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TO THE EUROPEAN AGENCY FOR COOPERATION

BETWEEN NATIONAL ENERGY REGULATORS AND THE EUROPEAN COMMISSION

ON THE REGULATORY ACTIVITIES AND FULFILMENT OF DUTIES OF THE REGULATORY AUTHORITY FOR ENERGY, NETWORKS AND ENVIRONMENT (ARERA)

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31 July 2026

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1 FOREWORD

This document, prepared by the Italian Regulatory Authority for Energy, Networks and Environment (ARERA), provides the Agency for the Cooperation of Energy Regulators (ACER) and the European Commission with an annual report on the activities carried out and on the implementation of regulatory tasks pursuant to Articles 59.1(i) and 78.1(l) of Directives (EU) 2019/944 and 2024/1788, respectively. The consolidated structure of the report was shared with ACER and with the European Commission's Directorate General for Energy, so that the Italian situation presented in this document can be easily compared with similar reports from other Member States.

The Board, which took office at the beginning of 2026, has inherited thirty years of experience and expertise in energy market regulation, embodied in a now well-established regulatory framework designed to protect consumers, provide certainty and stability for tariffs and for the investment required for the energy transition and energy security, and ensure the proper functioning of wholesale and retail markets with a view to ever greater integration at European level.

However, the international tensions that have emerged in recent years, coupled with volatility in wholesale markets, have highlighted the new and critical challenges that regulation must address if the above objectives are to be achieved effectively and consistently, particularly in terms of the ability to respond promptly to shocks affecting prices and the availability of resources.

Against this backdrop, cooperation with the EU institutions and other European regulators is particularly valuable, having become firmly established and especially effective within ACER.

Providing structural responses to the growing complexity of wholesale energy markets is a matter of paramount importance and, to this end, it is essential that such responses be developed at EU level. The Authority's focus on monitoring markets and market participants' conduct, including through the application of REMIT, forms part of this approach, reflecting a clear and coordinated commitment among Member States to protecting final consumers against market manipulation.

The energy systems of individual countries reflect different technological choices and varying levels of resource availability, factors that influence the composition of the electricity mix and result in different generation cost structures and related impacts on the system The common objective, to which ARERA's activities also contribute, is to develop the market design in such a way as to stimulate investment deemed to be a priority and provide consumers with transparent and reliable price signals, while avoiding both market distortions and undue administrative burdens that ultimately feed through to final costs.

The contribution of non-dispatchable renewable generation, which is increasingly influencing market price formation, together with the complementary role that storage can play in enabling such generation to be used when it can deliver the greatest value and efficiency, with the aim of achieving more robust and structural benefits in terms of wholesale price levels, are key to ensuring convergence between environmental and economic sustainability, as well as security of supply. These are opportunities for which regulation has introduced, and will continue to introduce, appropriate adjustments and innovations to the regulatory framework aimed at enabling the deployment of renewable energy resources and storage technologies, within a framework of competition between different solutions and accountability for all market participants.

The challenges arising from the increasing penetration of renewable energy resources also include long-term generation adequacy. The Italian model already provides for a capacity market which, through competitive procedures open to different technologies, helps protect the system against

potential underinvestment risks. The usefulness of this mechanism has been recognised at EU level, and the Authority intends, within its remit, to contribute to making it even more effective and economically efficient in supporting improvements in plant efficiency.

The energy transition relies to a significant extent on infrastructure capable of accommodating a generation fleet that is more diverse in terms of operation and more geographically distributed, as well as more active demand shifting towards more sustainable technologies. For this reason, regulation has a crucial role to play in promoting future-proof infrastructure, within a framework that identifies necessary and priority investments from a multi-year and cross-sectoral perspective. Such infrastructure must be capable of anticipating future needs, particularly in terms of flexibility and resilience to extreme weather conditions.

To this end, the Authority has introduced innovative regulation based on expenditure and service objectives, an instrument designed to promote network adequacy, efficiency and security in light of future challenges, while maintaining rigorous oversight of expenditure requirements and the setting of efficiency objectives for investment and operational activities.

Lastly, it is worth highlighting the renewed and considerable attention that the Authority has devoted to final consumers, who represent the ultimate benchmark against which the quality of market and service regulation is assessed. Strengthening consumer protection, including at the pre-contractual stage, and monitoring compliance with regulatory requirements; simplifying access to information and consumer protection channels; and developing tools for comparing commercial offers and enhancing billing transparency were all key areas of ARERA's activities in 2025 and will be further strengthened and developed in the coming years.

These initiatives are intended to ensure that consumers enjoy effective safeguards and rights within a framework of healthy competition between service providers, increasingly delivering tangible value to consumers in both economic and qualitative terms. Regulatory instruments are essential to achieving this objective and are even more effective when supported by the coordination of initiatives and the exchange of best practices at EU level, as well as, of course, by the establishment of common rules as part of the process of energy market integration laid down in the Directives.

Milan, 30 July 2026

THE PRESIDENT

Nicola Dell'Acqua

2 MAIN DEVELOPMENTS IN THE ELECTRICITY AND NATURAL GAS MARKETS

2.1.1 Main changes in Italian legislation

The main legislative measures affecting the energy sectors are summarised below, as customary, in chronological order.

Law No. 20 of 28 February 2025 approved Article 8, introducing urgent measures for the implementation of Reform No. 4 under the REPowerEU Chapter of the PNRR.[1]. The provision amends Article 28 of Legislative Decree No. 199/2021 concerning renewable energy Power Purchase Agreements (PPAs), providing that a ministerial decree shall establish the procedures and conditions under which the Energy Services Manager (Gestore dei Servizi Energetici – GSE) will act as the supplier of last resort guaranteeing against the risk of default under long-term contracts. The mechanism shall operate in accordance with market-based principles and risk-containment criteria, within an annual expenditure limit of €45 million for the period 2025–2027. The rules governing the organised PPA platform shall also define the requirements and guarantee obligations applicable to contracting parties, together with the measures to be adopted in the event of default. ARERA is responsible for determining the fee payable for access to the guarantee.

Of particular significance is **Law No. 60 of 24 April 2025**[2], which introduces urgent measures concerning tariff concessions, the protection of vulnerable customers, the transparency of offers and the strengthening of enforcement powers. The Law assigns several tasks to the Authority, including the granting, for 2025, of the extraordinary contribution of €200 to household customers with an equivalent economic status indicator[3] of up to €25,000, and the regulation of the future electricity service for vulnerable customers, to be introduced no earlier than the conclusion of the gradual standard offer service (31 March 2027). Pending its introduction, the supply of electricity to vulnerable customers without a supplier will continue to be guaranteed under conditions established by the Authority, including through the Acquirente Unico (it is the public company that carries out activities for the functioning of energy markets). The Law also provides specific safeguards for vulnerable customers, including protection from non-seizability against their sole residential property where condominium-related energy debts are below €5,000. The Law also provides for the six-monthly elimination of part of the A_{SOS} component of general system charges relating to support for renewable energy sources and cogeneration, applied to electricity withdrawn by non-domestic low-voltage customers with an available capacity exceeding 16.5 kW, within the limits of the resources available in the budget of the Energy and Environmental Services Fund (CSEA) to ensure the related financial coverage. Furthermore, the Law introduces mechanisms for monitoring the impact of energy costs on businesses and assigns the Authority the task of using this information to analyse and monitor the impact of energy costs, regulated service charges and general system charges on the various categories of undertakings, and to report

[1] The PNRR (Italian National Recovery and Resilience Plan) is the investment and structural reform programme established by the Italian Government to relaunch the economy following the COVID-19 pandemic. It is financed by the European Union through the *Next Generation EU* fund.

[2] Converting Decree-Law No. 19/2025 into law.

[3] The Equivalent Economic Status Indicator (ISEE) is the tool used to assess the economic circumstances of households. It measures income, assets (both movable and immovable) and household composition, and constitutes the fundamental requirement for access to bonuses, benefits and subsidised social services.

periodically on the results of such monitoring to the Ministry of the Environment and Energy Security.

Further provisions concern the decoupling of the long-term remuneration of renewable energy generation from spot market prices, as well as assigning ARERA responsibility for strengthening the transparency and comparability of electricity and gas offers in the free market, including through standard documents, the simplification of pricing components and the updating of the Code of Business Conduct. The Authority's enforcement powers are also clarified by providing that, in cases of particular urgency, the Authority may, on its own initiative and by means of a reasoned decision, adopt interim measures even before the commencement of sanction proceedings, in order to ensure the most effective and timely protection of the interests safeguarded.

Law No. 69 of 9 May 2025 extended the incompatibility regime applicable to members and senior executives of CONSOB[4] to all members of collegiate bodies of public administrations and independent authorities that adopt binding decisions intended to produce, directly or indirectly, effects in respect of specific private parties. By way of derogation from any contrary provision, such provisions cease to apply to the members of those bodies. The regime provides that members of governing bodies and senior executives may not, for one year after leaving office, enter into employment, consultancy or collaboration arrangements with regulated entities or with companies controlled by them. Contracts concluded in breach of this prohibition are null and void.

Law No. 100 of 2 July 2025 authorises expenditure of €15 million for each of 2027 and 2028, and €5 million for 2029, to support projects increasing Italy's liquefied natural gas (LNG) storage and regasification capacity, particularly in the maritime sector. The Law also introduces measures to accelerate investment in renewable energy by amending Article 12 of Legislative Decree No. 190/2024 (*Consolidated Act on the Administrative Regimes for Renewable Energy Production* (TU FER)). The amendments concern the national mapping of areas suitable for renewable energy installations and the designation of onshore acceleration areas for renewable energy plants, co-located renewable electricity storage facilities, associated works and the infrastructure necessary for their construction and operation. These measures are intended to support the achievement of the 2030 renewable energy targets set out in the National Integrated Energy and Climate Plan (PNIEC)[5] and the implementation of Reform 1 ("Simplification of authorisation procedures for renewable energy at central and local level") under Mission 7 (REPowerEU) of the Italian National Recovery and Resilience Plan (PNRR).

The Annual Law for the Market and Competition 2025 (Law No. 190 of 18 December 2025) introduces [6]new measures to ensure the efficient development of the electric mobility market and to guarantee users competitive conditions in relation to the services provided through charging infrastructure, with a view to encouraging a plurality of operators. More specifically, it provides that competitive, transparent and non-discriminatory procedures for the development and operation of charging infrastructure must be designed so as to favour, all other conditions being equal, the presence of a plurality of operators active in the management of charging infrastructure within municipal territories. It also provides that, where comparable authorisation applications are submitted,

[4] CONSOB (*Commissione Nazionale per le Società e la Borsa*) is Italy's independent administrative authority, established in 1974, responsible for supervising and regulating the country's financial markets, with the primary objectives of protecting investors, ensuring transparency of information and safeguarding the efficient functioning of the securities market.

[5] The Integrated National Energy and Climate Plan (PNIEC) is the ten-year strategic document defining Italy's objectives for the green transition to 2030, ranging from the reduction of CO_2 emissions and the development of renewable energy resources to energy efficiency and energy security.

[6] The Law also amends Article 57(8) of Decree-Law No. 76/2020 (*Simplification of the rules governing the installation of electric vehicle charging points and charging stations*).

municipalities must give priority to applications from operators holding less than 40% of the total charging infrastructure already installed or authorised for installation within the relevant municipal area.

The same Law further amends Article 30 of Legislative Decree No. 201/2022 concerning the periodic review of the management of local public services by introducing new obligations for the contracting authorities. Where service performance is unsatisfactory, the contracting authority must identify the underlying causes and, where these are attributable to the operator, adopt a directive requiring the preparation, within three months, of a corrective action plan, including an implementation timetable. The Law also specifies the circumstances in which service performance is to be regarded as unsatisfactory and recognises the contracting authority's power to terminate the contractual relationship early in the event of serious non-compliance by the operator in implementing the corrective action plan.

Law No. 199 of 30 December 2025 (approving the State Budget for 2026 and the 2026–2028 three-year budget) extends until 31 December 2026 the exemption from the payment of utility charges in the areas affected by the 2016–2017 earthquakes, together with concessions, including tariff concessions, in the electricity, water, gas, insurance and telecommunications sectors for holders of utility contracts relating to buildings rendered unfit for use in the areas affected by the seismic events.
The Law also amends the regulatory framework governing biomethane by introducing new rules for connecting production plants to the natural gas network. In particular, it places an obligation on transmission and distribution operators to connect new plants and plants resulting from the upgrading of biogas facilities, and entrusts the national regulator with updating the technical and economic conditions governing the connection service. The regulatory measures will, among other things, define the minimum biomethane quality requirements for injection into the network, infrastructure reinforcement and upgrading works, the allocation of costs between producers and network operators, technical standards, connection procedures and timeframes, measures in the event of inaction by network operators, metering and quality control systems, and dispute resolution procedures. It is also provided that the criterion for allocating tariff-related costs associated with the injection of biomethane into the network is to be established at national level.

Among the other legislative measures of interest is the **Ministerial Decree of the Minister for the Environment and Energy Security of 26 June 2025**, laying down *the criteria and arrangements for the supply of natural gas under the service of last resort for the 2025–2026 and 2026–2027 gas years*. The Decree assigns the Authority responsibility for determining the economic conditions applicable to the supply of natural gas under the service of last resort and identifies the geographical areas in which the service is to apply, which may also be grouped into larger geographical areas. The measure also provides for a price-moderation mechanism to limit costs for the customers concerned where auction outcomes result in excessively high prices.

Ministerial Decree of the Minister for the Environment and Energy Security No. 204 of 29 July 2025 updated the Energy Release mechanism following discussions with the European Commission. It constitutes an amending measure to the original Ministerial Decree No. 268 of 23 July 2024. The new decree (Energy Release 2.0) introduces a competitive procedure for selecting the entities responsible for developing new generation capacity and repaying the energy supplied in advance. The measure also introduces a provision designed to prevent any over-remuneration of investments in renewable energy facilities at the end of the twenty-year contractual period, taking into account the three-year advance supply of electricity at a moderated price.

Also worth mentioning is the **Decree of the Ministry of the Environment and Energy Security of 7 August 2025** (Thermal Account 3.0), which updates the framework governing incentives for small-scale measures to improve energy efficiency and produce thermal energy from renewable sources, in accordance with the principles of simplification, effectiveness, diversification and technological

innovation, as well as consistency with the objectives for the energy refurbishment of public administration buildings. In line with the National Integrated Energy and Climate Plan (PNIEC), it also contributes to achieving the decarbonisation and energy efficiency objectives for the civil sector. The measure assigns the Authority responsibility for updating, on a proposal from the Energy Services Manager (GSE), the standard contract [7]governing the granting of State incentives for the production of thermal energy from renewable sources and for small-scale energy efficiency measures (known as the **Thermal Account**). The provision also establishes that, where breaches identified during inspections are material to the granting of incentives, the GSE shall reject the application or revoke entitlement to the incentives and recover any amounts already paid, while notifying the Authority so that any applicable sanctions may be imposed.

The **Decree of the President of the Council of Ministers of 10 September 2025**, concerning the works and infrastructure required for the phase-out of coal in Sardinia and the decarbonisation of the island's industrial sectors[8], assigns the Authority responsibility for defining the regulatory framework applicable to the identified infrastructure, with particular reference to virtual connection arrangements, the sustainability of investments and equalisation with the national system.

Finally, mention should be made of the **Decree of the Minister of Infrastructure and Transport of 2 October 2025**, which redefined the total amount of resources allocated to Italian National Recovery and Resilience Plan Investment M3C2-2.3 – Cold Ironing at €305.6 million. The PNRR M3C2-2.3 Cold Ironing investment consists of the construction of a shore-side electricity supply network within port areas (quays) and the associated infrastructure connecting it to the national transmission network, also enabling the charging of electric vessels.

2.1.2 Regulation and Developments in the Electricity Market

Infrastructure and Key Regulatory Developments

In Italy, **power transmission** is carried out via 76,200 kilometres of power lines and electrical circuits, supported by 920 switching and conversion stations. The Transmission System Operator (TSO) is Terna, of which 29.85% is owned by the Italian State; apart from the State's shareholding and 0.2% of treasury shares, the remaining 69.95% of its share capital is held by the market. In 2024, there were nine companies holding assets forming part of the National Transmission Grid (NTG). Taking into account the assets of all the companies belonging to the Group, the Terna Group owns or operates almost all of the transmission infrastructure forming part of the NTG.

As of 31 December 2024, 110 **power distribution** companies (four fewer than in 2024) were registered in ARERA Registry of Operators, of which only 11 serve more than 100,000 customers and together distribute 98.6% of all energy withdrawn by users. There are five distribution companies serving more than 500,000 points of delivery: e-distribuzione (Enel Group), Unareti and the newly established Duereti (A2A Group), Areti (Acea Group) and Ireti (Iren Group). Overall, power distribution in Italy takes place through 1,294,500 km of networks, most of which (68.3%) are low voltage. e-distribuzione is the largest operator, accounting for 81.7% of the electricity distributed.

[7] Pursuant to Article 28(1) paragraph (e) of Legislative Decree No. 28/2011.

[8] The Decree replaces the previous Decree of the President of the Council of Ministers of 29 March 2022.

The *Integrated Text on the Output-Based Regulation of the Electricity Transmission Service for the 2024–2027 Regulatory Period* introduced, for 2024, an incentive mechanism for Terna to deliver additional transmission capacity up to the target values established by the Authority in October 2021. The regulatory framework also provides for an additional bonus where such transmission capacity is delivered at investment costs below the benchmark costs established by the Authority. In October 2025, two incentive payments were awarded to Terna for additional transmission capacity made available in 2024: the first, amounting to €6,944,000, for the Calabria–Sicily section, and the second, amounting to €86,446,000, for the North–North Centre (in both directions) and South Centre–North Centre (in both directions) sections. The Authority has also introduced an incentive mechanism for electricity distribution networks applicable to distribution companies serving at least 100,000 final customers. The bonus is linked to the expected benefits of the investment, corresponding to two years of gross benefits, subject to a cap based on the investment cost. Distribution companies are required to submit a cost-benefit analysis for each project both for the purpose of determining eligibility for the bonus and for assessing its admissibility under the scheme. During the first implementation phase, relating to projects launched from 2024, the Authority approved seven projects, involving investments of more than €5 million and estimated benefits of €8 million over the following 25 years. Other proposed projects were not approved because the discounted benefits did not exceed the discounted costs.

In August 2025, the Authority issued its assessment of the draft **2025 Transmission Network Development Plan.** The Authority issued a favourable opinion on the Italy–Montenegro HVDC interconnection, while excluding from approval a number of projects subject to the two-stage approval mechanism, including the Milan–Montalto HVDC, the Adriatic Backbone, the Sardinian Link and the new Italy–Greece HVDC. The Authority also noted that several projects do not include implementation activities within the ten-year planning horizon and granted clearance for approval of the 2025 Development Plan, subject to compliance, for the Italy–Tunisia and SA.CO.I. 3 projects, with the tariff limits previously established. For future Development Plans, the Authority also requested that Terna give priority, where compatible with the complexity of the authorisation procedures, to the interconnections with France, Switzerland and Austria, and clarify the activities planned for certain projects aimed at strengthening interconnections with the Alpine area.

During 2025, the largest electricity distribution companies submitted the pre-consultation draft of their development plans by 31 March 2025, and the post-consultation version by 30 June. The final versions of the **distribution network development plans** were subsequently published on the dedicated page of the Authority's website on distribution network development (https://www.arera.it/operatore-elettricita/sviluppo-reti-di-distribuzione-elettrica)..

Within the framework established by Legislative Decree No. 210/2021, the Authority continued implementing the ten-year rollout plan for the **installation and upgrading of intelligent metering systems**, with the aim of ensuring the widespread deployment of second-generation (2G) smart meters to final customers. For the larger electricity distribution companies, the regulatory framework governing the costs and penalties associated with the commissioning of 2G smart meters remained in force. In this context, in June 2025 a penalty of approximately €108 thousand was imposed for failure to achieve the prescribed deployment targets. During 2025, the implementation timetable was also updated, with an estimated 39.7 million 2G meters expected to be in service by the end of the year. Finally, in December 2025, the existing regulatory provisions were confirmed for the 2026–2028 regulatory period, ensuring continuity with the current regulatory framework.

With regard to **tariffs for electricity distribution and metering services**, the separation between the single tariff applied to final customers (the "mandatory tariff") and the reference tariffs established for determining the revenue caps applicable to each distribution company continued, in line with previous years. For distribution companies serving at least 25,000 withdrawal points and subject to the ROSS

tariff regime (Regulation based on Spending and Service Objectives), provisional reference tariffs for 2025 were established. At the same time, the 2025 parameters were approved ex ante to capture increases in operating costs arising from investments supporting the energy transition or from changes in the scope of activities. For distribution companies serving fewer than 25,000 withdrawal points and subject to the parametric tariff regime, the reference tariffs for distribution and metering services for the years 2019 to 2025 were determined during 2025.

In October 2025, the Authority launched a public consultation on its proposed revision of the parametric criteria for recognising the costs associated with electricity distribution and metering services for distribution companies serving fewer than 25,000 withdrawal points.

At the end of the year, the tariffs for the use of electricity distribution and metering infrastructure for household and non-household customers, together with the charges for the provision of connection services, were updated for 2026.

The **electricity dispatching service** is evolving in response to the increasing deployment of renewable energy sources, distributed energy resources, energy storage systems and self-consumption, all of which make the electricity system more variable and increase the need for flexibility services at both national and local levels. In this context, distribution networks are playing an increasingly active role, and distribution companies must also be able to procure local ancillary services. The main regulatory development is the *Dispatching Integrated Text* (TIDE), approved in 2023 and subsequently updated several times during 2024 and 2025. The framework reforms electricity dispatching by introducing a more open, technology-neutral model aligned with the European regulatory framework. TIDE enables distributed and aggregated resources to participate in ancillary services, distinguishes the roles of the Balancing Service Provider (BSP) and the Balance Responsible Party (BRP), reorganises electricity markets and settlement arrangements, enhances transparency regarding network models, and supports the transition from the Single National Price (PUN) to zonal pricing through a phased implementation comprising transitional, consolidation and full implementation stages.

During 2025, the transitional phase resulted in the adoption of quarter-hourly imbalance settlement, the launch of the GME nomination platform, and the application of the PUN Index as the reference price for compensation purposes. In preparation for the consolidation phase commencing in 2026, the Authority approved further amendments to TIDE and verified the compliance of numerous amendments to Terna's Network Code, including those relating to auctions for Frequency Containment Reserve (FCR), Virtual Enabled Units, the separation of the BSP and BRP roles, and reconnection to the European balancing platforms. The **interruptibility service**, incorporated into TIDE's extraordinary modulation framework, **was also updated**, together with Terna's **pilot demand modulation service**, which was extended to include the possibility of increasing electricity withdrawals in order to absorb excess renewable generation. In parallel, Terna's incentive mechanism for reducing dispatching costs was extended until 2030, with strengthened penalty arrangements and new performance targets linked to the implementation of TIDE. Finally, pilot projects relating to **local ancillary services** continued under the Edge, RomeFlex and MindFlex initiatives, aimed at procuring flexibility services from resources connected to the electricity distribution networks. The pilot projects were extended through 2025 and, in some cases, into 2026. The Authority also published its first report on the outcomes of the pilot projects concerning the participation of new resources in national and local ancillary services.

In July 2024, the Authority completed the first phase of the reform of the regulatory framework governing the physical and financial settlement of the electricity dispatching service, as provided for under the *Integrated Electricity Settlement Framework* (TIS). The reform, launched in 2023, also aimed to revise the treatment of network losses. From 1 January 2025, **quarter-hourly settlement** was introduced in line with TIDE and the European Balancing Regulation, although the implementation of

the new regulatory framework had originally been scheduled for 1 January 2026. The reform provides for more extensive use of actual metering data, strengthens the role of the Integrated Information System (SII) in profiling, data aggregation and data management activities, introduces the calculation of residual energy for each grid operator and bidding zone, and requires station own-use consumption and residual energy to be procured through the market, with specific arrangements for cost recovery. In June 2025, the Authority launched three public consultations to refine the regulatory framework. The first concerned the reorganisation of the TIS and the arrangements for settling financial transactions; the second focused on revising the *Integrated Metering Framework* (TIME) and the centralised management of metering data; and the third addressed completion of the reform, particularly with regard to loss factors, station own-use consumption, residual energy and the related cost recovery mechanisms. While stakeholders broadly supported the overall approach to the reform, they requested additional time to adapt their systems, algorithms and operational processes. The Authority therefore accepted this request by postponing the entry into force of the new regulatory framework until 1 January 2027, revising the timetable for the testing phase, launching further assessments of specific plant configurations, confirming for 2026 the percentage loss factors already applied for equalisation purposes, and deferring the rules governing unrecoverable fraudulent withdrawals to a subsequent measure.

The **Capacity Market** is intended to ensure the adequacy of the electricity system by securing sufficient generation capacity to meet electricity demand on a continuous basis while maintaining the required levels of security and quality of supply. Following the first auctions for the 2022–2024 delivery years, the procedures for the 2025 and 2026 delivery years were carried out in 2024, following updates to the regulatory framework and the relevant technical operating provisions. In May 2024, the Authority established the economic parameters for the procedures relating to the 2025-2028 delivery years, including the maximum premiums for new, existing and foreign capacity, the minimum investment threshold for access to fifteen-year contracts, and the criteria for determining the strike price. The allocation of 70% of the net cost to peak hours was confirmed until 2028. The main auctions for the 2025 and 2026 delivery years resulted in total capacity payments of approximately €1.72 billion and €1.82 billion, respectively. Existing capacity awarded amounted to approximately 37.6 GW for 2025 and 38.3 GW for 2026, while the volume of new capacity awarded was more limited, at approximately 0.2 GW and 0.1 GW, respectively. In both auctions, approximately 4.4 GW of cross-border capacity was also awarded.

In 2025, Terna launched a public consultation on further amendments to the Capacity Market framework, with the aim of aligning it with the TIDE consolidation phase scheduled to commence in 2026. The proposed amendments primarily concerned the calculation of available capacity, the verification of offer obligations, the determination of the variable remuneration component, and the distinction between the roles of the Balance Responsible Party (BRP) and the Balancing Service Provider (BSP). The Authority approved the proposed amendments, subject to the removal of a provision concerning the role of the BRP within the regulatory framework governing essential facilities, as the relevant arrangements had not yet been defined for the period after 2026.

The **Electricity Storage Capacity Procurement Mechanism** (MACSE) introduces a long-term procurement scheme for electricity storage capacity, operating alongside the energy, ancillary services and capacity markets, with the objective of encouraging investment in energy storage systems that support the energy transition. During 2025, the economic framework for the first auction dedicated to battery storage systems and electricity storage technologies other than batteries and pumped-storage hydropower was established. Following the consultation process, the Authority set the maximum premium for the first auction covering battery storage systems and electricity storage technologies other than batteries and pumped-storage hydropower at €37,000/MWh/year, increasing the value

initially proposed to reflect, among other factors, higher connection costs for greenfield projects, extended warranty requirements and higher operating costs. The Authority also clarified that MACSE storage facilities would be eligible to participate in the Frequency Containment Reserve (FCR) market mechanisms and, during the initial phase, would not be required to make the related mandatory reserve bands available free of charge.

The Authority also established the arrangements for recovering the costs of the independent assessment of MACSE. As a transitional measure, it provided for the use of the unit charge established under TIDE, taking into account the timing mismatch between the costs of the assessment and the commencement of payments to successful bidders.

The first auction, held on 30 September 2025 for the 2028 delivery year, secured virtually the entire national requirement of 10 GWh, with 9.968 GWh awarded, all relating to lithium-ion battery storage systems. Annual premium payments are expected to amount to approximately €129 million over a fifteen-year period. The marginal premium (corresponding to the last accepted bid) and the weighted average premium amounted to €18,800/MWh/year and €13,000/MWh/year, respectively, both below the maximum premium of €37,000/MWh/year established by the Authority in July 2025. The selected projects are primarily located in the Southern Italy and Calabria, South-Central Italy, Sardinia and Sicily market areas, with Enel Produzione being the largest successful bidder.

With regard to the **quality of electricity distribution services**, pursuant to the *Integrated Output-Based Regulation for Electricity Distribution Services for the 2024–2027 Regulatory Period*, in November 2025 the Authority determined the rewards and penalties for 2024 relating to the regulation of the duration and number of unplanned interruptions. Total penalties of €54.1 million were imposed (for the benefit of electricity system users liable for network tariffs), representing the net balance of: €61.4 million in net penalties under the standard continuity of service incentive scheme (based on the duration and number of unplanned interruptions); and €7.3 million in rewards granted to the top-performing 15% of districts under the incentive scheme promoting improved continuity of service.

In July 2025, the Authority launched a public consultation covering both the **output-based regulatory framework** and the **commercial quality regulation applicable to electricity distribution and metering services.**

With regard to output-based regulation, the consultation set out proposals concerning: the development of the individual continuity of supply incentive scheme; the revision of the definition of significant interruptions; the updating of the mechanism used to identify so-called periods of adverse operating conditions; and the revision of the rules governing sample monitoring of slow voltage variations in low-voltage networks.

With regard to commercial quality regulation, the Authority proposed the introduction of new commercial quality standards relating to the disconnection of distributed generation under high-voltage conditions on low-voltage networks. The proposal reflects the increasing difficulties in injecting electricity into these networks where excessive network voltage automatically disconnects customers' generation facilities.

In 2025, performance improved compared with 2024, both in terms of the average duration of unplanned interruptions, which fell to 69 minutes from 76 minutes, and the average number of long and short unplanned interruptions per low-voltage customer, which decreased to 4.92 from 5.12 in 2024. The improvement in interruption duration during 2025 was partly attributable to the reduced impact of extreme weather events, including floods, windstorms and heatwaves. At national level, the duration of unplanned interruptions attributable to distribution companies averaged 41 minutes, while the number of long and short unplanned interruptions attributable to distribution companies (together representing interruptions lasting more than one second) amounted to 3.69 interruptions per low-

voltage customer. During 2025, distribution companies paid automatic compensation totalling €38 million to approximately 627,000 low-voltage customers (averaging approximately €60 per customer) and just over €3 million to around 3,000 medium-voltage customers (averaging approximately €1,150 per customer).

With regard to high- and extra-high-voltage **connection requests**, during 2025 Terna received 4,241 applications for the connection of electricity generation facilities, representing a total capacity of 362.3 GW. During the same year, it issued 3,261 connection offers, corresponding to a total capacity of 291.3 GW. During the year, 1,429 of the 3,261 connection offers made available were accepted, corresponding to a total capacity of approximately 113.9 GW. Only five of these connection offers, representing a total capacity of 294 MW, resulted in requests for the provision of the Detailed Minimum Technical Solution (STMD). As Terna had not made the STMD available for any of these requests by 31 December 2025, no connections relating to applications received by Terna during 2025 were completed and commissioned during the year. With regard to active connection requests to medium- and low-voltage networks, in 2025 distribution companies received almost 291,000 applications for the connection of electricity generation facilities, corresponding to a total capacity of 37.6 GW. During the year, almost 240,000 of the connection offers issued in respect of those applications were accepted, representing a total capacity of 10.6 GW. During the year, more than 163,000 connections relating to applications submitted in 2025 were completed, corresponding to approximately 2.1 GW of installed capacity.

As regards passive customer connections, the data collected show that, in 2025, distribution companies carried out 213,773 activities relating to new standard permanent low-voltage connections, comprising 94,424 connection quotations, 81,544 simple connection works and 36,805 complex connection works. In addition, 7,934 activities relating to new standard permanent medium-voltage connections were completed, including 6,709 connection quotations, 121 simple connection works and 1,104 complex connection works. During 2025, Terna also completed four passive connections to the high- and extra-high-voltage transmission network.

With regard to **international coordination**, the Authority further strengthened its cooperation during 2025 with the Agency for the Cooperation of Energy Regulators (ACER), the Council of European Energy Regulators (CEER), the European Commission and other national regulatory authorities. This cooperation covered both the traditional areas of work relating to network codes, guidelines and market integration, and the implementation of new European legislation.

In addition to its established activities relating to network codes and guidelines adopted under the Third Energy Package and the Clean Energy Package, participation in European implementation processes intensified during 2025 following the adoption of new legislative acts in 2024. In particular, cooperation continued with the European Commission, ACER and other national regulatory authorities on the implementation of the legislative package on renewable gases and hydrogen (Directive 2024/1788 and Regulation 2024/1789), which assigns new responsibilities to regulators in relation to integrated network planning, the governance of future hydrogen grid operators and the development of dedicated hydrogen markets. In the electricity sector, ARERA contributed to European work on implementing electricity market design reforms, which in 2025 focused in particular on capacity mechanisms, consumer protection and the resilience of balancing markets, including cooperation with ACER and initiatives relating to the European balancing energy exchange platforms PICASSO and MARI. Regulatory discussions also continued on the full implementation of the 70% Rule under Article 16 of Regulation (EU) 2019/943, taking into account ACER's 2025 monitoring reports, which highlight the benefits arising from increased capacity available for cross-border trade and from the development of capacity calculation methodologies across the various European Capacity Calculation Regions (CCRs). At the same time, following the entry into force of the revised REMIT Regulation (Regulation (EU) 2024/1106), the first technical discussions between national regulatory authorities and the Agency for

the Cooperation of Energy Regulators (ACER) were launched in 2025 to adapt the requirements relating to registration, reporting and market surveillance. These discussions also took account of the updated Questions and Answers (Q&A) and ACER's first reports on Suspicious Transaction and Order Reports (STORs) and coordinated enforcement activities. Lastly, the Authority also participated in European initiatives concerning the development of strategic energy infrastructure, particularly the new monitoring cycle for Projects of Common Interest (PCIs) and Projects of Mutual Interest (PMIs) published by ACER in 2025, as well as the preparation of the 2025 list under the TEN-E Regulation, focusing on project implementation, permitting procedures and the consistency of network development plans.

Pursuant to Article 15 of Regulation (EU) 2019/942, during 2025 the Authority continued its cooperation with ACER and the Council of European Energy Regulators (CEER) in collecting, validating and submitting the data required for the preparation of the annual Market Monitoring Reports (MMRs), which are published in thematic volumes. Monitoring activities, carried out in accordance with ACER's implementation and effect monitoring strategy, are intended to assess the degree of integration of the European energy markets, the effective functioning of competition and the effectiveness of the internal energy market rules. In 2025, monitoring activities covered an expanded and increasingly structured range of areas, reflecting the continued development of ACER's analytical framework.

During 2025, implementation of the **Capacity Allocation and Congestion Management (CACM) Regulation** remained a key element in strengthening the integration of the European day-ahead and intraday electricity markets. In this context, the Authority monitored developments in the contractual and methodological framework governing market coupling at Italy's interconnections, assessing the consistency of operational agreements with both European and national regulatory requirements while supporting key initiatives aimed at strengthening cooperation between grid operators and nominated electricity market operators. In particular, the Authority's activities focused on: the governance arrangements for Nominated Electricity Market Operators (NEMOs); the introduction of 15-minute products in the day-ahead market coupling; the alignment of the Italian Border Working Table Operational Agreement with the European contractual framework; and preparations to ensure the efficient operation of the European electricity market and its extension to countries in the Balkan region. The Authority also approved the amendment to the Settlement Link Agreement between GME and CCP Austria (ABG) relating to the Single Day-Ahead Coupling.

At regional level, the Authority continued to monitor developments in the evolution of the Capacity Calculation Regions (CCRs), particularly the merger of the Core and Italy North CCRs into the new Central Europe region and the gradual transition towards flow-based methodologies, aimed at improving network utilisation, providing more efficient price signals and enhancing the integration of the European electricity markets.

In June 2025, the European Commission launched the comitology procedure for the **revision of the CACM Regulation** governing the operation of the European day-ahead and intraday electricity markets. The proposed revision addresses a wide range of issues, two of which are expected to have a particularly significant impact on the Italian electricity sector: the governance of market coupling and the requirement to make at least 70% of interconnection capacity available to market participants.

The Forward Capacity Allocation (FCA) Regulation governs the allocation of long-term transmission capacity between bidding zones by establishing harmonised rules for auctions, transmission rights and price risk management. During 2025, ARERA adopted measures confirming, for the 2026–2029 regulatory period, the continued use of Transmission Capacity Allocation Charge (FTR) hedging instruments, as these continue to provide the most effective protection against volatility in transmission capacity allocation charges. This remains the case despite the abolition of the Single National Price (PUN) from 1 January 2025, since market participants remain exposed to the difference between the

PUN Index (which continues to determine demand-side prices through the compensatory component) and zonal prices.

During 2025, the implementation of the provisions of the **System Operation Guideline (SOGL)** continued across the Continental Europe synchronous area. In February 2025, ARERA formally ratified the approval, jointly adopted by all regulatory authorities within the synchronous area, of the probabilistic methodology for sizing the Frequency Containment Reserve (FCR). The revised methodology takes account of the increasing penetration of resources with limited energy capacity and the growing volatility of demand and electricity generation from variable renewable energy sources. In July 2025, ARERA also ratified the update to the hierarchical structure of the Load Frequency Control Blocks (LFC Blocks), which had likewise been jointly approved by all regulatory authorities, to reflect the inclusion of the new control block comprising Lithuania, Latvia and Estonia, following their synchronisation with the Continental Europe synchronous area in February 2025.

The **Electricity Balancing Guideline (EBGL)** establishes the framework for the integration of the European balancing services markets by setting common rules for the procurement, activation and settlement of balancing reserves. In July 2025, ARERA approved the amendments to Terna's Network Code required for the full implementation of TIDE (Revision 4) and for reconnection to the European PICASSO platform, thereby fully enabling the activation of the automatic Frequency Restoration Reserve (aFRR) through a merit-order mechanism. In September 2025, ARERA also established the regulatory framework required for participation in the European MARI platform for the exchange of balancing energy from manual Frequency Restoration Reserve (mFRR). Finally, in October 2025, ARERA approved Terna's contractual arrangements relating to its participation in the European balancing platforms established under the Electricity Balancing Guideline. The Authority reviewed the agreements entered into by Terna and verified the operational readiness of the related technical and functional interfaces, identifying where appropriate the need for amendments to the Network Code and enhancements to information exchange processes.

As in previous years, the Authority has been particularly engaged in its interactions with countries outside the European Union.

Wholesale and retail markets

According to Terna's provisional data, **electricity demand** in 2025 amounted to 312.4 TWh, an increase of 0.1% compared with 2024. This marginal increase was entirely attributable to the services sector. Electricity available for consumption was met by 85% domestic generation (net of pumped storage and energy storage) and 15% net imports. Net domestic electricity generation increased by 2.4% compared with the previous year, while imports declined by 7.4% and electricity exports remained unchanged. As a result, net electricity imports decreased by 8%, from 51.0 TWh to 46.9 TWh. Peak electricity demand was recorded on 1 July 2025, when peak load reached 52.6 GW, representing a 9% decrease compared with the 2024 peak of 57.9 GW.

Gross domestic electricity generation increased from 271.0 TWh to 277.4 TWh (+2.4%). In particular, thermal generation increased by 5.2%, while generation from renewable energy sources declined by 1.5%. Within thermal generation, electricity production from solid fuels fell significantly (-15%), while generation from other fuels declined by 7.8%. By contrast, natural gas-fired generation increased by 7%, reaching almost 127 TWh. Renewable energy sources accounted for 48% of the national electricity generation mix in 2025, compared with 50% in the previous year. Generation increased only from solar photovoltaic (+25%) and bioenergy (+5.1%), while geothermal generation recorded only a marginal decline (-0.3%). Hydroelectric generation fell by 21% to almost 42 TWh, returning close to its 2023 level

(40.5 TWh), while wind generation decreased by 3.3%. The combined share of gross electricity generation accounted for by the three largest corporate groups (Enel, Eni and Edison) increased to 29.5%, compared with 28.9% in 2024. This was driven by the increase in Edison's market share, from 6.2% to 8.1%, while the shares of Enel and Eni declined from 13.5% to 12.3% and from 9.2% to 9.1%, respectively. The A2A Group and the EPH Group retained fourth and fifth place, respectively. Based on Terna's provisional data, three groups accounted for more than 5% of total net installed generating capacity: Enel, A2A and Edison.

The **volume of incentivised electricity generation** amounted to approximately 50.2 TWh. Overall, in 2025, the costs associated with supporting renewable energy resources amounted to around €9.3 billion, representing a 4.3% increase compared to the previous year.

Electricity imports declined by 7.4%, decreasing by 4.1 TWh compared with the previous year, from 55.9 TWh to 51.8 TWh, while exports remained unchanged at 4.9 TWh, the same level as in 2024. Consequently, the net import balance decreased from 51.0 TWh in 2024 to 46.9 TWh in 2025 (-8%).

In 2025, the volume of **electricity traded on the Day-Ahead Market (MGP) within the Italian electricity system** amounted to 286.2 TWh, an increase of 0.8% compared with 2024. Exchange-traded volumes increased to 234.4 TWh (+3.4%), while bilateral transactions registered on the Energy Accounts Platform of Bilateral Contracts (PCE) declined to 51.8 TWh (-9.4%), almost entirely relating to Italian bidding zones. Cross-border trading declined, mainly as a result of lower imports, which totalled 55.2 TWh (-3.8%). These accounted for 23% of exchange-traded sales (compared with 24% in 2024) and 1% of bilateral sales (compared with 3% in 2024). Conversely, exports increased to 7.4 TWh (+37%), with all export transactions executed through the exchange. Electricity purchases by the Acquirente Unico declined to 6 TWh (-54.7%), while sales by the Energy Services Operator (GSE) increased to 33 TWh (+1.5%). Together, these represented 7% of total traded volumes, a reduction of 1.2 percentage points compared with 2024. In 2025, the **average Single National Price (PUN)** for electricity increased by 7% compared with 2024, reaching €115.9/MWh. Higher prices were recorded across all three hourly bands: €122/MWh (+5%) during peak hours; €119/MWh (+10.5%) during off-peak hours on working days; and €105/MWh (+5%) on public holidays. Total volumes traded on the **Intraday Market** (MI) amounted to 37.2 TWh, representing an increase of 5% compared with the previous year. Average prices recorded on the intraday market remained closely aligned with the corresponding prices on the Day-Ahead Market. Throughout the year, average monthly prices broadly tracked the corresponding Day-Ahead Market selling price, with the exception of January, when all intraday sessions recorded lower prices (average differences of approximately €3/MWh for MI1 and MI2, and €4/MWh for MI3), and of April, May, October, November and December, when MI3 prices exceeded Day-Ahead Market prices by an average of between €3/MWh and €7/MWh. On the electricity **Forward Market** managed by GME, no trades were recorded in 2025 for standardised products with physical delivery. On an annual average basis, electricity prices across the **European power exchanges** increased across all markets in 2025 compared with 2024. In most European countries, wholesale electricity prices rose until February before falling significantly during the spring months. From June in Italy and Spain, and from July in the other markets, this trend reversed, with prices partially recovering to levels recorded during the first quarter of the year. Despite these increases, average prices in 2025 were the lowest recorded since 2021, the year in which the energy crisis began. Average prices in 2025 amounted to around 60% of the levels recorded in 2021 in the French, Spanish and Nordic electricity markets, while the corresponding figure was 92% for the Italian and German power exchanges. Moreover, although electricity prices increased across all markets, the increases were not uniform and did not reduce the long-standing price differentials arising from the different generation mixes of national electricity systems.

In July 2025, the Authority published a ***Report on the Outcomes of the Day-Ahead Electricity Market for the 2023-2024 Period***, as part of its fact-finding investigation into short-term auction-based

electricity markets. The purpose of the report was to assess the degree of competition and the proper functioning of the wholesale electricity markets, including the identification of any conduct that could be relevant under the REMIT Regulation. The analysis examined the relationship between zonal prices and marginal generation costs, identified potential economic withholding of generation capacity in accordance with ACER's guidelines, and included counterfactual simulations of market outcomes. The findings identified positive spreads between market prices and marginal generation costs, possible price-maker behaviour, and instances of economic withholding of generation capacity that affected price formation. The Authority therefore decided to continue its case-by-case investigations in order to determine whether market participants had legitimate grounds for their conduct. It also informed Terna of the need to strengthen the information available for system dispatching by updating the Gaudì system and improving the collection of technical and economic data relating to generation and electricity storage facilities.

In 2024, **two penalty proceedings were initiated for breaches** of the rules on integrity and transparency in wholesale markets under the **REMIT** regulation. The Authority also pursued enforcement activities, including one case concerning the failure to disclose inside information effectively and in a timely manner relating to the unavailability of a generation plant, and another concerning an alleged breach of the prohibition on market manipulation under the wholesale energy market rules.

The findings of the Annual Survey show a **modest recovery in electricity consumption** during 2025 (+1.1%), following the decline recorded in 2023 and the broadly stable level observed in 2024. in 2025 electricity consumption increased by almost 3 TWh, from just under 243 TWh to almost 246 TWh, supplied to 37.8 million customers. Compared with 2024, the number of withdrawal points increased by approximately 215,000 (+0.6%). The recovery in overall electricity demand reflected an **increase in sales to non-household customers**, which more than **offset lower sales to household customers.** In fact, the household sector purchased a total of 58.2 TWh, compared with 58.8 TWh in 2024, representing a 1% decline. By contrast, electricity purchased by the non-household sector increased by 1.8%, from 184.2 TWh to 187.6 TWh, although it remained below the pre-pandemic level of 198 TWh recorded in 2019.

In 2025, electricity sales in the **free market** amounted to 230.6 TWh, an increase of 5.5 TWh compared with 2024, supplied to almost 31 million customers, whose number increased by 4.9% year on year. Having grown steadily over time, customers in the free market now account for 81.5% of the Italian retail electricity market, while electricity sold through the free market represents 93.8% of total electricity sales in Italy. The number of household delivery points served in the free market increased by 1.105 million, equivalent to 4.8% compared with 2024. Average annual consumption by household customers was 1,983 kWh, representing a slight decrease of 2.4% from the previous year.

From 1 January 2021, small businesses connected to the low-voltage network and micro-enterprises with at least one low-voltage withdrawal point having a contracted capacity exceeding 15 kW ceased to be eligible for the **standard offer service**. Eligibility was subsequently withdrawn for all remaining micro-enterprises from 1 April 2023. Since May 2023, therefore, the service has been reserved exclusively for household customers. Finally, from 1 July 2024, only vulnerable household customers have remained eligible to purchase electricity under the standard offer service. In 2025, electricity sales under the standard offer service amounted to 4.7 TWh, supplied through approximately 3.2 million withdrawal points. Compared to 2024, there was a significant decline in consumption, amounting to 3.7 TWh (-44%), along with a decrease in the number of points served by about 2.4 million units (-42.8%). Average annual electricity consumption amounted to 1,496 kWh, a decrease of 2.1% compared with 2024.

The **gradual standard offer service** facilitates customers' transition to the free electricity market by ensuring continuity of supply for customers who, following the end of the standard offer service, have not yet selected a free-market offer. It is structured into three arrangements, serving respectively non-vulnerable household customers, micro-enterprises and small businesses. The service is provided on a territorial basis by suppliers selected through competitive tender procedures organised by the Authority. In 2025, the gradual standard offer service for non-vulnerable household customers recorded particularly strong growth. Total volumes reached 5.2 TWh, an increase of 67.5%, while the number of withdrawal points rose by 80.0% to 3.0 million. As a result, average annual consumption per household customer served under the Gradual Protection Service declined to 1,724 kWh (-6.9%). The gradual standard offer service for small businesses supplied a total of 1,038 GWh, a decrease of 16.1% compared with 1,238 GWh in 2024. Over the same period, the number of withdrawal points fell from 77,100 to 61,600 (-20.2%), while average annual consumption increased to 16,864 kWh (+5.1%). The gradual standard offer service for micro-enterprises supplied a total of 1,249 GWh, down 17.6% compared with 2024, through 680,400 withdrawal points (-17.9%). Average annual consumption per non-household customer was 1,835 kWh, representing a marginal increase of 0.4%.

The **supply of safeguard service** also recorded a further decline. The number of withdrawal points served decreased by 13.4% to 69,300, while electricity supplied fell by 17.6% to 2,936 GWh.

Although lower than in 2024, the **switching** rate among household customers remained particularly high in 2025, reaching 20.8% of customers, a decrease of 3% compared with the previous year. The *switching* rate for non-household customers edged down to 22.3% (in terms of volumes), recording a 0.3% decrease. In total, over 7.7 million withdrawal points switched suppliers during 2025. In terms of underlying volumes, this amounted to 53.4 TWh, representing 22% of total electricity market purchases.

In 2025, electricity suppliers offered household customers an average of 44 **retail offers** each, of which 7 were available exclusively through digital channels. For non-household customers, who generally benefit from a wider choice of products, had access to an average of 52 offers per supplier. However, only 6 of these were available exclusively through online channels. In 2025, contracts concluded online accounted for 9.3% of all contracts signed by domestic customers. The corresponding figure was even lower in the non-domestic segment, at 2.3%. With regard to **pricing structures**, household customers showed an almost even split between fixed-price offers (51%) and variable-price offers (49%), with very similar average prices of €236.69/MWh and €232.35/MWh, respectively. By contrast, the non-household segment showed a clear preference for variable-price contracts (79.5%), compared with fixed-price contracts (20.5%), with correspondingly lower average prices (€156.26/MWh versus €178.08/MWh). Among variable-price offers, **indexation** to the average PUN remained the predominant pricing mechanism, chosen by 89.1% of household customers and 78.8% of non-household customers. The average price for this type of contract was €233.12/MWh for household customers and €162.46/MWh for non-household customers, both figures being very close to the overall average prices for indexed contracts. Dynamic-price offers accounted for 7.2% of household contracts and 16.1% of non-household contracts. The survey also highlights the growing prevalence of **value-added services** in free-market offers. A Guarantee of Origin certifying that electricity is sourced from renewable energy sources was the most common additional service, included in 74.6% of fixed-price household contracts and 48.5% of variable-price household contracts. By contrast, in the non-household segment, more than half of all contracts (50.8% of fixed-price contracts and 53.0% of variable-price contracts) did not include any additional services, confirming that greater emphasis is placed on the price competitiveness of offers.

In 2025, the level of **concentration in the retail electricity market** declined across all market segments, as reflected by the various indicators commonly used to measure market concentration. The top three corporate groups' cumulative share (C3) declined, dropping from 42.3% to 39.8%. The Herfindahl–

Hirschman index (HHI) index fell from 988 to 806, well below the first threshold of concern, set at 1,500; indeed, an HHI value between 1,500 and 2,500 indicates a moderately concentrated market, while a value above 2,500 signals a highly concentrated one (the maximum possible HHI is 10,000). The number of corporate groups needed to exceed 75% of total sales increased from 14 to 15. However, concentration in the Italian retail electricity market presents two contrasting trends: it remains relatively high in the household segment, although it continues to decline steadily, whereas it is low in the non-household segment.

The results of the analysis of the data submitted by the operators show that in 2025 the **average pre-tax electricity price** for households was 306.3 c€/kWh (217.8 c€/kWh the average value of the component covering procurement costs and marketing services). As usual, the data highlight variability in the unit cost borne by customers, with an inverse relationship to consumption size: unit costs range from €227/MWh for large users (more than 15,000 kWh annually) to €656/MWh for those in the smallest band (0–1,000 kWh). This pattern reflects the behaviour of supply costs, which consistently decline with increasing per capita consumption – from €359/MWh for the lowest consumption group to €167/MWh for the highest.

Regarding the **commercial quality of the sales service**, in 2025 the companies serving electricity sector customers received a total of 278,336 written complaints, 278,336 enquiries, 13,981 invoice corrections, and 358 cases of duplicate invoicing. 94% of compensations are related to the failure to meet response times for written complaints. In 2025, more than €632,000 in automatic compensation payments was credited to customers' electricity bills. Most of these payments were made to customers in the free market (both household and non-household), while only 11% was paid to customers supplied under protection schemes or last resort services.

During 2025, the Authority strengthened its **monitoring and enforcement activities** to verify compliance with regulatory requirements, ensure the proper delivery of services and safeguard final customers, with the support of the Financial Police (*Guardia di Finanza*) and the *Carabinieri*. These activities covered an increasing number of market operators and included on-site inspections, telephone monitoring and documentary checks. A total of 32 inspections were carried out during the year. The Authority's enforcement activities resulted in the recovery of approximately €11.2 million, comprising €8.5 million relating to social bonuses, €2.5 million from checks on energy-intensive companies and €0.18 million from inspections concerning gas distribution safety.

With regard to **sanctioning proceedings**, 56 measures were adopted, including 25 proceedings initiated and 9 penalty decisions, resulting in ordinary financial penalties totalling €6.8 million. Key developments during the year included the initiation of eight proceedings for breaches of pre-contractual information requirements, identified in part through mystery calls, and two proceedings concerning misleading information provided to vulnerable customers regarding access to the gradual standard offer service. The Authority also took action in relation to cases involving supplier switching, transfer of customer, use of the Integrated Information System (SII), requests for supply disconnection and social bonuses, further strengthening consumer protection and market transparency.

2.1.3 Regulation and Developments in the Natural Gas Market

Infrastructure and Key Regulatory Developments

In Italy there are eight companies operating the **national** (10,490 km) and **regional** (24,936 km) **gas transmission network**. The largest gas transmission company is Snam Rete Gas; in addition, two other

companies operate on the national network, owning and managing smaller sections: Società Gasdotti Italia and Infrastrutture Trasporto Gas. The Snam group (consisting of Snam Rete Gas and Infrastrutture Trasporto Gas) owns 92.8% of the networks. The Italian gas transmission network is connected with several international gas pipelines: in the North it connects with the TENP natural gas pipeline for the import of gas from Northern Europe and with the TAG for the import of Russian gas; in the South it connects with the Transmed (Trans-Mediterranean Pipeline) for the import of Algerian gas and with the Greenstream for the import of Libyan gas, it connects with the TAP for the import of Azeri gas. In addition, five **liquefied natural gas** terminals are operational, through whose interconnection with the national network it is injected into the Italian national transmission network. In May 2025, the fifth LNG regasification plant entered into operation, namely the FSRU moored approximately 8 kilometres off the coast of Ravenna, which Snam acquired in July 2022. Built in 2015, the vessel has an import capacity of 4.5 bcm/year, a regasification capacity of 12.9 million cubic metres (mcm) per day, and LNG storage capacity of 175,000 cubic metres.

