transmission and metering activities, a threshold of 5%.

S 27. Comments on recovery factors and the simplification of the revenue approval process.

PART VI
FURTHER ASPECTS

22. **Information requirements relating to planned investments**

22.1 In consultation document 165/2026/R/gas, ARERA proposed reorganising the information submitted by TSOs regarding planned investments and disposals, as well as the monitoring of project implementation progress, through a single document to be submitted annually. This document would integrate the minimum information requirements of the business plan under Article 43 of the TIROSS with the information currently provided through the investment and disposal plan under the RTTG 6PRT. Together with their tariff proposals, and for the purposes of applying the capital expenditure efficiency mechanism referred to in paragraphs 12.10 et seq., TSOs would also be required to submit information relating to the monitoring of cost conditions and the actual technical characteristics of investments that became operational during the previous year.

22.2 The consultation responses support the objective of streamlining information requirements relating to investments and disposals, highlighting overlaps between the business plan, the TYNDP and the information on investments and disposals required under the RTTG. Although these instruments serve different purposes, they concern the same projects and therefore give rise to duplication, inefficiencies and potential inconsistencies in the data, with consequent effects on tariff predictability. Several respondents therefore support simplifying the required documentation, including through greater integration among existing instruments and the elimination of separate reporting obligations concerning planned investments and disposals, which could instead be incorporated into the business plan. In this context, proposals were also put forward to review the frequency and timing of document submissions and to consolidate project monitoring activities. Some respondents further proposed additional simplifications for operators subject to the simplified ROSS framework, arguing that all relevant information could be included within the TYNDP without requiring additional documents.

22.3 Conversely, network users highlighted the need to ensure adequate levels of transparency and information availability in order to facilitate the replicability of tariff calculations and improve the predictability of tariff developments.

22.4 In light of the comments received, ARERA considers that the approach proposed in consultation document 165/2026/R/gas appropriately balances the objectives of streamlining reporting requirements and ensuring transparency and therefore intends to confirm it. In particular, ARERA considers that the business plan should provide information on investments planned over the short to medium term, primarily relating to projects already under implementation, whereas the TYNDP, with its ten-year horizon, should remain a medium- to long-term planning document presenting potential infrastructure development projects on which the competent authorities are called upon to express their views.

22.5 More specifically, ARERA considers it appropriate for the business plan referred to in Article 44 of the TIROSS, which is subject to the cost assessment process under Article 45 of the TIROSS within the limits established therein, to be supplemented with:

a) the information currently submitted by TSOs regarding planned investments and disposals (see Article 39 of the RTTG 6PRT), thereby meeting and rationalising reporting requirements relating to investments;

b) the information required for the application of the capital efficiency incentive mechanism referred to in paragraphs 8.1 et seq.; in particular, for projects and works subject to cost assessment under Article 45 of the TIROSS, detailed information should be provided for each project, including project type, technical characteristics, completion date/date of entry into operation, reference unit costs, reference estimates and similar information;

c) information relating to the monitoring of projects and works that became operational during the previous year, including total investment costs, actual technical characteristics and other relevant information, compared with the ex-ante information used for the application of the capital expenditure efficiency mechanism referred to in paragraphs 8.1 et seq.

22.6 Furthermore, in order to make the business plan an effective tool supporting the capital efficiency incentive mechanism, ARERA considers it appropriate to establish a four-year duration for the plan. Given the timetable for tariff approvals, ARERA also considers it necessary for the first business plan of the new regulatory period to be submitted together with the next proposal for allowed revenues, scheduled for October 2027. Thereafter, the document may be submitted annually as part of the tariff proposal process.

S 28. Comments on information requirements relating to planned investments and disposals, and on the business plan.