For gas year 2025–2026, the firm and interruptible transmission capacity at entry points interconnected with foreign systems and LNG terminals (i.e. import entry points) amounted to 403 mcm/day, comprising 383.8 mcm/day of firm capacity and 19.5 mcm/day of interruptible capacity. This represents an increase compared with previous gas years, reflecting the commissioning of the entry point connected to the Ravenna LNG terminal. The national transmission system also provides approximately 46 mcm/day of firm export capacity, in addition to 21.3 mcm/day of interruptible capacity through commercial reverse flow at Melendugno.

Natural gas storage is carried out under 15 **storage** concessions held by four companies: Stogit, Ital Gas Storage, Thaleia and Blugas Infrastrutture. In June 2024, Snam submitted a bid to acquire Edison's gas storage facilities. In 2025, Stogit acquired the entire share capital of Edison Stoccaggio, subsequently renaming the company Stogit Adriatica. With effect from 1 January 2026, Stogit Adriatica was merged into Stogit. Consequently, from 2025 the Snam Group has held 13 of Italy's 15 gas storage concessions, of which 12 relate to active storage fields. All active storage sites are built at depleted gas fields. The Italian gas storage system is of significant size: in the 2025-2026 thermal year, which ended on 31 March 2026, the system offered a total working gas capacity of 18.51 G(m^3), of which 4.6 G(m^3) were allocated for strategic storage. The available capacity for peak modulation storage amounts to 7.961 G(m^3); the remaining capacity is linked to products with a uniform withdrawal profile throughout the year or that, in any case, enhance the flexibility offered.

The **distribution** of natural gas in Italy takes place through a network of 272,927 km (of which 520 km were non-operational in 2025), with 57% at low pressure, 42.4% at medium pressure, and 0.6% at high pressure. The length of the networks increased by approximately 700 km compared to 2024. In 2025, 174 companies were active in gas distribution, eight fewer than in 2024. These comprised eight very large operators (with more than 500,000 customers), 18 operators with between 100,000 and 500,000 customers, 17 medium-sized operators (50,000-100,000 customers), 86 small operators (10,000-50,000 customers) and 45 very small operators (fewer than 5,000 customers). Between 2020 and 2024, the number of companies with more than 100,000 redelivery points remained stable at 28; in 2025, this number decreased to 24. Overall, the 174 operators active in 2025 distributed 25 bcm of gas, 0.8 bcm less than in the previous year, to 21.7 million customers.

In 2024, the Authority launched an update of the provisions governing gas transmission network development plans, in light of changes to the national regulatory framework, the new European decarbonisation framework and recommendations concerning network planning. At the end of 2024, the Authority therefore launched a consultation on proposals for introducing a **Single Gas Transmission Network Development Plan**, covering both the preparation process and the minimum information requirements and cost-benefit analysis criteria. Following the consultation, in April 2025 the

Authority updated the regulatory framework, defining in particular: the central role of the largest gas transmission system operator in coordinating the Single Development Plan, verifying the consistency of projects proposed by other operators, validating cost estimates and developing cost-benefit analyses; the requirement to submit the Plan to the Authority by 28 February of every odd-numbered year, with an exceptional deadline of 15 October 2025 for the 2025 Plan; the extension of the Plan's information requirements to include third-party projects, infrastructure decommissioning or conversion measures, and estimates of tariff impacts over a five and ten-year horizon; the extension of cost-benefit analyses to decommissioning projects, except where justified by safety requirements, together with the requirement for specific justification for switching projects, safety-related interventions and the methanization of gas networks to new areas. The 2025 Single Development Plan was subject to public consultation from 1 October to 22 December 2025, together with the applicable cost-benefit analysis criteria and the scenario document prepared by Snam and Terna. As part of the consultation process, a public presentation session was also held on 4 December 2025 to provide stakeholders with further explanations and additional information.

With regard to **access to LNG regasification facilities and the provision of LNG regasification services**, in 2025 the Authority supported the commissioning of the new Ravenna LNG terminal by approving its Regasification Code and the procedure for the initial allocation of the terminal's capacity, which was subsequently amended in June 2025. The Authority also approved an urgent update to the PAR Rules (the regasification capacity allocation platform operated by GME), enabling activation of the section dedicated to capacity allocation auctions for the Ravenna terminal and introducing new functionalities relating to LNG Italia. In May 2025, the Authority also approved the proposal submitted by OLT Offshore LNG Toscana concerning the determination of charges for flexibility services and the recovery of the related incremental costs.

The regulatory framework **governing guarantees of non-discriminatory free access to the natural gas storage service** (RAST) was adopted in 2019. In March 2024, the Authority updated the RAST framework, adapting the regulatory regime and making the incentive mechanism introduced in 2019 a permanent feature, with parameters defined for the 2024–2025 period. For gas year 2025–2026, ministerial decrees issued in January and March 2025 introduced measures aimed at bringing forward capacity allocation and encouraging the filling of storage facilities, even under unfavourable market conditions. To implement these provisions, the Authority introduced, among other measures: confirmation of the reserve price formulas for annual and biennial products; specific criteria for multi-year products and for the priority offering of longer-duration capacity; quantitative limits on the capacity offered by each storage operator to prevent excess supply; the exclusion of technical gas consumption costs incurred by storage operators from charges payable by storage users; the continuation, for 2025-2026, of the compensation mechanism relating to insufficient storage filling; and the introduction of a **storage inventory award**, designed to encourage gas injection from April 2025. At the end of 2025, the existing framework for incentive services and the shares of revenues retained from their allocation was confirmed for the 2026-2027 period.

In 2013, TAP AG, the operator of the **natural gas pipeline Trans Adriatic Pipeline** (TAP), was granted an exemption from certain European rules governing third-party access, regulated tariffs and unbundling, subject to compliance with the conditions jointly established by the Italian, Greek and Albanian regulatory authorities in the Final Joint Opinion. These conditions include the requirement to conduct a Market Test at least every two years to assess market interest in booking long-term transportation capacity. Where the Market Test produces a positive outcome and the subsequent technical and economic assessments are favourable, TAP AG is required to expand the natural gas pipeline's capacity from the current 10 bcm to a maximum of 20 bcm per year. Since 2019, the Market Test procedure established under the Final Joint Opinion has, wherever possible, been coordinated with

the European incremental capacity process governed by the CAM NC Regulation. In 2025, together with the Greek and Albanian regulators, the Authority approved the **2025 Market Test Guidelines**, launching a new cycle for the collection of requests for incremental capacity, as well as the **Project Proposal** relating to the binding phase of the procedure initiated in 2023. The proposal defines the capacity levels for the potential expansion of the natural gas pipeline together with the criteria governing participation and capacity allocation to shippers.

In April 2025, the Authority established the **tariff methodology for gas storage services** for the 2026–2029 regulatory period. While largely confirming the previous framework, it introduced several updates, including: alignment with the ROSS criteria; a new reward-and-penalty mechanism to promote investment efficiency; a new asset category covering extraordinary maintenance works and an extension of the regulatory useful lives of assets; and replacement of the balancing mechanism based on the following year's reference revenues with a mechanism that compensates revenue deviations through the revenue recovery factor. In July 2025, the Authority approved operators' allowed revenues for 2026, revised those for 2025, and authorised payment of the amounts due under the 2024 revenue recovery factor. Storage tariffs now have only a limited application, being confined to operational balancing services and depleted gas producer storage, which together account for less than 2% of total storage capacity Strategic storage, representing around one quarter of total capacity, is remunerated through the CRV^{CS} charge, while more than 70% of total capacity, allocated to seasonal and multi-year modulation services, is awarded through auctions governed by the RAST framework.

For gas year 2025–2026, the auctions held by Stogit, Stogit Adriatica and Ital Gas Storage recorded a substantial increase in allocated capacity (+25%), accompanied by a sharp fall in average clearing prices, which declined from €2.979/MWh in 2024 to €0.093/MWh in 2025. The decline reflected weaker expectations regarding the economic value of storage, owing to higher wholesale gas prices at the time the auctions were held.

In 2024, the Authority initiated proceedings to implement the rulings of the Council of State concerning **gas distribution and metering tariffs**, with particular reference to the operating costs recognised for the 2020–2025 regulatory period, following extensive litigation brought by a number of operators challenging the relevant regulatory provisions. The Authority subsequently launched a consultation on its proposed tariff methodology, aimed at strengthening the transparency and consistency of the regulatory framework. The proposed measures focused in particular on: providing greater transparency regarding the methodology used to process companies' cost and revenue data; quantifying the productivity gains achieved during the 2014-2019 period; verifying the representativeness of the samples and the criteria used to exclude outliers in determining actual 2018 costs; recalculating the X-factors applicable to all operators and introducing a company-specific adjustment mechanism; and revising the tariff coefficients to reflect the customer density of the areas served.

During 2025, the Authority adopted a series of measures to complete implementation of the Council of State's rulings, including:

- recalculating the tariff components covering recognised operating costs for gas distribution services for the years 2020–2025, differentiated according to company size and the customer density of the areas served;
- recalculating the annual efficiency factors (X-factors) applicable to recognised unit operating costs, differentiated by company size, for use in updating those tariff components in the years following 2020; and
- introducing a mechanism, subject to specified conditions, enabling the rate of reduction in recognised operating costs to be determined using data for the individual company, rather than sector-wide data. This mechanism is intended to ensure that, by the end of the regulatory period,

each company's recognised operating costs are aligned with its actual 2018 costs, updated to 2025 to reflect inflation.

With the 2020-2025 regulatory period for gas distribution tariffs approaching its conclusion, in May 2025 the Authority launched proceedings to establish the new **regulatory framework for gas distribution and metering tariffs and service quality**, considering the adaptation of the ROSS approach already applied to other infrastructure services. To allow for a broader and more transparent consultation process, the current regulatory framework was extended through 2026-2027, postponing the start of the new regulatory period until 2028. Accordingly, in December 2025 the Authority approved the amendments required for the extension, including: setting the X-factor at zero for distribution, metering and commercialisation; establishing the rules governing recognised operating costs for area-based concessions during the seventh and eighth years of the concession period; reducing advance payments relating to metrological verification activities; updating the parameters applicable to customer contributions recognised as at 2011; confirming the tariff mitigation measures for Sardinia; defining the tariff framework for isolated gas networks; and recognising the costs incurred by distribution operators in implementing the European Regulation on methane emissions reduction.

In early April 2025, the Authority established the **tariff methodology and service quality requirements for gas storage services for the 2026-2029 regulatory period** (amendments to the RQTG 6PRT and the RAST), largely maintaining the existing regulatory framework. The main changes include: strengthening safety obligations by introducing new requirements for the detection, reporting and publication of data on gas leaks and emissions, in line with the European Methane Emissions Regulation; updating the requirements governing non-intrusive inspection of flow lines; replacing the previous penalty mechanism for non-compliance with contractual obligations; and introducing new reporting obligations requiring comparison between the service performance actually available to users and the performance curves established by ministerial decree.

In June 2025, the Authority amended the **Regulation for Metering Services on the Natural Gas Transmission Network** (RMTG) following its analysis of monitoring data on service performance and the charges applied in 2024 for failure to meet the required service levels (the first year in which the framework was applied), as well as observations submitted by facility operators.

At the end of May 2025, the Authority also initiated proceedings **to extend the Consolidated Gas Distribution Code (TUDG) through 2026 and 2027** and to define the subsequent (sixth) regulatory period. In September 2025, the Authority launched a consultation on its proposals to extend the regulatory framework governing safety and service quality, taking into account the European Regulation on methane emissions. Pending the full implementation of the new European framework, the Authority considered it appropriate to maintain the existing regulatory provisions on a transitional basis, introducing only one change: aligning the inspection frequency for low-pressure distribution networks to a 36-month cycle. This approach was confirmed in December 2025, when the Authority extended the *Integrated Regulation on the Quality of Gas Distribution and Metering Services 2020-2025* to cover 2026 and 2027. The Authority emphasised the need to coordinate the new European rules on methane emissions with the national service quality framework without compromising the overriding objectives of safety and continuity of service.

Accordingly, the **regulatory framework for the quality of gas distribution and metering services** continues to govern the principal activities relevant to distribution safety, with the objective of minimising the risk of explosions, bursts and fires caused by distributed gas and, ultimately, protecting people and property from damage resulting from gas-related incidents. In 2025, the average emergency response time from receipt of the telephone call to arrival on site exceeded 38 minutes, an increase compared with 2024. The percentage of emergency responses reaching the site within the maximum

time limit of 60 minutes was 99.9%, against a regulatory requirement of at least 90%. Early intervention can prevent gas accidents that could have very serious consequences. Compliance with the emergency response requirements, which apply to all gas distribution companies regardless of the number of final customers served, therefore remains an essential condition for eligibility for rewards under the reward-and-penalty mechanism relating to safety improvements. However, almost half of all calls to emergency call centres ultimately prove to be false alarms.

Data on connections are distinguished according to whether they are connections to transmission pipelines or to distribution networks. In 2025, 120 **connections to transport networks** were made, of which 116 were high-pressure pipelines and 4 medium-pressure pipelines. On average, the waiting time for connection works was 206.8 working days for high-pressure pipelines and 8.3 working days for medium-pressure pipelines. Just over 30% of the 120 connections completed were to high-pressure pipelines. **Local distribution networks** also recorded a decline in new connections in 2025, with around 16,000 fewer connections than in the previous year. The total number of new connections fell from 59,236 to 42,873. As always, most of the connections involved low-pressure pipelines (96.1%) and the remainder medium-pressure pipelines. Waiting times for connections to medium-pressure pipelines decreased from 11.8 to 8.6 working days, while those for connections to low-pressure pipelines increased from 36.7 to 43.1 working days.

In 2025, the Authority also introduced a number of changes to the **regulatory framework governing gas balancing**, updating the *Integrated Balancing Code* and aligning it with the tariff regulation for gas transmission. In particular, it revised the methodology for valuing certain gas quantities by introducing the daily System Average Price (SAP) as the reference value, thereby bringing the methodology more closely into line with the actual costs of providing the service. The Authority also clarified the rules governing the "small adjustment" applied to imbalance prices, providing for the relevant percentage to be updated every six months in line with movements in interest rates. In addition, the Authority introduced transitional provisions governing the supply of system gas, taking into account the priority use, until 30 June 2027, of biomethane produced by Snam and Italgas for their own consumption. It also clarified the treatment of settlement adjustments, ensuring consistency across the relevant regulatory provisions.

The **settlement framework** for the gas sector continued to evolve during 2024 along two main lines: on the one hand, the use of more granular consumption measurement data and, on the other, the reduction of discrepancies between expected and actual daily withdrawals in order to improve system balancing. In 2025, the Authority introduced further changes to gas settlement procedures to make them faster, more predictable and better aligned with operators' operational requirements. In particular, in July 2025 it consulted on revised timetables for the settlement adjustment sessions, beginning with the 2021-2024 multi-year adjustment session, based on proposals submitted by the Balance Responsible Entity and the Integrated Water Services Operator, with the aim of shortening processing times and improving the correction of withdrawal data. Also in July 2025, the Authority established the accounting rules for the alternative gas supply service applicable where gas networks are temporarily isolated. Finally, the Authority also amended the incentive mechanism introduced to encourage distribution companies to correct withdrawal data promptly. Following the emergence of particularly high penalties during the 2020-2023 settlement adjustment session, the Authority introduced corrective measures to prevent disproportionate effects.

As early as 2022, the Authority had introduced an incentive mechanism designed to increase the **accountability of gas distribution companies**, with the aim of improving operational efficiency, reducing network leakages and enhancing the quality of metering data. The mechanism is based on the **in–out delta**, namely the difference between the volumes measured at the entry points to the distribution network and the volumes measured or estimated at the exit points, which, ideally, should

tend towards zero. In 2025, the Authority refined the operation of the mechanism by providing for three calculation sessions covering the 2020-2022, 2021-2023 and 2022-2024 three-year periods. The methodology for allocating any penalties among interconnected distribution companies was also revised. The Authority further clarified the rules applicable where responsibility for operating distribution assets is transferred following the award of a concession through a competitive tender. In July 2025, the Operational Instructions were updated, establishing that, when calculating the in–out delta, the Balance Responsible Entity must also take into account the volumes injected into each city gate by tank trucks.

Wholesale and retail markets

According to provisional data published by the Ministry of the Environment and Energy Security, gross natural gas consumption increased by almost 2% in 2025, rising from 61.8 to 63 bcm. Following the sharp declines recorded in 2022 and 2023 (both -10%) and the modest recovery in 2024 (+1.2%), this increase represents a further positive signal for the sector. Final consumption nevertheless remained at its lowest level of the past thirty years.

Domestic production recorded a solid recovery, increasing from 2.6 bcm in 2024 to 3 bcm. The **non-domestic balance** also increased slightly (by 1%), reflecting higher imports, which rose from 59.5 to 61.6 bcm, partly offset by a recovery in exports, which returned to 2.1 bcm, in line with their 2023 level. As gas volumes in storage at year-end exceeded those at the beginning of the year by around 0.6 bcm, **gross domestic consumption** amounted to 63 bcm. As a result, **Italy's dependence on foreign supplies**, measured as the ratio of net imports to gross domestic gas consumption, declined slightly. In 2025, 94.3% of the gas available in Italy was imported, compared with 95.2% in 2024. Including system consumption and network losses, **net gas consumption** in 2025 is estimated at around 62 bcm.

According to the provisional data published by the MASE, Italy imported 2.4 bcm less natural gas in 2025 than in 2023, but 2.1 bcm more than in 2024. Gross imports rose from 59.5 to 61.6 bcm, an increase of 3.6%. Following the low recorded in 2024, gross import volumes therefore returned to broadly the same level as in 2023. The increase was driven primarily by imports from the United States, which almost doubled in 2025, rising from 5.2 to 9.8 bcm. Imports from Northern Europe also increased, with volumes from both Norway and the Netherlands rising by 43%, as did supplies from countries more recently added to Italy's supply mix (Nigeria, Equatorial Guinea, Mauritania and others), which increased from 0.9 to 2.2 bcm (+163%). Imports from Algeria (-890 mcm), Azerbaijan (-307 mcm), Qatar (-108 mcm) and Libya (-448 mcm) declined. The volumes statistically attributed to Russia, reflecting higher withdrawals from Austrian storage facilities delivered via the Tarvisio entry point, also fell sharply (-83%), dropping from 5.7 bcm in 2024 to 972 mcm. The increase in Italy's gas imports was driven largely by liquefied natural gas (LNG). In 2025, LNG imports increased by 44%, rising from 14.7 to 21.2 bcm. As a result, LNG accounted for just over one-third of total imports, compared with around one-quarter in 2024.

According to the provisional data collected through the Authority's Annual Survey of the Energy Sectors, Italy imported 58.8 bcm of natural gas in 2025, 1.2 bcm more than the 57.6 bcm imported in 2024. The increase, equal to 2%, was therefore slightly lower than that indicated by the provisional data published by the Ministry of the Environment and Energy Security (MASE). Around 3.1% of total gas procured from abroad (just over 1.8 bcm) was purchased on European gas exchanges.

Five corporate groups each accounted for more than 5% of total gas supplies (that is, domestic production plus imports): Eni, Edison, Azerbaijan Gas Supply Company Limited, Vitol and Enel. These were the same five groups as in 2024, except that Vitol replaced Royal Dutch Shell. Together, they

imported 44.4 bcm of the 58.8 bcm of gas entering the Italian market from abroad. These five groups were also the only ones each holding a market share of more than 5% of total gas available (which includes imports, domestic production and gas held in storage). Collectively, they accounted for 74.3% of total gas available, only slightly below their share of total gas supplies.

Based on their **remaining duration**, import contracts (both annual and multi-year) in force in 2025 show that 49.7% will expire within the next five years (compared with 50.5% in 2024), while 58.9% will expire within the next ten years (compared with 59.0% in 2024). Contracts with a remaining duration of more than 15 years account for 15.5% of those currently in force. This share has increased marginally from 14.8% in the previous year.

Total demand in the gas sector, defined as the sum of gas volumes sold in the wholesale market (including resale transactions), gas sold in the retail market and own consumption, increased by 1.8% to reach 291.7 bcm. This was driven primarily by the recovery in gas traded on the retail market and the broadly stable volumes traded on the wholesale market, although own consumption also made a significant contribution. The **wholesale market** handled 232.1 bcm, compared with 232.6 bcm in 2024 (-0.2%), while the retail market accounted for 46.6 bcm, an increase of 1.1% on 2024. Own consumption rose from 12.2 to 13.1 bcm, up 7.5%.

In 2025, the **number of companies** operating in the wholesale market increased significantly to **336**, compared with 2024. However, it should be noted that the number of market participants - which is based on the companies responding to the Authority's Annual Survey - is the indicator most affected by year-to-year variations in the survey response rate. The volume of gas sold on the wholesale market declined by 0.5 bcm (-0.2%), resulting in a 9.1% reduction in the average sales volume per company, from 760 mcm to 691 mcm. **Market concentration** also declined. The combined market share of the three largest companies - Shell Energy Europe, Engie Global Markets and Edison - fell to 21.1%, from 23.6% in 2024. The combined market share of the five largest companies (the three above together with Eni and Vitol) declined from 35.1% to 31.6%. The Herfindahl-Hirschman Index (HHI) for the wholesale market also fell, from 427 to 377.

The principal gas trading hub in Italy's wholesale market is **the Virtual Trading Point** (VTP), operated by Snam Rete Gas, the transmission system operator. Alienations that can be registered are both those that take place through bilateral contracts and those that take place within the regulated markets managed by the GME. In 2025, 351 entities traded, alienated and acquired gas at the PSV. Only 54 qualified as standalone traders, since they were not transport system users. The number of VTP subscribers increased compared with the previous year, reaching 420, up from 387 in 2024 (+9%). OTC volumes increased by 1.5%, rising from 123 to almost 125 bcm. By contrast, volumes subject to mandatory delivery at the PSV fell by 40%, from 183 to 109 mcm. As a result, total deliveries at the VTP increased only marginally, by 1.4% compared with 2024. By contrast, volumes resulting from market transactions recorded strong growth (+19%), reflecting both the increase in volumes traded on the organised markets (+14.1%) and the expansion in gas traded through the clearing house (+56.6%).

During 2025, a total of 210.4 TWh was traded on the **markets organised and operated by the Energy Markets Operator** (GME), an increase of 16% compared with 2024.

The **Day-Ahead Market** continued to account for the largest share of liquidity (78%, up 3 percentage points on 2024), with traded volumes increasing to 165 TWh (+20% compared with 2024). The largest share of these volumes (81%; -1%) was traded via continuous trading (133.8 TWh; +20%). Monthly trading patterns also showed higher volumes during the first two months of the year. The AGS segment of the Day-Ahead Market (MGP) recorded total trading volumes of 30.8 TWh, up 22% on 2024.

As in 2024, the share of volumes traded on the **Intraday Market** continued to decline, falling from 22% in 2024 to 19%. Total traded volumes amounted to 39.5 TWh, down 2% on the previous year.

Continuous trading remained the dominant mechanism, accounting for 98% of the market, with traded volumes of 38.9 TWh (-1%), while volumes traded in the AGS segment, at 0.6 TWh, were slightly less marginal than in the previous year. Trading on the Gas Storage Market (MGS) also increased, with volumes rising to 5.4 TWh (+54%).

Prices across the various trading platforms converged on an annual average of around €38.35/MWh, up 5% on 2024 and broadly in line with the annual average price of over-the-counter (OTC) transactions at the VTP (€38.56/MWh), which also increased by 5% compared with the previous year. In particular, the average prices in the two continuous trading segments of the M-GAS market, €37.95/MWh for the Day-Ahead Market (MGP) and €38.47/MWh for the Intraday Market (MI), followed an intra-year pattern closely mirroring that of VTP prices.

According to the provisional results of the Authority's Annual Survey, 46.4 bcm of gas was **sold on the retail market** in 2025. A further 186 mcm was supplied through the Supplier of Last Resort Service and default services. Total final sales therefore amounted to 46.5 bcm, an increase of 0.5 bcm compared with 2024. To obtain a figure comparable with final gas consumption published by the Ministry of the Environment and Energy Security and discussed above, it is also necessary to include own consumption, which amounted to 13.1 bcm. This brings total gas consumption recorded by the Annual Survey to 59.6 bcm, broadly comparable with the ministerial figure of 62.1 bcm. As usual, there are differences between the two sources, which classify the volumes of gas handled during the year differently. According to the Annual Survey data, total gas consumption recovered in 2025, increasing by 2.4% compared with 2024.

Unlike in the previous two years, the **number of suppliers** active in the retail market increased again in 2025, reaching 493 (11 more than in 2024). As gas sales also increased (by 1.1%), the average sales volume per supplier declined slightly, from 96 to 94 mcm (-1.2%). Of the 493 companies active in the end market, 27 (5.5%) sold more than 300 mcm in 2025. Together, these companies accounted for 85.4% of all gas sold in the retail market.

Analysing the sales performance of corporate groups, instead of individual companies, allows a more accurate assessment of market shares and the **level of concentration in the retail market.** Following a 9.7% increase in sales volumes, the Edison Group retained its leading position, with its market share rising from 15.5% to 16.8%. The Eni Group, which lost first place in 2023 but regained second place in 2024, consolidated that position in 2025. Supported by a 7.1% increase in sales, its market share also edged up, from 12.0% to 12.7%. The Enel Group remained in third place despite an 11.5% decline in sales, which reduced its market share from 11.1% in 2024 to 9.7%.

Given these contrasting trends among the largest groups, concentration in the retail gas market remained broadly unchanged compared with 2024, at least at the aggregate level across all customer segments. Based on market shares calculated from sales volumes, the number of groups accounting for more than 5% of the total market increased again to four. Moreover, in 2025, the top three groups control 44.8%, while in 2024 the share was 43.8%. The Herfindahl-Hirschman Index (HHI) for the retail market was 900, slightly higher than the 2024 figure of 858. However, the index remained below the threshold value of 1,000, below which market concentration is generally considered to be low. The highest level of concentration was observed in sales to industrial customers and electricity generators, where the C3 ratio exceeded 50%, while the lowest was recorded in sales to public service activities and the commercial and services sectors. Compared with 2024, both the C3 ratio and the HHI indicate slight increases in concentration in the apartment buildings, industrial and electricity generation segments, whereas concentration declined in all other segments, particularly in the commercial sector.

As noted above, total gas sales in 2025 amounted to 59.6 bcm, of which 13.0 bcm was for own consumption and 46.6 bcm for retail sales, supplied to just under 21.7 million customers (redelivery points). Overall, compared with 2024, gas consumption increased by 2.4%. Own consumption, which is

concentrated mainly in the industrial and electricity generation sectors, increased by 7.5%. Gas sold on the free market, amounting to 44.7 bcm, rose modestly by 0.9%, while sales under the Vulnerability Protection Service for household customers and through Supplier of Last Resort services, totalling 1.8 bcm, increased by 4.8%. Consumption in the household sector (households and apartment buildings) remained broadly stable at 13.7 bcm, while consumption in the productive sectors (industry and thermoelectric generation) increased from 37.6 bcm to 39.6 bcm (+5.5%). By contrast, consumption in the tertiary sector (the commercial and services sectors together with public service activities) declined by 10%, falling from 7.0 bcm to 6.3 bcm. Considering retail sales only, and therefore excluding own consumption, **96.1% of gas was purchased on the free market**, while the remaining 3.9% was supplied under the Vulnerability Protection Service and Supplier of Last Resort services. Measured by customer numbers, 87.1% purchased gas on the free market.

Looking solely at the **household sector**, the share of volumes purchased on the free market declined slightly to 86.2% for households, while reaching 99.4% for apartment buildings. Both shares are calculated on the basis of retail sales only, excluding own consumption. Measured by delivery points, 13.6% of households were supplied under the Vulnerability Protection Service, compared with 13.0% in 2024. A breakdown of retail sales by consumption sector and customer size (excluding own consumption) shows that customers with annual consumption of up to 5,000 m^3 accounted, on average, for 27.6% of all gas sold in the retail market.

Average annual consumption amounted to 579 m^3 for households, 11,787 m^3 for apartment buildings with domestic use, 5,635 m^3 for the commercial sector, 103.5 thousand m^3 for industry, 20.4 mcm for electricity generation and 11,746 m^3 for public service activities. On the free market, average household consumption (578 m^3) was slightly lower than that recorded under the Vulnerability Protection Service (586 m^3).

The **switching** rate - that is, the proportion of delivery points that changed supplier during the 2025 calendar year - stood at 18.8%, rising to 19.4% when measured by the gas volumes associated with customers that switched supplier. This was unchanged from 2024, confirming the high level of market dynamism achieved in recent years. More specifically, just over 4.2 million customers changed supplier at least once during the year, representing 18.7% of all household customers and accounting for 25.3% of household consumption volumes. An equally large proportion, amounting to 24.4%, of domestic-use condominiums switched to a different supplier, corresponding to 31% of the consumption volume in that sector.

Also in the gas sector, as already mentioned for electricity, the Annual Survey asked suppliers a number of questions aimed at assessing the quantity, types and modalities of offers that companies make available to customers who have chosen to supply in the free market.

The **average number of commercial offers** that each gas supplier is able to propose to its potential customers is 20.5 for household customers (9.2 are available for purchase online only), 8.8 for condominiums with domestic use (2.6 online only) and 15.7 for non-household customers (3.5 online only). Household interest in **online offers** remains limited, despite the growing digitalisation process. Only 9.7% of household customers have indeed chosen to subscribe to an offer through digital channels. The share is higher among non-household customers, where it stands at 20.6%, while it remains particularly low in the segment of residential buildings with household use, with a penetration rate of 2% (data substantially unchanged compared to 2023).

In 2025, natural gas suppliers offered household customers an average of 33.5 **retail offers**, of which 3.2 were available exclusively through online channels. For non-household customers, the average number of available offers was 18.1, including 1.9 that could be purchased exclusively through digital channels. For apartment buildings with domestic use, the average number of available offers stood at

8.1, of which an average of 1.3 were available exclusively online. Contracts concluded **online** accounted for 13.5% of all household contracts and 22.9% of those concluded by non-household customers.

As regards **pricing structures**, variable-price contracts remained the predominant type of offer in the free gas market across all customer segments in 2025. They accounted for 67.9% of household contracts, 94.1% of contracts for apartment buildings with domestic use and 86.2% of contracts for non-household customers. For household customers, the commodity component of variable-price contracts averaged 75.0 c€/m³, compared with 81.2 c€/m³ for fixed-price contracts. Variable-price offers were also slightly more competitive for apartment buildings with domestic use (61.1 c€/m³ versus 62.5 c€/m³), while in the non-household segment the average prices of the two contract types were broadly aligned, at 50.2 c€/m³ for variable-price contracts and 48.9 c€/m³ for fixed-price contracts.

Across all customer categories, **indexation** to the VTP remained the principal pricing reference for variable-price offers in the free gas market. Contracts indexed to the VTP accounted for 74.8% of offers for household customers, 84.2% for apartment buildings with domestic use and 75.4% for non-household customers, with average commodity prices of 76.7 c€/m³, 61.7 c€/m³ and 51.9 c€/m³, respectively. Offers indexed to the price components defined by the Authority for the protection services remained the second most common type, accounting for 13.2% of household customers, 10.0% of apartment buildings with domestic use and 9.6% of non-household customers. By contrast, offers indexed to the TTF remained relatively limited in number, accounting for 5.4% of household customers and around 7% of non-household customers, and generally featured higher average prices than PSV-indexed offers, reaching 77.5 c€/m³ in the household segment.

38.9% of household customers have signed a contract that includes a **rebate or a discount**; lower percentages are found among other customers (16.9% for condominiums and 17.8% for non-household clients).

In 2025, **value-added services** were more common in gas offers for household customers, while apartment buildings with domestic use and non-household customers showed a clear preference for contracts focused solely on gas supply. Among fixed-price contracts, the most common value-added service for household customers was loyalty rewards programmes, which featured in 57.6% of contracts. These contracts had an average commodity price of 85.6 c€/m³, above the average for fixed-price contracts as a whole (81.2 c€/m³). Contracts without value-added services accounted for 22.7% of the total. By contrast, offers without auxiliary services predominated among apartment buildings with domestic use and non-household customers, representing more than 65% and almost 80% of contracts, respectively. Among variable-price contracts, offers without value-added services accounted for 55.5% of household contracts, 65.6% of contracts for apartment buildings with domestic use and 95.3% of non-household contracts. For household customers, the most common auxiliary services were loyalty rewards programmes (20.2%) and offers guaranteeing 100% green gas (12.9%). In the non-household segment, however, value-added services played only a marginal role, confirming that customers in this segment place greater emphasis on the economic aspects of gas supply.

Analysis of the data collected through the Annual Survey shows that, in 2025, the **average** pre-tax **price of gas** charged by suppliers to final customers, weighted by sales volumes, was 71.9 c€/m³, 1.0% higher than the 71.2 c€/m³ recorded in the previous year. The increase, reflecting higher wholesale gas prices, affected almost all customer categories and, where observed, varied only slightly across consumption bands. The largest increase (4.8%) was recorded for very large customers with annual consumption exceeding 20 million m³, while the smallest (+1.4%) was observed for customers with annual consumption between 0.2 million and 2 million m³. By contrast, the smallest customers (with annual consumption of up to 5,000 m³, consisting mainly of household customers) recorded a slight decrease of 1.3% compared with the previous year.

Price **trends** over the past decade **for household customers** (households and, until 2023, apartment buildings with annual consumption of up to 5,000 m³) can be analysed by distinguishing between the two main contractual arrangements under which gas was supplied: the protection service (reserved exclusively for vulnerable customers since 2024) and the free market. With the exception of 2022, prices under the protection service were lower than those in the free market throughout the period. In that year, the free market showed a price lower than the protection service (-17.6%), due to the widespread use in that market of fixed-price contracts which, in the short term, limited the pass-through to final customers of the sharp rise in wholesale gas prices following the outbreak of the Russia-Ukraine conflict. This pass-through continued in both 2023 and 2024. In each of those years, prices in the free market increased by around 10 c€/m³, before easing slightly in the most recent year (-3 c€/m³). By contrast, prices under the protection service fell by as much as 33 c€/m³ in 2023, only partly offset by an increase of 11 c€/m³ over the following two years. As a result, the free market became markedly more expensive again in 2023. Over the past three years, prices in the free market have consistently exceeded those under the protection service by between 28% in 2023 and 20% in 2025.

With regard to the **commercial quality of retail services**, analysis based on data submitted by 457 gas suppliers shows that, in 2025, suppliers received a total of 178,695 written complaints, 437,829 requests for information, 12,547 billing adjustments and 238 corrections of double billing. There were 9,961 cases in which suppliers failed to comply with the service standards for the commercial quality of gas retail services, giving customers the **right to compensation.** Compensation payments were attributable primarily to failures to meet the standard response time for written complaints (94%) and, to a much lesser extent, to delays in completing billing adjustments (5%). Overall, the highest number of compensation payments was recorded in the free-market household customer segment.

In 2025, 102 suppliers reported serving 1.7 million customers under dual-fuel contracts. These customers submitted 27,519 written complaints, down 9.3% compared with the previous year, and 53,041 requests for information, more than double the number recorded in 2024. Bill and double-bill adjustments amounted to 1,496 (-3.4%) and 29 (-46.3%) respectively. Altogether, for customers with *dual fuel* contracts, the number of cases of non-compliance with the standards that triggered the right to automatic compensation on the bill for commercial quality performance was 1,818. Some 91.4% of cases of non-compliance were attributable to failures to respond to customer complaints within the prescribed time limits, while 7.8% related to delays in billing adjustments.

2.1.4 Customer protection and dispute resolution

The consumer protection system in the sectors regulated by the Authority consists of two macro-areas: the first concerns information and assistance to customers (basic level); the second concerns the resolution of problems and disputes that may arise between customer and service provider (second level). The **Energy and Environment Consumer Help Desk** and the **Conciliation Service** are operated on behalf of ARERA by the *Acquirente Unico*. The Help Desk provides answers to calls to the call centre, written requests for information, requests to activate special information procedures and second-level complaints.

In 2025, in line with the trend already observed in 2024, the overall number of incoming enquiries, both written and by telephone, continued to decline. In fact, in 2025 the Consumer Help Desk **call center** received 786,647 calls during operating hours, a decrease of 30% compared with 2024. The average call duration at the call centre was 214 seconds, compared with 233 seconds in 2024. Calls to the Consumer Help Desk mainly related to dispute resolution procedures (39% of the total, up 13% on 2024), followed

by enquiries concerning the social bonus (36%, down 6% compared with the previous year). A total of 233,790 calls concerned social bonuses for the electricity and gas sectors.

The Consumer Help Desk received 45,152 **written requests** relating to the energy sectors, a decrease of 17% compared with the previous year. The social bonus remained the most common topic, accounting for 32% of all enquiries (up 8% on 2024), with almost all requests concerning the automatic award of the benefit. Requests relating to the market (17%, up 5%), billing (15%, up 1%) and contracts (13%, up 2%) also increased. **Special information procedures** make it possible to provide information without the need for assistance of the Help Desk staff. They are operational as of 1 January 2017 only for some specific topics in the energy sectors. In 2025, the Consumer Help Desk received 42,044 written requests requiring the initiation of a special information procedure, down 18% compared with 2024. Of these requests, 60.5% concerned the electricity sector, 31.5% the gas sector, and the remaining 8.0% both sectors.

Activities relating to the second level of the protection system concern the **resolution of issues and disputes** arising in the relationship between the customer and the regulated service supplier. These issues may be resolved through the Consumer Help Desk's special settlement procedures or through conciliation procedures. The latter may be brought before the Authority Conciliation Service or ADR entities registered on the Authority's special list.

Similarly to what happens for special information procedures, also for the **special settlement procedures** the Help Desk accesses information encoded in centralised databases. Unlike information procedures, special resolution procedures allow the outcome of the dispute to be determined. They imply assistance of the Help Desk staff, in case further information is needed to consult databases, or to verify the correct fulfilment of the regulation following the resolution of the dispute. In 2024, the Help Desk received 13,679 requests to initiate resolution procedures, representing a 21% decrease compared to 2024. The procedure concerning the social bonus remains the most frequently used, accounting for 80%, a decrease of 22 percentage points compared to 2024. The electricity sector accounted for the largest share of special settlement procedures, representing 59% of all requests. In the other cases, the issue involved both sectors or dual fuel customers. The household sector was involved in 94% of the special settlement procedures, and 85% of the requests were submitted by end customers without the assistance of delegates. The principal method for triggering these procedures was via email, used in 58% of cases.

The **Authority's Conciliation Service** allows electricity and gas end customers to resolve disputes with operators online when complaints go unanswered or are unsatisfactorily addressed. The procedure, conducted in the presence of an impartial third-party conciliator, can conclude with an agreement that holds the binding effect of a settlement under Article 1965 of the Civil Code. Furthermore, for disputes within sectors regulated by the Authority, an attempt at conciliation is a mandatory prerequisite before taking the matter to court, except in cases involving tax, fiscal matters, or urgent decisions. In 2025, end customers and users in the energy sectors submitted 22,619 applications to the Conciliation Service, a decrease of 22.5% compared with the previous year. The electricity sector recorded the highest number of applications, with 12,027 (40% of the total, unchanged from 2024), followed by the gas sector with 7,450 applications (24% of the total, down 9% on 2024). Dual-fuel customers submitted 2,920 applications (10% of the total, down 1%), while prosumers submitted 222 applications, a slight increase on the 217 recorded in 2024. Among procedures concluded by the Service in 2025, the settlement rate was 74% in the gas sector (up 11 percentage points on 2024) and 60% in the electricity sector (up 1 percentage point). Excluding pending procedures, settlements were reached in 73% of cases involving suppliers (up 7 percentage points) and in 43% of those involving distributors (up 11 percentage points). The average time required to reach a settlement was 56 days, one day less than in 2024.

As an alternative to ARERA's Conciliation Service, the final customer may make a compulsory attempt at conciliation for judicial purposes also with recourse to other parties. ARERA, in implementation of the rules, established in December 2015 the **List of Organisations entrusted to handle ADR (Alternative Dispute Resolution procedures)**. At 31 March 2026, 25 ADR entities were registered in the Authority's List. Information submitted by ADR bodies shows a significant reduction in the total number of applications received in 2025, down 53% compared with the previous year. Of the 1,066 applications received, 702 related to disputes in the electricity and gas sectors or involving dual-fuel customers. Billing remained the predominant subject of disputes in the energy sectors, accounting for 50% of cases, up 25 percentage points on 2024.

Since 2009, a social bonus scheme has been in place to help household customers in economic or health-related hardship reduce their electricity and gas costs. In 2025, the electricity and gas social bonus schemes continued to provide support to households experiencing economic hardship with an equivalent economic status indicator (ISEE) of up to €9,530 (or up to €20,000 for households with at least four children), through the automatic entitlement mechanism introduced in 2021. As an exceptional measure, Decree-Law No. 19/2025 introduced, for 2025 only, a €200 contribution towards electricity supply costs for household customers with an ISEE of up to €25,000. The Authority established the operational arrangements for the automatic payment of this contribution. For beneficiaries of the electricity social bonus, the additional payment was granted together with the bonus between 1 April and 31 July 2025. For households with an ISEE between €9,530 and €25,000, eligible beneficiaries were identified through data exchange between National Social Security Institute (INPS), Acquirente Unico and the Integrated Information System (SII), enabling suppliers to apply the benefit directly to customers' electricity bills. The number of beneficiaries within the standard eligibility threshold for the social bonus (ISEE of up to €9,530 for households of up to four members and up to €20,000 for large families) declined slightly (-4.6%) compared with the previous year. Overall, around 2.7 million **electricity social bonuses** were granted during the year, in addition to the 3.4 million households that received the exceptional €200 contribution. More than 1.6 million **gas social bonuses** were also granted, with the number of beneficiaries again declining slightly compared with the previous year (-6.2%).

In 2025, the Authority continued its **information campaign** to support customers through the phase-out of regulated price protection, including the introduction of dedicated messages on energy bills. From 1 January 2025, a new information notice was introduced for household customers in the free electricity market, explaining the rights of vulnerable customers and the conditions for accessing the relevant protection services. From 1 July 2025, following the introduction of the new energy bill format, a dedicated notice was also included to help customers identify the free-market offers best suited to their needs. Existing communications on energy consumption remained in place, together with, for the gas sector, the information on the rights of vulnerable customers introduced in 2024.

In 2025, the strengthened **Code of Business Conduct** for the retail sale of electricity and gas entered into force, with the aim of improving transparency, enhancing the protection of final customers and making offers in the free market easier to compare. The main changes included stronger pre-contractual information requirements and enhanced safeguards for contract amendments, an extension of the right of withdrawal period to 30 days in specified cases of off-premises sales, mandatory written confirmation of contracts concluded by telephone, a minimum three-month notice period for unilateral contract changes and contract renewals, and an automatic compensation payment of €30 where the required notice period is not observed. To implement Decree-Law No. 19/2025, the Authority introduced transitional measures from 1 July 2025 to simplify the presentation of retail offers. These measures require suppliers to provide a clearer presentation of charges and to publish the contractual documentation, the Summary Information Sheet and the offer code on their websites. The Authority also adopted further measures, effective from 1 April 2026, providing for a standardised pricing

structure for offers to household customers and requiring all offers available through the Offers Portal (*Portale Offerte*) to be published online.

A new **energy bill** format also came into effect in 2025, with the aim of making bills simpler, more consistent and easier for customers to understand. From 1 July 2025, energy bills have comprised a Summary Bill, containing the Standardised Front Page, the Energy Summary, the Supply Contract Window and the Essential Information, together with the Detailed Information section, which has remained substantially unchanged. During the year, the Authority also introduced a number of refinements, including improved presentation of value-added services, a more detailed Supply Contract Window and specific simplifications for customers with multiple supply points. It also approved the Energy Bill Glossary to help customers better understand the terminology used. The new framework applies to low-voltage electricity customers and to domestic and small gas customers, and has also been extended to gas last-resort services and supplies to public administrations.

The ***Portale Consumi*** [Consumption Portal] continues to evolve, with ongoing enhancements aimed both at improving its performance and at expanding its functionality. In 2025, the programme to strengthen final customers' access to their energy consumption data was completed. In addition to the information already available on energy bills, through smart meters and on the *Portale Consumi*, a new system became fully operational in October 2025, enabling customers to authorise secure third-party access to their metering data. During the initial phase, authorisation may be granted to suppliers, certified Energy Service Companies (ESCOs), entities covered by the regulatory framework for self-consumption and dispatching, and representative consumer and business associations. The new model ensures that data are shared only with the customer's consent and solely for the purposes of comparing retail offers and providing energy services, thereby strengthening transparency and competition in the market.

In 2025, the ***Portale Offerte*** [Offers Portal] was enhanced with new features designed to support customers in the transition to the free market. In particular, access via SPID or the Electronic Identity Card (CIE) was introduced, enabling customers to use their actual historical consumption to estimate annual expenditure, view information on the Gradual Standard Offer Service , and access the details of their current retail offer, even where that offer is no longer available for sale. During the year, the Offers Portal recorded 1,552,757 unique visitors, averaging 129,400 visitors per month and reaching a peak of more than 184,000 users in January. As at 31 December 2025, the Portal listed 19,355 offers, comprising 15,861 free-market offers, 2,324 PLACET (free price offers under uniform contractual conditions) offers and 1,170 offers for which annual expenditure could not be estimated. The comparable offers included 10,027 electricity offers, 5,771 gas offers and 63 dual-fuel offers.

2.1.5 Implementation of the Clean Energy Package

Law No. 53 of 22 April 2021 is the ruling that defined the principles and guiding criteria for the delegation of powers to the Government for the implementation of the Clean Energy Package standards in the Italian legal system, with particular reference:

- to Directive 2018/2001/EU on the promotion of the use of energy from renewable energy resources (art. 5);
- to Directive 2019/944/EU concerning common rules for the internal market in electricity and amending Directive 2012/27/EU (recast) (art. 12);
- to the adaptation of national legislation to the provisions of Regulation (EU) 943/2019, on the internal market in electricity (recast), and Regulation (EU) 941/2019, on risk preparedness in the electricity sector and repealing Directive 2005/89/EC (art. 19).

In implementation of this law, the following were then enacted: Legislative Decree No. 199 of 8 November 2021, on the 'Implementation of Directive (EU) 2018/2001 on the promotion of the use of energy from renewable sources' (so-called Decree Red II); Legislative Decree No. 210 of 8 November 2021 on 'Implementation of EU Directive 2019/944 concerning common rules for the internal market in electricity and amending Directive 2012/27/EU, as well as laying down provisions for the adaptation of national legislation to the provisions of EU Regulation 943/2019 on the internal market in electricity and EU Regulation 941/2019 on risk preparedness in the electricity sector and repealing Directive 2005/89/EC' and other decrees transposing European directives.

At the beginning of 2020, Italy published its **National Integrated Energy and Climate Plan (PNIEC)**, which was submitted to the European Commission in accordance with the Governance Regulation (Regulation (EU) 2018/1999). Under the Regulation, Member States were required to submit their updated and final PNIECs to the European Commission by 30 June 2024, taking account of the recommendations issued by the Commission at the end of 2023. On 1 July 2024, the Ministry of the Environment and Energy Security (MASE) and the Ministry of Infrastructure and Transport submitted the final version of Italy's PNIEC to the European Commission. The Plan sets out measures to strengthen the country's pathway towards the energy transition and climate neutrality. The PNIEC adopts a technology-neutral approach, relying on a balanced mix of measures, including the expansion of renewable electricity generation, the development of biomethane, hydrogen and biofuels, the electrification of final energy consumption, wider deployment of heat pumps, building renovation, electric mobility, and carbon capture and storage (CCS) technologies. The principal focus remains the expansion of renewable energy, with a target of 131 GW of installed capacity by 2030, driven primarily by solar generation, followed by wind, hydropower, bioenergy and geothermal energy. The Plan also includes a dedicated section on sustainable nuclear energy. The scenarios developed envisage nuclear power contributing around 11% of electricity demand by 2050, with a potential contribution of up to 22%, complementing renewable and other low-carbon energy sources.

In the area of energy efficiency, the PNIEC provides for a substantial reduction in energy consumption, while recognising that further measures will be needed to achieve the most ambitious targets, although the target for cumulative annual final energy savings is expected to be met. As regards greenhouse gas emissions, the Plan aims to exceed the Fit for 55 target for industrial installations covered by the EU Emissions Trading System (EU ETS), achieving a 66% reduction compared with 2005 levels, against the EU target of 62%. In the non-ETS sectors (buildings, transport and agriculture) additional measures will still be required to meet the European targets. The PNIEC also strengthens Italy's energy security through the diversification of energy supplies, the development of new infrastructure and enhanced interconnections.

It aims to consolidate Italy's role as a European energy hub and a Mediterranean corridor for renewable energy by reinforcing electricity interconnections, market coupling and infrastructure for renewable gases. Research, development and innovation play a central role in accelerating the deployment of technologies consistent with the European Green Deal and in strengthening the competitiveness of Italy's industrial sector. The Plan was prepared with contributions from the competent public authorities, technical bodies and the research community, and benefited from a public consultation involving 133 stakeholders in 2024, including businesses, public institutions, trade associations and citizens.

One of the key measures linked to the Clean Energy Package was the approval, in 2023, of the Electricity Dispatching Integrated Text (TIDE). Its entry into force was deferred until 1 January 2025 - 18 months after its publication - to allow the main stakeholders, particularly Terna and the Energy Markets Operator (GME), sufficient time to implement the organisational changes required by the new regulatory framework. The TIDE reorganises the rules governing the day-ahead and intraday electricity markets in line with Commission Regulation (EU) 2015/1222 establishing a guideline on Capacity Allocation and

Congestion Management (CACM).

However, further regulatory developments in 2024 and 2025 prompted the Authority to revise the TIDE even before it entered into force. In particular, in July 2024 the Authority approved Version 2 of the TIDE, introducing arrangements for the replacement of the Single National Price (PUN) from 1 January 2025 in accordance with the provisions of the Ministerial Decree of 18 April 2024 (see last year's Annual Report). In June 2025, the Authority adopted further amendments through Version 4 of the TIDE (see Section 3.1.5 of this Annual Report), focusing in particular on the arrangements for market-based procurement auctions for Frequency Containment Reserve (FCR). The Authority subsequently approved the amendments to Terna's Grid Code required for the full implementation of TIDE (Revision 4), ensuring full consistency with the European target model for the integration of balancing markets.

3 THE ELECTRICITY MARKET

3.1 Infrastructure regulation

3.1.1 Unbundling

[9]In 2015, the Authority revised the framework governing obligations of functional separation (unbundling) in the electricity and gas sectors, approving the *Consolidated Act on Functional Unbundling* (TIUF), in line with Legislative Decree of 1 June 2011, No. 93, and Directives 2009/72/EC and 2009/73/EC. Among the measures introduced by the TIUF, in force since 1 January 2016, were new unbundling requirements concerning communication and branding policies for all electricity and natural gas distribution system operators, irrespective of their size or corporate form. These requirements imposed complete separation, without any risk of confusion, between electricity and natural gas supply activities and distribution activities.

In April 2025, the Authority made [10] a number of amendments to the *Integrated Accounting Unbundling Text* (TIUC[11]) to update, with effect from the 2024 financial year, the definitions of certain activities and segments relating to electricity transmission and dispatching operations, as well as natural gas transmission, regasification and metering activities.

As in previous years, enforcement activities relating to compliance with functional and accounting unbundling requirements continued throughout the year. In particular, an on-site inspection was carried out at a vertically integrated electricity distribution undertaking in relation to functional unbundling requirements. In addition, the Authority formally required 19 undertakings operating in the electricity and gas sectors to submit the notifications required under the TIUF. During the year, proceedings were also initiated in relation to breaches of functional unbundling requirements. Among other matters, the company was alleged to have failed to adopt appropriate measures to prevent confusion among the public as to the separate identity of the supply arm of the vertically integrated undertaking. Lastly, in 2025, proceedings initiated in 2024 against an operator providing natural gas distribution and metering services were concluded with the imposition of administrative fines totalling 390,625 euro, following findings of breaches of several provisions concerning tariffs and accounting unbundling.

3.1.2 Network extension and optimisation

Network extension

In Italy, **power transmission** is carried out through approximately 76,200 km of power lines and electrical circuits and 930 switching and conversion stations. The Electricity Transmission Grid Operator (TSO) is the company Terna. The 29.851% controlling interest in Terna is held by CDP Reti,

[9] With Resolution 296/2015/R/com of 22 June 2015, which superseded the prior Resolution No. 11 of 18 January 2007.

[10] By Resolution 188/2025/R/com of 30 April 2025.

[11] Annex A to Resolution 137/2016/R/com of 24 March 2016.

a subsidiary of Cassa Depositi e Prestiti.[12]. Apart from the State-held interest (through CDP Reti) and 0.2% of treasury shares, the remaining 69.9% of the share capital is held by the market, of which 58.2% is held by institutional investors. Among these, the only significant shareholder is [13]the US investment and asset management company BlackRock Inc., which holds a 5.014% interest.

In 2025, there were nine companies owning assets forming part of the National Transmission Grid (RTN), one more than in 2024, four of which belonged to the Terna group. In addition to Terna – Rete Elettrica Nazionale, the Terna group companies are Rete, Terna Crna Gora and the newly established Rete2, all wholly owned by Terna.

Rete is the company to which the infrastructure acquired from Ferrovie dello Stato Italiane was transferred. Rete2 was established in 2025 to facilitate the transfer to Terna of the high-voltage network located within the territory of Roma Capitale and owned by Areti, with the aim of rationalising the ownership and management of high-voltage network assets, in accordance with sector regulations and the efficiency objectives promoted by the Authority. In June 2025, Areti established Rete2 and transferred to it the business unit comprising the high-voltage network that it owned[14]. On the same date, Areti sold the entire share capital of Rete2 to Terna. Rete2 now owns the high-voltage assets previously owned by Areti and included in the RTN.[15].

There are also three merchant companies – Monita Interconnector, Piemonte Savoia (Pi.Sa.) and Resia Interconnector – established to develop and operate interconnection infrastructure under the regulatory framework laid down by Article 32 of Law No. 99/2009 That Law entrusted Terna with the task of selecting, through public tenders, companies willing to finance specific interconnections in return for the benefits arising from an exemption from third-party access in respect of the transmission capacity made available by the relevant infrastructure. The Law provides that, in return for being granted the exemption, these entities undertake to finance the interconnection infrastructure and grant Terna a mandate to construct and operate the interconnections. Under the legislative framework established by Law No. 99/2009, Terna therefore manages the operation and maintenance, both routine and extraordinary, of the Interconnectors that have been completed and entered into operation.

Lastly, companies active in electricity transmission but not belonging to the Terna group are Eneco Valcanale, which constructed a section of high-voltage line connecting to the Austrian national grid operated by APG (Austrian Power Grid), and Brulli Trasmissione Unipersonale, based in Reggio Emilia, which operates a 380 kV substation in Voghera (PV).

Monita Interconnector was established to construct the Italy-Montenegro interconnector, for which it now manages maintenance and operation. At the end of 2019, the Terna group transferred the

[12] The share capital of CDP Reti is owned 59.1% by Cassa Depositi e Prestiti, 35.0% by State Grid Europe Limited, a subsidiary of State Grid Corporation of China, and 5.9% by other Italian institutional investors.

[13] Significant shareholders are those whose interests in Terna's share capital exceed the relevant thresholds established by Consob Resolution No. 11971/1999 and Legislative Decree No. 58/1998, as subsequently amended and supplemented.

[14] The assets comprise 73 HV power lines, extending for a total of approximately 481 km, approximately 177 km of fibre-optic links installed alongside the power lines (equivalent to approximately 5,682 km of optical fibre overall), as well as three primary substations.

[15] By Decree No. 29 of the Ministry of the Environment and Energy Security of 28 January 2025, subsequently supplemented by Decree No. 137 of 30 May 2025.

company to private investors in return for an annual fee. Similarly, Piemonte Savoia (Pi.Sa.) holds the authorisation to construct and operate the merchant line forming part of the interconnector between Italy and France, which entered into operation in November 2022. Terna also transferred this company to private investors in 2017, in accordance with Law No. 99/2009. In December 2023, the alternate current interconnection with Austria developed by Resia Interconnector entered into operation. The project enabled Italy and Austria to increase electricity interconnection capacity by 300 MW, doubling the previous capacity. The assets owned by Monita Interconnector, Pi.Sa. and Resia Interconnector benefit from a ten-year exemption from third-party access from the date on which the merchant line enters into commercial operation. At the end of the exemption period, ownership of the portion of the network covered by the exemption and located in Italy must be transferred to Terna.

The Terna group therefore owns or operates almost all of the transmission infrastructure forming part of the RTN, comprising national power lines and substations.

Cross-border interconnection capacity and transmission capacity between the network's internal bidding zones are key indicators of electricity market integration and the energy transition. Since 2024, an output-based incentive mechanism has been in place to increase this capacity. The mechanism was updated in 2025 with new parameters and targets applying until 2027. Incentives apply both to increasing cross-border capacity and to increasing transmission capacity between zones within Italy. As at 31 December 2025, Terna had increased transmission capacity across several market zones, resulting in significant overall increases. With regard to cross-border interconnections, capacity into Italy across the northern borders with France, Switzerland and Austria increased by 60 MW, thanks to the 132/110 kV connection with the Austrian region of Tyrol through the Brenner Pass, from Prati di Vizze to Steinach.

As at 31 December 2024, 110 **electricity distribution** companies were registered in the Authority's Registry of Operators, four fewer than in 2024. Of these, only 11 serve more than 100,000 customers. Together, these companies serve 98.5% of all withdrawal points and distribute a similar share, 98.6%, of the electricity withdrawn from distribution networks. The remaining 99 distribution operators account for only 1.4% of all electricity withdrawn from distribution networks. Five companies have more than 500,000 withdrawal points: e-distribuzione (Enel group), Unareti (A2A group), Areti (Acea group), Ireti (Iren group) and the newly established Duereti.

At the end of 2024, Enel established Duereti, a company to which e-distribuzione transferred part of its distribution business in Lombardy: approximately 12,000 km of network and 800,000 withdrawal points in around 130 municipalities between Milan and Brescia. The transaction was aimed at rationalising the management of the distribution networks in Lombardy, through the transfer of the assets and customers to the A2A group. Duereti has been operational since 1 January 2025, with A2A holding 90% of its share capital and e-distribuzione retaining a 10% interest, governed by a shareholders' agreement providing for call and put options exercisable from the first anniversary of closing.

Overall, power distribution in Italy takes place through 1,294,500 km of networks, most of which (68.3%) are low voltage. In 2025, the length of electricity distribution networks decreased by approximately 3,300 km, comprising around 520 km of low-voltage networks and approximately 2,800 km of medium-voltage networks; high- and extra-high-voltage networks decreased by 20 km. e-distribuzione remains the leading operator, with a dominant 81.7% share of electricity distributed. It is followed by Unareti (A2A group), with 4.3% of volumes; Areti (Acea group), with 3.7%; Duereti (A2A group), with 3.1%; Ireti (Iren group), with 1.3%; V-Reti (Agsm Aim group), with 1.1%; and Edyna,

with 1%. All other distributors each account for less than 1% of the electricity distributed.

Incentives to build new transport capacity and promotion of investment cost efficiency

The "*Integrated Text on output-based regulation of the electricity transmission service for the 2024-2027 regulatory period" (ROTE)*[16] provided, for 2024, for an incentive mechanism for the development of additional transmission capacity up to target levels set by [17]the Authority in October 2021 for each section between network zones and for each border. The regulatory framework also provides for an additional bonus where such transmission capacity is delivered at investment costs below the reference costs established by the Authority.

In October 2025, bonuses were determined[18] for Terna for making the following increases in capacity available in 2024:

- 50 MW on the Calabria-to-Sicily section, through the adoption of capital-light solutions, involving an upgrade of the defence system through the adaptation of the UPDM equipment (peripheral defence and monitoring units) and the installation of additional PMUs (Phasor Measurement Units), with effect from 1 January 2024. Two bonuses were determined for these measures:
  - a bonus of €3.5 million for the delivery of additional transmission capacity;
  - a bonus of €3.5 million for investment cost efficiency, as the cost of the measures was below the reference costs established in the ROTE;
- 250 MW on the North-to-Central North section, and vice versa, as a result of the replacement of conductors on the 380 kV "Bargi-Calenzano" line and of the power-line carrier equipment on the 380 kV "Bargi-Martignone" line. Two bonuses were determined for these measures:
  - a bonus of €26.1 million for the delivery of additional transmission capacity, which, as a result of the multi-year caps on incentives, was set at €11.8 million;
  - a bonus of €5 million for investment cost efficiency, as the cost of the measures was below the reference costs established in the ROTE;
- 600 MW on the Central South-to-Central North section, and vice versa, as a result of the replacement of conductors along almost the entire length of the 220 kV "S. Barbara–Villavalle" line and along the entire length of the 220 kV "Candia-Villanova" line. The replacement of the 380/220 kV autotransformers at the Candia and Villanova substations also made a significant contribution to the increase in transfer capacity. Two bonuses were determined for these measures:
  - a bonus of €51.4 million for the delivery of additional transmission capacity, which, as a result of the applicable caps, was set at €23.1 million;
  - a bonus of €46.6 million for investment cost efficiency, as the cost of the measures was below the reference costs established in the ROTE.

[16] Annex A to resolution 55/2024/R/eel of 27 February 2024.

[17] Resolution of 26 October 2021, 446/2021/R/eel.

[18] Resolution of 7 October 2025, 440/2025/R/eel.

Incentive linked to the benefits of distribution network interventions

The Authority introduced into the Integrated Text on Distribution Quality (TIQD) an incentive mechanism linked to the benefits generated by interventions on electricity distribution networks. These provisions apply to distribution companies with at least 100,000 final customers and provide for incentives linked to the benefits associated with the relevant interventions, equal to two years of expected gross benefits, subject to a cap on the bonuses for each intervention based on the investment cost.

In their applications, distribution companies carry out cost-benefit analyses for each proposed intervention, covering both the benefits taken into account for the purposes of any incentives and those considered solely for determining eligibility for the incentive mechanism on the basis of the intervention's benefit-to-cost ratio.

Following the applications submitted by distribution companies for the first phase of application of the incentive mechanism to development interventions whose implementation commenced from 2024 onwards, the Authority:

- in April 2025, admitted[19] to the incentive mechanism seven interventions proposed by Unareti and commissioned by the end of 2024. These consisted mainly of the renewal of medium-voltage (MV) networks and the replacement of certain HV/MV transformers, involving investment of more than €5 million and generating benefits of €8 million over the subsequent 25 years;
- in the same month, did not admit [20]the intervention proposed by Ireti to the incentive mechanism, as the present value of the benefits did not exceed the present value of the costs;
- in July 2025, did not admit [21]the two interventions proposed by V-Reti to the incentive mechanism, as the present value of the benefits did not exceed the present value of the costs.

Investment in new transmission infrastructures

Preliminary scenarios supporting energy network development plans

In October 2024, following consultation, the Authority updated [22]the criteria for developing the scenarios underpinning the preparation of energy network development plans, establishing the following:

- every two years, Snam and Terna must collaboratively prepare the scenario description document for the transmission and transport development plans: for the 2025 plans, the deadline is 10 October 2024; for subsequent even-numbered years, the deadline is 31 July if the corresponding ENTSO-E and ENTSO-G scenarios are available by 31 March of that year, or 30 September if they are not;

[19] Resolution of 30 April 2025, 186/2025/R/eel.

[20] Resolution of 30 April 2025, 189/2025/R/eel.

[21] Resolution of 8 July 2025, 322/2025/R/eel.

[22] Resolution of 1 October 2024, 392/2024/R/com

- the scenario description document should set out the methodology applied in its preparation, addressing at least three study years with approximate timeframes of "n+5", "n+10", and "n+15" (where n denotes the year of the development plan), and consider differentiated scenarios over longer-term horizons, reflecting contrasting assumptions on macroeconomic context, commodity prices, and technological progress, and explicitly identifying a slow economy scenario;
- the scenario description document should contain dedicated sections, including an evaluation of any discrepancies relative to the information and assumptions established in the latest PNIEC edition or update, as well as an analysis of alignment with the scenarios developed for the ENTSO-E and ENTSO-G TYNDPs, explaining any use of alternative approaches or assumptions;
- Snam and Terna are to make public information available in a timely manner well in advance of the 2026 scenario description document and thereafter carry out one or more consultations with current and potential energy system users. In addition, by 30 September 2025, they must convene a public discussion on the long-term development of the Italian energy sector up to 2050, supplying, before the session, one or more technical briefs outlining plausible system development scenarios, backed by quantitative analysis and national-scale data.

Assessment of the 2023 Ten-Year Development Plan for the National Electricity Transmission Grid

Every two years, Terna prepares a ten-year transmission network development plan; the Authority assesses the development plan with a view to its subsequent approval by the Minister of the Environment and Energy Security.

In January 2025, the Authority issued its assessment[23] of the draft 2023 Transmission Network Development Plan. Specifically, the Authority:

- granted clearance for approval of the 2023 Plan by the Minister of the Environment and Energy Security, with the exception of the following projects and interventions, which are to be classified as "under assessment", meaning that no implementation activities may be carried out within the Plan's ten-year horizon:
  - the high-voltage direct current (HVDC) interconnection project between Italy and Slovenia, forming part of the broader intervention coded 200-I, without imposing any restrictions on the other project forming part of the same intervention, "Removal of constraints on the 380 kV and 220 kV grid interconnected with Slovenia";
  - intervention 354-P, Giglio Island interconnection;
  - intervention 630-P, Favignana Island interconnection;
- granted clearance for approval of the 2023 Plan by the Minister of the Environment and Energy Security subject to the further conditions that:
  - the "Milan-Montalto HVDC", "Adriatic Backbone (Foggia-Villanova-Fano-Forlì HVDC)", "Ionian-Tyrrhenian Backbone (Priolo-Rossano-Montecorvino-Latina HVDC)" and "Sardinian Backbone (Fiumesanto-Montalto HVDC and Sardinian Link)" interventions, for which Terna requested specific recognition of expenditure incurred prior to implementation (the so-called two-stage approval process), are not approved;

[23] Opinion 4/2025/I/eel of 14 January 2025.

- the favourable opinion on the Italy-Tunisia interconnection project, code 601-I, is subject to the provisions and limits on the inclusion of costs in tariffs established by the Authority in May 2020[24];
- the favourable opinion on the "SA.CO.I. 3 Sardinia-Corsica-Continental Italy" intervention, code 301-P, is subject to the provisions and limits on the inclusion of costs in tariffs established by the Authority in October 2024[25];
- the project for the new Italy-Greece HVDC interconnector (GRITA2), code 554-P, is to be subject to further assessment on the basis of updated scenarios for the development of the European energy system, which will be available for the 2025 Development Plan;
- the project for the second pole of the Italy-Montenegro HVDC interconnection, code 401-S, is to be subject to further assessment and analysis in order to determine the optimal timing for construction of the second pole;

- With regard to a new interconnection between Italy and Greece, the Authority:
  - required Terna to submit to the Authority, by 15 March 2025, a comparative study, including cost-benefit analyses, of the different options for developing the new interconnection in terms of location, technology and transmission capacity. The study must also take account of any interdependencies with the existing Galatina-Arachtos HVDC interconnection, including an assessment of alternative options for extending its technical life, and with the second pole of the interconnection with Montenegro;
  - provided that any application for authorisation to recognise preliminary expenditure on the new Italy-Greece interconnection for the purposes of accelerating the investment[26], submitted either together with or after the study, is to be deemed approved under the tacit consent procedure if, within 30 days of submission of the application, neither the Authority nor its offices requests further information or takes any other action.

Assessment of the 2025 Ten-Year Development Plan for the National Electricity Transmission Grid

In August 2025, the Authority issued[27] its assessment of the draft 2025 Transmission Network Development Plan. In particular, the Authority:

- issued a favourable assessment of the "Italy-Montenegro HVDC Interconnection" project, which had been subject to further analysis in the previous opinion;
- provided that the "Milan-Montalto HVDC" project, code 355-P, the "Foggia-Forlì HVDC Adriatic Backbone", code 447-P, the "Sardinian Link" project forming part of intervention 732-P, and the "new Italy-Greece HVDC" interconnection, code 554-P, for which recognition of preliminary expenditure prior to implementation is envisaged under the so-called two-stage approval process, are not to be approved;
- noted that no implementation activities are planned within the Plan's ten-year horizon for the

[24] Resolution 176/2020/R/eel of 21 May 2020.

[25] Resolution of 17 October 2024, 416/2024/R/eel.

[26] Investment acceleration mechanism governed by Resolution 562/2024/R/eel of 17 December 2024 and Article 47 of the Output-Based Regulation of the Transmission Service (ROTE).

[27] Opinion of 5 August 2025, 391/2025/I/eel.

following interventions:

- the Italy-Slovenia HVDC interconnection project forming part of the broader intervention coded 200-I;
- intervention 354-S, Giglio Island interconnection, under assessment;
- intervention 630-S, Favignana Island interconnection, under assessment;
- intervention 160-S, new 132 kV "Nava-S. Dalmas" interconnection, under assessment;
- intervention 1-I, "Increase in interconnection capacity with Switzerland pursuant to Law No. 99/2009";
- intervention 167-P, "Valchiavenna Rationalisation";
- intervention 205-S, 380 kV Italy-Slovenia interconnection power line, under assessment;
- intervention 206-S, 380 kV Veneto cross-regional power line, under assessment;
- interventions 563/1-P and 563/2-P, "Ionian-Tyrrhenian Backbone (Priolo-Rossano-Montecorvino-Latina HVDC)";
- the Fiumesanto-Montalto HVDC project forming part of intervention 732-P;

- granted clearance for approval of the draft 2025 Plan by the Minister of the Environment and Energy Security subject to the further condition that:
  - the assessment of the Italy-Tunisia interconnection project, code 601-I, is subject to the provisions and limits governing the inclusion of costs in tariffs established by the Authority in May 2020[28];
  - the assessment of the "SA.CO.I. 3 Sardinia-Corsica-Continental Italy" project, code 301-P, is subject to the provisions and limits governing the inclusion of costs in tariffs established by the Authority in October 2024[29];
- with regard to future development plans, following the consistency checks carried out pursuant to Article 36(14-bis) of Legislative Decree No. 93 of 1 June 2011, Terna was requested to:
  - assign high priority, insofar as feasible in view of recurring authorisation complexities, to interconnection projects with France, Switzerland and Austria, given the benefits of developing additional transmission capacity across those borders;
  - clearly identify the planned activities, including their locations and technical characteristics, for intervention 1-I, "Increase in interconnection capacity with Switzerland pursuant to Law No. 99/2009", and for the projects under study, "Italy-Switzerland-Germany North-South Corridor" and "Brenner Base Tunnel".

Distribution network development plans

In June 2023, the Authority established[30] the procedures and timetable for preparing electricity

[28] Resolution 176/2020/R/eel.

[29] Resolution 416/2024/R/eel.

[30] Resolution of 28 June 2023, 296/2023/R/eel.

distribution network development plans. The plans are submitted to public consultation and subsequently presented to the Authority, where appropriate in updated form, together with the comments received, the distribution companies' responses to those comments and details of the amendments made.

During 2025, the largest distribution companies submitted the pre-consultation drafts of their development plans by 31 March 2025 and the post-consultation versions by 30 June, with the exception of Duereti, for which a [31] derogation was granted in March 2025. The Authority published two notices to operators, on 18 April 2025 and 9 May 2025, providing web links to the development plans and specifying the deadlines for submitting any comments.

The final versions of the distribution network development plans were subsequently published on the dedicated page of the Authority's website on distribution network development (https://www.arera.it/operatore-elettricita/sviluppo-reti-di-distribuzione-elettrica).

In March 2025, following discussions with the distribution companies, the "Document describing the calculation of the benefits of electricity distribution network development interventions" was approved[32]. The document sets out in detail the methodology for calculating the benefits defined in the provisions adopted in June 2025.[33].

Investment plans for the modernisation of metering systems – 2G smart metering

Legislative Decree No. 210 of 8 November 2021, implementing Directive 2019/944/EU of the European Parliament and Council of 5 June 2019, sets out provisions regarding smart metering systems, assigning the Authority the task of preparing and publishing a ten-year schedule for the implementation, replacement, and upgrading of smart metering systems from the date the decree enters into force. The installations should guarantee that 80% of end users have smart meters in place by 31 December 2024.

For larger companies (with more than 100,000 withdrawal points), the regulatory framework for the recognition of costs and determination of penalties associated with the roll-out of 2G smart metering systems, introduced[34] in December 2022 for the 2023-2025 three-year period, continued to apply.

Within this framework, in June 2025 the Authority imposed[35] a penalty of €107,954 on the distribution company Ireti for failing to achieve the minimum cumulative number of 2G meters required by 2023 under the roll-out plan (PMS2) approved by the Authority. For the purposes of this assessment, 2022 was excluded in view of the effects of the COVID-19 pandemic and the semiconductor shortage.

During 2025, an updated timetable for the roll-out of 2G smart metering systems was published on the Authority's website (https://www.arera.it/area-operatori/smartmetering). For the largest distribution companies, which serve more than 98% of Italian users, the timetable covers planned installations up to 2031 and actual installations up to 2023. For distribution companies with up to

[31] Resolution 112/2025/R/eel of 25 March 2025.

[32] Resolution 112/2025/R/eel of 25 March 2025.

[33] Resolution 296/2023/R/eel.

[34] Resolution of 27 December 2022, 724/2022/R/eel.

[35] Resolution 231/2025/R/eel of 3 June 2025.

100,000 withdrawal points, it sets out the timetable for completion of the installation plan, which for these companies is scheduled by the end of 2025. Based on estimates provided by the main distribution companies, approximately 39.7 million meters are expected to be commissioned by the end of 2025.

As regards distribution companies with up to 100,000 withdrawal points, in March 2025 the Authority formally required[36] them, by no later than 31 July 2025, to comply with the obligation to notify the planned starting and completion six-month periods for the mass roll-out phase of 2G smart metering systems and to publish their detailed plan for the mass roll-out phase covering the July-December 2025 six-month period, as required by the provisions adopted in [37]March 2021, or, alternatively, to notify the Authority that they had ceased electricity distribution activities.

In December 2025, the Authority confirmed [38]that the existing regulatory provisions on 2G smart metering would remain in force for the 2026-2028 three-year period, as no significant issues had emerged and with a view to ensuring continuity and simplicity.

3.1.3 Tariffs for connection and network access

Tariffs for the electricity transmission service

In December 2023, the Authority approved [39]the tariff regulation for the electricity transmission service for the sixth regulatory period (RTTE 6PRTE – 2024-2027), effective from 1 January 2024.

In December 2025, in accordance with the provisions of the RTTE 6PRTE, the Authority determined [40]the reference revenues for cost recovery for the transmission service and for Terna's operation of the dispatching service, as well as the transmission tariffs for 2026.

Tariffs for electricity distribution and metering services

In line with previous years, a decoupling is planned between the single tariff applied to end customers (the mandatory tariff) and the reference tariffs set to establish revenue limits for each distribution company. For companies serving at least 25,000 withdrawal points and subject to the ROSS tariff regime[41], provisional reference tariffs for 2025 were set in May 2025. At the same time, the 2025 z-factor parameters were also approved ex ante for companies that had submitted a specific application, in order to capture increases in 2025 operating costs arising from investment in the energy transition or changes in the scope of activities. For companies serving fewer than 25,000 withdrawal points and subject to the parametric tariff regime, reference tariffs for distribution and

[36] Resolution 89/2025/R/eel of 11 March 2025.

[37] Article 4 of Annex A to Resolution 106/2021/R/eel of 16 March 2021.

[38] Resolution 575/2025/R/eel of 23 December 2025.

[39] Resolution 615/2023/R/eel of 27 December 2023.

[40] Resolution 573/2025/R/eel of 23 December 2025.

[41] Resolution 217/2025/R/eel of 27 May 2025.

metering services for the years 2019 to 2025 were determined [42]during 2025.

In October 2025, the Authority launched a public consultation [43]on its proposed revision of the parametric criteria for recognising the costs associated with electricity distribution and metering services for distribution companies serving fewer than 25,000 withdrawal points.

Lastly, in December 2025, the [44]tariffs for the use of infrastructure for electricity distribution and metering services applicable to household and non-household customers, as well as the economic terms for the provision of connection services, were updated for 2026. At the same time, the deadline for completion of the proceeding to revise the parametric cost recognition criteria for distribution companies serving fewer than 25,000 withdrawal points was postponed to 30 April 2026, in order to carry out further quantitative analysis to assess certain comments received during the October 2025 consultation.

Table 3.1 shows the breakdown of revenues generated by the network charges applied to users in 2025, distinguishing between customer types – household customers and the various contractual categories of non-household customers – for transmission, distribution and metering services.

Table 3.1 Allocation of revenues from network charges in force in 2025

TYPES	TRANSMISSION	DISTRIBUTION	METERING	UC3 and UC6	TOTAL NETWORK SERVICES					
	€ million	€ million	€ million	€ million	€ million	%	% PER WITHDRAWAL POINT	% PER kW	% PER kWh	TOT
Total households	681	2,653	577	113	4,024	42.7%	17.2%	63.6%	19.2%	100%
LV and MV public lighting customers	43	52	3	6	105	1.1%	0.0%	0.0%	100.0 %	100%
LV non-household customers(A)	769	1,934	146	117	2,966	31.5%	6.6%	62.1%	31.3%	100%
MV customers(A)	987	913	27	66	1,992	21.2%	4.4%	40.8%	54.8%	100%
HV and EHV customers(B)	286	31	1	11	329	3.5%	7.6%	79.2%	13.2%	100%
Total non-households	2,085	2,929	177	200	5,391	57.3%	5.7%	54.1%	40.2%	100%
TOTAL	2,766	5,582	755	313	9,416	100%	10.6%	58.2%	31.2%	100%

(A) Public lighting excluded.

(B) Including electricity consumption for rail traction.

Source: ARERA.

[42] Resolutions 37/2025/R/eel of 11 February 2025; 295/2025/R/eel of 1 July 2025; 368/2025/R/eel of 29 July 2025; and 513/2025/R/eel of 25 November 2025.

[43] Consultation Document 447/2025/R/eel of 14 October 2025, as part of the proceeding initiated by Resolution 89/2024/R/eel of 19 March 2024.

[44] Resolution 575/2025/R/eel of 23 December 2025.

General system charges for the electricity sector

The general system charges were updated quarterly during 2025[45].

Table 3.2 shows the breakdown of revenues from general system charges among the various components, confirming the significant contribution of the A_3*SOS component.

Table 3.3 shows, for 2025, the average unit value (in euro/MWh) of the A_{SOS} and A_{RIM} components paid by each customer category.

Table 3.2 Revenues from general system charges accruing in 2025, by component and related elements (in € millions)

RATE	DESCRIPTION	ANNUAL CHARGE FROM USERS	FROM DECREE-LAW 19/25
A_{SOS}	Charges related to the support of energy from renewable energy resources and CIP 6/92 cogeneration	8,649.21	1,585.00
*A3*SOS* (A)	Support for renewable energy resources and CIP 6/92 cogeneration	7,163.22	1,585.00
A_{ESOS}	Charges resulting from breaks for energy-intensive companies	1,560.06	-
$A_{91/14SOS}$ (B)	Discounts/reductions provided for by Decree-Law No. 91 of 24 June 2014	-74.08	-
***A*_RIM** (C)(D)	**Other general system costs**	**2,473.27**	**-**
A4RIM	Special rail tariff schemes	1,266.29	-
A5RIM	Research financing	52.92	-
A_{SRIM}	Social bonus	815.28	1,200.00
Auc4RIM	Minor electricity companies	63.27	-
Auc7RIM	Energy efficiency in end use	226.43	-
A_{SVRIM}	Technological development	49.06	-
TOTAL		11,122.47	4,380.00

(A) Including discounts to energy-intensive companies.
(B) The A91/14SOS element is negative because it represents discounts granted to LV and MV users that are not classified as energy-intensive companies.
(C) With effect from 1 January 2023, the A2RIM and AmctRIM elements of the ARIM tariff component were abolished, as, from 2023 onwards, "nuclear costs" have been funded through general taxation pursuant to the 2023 Budget Law.
(D) With effect from 1 January 2024, the A3RIM element of the ARIM tariff component was abolished, as no further costs are expected in relation to plants fuelled by non-biodegradable waste.

Source: ARERA, based on data from CSEA (Energy and Environmental Services Fund).

[45] Resolutions 599/2024/R/com, 131/2025/R/com, 281/2025/R/com and 429/2025/R/com.

Table 3.3 Average unit value of the A_{SOS} and A_{RIM} components paid by each customer category in 2025

CUSTOMERS	WITHDRAWN ENERGY TWh	A_{SOS}		A_{RIM}	
		€ million	€/MWh	€ million	€/MWh
HOUSEHOLDS					
Residential	49.84	1,479.10	29.68	49.84	1.86
Non-residential	7.54	796.33	105.55	7.54	1.86
TOTAL HOUSEHOLDS	57.38	2,275.43	39.65	106.82	1.86
NON-HOUSEHOLDS					
Public lighting customers (medium and low voltage)	3.43	165.75	48.30	3.43	3.21
Charging points for electric vehicles	0.14	9.54	67.39	1.19	8.39
Non-household low-voltage customers not classified as energy-intensive (excluding public lighting)	64.54	2,597.16	40.24	329.20	5.08
Low-voltage non-household energy-intensive customers	0.32	1.36	4.22		
Medium-voltage non-energy-intensive customers (excluding public lighting)	58.02	2,673.84	46.08	223.98	2.51
Energy-intensive medium-voltage customers (A)	31.13	170.05	5.46		
High and extra-high voltage non–energy-intensive customers (including railway traction consumption)	5.62	52.46	9.34	30.18	0.88
High and extra-high voltage energy-intensive customers(A)	28.69	61.83	2.15		
TOTAL NON-HOUSEHOLDS	191.90	5,731.99	29.87	595.57	3.10
TOTAL	249.28	8,007.42	32.12	702.39	2.82

(A) The contribution from energy-intensive companies classified under VAL was allocated between medium voltage and high/extra-high voltage based on the underlying volumes.

Source: ARERA.

Charges for Supporting Renewable Energy (account A_{SOS})

The charges allocated to the account funded through the A_{SOS} component accruing in 2025 were approximately 1.7 billion euro higher than those for 2024, as shown in Table 3.4. This increase is attributable to the full implementation of certain incentive mechanisms (biogas, biomass and bioliquid production) and the Energy Release mechanism[46].

For the entire year 2025, the costs of the A_{SOS} account were covered by the fees charged to electricity consumers.

[46] The Energy Release is a mechanism designed to promote the installation of new renewable electricity generation capacity by energy-intensive final customers.

Table 3.4 Breakdown of charges for supporting renewable energy under the A_{SOS} account

CHARGES FOR THE PERIOD	2024		2025	
	AMOUNT (€M)	SHARE %	AMOUNT (€M)	SHARE %
Trade of renewable electricity under CIP 6	-	-	-	-
Redemption of green certificates	4	0.04%	2	0.02%
Conversion of green certificates into incentives	627	6.78%	562	5.14%
Photovoltaic	5,590	60.48%	5,763	52.69%
Buy-back mechanism	103	1.12%	166	1.52%
All-inclusive feed in tariff	1,178	12.74%	977	8.93%
Economic net metering	265	2.87%	354	3.24%
Regulated renewable energy incentives	320	3.47%	253	2.32%
Self-consumption and energy communities	1	0.01%	5	0.05%
Energy release	-	0.00%	1,143	10.45%
PMG Bio-gas and Biomass - Resolution 305/2024	425	4.60%	480	4.38%
PMG Bio-liquids – Resolution 306/2024	753	8.14%	1,232	11.25%
Other	-22	-0.25%	1	0.01%
TOTAL RENEWABLES	9,244	100.00%	10,938	100.00%
CIP 6-equivalent electricity trading	-	-	-	-
CO_2 -related charges	-	-	-	-
Green certificate-related coverage	-	-	-	-
CIP 6 Resolution	-	-	-	-
TOTAL EQUIVALENT CHARGES	-	-	-	-
TOTAL Asos CHARGES	9,244	100.00%	10,938	100.00%

Source: ARERA.

Nuclear system charges

The 2023 Budget Law provided that[47], from 2023, nuclear costs would no longer be borne by electricity customers but would instead be funded directly from the State budget.

This is the transfer to general taxation (so-called taxation) of nuclear liabilities, i.e. the costs of decommissioning and territorial compensation for local authorities hosting nuclear sites are to be borne by the state as of 1 January 2023. Until the end of 2022, these charges were borne by the electricity user and financed by the A_{2RIM} and A_{mctRIM} elements of the A_{RIM} tariff component, respectively. Consequently, the Authority removed[48] these elements from the A_{RIM} tariff component with effect from 1 January 2023. This provision constitutes a structural measure that also applies in the years following 2023.

3.1.4 Regulation of network security and reliability

Dispatching service: a changing operating environment

The electricity system is undergoing a profound transformation, with an increasing penetration of

[47] Article 1, paragraphs 20, 21 and 22 of Law No. 197 of 29 December 2022.

[48] Resolution 735/2022/R/com.

distributed, small-scale resources – driven by European decarbonisation targets, which are promoting renewable generation and greater uptake of self-consumption – at the expense of large-scale, centralised resources. This entails both greater reserve requirements to compensate for the volatility of production from random sources (such as wind, solar and run-of-river hydro) and the need to enable more resources (such as loads, diffuse storage devices such as batteries, small generation plants) to provide ancillary services to cope with the reduction of the large plants that had been providing these services to date.

In this new context, the function of distribution networks also changes, as they become "active", i.e. capable not only of absorbing energy from the transmission network, but also of delivering energy in the opposite direction to the usual one (referred to as "flow inversion", a reality that is already concrete in some areas of the country characterised by a significant penetration of distributed generation). Furthermore, under certain network configurations, distribution networks may experience new phenomena, such as sudden voltage fluctuations or overloads, which need to be addressed locally. Accordingly, it is no longer only Terna that requires global ancillary services to ensure the secure operation of electricity networks: distribution companies must also be able to procure specific local services from distributed resources connected to their networks.

In other words, as distributed and variable renewable energy sources replace conventional, centralised and dispatchable generation, network regulation and control requirements change significantly, both quantitatively – more services are required, meaning that all resources must or can contribute – and qualitatively, as the services themselves increasingly become distributed and local in nature.

The dispatching regulatory framework must reflect this new environment. The rules developed when the electricity market was launched in 2004, based on the assumption of centralised dispatchable resources, are no longer able to accommodate the changes under way. The Italian Regulatory Authority for Energy, Networks and Environment has therefore been addressing this challenge for several years, having already launched a specific proceeding[49] in July 2015 covering both global and local ancillary services, with the aim of establishing a dispatching regulatory framework suited to the evolving electricity system.

Dispatching service: global ancillary services

For global ancillary services – i.e. those required by Terna to ensure the secure operation of the National Transmission Grid (RTN) and the electricity system as a whole – a key milestone was the adoption, in July 2023, of the Dispatching Integrated Text (TIDE). Drawing on several years of experience gained through the pilot projects introduced[50] in 2017 and in line with the European regulatory framework, the TIDE established a dispatching model under which all network resources can, at least in principle, perform a dual role: a "primary" role of generating or consuming electricity and an "ancillary" role of providing services to the grid, consisting in their availability to modify their injection and withdrawal profiles.

The new Integrated Text, in particular:

- defines the roles and tasks of the Balancing Service Provider (BSP), responsible for the provision

[49] Resolution of 30 July 2015, 393/2015/R/eel.

[50] Resolution 300/2017/R/eel of 5 May 2017.

of ancillary services, and of the Balance Responsible Party (BRP), responsible for the scheduling of units, both production and consumption, and for the regulation of imbalances; the roles may be entrusted to the same entity or to different entities, according to the free choice adopted by the owner of each resource;

- promotes competition among all units in the provision of global ancillary services based on the principle of technological neutrality: all resources that meet Terna's technical requirements for a given service may go towards providing it;
- separates the unit scheduling phase from the trading phase in the day-ahead and intraday energy markets, an arrangement initially tested in 2021 through the partial coupling of intraday markets limited to XBID transactions. Within TIDE, this separation is comprehensively implemented: unit scheduling is decoupled from traded quantities, thereby enhancing alignment with technical operating requirements. The sole condition is that, at the zonal level, the aggregate scheduled injections and withdrawals of a BRP's units must be no less than the volumes transacted in the markets. Thus, the framework maximises scheduling flexibility whilst maintaining conformity with market trading constraints
- rationalises, in accordance with the European regulatory framework established by the Clean Energy Package and the central dispatch rules under Regulation (EU) 2195/2017, the purposes of the dispatching market, transforming it into a balancing and redispatch market, in which the nodal Integrated Scheduling Process coexists with Terna's participation in the European platforms for trading balancing products;
- differentiates services according to the delivery perimeters, either nodal (coinciding with a node or an aggregate of neighbouring nodes) or zonal (coinciding with a market area), aligning them with the nomenclature of European regulations and grouping within the extraordinary modulation service all services of an emergency nature required by Terna outside the market for dispatching service, such as load interruptibility, remote disconnection of renewable generation, and the implementation of procedures for the reduction of distributed generation (RIGEDI);
- redefines the qualification criteria for resources providing global ancillary services, whether individually as a Single Qualified Unit (*Unità abilitata singolarmente* – UAS) or aggregated with other units at nodal level as a Nodal Qualified Virtual Unit (*Unità virtuale abilitata nodale* – UVAN) or at zonal level as a Zonal Qualified Virtual Unit (*Unità virtuale abilitata zonale* – UVAZ), also enabling smaller aggregations to qualify and offer services;
- redefines, in line with the previously mentioned eligibility criteria, the relevant aggregates for unit scheduling and imbalance management: single enabled units (UAS for injection and withdrawal) remain, while nodal virtual units (UVN) for injection and withdrawal are introduced as subsets of UVAN, distinguished by BRP, by injection or withdrawal, and by production unit type. Terna also specifies non-enabled units to be scheduled (UnAP), for which having an explicit programme is helpful for secure system operation. All other units within a BRP's scope are grouped as zonal virtual units (UVZ), categorised by injection/withdrawal and production type;
- revises the dispatching service settlement, introducing non-movement charges, functionally comparable to imbalance costs but attributed to the BSP, together with compensation mechanisms between BSPs and BRPs for activations mandated by Terna on the balancing and redispatching markets, and compensation arrangements for BRPs in respect of activations under the extraordinary modulation service;
- streamlines the dispatching charge by separating out from the uplift charge all financial transactions – the transmission capacity charges (CCT), the transmission capacity charges coverage component (FTR), proceeds from cross-border interconnection auctions and adjustments relating to corrections – that are not directly related to the procurement of global ancillary services.

Furthermore, the TIDE also streamlines the provisions governing the organisation of the day-ahead and intraday electricity markets, which had become layered over time due to rulings by regulatory bodies and ACER, in accordance with Regulation (EU) 1222/2015 on Capacity Allocation and Congestion Management (CACM). The result is a single document encompassing all rules governing electricity markets, regardless of whether they originate from ACER or from decisions made by national regulatory authorities, including aspects such as product selection, bidding procedures, and the specific responsibilities of GME and Terna.

Finally, the TIDE sets out the criteria for developing network models and the algorithms used to determine the optimal dispatching solution. Significant advancements have also been made in transparency: Terna will be obliged to disclose both the network model employed for dispatching optimisation - comprising nodes, transmission lines, resistances, reactances, and ground susceptances - and granular operational data, including line and plant availability, projected ancillary service requirements, and anticipated injections and withdrawals at each node.

The TIDE was set to come into effect on 1 January 2025, eighteen months after its publication, in order to enable Terna and GME to revise the Transmission, Dispatching, Network Development and Security Code (Network Code), the Integrated Electricity Market Code (TIDME), and the Energy Accounts Platform Regulation (PCE Regulation), as well as to allow other interested parties to carry out the organisational adjustments necessitated by the new regulatory system.

However, during 2024, regulatory changes occurred which led the Authority to update the TIDE even before it came into effect: in particular, in July 2024, the[51] Version 2 of the TIDE containing the procedures for exceeding the Single National Price (PUN) from 1 January 2025 in accordance with the provisions of the ministerial decree of 18 April 2024. In particular, the following measures have been introduced:

- the transition to a valuation of day-ahead market purchases based on zonal pricing, replacing the PUN, alongside the introduction by GME of a market index (PUN Index) calculated ex-post using the same methodology as the PUN;
- pursuant to the Ministerial Decree of 18 April 2024, the compensatory mechanism, defined as the differential between the PUN Index and zonal prices, will be directly applied to purchases in the day-ahead market. In this way, the regulatory framework concerning transport capacity allocation charges and non-arbitrage mechanisms is preserved.

In July 2024, the Authority, taking into account the complexity of the matter, also deemed it appropriate to articulate[52] the implementation of TIDE in three distinct phases:

- a transitional phase, from 1 January 2025 to 31 January 2026;
- a consolidation phase, from 1 February 2026;
- and a full implementation phase, from a date to be determined by Terna, when all the provisions of the TIDE will be implemented.

During 2025, the transitional phase was therefore implemented and was characterised by:

- the transition from hourly to 15-minute imbalance settlement periods (as required by Regulation (EU) 2017/2195 from 1 January 2025);
- the launch of the nomination platform operated by GME;

[51] Resolution 304/2024/R/eel of 23 July 2024.

[52] Resolution 304/2024/R/eel of 23 July 2024.

- and the discontinuation of the single national price (PUN), with the transition to zonal pricing also on the demand side and the application to all withdrawals of an ex-post compensation component calculated by reference to a specific index (PUN Index), calculated by GME as the weighted average of zonal prices based on purchases in each bidding zone. The relevant documentation for this phase (TIDME and Terna's Network Code) was finalised during 2024.

In preparation for the launch of the TIDE consolidation phase on 1 February 2026 – involving the separation of the roles of BSP and BRP, the introduction of UVANs and UnAPs and the launch of market-based auctions for the procurement of Frequency Containment Reserve (FCR) – during 2025 the Authority considered it appropriate to make further updates to the TIDE, particularly with regard to the arrangements for conducting FCR procurement auctions. The new version of the TIDE (Version 4) was approved[53] in June 2025 and introduced the following changes:

- the requirement for forward procurement of FCR ahead of the day-ahead market was removed, with the definition of procurement timelines left to Terna under the Network Code;
- specific arrangements were adopted for participation in the Balancing and Redispatching Market (MBR) by generation facilities benefiting from the FER X support mechanisms;
- with effect from the consolidation phase, provisions governing remuneration for foregone generation following activation of the downward emergency modulation service were incorporated into the TIDE, thereby ensuring continuity with the provisions adopted in [54]March 2025, which had extended the arrangements for foregone generation to all non-dispatchable renewable energy sources until the end of the TIDE transitional phase.

The approval of the above-mentioned Version 4 of the TIDE did not, however, mark the end of the Authority's activities relating to the TIDE. During 2025, measures were adopted whereby the regulatory compliance of the following elements was successfully verified:

- Annexes A.7 and A.73 to Terna's Network Code concerning the remuneration of energy supplied as FCR, amended to take account of the possibility for UVANs and UVAZs to provide this service[55];
- the new Annex A.81 to Terna's Network Code concerning the technical requirements for the provision of balancing ancillary services and for redispatching by UVANs and UVAZs, applicable from the start of the TIDE consolidation phase[56];
- Annex A.61 to Terna's Network Code concerning the guarantee rules, amended with effect from the start of the TIDE consolidation phase to take account of the separation of the roles of BSP and BRP[57];
- Annex A.26 to Terna's Network Code concerning contracts for the dispatching service and the provision of global ancillary services, amended with effect from the start of the TIDE consolidation phase to reflect the separation of the roles of BSP and BRP[58];
- amendments to Terna's Network Code necessary for the implementation of the TIDE consolidation phase and for reconnection to the PICASSO platform for the exchange of balancing

[53] Resolution 227/2025/R/eel of 3 June 2025.

[54] Resolution 128/2025/R/efr of 27 March 2025.

[55] Resolution 166/2025/R/eel of 15 April 2025.

[56] Resolution 242/2025/R/eel of 10 June 2025.

[57] Resolution of 8 July 2025, 314/2025/R/eel.

[58] Resolution of 8 July 2025, 315/2025/R/eel.

energy resulting from the activation of automatic Frequency Restoration Reserve (aFRR)[59];

- the new Annex A.83 to Terna's Network Code concerning the timing and procedures for the forward procurement of FCR, providing for a single auction to be held after the first intra-day market auction and before the deadline for submitting bids for the dispatching service market (MSD) phase of the MBR[60];
- amendments to Terna's Network Code concerning the arrangements for the participation of UVAZs in the balancing market (pending Italy's connection to the MARI platform for the exchange of balancing energy resulting from the activation of manual Frequency Restoration Reserve – mFRR) and updates to certain MBR operating timelines to reflect the shift in intra-day market gate closure to 30 minutes before real time[61].

Dispatching service: interruptibility service

Historically, the interruptibility service was regulated by the Authority under the mandate conferred by Article 30(18) of Law No. 99 of 23 July 2009, providing for three-year, annual, quarterly, monthly and multi-month forward procurement procedures, with a premium in euro/MW/year determined through an auction conducted in accordance with the specific guidelines issued by the Ministry. Participation was restricted to final customers willing to have their load instantaneously interrupted at Terna's request.

Article 21(1) of Decree-Law No. 69 of 13 June 2023 amended Article 30(18) of Decree Law No. 99/09, mandating the Authority to establish the criteria and procedures for procuring the interruptibility service on the basis of the technical criteria defined by Terna, while also allowing storage systems to participate.

The Authority implemented these provisions starting with the procurement procedures for 2024. In November 2023, it was established that [62]the service would be procured through annual, quarterly or monthly forward procurement procedures (with three-year auctions no longer envisaged), using auction reserve prices similar to those applied until 2023 (105,000 euro/MW/year for resources located on the Italian mainland and 126,000 euro/MW/year for resources located in Sicily and Sardinia). The service was also structured into products with no duration limit – whose successful bidders may be called upon to provide the service for an indefinite period not known in advance – and limited-duration products, whose successful bidders may be called upon to provide the service for a maximum period specified by Terna as part of the forward procurement procedure. The limited-duration product was specifically designed for storage systems that provide the service by increasing injections into the grid up to their maximum capacity, but which may have difficulty maintaining such injections for an extended period due to constraints on energy availability.

From 1 January 2025, the interruptibility service was incorporated into the emergency modulation service provided for under the TIDE, while continuing to be governed by criteria similar to those

[59] Resolution 364/2025/R/eel of 8 July 2025.

[60] Resolution 466/2025/R/eel of 28 October 2025.

[61] Resolution 566/2025/R/eel of 23 December 2025.

[62] Resolution 564/2023/R/eel of 30 November 2023.

established in November 2023[63]. For 2025, in line with the approach adopted in 2024, Terna drew up a dedicated set of rules. From 2026, with a view to streamlining the regulatory framework, the specific rules were incorporated into the new Annex A.82 to the Network Code, which is generally applicable and therefore no longer subject to approval on an annual basis. n July 2025, the Authority confirmed that the first – and currently applicable – version of this Annex complied with [64]the regulatory framework, together with the other amendments to the Network Code required to implement the TIDE and reconnect to the PICASSO platform.

Dispatching service: modulation of withdrawals by Terna

Article 21(2) of Decree-Law No. 69 of 2023 provides that Terna may, on the basis of guidelines issued by the Ministry of the Environment and Energy Security (MASE) and the criteria and procedures defined by the Authority, implement innovative mechanisms to ensure the secure operation of the National Energy Strategy (SEN) through instantaneous load interruption. These mechanisms are additional to the emergency modulation service already provided for under the TIDE.

The Authority implemented this provision by introducing, on a trial basis for 2025 (with the possibility for Terna to renew the service annually, subject to the Authority's approval), a withdrawal reduction service based on a call by Terna on D-2, enabling operators to schedule the reduction as part of the outcomes of the energy markets. Terna consulted on and prepared the relevant rules in autumn 2024 and submitted them to the Authority, which approved them at the end of that year.

For 2026, Terna requested certain changes to the service, providing for the contracting not only of resources capable of reducing their withdrawals, potentially to zero, but also of resources capable of increasing their withdrawals so as to absorb excess generation from non-dispatchable renewable sources, particularly at weekends and during spring public holiday periods, when downward regulation margins are significantly reduced. The Authority accepted Terna's proposal and, at the end of 2025, updated [65]the TIDE criteria governing the withdrawal reduction service to allow a broader range of both upward and downward modulation. It also instructed Terna to submit the relevant rules to the Authority for approval in sufficient time to enable implementation as early as spring 2026.

Dispatching service: incentives to reduce costs

At the end of 2021, the Authority introduced [66]an output-based incentive mechanism to reduce the dispatching costs borne by final customers. The mechanism operates on a profit-sharing basis, with Terna receiving as an incentive a share of the savings achieved (12% per year); conversely, where dispatching costs increase, Terna is required to pay a penalty proportional to that increase (4% per year).

The mechanism was applied over the 2022-2024 three-year period, with the incentive recognised by

[63] Resolution 564/2023/R/eel.

[64] Resolution 364/2025/R/eel of 29 July 2025.

[65] Resolution 564/2025/R/eel of 23 December 2025.

[66] Resolution 597/2021/R/eel of 21 December 2021.

the Authority in the year following the relevant year. For each year, the incentive is determined by comparing the dispatching costs incurred with a reference cost (the so-called baseline).

In July 2024, the incentive mechanism was extended [67]to the 2025-2030 period, subject to an interim review, with the following adjustments:

- Terna was also incentivised to reduce balancing costs, measured as the difference between the actual cost of balancing and the minimum cost that would have been incurred by selecting only the lowest-cost resources, optimising between procurement through the various European platforms and activation at national level through the Integrated Scheduling Process (ISP);
- the penalty for increases in dispatching costs was set at 6% per year;
- for each three-year period, the reference dispatching cost is the cost for the latest year for which actual data are available (2023 for the 2025-2027 period and 2026 for the 2028-2030 period), plus an incremental cost reflecting the costs that the system is expected to incur as renewable generation increases. For the first three-year period, this incremental cost is determined on the basis of an empirical curve proposed by Terna, while for the second three-year period Terna will be required to develop a specific model;
- an additional incentive of 1 percentage point was introduced, linked to: compliance with a timetable for implementing the TIDE; the development of an ISP algorithm consistent with the principles set out in the TIDE; the development of a model for determining the incremental cost for the 2028-2030 period; the review of the configuration of market zones; the updating of the market simulator in line with the new framework envisaged by the TIDE; and the development and maintenance of the Central Register of Generation Units (GAUDÌ) in line with the evolving regulatory framework;
- active participation by market operators was strengthened, with operators invited to provide input through consultations to be conducted by Terna on the definition of the implementation timetable, the methodology for determining the minimum balancing cost and the model for determining the incremental cost.

The incentive mechanism is designed to remain unchanged throughout the relevant three-year period. However, the mechanism was refined during 2025:

- in June, the scope of milestone ML3 for TIDE implementation (with a final deadline of 30 June 2025) was revised[68], limiting it to the technical requirements for qualification to provide FCR and excluding the timing of the auctions, since the criteria governing those timings had been updated through Version 4 of the TIDE, as amended by the same measure;
- in July, it was clarified that, [69]from 1 April 2025, the costs of foregone wind generation also include the costs of foregone generation from all non-dispatchable renewable sources, consistently with the provisions of Resolution 128/2025/R/efr.

Through the July 2025 measure, the Authority also awarded [70]Terna the incentive for 2024. After taking account of the applicable neutralisation adjustments, Terna achieved dispatching cost savings of 94 million euro, corresponding to an incentive of approximately 11 million euro (12% of the benefit

[67] Resolution 326/2024/R/eel of 30 July 2024.

[68] Resolution 227/2025/R/eel of 3 June 2025.

[69] Resolution 313/2025/R/eel of 8 July 2025.

[70] Resolution 313/2025/R/eel.

achieved).

Dispatching service: local ancillary services

In August 2021, the Authority launched [71]a trial scheme for the procurement by distribution companies of flexibility services offered by energy-providing units connected to distribution networks. The scheme was to be implemented through pilot projects proposed directly by the distribution companies and submitted to the Authority for approval Distribution companies were invited to coordinate with one another when drawing up the projects, with a view to adopting rules that were as harmonised as possible for the same type of service, and also with Terna, in order to prevent the same energy from a given unit from being used to provide both global and local ancillary services.

The Authority received three pilot projects to be implemented from 2024 onwards:

- e-distribuzione submitted the Edge project, which provides for the procurement of flexibility resources through the third-party Piclo platform, already successfully used for the same purpose in the UK market;
- Areti submitted the RomeFlex project, which provides for the procurement of flexibility resources through a dedicated platform for the local flexibility market (MLF), specifically developed by GME as a tool open to participation by all interested distribution companies;
- Unareti submitted the MindFlex project, which is also based on the MLF platform.

All the projects initially provide for offers to be selected through time contracts of varying duration, designed to ensure the availability of flexibility resources for a predefined period during the day. Remuneration consists of an availability price, expressed in euro/MW/year and linked to the actual availability required from the resource, and a utilisation price, expressed in euro/MWh and linked to the actual activation requested by the distribution company.

The Edge and MindFlex projects provide for direct activation by the distribution company. RomeFlex, by contrast, following an initial phase in which resources were activated directly by the distribution company, established a spot market through which the distribution company can use market-based mechanisms to select the resources to be activated in real time on the basis of their offer price. Resources contracted on a time contract basis are required to submit offers on this market at a price no higher than the utilisation price indicated during the time contract selection stage; resources not initially contracted on a forward basis may also participate in the market.

Any extension of the pilot projects must be approved annually by the Authority, following submission by the proposing distribution companies of a new technical report setting out the specific local ancillary service procurement requirements for the following year and assessing the needs and development of this market. The extension of the Edge and RomeFlex projects for 2025 was approved[72] in December 2024, while the extension of the MindFlex project was approved[73] in May 2025.

All distribution companies expressed an interest in extending their respective projects for 2026. The

[71] Resolution 352/2021/R/eel of 3 August 2021.

[72] Resolutions 516/2024/R/eel of 3 December 2024 and 555/2024/R/eel of 17 December 2024.

[73] Resolution 197/2025/R/eel of 8 May 2025.

extensions of the Edge and RomeFlex projects were approved at the end of 2025[74], while the extension of the MindFlex project will be approved at a later date, as it concerns delivery periods starting in spring 2026.

During 2025, the Authority also published [75]the first version of its report on the outcomes of the pilot projects for enabling new resources to provide ancillary services, both global and local, reflecting the situation as at 2024.

Development of the settlement framework

In July 2024, the first phase[76] of the process to modernise the regulation of the physical and financial settlement items relating to the electricity dispatching service, established under the Integrated Settlement Regulation (hereinafter: settlement), was completed. The process was launched in [77]July 2023, also for the purpose of reforming the procedures for the treatment of network losses.

As a result, measures have been put in place:

- to introduce, as of 1 January 2025 and without altering the current regulatory framework, a quarter-hourly settlement process pursuant to Article 53 of Regulation (EU) 2195/2017 and the TIDE, and to amend the Integrated Settlement Text (TIS) and the Integrated Metering Text (TIME) accordingly, with effect from the same date;
- to define the core components of the revised settlement framework to ensure that distribution system operators, Terna, the Integrated Information System (SII) manager, and Distribution Users are equipped with the information required to initiate system and data flow adjustments;
- to set the start-up phase of the new settlement regulation at 1 January 2026; consequently, the deadline for completing the procedure launched in July 2023 on the regulatory framework for settlement and network losses is extended to 31 December 2025.

The provisions introduced from 1 January 2025 were described in detail in the 2025 Annual Report, to which reference should be made. In summary, from 2025 the new provisions introduce more extensive and systematic use of actual metering data, prioritising 15-minute settlement and providing for specific profiling arrangements for points not settled on a 15-minute basis. Distribution companies are required to make actual or estimated data available to the SII, including data relating to single-rate points up to 16.5 kW, interconnection points between networks and own-use consumption for transmission and distribution. The rules also provide that metering data are to be grossed up solely for technical losses, excluding commercial losses, and introduce the determination of residual energy (ER) for each grid operator and bidding zone. ER includes differences between actual and standard losses, differences between actual and conventional profiles, unmetered own-use consumption and mismatches arising from errors or estimated data. This energy, together with metered or meterable own-use consumption, must be procured on the free market and is not subject to transmission and distribution charges or the related surcharges. From an operational perspective, the reform strengthens the role of the SII, which is assigned responsibility for profiling, aggregation,

[74] Resolutions 508/2025/R/eel of 25 November 2025 and 527/2025/R/eel of 2 December 2025.

[75] Resolution 342/2025/I/eel of 22 July 2025.

[76] Resolution of 30 July 2024, 325/2024/R/eel.

[77] Resolution of 25 July 2023, 336/2023/R/gas.

management of data relating to interconnection points and determination of partial residual energy. Terna then completes the calculation of ER and updates the SII Register in respect of the matters falling within its remit. The provisions also provide for the registration of withdrawal points for own-use consumption, the abolition of the aggregation charge and the associated incentive regulation, and a testing phase in the final quarter of 2025, ahead of full implementation of the new arrangements from 1 January 2026.

In June 2025, the Authority conducted three consultations aimed at refining the settlement framework.

In the first consultation, the Authority proposed [78]reorganising the existing provisions of the TIS[79] in order to take account of: (i) the widespread availability of 15-minute data; (ii) the phasing out of the load profiling framework and the residual role currently assigned under that framework to *Acquirente Unico*; and (iii) the new dispatching regulatory framework established by the TIDE.

In particular, compared with the provisions established in[80] July 2024, the Authority:

- clarified that residual electricity (ER) – the difference between the electricity injected into each distribution network and the total electricity withdrawn by final customers connected to that network – must also be determined for closed distribution systems (SDCs), consistently with the arrangements applying to other distribution networks and the RTN
- set out, for each Imbalance Settlement Period (ISP), the formulas for aggregating metering data both for the injection and withdrawal units introduced by the TIDE and for determining the ER allocated to grid operators;
- with regard to financial settlement, and consistently with the TIDE, extended to Balancing Service Providers (BSPs) the same deadlines for financial settlement vis-à-vis Terna as those applicable to Balance Responsible Parties (BRPs) in monthly settlement and adjustment sessions;
- proposed streamlining the management of adjustment sessions, including through simplified terminology based exclusively on the general term "correction", consistently with the TIME, thereby removing the distinction between settlement corrections and late corrections while retaining the distinction between six-monthly adjustment sessions and late adjustment;
- extended to *Acquirente Unico*, in respect of customers still supplied under the enhanced protection service, the same provisions applying to free-market BRPs for financial settlement purposes, so that it is treated in the same way as other BRPs, including in adjustment sessions;
- identified the information requirements relating to the provision of data aggregated by unit and the data required to determine ER;
- proposed revising the deadlines by which the Integrated Information System Operator (SII) must take account of data provided by distribution companies for both monthly settlement and adjustment.

In the second consultation, the provisions of the TIME were revised [81]compared with those previously

[78] Consultation Document 269/2025/R/eel of 19 June 2025.

[79] Integrated Regulation governing the physical and financial settlement items of the dispatching service.

[80] Resolution 325/2024/R/eel.

[81] Consultation Document 270/2025/R/eel of 19 June 2025.

envisaged for the metering service in July 2024[82] and February 2025[83]. Specifically, the Authority:

- proposed revising Terna's responsibilities for the management of commercial data, with a view to minimising the impact of the reform on processes currently managed by distribution companies;
- reorganised the provisions governing the provision of metering data, particularly those relating to the SII Operator and network operators, bringing the management of metering data for energy exchanged at interconnection points between networks operated by different network operators within the scope of the processes managed by the SII;
- proposed bringing forward to the 10th day of the month following the relevant month the deadline for providing metering data relating to interconnection points and non-15-minute metering data, compared with the current deadline of the 20th day for the latter;
- streamlined the terminology following the introduction of the 15-minute ISP by removing references to single-rate or time-band metering data;
- proposed transferring to the new TIME certain TIS provisions governing the provision to Terna of metering data relating to electricity injections, as these were considered more appropriately addressed within the metering provisions, also with a view to centralising their management within the SII.

In the third consultation, the Authority set out[84] its proposed approach to completing the measures required for the reform. These concerned amendments to the provisions governing the procurement and market-based management by grid operators of electricity for transmission and distribution own-use consumption and of residual electricity (ER), as well as the definition, for grid operators subject to third-party connection obligations, of new arrangements for recovering the related costs. These arrangements would replace the existing equalisation mechanisms under Articles 28 and 29 of the Integrated Regulation governing the provision of last-resort electricity supply services (TIV), and the mechanism under Article 31 of the TIV for recognising network losses attributable to unrecoverable fraudulent withdrawals. In summary:

- the Authority proposed revising the application of loss factors to electricity injected by distributed generation facilities, using differentiated loss factors depending on whether or not reverse power flow occurs at the primary substation, where the facility is connected at MV, or at the secondary substation, where it is connected at LV. Two alternative approaches were proposed:
  - differentiating the loss factors according to the incidence of reverse power flow at the substations to which the generation facility is connected, using a 40% threshold;
  - for year n+1 and for each primary and secondary substation, setting loss factors calculated, with reference to the period from 1 August of year n-1 to 31 July of year n, as the average of the standard percentage loss factors weighted across 15-minute periods according to whether or not reverse power flow occurred at the primary or secondary substation to which the generation facility is connected;

[82] Resolution 325/2024/R/eel.

[83] Resolution 40/2025/R/eel of 11 February 2025.

[84] Consultation Document 268/2025/R/eel of 19 June 2025.

- with regard to the obligation imposed [85]on Terna and distribution companies in July 2024 to procure independently the electricity withdrawn for their transmission and distribution own-use consumption, the following approaches were outlined:
  - licensed distribution companies and SDCs would procure such electricity through a supply contract with a commercial counterparty and its corresponding BRP, while Terna would procure it using arrangements of its own choosing, including as part of its dispatching requirements;
  - the related costs would be recovered, in Terna's case, through the unit uplift charge and, in the case of distribution companies, through a specific lump-sum cost recovery mechanism;
- finally, with regard to ER, the following approaches were outlined:
  - licensed distribution companies and SDCs would procure ER through a supply contract with a commercial counterparty and its corresponding BRP, while Terna would procure it using arrangements of its own choosing, including as part of its dispatching requirements;
  - the costs of procuring ER would be recovered, in Terna's case, through the unit uplift charge and, in the case of licensed distribution companies, through a specific cost recovery mechanism covering the regulatory period and based on three key elements:
    i. a recognised or reference cost determined on the basis of the residual electricity value for a specified reference year (baseline) and updated annually in accordance with predefined criteria;
    ii. the ex-ante collection, through the UC3 component, of the amount required to cover the costs incurred by the licensed distribution company in procuring ER, thereby reducing its financial exposure;
    iii. an annual equalisation mechanism between licensed distribution companies, designed to manage the tariff decoupling between the revenue collected by each licensed distribution company through application of the tariff instrument referred to in point (ii) and the allowed revenue. The latter includes a sharing mechanism designed to promote efficiency gains.

In response to the three consultations, while generally supporting the reform, most stakeholders requested that its entry into force be postponed to 1 January 2027, to allow sufficient time to adapt the algorithms, systems and procedures currently used for energy balancing and reconciliation of the related financial settlement items. In addition, stakeholders highlighted:

- the need to clarify, including through focus groups, certain complex scenarios relating to interconnections between grid operators;
- the opportunity of managing the transitional period – from 1 January 2026 until the new implementation date – under the existing regulatory framework, given the changes already made to load profiling in previous years, which should ensure the financial stability of operators providing the enhanced protection service.

Lastly, in September 2025, in response to stakeholders' request for an extension, the Authority not only postponed the entry into force of the new framework to 1 January 2027, but also[86]:

[85] Resolution 325/2024/R/eel.

[86] Resolution 430/2025/R/eel of 30 September 2025.

- revised the timetable for the testing phase, including dry-run testing aimed at verifying the correct implementation of the new activities assigned to the SII under the new settlement framework, which the SII Operator is required to carry out pursuant to the provisions [87]adopted in February 2025;
- provided for the identification of "specific network configurations" relevant to the accounting of energy exchanges at interconnection points and of RE, following consultation with the various parties involved;
- amended the TIV to confirm, for 2026, the percentage loss factors already applied for equalisation purposes in 2025;
- deferred to a subsequent measure the rules governing "unrecoverable" fraudulent withdrawals under Article 31 of the TIV, in order to align them with the new settlement framework.

Provisions on Load Profiling and Network Losses for the Year 2025

In December 2024, the Authority amended and supplemented the existing load profiling and network loss equalisation framework [88]to extend its application to 2025, pending its replacement and the application of the new framework from 1 January 2026 in accordance with the new settlement rules. The two main aspects are as follows:

- the removal of specific simplifications and approximations in the load profiling methodology, which in 2024 caused operational challenges due to the declining share of non-hourly metered electricity, driven by the widespread deployment of hourly metering devices;
- the Authority has established the regulatory components necessary to prolong, for the year 2025, selected provisions governing network loss regulation, including the equalisation mechanism, which had previously applied over the 2022–2024 period.

The updated regulation has redefined the calculation method for the Coefficients for the Allocation of Withdrawal Points (CRPP), which quantify the portion of residual area withdrawals assigned to each non-hourly withdrawal point. The modification involves calculating the energy underlying non-hourly withdrawal points, serving as the denominator of the CRPP coefficients, more directly, by summing the actual energy withdrawn at those points.

Regarding network losses, the updated regulation establishes the following provisions:

- it has confirmed, for 2025, the percentage factors previously applied in 2023 and 2024 for the equalisation of commercial electricity losses on networks with third-party connection obligations, as specified in Table 10 of the Integrated Sales Text (TIV): 0.90% in the North zone, 1.72% in the Central zone, and 4.87% in the South zone;
- it has extended the corrective mechanisms set out in paragraphs 29.2 and 29.3 to 2025, given that the extraordinary circumstances which drove high wholesale electricity prices in previous years have not yet been entirely overcome;
- it also confirmed that the recognition mechanism for non-recoverable fraudulent electricity withdrawals, as set out in Article 31 of the TIV, will remain in force for 2025. Accordingly, 2025 has been consolidated with the 2022–2024 regulatory period;
- an advance payment shall be made in 2025 to facilitate the prompt recognition of amounts

[87] Resolution 40/2025/R/eel.

[88] Resolution 535/2024/R/eel of 3 December 2024.

accrued during the 2022–2024 period and to prevent undue delays. The balance will be paid by the end of May 2026.

Finally, the new regulation has also provided for:

- the revised methodology for calculating CRPPs to be applied in time for the January 2025 coefficients, or no later than February 2025, subject to the condition that the consistency checks performed by the SII have not persistently failed since July 2024;
- the possibility, for each operator of the standard offer service, to request from CSEA, upon submission of a specific application, for compensation aimed at partially offsetting the financial exposure arising from anomalies in the advance estimation of electricity withdrawals at non-hourly processed points.

Capacity Market

The Capacity Market, the establishment of which was provided for by Legislative Decree No. 379 of 19 December 2003, is designed to achieve and maintain generation adequacy, so as to ensure that electricity demand can be met on a structural basis while complying with predefined security and quality standards[89].

The first Capacity Market auctions were held in 2019 and covered delivery years 2022 and 2023. The auction for the year 2024 was then held in 2022. Therefore, as of January 2022, the recognition of the fixed consideration to the assignees began and the application of the rules on the obligation to offer and return the commodity-based charge, equal to the difference between the reference price and the strike price, began.

The technical and economic parameters and the methodology for determining the strike price for the 2022-2023 and 2024-2025 delivery periods were defined in 2019 and 2021, respectively[90]. The strike price, representing the standard variable cost of a hypothetical natural gas-fired open-cycle gas turbine generation unit, is equal to the sum of a number of components, including a component covering the cost of natural gas (natural gas component) and a component covering the cost of emission allowances to be surrendered under the Emissions Trading System (emissions component).

During 2024, two tendering procedures were conducted, corresponding to the delivery periods 2025 and 2026. The aforementioned auction procedures were preceded by an extensive administrative process that led to significant amendments to the Capacity Market rules and the related technical operating provisions, a detailed description of which is provided in the Annual Report 2025.

In September 2024, the Minister for the Environment and Energy Security approved [91]the Capacity Market rules for the purposes of conducting the auction procedures for the 2025, 2026, 2027 and 2028 delivery years.

The combined effect of the provisions adopted [92] by the Authority in July 2011 and the updated

[89] For a more detailed description of the regulatory framework governing the Capacity Market, reference should be made to previous Annual Reports.

[90] Resolutions 363/2019/R/eel of 3 September 2019 and 399/2021/R/eel of 28 September 2021.

[91] Ministerial Decree No. 180 of 5 September 2024.

[92] Resolution ARG/elt 98/11 of 21 July 2011.

Capacity Market rules requires the Authority to publish the following economic parameters for each auction procedure:

- the maximum premium value that may be granted to new generation capacity (for up to 15 years, if requested by the participant), which also applies to capacity associated with consumption units and generation capacity requiring upgrades due to administrative measures (for one year);
- the premium value associated with the central point of each demand curve;
- the maximum premium value that may be granted to existing generation capacity and, where differentiated, the highest premium that may be proposed for the same capacity (for one year); these values also apply to foreign capacity (for one year);
- the minimum investment amount per unit of capacity that must be made by the operator, in the event of acceptance following a capacity market auction, in order to qualify for a 15-year contract for their new generation capacity;
- the parameters for defining the strike price.

Furthermore, the Authority's July 2011 provision stipulates that no less than 70% of the net capacity supply cost must be allocated to the withdrawal of dispatching users during system peak hours. The aforementioned percentage, which is considered among the economic parameters, was set at 70% for the delivery years 2022, 2023, 2024 and 2025.

Following the consultation launched [93]in March 2024, in May 2024 the Authority set [94]the economic parameters for the Capacity Market auction procedures for the 2025, 2026, 2027 and 2028 delivery years. In detail:

- the maximum premium value that may be granted to new generation capacity is defined based on the upper limit of the fixed cost of the reference technology (open-cycle gas turbine) and is equal to:
  - €85,000/MW/year for the auction procedure relating to the 2025 delivery year;
  - €86,000/MW/year for the auction procedures relating to the 2026, 2027 and 2028 delivery years
- the premium at the midpoint of each curve is determined using the lower limit of the fixed cost of the reference technology and is equal to:
  - €71,000/MW/year for the auction procedure relating to the 2025 delivery year;
  - €72,000/MW/year for the auction procedures relating to the 2026 and 2027 delivery years;
  - €73,000/MW/year for the auction procedure relating to the 2028 delivery year;
- the maximum premium value that may be granted to existing generation capacity is determined by the avoidable fixed costs of the main technology in Italy's generation mix (combined cycle) and amounts to €45,000 per MW per year, €46,000 per MW per year, €47,000 per MW per year and €48,000 per MW per year for the auctions covering the delivery years 2025, 2026, 2027 and 2028, respectively;
- the minimum investment amount is equal to €215,000 per MW;
- the parameters for determining the strike price are set using an approach that ensures the price reflects the variable cost of the reference technology, and include, among other things, daily

[93] Consultation Document 102/2024/R/eel of 26 March 2024.

[94] Resolution 199/2024/R/eel of 23 May 2024.

indexation of relevant natural gas and emissions values, a reduction in the standard specific consumption of natural gas, and changes to the calculation method for the standard national logistics cost included in the natural gas component;
- the share of the net cost to be allocated to peak hours is set at 70% until 2028;

Outcomes of the main capacity market auctions for the delivery years 2025 and 2026

The main auction of the Capacity Market relating to the 2025 delivery period was held on 25 and 26 July 2024, with the auction for the 2026 delivery period taking place on 18 December 2024.

Terna's reports on the main capacity market auctions for the 2025 and 2026 delivery years reveal, among other findings, that:

- the total expenditure on premiums amounts to approximately €1.72 and €1.82 billion for the years 2025 and 2026, respectively, net of the premiums for new capacity already awarded in previous auctions under fifteen-year contracts that include the 2025 and 2026 delivery years;
- the existing capacity awarded totals around 37.6 GW for 2025 and 38.3 GW for 2026, with balancing premiums set at the respective maximum values for existing capacity (€45,000 and €46,000 per MW per year) across all areas;
- approximately 1 GW of the selected existing capacity concerns thermoelectric plants for which a commitment has been made to carry out retrofitting interventions aimed at increasing availability during critical summer hours;
- the awarded new capacity, all of which is fully authorised, totals around 0.2 GW for 2025 and 0.1 GW for 2026, with balancing premiums of €67,500 and €56,160 per MW per year, respectively;
- in both auctions, the selected foreign capacity amounts to approximately 4.4 GW, with recognised premiums differentiated across the various foreign areas (ranging from approximately €3,500 to €4,800 per MW per year for 2025 and from €4,500 to €11,200 per MW per year for 2026);
- the 2025 auction awarded new capacity comprising 89 MW of battery storage and 85 MW of repowered combined-cycle thermal generation, while the 2026 auction included 84 MW of battery storage, 42 MW of repowered thermal generation, and 10 MW of wind energy;

Results of the Capacity Market main auction for the 2027 delivery year

In October 2025, with regard to the rules applicable to auction procedures for delivery years after 2024 and the technical operating provisions governing those procedures, Terna consulted on a number of amendments aimed at adapting their content to the TIDE provisions applicable during the consolidation phase.

Following the consultation, Terna submitted to MASE and the Authority, among other things:

- the proposed amendments to the documents covered by the consultation;
- a document setting out the amendments that, following approval of the aforementioned proposals, would be automatically incorporated, from the start of the TIDE consolidation phase, into the rules governing auction procedures for the 2022-2024 delivery years and the related technical operating provisions.

The main changes contained in the proposed amendments to the documents covered by the consultation concerned:

- the methods for calculating de-rated capacity to be applied from 1 February 2026, consistently

with the TIDE provisions for the consolidation phase;
- the procedures for verifying compliance with bidding obligations and determining the variable consideration, in order to take account of the new elements introduced by the TIDE for that phase, particularly as regards the aggregation of units and the distinction between Balance Responsible Parties and Balancing Service Providers (BRPs/BSPs);
- the definition of an unavailable Production Unit (UP).

As Terna's proposals to amend the rules applicable to auction procedures for delivery years after 2024 and the related technical operating provisions complied with the criteria and conditions laid down in the provisions adopted[95] in July 2011, the Authority positively assessed those proposals. However, the Authority made its approval conditional on the removal from the Capacity Market rules of the provision assigning the BRP responsibility for selecting the minimum grouping through which to comply with the obligations laid down under the essentiality framework, since that framework has not yet identified the party responsible for making that selection for years after 2026.

Electricity storage capacity forward supply system

Article 18 of Legislative Decree No. 210 of 8 November 2021 introduced into the architecture of the Italian electricity market a forward procurement mechanism for electricity storage resources (MACSE), alongside the energy, ancillary services and capacity markets. The process for defining the MACSE regulatory framework is described in previous Annual Reports.

Economic parameters of the electricity storage capacity procurement mechanism

In February 2025, the Ministry of the Environment and Energy Security provided [96]for the first auction dedicated to batteries and to electricity storage technologies other than batteries and pumped-storage hydropower. In April 2025, the Authority set out [97]its proposed approach to defining the maximum premium for that auction, taking account of the constraints introduced by the European Commission decision of December 2023[98], the provisions adopted by the Ministry of the Environment and Energy Security in October 2024 [99]and the information contained in the updated version of Terna's study on electricity storage technologies. More specifically, the Authority indicated its intention to set the maximum premium on the basis of the cost of new entry (CONE) for batteries with a four-hour duration and indicated a maximum premium of €32,000/MWh/year, determined by applying the CONE calculation formula set out in the European Commission decision of 21 December 2023 and the values of the following parameters:

- with regard to investment costs (INV parameter), a value of €241,000/MWh, defined as the sum of the lower end of the investment cost range reported in Terna's study on electricity storage technologies (€191,000/MWh), the costs associated with oversizing the facility, equal to 12% of the aforementioned lower-end value, as indicated in that study, and the financing costs incurred

[95] Resolution ARG/elt 98/11 of 21 July 2011.

[96] Decree No. 53 of the Minister for the Environment and Energy Security of 27 February 2025.

[97] Consultation Document 168/2025/R/eel of 15 April 2025.

[98] European Commission Decision of 21 December 2023 (SA.104106), which approved the MACSE, finding it compatible with EU State aid rules.

[99] Ministerial Decree No. 346 of 10 October 2024.

during the construction period. The latter were determined assuming a two-year construction period, a rate equal to the rate of return on invested capital (WACC parameter) and a financed amount equal to the sum of costs other than financing costs, with half disbursed at the beginning of the construction period and the other half at the beginning of the second year of that period;
- with regard to fixed operating costs other than depreciation (CFO parameter), a value of €4,000/MWh/year, equal to 2% of the INV parameter[100], calculated net of costs falling outside the scope of the battery and financing costs incurred during the construction period;
- with regard to useful life (parameter n), a period of 15 years, representing both the lower end of the range indicated in Terna's study on electricity storage technologies and the duration of the delivery period specified in the technical report required under the MACSE rules;
- with regard to the WACC parameter, a rate determined by applying, with certain adjustments, the methodology established [101]by the Authority in this area (TIWACC), as updated at 28 February 2025. The Authority clarified, however, that the rate would be updated when setting the maximum premium for the first auction dedicated to batteries and to electricity storage technologies other than batteries and pumped-storage hydropower.

In general, while appreciating the methodological approach adopted by the Authority and the decisions to set the maximum premium shortly before the auction and to publish the different versions of the study on electricity storage technologies, most respondents to the consultation requested an increase in the maximum premium indicated by the Authority in the consultation, considering it insufficient to attract new investment. At the same time, however, some respondents supported the maximum premium indicated by the Authority, while a couple of operators highlighted the desirability of limiting its value, including to avoid increasing developers' risk exposure and generating disproportionate financial liabilities, given that, under the MACSE rules, the maximum premium has a direct impact on the amount of collateral required and on penalties for unavailability.

With particular regard to the INV parameter:

- several respondents to the consultation requested that an average value within the range set out in Terna's study on electricity storage technologies be used. Some operators noted that the value indicated by the Authority, being towards the lower end of the range in the study, could disadvantage projects other than the largest ones and greenfield projects. They also noted that the study identifies the cost of connection to the high-voltage network and the construction of a new substation as the main factors underlying the wide range of costs falling outside the scope of the battery;
- most respondents considered that the determination of investment costs should not rely on assumptions regarding any margins obtainable from the additional capacity resulting from oversizing, the possibility of retaining a percentage of profits earned on the balancing and redispatching market, or the economic benefits arising from operating the capacity beyond the fifteenth year. They cited the uncertainty associated with these factors and the need to preserve the additional capacity resulting from oversizing in order to comply with the degradation curve specified in the technical report required under the MACSE rules;
- some respondents noted that, if storage systems contracted under the MACSE were required to provide Frequency Containment Reserve (FCR) capacity free of charge and were therefore

[100] Net investment cost, expressed in euro per usable MWh.

[101] Resolution 614/2021/R/com of 23 December 2021.

excluded from the market-based procurement mechanisms provided for under the dispatching framework (TIDE), investment costs should be appropriately increased to reflect this requirement.

With regard to the CFO parameter, a number of respondents requested an increase in its value, while one supported the Authority's proposed approach. Those calling for an increase argued, among other things, that the CFO parameter should cover the extension of warranties to 15 years and reflect the fact that many operators, lacking established experience in the development and operation of utility-scale batteries, may be required to enter into full-service contracts.

With regard to the WACC parameter, several operators pointed out that the parameter β^{asset} submitted for consultation only partially reflects the risks associated with investment in batteries. Some respondents requested the use of a post-tax rather than a pre-tax rate, in order, among other things, to avoid overstating the economic viability of projects.

In July 2025, consistently with the ministerial provisions adopted in October 2024, the Authority set [102]the maximum premium for the first auction dedicated to batteries and to electricity storage technologies other than batteries and pumped-storage hydropower at €37,000/MWh/year. This amount was determined using the methodological approach set out in the consultation, with certain adjustments to take account of the comments received. Specifically:

- the INV parameter was increased to €264,000/MWh, reflecting the increase in costs outside the battery perimeter, which were set at the average of the corresponding range of values reported in Terna's study on electricity storage technologies, in order to take account of the comments submitted by consultation respondents concerning connection costs for greenfield projects;
- the rate of return on invested capital was set by applying, as at 30 June 2025, the methodology submitted for consultation (TIWACC);
- the CFO parameter was increased to €6,000/MWh/year, so as to include the extension of guarantees to the entire delivery period and any additional costs or elements of risk and uncertainty not otherwise taken into account.

It was also clarified that:

- the consultation did not present a CONE calculated net of margins relating to additional capacity resulting from oversizing and the possibility of retaining a percentage of profits earned on the balancing and redispatching market or benefiting from the economic advantages arising from operating the capacity beyond the fifteenth year; rather, it highlighted the existence of various potential sources of margins from which owners of storage facilities contracted under the MACSE could benefit;
- Terna's study on electricity storage technologies shows that the battery oversizing referred to in that study, designed to take account of the deterioration in plant performance, was introduced by Terna also following extensive discussions with industry operators;
- the possibility of entering into 15-year contracts for the construction of new batteries significantly reduces the associated investment risks compared with a context characterised by an energy-only electricity market and, therefore, when determining the rate of return on capital for the purpose of calculating the CONE, account must be taken of the lower level of risk faced by a new investor operating in a market characterised by the presence of a capacity remuneration mechanism such as the MACSE, compared with an energy-only market;

[102] Resolution 362/2025/R/eel of 29 July 2025.

- defining a post-tax rate of return on invested capital, as requested by certain operators, is, ceteris paribus, inconsistent with those same operators' request for a rate higher than that indicated by the Authority, since a post-tax rate is net of the effect of taxation;
- Terna's study indicates that, where reference is made to installed capacity, this is to be understood as capacity that is fully available for operation and, for the storage systems analysed, Terna used the concept of net round-trip efficiency measured at the point of connection to the electricity grid, which therefore takes account of both the entire charging and discharging process and the consumption and losses of the plant's auxiliary systems.

With regard to the arrangements under which storage facilities contracted under the MACSE following the first auction will participate in the provision of FCR, in order to enable participants in that auction to take these arrangements into account when submitting their bids, the Authority established that:

- until FCR begins to be procured exclusively through market-based mechanisms, storage facilities contracted under the MACSE following the first auction will not be required to make the mandatory FCR bands available free of charge, since, for these resources, making such bands available free of charge would entail an additional technical and operational burden for only a limited period of time;
- among the above-mentioned storage facilities, those eligible to provide FCR may participate in the mechanisms provided for under the TIDE for the market-based procurement of that service.

With regard to the coverage of costs associated with the MACSE evaluation activities, Article 3 of the MASE Decree of 10 October 2024 provides that:

- the Ministry of the Environment and Energy Security (MASE) is to identify a functionally independent entity to carry out the evaluation of the MACSE, in accordance with the criteria set out in the evaluation plan approved by the European Commission by decision of 21 December 2023 and published in outline on the Ministry's website;
- the selected evaluator must be independent of the Ministry, have no conflict of interest with the potential beneficiaries of the measure, have significant experience in economic and quantitative analysis, including in the energy and environmental sectors, and submit to the Ministry a detailed evaluation plan providing for at least an interim evaluation report by 31 December 2025 and a final evaluation report by 31 March 2032; by those same deadlines and following public consultation, the reports are to be submitted to the Ministry, which will publish them on its website;
- the evaluator is to coordinate, in accordance with the specific analytical requirements of the evaluations envisaged in the evaluation plan approved by the European Commission, with the GSE and its subsidiary *Ricerca sul Sistema Energetico*, with Terna and with the *Gestore dei Mercati Energetici*;
- the Authority is to establish, by means of a specific measure, the arrangements for covering the costs associated with the activities of the evaluator from the fixed payments awarded to the beneficiaries of the measure.

In this regard, the provisions [103]adopted by the Authority in July 2025 stipulate that, until such time

[103] Resolution 362/2025/R/eel.

as the Authority adopts any further measures, the costs [104] incurred by the evaluator in carrying out the MACSE evaluation activities are to be covered through the unit charge governed P_q^{oth} by the TIDE. The approach adopted by the Authority is based on the consideration that the cost of the interim evaluation, which was not yet known at the date of the measure, will presumably be incurred well before 2028, the year in which payment of the fixed amounts to MACSE awardees will begin. Consequently, resources external to the MACSE will necessarily be required to cover this cost. Moreover, even if payment of the fixed amounts were to begin before the costs associated [105]with the evaluation of the MACSE are incurred:

- the timing mismatch between the collection of the resources intended to cover those costs, which could extend over several years, and the disbursement of those resources, concentrated at specific points in time between the start of the evaluation activities and a few months after their completion, would make it necessary to establish a fund. Such a fund would, in any event, initially have to be financed using resources external to the MACSE, and its management would entail an administrative burden that would be significant relative to any cost that could reasonably be expected to be incurred in carrying out the evaluation, as well as greater than that associated with covering such cost using proceeds from an increase in one of the existing charges applied to electricity withdrawals;
- the unit cost of the evaluation to be covered out of the fixed payments would be so limited as to have no impact on the maximum premium, irrespective of any cost that could reasonably be expected to be incurred in carrying out the evaluation and given the requirement that the MACSE is intended to meet.

Outcome of the auction under the long-term supply mechanism for electricity storage capacity for the 2028 delivery year

Pending the definition of the timeline for electricity storage capacity requirements pursuant to Article 18 of Legislative Decree No. 210/2021, the MASE Decree of 27 February 2025 approved the capacity requirement proposals submitted by Terna for the procurement, for the 2028 delivery year, of new electricity storage capacity through the first auction dedicated to batteries and electricity storage technologies other than batteries and pumped hydro storage. For 2028, a nationwide requirement of 10 GWh was established, together with a maximum requirement for each macro-area.

On 30 September 2025, the first auction dedicated to batteries and electricity storage technologies other than batteries and pumped hydro storage was held with the aim of meeting the above-mentioned requirement. The report published by Terna shows, inter alia, that:

- all the storage systems selected are lithium-ion batteries;
- total expenditure on premiums will amount to approximately €129 million per year, payable for each of the 15 years of the contracts entered into by Terna with the successful bidders;
- the marginal premium (the premium relating to the last accepted bid) and the weighted average premium amounted to €18,800/MW/year and €13,000/MW/year, respectively, both below the maximum premium established[106] in July 2025;
- the selected storage systems, corresponding to 9.968 GWh, cover almost the entire requirement

[104] Referred to in Article 3 of the Ministerial Decree of 10 October 2024.

[105] Referred to in Article 3 of the Ministerial Decree of 10 October 2024.

[106] Resolution 362/2025/R/eel.

for the first auction dedicated to batteries and electricity storage technologies other than batteries and pumped hydro storage;
- the difference between the overall requirement and the quantity selected is due to an operator having exercised its right not to undertake the capacity commitment in respect of partially accepted bids, in accordance with the applicable rules;
- the energy-to-power ratio of the selected capacity averages approximately 6.7 hours;
- Enel Produzione is the largest successful bidder (5 projects out of a total of 14, corresponding to 5.231 GWh);
- the selected projects will be developed in the South and Calabria (6.968 GWh), Central-South (2 GWh), Sardinia (0.5 GWh) and Sicily (0.5 GWh) areas.

3.1.5 Regulations on the quality of electricity distribution and transmission services

Quality and continuity of the electricity transmission service

In implementation of the "*Integrated Text on the output-based regulation of the electricity transmission service for the 2024-2027 regulatory period*" (ROTE)[107], in October 2025 the Authority awarded [108]Terna an incentive of €13.9 million in respect of the continuity of service performance recorded in 2024.[109].

In December 2025, the Authority extended[110] the incentive-based regulation of transmission service continuity provided for under the ROTE to 2026, confirming the application of the trajectory for setting target levels, with an annual improvement of 3.5% in energy not supplied (ENS).

As provided for in Article 43 of the ROTE, the Authority determined [111]the parameters and targets for the incentive mechanism relating to the development of interzonal transmission capacity for the 2025-2027 period, with regard to borders, sections, initial transmission capacity, target transmission capacity, the reference period for historical congestion (in line with the approach adopted under the previous 2019-2023 incentive mechanism, corresponding to the latest two full years for which data were available, namely 2023 and 2024) and the valuation coefficients relating to benefit B1 (based on the projects included in the 2023 Development Plan, calculated as the average of the B1 benefits across each of the scenarios analysed in the Plan).

Quality and continuity of electricity distribution and measurement services

In implementation of the "Integrated Text on the output-based regulation of the electricity

[107] Annex A to resolution 55/2024/R/eel of 27 February 2024.

[108] Resolution 441/2025/R/eel of 7 October 2025.

[109] The award was determined on the basis of an ENSR indicator of 224 MWh, compared with a target level of 737 MWh for 2024.

[110] Resolution 573/2025/R/eel of 23 December 2025.

[111] Resolution 366/2025/R/eel of 29 July 2025.

distribution service for the 2024-2027 regulatory period (TIQD)"[112], in November 2025 the incentives and penalties relating to the regulation of the duration and number of unplanned interruptions were determined[113] for 2024. Penalties totalling €54.1 million were imposed (for the benefit of electricity system users subject to network tariffs), representing the net balance of:

- €61.4 million in net penalties under the ordinary regulation of continuity of service (indicators relating to the duration and number of unplanned interruptions);
- €7.3 million in incentives for the 15% of district areas with the best service continuity performance under the incentive-based regulation for improved continuity of service. The following tables show, by population density, the three best-performing areas for the "duration" indicator and the "number" indicator.

Table 3.5 shows the top three areas with the best continuity of service, by population density, indicator and distribution company.

Under the same ruling[114], penalties totalling €17.8 million were also suspended. Distribution companies will become liable for these penalties in the event of a second occurrence of continuity of service underperformance in the same district area.

Table 3.5 Top three areas, by population density, with the best continuity of service for the "duration of unplanned interruptions" and "number of unplanned interruptions" indicators

INDICATOR AND DISTRICTS	DENSITY LEVEL		
	HIGH	MEDIUM	LOW
Duration of unplanned interruptions indicator			
1st district	Edyna – Province of Bolzano	AcegasApsAmga – Municipality of Gorizia	Distribuzione Elettrica Adriatica – Municipality of Offida
2nd district	Set Distribuzione – Province of Trento	Set Distribuzione – Province of Trento	LD Reti, now Unareti – Municipality of Cremona
3rd district	e-distribuzione – Province of Cuneo	Deval – Province of Aosta	Set Distribuzione – Province of Trento
Number of unplanned interruptions indicator			
1st district	Set Distribuzione – Province of Trento	AcegasApsAmga – Municipality of Gorizia	LD Reti, now Unareti – Municipality of Cremona
2nd district	Edyna – Province of Bolzano	Deval – Province of Aosta	Set Distribuzione – Province of Trento
3rd district	e-distribuzione – Province of Piacenza	Set Distribuzione – Province of Trento	Distribuzione Elettrica Adriatica – Municipality of Offida

Source: ARERA.

Furthermore, in implementation of the TIQD, under a separate measure adopted in November 2025,

[112] Annex A to Resolution 617/2023/R/eel of 27 December 2023.

[113] Resolution 511/2025/R/eel of 25 November 2025.

[114] Resolution 511/2025/R/eel.

the [115]financial amounts relating to the regulatory trials for 2024 were determined: overall, penalties of €10.3 million were determined, of which approximately €0.8 million related to Areti and approximately €9.6 million to e-distribuzione. As regards the "duration" indicator, none of the 39 district areas for which 40% of the penalty had been suspended achieved the target set for the trial in 2024, while, as regards the "number" indicator, only one of the 42 district areas (Province of Syracuse, low population density) achieved the trial target in 2024.

In December 2025, the Authority published on its website the 13th ranking of electricity distribution companies based on the number and duration of interruptions.[116]. To improve comparability between companies, the use of the composite index of interruption duration and frequency (introduced with the 10th ranking) was confirmed. This index assigns equal weight to the duration and number of interruptions and has a national average value of 10: a value below 10 indicates performance above the national average, while a value above 10 indicates performance below the national average. In addition to this index, data were published on the average annual duration of interruptions (for long unplanned interruptions) and the average number of interruptions (for long and short unplanned interruptions).

In implementation of the TIQD, in April 2025 the Authority revised [117]the baseline levels applicable solely to 2025 and the target levels for 2025 for the regulation of the duration of long unplanned interruptions and the number of long and short unplanned interruptions, for the district areas affected by the transfer, with effect from 1 January 2025, of electricity distribution activities from e-distribuzione to the new distribution company Duereti (covering certain municipalities in the western, southern and eastern areas of Milan and the Valtrompia area in the Province of Brescia).

Update of the output-based regulation and commercial quality regulation of electricity distribution and metering services

In July 2025, the Authority launched a consultation [118]on both output-based regulation and commercial quality regulation.

With regard to output-based regulation, proposals were put forward concerning:

- the development of individual continuity of service regulation;
- the update of the definition of relevant interruptions;
- the update of the mechanism for identifying so-called periods of disturbed conditions (PCPs);
- and the update of the regulation governing sample-based monitoring of slow voltage variations in LV networks.

With regard to commercial quality regulation, the Authority put forward proposals for the introduction of new commercial quality standards relating to the disconnection of distributed generation under high-voltage conditions on low-voltage (LV) networks. These proposals address

[115] Resolution 512/2025/R/eel of 25 November 2025.

[116] https://www.arera.it/area-operatori/elequalita.

[117] Resolution 187/2025/R/eel of 30 April 2025.

[118] Consultation Document 332/2025/R/eel of 15 July 2025.

the growing difficulties in feeding electricity into LV distribution networks due to high network voltage levels, which may cause users' generation facilities to be automatically disconnected when the voltage becomes excessively high.

In December 2025, in order to ensure continued protection for medium-voltage (MV) users against excessive interruptions, [119]the "Individual continuity of service regulation" (Title 4 of the TIQD) was extended to 2026.

Resilience of the electricity distribution system

At the end of 2023, the provisions aimed at incentivising the resilience of electricity distribution networks for the 2019-2024 period were updated[120]. Among other things, it was stipulated that, starting from the February 2024 application, the incentive mechanism would only apply to distribution companies to whose network at least 100,000 final customers are connected and the interventions would be eligible for a bonus only, with potential cancellation in the event of a significant delay.

In implementation of the "Integrated Text on the output-based regulation of electricity distribution and metering services for the 2020-2023 regulatory period" (TIQE)[121], in September 2025 the Authority determined [122]the three-year balance (2022-2024) of net incentives for nine distribution companies, in relation to measures to enhance the resilience of the electricity distribution service.

Taking into account the incentives and penalties received or payable by the companies for measures completed in 2022 and 2023, and the potential incentives or penalties relating to measures to enhance the resilience of the electricity distribution service completed in 2024, the measures completed over the 2022-2024 period resulted in an overall negative balance for the companies, requiring a payment of €2.6 million to Energy and Environmental Services Fund (CSEA).

Quality of electricity distribution: duration and number of interruptions

In 2025, there was an improvement compared with 2024 both in the average duration of unplanned interruptions, which fell to 69 minutes from 76 minutes in the previous year (Figure 3.1), and in the average number of long and short unplanned interruptions per low-voltage customer, which fell to 4.92 from 5.12 in 2024 (Figure 3.2).

The improvement in performance in 2025 was partly attributable to the lower impact of extreme weather events (floods, windstorms and heatwaves). In 2025, the regions most affected by these weather events were Valle d'Aosta and, to a lesser extent, Campania and Sicily.

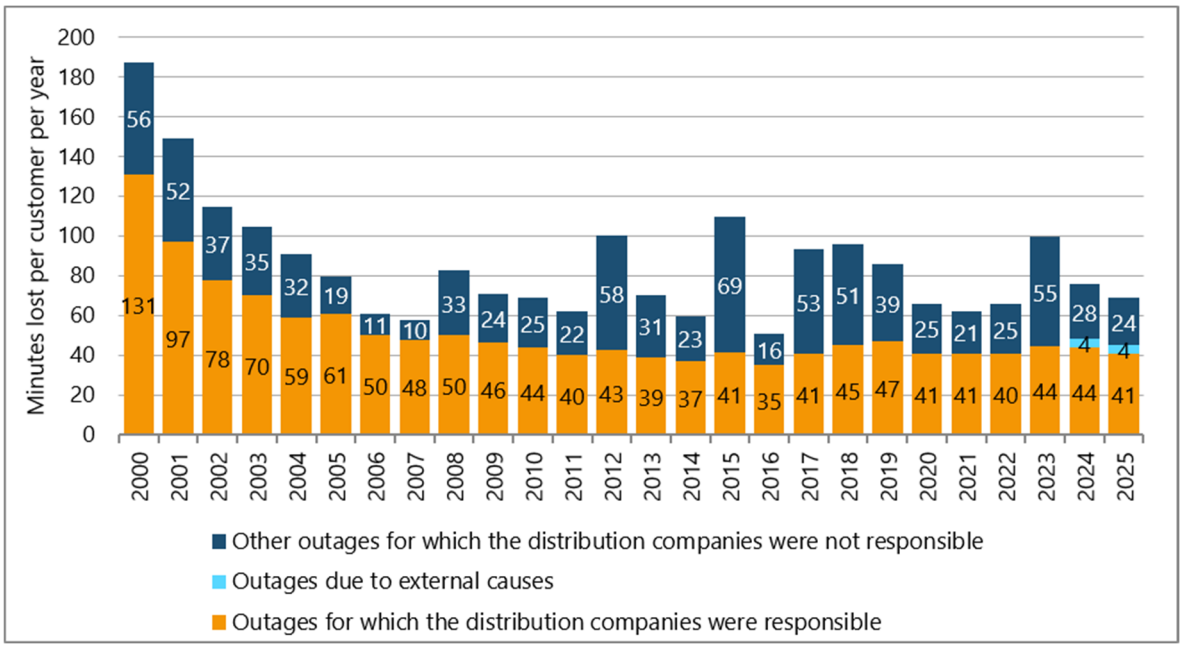
[119] Resolution 575/2025/R/eel of 23 December 2025.

[120] Resolution 614/2023/R/eel of 27 December 2023.

[121] Annex A to Resolution 566/2019/R/eel of 23 December 2019.

[122] Resolution 418/2025/R/eel of 23 September 2025.

Figure 3.1 Duration of long unplanned interruptions per low-voltage customer(A)

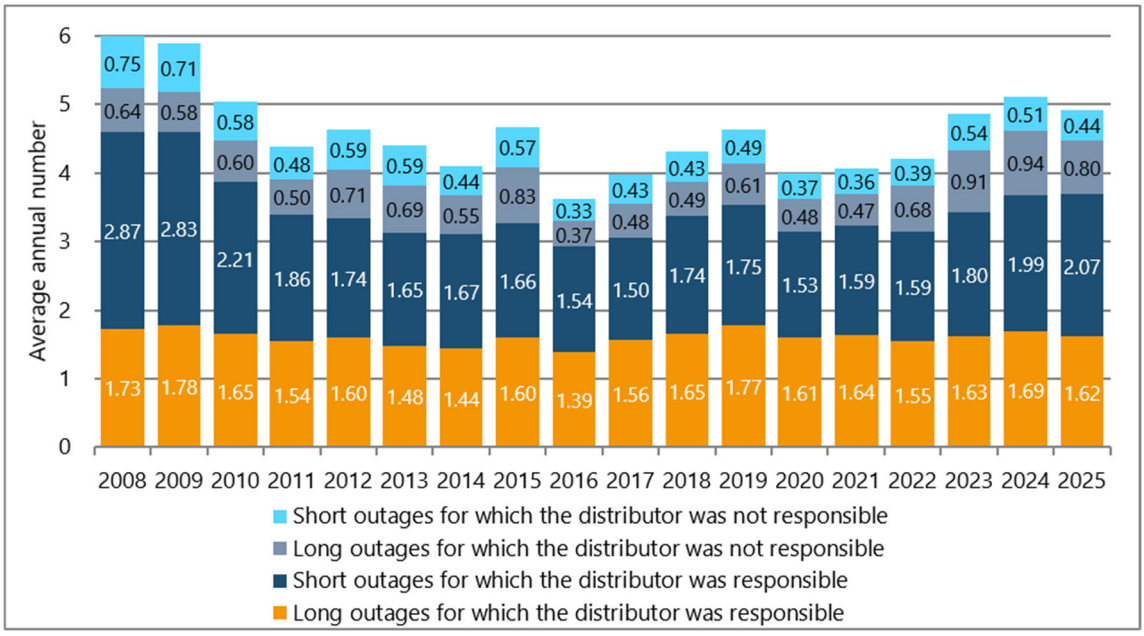


(A) Excluding major incidents on the National Transmission Network, defence system interventions and interruptions caused by theft.

Source: ARERA. Processing of declarations of operators.

Analysing in detail the causes of interruption related to 2025, still under review by the Authority, the duration of unplanned interruptions attributable to distribution companies stands at 41 minutes per user in low voltage (Figure 3.1). Furthermore, the frequency of long and short unplanned interruptions, collectively defined as events exceeding one second, reached 3.69 per low-voltage user (Figure 3.2).

Figure 3.2 Number of long and short unannounced interruptions per low-voltage user(A)



(A) Excluding major incidents on the transmission grid and defence system interventions.

Source: ARERA. Processing of declarations of operators.

The calculation of these values excludes: interruptions originating on the National Transmission Grid (RTN) and the high-voltage network; exceptional interruptions occurring during periods of disturbed conditions and on days with exceptional lightning activity (identified using two specific statistical methods); interruptions due to exceptional events, acts of public authorities and theft; and, from 2024 onwards, interruptions due to external causes (for the 2005-2023 period, interruptions due to external causes were included among interruptions attributable to distribution companies for most of the distribution companies participating in the incentive mechanism for the regulation of continuity of the electricity distribution service).

Individual standards on maximum interruption duration have applied since 2009 to low and medium-voltage users, and since 2012 also to producers at the same voltage levels, regardless of the cause of the outage. Starting from 2024, the standard for maximum interruption duration has been set at 8 hours for both low-voltage and medium-voltage users, and applies to both planned and unplanned interruptions (regardless of the population density of the municipality where the user is located, also referred to as the "degree of concentration").

In 2025, distribution companies paid automatic compensation of €38 million to approximately 627,000 low voltage users (an average of approximately €60 per user) and more than €3 million to approximately 3,000 medium voltage users (an average of approximately €1,150 per user).

For 2025, approximately €24 million of the total €41 million in compensation is borne by the Exceptional Events Fund established with CSEA, as it relates to interruptions for which the companies are not responsible. By contrast, approximately €18 million in compensation is borne by the distribution companies or Terna in respect of long-duration interruptions for which they are responsible.

Network connection times

User connections to the network can be active or passive. "Active connections" are those required by power generation plants to the transmission network or distribution networks, primarily to enable these plants to feed energy into the electricity system. "Passive connections", on the other hand, are those requested by final customers to the transmission or distribution networks to allow energy withdrawals from the electricity system.

The data presented in these pages on the **connection of active users** to the transmission network relate to activities carried out by Terna, while the data on the connection of active users to distribution networks relate exclusively to activities carried out by distribution companies with more than 100,000 customers.[123]. By contrast, data on the connection of passive users were collected from Terna and distribution companies as part of the data collection exercises on quality of service.

In 2025, Terna received 4,241 connection requests for electricity generation plants, corresponding to a total capacity of 362.3 GW, for which, in the same year, it issued 3,261 connection offers, corresponding to a total capacity of 291,3 GW. The average time for making the quotation available, net of permitted interruptions, was 52 working days. During the year, 1,429 of the 3,261 connection

[123] The analyses are based on data made available by distribution companies with more than 100,000 customers in accordance with Article 38 of the TICA. Specifically, for 2025, the data used were those provided by AcegasApsAmga, Areti, Deval, Duereti, e-distribuzione, Edyna, Ireti, SET Distribuzione and Unareti, which submitted information on connections of electricity generation facilities to the Authority in time for the preparation of this report. Data not submitted in time have therefore been excluded.

offers made available were accepted, corresponding to a total capacity of approximately 113.9 GW. Only five of these connection offers, representing a total capacity of 294 MW, resulted in requests for the provision of the Detailed Minimum Technical Solution (STMD). As Terna had not made the STMD available for any of these requests by 31 December 2025, no connections relating to applications received by Terna during 2025 were completed and commissioned during the year.

Distribution companies also received almost 291,000 connection requests for electricity generation facilities to be connected to low- and medium-voltage networks[124], corresponding to a total capacity of 37.6 GW. During the same year, they issued just over 256,000 connection quotations, corresponding to a total capacity of 23.7 GW, with the following average times for issuing quotations, net of permitted suspensions:

- 16 working days, for required feed-in power up to 100 kW;
- 46 working days, for required feed-in power of more than 100 kW and up to 1,000 kW;
- 63 working days, for required feed-in power of more than 1,000 kW.

Almost 240,000 of the connection quotations issued were accepted during the year, corresponding to a total capacity of 10.6 GW.

With regard to the requests received in 2025, more than 163,000 connections were completed by the end of the year, corresponding to approximately 2.1 GW, with the following average connection completion times, net of permitted suspensions:

- 22 working days in the case of simple works[125];
- 67 working days in the case of complex works[126],

while the average activation time for connections, net of permitted interruptions, was 6 working days.

In 2025, the only distribution companies to receive connection requests for electricity generation facilities to be connected to high-voltage networks were Edyna and e-distribuzione, which received 552 requests corresponding to a total capacity of 9.7 GW. During the same year, 258 connection quotations were issued, corresponding to a total capacity of almost 4.8 GW, with an average time for issuing a quotation, net of permitted suspensions, of 64 working days. Of the connection quotations issued, 74, corresponding to a total capacity of 1.4 GW, were accepted during the year; for three of these (representing a total capacity of approximately 32 MW), a request for the STMD to be made available was submitted by 31 December 2025.

With regard to the **connection of passive users** to distribution networks, the following was found:

For approximately 2,300 services involving simple works for new standard permanent connections, authorisations were required, with an average time of approximately 80 calendar days for distribution

[124] It should be noted that the data presented relate exclusively to activities carried out in 2025 by distribution companies with more than 100,000 customers that submitted the relevant information to the Authority in time for the preparation of this *Annual Report*.

[125] Simple works comprise the construction, modification or replacement, in accordance with good engineering practice, of the grid operator's facilities, where the work is limited to the service connection and, where applicable, the metering unit.

[126] Complex works comprise the construction, modification or replacement, in accordance with good engineering practice, of the grid operator's facilities in all cases not covered by the definition of simple works.

companies to obtain them; for approximately 15,200 services involving complex works for new standard permanent connections, authorisations were required, with an average time of approximately 152 calendar days for distribution companies to obtain them.

More generally, data collected as part of the quality of service data collection exercises, which cover data submitted by distribution companies with more than 5,000 connected users, comprising final customers and producers, showed that the following services were provided during the year:

- 213,773 services relating to new standard permanent connections for low-voltage users (94,424 requests for quotations, 81,544 instances of simple works and 36,805 instances of complex works) (Table 3.6). The average waiting times for these services were 10.6 days for obtaining quotations, 7.1 days for the completion of simple works and 40.7 days for the completion of complex works, all well within the standards set by the Authority;
- 7,934 services relating to new standard permanent connections for medium-voltage users (6,709 requests for quotations, 121 instances of simple works and 1,104 instances of complex works) (Table 3.7). The average waiting times for these services were 23.1 days for obtaining quotations, 46.6 days for the completion of simple works and 28.6 days for the completion of complex works. These times were within the standards set by the Authority, with the exception of the completion of simple works, for which the average time was more than twice the standard set by the Authority.

Table 3.6 Specific commercial quality standards for new standard permanent connections for LV users completed in 2025 by electricity companies with more than 5,000 connected users, comprising final customers and producers, for a total of 213,773 services

SERVICE	STANDARD	ANNUAL NUMBER OF REQUESTS	ACTUAL AVERAGE TIME	% NON-COMPLIANCE WITH THE STANDARD	NUMBER OF AUTOMATIC COMPENSATION PAYMENTS
Quotation for works on the LV network for new standard permanent connections	15 working days	95,424	10.59	4.18%	4,547
Completion of simple works for new standard permanent connections	10 working days	81,544	7.10	5.05%	4,606
Completion of complex works for new standard permanent connections	50 working days	36,805	40.68	12.06%	4,841

Source: ARERA. Based on data provided by distribution companies.

Table 3.7 Specific commercial quality standards for new standard permanent connections for MV users completed in 2025 by electricity companies with more than 5,000 connected users, comprising final customers and producers, for a total of 7,934 services

SERVICE	STANDARD	ANNUAL NUMBER OF REQUESTS	ACTUAL AVERAGE TIME	% NON-COMPLIANCE WITH THE STANDARD	NUMBER OF AUTOMATIC COMPENSATION PAYMENTS
Quotation for works on the MV network for new standard permanent connections	30 working days	6,709	23.08	6.64%	461
Completion of simple works for new standard permanent connections	20 working days	121	46.57	4.96%	6
Completion of complex works for new standard permanent connections	50 working days	1,104	28.55	9.70%	120

Source: ARERA. Based on data provided by distribution companies.

In 2025, Terna also realised 4 passive high and extra-high voltage connections with an average time of 322 working days.

3.1.6 Monitoring the electricity supply and demand balance

Monitoring the balance between electricity supply and demand does not fall within the competence of the Authority: according to Art. 1 of Legislative Decree No. 93/11, this competence is attributed to the Ministry for the environment and energy security (MASE).

3.1.7 Monitoring investments in generation and storage capacities from a security of supply perspective

Pursuant to Legislative Decree No. 93/11, the following functions regarding the monitoring of capacity investments have been assigned to the MASE:

- operational network security (Art. 7 directive 89/2005/EC);
- investments in interconnection capacities in the next 5 years or more (Art. 7 directive 89/2005/EC);
- supply and demand forecast for the next 5 years and 1-15 years (Art. 7 directive 89/2005/EC).

3.1.8 International coordination on the topics of electricity and natural gas

Coordination between European countries

For years, the Authority has been actively cooperating with other European regulators, both multilaterally, through the Agency for the Cooperation of Energy Regulators (ACER), the Council of European Energy Regulators (CEER) and the regional platforms provided for in the European electricity market regulations, and through bilateral meetings to explore topics of common interest, in particular with regulators from neighbouring countries.

In addition to its established activities relating to network codes and guidelines adopted under the Third Energy Package and the Clean Energy Package, participation in European implementation processes intensified during 2025 following the adoption of new legislative acts in 2024. In particular, cooperation continued with the European Commission, ACER and other national regulatory authorities on the implementation of the legislative package on renewable gases and hydrogen (Directive 2024/1788 and Regulation 2024/1789), which assigns new responsibilities to regulators in relation to integrated network planning, the governance of future hydrogen grid operators and the development of dedicated hydrogen markets. In the electricity sector, ARERA contributed to European work on implementing electricity market design reforms, which in 2025 focused in particular on capacity mechanisms, consumer protection and the resilience of balancing markets, including cooperation with ACER and initiatives relating to the European balancing energy exchange platforms PICASSO and MARI. Regulatory discussions also continued on the full implementation of the 70% Rule under Article 16 of Regulation (EU) 2019/943, taking into account ACER's 2025 monitoring reports, which highlight the benefits arising from increased capacity available for cross-border trade and from the development of capacity calculation methodologies across the various European Capacity Calculation Regions (CCRs). At the same time, following the entry into force of the revised REMIT Regulation (Regulation (EU) 2024/1106), the first technical discussions between national regulatory authorities and the Agency for the Cooperation of Energy Regulators (ACER) were launched in 2025 to adapt the requirements relating to registration, reporting and market surveillance. These discussions also took account of the updated Questions and Answers (Q&A) and ACER's first reports on Suspicious Transaction and Order Reports (STORs) and coordinated enforcement activities. Lastly, the Authority also participated in European initiatives concerning the development of strategic energy infrastructure, particularly the new monitoring cycle for Projects of Common Interest (PCIs) and Projects of Mutual Interest (PMIs) published by ACER in 2025, as well as the preparation of the 2025 list under the TEN-E Regulation, focusing on project implementation, permitting procedures and the consistency of network development plans.

European agency for the cooperation of energy regulators (ACER)

ACER is the agency introduced with the Third Energy Package to foster cooperation between the regulatory authorities of EU countries and assist them in the exercise, at Community level, of the regulatory functions performed in the Member States. The operational set-up is currently governed by Regulation 942/2019, which made some changes to the governance and competences of the Agency. In particular, ACER is now responsible for all the decisions concerning the implementing acts of the network codes originally submitted for approval by all authorities at European level: these recommendations are then directly sent to the Agency, which gives its own decision within six months of receipt. On the other hand, the primary competence of the regulatory authorities remains unchanged with regard to implementing acts of regional competence. ACER is also responsible for adopting a set of methodologies under regulation 943/2019 concerning the adequacy of the system

and the tasks of the Regional Coordination Centres.

At organisational level, the Agency underwent significant changes in its senior leadership in 2025. Director Christian Zinglersen stepped down on 15 October 2025 to take up a new role at the European Investment Bank; following his departure, the Administrative Board appointed Volker Zuleger as interim Director, with effect from 16 October 2025 and until the completion of the selection procedure for the new Director.

Within the Board of Regulators (BoR), comprising representatives of the national regulatory authorities of the 27 Member States, Clara Poletti completed her term of office and was succeeded on 17 September 2025 by Emmanuelle Wargon, Chair of the Commission de Régulation de l'Énergie (CRE), while George Niculescu (ANRE, Romania) was appointed Vice-Chair.

In 2025, the activities of the European Union Agency for the Cooperation of Energy Regulators (ACER) focused on the main areas of action set out in the Single Programming Document 2025-2027, aimed at ensuring the integrated, secure and transparent functioning of the internal energy market. Within this framework, the Agency continued to monitor and oversee the EU electricity and gas markets, conducting more in-depth analysis of wholesale markets, infrastructure, security of supply and the degree of integration of cross-border trade.

A significant area of activity during the year concerned the implementation of the new responsibilities arising from the legislative packages adopted in 2024, particularly the electricity market design reform and the renewable gas and hydrogen package, which assign ACER supervisory tasks in relation to emerging networks and markets, as well as responsibilities associated with the governance of future dedicated hydrogen systems. At the same time, the Agency further strengthened its tools for monitoring the integrity and transparency of wholesale markets, updating its implementation guidance following the revision of the REMIT Regulation and coordinating the activities of national authorities in relation to reporting, controls and enforcement.

During the year, ACER also continued its guidance and oversight activities relating to the European balancing platforms, assessing amendments to the implementation frameworks and monitoring the status of access by European transmission grid operators. As regards infrastructure, the Agency launched the new monitoring cycle for Projects of Common Interest and Projects of Mutual Interest (PCI/PMI), while also contributing to the process for selecting the 2025 list under the TEN-E Regulation.

Overall, the activities carried out in 2025 confirm the Agency's role in promoting regulatory consistency across Member States, enhancing the integration of European energy markets and supporting the implementation of the regulatory framework for the energy transition. The Authority has always worked closely with ACER. In particular, during 2025, ARERA representatives led specific task forces (system operation, infrastructure and hydrogen) and actively contributed to discussions within the various working groups by providing input and comments.

Council of European energy regulators (CEER)

CEER, the independent association of national energy regulatory authorities, brings together not only representatives from EU Member States, but also those from the United Kingdom, Norway and Iceland, as well as, with observer status, Albania, Switzerland, Montenegro, North Macedonia, Kosovo, Moldova, Bosnia and Herzegovina, Georgia and Serbia. Since December 2018, the role of President has been held by Annegret Groebel, Head of Department at the German regulatory authority.

In 2025, CEER continued its activities in line with its multiannual strategy, Empowering Consumers for the Energy Transition 2022-2025, aimed at promoting a regulatory framework capable of supporting the energy transition while strengthening consumer protection and the effective functioning of markets. Under its 2025 Work Programme, the association focused on three main areas: efficient integration of energy systems and infrastructure; dynamic, consumer-centric regulation; and well-functioning markets.

Activities carried out in 2025 included, first and foremost, initiatives to foster the development of sustainable infrastructure and the integration of energy systems, with analyses and guidelines on grid connections, flexibility, digitalisation and coordinated planning. A second pillar focused on strengthening consumer protection regulation, with particular attention to the comparability of offers, the development of tools for active consumer participation (including energy communities and energy sharing), the protection of vulnerable customers and transparency in the retail market. At the same time, CEER carried out work on cross-cutting issues such as data governance, cybersecurity and quality of service, reflecting the growing role of data and digitalisation in energy markets.

A further area of activity involved supporting the effective functioning of wholesale markets, through analysis of market innovations, monitoring of competitive dynamics and contributions to European discussions on security of supply and the evolution of market design. Activities also included the publication of 14 thematic reports during the year and the organisation of opportunities for discussion and training for national regulatory authorities, with a view to promoting the sharing of good practices and regulatory coordination at European level.

Overall, CEER's work in 2025 helped strengthen the role of national regulators in implementing EU energy legislation, supporting a consistent approach across Member States and promoting an energy transition centred on consumers, infrastructure efficiency and reliable markets.

CEER also promotes a range of training courses, open both to its members and to external participants, in which ARERA staff are frequently involved as trainers and/or speakers.

ACER Market Monitoring

Pursuant to Article 15 of Regulation (EU) 2019/942, during 2025 the Authority continued to work with ACER and CEER on the collection, validation and transmission of the data required for the preparation of the Market Monitoring Report (MMR), which is published annually and comprises a series of thematic volumes. Monitoring activities, carried out in accordance with ACER's implementation and effect monitoring strategy, are intended to assess the degree of integration of the European energy markets, the effective functioning of competition and the effectiveness of the internal energy market rules.

In 2025, monitoring activities covered an expanded and increasingly structured range of areas, reflecting the continued development of ACER's analytical framework. According to information published by the Agency, the 2025 volumes of the Market Monitoring Report covered:

- wholesale electricity and gas markets, including in-depth analysis of the functioning of spot and forward markets and price volatility dynamics;
- the availability of cross-border capacity and congestion management, including progress and challenges in the use of interconnectors, an issue of particular importance given the high congestion costs recorded in recent years;
- the degree of electricity market integration, with particular reference to day-ahead and intraday market coupling and the operation of the European balancing platforms (PICASSO for aFRR,

Automatic Frequency Restoration Reserve; MARI for mFRR, Manual Frequency Restoration Reserve), for which ACER notes that participation by European TSOs remains incomplete;
- security of electricity supply, focusing on system adequacy, demand dynamics, the role of interconnectors and analysis of capacity remuneration mechanisms;
- barriers to the participation of distributed energy resources, including non-dispatchable resources, storage systems and demand response, with particular attention to price signals and regulatory and technical barriers;
- retail markets and consumer protection, an area jointly monitored by ACER and CEER, with a specific focus in 2025 on the remuneration of flexibility and innovative contractual arrangements ("Rewarding Flexibility");
- the development of electricity infrastructure, including progress on investments that are essential to reduce congestion and facilitate the energy transition, an area in which ACER has identified uneven progress across Member States;
- the development of the liquefied natural gas (LNG) market, including analysis of developments in flows and liquidity and the increasingly important role of LNG in European energy security;
- and the emerging hydrogen market, for which ACER's monitoring activities included, for the first time, the systematic collection of data and indicators, in line with the new EU regulatory framework for renewable gas and hydrogen markets.

In recent years, ACER has also progressively changed the way in which the Market Monitoring Report is published, adopting a modular, multi-volume approach with publications staggered throughout the year. This approach reflects the increasing level of detail of the analyses, the expansion of the areas covered by monitoring activities and the need to make findings relating to individual market segments available more promptly.

Relations and initiatives with non-EU countries

In 2025, the Authority further consolidated its role as an international point of reference, reaffirming its commitment to promoting cooperation and collaboration in order to facilitate the exchange of best practices and technical and institutional expertise, at both bilateral and multilateral level.

Against the backdrop of ongoing developments and the challenges that continue to affect the energy sector, the Mediterranean and Balkan regions remained strategically important for the national energy system in 2025.

Energy market in south-eastern European countries

With the aim of supporting the integration of European and Balkan energy markets, in 2025, the Authority continued to build on activities launched in previous years, participating in the work of the Energy Community Regulatory Board (ECRB) and continuing its coordination activities and support for the implementation of the acquis communautaire by the Contracting Parties to the Energy Community Treaty.

At the Athens Forum in June 2025, the European Commission provided clarification on the procedure for validating the transposition of the Electricity Integration Package (EIP) by the Contracting Parties. The Energy Community Secretariat was tasked with collecting the tables of concordance and carrying out a preliminary assessment of the compliance of national legislation with the EIP requirements. The final assessment is carried out by the European Commission. The Commission also identified two further conditions for the integration of the Contracting Parties' electricity markets with the EU

electricity market: approval of the plan for integrating the Energy Community's Nominated Electricity Market Operators (NEMOs) into the operational arrangements for European market coupling; and the new capacity calculation regions, comprising both Member States and Contracting Parties to the Treaty, becoming operational.

In 2025, work also continued within the implementation group for the Italy-Montenegro market coupling project, established in 2024 by ARERA, REGAGEN (the Montenegrin regulatory authority), TERNA and CGES (Montenegro's transmission system operator). The group focused on defining the roadmap expected to lead to the integration of the Montenegrin electricity market with the Italian market by 2028, also in connection with the existing electricity interconnector between the two countries, as well as on developing the regional methodologies that grid operators will be required to submit to the regulatory authorities for approval once the transposition of the EIP in Montenegro has been completed, in accordance with the CACM Regulation adopted within the framework of the Energy Community.

Balkan Energy School – BES

In 2025, the Balkan Energy School (BES) [127]further strengthened its role as a regional hub for energy regulation, policy dialogue and capacity building in South-East Europe.
The activities were supported by the Central European Initiative (CEI) Fund at the European Bank for Reconstruction and Development under the Know-how Exchange Programme (KEP).
In 2025, four international seminars were organised, a new multi-year project on natural gas markets was launched and cooperation with institutions and energy-sector stakeholders was strengthened.
The seminar held in Podgorica on 13 March focused on forward electricity markets and their role in stabilising prices and supporting the energy transition. The discussion highlighted the essential role played by forward markets in risk management and in financing investment in renewable energy resources, particularly against a backdrop of high volatility and geopolitical uncertainty. Particular attention was paid to the Italian experience in congestion management and the multi-zonal model, as well as to the revision of the European guidelines on Forward Capacity Allocation (FCA). Innovative instruments such as Financial Transmission Rights (FTRs), Contracts for Difference (CfDs) and Virtual Hubs were also examined. The discussion clearly highlighted the need to strengthen the integration and liquidity of European forward markets while ensuring an adequate level of protection for smaller market participants.
The seminar held in Tirana on 8 April marked the launch of a new strand of work focusing on natural gas as part of the "EU Natural Gas Markets" project. It was the first event to focus entirely on gas market regulation, systematically addressing the functioning of supply and demand mechanisms, the role of hubs and the main price drivers. Considerable attention was devoted to infrastructure regulation and transmission tariffs, the prospects for decarbonisation through the integration of hydrogen and renewable gases, and security of supply, with particular reference to liquefied natural gas (LNG) and gas storage. The seminar reaffirmed the importance of alignment with EU regulatory standards as an essential condition for fostering market integration and supporting the accession process of the Balkan countries.
The seminar held in Skopje on 24 September examined the recent blackouts affecting a number of

[127] The BES brings together the national regulatory authorities of Albania (ERE), Bosnia and Herzegovina (SERC), Greece (RAEEY), Kosovo (ERO), Italy (ARERA), Montenegro (REGAGEN) and North Macedonia (ERC), with Serbia (AERS) participating as an observer. Its mission is to strengthen regulatory expertise, foster market integration and support the alignment of the Balkan energy systems with EU legislation and decarbonisation objectives. The BES is led by ARERA, which has held the presidency since the School was established in 2022.

European and Balkan electricity systems, highlighting the close interconnection between technical, operational and regulatory factors in managing system-wide crises. The discussion identified the need for more effective vegetation management, the adoption of more advanced monitoring and observability tools, stronger flexibility resources and increased investment in modern, digital and resilient grids. The exchange helped translate the lessons learned from critical events into practical guidance for improving grid stability and security.
The seminar held in La Spezia on 7 October explored the regulation of gas infrastructure under the European Gas and Hydrogen Package, focusing on rules governing non-discriminatory access to networks, developments in network codes, tariff transparency and cost reflectivity, and the main regulatory models – from cost-plus approaches and incentive-based regulation to the TOTEX approach. Particular emphasis was placed on preparing networks for the future integration of hydrogen and on the need to combine investment efficiency with economic sustainability. The programme also included a technical visit to the Panigaglia LNG terminal, providing participants with practical insights into issues relating to security of supply.
Between May and June, a five-session online course was organised on developing soft skills to improve communication skills, active listening, the ability to manage discussions and the provision of constructive feedback.
On 19 November, the first meeting with the Council of European Energy Regulators (CEER) was held in Brussels.
The initiatives described above promoted extensive knowledge transfer across the electricity and gas sectors, supporting the adoption of innovative regulatory models – such as TOTEX, revenue caps and incentive-based mechanisms focused on quality of service – while also helping to strengthen the resilience of energy systems. In parallel, progress continued towards alignment with the EU acquis, consolidating the BES's role as a reliable partner in the energy integration and transition process.
In 2025, country reports were prepared in close cooperation with the regulatory authorities of the member countries, including ARERA, ERE, SERC, RAAEY, REGAGEN and ERC. These highlighted significant developments across the different national contexts: from the integration of energy storage systems in North Macedonia to the launch of virtual power plants in Bosnia and Herzegovina; from ambitious auctions for battery storage systems in Greece to Albania's progress towards carbon pricing mechanisms aligned with the European Union; and cooperation between Italy and Montenegro on the implementation of market coupling.
Lastly, a study entitled "The evolution of forward electricity markets in Europe: review of policy options" was produced.

Energy market in Mediterranean countries

In 2025, ARERA continued to play an active role in supporting MEDREG (Mediterranean Energy Regulators), an association in which it holds the position of Permanent Vice-President and whose Secretariat it hosts in Milan.
During the year, the Authority participated in the following meetings:

- on 16 April in Como, where MEDREG promoted discussion on the innovative role of artificial intelligence in the energy sector through the workshop Energy Regulators of the Mediterranean Explore Artificial Intelligence's Transformative Role in the Energy Sector, examining practical applications, development opportunities and potential regulatory and operational implications;
- on 27 May in Antalya, where MEDREG and Med-TSO (the Association of Mediterranean Transmission System Operators) organised a workshop entitled Tighten Cooperation for an Interconnected Mediterranean Electricity Market. The workshop examined practical strategies for enhancing the efficiency and reliability of electricity interconnections in the Mediterranean

region, which play an essential role in ensuring energy security, the stability of electricity systems and more effective integration of renewable energy sources into national and regional markets;
- on 28 May in Antalya, where the 39th MEDREG General Assembly was held;
- on 26 November in Madrid, where MEDREG organised the workshop Powering the Lights: Energy Regulation, Resilience and Regional Integration in the Mediterranean, with the aim of identifying practical recommendations to improve cross-border electricity interconnections and strengthen the resilience of electricity systems in the Euro-Mediterranean region;
- and on 27 November in Madrid, where the 40th General Assembly was held.

During 2025, the technical working groups focused on the following areas:
- the Institutional Working Group, chaired by the Italian Authority, prepared the report Benchmark of Good Practice on Dynamic Regulation and organised the related workshop, which examined the adoption by MEDREG members of more flexible regulatory approaches in the energy sector in response to price volatility, technological change and market uncertainty;
- the Electricity Working Group prepared the report Adequacy Mechanism's Role in the Improvement of the Electricity System, which provides a comprehensive analysis of the adequacy mechanisms currently used in the Mediterranean region and examines how these mechanisms, which are essential to ensuring a stable and reliable electricity supply, are designed, implemented and monitored from a regulatory perspective;
- the Renewable Energy and Energy Efficiency Working Group prepared the report Regulatory aspects of Green Electricity Trading in the Mediterranean Region and organised the Energy Storage workshop. The report compares the regulatory frameworks governing green electricity trading across the Mediterranean region, covering EU Member States, Balkan countries and countries on the southern and eastern shores of the Mediterranean. It analyses renewable energy integration mechanisms, the role of Corporate Power Purchase Agreements (CPPAs) and green electricity certification schemes, highlighting the main challenges and setting out recommendations to support an integrated Mediterranean green electricity market.
- the Gas Working Group prepared the report The Impact of Emission Reduction, which examines the decarbonisation of the Mediterranean energy sector, a key issue for the region's energy security and climate objectives. The report shows that the gas supply chain needs to reduce methane and carbon dioxide emissions through the use of advanced technologies such as leak detection and repair, satellite monitoring, combined cycle gas turbines, carbon capture and storage facilities and biomethane injection. The transition is being slowed by differences in regulatory frameworks between European and non-European countries, high costs and the risk of carbon leakage. A two-pronged strategy is therefore required: on the one hand, strengthening regulatory frameworks in line with international standards and, on the other, mobilising the market to attract private investment. National regulatory authorities need to have full powers over technical compliance and infrastructure in order to optimise decarbonisation efforts and protect critical energy infrastructure;
- the Hydrogen Task Force presented the Benchmark report on low carbon/green hydrogen policy and regulation, which is structured around four key pillars: national strategy, regulatory framework, institutional framework and financial support. On 24 September, MEDREG, CEER and ECRB held a trilateral workshop in Vienna entitled Hydrogen in Action: Regulation, Decarbonization and Cross-Border Exchange. The workshop aimed to strengthen understanding of the EU regulatory framework for hydrogen and foster the exchange of regulatory experience and practices among the different authorities, helping to identify common challenges in the development of renewable and low-carbon hydrogen markets;
- the Consumer Working Group produced the report Update Technical and Non-Technical Losses,

an update of the 2022 report on the same topic, which examined the quantitative effects of COVID-19 and rising prices on technical and non-technical losses. The new report provides a comprehensive analysis of the strategies adopted to mitigate both technical losses (TL) and non-technical losses (NTL) in Mediterranean electricity and gas networks. The findings show that, although the fundamental challenge of reducing losses is universally recognised, the effective management of such losses is hampered by data gaps and the absence of fully modernised regulatory frameworks.

As part of MEDREG's activities, the 7th trilateral workshop with the Council of European Energy Regulators (CEER) and the Energy Community Regulatory Board (ECRB) was held in Vienna, focusing on consumer protection and engagement in the energy sector. The main topics addressed included reducing energy costs through market reforms and energy efficiency, the role of energy sharing and renewable energy, and the importance of providing consumers with clear information on their bills and the origin of their energy to enable them to make more informed choices.
As part of the cooperation between MEDREG and Med-TSO, a Joint Workshop on Guarantees of Origin in the Mediterranean Region was held on 25 October 2025, followed by the preparation of a report analysing how Guarantees of Origin (GOs) support the traceability of renewable energy, the integration of green energy markets and cross-border Power Purchase Agreements (PPAs) between the European Union and Southern Mediterranean partners, while also highlighting the main challenges relating to transparency, credibility and regional interoperability.
It is worth noting that, for the 2026-2029 period, MEDREG will support the European Commission's Trans-Mediterranean Renewable Energy and Clean-Tech Cooperation Initiative (T-MED) under the Pact for the Mediterranean, promoting regulatory convergence and the development of the Euro-Mediterranean energy sector. In particular, MEDREG will contribute to improving the regulatory framework for investment in renewable energy, including through new national regulatory reviews aimed at monitoring and comparing sector governance, and will foster dialogue between regulators, governments and the private sector. It will also work to strengthen the regulatory framework for the development of sustainable infrastructure (electricity and hydrogen) and promote training and knowledge-sharing activities among regulators across the region.

Bilateral relations

In 2025, ARERA also continued its dialogue with institutions and regulatory authorities from non-European countries:

- on 27 January, a meeting was held with a Tunisian delegation comprising representatives of the Ministry of Energy and the transmission system operator STEG. The delegation's visit formed part of a project funded by the German development agency GIZ under a programme for the development of renewable energy in Tunisia;
- on 31 March, a meeting was held with representatives of Bhutan's Energy Regulatory Authority (ERA) to discuss energy-sector issues, with particular emphasis on gathering information that could support the development of incentive mechanisms for renewable energy sources in Bhutan, specifically in the geothermal and solar photovoltaic sectors.

3.1.9 Implementation of Network Codes and guidelines for the integration of european electricity markets

Integration of the wholesale electricity market and implementation of European regulations

Network Codes and Guidelines constitute technical regulatory rulings, designed to facilitate the completion of the internal energy market. Informally, they can be grouped into three major categories: market, connection, and network management.

The regulations are divided into Network Codes (NCs) and Guidelines (GLs): the former set out rules that are directly applicable in all EU Member States, while the latter provide a general framework on the basis of which a series of implementing provisions, known as Terms and Conditions or Methodologies (referred to generically in Italian as metodologie), must be developed. The publication of regulations does not, therefore, complete the work of developing and issuing secondary rules; conversely, each regulation as a guideline foresees the preparation, by the Transmission System Operator (TSO) and/or the Nominated Electricity Market Operator (NEMO), of specific provisions (namely, the methodologies) to be assessed and approved by the regulatory authorities of each EU member state or ACER; methodology development can also be provided for under Network Codes, albeit to a lesser extent.

Table 3.8 Network Codes and Guidelines under Regulation (EC) No 714/2009

CODE	REGULATION	ABBREVIATION (ACRONYM)	EFFECTIVE DATE
Market Codes	Regulation (EU) 2015/1222	*Capacity allocation and congestion management guideline* (CACM GI)	15 August 2015
	Regulation (EU) 2016/1719	*Forward capacity allocation guideline* (FCA GI)	17 October 2016
	Regulation (EU) 2017/2195	*Electricity balancing guideline* (EB GI)	18 December 2017
Connection Codes	Regulation (EU) 2016/631	*Requirements for network code generators* (RfG NC)	17 May 2016
	Regulation (EU) 2016/1388	*Demand connection network code* (DCC NC)	7 September 2017
	Regulation (EU) 1447/2016	High voltage direct current network code (HVDC NC)	28 September 2016
Network management codes	Regulation (EU) 1485/2017	System operation guideline (SO GI)	14 September 2017
	Regulation (EU) 2196/2017	Emergency and restoration network code (ER NC)	18 December 2017

Source: ARERA.

Regulation (EU) 1222/2015 (CACM Regulation)

Regulation (EU) 2015/1222, known as the Capacity Allocation and Congestion Management (CACM) Regulation, lays down common rules for the operation of European market coupling in the day-ahead and intraday markets, ensuring the efficient use of transmission capacity and price convergence across the EU. It establishes methodologies for coordinated capacity calculation, implicit allocation processes and the development and operation of coupling algorithms. The Regulation also governs the roles of TSOs and NEMOs, providing for mandatory cooperation mechanisms and the establishment of Capacity Calculation Regions (CCRs). CACM provides the technical and regulatory framework underpinning the integration of European electricity markets, ensuring transparency, interoperability and the secure management of cross-border flows.
During 2025, implementation of the CACM Regulation continued to play a central role in further consolidating the integration of European day-ahead and intraday electricity markets. In this context,

the Authority monitored developments in the contractual and methodological framework governing market coupling at Italy's interconnections, assessing the consistency of operational agreements with both European and national regulatory requirements while supporting key initiatives aimed at strengthening cooperation between grid operators and nominated electricity market operators.
The measures concerned, in particular:

- the governance of Nominated Electricity Market Operators (NEMOs)[128];
- the introduction of 15-minute products in day-ahead market coupling[129];
- the alignment of the Italian Border Working Table Operational Agreement [130]with the European contractual framework and preparations to ensure the proper functioning of the European electricity market and its extension to the Balkan countries;
- the successful assessment [131]of the amendment to the Settlement Link Agreement between GME and CCP Austria (ABG), relating to Single Day-Ahead Coupling.

At regional level, the Authority continued to monitor developments in the evolution of the Capacity Calculation Regions (CCRs), particularly the merger of the Core and Italy North CCRs into the new Central Europe region and the gradual transition towards flow-based methodologies, aimed at improving network utilisation, providing more efficient price signals and enhancing the integration of the European electricity markets[132].

CACM 2.0 Regulation

In June, the European Commission launched the comitology procedure under Regulation (EU) 182/2011 for the revision of Regulation (EU) 2015/1222 (CACM), which governs the operation of the European day-ahead and intraday electricity markets.
The proposed revision addresses a wide range of issues, two of which are expected to have a particularly significant impact on the Italian electricity sector: the governance of market coupling and the requirement to make at least 70% of interconnection capacity available to market participants.
Currently, market coupling governance is based on a decentralised cooperation model, under which the Market Coupling Operator (MCO) function is performed by NEMOs on a rotating basis. In addition, subject to verification that certain legal conditions are met, Member States may decide which market model to adopt for the provision of NEMO services. In accordance with Legislative Decree No 79/99, Italy has opted for a legal monopoly regime. Lastly, the decentralised cooperation approach also applies to transmission grid operators, particularly with regard to activities relating to the calculation of interconnection capacity.
The Commission proposed three changes to the governance framework described above: (i) a transition to a centralised model based on the establishment of a single European entity, known as the Single Market Coupling Operator (SMCO), which would replace NEMOs in performing the MCO function; (ii) the general abolition of legal monopolies for NEMOs within three years of the Regulation entering into force; and (iii) the transfer to Regional Coordination Centres (RCCs) of certain

[128] Resolution 233/2025/R/eel of 3 June 2025.

[129] Resolution 372/2025/R/eel of 29 July 2025.

[130] Resolution 406/2025/R/eel of 9 September 2025.

[131] Resolution 578/2025/R/eel of 23 December 2025.

[132] Resolution 461/2025/R/eel of 21 October 2025.

responsibilities currently assigned, at regional level, to national transmission grid operators.
With regard to the second aspect, concerning the provision of interconnection capacity, the Commission proposed amending the capacity calculation methodologies to ensure higher levels of cross-border trade capacity and to extend compliance with the 70% rule laid down in Regulation (EU) 2019/943 to the intraday timeframe.

Regulation (EU) 2016/1719 (FCA Regulation)

Regulation (EU) 2016/1719, known as the Forward Capacity Allocation (FCA) Regulation, governs the long-term allocation of transmission capacity between bidding zones, laying down harmonised rules for auctions, products and price risk management. The Regulation introduces Long-Term Transmission Rights (LTTRs) and the related compensation mechanisms, facilitating efficient hedging against zonal price spreads. It also establishes the roles and responsibilities of TSOs and NEMOs in allocation processes, as well as the requirement for common methodologies for forward capacity calculation. The FCA Regulation is a key pillar of European electricity market integration, ensuring predictability, transparency and consistency across the different Capacity Calculation Regions.
Against this backdrop, during 2025 ARERA launched [133]a consultation in May and adopted [134]provisions in July confirming, for the 2026-2029 four-year period, the continued use of hedges against volatility in the consideration for the allocation of transmission capacity (CCC/FTR), as these are better suited to the hedging needs of market participants. Even following the discontinuation of the single national price from 1 January 2025, market participants remain exposed to the difference between the PUN Index (to which demand-side prices are linked through the application of the compensatory component) and zonal prices.

Regulation (EU) 2017/1485 (SOGL Regulation)

Regulation (EU) 2017/1485, known as the System Operation Guideline (SOGL), lays down harmonised rules for the secure and coordinated operation of European electricity systems. It governs the operational requirements for TSOs and DSOs, frequency and voltage management, information exchange procedures and cross-border cooperation mechanisms. The Regulation introduces key concepts such as Load-Frequency Control Blocks, common reserve dimensioning and common methodologies for operational security. SOGL provides the technical framework for ensuring the stability, reliability and interoperability of the European electricity system in the context of market integration and the increasing penetration of renewable energy.
During 2025, implementation of the SOGL provisions continued in the Continental Europe synchronous area. In February 2025, ARERA formally ratified [135]the approval, jointly adopted by all regulatory authorities within the synchronous area, of the probabilistic methodology for sizing the Frequency Containment Reserve (FCR). The revised methodology takes account of the increasing penetration of resources with limited energy capacity and the growing volatility of demand and electricity generation from variable renewable energy sources. In July, ARERA ratified the update,

[133] Consultation 214/2025/R/eel of 27 May 2025.

[134] Resolution 338/2025/R/eel of 22 July 2025.

[135] Resolution 35/2025/R/eel of 11 February 2025.

again jointly approved [136]by all regulatory authorities, to the hierarchical structure of the Load-Frequency Control Blocks to take account of the new block comprising Lithuania, Latvia and Estonia, which synchronised with Continental Europe on 9 February.
Lastly, in 2025 a new proposal was submitted by the TSOs of the Continental Europe synchronous area concerning the definition of the minimum FCR delivery period for limited energy reservoir devices during the system alert state. The proposal is currently being assessed by the regulatory authorities, which are expected to adopt a decision in 2026.

Regulation (EU) 2017/2195 (Electricity Balancing Regulation)

Regulation (EU) 2017/2195, known as the Electricity Balancing Guideline (EBGL), governs the European integration of balancing markets, laying down common rules for the procurement, activation and settlement of balancing reserves. The Regulation introduces common European platforms – MARI for manual Frequency Restoration Reserve (mFRR), PICASSO for automatic Frequency Restoration Reserve (aFRR) and IN for imbalance netting – promoting competition, allocational efficiency and the coordinated use of cross-border resources. It also establishes the roles and responsibilities of TSOs and NEMOs, together with harmonised methodologies for the prequalification of resources, price formation and imbalance management. The EBGL is a key pillar of European dispatching market integration, enhancing operational security, transparency and consistency with the internal energy market.
In July 2025, ARERA approved [137]the amendments to Terna's Network Code required for the full implementation of TIDE (rev. 4) and reconnection to the European PICASSO platform for the exchange of balancing energy from aFRR. To ensure full alignment with the European target model for balancing market integration, the coordination model between national dispatching and participation in the platform was completely revised. This fully implemented the activation of aFRR according to the merit-order mechanism and enabled all available aFRR bids to be shared on the platform, in addition to those procured by Terna (the so-called "free bids"). In September 2025, ARERA also established[138] the regulatory framework required to begin participation in the European MARI platform for the exchange of balancing energy from mFRR. In particular, amendments to the Network Code were approved to coordinate the national balancing and redispatching market with the platform. These include a bid conversion process and a security analysis to ensure that bids submitted to the platform are compatible with the technical constraints of generating units and network security constraints, as well as arrangements for calculating Terna's mFRR demand and rules governing settlement with Balancing Service Providers. Finally, in October 2025, ARERA approved [139] Terna's contractual arrangements relating to its participation in the European balancing platforms established under the Electricity Balancing Guideline. The Authority reviewed the agreements entered into by Terna and verified the operational readiness of the related technical and functional interfaces, identifying where appropriate the need for amendments to the Network Code and enhancements to information exchange processes.

[136] Resolution 330/2025/R/eel of 15 July 2025.

[137] Resolution 364/2025/R/eel of 29 July 2025.

[138] Resolution 423/2025/R/eel of 23 September 2025.

[139] Resolution 468/2025/R/eel of 28 October 2025.

Regulation (EU) 2019/943

Regulation (EU) 2019/943 lays down the fundamental principles governing the operation of the EU internal electricity market, promoting competition, integration and system security. The Regulation establishes requirements relating to price formation, network access, congestion management and the participation of flexible resources and demand response. It introduces harmonised rules for efficient market operation, ensuring technology neutrality and appropriate investment incentives. It also provides for common mechanisms to ensure the availability of the resources required for system balancing and stability. Overall, the Regulation forms the cornerstone of the new European electricity market framework, in line with the Clean Energy Package.
Regulation (EU) 2019/943 introduces a harmonised framework for assessing electricity system adequacy, entrusting ENTSO-E with the preparation of the European Resource Adequacy Assessment (ERAA) and ACER with the review of the related methodology, thereby ensuring a common approach to security of supply. It also establishes the "70% rule", which requires transmission grid operators to make at least 70% of interconnection capacity available for cross-border trade, thereby fostering market integration and reducing internal congestion. Lastly, Article 19 provides that congestion rent is to be used as a priority to guarantee the availability of allocated capacity and to maintain or increase network capacity, allowing it to be used to reduce network tariffs only where these conditions have been met. Building on this framework, Regulation (EU) 2024/1747 further strengthened the European focus on flexibility, recognising it as a structural component of the internal electricity market and of the secure operation of an electricity system increasingly dominated by variable renewable generation. The new provisions introduced more stringent requirements for assessing flexibility needs and removing barriers to the participation of flexible resources in the markets, in line with the new Flexibility Needs Assessment Methodology (FNAM), while helping to align national assessments with European objectives for security, efficiency and market integration.

Implementation of Regulation (EU) 2019/943 – National Electricity System Adequacy Assessment

ENTSO-E prepared the 2025 edition of the European Resource Adequacy Assessment (ERAA), which provides a probabilistic assessment of adequacy risks for the European electricity system over the 2026-2035 period. In December 2025, ENTSO-E published the assessment on its website and submitted it to ACER for review of the methodology applied.
The assessment confirms that, over the short to medium term (2028-2030), 6-8 GW of dispatchable capacity could potentially be decommissioned, with possible implications for adequacy margins in several Member States. It therefore highlights the need to accelerate investment in network infrastructure, strengthen flexibility resources – including energy storage systems, demand response and cross-border resources – and develop new interconnections. These are essential to ensuring sufficient capacity availability by 2035, against a backdrop of strong demand growth and increasing investment uncertainty. In parallel, during 2025 ENTSO-E continued to update the ERAA methodology, as requested by the European Commission and ACER, in order to improve the representation of active demand, energy storage and interactions between systems, in line with the reformed Electricity Market Design framework.

Implementation of Regulation (EU) 2019/943 – Flexibility

In 2025, the adoption of the Flexibility Needs Assessment Methodology (FNAM), approved by ACER on 16 April 2025, was also completed. For the first time, the FNAM introduces a harmonised methodology for assessing the flexibility needs of European electricity systems, implementing the

reformed Electricity Market Design framework. The FNAM establishes common criteria for quantifying flexibility needs and assessing the contribution of different resources – energy storage systems, demand response and cross-border resources – ensuring comparability and consistency between national and European assessments.
Following its approval, Member States are required to prepare their Flexibility Needs Reports by April 2026, using the FNAM methodology as a binding reference framework. These reports will be assessed by ACER, which will review their methodological consistency, the transparency of the underlying assumptions and their alignment with European standards, thereby contributing to the development of an integrated framework for national and pan-European assessments. During 2025, ENTSO-E also began progressively integrating the FNAM into its analytical activities, improving the representation of active demand and energy storage within the ERAA methodological framework. As part of the consultation process, ACER highlighted the need to enhance data transparency and harmonise underlying assumptions in order to ensure fully comparable assessments that can effectively support European planning processes. Overall, 2025 marked a year of consolidation for the common European framework for assessing flexibility needs, which is intended to support system security and the integration of flexible resources into energy markets.

3.1.10 Regulations governing borders with non-EU countries

Interconnections with non-EU countries require specific regulatory attention, as these borders do not fall within the market coupling mechanisms governed by EU regulations and capacity continues to be allocated explicitly. In this context, the Authority acts to ensure transparency, operational coordination and consistency with the principles of the CACM/FCA framework, while ensuring non-discriminatory access and the efficient use of interconnections. In 2025, these requirements resulted in updates to the allocation rules at the borders with Switzerland and Montenegro, taking into account both the institutional specificities of third countries and the need to maintain compatibility with developments in the methodologies applied by the EU Capacity Calculation Regions. These measures are aimed at reducing operational risks, enhancing predictability for market participants and preserving technical integration with European processes for cross-border capacity calculation and management.

Rules governing the border with Switzerland

In March 2025, ARERA approved [140]the rules for the explicit allocation of transmission capacity at the Italy-Switzerland border for the long-term, day-ahead and intraday timeframes, ensuring consistency with the principles of the CACM/FCA framework while taking account of the institutional specificities of the Swiss counterpart. The framework governs product and rights types, auction platforms and calendars, participation requirements, firmness conditions and curtailment management, fallback procedures and information requirements for market participants. This approach provides regulatory certainty and operational predictability in a context where explicit allocation remains in place, while preserving compatibility with the market coupling model where applicable and with methodological developments in neighbouring Capacity Calculation Regions (CCRs).

[140] Resolution 119/2025/R/eel of 25 March 2025.

Rules governing the border with Montenegro

In November 2025, ARERA approved [141]the rules for the allocation of long-term transmission rights and daily transmission rights at the Italy-Montenegro border, applicable from 2026, in line with the principles of the CACM/FCA framework and the Energy Community regulatory framework. The rules define the products and allocation of responsibilities between the TSOs, the level of firmness of the rights, as well as information procedures and operational coordination arrangements for managing auctions and the settlement of financial transactions. In particular, ARERA approved the joint proposal submitted by Terna and the Montenegrin transmission grid operator CGES to entrust the Joint Allocation Office (JAO), from 2026, with the allocation of transmission rights previously carried out by the Coordinated Auction Office in South East Europe (SEE CAO, the allocation office based in Podgorica). The transition to JAO as the allocation office will enable greater harmonisation of the auction rules applicable at the Italy-Montenegro border with those applied at borders between EU Member States.

3.2 Competition and the functioning of markets

3.2.1 Wholesale markets

Table 3.9 shows the electricity balance in Italy in 2025 compared to the previous year; the data is from Terna and is provisional for 2025.

Table 3.9 Terna's balance of electricity in Italy

AVAILABILITY AND USE (GWh)	2024	2025(A)	CHANGE
Gross production	270,963	277,375	2.4%
Auxiliary services	7,734	7,919	2.4%
Net production	263,229	269,456	2.4%
Received from foreign suppliers	55,908	51,798	-7.4%
Sold to foreign customers	4,908	4,909	0.0%
Intended for pumping	2,141	2,323	8.5%
Absorption of stand-alone storage	174	1,662	855.8%
Availability for consumption	311,914	312,360	0.1%
Network leakages	19,201	19,207	0.0%
Consumption net of leakage	292,713	293,153	0.2%

(A) Provisional data.

Source: ARERA processing based on Terna data.

In 2025, electricity demand amounted to approximately 312.4 TWh, up 0.1% compared with 2024. Taking into account network losses of 19.2 TWh, electricity consumption increased slightly from 292.7 TWh to 293.2 TWh (+0.2%). This modest increase was entirely attributable to the services sector (see below). Electricity available for consumption (or demand) was met for 85% by domestic generation (net of electricity used for pumped storage and absorbed by storage systems), with the remaining 15% covered by the net balance of electricity exchanges with other countries. Gross domestic generation increased by 2.4%, imports fell by 7.4%, while electricity exports remained unchanged; as

[141] Resolution 517/2025/R/eel of 25 November 2025.

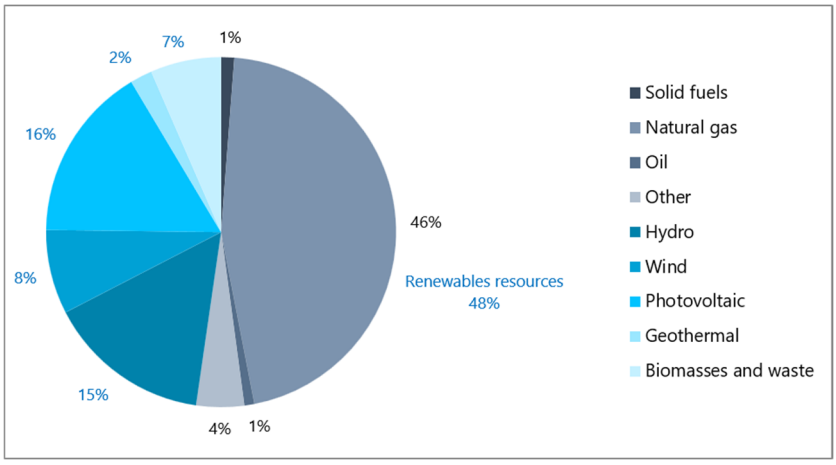
a result, the net import balance decreased by 8%, from 51 TWh to 46.9 TWh.

Also noteworthy was the sharp increase, from 0.2 TWh to 1.7 TWh, in electricity absorbed by stand-alone storage systems. This represents the amount of electricity that large storage systems not directly connected to generation facilities draw from the national grid to charge during periods of excess generation or low prices and subsequently feed back into the grid during periods of peak demand or emergencies, thereby helping to ensure the stability of the electricity system. This is an important component of the energy balance, as it shows how electricity generated can be stored rather than lost and subsequently used efficiently, thereby supporting the energy transition.

In 2025, peak demand, at approximately 56.2 GW, was recorded on Tuesday, 1 July between 2:00 pm and 3:00 pm (-9% compared with the 2024 peak of 57.9 GW).

Gross domestic electricity generation also increased by 2.4%, reaching 277.4 TWh compared with almost 271 TWh in the previous year. In particular, thermal generation increased by 5.2%, while generation from renewable energy sources declined by 1.5%. Within thermal generation, electricity production from solid fuels fell significantly (-15%), while generation from other fuels declined by 7.8%. By contrast, natural gas-fired generation increased by 7%, reaching almost 127 TWh.

Figure 3.3 Gross production by source in 2025



Source: Terna, provisional data.

Renewable energy resources accounted for 48% of the domestic electricity generation mix in 2025 (Figure 3.3), compared with 50% in the previous year. An increase was recorded only for solar PV (+25%) and bioenergy (+5.1%), while geothermal generation declined only marginally (-0.3%). Hydroelectric generation fell by 21% to almost 42 TWh, returning close to its 2023 level (40.5 TWh), while wind generation decreased by 3.3%. Despite the decline in renewable generation, hydropower plants still accounted for 31.7% of renewable electricity generation; among the other renewable sources, solar PV plants accounted for the largest share, at 34%.

Table 3.10 Producers, plants and electricity generation in 2025

PRODUCERS, PLANTS AND GENERATION BY SOURCE	THERMOELECTRIC	RENEWABLES	MIXED	TOTAL
Number of producers	416	17,995	644	19,055
Gross power (MW)	22,520	46,221	52,501	121,241
Gross generation (TWh)	71.3	91.9	88.0	251.2

Source: ARERA. Annual Survey of Regulated Sectors.

Table 3.10 shows the number of producers, available capacity and related generation in 2025 for thermal, renewable and mixed generation, based on data collected through the Authority's Annual Survey of Regulated Sectors, which this year covers 90.5% of the gross generation reported by Terna in its provisional data. Mixed operators, with both thermal and renewable generation, account for a large share of total capacity, amounting to 52,501 MW (43% of total capacity), while, as usual, representing just over 3% of the electricity producers participating in the survey (644 out of 19,055). Their share of total generation increased compared with the previous year, rising to 35% (88 TWh out of a total 251.2 TWh), from 32.5% in 2024.

The combined share of gross electricity generation accounted for by the three largest corporate groups (Enel, Eni and Edison) increased to 29.5%, compared with 28.9% in 2024. This was driven by the increase in Edison's market share, from 6.2% to 8.1%, while the shares of Enel and Eni declined from 13.5% to 12.3% and from 9.2% to 9.1%, respectively. The groups A2A (this year 5.4% versus 5.8% in 2024) and EPH (4.6% instead of 4.3% in 2024) remained, respectively, in fourth and fifth position. The Herfindahl-Hirschman Index (HHI) for gross generation, which has consistently remained very low over time, stood at 400, broadly unchanged from the previous year.

Table 3.11 Evolution of demand and installed capacity in the electricity sector

YEAR	REQUEST(A) (TWh)	PEAKING DEMAND (GW)	INSTALLED CAPACITY NET CAPACITY (GW)	CORPORATE GROUPS WITH >5% SHARE IN NET GENERATION	% SHARE OF TOP 3 GROUPS IN NET GENERATION
2010	326.2	56.4	106.6	5	48.2
2011	332.3	56.5	118.8	4	43.6
2012	325.5	54.1	124.6	3	41.2
2013	316.0	53.9	124.5	3	39.1
2014	308.2	51.6	121.8	3	41.2
2015	315.0	60.5	117.0	3	40.1
2016	311.8	56.1	114.2	4	43.9
2017	318.1	56.4	114.2	5	35.6
2018	319.1	57.6	115.2	4	35.4
2019	317.2	58.8	116.4	5	33.3
2020	298.5	55.4	116.4	5	31.7
2021	317.0	56.1	117.2	5	33.6
2022	312.4	57.4	120.9	5	34.4
2023	302.8	58.5	127.8	4	34.3
2024	309.8	57.9	135.4	2	31.6
2025(B)	310.0	56.2	142.6	3	32.0

(A) Net of energy for pumping and gross of network leakages.
(B) Provisional data.

Source: Compiled by ARERA using data from Terna and the Annual Survey on Regulated Sectors.

In 2025, total net capacity recorded by the Annual Survey stood at 118.6 GW (provisional figure), comprising 52% renewable capacity and 48% thermal capacity[142]. Peak demand on the electricity system was recorded on 1 July, when it reached 56.2 GW, down from the 2024 peak of 57.9 GW. The summer peak, however, no longer reached the all-time maximum for the Italian electricity system, recorded in summer 2015 at 60.5 GW. Based on Terna's provisional data, three groups accounted for more than 5% of total net installed generating capacity: Enel, A2A and Edison. The share of capacity

[142] Terna's installed net capacity amounted to 135.4 GW in 2024 and 142.6 GW in 2025 (Table 3.11).

held by the first three groups is 32%. The HHI for net capacity stands at 527.

In Italy, a range of support schemes coexist for electricity generation plants powered by renewable energy sources, ranging from all-inclusive feed-in tariffs[143] to feed-in premium[144] support schemes. The calculation of annual public expenditure on feed-in tariff incentives is a function of electricity output and prevailing average market prices. Such costs may be negative where the expenditure incurred by GSE in disbursing fixed all-inclusive tariffs is outweighed by the income realised from wholesale electricity sales. In contrast, for a variable feed-in premium, the cost impact cannot fall below zero.

Overall, the incentivisation of renewable energy resources cost approximately €9.3 billion in 2025, an increase of 4.3% compared to the previous year. Resources for the support of renewable energy resources are generally placed in the Account for new installations powered by renewable and assimilated resources, fed by the A_{SOS} tariff component. The account for new plants powered by renewable and assimilated resources also includes the costs of special commercial schemes (guaranteed minimum prices and on-the-spot trading). In the period between 1 October 2021 and 31 March 2023, these costs were charged to general taxation.

In 2025, support schemes provided incentives for approximately 50.2 TWh of electricity, of which 44% was generated by solar plants, 23% by wind farms, 16% from biomass, 15% by hydropower plants and, finally, 2% from geothermal sources (Figure 2.5). Compared with 2024, solar generation increased by 2.7 TWh, while generation from the other sources declined. In particular, supported generation from wind farms decreased by 2.1 TWh, while that from biomass fell by 3.8 TWh.

According to Terna's provisional data, electricity demand in Italy amounted to 312.4 TWh in 2025, a very slight increase from 311.9 TWh in 2024. Demand was met for 85% by domestic generation (net of electricity used for pumped storage and absorbed by stand-alone storage systems), while the remaining 15% was covered by the net balance of electricity exchanges with other countries. Although the share covered by imports decreased slightly from 16.4% in 2024, it nevertheless remained high compared with levels recorded over the past 20 years. Despite broadly stable overall demand, the net import balance declined: net imports fell from 51 TWh in 2024 to 46.9 TWh in 2025, a decrease of 8%. More specifically, gross imports fell by 7.4%, decreasing by 4.1 TWh compared with the previous year, from 55.9 TWh to 51.8 TWh, while exports remained unchanged at 4.9 TWh, the same level as in 2024. The decrease in the net import balance therefore essentially reflects the decline in imports.

Looking at the origin of electricity flows, imports from France (+2.8 TWh), Austria (+0.3 TWh) and Slovenia (+0.1 TWh) increased in 2025. By contrast, flows from Switzerland (-4.5 TWh), Greece (-1.3 TWh) and Montenegro (-1.4 TWh) decreased.

[143] A feed-in tariff means that the support granted for electricity fed into the grid includes the sale of that electricity, which therefore no longer remains at the producer's disposal. The electricity fed into the network is taken back at a price that already includes the incentive.

[144] A feed-in premium means that the support granted for electricity generated does not include the sale of the electricity, which remains at the producer's disposal.

The structure of the electricity market

The Energy Markets Operator (GME) is in charge of managing the energy markets, historically divided between the Spot Electricity Market (MPE) – itself subdivided into the Day-Ahead Market (MGP), the Intraday Market (MI), and the Daily Products Market (MPEG) – and the Forward Electricity Market (MTE), which requires physical delivery of electricity. The GME now collects offers on the Balancing and Redispatching Market, previously known as the Dispatching Service Market (MSD) and managed by Terna.

During 2024, no changes occurred in the process of extending the coupling of the Italian day-ahead market with the day-ahead markets of other European states (market coupling), which began in 2011 with the coupling of the Italian and Slovenian markets. Accordingly, at the end of 2022, 26 countries were still participating in the Single Day-Ahead Coupling (SDAC)[145]. With reference to national borders, the explicit allocation of transmission capacity between Italy and Switzerland and between Italy and Montenegro remains.

On 1 June 2022, the European Platform for the Exchange of Balancing Energy from Reserves for Frequency Restoration with Automatic Activation, better known as PICASSO (Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation), became operational, while on 5 October 2022, the European Platform for the Exchange of Balancing Energy from Reserves for Frequency Restoration with Manual Activation, better known as MARI (Manually Activated Reserves Initiative), became operational. Terna began using the PICASSO platform on 19 July 2023, while it is not yet operational on the MARI platform[146].

In 2025, the number of participants registered on the electricity market increased to 399 (23 more than in 2024), while the number registered on the Energy Accounts Platform (PCE) bilateral contracts rose to 445 (28 more than in 2024).

Stock exchange and bilateral contracts

In 2025, the volume of electricity traded on the MGP in the Italian system amounted to 286.2 TWh, up 0.8% compared with 2024. In particular, volumes traded on the power exchange increased to 234.4 TWh (+3.4%), at the expense of bilateral trades registered on the PCE, which fell to 51.8 TWh (-9.4%) and related almost entirely to domestic bidding zones (Table 3.12; see Table 3.13 for details of bilateral contracts).

Cross-border trading declined, mainly as a result of lower imports, which totalled 55.2 TWh (-3.8%). These accounted for 23% of exchange-traded sales (compared with 24% in 2024) and 1% of bilateral sales (compared with 3% in 2024). Conversely, exports increased to 7.4 TWh (+37%), with all export transactions executed through the exchange. Electricity purchases by the Acquirente Unico declined to 6 TWh (-54.7%), while sales by the Energy Services Operator (GSE) increased to 33 TWh (+1.5%). Together, these represented 7% of total traded volumes, a reduction of 1.2 percentage points

[145] Austria, Belgium, Bulgaria, Croatia, Czechia, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain and Sweden.

[146] Following the requirements set out in Resolution 60/2024/R/eel of 27 February 2024, Terna's operational participation in the PICASSO platform was suspended on 15 March 2024. On 25 November 2025, Terna resumed participation in the PICASSO platform. Resolution 423/2025/R/eel of 23 September 2025 approved the proposed amendments to the Network Code relating to the launch of Terna's participation in the MARI platform.

compared with 2024.

Table 3.12 Day-ahead electricity market

YEAR	CONTRACTS ON THE MGP (TWh) Comprehensive	*of which Stock Exchange*	*of which bilateral*
2010	318.6	*199.5*	*119.1*
2011	311.5	*180.4*	*131.1*
2012	298.7	*178.7*	*120.0*
2013	289.2	*206.9*	*82.3*
2014	282.0	*185.8*	*96.1*
2015	287.1	*194.6*	*92.5*
2016	289.7	*202.8*	*86.9*
2017	292.2	*210.9*	*81.3*
2018	295.6	*213.0*	*82.6*
2019	295.8	*213.3*	*82.6*
2020	280.2	*209.8*	*70.3*
2021	290.4	*221.3*	*69.1*
2022	289.2	*210.9*	*78.3*
2023	278.0	*209.9*	*68.1*
2024	283.9	*226.8*	*57.1*
2025	286.2	*234.4*	*51.8*

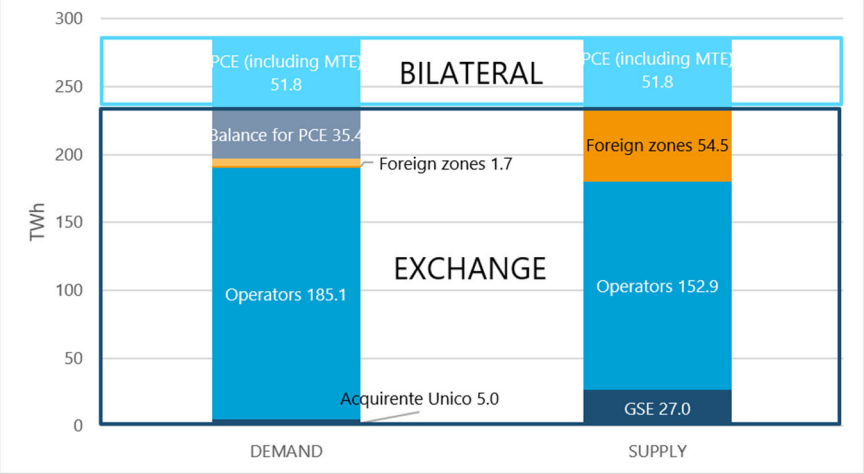
Source: ARERA processing of GME data.

Table 3.13 Bilateral contracts purchased in the electricity sector

CONTRACTS (GWh)	2020	2021	2022	2023	2024	2025
National	114,745	112,531	106,736	96,914	90,089	87,171
of which Acquirente Unico	-	0.02	-	186	317	779
of which other operators	114,745	112,531	106,736	96,728	89,772	96,392
Foreign	4	34	19	2	6	21
PCE programme balance	-44,403	-43,445	-24,490	-28,861	-32,967	-35,421
Bilateral contracts	70,346	69,121	78,265	68,055	57,128	51,771

Source: ARERA processing of GME data.

Figure 3.4 Breakdown of electricity supply and demand in 2025



Source: ARERA processing of GME data.

Total volumes sold in domestic bidding zones increased to 231 TWh (+2% compared with 2024), accounting for more than 80% of sales across the entire system. At zonal level, volumes purchased increased in the South (42 TWh; +4.3%), Sardinia (12.4 TWh; +4.5%) and Centre-South (29.8 TWh; +9.3%) bidding zones, while volumes purchased in Sicily declined (12 TWh; -5.9%).

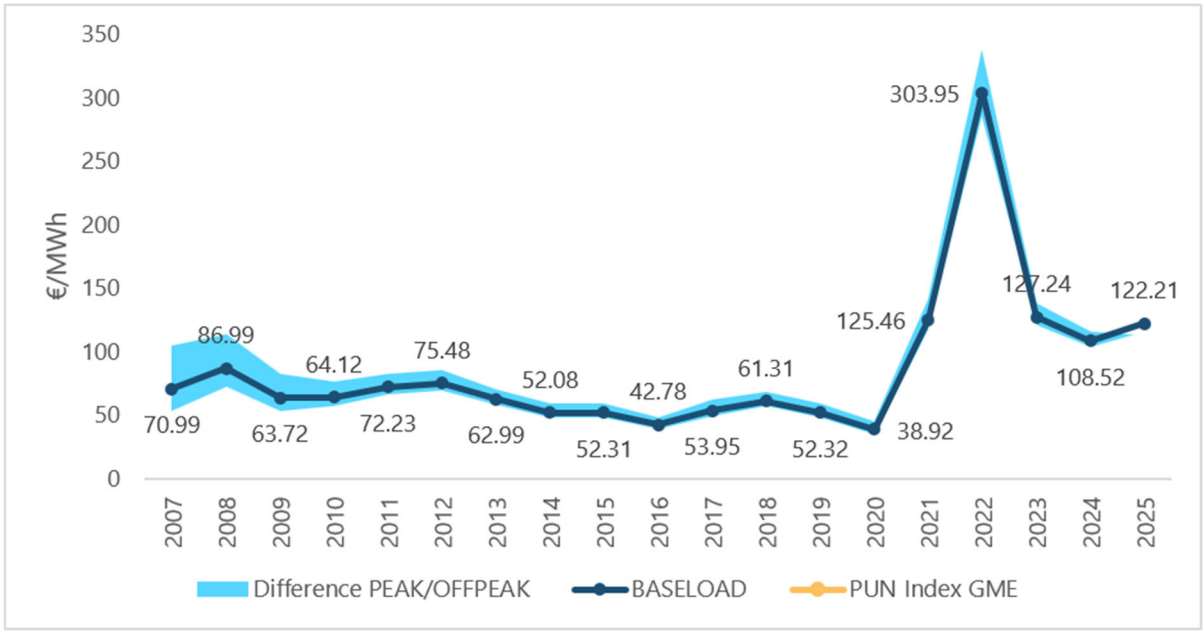
Sales from renewable energy plants decreased to 105 TWh (-3.6%), accounting for 46% of total sales, down 3 percentage points compared with 2024. In particular, the share of hydropower excluding pumped storage decreased by 3 percentage points (48 TWh; -12%), while the share of solar PV sales increased by 2.5 percentage points (5.8 TWh; +73%). Finally, the share produced by wind power plants remained stable (20 TWh; -2%).

3.2.1.1 Monitoring of wholesale market prices

The day-ahead market

The average electricity single national price (PUN) increased by 7% compared with 2024, reaching €115.9/MWh in 2025 (Figure 2.8). The increase was recorded across all three hourly bands: €122/MWh (+5%) during peak hours, €119/MWh (+10.5%) during off-peak hours on working days and €105/MWh (+5%) on public holidays (Figure 3.5).

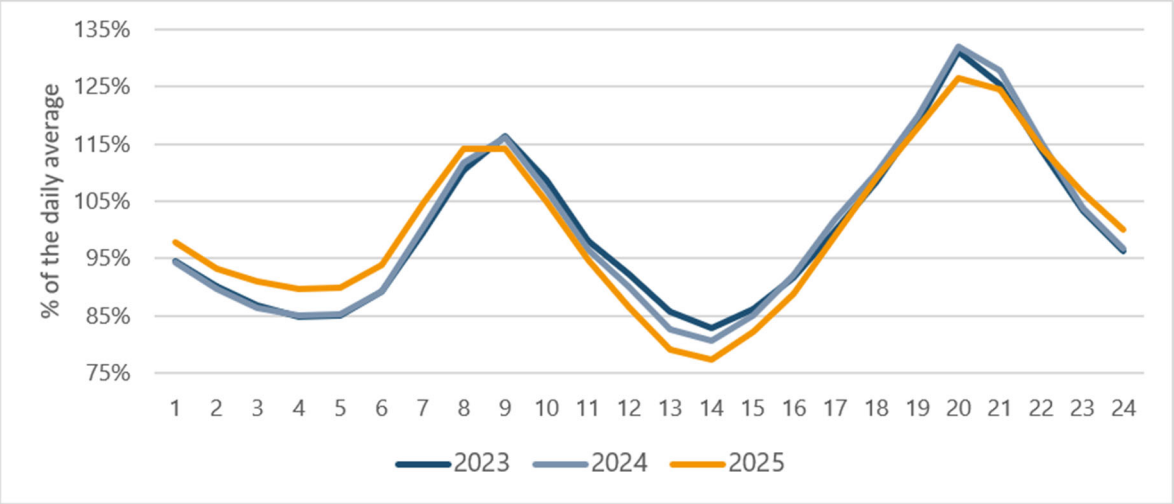
Figure 3.5 Annual PUN and peak/off-peak differential trends



Source: GME.

Looking at the hourly profile (Figure 3.6), in 2025 the differential from the daily average for the morning hours, "1-8", increased (95%; +4% compared with 2024), while the differential for peak hours, "9-19", decreased (94%; -3% compared with 2024). The differential for the evening hours, "20-24", also decreased, albeit slightly (112%; -1% compared with 2024).

Figure 3.6 24-hour average hourly PUN trend compared to daily average

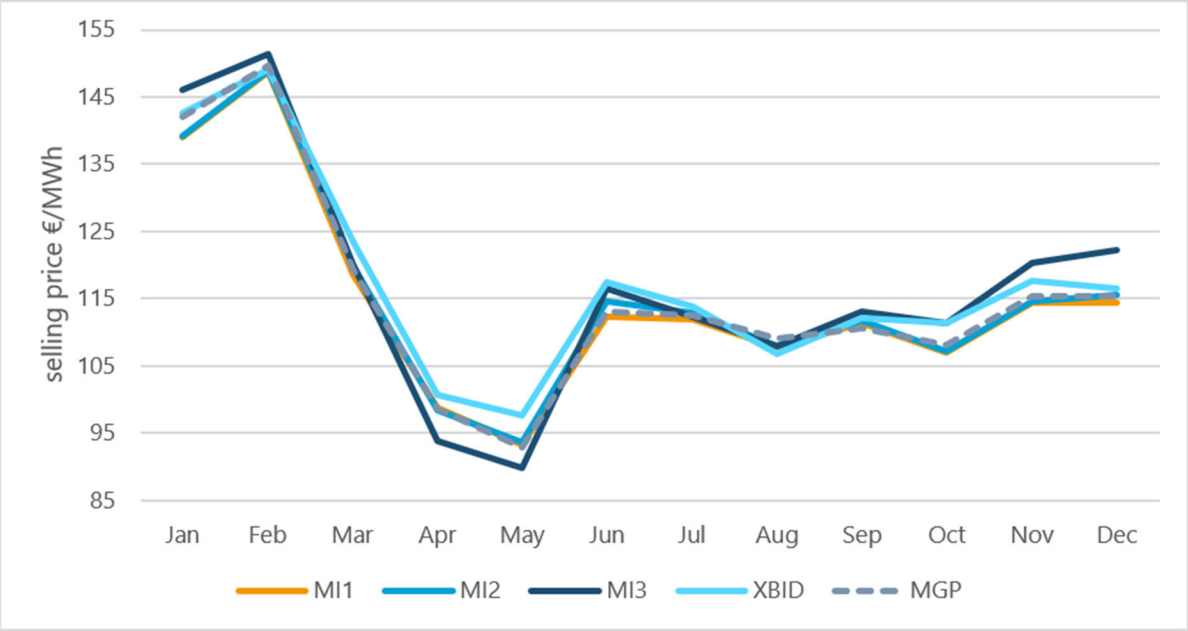


Source: GME.

Intra-day market

The total volumes traded in 2025 on the intra-day market (37.2 TWh) increased compared to the previous year (+5%). Most of these volumes (43%) were traded in the first intra-day market MI-A1 auction session (16 TWh; +6% compared with 2024). Smaller shares were traded in the remaining auction sessions: 19% in MI-A2 (7.1 TWh) and 9% in MI-A3 (3.2 TWh), while the remaining 29% was traded in the XBID continuous trading session (10.9 TWh; -5.5% compared with 2024).

Figure 3.7 Monthly price development in MI in 2025



Source: GME.

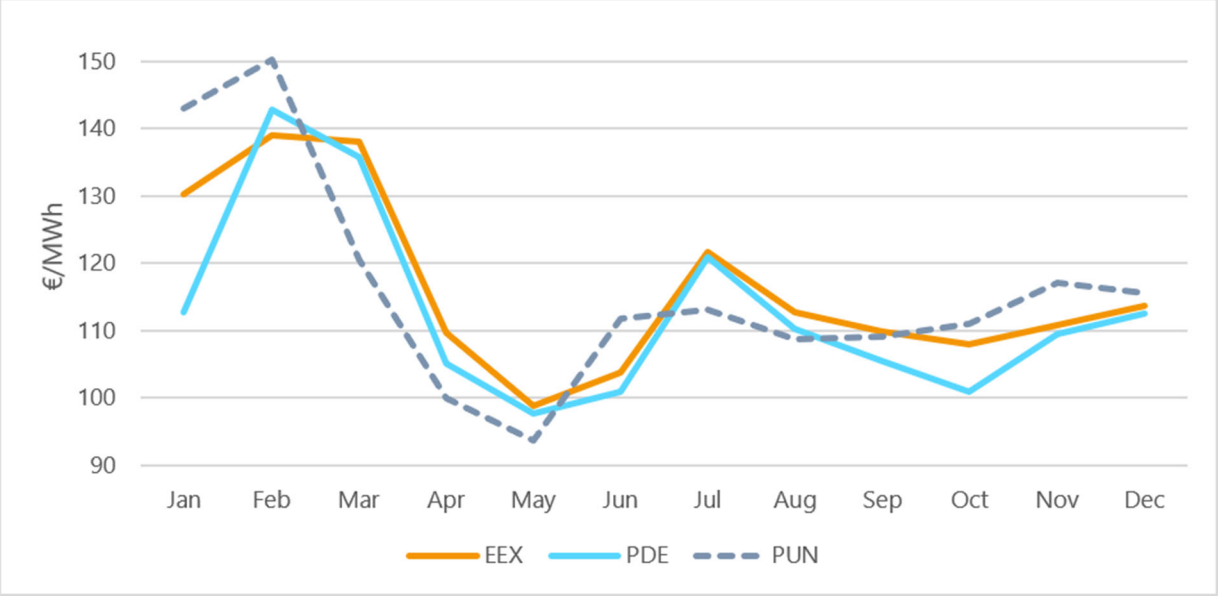
Average prices recorded on the MI (Figure 3.7) remained closely correlated with the average levels of the corresponding MGP prices, particularly in the second auction session (MI2), where the average

annual differential relative to the day-ahead market (MGP) price was consistently negative and below 0.5% in all bidding zones. The differential was also consistently negative and never exceeded one percentage point in any bidding zone in the first auction session (MI1), whereas it was positive in the third auction session (MI3), which covers only hours 13-24, reaching a maximum of +1.9% in the Sicily bidding zone. Throughout the year, average monthly prices broadly tracked the corresponding Day-Ahead Market selling price, with the exception of January, when all intraday sessions recorded lower prices (average differences of approximately €3/MWh for MI1 and MI2, and €4/MWh for MI3), and of April, May, October, November and December, when MI3 prices exceeded Day-Ahead Market prices by an average of between €3/MWh and €7/MWh.

Forward energy market

On the forward market operated by GME, no trades in standardised products with physical delivery were matched in 2025. There were, however, 120 bilateral transactions for clearing purposes only, totalling 1.1 TWh (+1 TWh compared with 2024). Of these transactions, 94% related to the baseload profile and only 6% to the peakload profile, with monthly maturities accounting for 53%, quarterly maturities for 18% and annual maturities for 29%.

Figure 3.8 Monthly trend in 2025 of forward prices for the M+1 product by delivery month



Source: Processed by ARERA on GME (PUN, PDE) and Refinitiv (EEX) data.

After eight years of inactivity, bilateral transaction registrations for clearing purposes resumed on the MTE, amounting to 107 GWh across 16 pairings.

Looking at price trends for the generally most liquid forward product, namely the monthly baseload product for delivery in the immediately following month (M+1), trades by market participants (reported on the PDE time contracts platform pursuant to the Integrated Text on Monitoring of the Wholesale Electricity Market and the Dispatching Services Market[147]) resulted in prices rising during the first two months of 2025 to a high of €143/MWh, before declining until May, when they reached

[147] Pursuant to Resolution ARG/elt 115/08 of 5 August 2008.

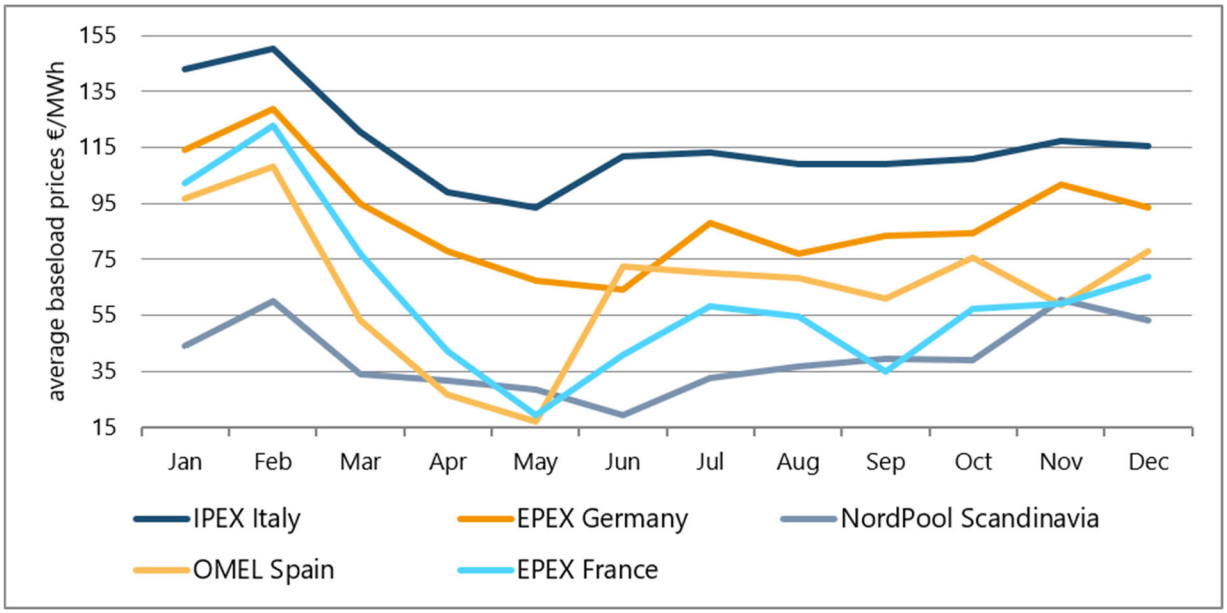
a low of €98/MWh, and subsequently recovering to €112/MWh in December (Figure 3.8). This trend was consistent with that recorded by the underlying PUN over the course of the year.

Trading on the Daily Products Market (MPEG) decreased in 2025, with 241 transactions (-53% compared with 2024) and a total traded volume of 296 GWh, almost entirely relating to the baseload profile. For the latter, the average price of daily baseload products stood at around €0.69/MWh, down 20% compared with the previous year.

The Italian market in the European context

On an annual average basis, electricity prices across the European power exchanges increased across all markets in 2025 compared with 2024. In most European countries, electricity market prices rose until February before falling significantly during the spring months. From June in Italy and Spain, and from July in the other markets, however, the trend reversed again, with prices partially recovering towards the levels recorded in the first quarter of the year (Figure 3.9).

Figure 3.9 – Monthly average price trends on the main European power exchanges in 2025 (average baseload prices)



Source: ARERA analysis using data from the European electricity markets.

The significant price declines recorded in the first part of the year were undoubtedly supported by increases in renewable generation, particularly solar PV generation. From the summer onwards, however, upward pressure on electricity prices was driven by developments in oil markets, rising gas prices and higher CO_2 emission allowance prices. On an annual average basis, the German market recorded the largest increase, at +13.8%, followed by the Nordic market at +10.1%. Price increases on the Italian and French markets were at an intermediate level, at +6.8% and +65.3%, respectively, while the Spanish power exchange recorded a more limited increase of 3.6%.

Despite these increases, average prices in 2025 were the lowest recorded since 2021, the year in which the energy crisis began. Average prices in 2025 amounted to around 60% of the levels recorded in 2021 in the French, Spanish and Nordic electricity markets, while the corresponding figure was 92% for the Italian and German power exchanges.

Moreover, the widespread price increases, albeit varying in scale across markets as noted above, did not help to narrow the long-standing price differentials associated with the characteristics of national generation mixes. On an annual average basis, European electricity prices ranged from €39.7/MWh, the lowest price recorded on Nord Pool, to €115.9/MWh, the highest price, recorded on the Italian power exchange. The Italian price therefore remained significantly higher than those recorded on the French and Spanish power exchanges, at €61.1/MWh and €65.3/MWh, respectively. This is because Italy is heavily dependent on gas-fired generation and is therefore more exposed to fluctuations in international gas markets. Germany, which, like Italy, makes extensive use of gas, recorded a higher average price of €89.3/MWh, although still below the Italian level.

With the exception of Nord Pool, where the annual high was recorded in November (€60.58/MWh), prices peaked across all markets in February, reaching €150/MWh in Italy, €128.5/MWh in Germany, €122.7/MWh in France and €108.3/MWh in Spain. Despite the recovery in the final months of the year, 2025 ended with significantly lower prices: in December, prices stood at €115.5/MWh in Italy, €93.5/MWh in Germany, €77.9/MWh in Spain, €68.7/MWh in France and €53/MWh in the Nordic countries.

3.2.1.2 Monitoring of the level of transparency, including compliance with obligations on transparency and on the degree and on the efficiency of market opening and competition

Monitoring of the wholesale market

At an advanced stage of regulation, the wholesale market monitoring function is the main tool the Authority has for assessing the structure of markets and their proper functioning, as well as the behaviour of operators and the adequacy of the system. In the electricity sector, as early as 2008 the Authority adopted[148] the Integrated Text on Monitoring of the Wholesale Electricity Market and the Dispatching Services Market (TIMM), with a view to strengthening its market monitoring activities in the sector.

The TIMM establishes the modalities and criteria for the performance by the Energy Markets Operator (GME), the TSO (Terna) and the Energy Services Manager (GSE) of the activities instrumental to the exercise of the electricity market monitoring function by the Authority. More specifically, each of them carries out the activities of acquiring, organising and storing data for monitoring (established by the Authority), the activity of sharing the same data with the Authority, as well as the necessary processing and analysis activities, as instrumental to the exercise of the monitoring function by the Authority.

In addition:

- the GME draws up and transmits to the Authority, on a weekly basis, a report on the structure and performance of the wholesale electricity market, as well as on the conduct of the relevant market operators active in that market; in drawing up this report, GME shall report as promptly as possible any anomalous data or situation of which it has become aware in the course of providing the utility service. In addition, at the Authority's request, it carries out *ad hoc* analyses

[148] By Resolution ARG/elt 115/08 of 5 August 2008, as subsequently amended and supplemented.

in support of the investigative activities conducted by the Authority;
- Terna (the TSO) prepares and submits to the Authority, on a weekly basis, a weekly report on the structure and outcome of the market for dispatching service as well as on the conduct of the relevant dispatching users active in the same market; in preparing this report, Terna is required to report as promptly as possible any anomalous data or situations of which it has become aware in the course of its public utility service.

In July 2025, the Authority published a Report on the Outcomes of the Day-Ahead Electricity Market in 2023-2024[149], thereby following up on the fact-finding investigation aimed at assessing the outcomes of short-term auction-based electricity markets.[150]. The fact-finding investigation was launched in response to the need to monitor the degree of effective competition and the proper functioning of wholesale electricity markets, identify conduct potentially constituting abusive practices under the REMIT Regulation and, based on the findings of the investigation, assess possible courses of action in terms of additional regulatory and/or enforcement measures and legislative proposals, as well as referring any potential breaches of competition law to the Italian Competition Authority.

The analysis was conducted in three main stages: (i) the definition of an initial set of indicators designed to measure the extent to which zonal prices formed on the day-ahead market for each bidding zone reflected the marginal costs of relevant generating units that may have been marginal in the same zone, with reference to the technology subtypes "combined-cycle thermal", "wind" and "solar PV"; (ii) the development of a second set of indicators to identify potential economic capacity withholding, in accordance with the ACER Guidelines of 18 December 2024; and (iii) a counterfactual ("what-if") analysis of the day-ahead market, simulating market participants' conduct under the assumption that they had no ability to influence zonal prices.

The analysis identified: (i) positive spreads between zonal prices and marginal costs, indicating potential price-making behaviour by market participants; (ii) economic capacity withholding, namely bids rejected by the market algorithm because they were submitted at prices above (or, in specific cases, equal to) the market price, even though the underlying marginal costs were lower than the market price; and (iii) the impact of economic capacity withholding on market price formation.

The findings of the investigation therefore indicate that, during the hours in which potential economic capacity withholding had an impact on prices, price levels appeared to be artificial. For price levels to be considered actually artificial, however, it is necessary, on the one hand, to refine on a case-by-case basis the simplifying assumptions adopted, albeit prudentially and in view of the fact-finding nature of the investigation, and, on the other, to establish the absence of legitimate justifications underlying the economic capacity withholding by individual market participants, which bear the burden of proving the existence of any such justifications.

The Authority therefore decided to follow up on the findings of the fact-finding investigation by further refining its economic capacity withholding and what-if analyses and assessing, on a case-by-case basis, as provided for under the REMIT Regulation and the ACER Guidelines, whether legitimate justifications were absent for the conduct identified by the investigation and engaged in by individual market participants, which bear the burden of proving the existence of any such justifications.

[149] By Resolution 302/2025/R/eel of 1 July 2025.

[150] Launched by Resolution 401/2024/R/eel of 8 October 2024.

Lastly, the Authority informed Terna of the need to strengthen and update the information base used for dispatching purposes. In particular, Terna will be required to: (i) record in the Gaudì system any gas withdrawal meters installed at individual relevant thermal generating units, specifying their capacity and calibration settings; (ii) verify that dispatching users submit gas withdrawal data at the highest level of detail supported by the registered meters; (iii) update the classification used in the Gaudì system so as to provide a more accurate representation of the technical and economic characteristics of the different generation and storage technologies; (iv) make it mandatory to complete certain fields relating to the scheduling of hydropower plants used by the dispatching service market (MSD) algorithm; and (v) prevent potential information gaps concerning new generation or storage technologies by coordinating with the Authority on the design of future developments of the Gaudì system and other tools through which market participants and Terna exchange information relevant to dispatching, redispatching and participation in electricity markets.

Implementation of REMIT

The importance of the monitoring function carried out by national regulatory authorities – already provided for ARERA by its founding legislation – is also recognised at European level: in addition to the energy market directives, Regulation (EU) 1227/2011, as amended and supplemented by Regulation (EU) 1106/2024 of the European Parliament and Council of 11 April 2024 on wholesale energy market integrity and transparency (REMIT), has strengthened and expanded the monitoring powers of national regulatory authorities. In particular, the monitoring function envisaged by REMIT is aimed at increasing the general transparency of markets and promoting a more level playing field among operators, intercepting abusive conduct relating to market manipulation and insider trading, including cross-border and cross-product practices (spot and forward, physical and financial products); this important function is therefore coordinated at European level by the Agency for the Cooperation of Energy Regulators (ACER).

Market monitoring activities aimed at identifying conduct potentially constituting market abuse under the REMIT Regulation continued throughout 2025. These activities, in some cases, were preparatory to the initiation of sanction proceedings.

Penalty proceedings in the wholesale market

In 2025, two sanction proceedings were initiated for breaches of the provisions on wholesale energy market integrity and transparency laid down in Regulation (EU) No 1227/2011, as subsequently amended. (REMIT). In one of these proceedings, Enel Produzione S.p.A. was alleged to have breached Article 4 of REMIT by failing to disclose to the public in a timely manner inside information in its possession concerning the unavailability of a generating unit.

Having identified a connection between the parties and subject matter of these proceedings [151]and two previous proceedings, the Authority joined the proceedings in the interests of procedural efficiency and completeness of the investigation. In the context of the above proceedings, the company submitted commitments with a total value of between €900,000 and €1.3 million, which were declared admissible and subsequently approved and made binding, with the proceedings being

[151] The proceedings were initiated against Enel Produzione in 2023 and 2024.

closed at the same time.

In the other proceeding, A2A S.p.A. was alleged to have breached Article 5 of REMIT by engaging in market manipulation in wholesale energy markets within the meaning of Article 2(2)(a)(ii) of REMIT, consisting in setting the market price at an artificial level, i.e. at a price different from that which would have resulted from "a fair and competitive interplay between supply and demand" reflecting market fundamentals.

3.2.2 Retail market

According to provisional data published by Terna, final electricity consumption, net of losses, stood at approximately 293 TWh in 2025, broadly unchanged compared with 2024 (+0.2%). This trend was almost entirely attributable to higher consumption in the commerce and public services sector, which increased by approximately 1.8 TWh. Excluding this increase and the slight rise recorded in the energy sector (+0.2 TWh), all other sectors recorded a decline in consumption (Table 3.14).

Table 3.14 – Breakdown of domestic electricity consumption by sector

SECTOR (GWh)	2024	2025(A)	CHANGE
Energy	8,646	8,890	2.8%
Industry	106,633	105,530	-1.0%
Transport	8,982	9,090	1.2%
Household	65,822	65,180	-1.0%
Trade and public services	95,766	97,520	1.8%
Agriculture/Forestry	6,452	6,420	-0.5%
Fishing	233	210	-9.9%
Others	106	240	125.9%
TOTAL	292,640	293,080	0.2%

(A) Provisional data.

Source: Terna.

According to the Authority's Registry of Operators, the following companies reported that they had engaged in electricity retailing in 2025, even if only for part of the year: 102 companies under the standard offer service, 7 under the gradual standard offer service for household customers, 16 under the gradual standard offer service for small enterprises, 18 under the gradual standard offer service for micro-enterprises[152], 2 under the safeguard service and 710 in the free market.

Of the 710 companies that reported in the Authority's Registry of Operators that they sold electricity to customers in the free market, 631 (89%) responded to the Annual Survey, with 61 reporting that they had remained inactive during the year. Taking into account that 43 of the active companies sell electricity in both the free market and the regulated market, and that companies operating under the safeguard service and the gradual standard offer services also sell electricity in the free market and/or under the standard offer service (and are therefore already included in those segments), the

[152] The number of suppliers under the gradual standard offer services also includes entities which, although they did not participate in the auctions, apply the terms and conditions of these services to eligible customers on non-interconnected islands.

total number of active companies that operated in the final electricity retail market in 2025 and responded to the Annual Survey was 690.

Table 3.15 presents the breakdown of final electricity sales (net of self-consumption and network losses), together with the total number of customers [153]by market segment, based on data from the Authority's Annual Survey provided by electricity operators: producers, providers of the standard offer service, gradual standard offer services and safeguard service, wholesalers and free-market suppliers. The Survey results cover approximately 92% of final consumption estimated by Terna for 2025[154]. This percentage is indicative, however, given the preliminary nature of the data used, both those provided by Terna and those collected through the Authority's Annual Survey of suppliers.

Table 3.15 Final electricity sales market (net of fuel gas and leakage)

MARKET AND CUSTOMERS	VOLUMES			WITHDRAWAL POINTS		
	2024	2025	CHANGE	2024	2025	CHANGE
Standard offer service	8,488	4,750	-44.0%	5,553	3,176	-42.8%
Household	8,488	4,750	-44.0%	5,553	3,176	-42.8%
Gradual standard offer service for households	3,103	5,197	67.5%	1,675	3,015	80.0%
Gradual standard offer service for micro enterprises(A)	1,516	1,038	-16.1%	829	62	-20.2%
Gradual standard offer service for small enterprises(A)	1,238	1,249	-17.6%	77	680	-17.9%
Safeguard service	3,563	2,936	-17.6%	80	69	-13.4%
Free market	225,075	230,603	2.5%	29,399	30,827	4.9%
Household	47,169	48,236	2.3%	23,222	24,327	4.8%
Non-household	177,906	182,367	2.5%	6,177	6,500	5.2%
END MARKET	242,983	245,773	1.1%	37,613	37,828	0.6%

(A) Estimates based on data collected indistinctly between gradual standard offer service for small enterprises and gradual standard offer service for micro enterprises.

Source: ARERA. Annual Survey of Regulated Sectors.

In 2025, there was a further significant shift of household customers away from the standard offer service, following the already substantial decline recorded in the previous year. The further contraction of the standard offer market was again due to the discontinuation of the service for household customers generally and the introduction of the gradual standard offer service for customers who had not chosen a supplier in the free market. As is well known, since 1 July 2024 the standard offer service has been reserved for vulnerable household customers[155].

The data collected through the Annual Survey also show a slight recovery in consumption (+1.1%),

[153] Approximated by the number of withdrawal points, calculated in all cases on a pro die basis (i.e. weighted according to the fraction of the year during which they were supplied).

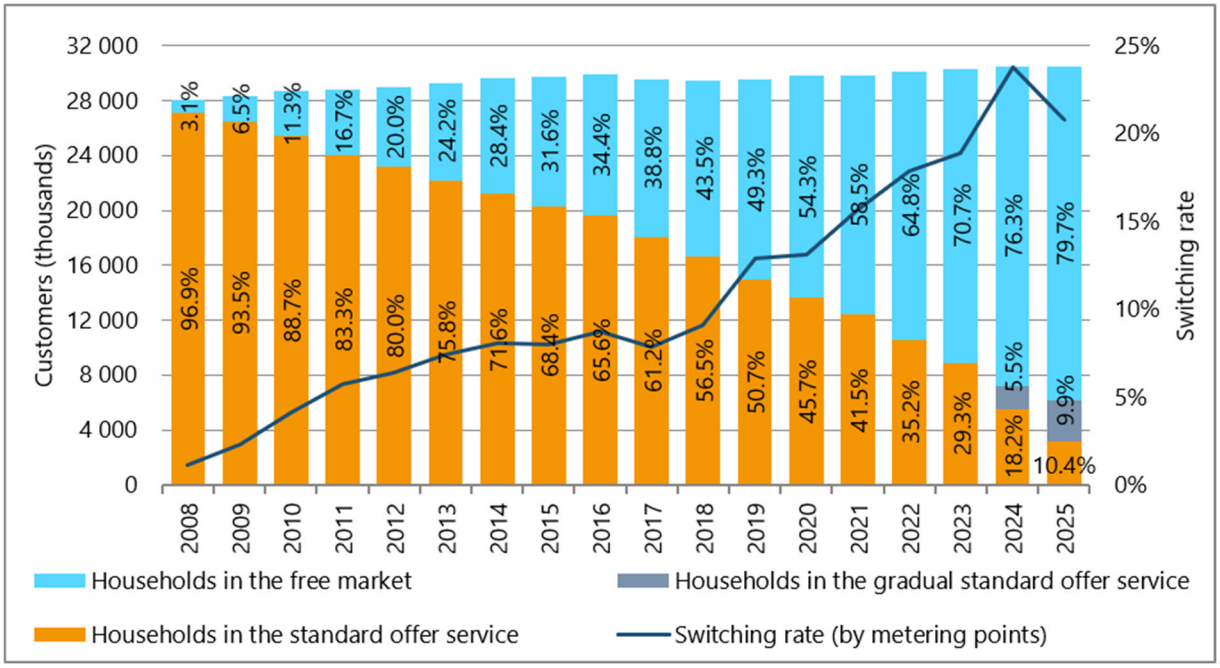
[154] To obtain the percentage indicated, the volumes reported in the Survey as self-consumption (own and group self-consumption), amounting to approximately 23.5 TWh, must also be added to the final consumption figures shown in Table 3.15.

[155] Namely, customers who meet at least one of the following conditions: they are aged 75 or over; are entitled to receive the electricity social bonus; have a disability (pursuant to Article 3 of Law No 104/92); live in emergency accommodation following natural disasters; or are located on a non-interconnected minor island.

following the decline in 2023 and the broad stability observed in 2024. In 2025, electricity consumption increased by almost 3 TWh, from just under 243 TWh to almost 246 TWh, purchased by 37.8 million customers. Compared with 2024, the number of withdrawal points increased by approximately 215,000 (+0.6%). (Table 3.15).

The recovery in overall electricity demand reflected an increase in sales to non-household customers, which more than offset lower sales to household customers. In fact, the household sector purchased a total of 58.2 TWh, compared with 58.8 TWh in 2024, representing a 1% decline. By contrast, electricity purchased by the non-household sector increased by 1.8%, from 184.2 TWh to 187.6 TWh, although it remained below the pre-pandemic level of 198 TWh recorded in 2019.

Figure 3.10 Households in the standard offer service and in the free market since 2008



Source: ARERA, Annual Survey of Regulated Sectors.

In 2025, the number of household withdrawal points stood at just over 30.5 million, up 0.2% (+67,000 withdrawal points) compared with 2024. Of these, 3.2 million were supplied under the standard offer service, 3 million under the gradual standard offer service and approximately 24.3 million in the free market (Figure 3.10). The share of household withdrawal points supplied in the free market rose to 79.7%, while the share supplied under the standard offer service fell to 10.4% and that under the gradual standard offer service accounted for 9.9%. The substantial reduction in the number of withdrawal points under the standard offer service and the corresponding increase in those entering the gradual standard offer service were again due, as noted above, to the discontinuation of the standard offer service for household customers generally, which resulted in the automatic transfer of non-vulnerable household withdrawal points to the gradual standard offer service. This is because the number of customers is calculated on a pro die basis, meaning that a customer who left the standard offer service in 2024 and switched to the gradual standard offer service from 1 July because they were non-vulnerable was counted in the 2024 data under both services (0.5 under the standard offer service and 0.5 under the gradual standard offer service). In 2025, by contrast, household customers who left the standard offer service are counted entirely under the gradual standard offer service. In 2025, the gradual standard offer service also took on a number of vulnerable customers previously supplied in the free market or under the standard offer service who, taking advantage of

the option introduced by the 2024 Competition Law[156], explicitly requested activation of the gradual standard offer service by 30 June 2025.

As noted above, while the share of **household** withdrawal points supplied in the free market reached 79.7% in 2025, its share in terms of volumes of electricity sold to the household sector alone was higher, at 83%. Again in volume terms, the share of the **standard offer service** fell to 8.2% in 2025, while that of the **gradual standard offer service** rose to 8.9%.

In 2025, **consumption under the gradual standard offer service** for small enterprises (introduced in 2021 for small enterprises connected to low-voltage networks and micro-enterprises with contractually committed capacity exceeding 15 kW that were no longer eligible for the standard offer service and had not selected an offer in the free market) decreased by 200 GWh (-16.1%). The number of withdrawal points supplied under the service also fell by 16,000 (-20.2%). Similarly, under the **gradual standard offer service for micro-enterprises** (introduced on 1 April 2023 for non-household customers with withdrawal points of up to 15 kW that were no longer eligible for the standard offer service and had not yet selected a supplier in the free market) consumption fell to 1.2 TWh (-17.6%), while the number of withdrawal points supplied declined by 17.9% to approximately 680,000. According to data collected through the Annual Survey (to be considered provisional here and throughout the report), the **safeguard service** also experienced a decline: 69,000 withdrawal points were served, 13.4% fewer than in 2024, with a withdrawal of 2,936 GWh, down from 3,563 GWh in 2024 (-17.6%). By contrast, sales in the **free market** increased by 2.5%, reaching a substantial volume of almost 231 TWh, supplied to 30.8 million customers.

Switching

As usual, switching activity is assessed on the basis of data provided by distributors as part of the Annual Survey and data from the SII[157].

Although down compared with 2024, switching among household customers remained very high in 2025, undoubtedly still driven by the changes resulting from the end of the standard offer service. It is reasonable to assume that the automatic exit from the Standard Offer Service encouraged some customers to seek information and switch supplier in the free market, thereby changing their contractual arrangements.

Indeed, the switching rate for household customers (which does not include automatic transfers from the standard offer service to the gradual standard offer service) fell by three percentage points compared with 2024 in terms of customer numbers and by more than five percentage points in terms of volumes (Table 2.30), bringing it into line with the rate for non-household customers.

In total, over 7.7 million withdrawal points switched suppliers during 2025. In terms of underlying volumes, this amounted to 53.4 TWh, representing 22% of total electricity market purchases.

[156] Specifically, pursuant to Article 24 of Law No 193/24 (2024 Competition Law).

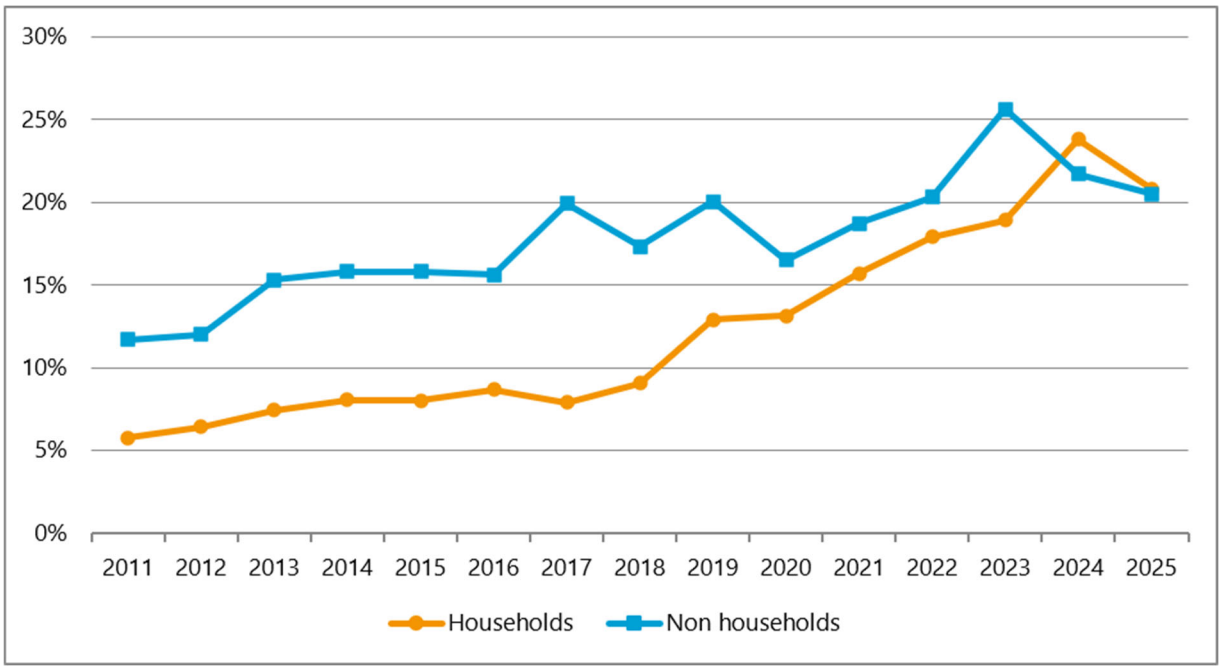
[157] Integrated Information System (SII): an information system established at *Acquirente Unico* by Law No 129 of 13 August 2010 to manage information flows between the parties (mainly distributors and suppliers) participating in the electricity and gas markets, in accordance with the rules and procedures established by the Authority. It is based on a database, called the Official Central Register, which contains the complete list of national withdrawal points and the basic data for the management of the related processes.

Table 3.16 Electricity customer switching rates

CUSTOMER TYPE	2024		2025	
	CUSTOMERS	VOLUMES	CUSTOMERS	VOLUMES
Household	23.8%	26.8%	20.8%	21.0%
Non-household:	21.7%	22.6%	20.5%	22.3%
of which:				
- low voltage	21.8%	26.9%	20.5%	24.3%
- medium voltage	19.7%	22.5%	17.2%	20.4%
- high and extra-high voltage	27.8%	13.5%	22.0%	23.8%
TOTAL	23.4%	23.6%	20.7%	22.0%

Source: ARERA. Annual survey of regulated sectors and the SII.

Figure 3.11 – Switching rates (of withdrawal points) in the electricity sector



Source: ARERA, Annual survey on regulated sectors and processing on SII data.

Standard offer service

The standard offer service is provided by specific sales companies or by distribution companies with less than 100,000 users connected to their network, on the basis of economic and commercial quality conditions indicated by the Authority. Under the standard offer regime, a single buyer (the company "Acquirente Unico") is responsible for the supply of electricity on the wholesale market, which it resells to the operators at a price reflecting the costs it has incurred, including those for energy materials. The higher standard offer prices are set by the Authority on the basis of wholesale market prices in order to cover the supply costs incurred by the companies entrusted with providing this service. As regards the component covering marketing costs, the criterion used by the Authority reflects the costs incurred by a hypothetical new operator to the market segment of electricity sales to households. In summary, the energy component of the standard offer prices is linked to market performance, while the marketing component is set according to a standard cost methodology,

based on the entry costs of a hypothetical new operator. The total price is charged to all customers without geographic differentiation.

From its inception, the service has catered to customers without a supplier in the free market, but over time it has undergone a gradual removal of those entitled to access it. In particular, from 1 January 2021, small enterprises connected [158]to low-voltage networks and micro-enterprises [159]with at least one withdrawal point connected to a low-voltage network and contractually committed capacity exceeding 15 kW ceased to be eligible for the service; from 1 April 2023, eligibility also ceased for all other micro-enterprises. Since May 2023, therefore, the service has been reserved exclusively for household customers. Most recently, from 1 July 2024, only vulnerable household customers [160]may be supplied by the existing standard offer service providers.

In 2025, sales under the standard offer service amounted to 4.7 TWh, across approximately 3.2 million withdrawal points (calculated on a pro die basis). Compared with 2024, consumption decreased significantly, by 3.7 TWh (-44%), while the number of withdrawal points supplied fell by approximately 2.4 million (-42.8%).

In 2025, average annual consumption by **household customers** supplied under this service was 1,496 kWh, down 2.1% compared with 2024. As usual, resident household customers recorded higher average consumption, at 1,698 kWh per year, although this was down 3.2% compared with the previous year. Average consumption by non-resident customers, which is significantly lower, stood at 799 kWh per year, down 1% compared with 2024 (Table 3.17). Almost all withdrawal points (93.1%) fall within the first four consumption classes, i.e. they purchase no more than 3,500 kWh per year. The contractual conditions offered in the standard offer service are structured in two ways: single-rate and dual-rate. In 2025, the standard offer service continued to consist almost entirely of customers on a two-tier tariff, accounting for 99.5% of total volumes and 99.6% of withdrawal points. A comparison of average consumption between customers on a non time-of-use tariff and those on a two-tier tariff shows that the former recorded average annual consumption of 1,719 kWh, 15% higher than the 1,495 kWh recorded by customers on a time-of-use tariff.

As usual, this market segment remains highly concentrated, with the dominant operator, Servizio Elettrico Nazionale, supplying 4,046 GWh and accounting for 85.2% of total national volumes (+1.4 percentage points compared with 2024). Acea Energia ranks second, with 283 GWh and a 5.9% share (compared with 7.1% in the previous year), followed by A2A Energia, with 122 GWh and 2.6% of the national total. The other operators have smaller shares, including Iren Mercato (1.8%), Dolomiti Energia (0.9%) and Estenergy (0.4%).

Overall, the top three companies account for 93.7% of the standard offer service, broadly in line with

[158] Pursuant to Decree-Law No 73 of 18 June 2007, converted with amendments by Law No 125 of 3 August 2007, small enterprises are final customers, other than household customers, supplied at low voltage, with fewer than 50 employees and annual turnover or a balance sheet total not exceeding €10 million.

[159] Micro-enterprises are businesses with fewer than 10 employees and annual turnover not exceeding 2 million euro that have only low-voltage withdrawal points.

[160] Vulnerable customers are household customers who meet at least one of the following conditions:

- they are 75 years of age or older;
- are entitled to receive the social electricity bonus because they are in a state of economic hardship or the bonus for serious health conditions (such as requiring the use of medical-therapeutic equipment powered by electricity);
- are persons with disabilities pursuant to Article 3 of Law no. 104 of 1992;
- they are residing in an emergency housing facility following a natural disaster;
- are located on a smaller non-interconnected island.

the previous year (93.9%). The HHI, by contrast, rose slightly from 7,257 in 2024 to 7,353, remaining relatively close to 10,000, which represents maximum concentration, corresponding to a market with a single operator.

Table 3.17 Households in the standard offer service in 2025, by type and consumption class

CUSTOMER TYPE AND ANNUAL CONSUMPTION CLASSES	VOLUMES (GWh)	VOLUME SHARE	WITHDRAWAL POINTS (thousands)	CUSTOMER SHARE	AVERAGE CONSUMPTION (kWh)
0-1.000 kWh	534	11.2%	1,323	41.7%	404
1.000-1.800 kWh	1,151	24.2%	834	26.3%	1380
1.800-2.500 kWh	1,005	21.2%	475	15.0%	2116
2.500-3.500 kWh	945	19.9%	325	10.2%	2908
3.500-5.000 kWh	617	13.0%	152	4.8%	4059
5.000-15.000 kWh	415	8.7%	62	2.0%	6694
> 15,000 kWh	81	1.7%	3	0.1%	27000
TOTAL HOUSEHOLDS	4,750	100.0%	3,176	99.94%	1,496
OF WHICH:					
Residential	4,180	88.0%	2,462	77.5%	1,698
Non-residential	570	12.0%	714	22.5%	799

Source: ARERA. Annual Survey of Regulated Sectors.

Gradual standard offer service

The gradual standard offer service is the service regulated by the Authority to support the transition to the free electricity market and to ensure continuity of supply for those customers who, after the removal of price protection (i.e., when they lose the right to purchase electricity under the standard service), have not chosen an offer in that market. This service varies according to the type of customers and is divided into three categories: one for non-vulnerable households, one for micro-enterprises, and one for small enterprises. The supply is provided by selected suppliers through specific tender procedures. Each territorial area is served by a single supplier, who may operate in multiple areas simultaneously, provided they have participated in and won the tenders for the award of the service.

Gradual standard offer service for Non-Vulnerable Household Customers

The gradual standard offer service is intended for non-vulnerable household customers who, at the end of the standard offer service, had not yet selected a supplier in the free electricity market. The service became operational as of 1 July 2024.

Following the competitive procedures for the service period from 1 July 2024 to 31 March 2027, the 26 geographical areas into which the country was divided were awarded to seven operators (the number of areas awarded to each operator is shown in brackets): A2A Energia (2), E.ON Energia (1), Edison Energia (4), Enel Energia (7), Hera Comm (7), Illumia (3), and Iren Mercato together with Salerno Energia Vendite (2). Enel Energia and Hera Comm have secured the largest number of areas, emerging as winners in seven areas each.

According to Annual Survey data, in 2025 the seven successful gradual standard offer service

providers supplied a total of 3.0 million withdrawal points, calculated on a pro die basis, and approximately 5.2 TWh of electricity (Table 3.18). Compared with 2024, the service recorded particularly strong growth. Total volumes increased by 67.5%, while the number of withdrawal points rose by 80.0%, resulting in a 6.9% decrease in average consumption per withdrawal point, to 1,724 kWh.

Table 3.18 Gradual standard offer service for non-vulnerable household customers in 2025 by consumption class

CONSUMPTION CLASS	VOLUMES (GWh)	VOLUME SHARE	WITHDRAWAL POINTS (thousands)	CUSTOMER SHARE	AVERAGE CONSUMPTION (kWh)
< 1000 kWh	451	8.7%	1,058	35.1%	426
1000 - 1800 kWh	1,049	20.2%	751	24.9%	1,397
1800 - 2500 kWh	1,130	21.7%	531	17.6%	2,126
2500 - 3500 kWh	1,189	22.9%	407	13.5%	2,922
3500 - 5000 kWh	755	14.5%	185	6.2%	4,070
5,000 - 15,000 kWh	537	10.3%	79	2.6%	6,790
> 15000 kWh	87	1.7%	3	0.1%	26,198
TOTAL HOUSEHOLDS	5,197	100.0%	3,015	100.0%	1,724
OF WHICH:					
Residential	4,456	85.7%	2,243	74.4%	1,987
Non-residential	741	14.3%	772	25.6%	960

Source: ARERA. Annual Survey of Regulated Sectors.

Customers served under the gradual standard offer service for non-vulnerable household customers are predominantly concentrated in the low-to-medium consumption bands, while overall consumption is more evenly distributed across the different bands. Indeed, 77.6% of withdrawal points fall within the first three consumption bands, i.e. they consume less than 2,500 kWh per year. Although these first three bands account for the largest share of customers, together they consume half of the electricity supplied (50.6%). By contrast, the most significant consumption band in terms of electricity consumed is the fourth, comprising customers with annual consumption of between 2,500 and 3,500 kWh. Although this band accounts for only 13.5% of total withdrawal points, it represents 22.9% of total volumes.

Gradual standard offer service for small enterprises

As stated in the previous paragraphs, from 1 January 2021 the standard offer service ended for small electricity enterprises connected to low voltage and for micro-enterprises holding at least one withdrawal point connected to low voltage with contractually committed capacity exceeding 15 kW. The Authority has therefore established the economic and contractual conditions for providing the gradual standard offer service to small enterprises.

The service is awarded through competitive procedures in which suppliers compete for the different geographical areas. For the second allocation period, from 1 July 2024 to 31 March 2027, the service was divided into seven geographical areas and awarded to three providers: A2A Energia, Enel Energia and Iren Mercato.

Annual Survey data for the gradual standard offer service for small enterprises show a significant

decline in both the volume of electricity supplied and the number of withdrawal points in 2025 compared with the previous year. During the year, the service supplied a total of 1,038 GWh, 16.1% less than the 1,238 GWh recorded in 2024. At the same time, the number of withdrawal points (calculated on a pro die basis) fell from 77,100 to 61,600, a decrease of 20.2%. Despite this decline, average consumption per withdrawal point increased by 5.1%, from 16,050 kWh to 16,864 kWh (Table 3.19)

Table 3.19 – Non-household customers under the gradual standard offer service for small enterprises in 2025, by type and consumption class

CUSTOMER TYPE AND ANNUAL CONSUMPTION CLASSES	VOLUMES (GWh)	VOLUME SHARE	WITHDRAWAL POINTS	CUSTOMER SHARE	AVERAGE CONSUMPTION (kWh)
0-5 MWh	56	5.4%	31,260	50.8%	1,792
5 – 10 MWh	57	5.5%	7,103	11.5%	8,082
10 - 15 MWh	79	7.6%	5,901	9.6%	13,459
15 - 20 MWh	45	4.3%	2,494	4.1%	17,913
20 - 50 MWh	314	30.3%	9,953	16.2%	31,587
50 - 100 MWh	236	22.7%	3,394	5.5%	69,533
100 - 500 MWh	233	22.5%	1,434	2.3%	162,513
500 – 2,000 MWh	17	1.7%	26	0.0%	672,775
TOTAL NON-HOUSEHOLDS	1,038	100.0%	61,565	100.0%	16,864
OF WHICH:					
Public lighting	86	8.3%	6,634	10.8%	12,964
Other non-household uses	952	91.7%	54,930	89.2%	17,331

Source: ARERA. Annual Survey of Regulated Sectors.

The "other uses" category (non-household customers with uses other than public lighting) accounts for by far the largest share of the service, representing approximately 92% of total volumes and almost 90% of withdrawal points. Consumption by these customers stood at 952.5 GWh, down 15.4% compared with the previous year, while the number of withdrawal points fell from 68,030 to 54,930 (-19.3%). At the same time, average consumption increased by 4.8% to 17,340 kWh per withdrawal point.

The consumption band with the largest number of withdrawal points is that below 5 MWh per year, with 31,300 withdrawal points, equal to 50.8% of the total. However, this band accounts for only 56.0 GWh, corresponding to 5.4% of total volumes, with average annual consumption of just 1,792 kWh. In volume terms, the largest shares are concentrated in the consumption classes between 20 and 500 MWh. In particular, the 20–50 MWh band accounts for 314.4 GWh, or 30.3% of the total electricity supplied, despite representing only 16.2% of withdrawal points.

Gradual standard offer service for micro-enterprises

As of 1 April 2023, micro-businesses, meaning non-household clients with withdrawal points up to 15 kW, have lost the right to access the standard offer service. The Authority has therefore established the economic and contractual conditions for providing the gradual standard offer service to micro-enterprises for a period of four years.

Following the competitive procedures for the service award period from 1 April 2023 to 31 March 2027, the 12 geographical areas were awarded to seven providers: A2A Energia, ACEA Energia, AGSM

AIM Energia, Estra Energie, Hera Comm, Illumia and Sorgenia. A2A Energia and Sorgenia were awarded the largest number of areas, securing four and three respectively.

Annual Survey data show that in 2025 the service supplied a total of 1,248.7 GWh, down 17.6% from 1,515.7 GWh in 2024. At the same time, the number of withdrawal points (calculated on a pro die basis) fell from just under 829,100 to approximately 680,400, a decrease of 17.9%. Average consumption, by contrast, remained broadly stable, rising from 1,828 kWh to 1,835 kWh per withdrawal point (+0.4%) (Table 3.20).

Table 3.20 Gradual standard offer service for micro-enterprises in 2025 by consumption class

CUSTOMER TYPE AND ANNUAL CONSUMPTION CLASSES	VOLUMES (GWh)	VOLUME SHARE	WITHDRAWAL POINTS	CUSTOMER SHARE	AVERAGE CONSUMPTION (kWh)
0-5 MWh	619	49.6%	625,430	91.9%	990
5 – 10 MWh	248	19.8%	33,613	4.9%	7,372
10 - 15 MWh	139	11.1%	11,034	1.6%	12,601
15 - 20 MWh	87	7.0%	4,924	0.7%	17,652
20 - 50 MWh	144	11.5%	5,191	0.8%	27,741
50 - 100 MWh	11	0.9%	185	0.0%	60,754
100 - 500 MWh	1	0.1%	4	0.0%	189,285
TOTAL NON-HOUSEHOLDS	1,249	100%	680,381	100%	1,835
OF WHICH:					
Public lighting	4	0.3%	849	0.1%	4,711
Other non-household uses	1,245	99.7%	679,839	99.9%	1,831

Source: ARERA. Annual Survey of Regulated Sectors.

The "other uses" category accounts for almost the entire service, with 1,245.1 GWh, representing over 99% of total volumes, and 679,800 withdrawal points, corresponding to approximately 99.9% of customers supplied. Compared with 2024, consumption in this category fell by 17.6%, while the number of withdrawal points decreased by 17.9%. Average consumption remained broadly unchanged at 1,831 kWh per withdrawal point.

The data show a strong concentration of customers in the lower consumption bands. The band with annual consumption below 5 MWh is by far the largest, with 625,400 withdrawal points, equal to 91.9% of the total, and accounts for 618.9 GWh, corresponding to 49.6% of total volumes supplied. Average annual consumption in this band stood at 990 kWh. The consumption bands between 5 and 15 MWh together account for 6.5% of withdrawal points and approximately 31% of volumes.

Safeguard service

The safeguard service accommodates non-households who find themselves, even temporarily, without an electricity trading contract in the free market, but who are not entitled to access the standard offer service or gradual standard offer service. These same customers are also admitted to the safeguard service when they persist in a condition of non-payment of bills. Since 2008, the service has been provided by sales companies selected by tender, which obtain the right to operate the service for two consecutive years.

The auction for the safeguard service for the 2025–2026 two-year period concluded in November

2024, with the service awarded to two suppliers: Enel Energia and Hera Comm. Hera Comm operates in seven of the nine geographical areas, covering much of Central and Northern Italy and the two major islands, while Enel Energia operates in two areas, concentrated in the North-West and South-East. In this context, Hera Comm became the leading safeguard service provider nationwide, with volumes reaching 2,150 GWh, an increase of 149.2%. Enel Energia, by contrast, continued to record declining volumes, which stood at 786 GWh in 2025 (-25% compared with 2024), while A2A Energia exited the service entirely.

According to data provided by the service providers, the safeguard service contracted further in 2025, confirming the downward trend already observed in 2024. The number of withdrawal points supplied fell to 69,300, calculated on a pro die basis, i.e. taking into account only the fractions of the year during which the points were actually supplied, a decrease of 13.4%. In 2024, there were 80,000 withdrawal points, itself significantly below the 97,800 recorded in 2023. The number of withdrawal points supplied in 2025 therefore represents one of the lowest levels recorded in the safeguard market since its introduction. Indeed, the previous historical low up to 2025 was recorded in 2020, when 69,900 customers were supplied. Volumes of electricity withdrawn also declined further: a total of 2,936 GWh was withdrawn in 2025, compared with 3,563 GWh in 2024, a decrease of 17.6% (Table 3.21).

Table 3.21 Safeguard service by customer type

CUSTOMER TYPE	VOLUMES (GWh)			WITHDRAWAL POINTS (thousands)		
	2024	2025	CHANGE	2024	2025	CHANGE
Public lighting	290	223	-23.1%	16.2	12.8	-21.0%
Other uses	3,273	2,712	-17.1%	63.83	56.52	-11.5%
TOTAL SAFEGUARD	3,563	2,935	-17.6%	80	69	-13.4%

Source: ARERA. Annual Survey of Regulated Sectors.

Low-voltage customers represent the predominant component of the service, numbering approximately 65,000 and accounting for 93.9% of the total, while medium-voltage customers account for 6.1% and high-voltage customers continue to represent a marginal share, at 0.04% of withdrawal points supplied. In terms of volumes, as would be expected, the breakdown is different: low-voltage customers account for 36.4% of total consumption, medium-voltage customers represent the largest share at 47.1%, while high-voltage customers, despite their extremely small number, account for 16.5% of total volumes. Overall, 81.5% of withdrawal points under the safeguard service fall within the "other uses" category and 18.5% within the public lighting category. Both categories recorded a decline compared with 2024: among low-voltage customers, withdrawal points for other uses decreased by 11.6%, while those for public lighting fell by 20.8%.

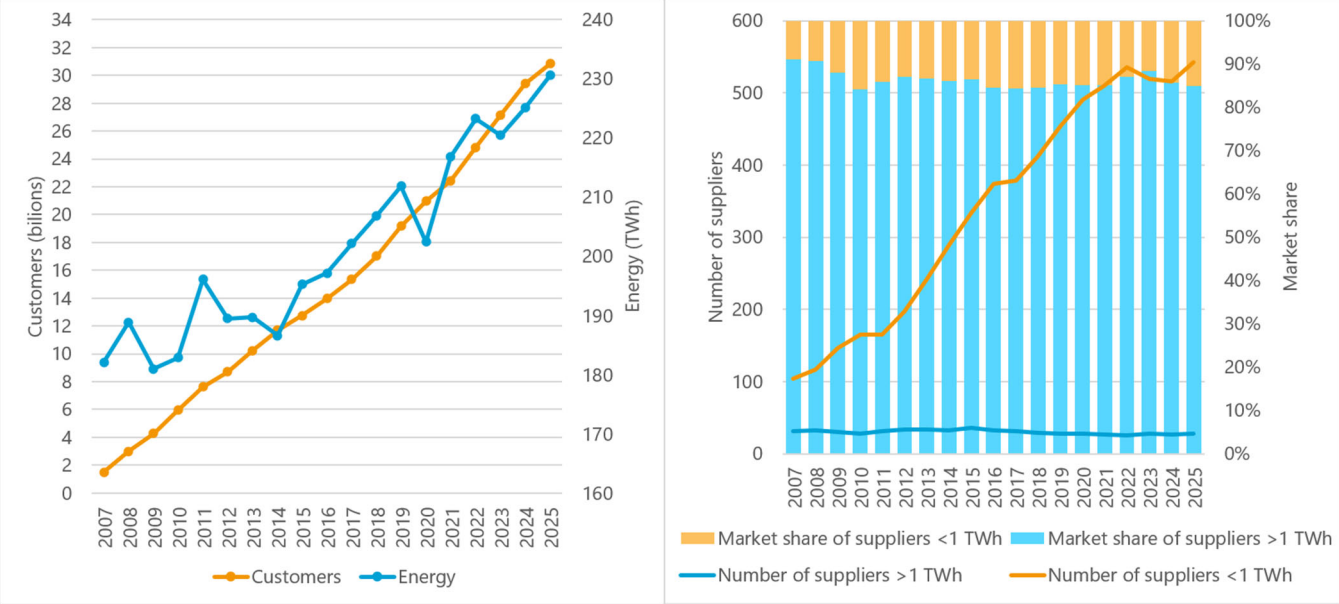
Average consumption per low-voltage customer rose from 15.2 to 16.4 MWh (+8.1%), while that of medium-voltage customers decreased from 384 to 327 MWh (-14.8%). Lastly, average consumption among high-voltage customers increased from 17 to 19 GWh (+13.9%).

Free market

As already noted in the preceding pages, according to the provisional data collected through the Annual Survey of Regulated Sectors, 230.6 TWh of electricity was sold on the free market in 2025, 5.5 TWh more than in 2024, to almost 31 million customers, up 4.9% compared with 2024. he number of customers on the free market, which has grown steadily and strongly over time, has now reached

81.5% of the entire Italian electricity retail market, while the volume of electricity traded on the free market has reached 93.8% of the total Italian electricity retail market. This expansion has not, however, always proceeded at the same pace and has experienced occasional setbacks over time (Figure 3.12). Irrespective of market developments, the number of active suppliers expanded steadily from 2007 through 2022. The trend was interrupted for the first time in 2023, and a slight decline was also recorded in 2024, while the number of suppliers increased again in 2025.

Figure 3.12 Development of the electricity free market



Source: ARERA. Annual Survey of Regulated Sectors.

In 2025, according to the responses to the Annual Survey of Regulated Sectors, there were 570 companies active on the free market, 27 more than in 2024 (+6.1%). As sales increased by almost the same rate over the same period (+6.3%), the average sales volume per company operating on this market declined again, to 405 GWh compared with 415 GWh in 2024. Compared to the 1,349 GWh observed in 2007, when the market was fully opened, the present value is 3.3 times lower.

The composition of the share capital of companies selling electricity to free-market final customers as at 31 December 2025, considering only direct, first-tier shareholdings[161], shows the significant role of individuals, who hold 33.3% of the share capital of electricity suppliers. Significant shares are also held by national energy companies (10.7%) and local energy companies (5.6%). Public bodies and financial institutions do not appear to be very present in the shareholding structure of the suppliers (their respective shares amounting to 3% and 0.3%), while the most significant shareholder category is that of miscellaneous companies, which appears to own 44.6% of the share capital of all suppliers. With regard to the origin of the shareholders holding shares in the share capital of the respondents, it is noted that it is substantially Italian, with 4.2% being held by individuals of foreign origin.

21.1% of the 570 active suppliers who responded to the Annual Survey sell energy in between 1 and 5 regions; 44.9% of suppliers sold electricity across the entire national territory (i.e., in at least 18 regions); the remaining 34% of companies operated in 6 to 17 regions. The share of companies

[161] Shares are calculated without applying any weighting.

serving the entire country has increased steadily over time (from 37.5% in 2023 to 42.9% in 2024).

The breakdown of customers by type and voltage level (Table 3.22) shows an increase of more than 1.4 million withdrawal points supplied compared with 2024. This increase was almost entirely attributable to low-voltage customers, particularly household customers, although there was also a significant increase in the number of low-voltage withdrawal points for other uses. The number of household withdrawal points supplied on the free market increased by 1,105,000, or 4.8% compared with 2024. Approximately 311,000 additional low-voltage withdrawal points for other uses (+5.3%) purchased electricity on the free market, while the number of medium-voltage withdrawal points increased by 2,100 (+2%). Conversely, high and extra-high voltage withdrawal points decreased by nearly 262 units (-24.9%), bringing the total to around 790 units. A sizeable increase (+10,200) was also recorded in low-voltage withdrawal points for public lighting, while those at medium voltage almost doubled (from 750 to 1,100).

Table 3.22 Free electricity market by customer type and voltage level

CUSTOMER TYPE	VOLUMES (GWh)			WITHDRAWAL POINTS (thousands)		
	2024	2025	CHANGE	2024	2025	CHANGE
Low voltage	111,775	113,405	1.5%	29,295	30,720	4.9%
Household	47,169	48,236	2.3%	23,222	24,327	4.8%
Public lighting	2,938	2,825	-3.8%	256	266	4.0%
Other uses	61,668	62,344	1.1%	5,816	6,128	5.3%
Medium voltage	92,575	92,012	-0.6%	103,462	105,563	2.0%
Public lighting	214	242	13.3%	0.75	1.11	47.5%
Other uses	92,361	91,770	-0.6%	103	104	1.7%
High and extra-high voltage	20,725	25,186	21.5%	1.05	0.79	-24.9%
Other uses	20,725	25,186	21.5%	1.05	0.79	-24.9%
TOTAL	225,075	230,603	2.5%	29,399	30,827	4.9%

Source: ARERA. Annual Survey of Regulated Sectors.

In terms of electricity sold, with the exception of low-voltage public lighting and medium-voltage customers in the "other uses" category, all other uses and voltage levels recorded an increase. Sales to low-voltage customers rose by 1.5% compared with 2024, mainly due to growth in the household sector. Medium-voltage customers purchased approximately 563 GWh less than in the previous year (-0.6%), while, as noted above, consumption by high-voltage customers increased by 4.5 TWh, up 21.5%.

In 2025, average consumption by **household customers** was 1,983 kWh per year, slightly lower than in 2024 (-2.4%). As usual, the largest consumption bands in terms of withdrawal points are the first two, covering annual consumption of up to 1,800 kWh, which together account for more than half of customers (54%). However, the next two bands also account for a sizeable share (34%). Overall, 88% of Italian customers consume less than 3,500 kWh per year (Table 3.23).

Table 3.23 Household free electricity market in 2025 by consumption class

CONSUMPTION CLASS	VOLUMES (GWh)	VOLUME SHARE	WITHDRAWAL POINTS (thousands)	SHARE ON WITHDRAWAL POINTS	AVERAGE CONSUMPTION (kWh)
< 1,000 kWh	3,306	6.9%	6,833	28.1%	484
1.000-1.800 kWh	8,797	18.2%	6,292	25.9%	1,398
1.800-2.500 kWh	9,602	19.9%	4,509	18.5%	2,129
2.500-3.500 kWh	10,835	22.5%	3,695	15.2%	2,932
3.500-5.000 kWh	8,097	16.8%	1,979	8.1%	4,091
5.000-15.000 kWh	6,664	13.8%	981	4.0%	6,793
> 15,000 kWh	934	1.9%	37	0.2%	25,390
TOTAL HOUSEHOLDS	48,236	100.0%	24,327	100.0%	1,983
of which with dual fuel contract					
< 1,000 kWh	197	5.9%	340	20.9%	578
1.000-1.800 kWh	662	19.8%	471	28.9%	1,404
1.800-2.500 kWh	747	22.3%	351	21.6%	2,128
2.500-3.500 kWh	820	24.5%	281	17.2%	2,922
3.500-5.000 kWh	537	16.1%	132	8.1%	4,064
5.000-15.000 kWh	348	10.4%	52	3.2%	6,647
> 15,000 kWh	33	1.0%	1	0.1%	23,392
TOTAL WITH DUAL FUEL CONTRACT	3,345	100.0%	1,629	100.0%	2,053

Source: ARERA. Annual Survey of Regulated Sectors.

Across the various consumption bands, with the exception of the first and last, the average consumption figures for the free market are very similar to those of household customers supplied under the standard offer service and the gradual standard offer service (Tables 3.17 and 3.18). Owing to the differences in the two extreme bands, however, overall average consumption by households on the free market, at 1,983 kWh, is one-third higher than that of households under the standard offer service, at 1,496 kWh, and 15% higher than that of households under the gradual standard offer service, at 1,724 kWh.

In 2025, approximately 1.63 million household withdrawal points had a dual-fuel contract[162]. This number increased compared with 2024, when it stood at 1.55 million, while their share of total household customers supplied on the free market remained unchanged at 6.7%. Total electricity consumption by customers with a combined electricity and gas supply contract amounted to just over 3.3 TWh, equal to 6.9% of all electricity sold to household customers on the free market. With the exception of the first two consumption bands, average consumption by dual-fuel customers is generally lower than that of customers with electricity-only contracts. However, owing to higher consumption in the first two bands, overall average consumption is 3.5% higher than that of household customers as a whole.

The breakdown of customers by tariff applied in the free market shows a substantial preference for the single-rate price, which in 2024 was chosen by 69.7% of all customers, equivalent to 69.2% of volumes. 10.8% of customers chose the two-tier tariff, and 19.5% the time of use mode. The prevalence of single-rate pricing increased by 1.3 percentage points in 2025 compared with 2024

[162] Dual-fuel customers are defined as customers who receive a single bill for their electricity and gas supply; the figure therefore excludes customers who, despite having contracts with the same supplier for both electricity and natural gas, receive separate bills for the two services.

and, with the exception of a few years, has increased over time. The factors that probably make it more attractive include the simplicity of calculating and monitoring bill costs, as well as the absence of restrictions on when electricity is consumed. The two-tier tariff now accounts for only a very small share of customers, while time-of-use tariff has been growing slowly but steadily for several years.

Compared with 2024, interest in dual-fuel contracts among **non-household customers** remained unchanged: withdrawal points opting for a combined electricity and gas supply accounted for 1.7% of the total 6.5 million non-household customers, almost all of which were connected at low voltage. In 2025, however, the share of electricity purchased by dual-fuel customers as a proportion of total electricity sold to non-household customers fell from 2% to 1.7%. Dual-fuel customers purchased 3.1 TWh out of a total of 182.4 TWh sold to non-household customers (Table 3.24).

Table 3.24 Non-household free market in 2025 by voltage level

CUSTOMER TYPE	VOLUMES (GWh)	OF WHICH DUAL FUEL GWh	WITHDRAWAL POINTS	OF WHICH DUAL FUEL
Low voltage	65,169	1,669	6,393,797	108,840
Medium voltage	92,012	1,297	105,563	1,142
High and extra-high voltage	25,186	146	790	14
TOTAL NON-HOUSEHOLDS	182,367	3,113	6,500,151	109,996

Source: ARERA, Annual Survey of Regulated Sectors.

Table 3.25 Non-household free market in 2025 by consumption class

CONSUMPTION CLASS	VOLTAGE LEVEL	VOLUMES (GWh)	VOLUME SHARE	WITHDRAWAL POINTS	AVERAGE CONSUMPTION (kWh)
<5 MWh	LV	5,967	3.3%	4,519,127	1,320
5-10 MWh	LV	4,574	2.5%	637,377	7,177
10-15 MWh	LV	3,731	2.0%	301,122	12,389
15-20 MWh	LV	3,344	1.8%	191,469	17,466
< 10 MWh	MV	50	0.0%	11118	4,474
10-20 MWh	MV	84	0.0%	5873	14,383
< 20 MWh	HV and EHV	0.2	0.0%	46	3,768
20-50 MWh	All	14,928	8.2%	474,046	31,490
50-100 MWh	All	12,511	6.9%	180,680	69,246
100-500 MWh	All	28,497	15.6%	139,063	204,922
500-2.000 MWh	All	27,905	15.3%	30,092	927,311
2.000-20.000 MWh	All	46,894	25.7%	9,630	4,869,689
20.000-50.000 MWh	MV, HV and EHV	10,270	5.6%	348	29,504,469
50.000-70.000 MWh	MV, HV and EHV	3,049	1.7%	52	58,527,630
70.000-150.000 MWh	MV, HV and EHV	6,449	3.5%	68	94,738,833
> 150,000 MWh	MV, HV and EHV	14,113	7.7%	41	343,074,533
TOTAL NON-HOUSEHOLDS	-	182,367	100.0%	6,500,151	28,056

Source: ARERA. Annual Survey of Regulated Sectors.

The breakdown of non-household customers by consumption class (Table 3.25) shows that sales volumes are fairly concentrated in the consumption classes between 100 and 20,000 MWh/year, which together account for 56.6% of the total electricity purchased by these customers. However,

69.5% of customers come under the first class, i.e. they consume less than 5 MWh per year. Average consumption by non-household customers naturally varies considerably across the different bands, but is generally lower than in 2024.

Overall, average consumption by all non-household customers purchasing electricity on the free market amounted to 28,056 kWh in 2025, 2.6% lower than the figure recorded in 2024 (28,802 kWh).

Available offers and sales contracts in the free electricity market

Once again this year, the Annual Survey of Regulated Sectors asked electricity and natural gas suppliers a number of questions aimed at assessing the number of offers that companies make available to customers choosing to purchase on the free market and, above all, the distribution of their customers among the different types of contract actually chosen[163]. The aim of the questions asked to suppliers on the quantity and quality of commercial offers then actually chosen by their customers is to classify the extreme variety of contracts in the market, composing a picture that, of course, cannot be considered exhaustive of reality. The results presented in these pages should be treated with caution.

In 2025, suppliers made an average of 44 commercial offers available to household customers, seven of which could be taken up exclusively through digital channels. For non-household customers, who generally have a wider range of options and for whom suppliers can offer more customised services and contracts tailored to their specific needs, the average number of offers rises to 52. However, only 6 of these were available exclusively through online channels. The average number of commercial offers available on the free market increased steadily between 2023 and 2025. For household customers, the average number of offers rose from 26.4 in 2023 to 30.6 in 2024 and then to 44 in 2025, an increase of more than 60% over the three-year period. Significant growth was also recorded for non-household customers, with the average number of offers rising from 30 in 2023 to 35.7 in 2024 and 51.9 in 2025, approximately 70% higher than two years earlier. This reflects the increasing variety of commercial offers developed by suppliers to meet the needs of increasingly diverse customer segments. In 2025, contracts concluded online accounted for 9.3% of all contracts signed by domestic customers. The figure is even lower in the non-household segment, where online offers account for 2.3% of active contracts.

Among household customers, fixed-price and variable-price contracts are distributed fairly evenly. Fixed-price offers are slightly more prevalent, having been chosen by 51.0% of customers, while the remaining 49.0% opted for variable-price arrangements. The difference in average prices between the two types of contract is very small: €236.69/MWh for fixed-price contracts compared with €232.35/MWh for variable-price contracts, a difference of less than 2%. The situation is different for non-household customers, among whom variable-price contracts clearly predominate, having been chosen by 79.5% of customers, while only 20.5% opted for fixed-price offers. This distribution reflects businesses' greater willingness to assume the risk associated with wholesale price movements, also in view of the possibility of benefiting more quickly from any decline in market prices. In this segment too, variable-price contracts are associated with a lower average price than fixed-price offers (€156.26/MWh compared with €178.08/MWh), a difference of approximately 12%. A comparison of the two segments also shows that the average prices paid by non-household customers are

[163] The data discussed in the section on contract types chosen by customers also take into account PLACET Offers (free-price offers under standardised contractual conditions).

significantly lower than those paid by household customers (Table 3.26).

Table 3.26 Contracts for the supply of electricity in the free market in 2025 by price type and average price

CONTRACTS	HOUSEHOLDS		NON-HOUSEHOLDS	
	SHARE(A)	PRICE(B) €/MWh	SHARE(A)	PRICE(B) €/MWh
Fixed-price contracts	51.0%	236.69	20.5%	178.08
Variable-price contracts	49.0%	232.35	79.5%	156.26
TOTAL CUSTOMERS	100%	234.51	100%	158.10

(A) Percentage of customers who signed the indicated contracts.
(B) Supply cost component.

Source: ARERA, Annual Survey of Regulated Sectors.

Analysis of variable-price offers confirms that indexation to the average PUN is by far the most common contractual arrangement in the free electricity market. In 2025, this arrangement was chosen by 89.1% of household customers and 78.8% of non-household customers with variable-price contracts. The average price associated with this type of contract stood at €233.12/MWh for household customers and €162.46/MWh for non-household customers, very close to the overall average prices for indexed contracts. A smaller proportion of customers opted for contracts linked to the hourly wholesale price of electricity, i.e. the dynamic-price offers provided for under European legislation. This type of contract accounted for 7.2% of household customers and 16.1% of non-household customers. The average prices under these contracts were lower than those indexed to the average PUN, at €227.79/MWh and €145.31/MWh respectively. Other forms of indexation continued to account for only a marginal share.

As usual, the Annual Survey also examined the presence and extent of additional services included in contracts (Table 3.27).

The results show that free-market offers are increasingly characterised by the inclusion of additional features alongside the supply of electricity. This trend is particularly pronounced in the household segment, whereas offers without additional services remain more prevalent among non-household customers.

Among fixed-price contracts, the most common additional feature is a guarantee that the electricity is sourced from renewable sources, included in 74.6% of contracts taken out by household customers and 44.6% of those taken out by non-household customers. The average prices of these offers stood at €237.32/MWh for household customers and €187.49/MWh for non-household customers, slightly above the respective segment averages. In the household fixed-price market, loyalty points schemes also have a certain significance, being included in 9.3% of contracts, while the category of other products or services offered together with electricity accounts for 8.1% of customers. By contrast, only 2.5% of household customers have contracts without any additional services. The situation is markedly different in the non-household segment, where more than half of fixed-price contracts (50.8%) do not include any auxiliary services, although green offers remain the main type of additional feature.

Table 3.27 Contracts for the supply of electricity in the free market in 2025 by type of additional services and average price

CONTRACTS	HOUSEHOLDS		NON-HOUSEHOLDS	
	SHARE(A)	PRICE(B) €/MWh	SHARE(A)	PRICE(B) €/MWh
Additional services of fixed-price contracts				
No additional service	2.5%	226.5	50.7%	172.3
Guarantee of energy from renewable energy resources	74.6%	237.3	44.5%	187.5
Guarantee of energy produced in Italy	0.0%	175.1	0.0%	172.7
Points collection programme (own or others)	9.3%	224.7	3.1%	215.5
Auxiliary energy services	2.4%	226.3	1.0%	183.9
Free gift or gadget	0.9%	212.2	0.0%	158.7
Electric mobility services	0.0%	198.4	0.0%	224.7
Other products or services offered together with electricity	8.1%	262.2	0.3%	177.3
Other	2.1%	227.0	0.4%	151.9
TOTAL FIXED-PRICE CONTRACTS	100.0%	236.7	100.0%	178.1
Additional services of variable-price contracts				
No additional service	29.1%	228.0	53.0%	149.3
Guarantee of energy from renewable energy resources	48.5%	234.4	38.3%	168.5
Guarantee of energy produced in Italy	9.8%	149.5	0.0%	147.5
Points collection programme (own or others)	0.3%	230.5	1.6%	188.5
Auxiliary energy services	6.7%	234.4	3.7%	152.4
Free gift or gadget	1.0%	240.9	0.1%	169.5
Electric mobility services	0.0%	0.0	0.0%	0.0
Other products or services offered together with electricity	2.6%	219.6	1.1%	231.0
Other not included in the aforementioned items	2.1%	251.2	2.3%	165.2
TOTAL VARIABLE-PRICE CONTRACTS	100.0%	232.3	100.0%	156.3

(A) Percentage of customers who signed the indicated contracts.
(B) Supply cost component.

Source: ARERA, Annual Survey of Regulated Sectors.

For variable-price contracts too, the guarantee that electricity is sourced from renewable sources is the most widespread additional service, covering 48.5% of household customers and 38.3% of non-household customers. However, compared with fixed-price contracts, the share of offers without additional services is significantly higher, reaching 29.1% of household customers and 53.0% of non-household customers. This suggests that indexed offers are more focused on price competitiveness and less on differentiation through additional services. Among household customers who opted for variable-price contracts, additional energy services (9.8%) and loyalty points schemes (6.7%) also feature prominently, while other types of benefits remain relatively uncommon. In the non-household segment, by contrast, the shares accounted for by the various additional features are generally below 4%, confirming less emphasis on loyalty schemes and additional services.

Concentration in the retail electricity market

The ranking of the top twenty groups by total sales to the final market in 2025 (provisional, given the preliminary nature of the data collected) shows some changes in position: the Edison, Eni and Iren groups moved up the ranking, while Hera, Axpo Group, Acea and E.On lost ground (Table 3.28).

The Enel group remains the dominant operator in the Italian electricity market as a whole, although its market share, at 22.3%, has been declining for several years (from 33.5% in 2023 and 26.8% in 2024), due to a sharp decrease in the group's sales (-15.8%), which fell by approximately 10 TWh. In

particular, sales to both household customers and non-household customers connected at low voltage decreased by approximately 3.3 TWh, while sales to medium-voltage customers fell by 4 TWh. By contrast, sales to high-voltage customers increased by approximately 0.4 TWh (+11%), although this was not enough to prevent the group from slipping further to third place in the sales ranking for this segment (having fallen from first to second place in 2024). The Enel group nevertheless maintained a significant lead in the mass market, comprising household customers and non-household customers connected at low voltage: Enel serves 28.6% of this market (compared with 41.6% in 2023 and 33.7% in 2024), while the share held by its nearest competitor, A2A, remains 20 percentage points lower.

Table 3.28 Top twenty groups by end-electricity market sales in 2025

GROUP	SALES (GWh)					SHARE	POSITION IN 2024
	CUSTOMERS HOUSEHOLDS	NON-HOUSEHOLDS LV	NON-HOUSEHOLDS MV	NON-HOUSEHOLDS HV/VHV	TOTAL		
Enel	22 575	13 716	14 783	3 825	54 900	22.3%	1 °
A2A	2 813	8 375	11 978	1 424	24 590	10.0%	2 °
Edison	3 192	3 202	7 544	4 422	18 360	7.5%	4 °
Hera	3 757	4 501	7 683	164	16 106	6.6%	3 °
Eni	5 950	1 427	3 806	473	11 656	4.7%	6 °
Axpo Group	324	2 587	6 285	2 071	11 267	4.6%	5 °
Engie	537	288	3 156	6 496	10 477	4.3%	7 °
Alperia	623	1 647	3 477	230	5 977	2.4%	8 °
Duferco	466	2 122	1 343	1 616	5 547	2.3%	9 °
Iren	2 135	1 700	1 384	166	5 386	2.2%	11 °
Royal Dutch Shell	0	0	2 061	2 992	5 086	2.1%	22 °
Sorgenia	795	2 276	1 728	48	4 847	2.0%	12 °
Acea	1 616	1 424	1 418	131	4 590	1.9%	10 °
Agsm Aim	585	1 586	1 856	172	4 199	1.7%	16 °
Repower	0	2 196	1 763	0	3 960	1.6%	15 °
E.On	934	1 015	1 920	0	3 868	1.6%	13 °
Nova Coop	0	1 120	2 202	27	3 425	1.4%	14 °
Dolomiti Energia	809	1 208	901	0	2 917	1.2%	18 °
Alpiq	0	0	2 631	114	2 845	1.2%	19 °
MET Holding	0	716	1 885	142	2 801	1.1%	21 °
Other groups	11 072	17 419	13 590	1 158	42 970	17.5%	
TOTAL GROUPS	58 183	68 526	93 395	25 669	245 773	100.0%	

Source: ARERA. Annual Survey of Regulated Sectors.

The A2A group consolidated its second place in the overall ranking, with its market share increasing from 8.9% to 10%. In 2025, the A2A group's total sales increased by 2.9 TWh (13.3%), with growth in almost all segments and particularly among non-household customers connected at low voltage (+30%). It therefore also retained second place in the mass-market segment, with a share of 8.8%, 1.7 percentage points higher than in 2024. However, the group's sales to high-voltage customers fell sharply compared with the previous year (-28%).

In the overall sales ranking, the Edison group moved up from fourth to third place, driven by an increase in sales of almost 4 TWh (+26.4%). Growth was particularly significant in the high- and medium-voltage segments, where the group sold 1.9 TWh and 1 TWh more, respectively, than in 2024. However, mass-market sales also increased by 0.8 TWh (+17%), making a significant contribution to the group's rise in the overall ranking.

Table 3.29 shows the details of the concentration measures, also broken down by voltage level. In the first part of the table, measures are calculated from the volumes sold by the corporate groups in the retail market, while in the second part of the table, measures are calculated from the customers (withdrawal points) served by the corporate groups themselves.

Based on measures calculated using electricity sales, the level of concentration in the overall market decreased in almost all market segments in 2025, the only exception being the segment comprising non-household customers connected at high and extra-high voltage. Overall, the C3, i.e. the combined market share of the three largest operators (corporate groups), fell from 42.3% to 39.8%. The Herfindahl–Hirschman index (HHI) index fell from 988 to 806, well below the first threshold of concern, set at 1,500; indeed, an HHI value between 1,500 and 2,500 indicates a moderately concentrated market, while a value above 2,500 signals a highly concentrated one (the maximum possible HHI is 10,000). The number of corporate groups needed to exceed 75% of total sales increased from 14 to 15.

Table 3.29 Market concentration in the electricity retail sector (based on corporate groups)

VOLTAGE LEVEL	2024			2025		
	GROUPS >5%	C3	HHI	GROUPS >5%	C3	HHI
METERING CALCULATED ON THE BASIS OF ENERGY SOLD BY CORPORATE GROUPS						
Households	3	59.9%	2,165	4	55.5%	1,748
Non-households	5	38.6%	783	6	36.9%	671
Low voltage	3	41.0%	857	3	38.8%	707
Medium voltage	5	39.5%	795	5	36.9%	690
High and extra-high voltage	6	52.9%	1,328	7	57.4%	1,440
TOTAL MARKET	5	42.3%	988	4	39.8%	806
METERING CALCULATED ON THE BASIS OF WITHDRAWAL POINTS SERVED BY CORPORATE GROUPS						
Households	3	62.8%	2,461	4	57.5%	1,913
Non-households	4	42.6%	964	3	38.4%	762
Low voltage	4	42.5%	963	3	38.3%	762
Medium voltage	4	46.8%	1,095	5	43.7	909
High and extra-high voltage	7	31.6%	659	6	33.1%	705
TOTAL MARKET	4	57.5%	2,090	4	52.3%	1,616

Source: ARERA. Annual Survey of Regulated Sectors.

However, concentration in the Italian electricity market presents two contrasting pictures: it remains relatively high in the household segment (the C3 fell from 59.9% to 55.5%, while the HHI decreased from 2,165 to 1,748), albeit continuing its steady decline, whereas it is low in the non-household segment: the C3 fell to 36.9% (from 38.6%) and the HHI decreased from 783 to 641.

Using indicators calculated on the basis of withdrawal points, concentration levels are slightly higher than those based on electricity sales volumes, except, of course, for non-household customers supplied at high and extra-high voltage, for which they are considerably lower.

3.2.2.1 Monitoring of the level of retail market prices, of the level of transparency and of the degree and of the efficiency of market opening and competition

Monitoring of the retail market price level

For retail electricity market pricing, the Authority has access to two main data sources:

- the survey of *Average prices charged in the electricity and natural gas market,* carried out pursuant to Resolution 168/2018/R/com of 29 March 2018, which collects, on a half-yearly basis, quarterly data on the prices billed [164] by suppliers to household and non-household customers, broken down by consumption class and type of market;
- that carried out as part of the *Annual Survey of Regulated Sectors*, in which data is collected for the previous year and broken down according to various categories of detail (type of market, sector and consumption classes, type of contract applied).

The prices collected pursuant to Resolution 168/2018/R/com are also used for the retail market monitoring carried out by the Authority under the *Integrated Text on Monitoring of the Retail Electricity and Natural Gas Markets* (TIMR)[165], which, in addition to prices, analyses numerous indicators relating to electricity suppliers serving more than 50,000 withdrawal points (see below). Furthermore, under an institutional agreement, all data collected pursuant to Resolution 168/2018/R/com are provided every six months to the Ministry of the Environment and Energy Security, which forwards them to Eurostat in order to fulfil the obligations concerning statistics on final electricity and natural gas prices laid down in *Regulation (EU) 2016/1952 on European statistics on natural gas and electricity prices and repealing Directive 2008/92/EC*[166].

In view of the obligations to be fulfilled, the Authority has introduced a procedure for suppliers under which, where they fail to comply with the requirements for the half-yearly reporting of average electricity and gas prices, penalties are imposed in proportion to the size of the company in terms of the number of customers served.[167] This is because such failures to communicate create distortions of information which, in addition to hindering the Authority's functions or leading to the publication of incorrect data by the Authority itself (albeit under the responsibility of the companies), harm transparency in the two sectors and negatively affect consumers and other operators. Knowledge of price dynamics, on the other hand, has become particularly important in recent years, given the transition of significant categories and shares of final customers from protected regimes to the free market. For failure to submit data for the first half of 2025[168], penalties were imposed on 13 companies (for four of which the penalty was increased by 10% because they had already failed to comply with the data submission requirements for the second half of 2024); for failure to submit price data for the second half of 2025[169], penalties were imposed on nine companies that failed to provide any response (for four of which the penalty was increased by 10% because they had already failed to comply with the data submission requirements for the first half of 2025).

The prices gathered through the *Annual Survey*, recorded on an accrual basis, are more consistent with the requirements of annual reporting As part of the *Annual Survey of Regulated Sectors*, sales

[164] More specifically, these are average unit revenues calculated as the ratio of revenues collected to the quantities of energy billed in the reference quarter.

[165] Approved by Resolution ARG/com 151/11 of 3 November 2011.

[166] Italy was granted a derogation from the application of Regulation (EU) 2016/1952 until 2018.

[167] Resolution 592/2021/R/com of 21 December 2021.

[168] Resolution 521/2025/E/com of 2 December 2025.

[169] Resolution 172/2026/E/com of 19 May 2026.

operators were asked, as usual, to submit data on the final prices charged to their customers both net of taxes and for the part related only to supply costs, which are given by the sum of the components relating to energy, dispatching, network leakages, imbalance and sales marketing costs.

The analysis of the data submitted by the companies shows the usual variability in the unit expenditure incurred by customers, with values inversely proportional to the size of consumption. As can be seen in Table 3.30, which shows the average prices charged to households by annual consumption class, the values range from 227 €/MWh, found for the largest customers (consumption of more than 15,000 kWh/year), to 656 €/MWh, for the smallest class (0-1000 kWh). The price falls steadily as the size of customers increases. This trend is attributable to procurement costs which, as usual, decrease steadily as per capita consumption increases, falling from €359/MWh for the lowest consumption band to €167/MWh for the highest.

Table 3.30 Average electricity prices to households in 2025

CONSUMPTION CLASS (kWh/year)	QUANTITY OF ENERGY (GWh)	WITHDRAWAL POINTS (thousands)	AVERAGE PRICE NET OF TAXES (€/MWh)	OF WHICH: SUPPLY COSTS (€/MWh)
< 1,000	4,291	9,214	655.6	359.5
1.000-1.800	10,998	7,878	335.2	238.9
1.800-2.500	11,738	5,517	287.0	213.8
2.500-3.500	12,970	4,427	265.5	201.1
3.500-5.000	9,470	2,317	252.9	191.9
5.000-15.000	7,616	1,123	244.4	181.6
> 15,000	1,101	43	227.2	167.1
TOTAL HOUSEHOLDS	58,184	30,517	306.3	217.8

Source: ARERA. Annual Survey of Regulated Sectors.

Table 3.31 Average electricity prices to households in 2025 by consumption class and market type

CONSUMPTION CLASS (kWh/year)	PRICE NET OF TAXES (€/MWh)				
	STANDARD OFFER	GRADUAL STANDARD OFFER SERVICE	FREE MARKET	DIFFERENCE FREE MARKET/STANDARD OFFER SERVICE	DIFFERENCE FREE MARKET/GRADUAL STANDARD OFFER SERVICE
< 1,000 kWh	583.0	348.1	709.3	22%	104%
1.000-1.800 kWh	268.9	205.7	359.3	34%	75%
1.800-2.500 kWh	234.9	193.7	303.4	29%	57%
2.500-3.500 kWh	220.4	191.6	277.6	26%	45%
3.500-5.000 kWh	215.3	193.7	261.3	21%	35%
5.000-15.000 kWh	205.3	199.0	250.5	22%	26%
> 15,000 kWh	180.9	197.1	234.0	29%	19%
TOTAL HOUSEHOLDS	273.3	209.6	319.9	17%	53%

Source: ARERA. Annual Survey of Regulated Sectors.

Table 3.31 provides a breakdown and comparison of prices between the free market and the standard offer service. Following the temporary reversal in 2022, prices on the free market are once again higher than under the standard offer service across all consumption classes. More specifically, with

reference to the final price, including all components except taxes, the free-market premium is highest (+34%) in the second consumption band (customers consuming between 1,000 and 1,800 kWh/year), while the fifth band (customers consuming between 3,500 and 5,000 kWh/year) shows the smallest differential, although this remains significant (+21%).Customers under the standard offer service who, as at 1 July 2024, were not vulnerable and had not chosen a supplier on the free market were transferred to the new gradual standard offer service, provided by suppliers selected through competitive procedures in which participants offered a fixed discount (euro/customer/year) for the benefit of final customers. The new service therefore generally has lower price levels than the standard offer service and even wider differentials compared with the free market, particularly for the lower consumption bands. More specifically, the free-market premium over the gradual standard offer service for household customers ranges from +104% in the first band (consumption of up to 1,000 kWh/year) to +19% in the last band (consumption above 15,000 kWh/year). Across the main consumption bands as a whole (customers consuming between 1,000 and 5,000 kWh/year, which account for more than three-quarters of total household consumption), the average differential exceeds 50%.

For non-household customers, Table 3.32 shows data on the quantities purchased and the prices charged to them, broken down by voltage level. Unsurprisingly, the highest prices relate to low-voltage customers, whose average unit consumption is very low.

Table 3.32 Average electricity prices to non-households in 2025

VOLTAGE LEVEL	QUANTITY OF ENERGY (GWh)	WITHDRAWAL POINTS (thousands)	AVERAGE PRICE NET OF TAXES (€/MWh)	OF WHICH: SUPPLY COSTS (€/MWh)
Low voltage	68,524	7,200.4	270.9	179.3
Medium voltage	93,395	109.8	198.7	143.6
High and extra-high voltage	25,669	0.8	140.7	122.3
TOTAL NON-HOUSEHOLDS	187,588	7,311.0	217.2	153.7

Source: ARERA. Annual Survey of Regulated Sectors.

Table 3.33 Average electricity prices for non-household low voltage customers in 2025, by market type

TYPE OF MARKET	QUANTITY OF ENERGY (GWh)	WITHDRAWAL POINTS (thousands)	AVERAGE PRICE NET OF TAXES (€/MWh)	OF WHICH: SUPPLY COSTS (€/MWh)
Gradual standard offer for small enterprises	1,036	61	234.4	152.1
Gradual standard offer for micro enterprises	1,249	680	373.5	168.8
Safeguard	1,070	65	246.0	165.9
Free market	65,169	6,394	270.0	180.1
NON-HOUSEHOLDS IN LV	68,524	7,200	270.9	179.3

Source: ARERA. Annual Survey of Regulated Sectors.

The breakdown of low-voltage non-household customers by market type shows significant price differentials (Table 3.33). The two gradual standard offer services (for micro-enterprises and small enterprises), which benefit from the competitive effects of the tender procedures used to award the services, have the lowest procurement component (€120/MWh and €139/MWh respectively), followed by the free market (€176/MWh) and, finally, the supply of last resort service, at a

considerably higher level (€254/MWh).

Table 3.34 Electricity prices in the free market for customers with dual fuel contracts in 2025

CONSUMPTION CLASS (kWh/year)	QUANTITY OF ENERGY (GWh)	WITHDRAWAL POINTS (thousands)	AVERAGE PRICE NET OF TAXES (€/MWh)	OF WHICH: SUPPLY COSTS (€/MWh)
Households				
< 1,000 kWh	197	340	576.0	321.9
1.000-1.800 kWh	662	471	331.0	223.1
1.800-2.500 kWh	747	351	279.6	198.3
2.500-3.500 kWh	820	281	252.8	183.1
3.500-5.000 kWh	537	132	234.6	170.3
5.000-15.000 kWh	348	52	219.9	158.4
> 15,000 kWh	33	1	202.0	147.6
TOTAL HOUSEHOLDS	3,345	1,629	286.5	197.6
Low voltage	1,669	108,840	214.2	148.5
Medium voltage	1,297	1,142	154.2	116.0
High and extra-high voltage	146	14	140.2	124.7
TOTAL NON-HOUSEHOLDS	3,113	109,990	185.7	133.8

Source: ARERA. Annual Survey of Regulated Sectors.

Finally, Table 3.34 shows the procurement costs paid by free market customers who signed a dual fuel contract. For free-market customers, the electricity prices under dual-fuel contracts (averaging €286.5/MWh for household customers and €185.7/MWh for non-household customers) are lower than those for electricity purchased under a separate, single-commodity contract.

Monitoring of the level of transparency and of the degree and efficiency of market opening and competition

Legislative Decree No. 93 of 1 June 2011, implementing directives 2009/72/EC and 2009/73/EC, gave the Authority the task of monitoring retail markets, with reference to both the electricity and natural gas sectors. This activity was launched in 2011 for both sectors with the *Integrated Text on Monitoring of the Retail Electricity and Natural Gas Markets* (TIMR)[170], which introduced the publication of an annual monitoring report. Since, as just mentioned, the analysis is joint between the electricity and gas sectors, the **monitoring results for both sectors** are reported below.

The ***Retail Monitoring: Report for the year 2024***[171], published in November 2025, sets out the main findings of the monitoring activity and, where possible, describes developments in the relevant trends since 2012, the first year in which monitoring was carried out. In line with previous reports, the 2024 Report examines the data collected regarding: competitive behaviour, offers and prices, service quality in sales, billing standards, and payment default. Within each thematic area, results are

[170] Adopted by Resolution ARG/com 151/11 of 7 November 2011.

[171] Report 486/2025/I/com of 11 November 2025 (2024 Report). All the content of the 2024 Report and previous reports, together with retail monitoring data and analyses, is available on the Retail Monitoring page of the Authority's website (https://www.arera.it/rapporti-e-relazioni/monitoraggio-retail).

analysed, where necessary, separately by sector and customer type, taking into account the uneven levels of maturity and competitiveness achieved among the various customer segments.

The results of retail monitoring for 2024 in the electricity sector confirm that there are no specific significant concerns for medium-voltage "other uses" customers. Concentration is limited and, according to many of the relevant indicators, declining, and is consistent with conditions of effective competition. Customer switching activity remains strong, although lower than in previous years. For low-voltage "other uses" customers, the evidence on competitive dynamics and the structure of the retail market shows some encouraging signs of market activity, such as high levels of customer switching, but also some areas requiring attention, including a higher level of concentration than that recorded for medium-voltage "other uses" customers.

For household customers in the electricity sector and household and condominium customers in the gas sector, despite improvements particularly in terms of customer switching, the issues that have historically characterised these segments persist. These suggest more attention in the accompanying process, including regulatory, to the full liberalisation of the market. Particular attention should be paid, first and foremost, to the high levels of concentration, the continuing competitive advantage enjoyed by standard offer service providers and the still insufficient awareness of the "average" customer, who does not yet appear able to make choices in the market to their advantage. For household customers in the electricity sector, factors that adversely affect competition in the retail market remain significant, despite some signs of improvement. These include high market concentration, the competitive advantage enjoyed by standard offer service providers and barriers to growth. Although concentration in the free market remains high, the allocation of more than 3.6 million withdrawal points belonging to non-vulnerable household customers through competitive procedures to the new gradual standard offer service for non-vulnerable household customers (hereinafter: STG_{NV}) has had an impact on the structure of supply in the market as a whole. The level of concentration across the free market, the standard offer service and the STG_{NV} decreased significantly between the first and second halves of 2024, mainly as a result of those competitive procedures and subsequently as a result of competitive dynamics in the free market. This rapid and significant decline in market concentration could potentially increase competition, the effects of which may become apparent over the coming years. In the gas sector, the trend towards greater switching activity among household customers has become more firmly established, but concentration in the free market has not yet fallen to a level at which potential future concerns regarding the full realisation of the benefits of competition can be ruled out. Although concentration indicators are lower than those recorded for electricity sales to household customers, compared with other types of gas customer, gas sales to households are characterised by greater concentration on the supply side and lower switching activity on the demand side. Moreover, incumbent suppliers continue to enjoy a strong competitive advantage over new entrants.

In both sectors, the proportion of customers using the *Portale Offerte* remains low, despite the peak in usage recorded around the end of the Standard Offer Service in the gas sector (1 January 2024). This suggests that customers predominantly sign up to offers after being contacted by call centres or sales agents and that, by failing to check information obtained through other channels against the *Portale Offerte*, they do not make full use of the tools available to them to make an informed choice. It is therefore necessary to continue measures aimed at raising awareness of the *Portale Offerte* and encouraging its use among the wider customer base.

The evidence set out above regarding market concentration and the difficulties faced by final customers in navigating the offers available on the free market must be given due consideration in the process towards full liberalisation (1 April 2027) provided for by Law No. 124/17, which envisages

the removal of standard offer arrangements. This is necessary to ensure that, in the forthcoming fully liberalised market, customers are able to take full advantage of all the opportunities offered by the free market.

In addition to the Annual Retail Monitoring Report, the Authority is required by law[172] to submit to the competent Parliamentary Committees, by 31 March each year from 2025 onwards, a ***Report monitoring the electricity supply conditions applied to non-vulnerable household customers***, covering:

• the electricity supply conditions applied to household customers following completion of the competitive procedures for awarding the gradual standard offer service for non-vulnerable household customers;

• the correct application of the service conditions by the successful bidders for the STGNV, selected through the aforementioned competitive procedures.

On 1 April 2025, the Authority submitted this Report to the competent Parliamentary Committees[173]. Its analyses focus on non-vulnerable household customers who left the standard offer service between January and June 2024 and those who left the STG_{NV} after the service was launched, i.e. between July and December 2024.

Complaints related to the commercial quality of the electricity sales service and compensation

The provisions for **monitoring the quality of sales services** ensure, on the one hand, the protection of customers in relation to certain sales service performances and, on the other hand, the availability of comparative elements also in relation to the results emerging from the Retail Monitoring Report.

The quality of sales services involves all the suppliers engaged in the sale of electricity and natural gas to final customers. The *Integrated Text on the Regulation of the Quality of Electricity and Natural Gas Retail Services* (TIQV)[174] has established a set of rules for the protection of final customers and commercial quality indicators with which all electricity and gas suppliers are required to comply. These indicators are of two types: general and specific.

General standards represent the level of quality relating to all services of the same type. Failure to comply with them does not result in compensation to the customer, but in the event of a serious breach of these standards, the Authority may open proceedings to impose administrative sanctions on the offending supplier. Where a supplier fails to meet the **specific commercial quality standards**, the customer automatically receives compensation in the next available bill. The basic automatic compensation (equal to Euro 25) doubles if the performance of the indemnified service takes place beyond a time twice the standard and triples if the performance takes place beyond a time three times the standard or more. Irrespective of the escalation process, compensation must always be paid to the customer within six months by the supplier who received the written complaint or the request concerning billing adjustments or double billing. Compensation is not due if compensation has already been paid to the customer in the calendar year for failure to meet the same quality standard and in the case of complaints for which the customer cannot be identified (because the

[172] Pursuant to Article 14(7) of Decree-Law No. 181 of 9 December 2023 (hereinafter: Decree-Law 181/23).

[173] Report 143/2025/I/com.

[174] Annex A to Resolution 413/2016/R/com of 21 July 2016, as most recently amended by Resolution 399/2025/R/com of 5 August 2025.

complaint does not contain the minimum necessary information). Furthermore, the supplier does not have to pay automatic compensation if the non-compliance with the specific quality standards is attributable to *force majeure* - understood as acts of public authority, exceptional natural events for which a state of calamity has been declared, strikes called without statutory notice, failure to obtain authorisation - or to causes attributable to the customer or third parties, or damage or hindrances caused by third parties.

The time taken to respond to written complaints, make billing adjustments and make double-billing adjustments is subject to a specific standard applying to each individual service, whereas the response time for written requests for information is subject to a general standard applying to all services provided during the reference year.

For 2025, 589 companies reported data on the commercial quality of electricity retail services, stating that they had served a total of 33.1 million electricity customers. The actual average times reported by suppliers in 2025 for responding to complaints, making billing adjustments and responding to requests for information were well below the standards set by the TIQV, while the actual time taken to make double-billing adjustments exceeded the applicable standard (Table 3.35). Compared with the previous year, average completion times improved for all the services considered (from 15 to 13 days for responses to complaints, from 33 to 11 days for billing adjustments and from 35 to 23 days for double-billing adjustments). For written requests for information, which are subject to a general standard[175], the average supplier response time, at 2 calendar days, also improved significantly compared with 2024 (6 calendar days).

Table 3.35 Standards for electricity sales service and actual average times in 2025

PERFORMANCE	SPECIFIC STANDARDS (calendar days)	EFFECTIVE AVERAGE TIMES (calendar days)
Maximum time for a reasoned response to written complaints	30	13
Maximum time for bill adjustments	60 or 90(A)	11
Maximum time for double bill adjustments	20	23
Replies to written requests for information sent within a maximum of 30 calendar days	-	2

(A) 90 calendar days in the case of four-monthly invoices.

Source: ARERA, processing of data declared by operators.

Overall, companies serving customers in the electricity sector received 278,336 **written complaints**, down 6.8% on the previous year (Table 3.36). Most were submitted by household customers on the free market, consistent with the size of this customer base. Of the total complaints, 63.3% were submitted by household customers on the free market, 17.5% by non-household customers on the free market, 6.6% by household customers under the standard offer service, 6.7% by multi-site customers, 2.1% by non-household customers under the gradual standard offer service for micro-enterprises and 3.5% by household customers under the gradual standard offer service.

[175] For responses to written requests for information, suppliers are required to ensure that at least 95% of responses are provided within the maximum period of 30 days.

Table 3.36 Complaints, requests for information and billing adjustments received by suppliers

	2021	2022	2023	2024	2025
Number of complaints	289,035	337,863	325,681	298,690	278,336
Number of written requests for information	228,171	313,144	329,429	261,117	778,607
Number of bill adjustments	7,862	10,567	6,606	6,566	13,981
Number of double bill adjustments	859	713	1,320	565	358

Source: ARERA processing of data declared by operators.

Companies received a total of 778,607 **written requests for information**, the vast majority from free-market customers and, within this segment, particularly from household customers. This figure more than doubled compared with the previous year, when a total of 261,117 requests were recorded.

There were 13,981 **billing adjustments** overall, a substantial increase (+113%) compared with the previous year. These adjustments, which follow written complaints concerning bills that have already been paid but are subsequently disputed, mainly concerned household electricity customers on the free market (86.6%), followed by non-household customers on the free market (8.2%). Multi-site customers accounted for 4.3% of adjustments, while 0.3% concerned non-household customers under the gradual standard offer service for micro-enterprises, 0.1% household customers under the standard offer service and 0.3% household customers under the gradual standard offer service.

There were 358 **double-billing adjustments** resulting from errors in switching procedures (where, for the same consumption period, the final customer receives a bill from both the outgoing and incoming supplier), down 36.6% compared with the previous year and, in any event, limited in number relative to the millions of switches carried out each year. The adjustments primarily affected household electricity clients in the free market (59.5%), with non-household free market customers next (30.2%) Multi-site customers accounted for 7.8% of these adjustments, while only 0.6% concerned non-household customers under the gradual standard offer service for micro-enterprises and 1.4% household customers under the gradual standard offer service. Finally, 0.6% of the adjustments concerned the household segment under protection.

Analysis of the reasons for failure to meet the applicable standards shows that, overall, 97% of cases of non-compliance were attributed to causes for which the company was responsible. The remaining 3% were attributed to third parties (customers or other parties), with only a very small proportion attributable to force majeure.

Of the **automatic compensation** paid as a result of electricity suppliers failing to meet specific standards, 94% related to failure to meet the standard response time for written complaints, 5% to failure to meet the standard for billing adjustments and 1% to failure to meet the standard for double-billing adjustments. Of the total compensation payments, 59.9% were received by household customers on the free market, 21% by non-household customers on the free market, 6.9% by household customers under the standard offer service, 7% by multi-site customers, 1.9% by non-household customers under the gradual standard offer service for micro-enterprises and 3.3% by household customers under the gradual standard offer service. In terms of the amounts paid to customers, more than €632,000 in automatic compensation was paid out. Like the number of compensation payments, this figure represents a significant decrease compared with the previous year (approximately €1.16 million in 2024). Most of the amount paid out relates to delays in responding to written complaints. Consistent with the size of the customer base, most of the compensation was paid to free-market customers (household and non-household), while only 11% was paid to customers under standard offer or last resort arrangements.

3.2.2.2 Recommendations on final sales prices, investigations, inspections and imposition of measures to promote competition

Investigations and inspections

The Authority's monitoring and enforcement activities are aimed at verifying that regulated services are provided correctly and that operators comply with the applicable regulatory framework, in order to protect final customers and ensure the proper functioning of markets. Where breaches or non-compliance are identified, the Authority may adopt prescriptive and sanctioning measures, approve remedial commitments and order the recovery of amounts unduly received. The findings of monitoring activities also support the continuous updating and improvement of the regulatory framework. In carrying out inspections and investigations, the Authority works in cooperation with the Italian Financial Police (*Guardia di Finanza*) and the *Carabinieri*. In particular, the new Memorandum of Understanding with the *Guardia di Finanza* [176]confirms the role of its Special Unit for Goods and Services (NSBS) in carrying out on-site inspections, documentary checks and other technical and operational support activities. Cooperation with the *Carabinieri*'s ARERA Unit also continues.[177]. During 2025, the Unit continued the investigative work launched in 2024 on environmental matters and initiated specific on-site investigations aimed at regularising the registration details of operators that had failed to comply with the reporting requirements laid down in the Integrated Text on Registration-Related Reporting Requirements (TIAO), with regard to the Registry of Operators and territorial registers.

In 2025, monitoring activities expanded in scope, covering a growing number of operators and final customers, and comprised on-site inspections, telephone checks and documentary checks.

On-site inspections (Table 3.37) covered consumer protection, with particular reference to social bonuses, the implementation of remedial commitments relating to billing and the proper use of the Integrated Information System (SII) in suppliers' commercial processes; the safety and quality of services provided by grid operators; the proper functioning of markets, including the mechanism for reimbursing unpaid general system charges; distribution tariffs, with particular reference to the accuracy of the declarations submitted by distribution companies to the Energy and Environmental Services Fund (CSEA) for the payment of general system charges and equalisation balances; and checks on electricity generation plants in relation to the electricity system restoration service.

As regards **telephone checks**, a tool already used to verify the accuracy of pre-contractual information provided by suppliers and compliance with obligations relating to the gas emergency service, checks were also carried out on access by vulnerable household customers to the gradual standard offer service, through anonymous calls made by Guardia di Finanza officers (mystery shopping). In addition, **documentary checks** were carried out in cooperation with the *Guardia di Finanza* concerning, among other matters, the tax data declared by energy-intensive companies, compliance with accounting unbundling requirements and the reporting of investments in electricity and gas infrastructure services.

[176] Approved by Resolution 307/2025/A of 8 July 2025.

[177] Established by Resolution 164/2024/A of 8 May 2024.

Table 3.37 Number of on-site inspection audit

SUBJECT	2021	2022	2023	2024	2025
Customer protection	1	4	3	7	8
Tariffs and unbundling	-	2	-	3	2
Quality of service	16	17	19	8	7
Wholesale and retail markets	2	2	2	2	2
Connection of production facilities	-	-	-	2	5
Reporting requirements to ARERA					8
TOTAL	19	25	24	22	32

Source: ARERA.

Based on the amounts quantified to date, the economic items recovered during 2025 are therefore estimated at €11.2 million (of which €8.5 million relates to inspections concerning social bonuses, €2.5 million to checks on energy-intensive companies and €0.18 million to inspections concerning recoveries relating to gas distribution safety).

Monitoring of operators in the regulated sectors also continued through the Registry of Operators, supplemented by more detailed analyses at municipal level using the territorial registers for the gas, water, district heating and waste sectors, with a view to improving knowledge and oversight of the management arrangements for regulated services.

Investigation, survey and documentary review activities are carried out to analyse or examine specific areas in greater depth, through the assessment of data and information contained in documentation obtained by the Authority and comparison with additional sources concerning the same matters. These activities may be carried out independently or may be preparatory to on-site inspections. In carrying out these activities, the Authority may also cooperate with the *Carabinieri* and the *Guardia di Finanza*.

Sanction proceedings concerning conduct in retail markets and protecting final customers

In 2025, in continuity with previous years, the Authority's exercise of its sanctioning powers contributed to ensuring the effective implementation of the regulatory framework falling within ARERA's remit, by ensuring compliance with the applicable rules through the investigation of infringements and, where appropriate, the imposition of administrative fines.

A total of 56 measures were adopted in the exercise of these powers, comprising: 25 decisions to initiate proceedings; 9 notices of investigation findings; 9 resolutions concerning commitments (4 findings of admissibility, 1 finding of inadmissibility and 4 approvals); 9 sanctioning measures (excluding the 11 proceedings concluded under the simplified procedure); and 4 decisions to close proceedings without further action.

Two new developments in 2025 are particularly noteworthy: the initiation of **proceedings for breaches relating to pre-contractual information** and **for breaches concerning access by vulnerable household customers to the gradual standard offer service**. The transparency and completeness of information on commercial offers provided by suppliers to final customers at the pre-contractual stage are crucial, given the impact of these activities in the sensitive context of the transition to the free market. To safeguard these requirements, the Authority launched a specific monitoring initiative in cooperation with the *Guardia di Finanza*'s Special Unit for Goods and Services, involving, for the first time, anonymous calls (so-called mystery calls) to the commercial telephone

services of certain suppliers operating in the liberalised electricity and/or natural gas markets. The findings resulted in the initiation of **eight sanctioning proceedings** against eight suppliers for alleged failure to comply with certain reporting requirements laid down in the Code of Business Conduct.[178]. The second group of proceedings initiated concerned the information requirements that providers of the gradual standard offer service were required to comply with in order to enable vulnerable customers to exercise the option – introduced by Law No. 193/2024 – of requesting access to that service by 30 June 2025. The Authority initiated two sanctioning proceedings against two companies for having provided, through their customer services, incorrect information concerning the possibility for vulnerable customers to opt for the gradual standard offer service.

With the exception of four proceedings closed without further action and four proceedings concluded with the approval of commitments, all other proceedings concluded with a finding of liability and the consequent imposition of sanctions. Nine sanctions were imposed following ordinary sanctioning proceedings, for a total of €6,795,023.90, to which must be added the 11 reduced sanctions paid under the simplified procedure in 2025, totalling €222,319.15. In this regard, during 2025 the Authority completed the activities required to enable the payment of sanctions through the pagoPA platform[179].

More specifically, in the area of retail markets and customer protection, two sanctioning proceedings were initiated in 2025 for breaches relating to switching in the electricity sector. The last two proceedings in a series initiated in 2024 were also concluded. These concerned suppliers alleged to have used personal credentials to access the SII through automation software, in breach of the fundamental operating rules designed to safeguard the integrity of infrastructure such as the Integrated Information System (SII). Proceedings were also initiated to investigate a breach of the provisions governing the SII pre-check service, which is designed to support the submission of a switching request and may be accessed by the commercial counterparty that has subscribed to the service after entering into a supply contract with the final customer. In addition, proceedings were initiated concerning breaches relating to changes of account holder in the electricity sector. Also in relation to final customer protection, and specifically billing transparency and accounting unbundling, proceedings initiated in 2024 were concluded with the imposition of sanctions totalling €33,750. In 2025, sanctioning proceedings were also initiated in relation to requests to suspend supply to customers who were not in arrears.

As mentioned above, eight proceedings were also initiated for breaches relating to pre-contractual information provided to final customers, together with two proceedings for breaches of the information requirements applicable to providers of the gradual standard offer service in respect of vulnerable customers. In addition, two proceedings concerning the electricity and gas social bonuses were initiated in 2025. These were concluded through recourse to the simplified procedure, following cessation of the contested conduct, namely the payment of social bonuses to eligible customers and the correct reporting to the SII, every two months, of the social bonuses paid, together with the payment of reduced sanctions totalling €88,569. Also in relation to social bonuses, following complex sanctioning proceedings involving three suppliers, administrative fines totalling €475,000 were imposed on a natural gas distribution company for failure to issue invoices, or delays in doing so,

[178] Failure to provide, or the provision of incorrect, information to final customers concerning the economic terms of the offer and/or the guarantees required, payment and billing arrangements, the renewal arrangements or duration of the economic terms of the offers, and any charges provided for under the offer in the event of early withdrawal.

[179] pagoPA is the digital platform used to make payments to the Italian Public Administration; it became operational for the payment of sanctions imposed by the Authority on 18 February 2025.

and for failure to pay the gas social bonus to its distribution service users.

Measures for the effective promotion of competition: initiatives to overcome standard offer

Over the course of time, the Authority has helped to provide final customers with numerous tools (described in the various editions of the Annual Report) to increase their understanding of the free market and their ability to consciously choose their supplier, as well as to regulate numerous aspects (such as, for example, the content of bills, changes to the code of business conduct, etc.).

These are in particular:

- Portale Offerte, which contains descriptions of fixed-price and variable-price offers available on the free market, PLACET offers (and the rules governing them), as well as calculations of expenditure under the standard offer services for both electricity and natural gas;
- Portale Consumi, which is the institutional website where customers can access data on their electricity and natural gas supplies, i.e. historical consumption data and key technical and contractual information;
- framework of gradual standard offer service;
- transparency and comparability measures and amendments of the Code of business conduct;
- consolidation of the revised energy bills for final customers;
- insurance cover for final customers of the gas service (final customers are covered against the risks of accidents, fire and third-party liability arising from the use of gas downstream of the redelivery point);
- list of electricity suppliers;
- list of natural gas suppliers.

For the consistency of these instruments, see Chapter 5.

4 THE NATURAL GAS MARKET

4.1 Infrastructure regulation

4.1.1 Network extension, development and optimisation

Gas facilities

In Italy there are eight companies operating the **National** (10,797 km) **and Regional** (24,904 km) **Gas Transmission Network**: three for the national and regional network and five for the regional network only. The largest gas transmission company and Italian TSO is Snam Rete Gas; in addition, two other companies operate on the national network, owning and managing smaller sections: Società Gasdotti Italia and Infrastrutture Trasporto Gas. The Snam group (consisting of Snam Rete Gas and Infrastrutture Trasporto Gas) owns 92.8% of the networks.

The Italian gas transmission network is connected to several international natural gas pipelines:

- at Gries Pass, in Piedmont, it connects with the TENP (Trans Europa Naturgas Pipeline) natural gas pipeline to import gas from the Netherlands and Northern Europe;
- in Tarvisio, Friuli-Venezia Giulia, it connects with the TAG (Trans Austria Gas Pipeline) for the import of Russian gas;
- in Mazara del Vallo, Sicily, it connects with the Transmed (Trans-Mediterranean Pipeline) for the import of Algerian gas;
- in Melendugno, Apulia, it connects with the TAP (Trans Adriatic Pipeline) for the import of Azeri gas;
- in Gela, also in Sicily, it connects with the Greenstream for the import of Libyan gas.

The TAP is the newest gas pipeline; it forms the European section of the Southern Gas Corridor, entered service at the end of 2020, and in 2013 received from the competent authorities in Greece, Albania, and Italy a 25-year exemption from third-party access for its initial capacity of 10 billion cubic metres per year (its current capacity can be expanded up to 20 G m^3 per year). An initial expansion phase increased the pipeline's long-term capacity to 11.2 bcm/year during 2026.

Liquefied natural gas is injected into the Italian national transmission network through interconnections with the five terminals currently in operation at Panigaglia (Liguria), Cavarzere (Veneto), Livorno and Piombino (Tuscany) and, most recently, Ravenna (Emilia-Romagna). The Panigaglia facility, operated by Snam Energy Terminals, a Snam group company, has LNG storage capacity of approximately 100,000 m^3 of liquid LNG, equivalent to around 60 mcm, regasification capacity of 10.5 mcm/day and annual import capacity of approximately 3.5 bcm. The Cavarzere terminal is an offshore facility located in the Adriatic Sea off the coast of Rovigo and has LNG storage capacity of approximately 250,000 m^3 of liquid LNG. In 2025, work to increase its import capacity was completed, raising it from 9 to 9.5 bcm/year. At the same time, maximum daily regasification capacity was increased from 26.4 to 28.5 mcm/day. The additional import capacity of 0.5 bcm/year has already been fully allocated until December 2045, while 80% of the original capacity, equivalent to 21 mcm/day, is booked until gas year 2033/2034, as the terminal operator, Terminale GNL Adriatico, was granted a 25-year exemption from third-party access requirements[180]. The import capacity of

[180] Pursuant to Law No. 239 of 23 August 2004 and European Directive 2003/55/EC.

the Livorno terminal, also an FSRU, which entered service in December 2013 and is operated by OLT Offshore LNG Toscana, was authorised to increase in 2023[181] from the original 3.75 to 5 bcm/year. The terminal has LNG storage capacity of 137,100 m³ of liquid LNG and regasification capacity of approximately 15 mcm/day. Since March 2026, OLT Offshore LNG Toscana has been wholly owned by Snam. The Italis LNG FSRU (formerly Golar Tundra), moored in the port of Piombino, became operational in July 2023. Built in 2015 and acquired by Snam in 2022, the FSRU has LNG storage capacity of approximately 175,000 m³ of liquid LNG, import capacity of 4.5 bcm/year and regasification capacity of 12.9 mcm/day. In the first half of 2023, the procedures for the initial allocation of regasification capacity at the terminal were completed for the 20-year period from gas year 2023/2024 to gas year 2043/2044. These resulted in the allocation of 95% of capacity for the 2023/2024–2025/2026 period and 86% of capacity until 2044. In May 2025, the fifth LNG regasification plant entered into operation, namely the FSRU moored approximately 8 kilometres off the coast of Ravenna, which Snam acquired in July 2022. Built in 2015, the vessel has an import capacity of 4.5 bcm/year, a regasification capacity of 12.9 million cubic metres (mcm) per day, and LNG storage capacity of 175,000 cubic metres.

For gas year 2025–2026, the firm and interruptible transmission capacity at entry points interconnected with foreign systems and LNG terminals (i.e. import entry points) amounted to 403 mcm/day, comprising 383.8 mcm/day of firm capacity and 19.5 mcm/day of interruptible capacity. This represents an increase compared with previous gas years, reflecting the commissioning of the entry point connected to the Ravenna LNG terminal. The national transmission system also provides approximately 46 mcm/day of firm export capacity, in addition to 21.3 mcm/day of interruptible capacity through commercial reverse flow at Melendugno.

Natural gas **storage** activities are carried out under 15 concessions (covering 13 active fields) held by four companies: Stogit, Ital Gas Storage, Thaleia and Blugas Infrastrutture. Until 2015, Stoccaggi Gas Italia, known as Stogit and wholly owned by the Snam group, held ten of the concessions in force, while three of the remaining five were held by Edison Stoccaggio. In 2025, Stogit acquired the entire share capital of Edison Stoccaggio, subsequently renaming the company Stogit Adriatica. With effect from 1 January 2026, Stogit Adriatica was merged into Stogit. Consequently, from 2025 the Snam Group has held 13 of Italy's 15 gas storage concessions, of which 12 relate to active storage fields. The only concession relating to an active site that is not held by Stogit is Cornegliano Laudense, in Lombardy, which is held by Ital Gas Storage, almost all of whose share capital was acquired in 2023 by F2i Fondi Italiani per le Infrastrutture Società di Gestione del Risparmio. The storage facility became operational in 2019. Stogit is therefore the largest storage operator, with approximately 17.5 bcm of working gas capacity, while Ital Gas Storage manages approximately 1 bcm.

All active storage sites are built at depleted gas fields. The Italian gas storage system is of significant size: in the 2025-2026 thermal year, which ended on 31 March 2026, the system offered a total working gas capacity of 18.51 G(m^3), of which 4.6 G(m^3) were allocated for strategic storage. The available capacity for peak modulation storage amounts to 7.961 G(m^3); the remaining capacity is linked to products with a uniform withdrawal profile throughout the year or that, in any case, enhance the flexibility offered.

The **distribution** of natural gas in Italy takes place through a network of 272,927 km (of which 520 km were non-operational in 2025), with 57% at low pressure, 42.4% at medium pressure, and 0.6% at high pressure. The length of the networks increased by approximately 700 km compared to 2024.

[181] The increase was authorised by the Decree of 26 May 2023 issued by the Ministry of the Environment and Energy Security in agreement with the Ministry of Infrastructure and Transport.

In addition to the networks, gas distribution infrastructure comprises 8,207 pressure-reduction stations and 110,631 final pressure-reduction units[182]. 57.1% of the networks (155,721 km) are located in the North, 22.6% in the Centre (61,725 km) and the remaining 20.3% (55,481 km) are in the South and Islands. In 2025, 174 companies were active in gas distribution, eight fewer than in 2024. These comprised eight very large operators (with more than 500,000 customers), 18 operators with between 100,000 and 500,000 customers, 17 medium-sized operators (50,000-100,000 customers), 86 small operators (10,000-50,000 customers) and 45 very small operators (fewer than 5,000 customers). Between 2020 and 2024, the number of companies with more than 100,000 redelivery points remained stable at 28; in 2025, this number decreased to 24. Their share of gas distributed also remained stable at around 85% between 2020 and 2024, while in 2025 – despite the reduction in the number of companies – it rose to 86.6%. Overall, the 174 operators active in 2025 distributed 25 bcm of gas, 0.8 bcm less than in the previous year, to 21.7 million customers.

Ten-year development plans for the gas transmission network

In January 2024, the Authority initiated [183]proceedings to update its provisions governing natural gas transmission network development plans, with the aim, among other things, of taking account of recent legislative requirements under which the largest transmission system operator is required to submit a single natural gas transmission plan every two years.

New methodology for the unified gas transmission development plan

During 2024, the Authority also began updating its provisions governing the preparation of natural gas transmission network development plans, in response both to changes in the primary legislative framework [184]and to a number of other developments and recommendations at European level concerning planning activities. Accordingly, as part of the proceedings initiated in [185] January 2024, in December of the same year the Authority presented[186] its proposed approach to the preparation of a single transmission network development plan.

The Authority's proposals take into account, as noted, recent developments in the EU framework, both with regard to the "Decarbonisation Package" [187]and in relation to recent energy and environmental policies.

More specifically, the consultation (described in detail in last year's Annual Report, to which reference

[182] The data reported in the tables reflect the updating and realignment of the information databases carried out by the distribution companies involved in the corporate transactions described at the beginning of this section.

[183] Resolution 23/2024/R/com of 30 January 2024.

[184] Law no. 214 of 30 December 2023.

[185] Resolution 23/2024/R/com of 30 January 2024.

[186] Consultation document of 3 December 2024, 522/2024/R/gas.

[187] The "decarbonisation package" consists of two legislative texts: Directive (EU) 2024/1788 of the European Parliament and of the Council of 13 June 2024 on common rules for the internal markets in renewable gases, natural gas and hydrogen, and Regulation (EU) 2024/1789 of the European Parliament and of the Council of 13 June 2024 on the internal markets in renewable gases, natural gas and hydrogen.

should be made) set out proposed approaches concerning:

- the process of preparing the Unified Plan, in particular with regard to the responsibilities of the parties involved, their coordination, and the timelines;
- updating the minimum requirements for the preparation of the Unified Plan and for the cost–benefit analysis.

Following the consultation, in April 2025 the provisions [188]concerning the minimum requirements for the natural gas transmission network development plan were updated.
More specifically, the Authority:

- defined arrangements for coordination between the largest transmission system operator and the smaller transmission system operators for the preparation of the single plan, providing, in particular, that the largest transmission system operator should be responsible not only for assessing the coordination of all projects, but also for examining the consistency of development proposals put forward by the other transmission system operators with the potential network configuration, verifying the cost estimates submitted by the other operators, and developing and updating cost-benefit analyses;
- provided that the single plan must be submitted to the Authority by 28 February of odd-numbered years and, for 2025, by 15 October 2025;
- with regard to the minimum information to be included in the Plan, provided that:
  - it should also collect and make available information on transmission projects promoted by parties other than transmission operators and on storage and LNG regasification projects, and that the largest transmission system operator should identify any infrastructure that may be required as a result of the implementation of such third-party projects;
  - information should be provided on planned projects for the decommissioning of existing infrastructure, including where the purpose is to repurpose it for other uses;
  - estimates should be provided, over five- and ten-year horizons, of the tariff impacts arising from the implementation of the projects, taking into account forecasts for natural gas demand and supply, cross-border flows and the use of transmission infrastructure;
- with regard to cost-benefit analysis (CBA), provided that:
  - decommissioning projects should also be subject to specific CBAs, except where they are justified on safety grounds;
  - replacement and safety projects should be supported by specific assessments demonstrating their benefits to the system;
  - for projects to extend methanization to new areas, operators should provide an analysis assessing the cost-effectiveness of the project compared with possible alternatives based on other energy carriers.

Pursuant to Article 16(2) of Legislative Decree No. 93 of 1 June 2011 and the provisions adopted by the Authority in April 2025[189], the Authority submits the single ten-year natural gas transmission network development plan for consultation with network users (actual or potential) and all other interested parties, and subsequently publishes the results of the consultation.

The consultation on the 2025 single plan was launched on 1 October 2025 and concluded on 22 December 2025. For the purposes of the consultation, the Authority also made available the following

[188] Resolution 170/2025/R/gas of 15 April 2025.

[189] Resolution 170/2025/R/gas.

supporting documents:

- the criteria for applying the cost-benefit analysis, including the related Information Appendix;
- and the document describing the scenarios used in the 2025 Plan, prepared jointly by Snam and Terna in accordance with the provisions [190]adopted by the Authority in October 2024.

During the consultation, a public session presenting the Plan was held on 4 December 2025 to provide interested parties with clarifications and additional information.

4.1.2 Access to gas networks and facilities

Access to plants and delivery of the LNG regasification service

With a view to increasing gas availability to replace gas of Russian origin, following the entry into operation in 2023 of the new regasification terminal initially located in the port of Piombino, work on the Floating Storage and Regasification Unit (FSRU) and the mooring platform for the new regasification terminal located off the coast of Ravenna was completed during 2024. The terminal has annual regasification capacity of approximately 4.5 billion standard cubic metres (Sm^3) and is operated by Snam Energy Terminals. In January 2024, the Authority approved[191] the regasification code and the proposed procedure for the initial allocation of regasification capacity at the Ravenna Terminal, while in June 2025 it approved [192]a proposal to amend that procedure in connection with the entry into operation of the new regasification plant. Against this background, in March 2025 the Authority had also approved [193]a proposal for an urgent amendment to the PAR Regulation[194],, necessary to activate the new management segment (for conducting auctions to allocate capacity at the above terminal) and to implement new functionalities in the LNG Italia segment.

Lastly, in May 2025 the Authority approved [195]OLT Offshore LNG Toscana's proposal for setting the charges for flexibility services and the maximum amount of revenue intended to cover the incremental costs generated by those services.

Access to the storage service

In 2019, an incentive scheme for storage operators was introduced and incorporated into the Regulation governing guarantees of open access to natural gas storage services (RAST)[196], with the

[190] Resolution 392/2024/R/com of 1 October 2024.

[191] Resolution 16/2024/R/gas of 30 January 2024.

[192] Resolution of 19 June 2025, 266/2025/R/gas.

[193] Resolution of 11 March 2025, 86/2025/R/gas.

[194] Regasification capacity allocation platform managed by GME.

[195] Resolution of 20 May 2025, 207/2025/R/gas.

[196] Integrated text on the "Regulation of access to storage services", approved by Resolution 67/2019/R/gas of 26 February 2019.

aim of encouraging the provision of short-term capacity and services that enable greater flexibility in storage operations.

Since 2022, storage companies have introduced several innovative services (such as the residual inventory service, the winter backhaul service), and intra-seasonal services, which, also via the implicit allocation of seasonal capacity, have contributed significantly to meeting filling targets. This development has required clarification that the incentive scheme applies solely to capacities over and above those linked to basic services.

Against this background, in March 2024 the Authority introduced[197] a number of amendments to the RAST aimed both at adapting the regulatory framework for storage services to developments in the broader context and at revising the incentive scheme, making it a structured, permanent regulatory mechanism. The Authority has also set, for the two-year period 2024-2025, the parameters by which storage companies calculate the revenues retained as an incentive.

In view of the negative price spread between summer 2025 and winter 2026, by Decree of 30 January 2025 the Minister of the Environment and Energy Security introduced a number of provisions for the 2025/2026 storage year, with the aim of bringing forward the allocation of part of the capacity and facilitating the filling of storage facilities during the injection campaign running from 1 April to 31 October 2025. In February 2025, the Authority defined [198]the arrangements for implementing the above provisions and, in particular:

- confirmed the reserve price formulas for one- and two-year products, established[199] in April 2024, updating the relevant time references to reflect the capacity being allocated;
- provided that, for products with durations of between three and five years, the reserve price should also take account of the average results of auctions held over the previous four years for the allocation of multi-year services;
- provided that the quantity offered by each storage operator should not exceed 1,000 million standard cubic metres, in order to avoid potential oversupply;
- provided, for multi-year capacity, for priority to be given to offering longer-duration services, with any capacity not allocated being made available for shorter-term services on a rolling basis;
- confirmed, in line with the arrangements adopted for recent storage years, that storage users would not be charged the costs of storage operators' own technical consumption in respect of capacity allocated pursuant to the Decree of 30 January 2025, including capacity allocated for multi-year services. These costs were covered through the storage operators' financial balancing mechanism under Article 28 of the RAST;
- confirmed the supplementary charges for failure to meet storage filling requirements under Article 26 of the RAST, also for the 2025/2026 storage year.

By Decree of 25 March 2025, the Minister of the Environment and Energy Security issued the provisions governing the ordinary allocation of storage capacity for the 2025/2026 storage year. In general, these provisions confirmed the existing framework for storage services already laid down in the RAST. They also introduced further measures to encourage the filling of storage facilities, in particular by assigning the Authority the task of establishing incentive mechanisms for this purpose that are "*appropriate for achieving the level provided for in Article 21(1)(a) of Decree-Law No. 17 of 1*

[197] Resolution of 12 March 2024, 76/2024/R/gas.

[198] Resolution of 13 February 2025, 45/2025/R/gas.

[199] Resolution of 2 April 2024, 129/2024/R/gas.

March 2022 and consistent with Article 6a of Regulation (EU) 2017/1938. he costs of the incentive mechanisms are to be borne by the national energy system in accordance with arrangements to be established by the Ministry of the Environment and Energy Security in a subsequent ruling. In defining the incentive mechanisms, the Authority, in line with Commission Recommendation (EU) 2025/466, must take account of actual market conditions and, where appropriate, make use of the flexibility provided for under European legislation concerning the achievement of storage filling targets".

In April 2025, the Authority defined [200]the arrangements for implementing the provisions of the above Decree, also taking account of the outcome of the advance [201]allocation of storage capacity for the 2025/2026 storage year. In particular, the Authority:

- confirmed the reserve price formulas for one-year products;
- provided that, for the two-year product, TTF seasonal product quotations should be taken into account, for the second year only, when calculating reserve prices;
- provided for storage capacity allocated to users to be associated with an incentive mechanism, known as the "storage inventory award"[202], designed to encourage the filling of storage facilities through injections starting from April 2025;
- confirmed, as in previous years, that the costs incurred by the *Gestore dei servizi energetici* (GSE) and the largest transmission system operator in connection with the allocation of storage capacity would be covered through the "Storage Costs Account", the "Fund for the coverage of costs associated with the gas system balancing mechanism" and the "Fund for the coverage of costs associated with the gas settlement system", as applicable and taking account of the respective available balances.

In September 2024, In September 2024, following consultation, the Authority had [203]instructed the GSE to update and submit to the Authority for approval the "*Operating Rules for reimbursement of the RE_{TEE} element pursuant to ARERA Resolution 96/2020/R/eel of 26 March 2020*", ensuring full procedural consistency between reimbursement of the OS^{STUI} element and reimbursement of the RE element. In March 2025, the Authority approved [204]the proposed update to those Operating Rules submitted by the GSE.

Ene

In early May 2025, the Authority updated[205] the value of the CRV^{OS} component referred to in Article 41(1)(f) of the RTTG for the period from 1 October 2025 to 31 March 2026, setting it at €0.0221/Sm³. The component covers the costs arising from the application of the adjustment factor to reference revenues for the storage service, the recognised costs of that service where its value is below the

[200] Resolution of 1 April 2025, 150/2025/R/gas.

[201] Resolution 45/2025/R/gas.

[202] The storage inventory award is determined on the basis of the spread between the price of the product for delivery during the winter period and that of the product for delivery during the injection period (calculated at the time of the capacity allocation procedure), and includes an estimate of the financing costs associated with holding gas in storage.

[203] Resolution of 17 September 2024, 364/2024/R/com. Through that measure, the Authority established the arrangements for reimbursing thermal power producers for part of the CRVOS component (referred to as the "OS^{STUI} element"), intended to cover the costs of the last-resort storage filling service, and for recovering the amounts reimbursed through a tariff component charged to electricity final customers as a whole.

[204] Resolution of 18 March 2025, 97/2025/R/com.

[205] Resolution of 8 May 2025, 198/2025/R/gas.

allowed tariff revenue, and the adjustment for restoration costs.

In November 2025, the Authority issued[206] instructions to the Energy and Environmental Services Fund (CSEA) for the payment to Snam Rete Gas of the amounts relating to the storage inventory award[207], governed by the provisions adopted in early April, to be paid to users.

In December 2025, the Authority confirmed the existing framework for incentive-based services and the shares of the proceeds from their allocation that may be retained for the [208]2026–2027 period.

Access to the gas transmission service

In April 2024, the Authority updated [209]certain provisions of the Integrated Balancing Code (TIB) to align them with the new arrangements for managing certain financial items (relating to own consumption, network losses and unaccounted-for gas) introduced by the "Tariff regulation for natural gas transmission and metering services for the sixth regulatory period 2024-2027" (RTTG), approved[210] in April 2023. At the same time, a fixed price for the linepack was established, conventionally set in line with the current market value, ensuring that Snam remains neutral with respect to price fluctuations under the previous valuation method.

In September 2024, the regulation governing the transmission default service was amended [211]to provide that Snam may procure the quantities of gas required for the service using the same mechanisms and criteria as those used for the operation of the system[212], or under arrangements defined by Snam and approved by the Authority.

In detail:

- the Integrated Balancing Code (TIB) was amended to introduce arrangements for procuring the quantities required for the transmission default service on the GME's AGS platform (where the quantities required for the operation of the system are purchased), together with the inclusion of a mechanism ensuring Snam's neutrality in respect of the related financial items;
- the price[213] applied to parties supplied under the transmission default service was amended. In particular, it is stipulated that the price covering the costs of sourcing the raw material is not only linked to the costs incurred by Snam but must have a minimum level equal to the imbalance price applied to "short" users, in order to prevent potential misuse of the service due to more favourable conditions than those applied to such users.

[206] Resolution of 18 November 2025, 493/2025/R/gas.

[207] Resolution 150/2025/R/gas.

[208] Resolution of 16 December 2025, 554/2025/R/gas.

[209] Resolution of 2 April 2024, 120/2024/R/gas.

[210] Resolution of 4 April 2023, 139/2023/R/gas.

[211] Resolution of 24 September 2024, 374/2024/R/gas.

[212] Paragraph 1.4 of the TIB.

[213] Resolution of 14 June 2012, 249/2012/R/gas.

In addition, amendments to the TIB concerning the neutrality system were approved to incorporate arrangements reflecting the provisions[214] governing the mechanism for protection against non-payment risk. It was also provided that, from 1 October 2024, neither the term representing the difference between actual and estimated consumption in gas settlement procedures nor the imbalance attributable to the transmission default service would be subject to financial settlement under the neutrality mechanisms.[215].

In September 2024, the Authority partially amended [216]the core provisions [217]governing access to the transmission service to introduce additional flexibility in the use of transmission capacity, with the aim of removing uncertainty surrounding the effects of any early termination of a supply contract due to default by the final customer, while also facilitating the conclusion of contracts with a duration of less than one year. In more detail, for redelivery points linked directly to industrial and thermoelectric users, rules now allow the user assuming supply to terminate the associated annual transport capacity before expiry, where the supply contract ends within the same gas year and is not renewed, subject to set procedures and timings.

Lastly, in November 2024, a number of amendments were made[218] to the balancing rules, with particular regard to:

- a new formulation of the so-called *small adjustment*[219], designed to reduce opportunities for arbitrage arising from the timing mismatch between the GME and Snam settlement systems. The value of the small adjustment was linked to the cost of a short-term financing transaction with a maturity consistent with the timing mismatch between the settlement of payments for gas purchased on the centralised market (GME) and the settlement of imbalance costs (Snam). Since this modification affects the entire community of balancing users, the resolution provides that it will take effect in October 2025, allowing it to be anticipated in wholesale gas trading dynamics;
- adjustments to the incentive scheme for Snam, both to take account of specific circumstances in which it may be required to operate (e.g. market price volatility) and to improve the accuracy of expected withdrawal estimates for withdrawal points with daily metering.

For further details on the above provisions adopted in 2024, reference should be made to last year's Annual Report.

Access to transport service at foreign interconnection points

With regard to international transmission networks, in 2013 TAP AG was granted an exemption from certain EU rules (third-party access, regulated tariffs and unbundling), subject to the conditions laid down in the so-called Final Joint Opinion, a document jointly approved by the regulatory authorities

[214] Art. 10 of resolution 249/2012/R/gas.

[215] Art. 8 of the TIB and paragraphs 16.3 and 24.3 of the TISG.

[216] Resolution of 17 September 2024, 363/2024/R/gas.

[217] Resolution of 17 July 2002, 137/02.

[218] Resolution of 19 November 2024, 482/2024/R/gas.

[219] Article 5, paragraph 1, letter (a) of the TIB.

of Italy (ARERA), Greece (RAAEY) and Albania (ERE). Among the conditions imposed, TAP AG is required to conduct a Market Test at least every two years to assess market interest in booking transmission capacity under long-term contracts between the entry and exit points of the pipeline. If the Market Test has a positive outcome (and subject to verification of the technical and economic feasibility of the requests and the subsequent assumption of binding commitments by the applicants), TAP AG is required to expand capacity from the current 10 bcm/year up to the maximum expansion capacity of 20 bcm/year. Since 2013, EU legislation has evolved and, in particular, Regulation (EU) 2017/459 of the European Parliament and of the Council of 16 March 2017 (the so-called CAM NC) was adopted. In addition to governing the allocation of existing capacity, the Regulation contains specific provisions on the development of incremental capacity, likewise providing for a biennial procedure (generally commencing in odd-numbered years). Against this background, at the request of the regulatory authorities of Italy, Greece and Albania, since 2019 (the year in which the first Market Test was launched), TAP has coordinated, to the extent possible, the Market Test procedure provided for in the Final Joint Opinion with the incremental capacity process governed by the CAM NC.

In July 2025, the Authority, jointly with the Greek (RAAEY) and Albanian (ERE) regulators, approved [220]the "Market Test Guidelines 2025" for the launch of a new cycle for collecting incremental capacity requests relating to the development of the TAP natural gas pipeline. These Guidelines follow the same principles as the previous incremental capacity offering procedures.

In August 2025, the Authority, together with the Greek (RAE) and Albanian (ERE) regulators, approved[221]the "Project Proposal", which governs the binding phase of the incremental capacity process launched in 2023 and sets out the capacity levels for the potential expansion of the natural gas pipeline, as well as the criteria for participation and the allocation of capacity to shippers.

4.1.3 Tariffs for access to gas infrastructures

Tariffs for the LNG regasification service

In May 2023, the Authority adopted [222]the tariff regulation criteria for LNG regasification services for the sixth regulatory period (RTRG 2024–2027). These were supplemented[223] in June 2024 by aligning inflation-related items with the ROSS criteria and, in order to ensure that tariffs reflect the costs specific to the service, by introducing a mechanism to regulate differences arising from the redetermination of reference revenues to take account of any changes in the WACC, inflation and actual asset data.

In early July 2025, the Authority approved [224]the tariff proposals for LNG regasification services for 2026 (pursuant to the RTRG 6PR GNL) for the Panigaglia, Rovigo, Livorno and Piombino terminals

[220] Resolution of 8 July 2025, 316/2025/R/gas.

[221] Resolution of 5 August 2025, 388/2025/R/gas.

[222] Resolution of 9 May 2023, 196/2023/R/gas.

[223] Resolution of 25 June 2024, 253/2024/R/gas.

[224] Resolution of 1 July 2025, 293/2025/R/gas.

and determined the amounts due in respect of the revenue coverage factors and the adjustments relating to 2024.

At the end of July 2025, the Authority approved[225] the tariff for LNG regasification services for 2026 and the redetermination of reference revenues for 2025 for the Ravenna FSRU terminal, excluding the costs relating to ancillary infrastructure serving the terminal (such as the new platform for mooring and natural gas transmission, the upgrading of the existing platform providing logistical support for operations, and the protective breakwater). This exclusion reflected the ongoing process to update the scope of the National Natural Gas Pipeline Network for 2025 and the related request submitted by Snam Rete Gas to include the above ancillary infrastructure. By means of a Ministerial Directorate Decree issued by the Ministry of the Environment and Energy Security on 9 September 2025, this infrastructure was included within the scope of the National Natutal Gas Pipeline Network and therefore definitively reallocated from regasification activities to gas transmission activities.

Tariffs and prices for the storage service

The tariff regulation criteria for natural gas storage services (RTSG) for the sixth regulatory period (6PRS) 2026–2029 were established [226]in April 2025. While leaving the previous criteria broadly unchanged, the Authority introduced the following new elements:

- alignment with the ROSS criteria for the duration of the regulatory period, the treatment of inflationary items, the operational cost items excluded from tariff recognition, and the activation methods for the Y parameter;
- the introduction of an investment efficiency incentive mechanism based on a symmetrical reward/penalty system, to be phased in during 2026 and 2027, with enhanced incentives where cost estimates are contained during the design and authorisation stages, as well as the possibility of reopening and revising the reference cost estimate;
- the introduction of a new asset category, with a shorter useful life than wells and pipelines, for extraordinary maintenance work and measures aimed at keeping assets in operation and extending their useful life, where such measures do not involve their replacement or reconstruction;
- the discontinuation of the adjustment mechanism applied to the level of reference revenues for the following year and the introduction of a mechanism for compensating differences through the revenue coverage factor.

In July 2025, the Authority approved [227]company revenues for storage services for 2026, as well as the redetermination of company revenues for 2025 (based on actual increases in assets relevant to determining the 2025 revenue coverage factor), and authorised the payment of the amounts due under the 2024 revenue coverage factor, as provided for by the regulation.

It should, however, be emphasised that the tariffs now have a residual application, as they only concern the operational balancing services of transmission operators and the gas producer storage of household production companies, which account for less than 2% of the total storage capacity.

[225] Resolution of 29 July 2025, 369/2025/R/gas.

[226] Resolution of 1 April 2025, 137/2025/R/gas.

[227] Resolution of 29 July 2025, 367/2025/R/gas.

Strategic storage, which accounts for around one quarter of capacity and is intended to address potential supply disruptions or problems affecting the operation of the gas system, is remunerated through the variable CRVCS charge, applied to the quantities of gas transported[228]. For the period from 1 April 2025 to 31 March 2026 the CRV^{CS} charge is equal to 0.3448 €/S(m^3)[229].

The remaining storage capacity (over 70%), intended for seasonal and multi-year modulation services, is allocated and remunerated through competitive procedures governed by the Regulation on access to and provision of storage services (RAST), as established by the Authority in February 2019[230]. The charges for services relating to this capacity are determined by the market through dedicated auctions open to natural gas market operators (primarily wholesalers and suppliers to final customers).

During 2026, Stogit, Stogit Adriatica (formerly Edison Stoccaggio) and Ital Gas Storage held auctions for the storage year from 1 April 2025 to 31 March 2026. Compared with the previous year, there was a significant increase in capacity allocated through auctions (+21 TWh, +25%) and a sharp fall in charges (average allocation prices), from €2.979/MWh in 2024 to €0.093/MWh in 2025. The decline was attributable to higher wholesale natural gas prices during the auction period compared with the corresponding period of the previous year, which reduced expectations of the savings achievable by purchasing gas in summer for storage.

Tariffs for gas transmission service

In April 2023, the Authority approved[231]the tariff regulation for natural gas transmission and metering services (RTTG) for the 2024–2027 period (sixth regulatory period – 6PRT). In particular, the regulation sets out the criteria for:

- determination of recognised revenues, including how to reconcile with the ROSS methodology (Regulation by Expense and Service Objectives) for capital and operating costs;
- incentivising and improving the efficiency of facility development by introducing on an experimental basis: a mechanism to stimulate the continued operation of fully depreciated natural gas transmission networks, an incentive mechanism for dual-fuel compressor stations, and criteria for improving the efficiency of transmission network development in newly methanised areas;
- simplification of the determination of items to cover network leakages, fuel gas, unaccounted-for gas, ETS charges;
- determination of charges for the transport service, confirming the adoption of the capacity-weighted distance methodology and providing for a change in the entry/exit split from 28/72 to 25/75;
- determination of the fees for the transmission metering service, confirming the tariff articulation in two components, one covering the general metering costs and one covering the metering costs of the redelivery points of final customers only, the latter expressed in €/withdrawal

[228] Resolution of 20 October 2020, 396/2020/R/gas.

[229] Paragraph 2.12 of Resolution of 27 March 2025, 131/2025/R/com and paragraph 2.12 of Resolution of 30 December 2025, 588/2025/R/com.

[230] Resolution of 26 February 2019, 67/2019/R/gas.

[231] Resolution of 4 April 2023, 139/2023/R/gas.

point/year and divided into five distinct classes according to the capacity of the metering plant.

At the end of May 2025, following its review of the tariff proposals submitted by transmission operators pursuant to the applicable regulation (RTTG – 6PRT), the Authority approved[232] the tariff charges for natural gas transmission and metering services for 2026 and redetermined the reference revenues for 2025.

In August 2025, the Authority closed[233], without adopting any measures, the proceeding concerning the containment of transmission tariffs for customers with high natural gas consumption, which had been reopened[234] in April 2024 in compliance with a number of judgments of the Regional Administrative Court (TAR) of Lombardy[235]. Consequently, the tariff regulation criteria for natural gas transmission services for the 2018–2019 and [236]2020–2023 [237] periods were confirmed.

Tariffs for distribution and metering services

In June 2024, the Authority launched [238]proceedings to implement the judgments of the Council of State[239] concerning tariffs for natural gas distribution and metering services, with particular reference to the determination of recognised operating costs for the 2020-2025 regulatory period. The judgments followed complex litigation brought by a number of operators against the relevant provisions approved [240]in December 2019 for the 2020-2025 period. Also taking account of the clarifications provided in a number of judgments of the Lombardy Regional Administrative Court (TAR)[241], in October 2024 the Authority set out [242]its proposed approach, based on the general principle of consistency in regulatory action, as follows:

- lack of transparency:
  - criteria for the processing of cost/revenue data for the companies;
  - quantification of the total value of the greater productivity gains achieved by the sector in the 2014-2019 regulatory period;

[232] Resolution of 27 May 2025, 215/2025/R/gas.

[233] Resolution of 5 August 2025, 400/2025/R/gas.

[234] Resolution of the Authority of 23 April 2024, 156/2024/R/gas.

[235] Judgments of the Lombardy Regional Administrative Court (TAR) of 7 March 2024, numbers 645, 646, 647, 648, 649, 650 and of 23 March 2024, no. 878

[236] Resolution of 3 August 2017, 575/2017/R/gas.

[237] Resolution of 28 March 2019, 114/2019/R/gas.

[238] Resolution of 11 June 2024, 231/2024/R/gas.

[239] Section II, numbers 10185/2023, 10293/2023, 10294/2023, 10295/2023 and 1450/2024.

[240] Resolution of 27 December 2019, 570/2019/R/gas.

[241] Section I, numbers 507/2024, 877/2024, 883/2024, 884/2024 and 1029/2024.

[242] Consultation document of 22 October 2024, 427/2024/R/gas.

  - clarification of the criteria and calculation methods used to determine the recognised operating costs for the 2020–2025 period, established [243]in December 2019;
- calculation of the actual operational costs for 2018:
  - representativeness of the samples;
  - criteria for the exclusion of outlier values;
  - calculation of the sector's average actual unit costs;
- rates of reduction in recognised operating costs (X-factor):
  - recalculation of the X-factor to be applied to all businesses;
  - correction mechanism of the enterprise-specific X-factor, ensuring the achievement of efficiency targets set by the regulation, activated upon individual request when specific conditions are met;
  - adjustment of coefficients to differentiate recognised costs based on the density of the served user base.

During 2025, the Authority adopted a series of measures to complete implementation of the Council of State's rulings. In detail:

- More specifically, in March 2025 the Authority completed [244]the first phase of the proceedings, aimed at addressing the shortcomings in the investigation and reasoning identified by the courts in the above judgments, including by:
  - recalculating the tariff components covering recognised operating costs for gas distribution services for the years 2020–2025, differentiated according to company size and the customer density of the areas served;
  - recalculating the annual efficiency factors (X-factors) applicable to recognised unit operating costs, differentiated by company size, for use in updating those tariff components in the years following 2020; and
  - establishing a mechanism, subject to certain conditions, for determining the rate of reduction in recognised operating costs on the basis of data for the individual operator (rather than "industry-wide" data), so that, at the end of the regulatory period, the recognised cost for each operator is aligned with the actual cost it incurred in 2018, appropriately adjusted to 2025 to take account of inflation;
- in June 2025, two applications [245]for admission to the X-factor redetermination mechanism based on the individual operator's specific unit operating cost, introduced by the previous measure adopted in March, were approved[246];
- in July 2025, the Authority presented [247]its proposed approach concerning the second area of intervention, relating to the impact on the operating costs of gas distribution services of the

[243] Resolution 570/2019/R/gas.

[244] Resolution of 11 March 2025, 87/2025/R/gas.

[245] Resolution of 18 June 2025, 260/2025/R/gas.

[246] Resolution 87/2025/R/gas.

[247] Consultation document of 22 July 2025, 346/2025/R/gas.

specific characteristics of the area served and of the costs arising from service obligations to ensure bilingualism;

- in November 2025, the Authority concluded[248] the proceedings launched [249] in June 2024, providing:
  - with regard to the impact of the specific characteristics of the area served on operating costs, for confirmation of the charges covering recognised operating costs approved[250] in March 2025;
  - with regard to the impact on operating costs of the costs arising from service obligations to ensure bilingualism, for such costs to be recognised in addition to recognised operating costs, on the basis of the costs reported by operators through a dedicated data collection exercise.

In view of the end of the 2020-2025 distribution regulatory period, in May 2025 the Authority launched [251]proceedings to establish the tariff and quality regulation for gas distribution and metering services for the sixth regulatory period. As part of these proceedings, the Authority considered it appropriate to:

- carry out specific analyses to assess how the regulatory solutions adopted for other energy infrastructure services, based on the ROSS approach, could be adapted to gas distribution and metering services;
- extend the current tariff and quality regulation for gas distribution and metering services to 2026 and 2027, in order to allow for an adequate consultation process that ensures the effective participation of interested parties and to guarantee transparency and effectiveness in establishing the tariff regulation for the regulatory period commencing in 2028.

Accordingly, in December 2025, following the consultation launched [252]in September 2025, the Authority approved[253] the amendments required to extend the validity of the existing tariff regulation to 2026 and 2027. These provide for:

- annual rates of reduction in recognised unit costs covering operating costs (X-factor) of 0% for gas distribution, metering and commercial services;
- rules for determining the components relating to operating costs for area-based concessions in the seventh and eighth years of the concession period;
- a reduction in the amount recognised on account to distribution operators to cover the operating costs associated with metrological checks;
- an update to the parameters used to determine the gradual run-off of the stock of existing contributions as at 31 December 2011, pursuant to Article 14 of the Gas Distribution and Metering Tariff Regulation (RTDG);

[248] Resolution of 18 November 2025, 496/2025/R/gas.

[249] Resolution 231/2024/R/gas.

[250] Resolution 87/2025/R/gas.

[251] Resolution of 27 May 2025, 221/2025/R/gas.

[252] Consultation document of 23 September 2025, 419/2025/R/gas.

[253] Resolution of 2 December 2025, 532/2025/R/gas.

- confirmation, for final customers in the Region of Sardinia, of the mechanisms for mitigating the tariff impacts arising from the higher costs of providing distribution services on the island, so as to ensure that users of the island's distribution networks are charged tariffs in line with those applicable in tariff areas with comparable costs, as identified by the tariff regulation, pursuant to the Prime Ministerial Decree of the Council of Ministers of 10 September 2025;
- as regards isolated natural gas networks, closure of the proceedings launched[254] in December 2021, providing for:
  - for networks already in operation as at 31 December 2019 that submitted an application to be treated as equivalent to interconnected networks pursuant to Article 14 of Resolution 570/2019/R/gas, continuation of the regime under which they are treated as equivalent to interconnected distribution networks;
  - for networks not in operation as at 31 December 2019, confirmation of the transitional regime under which they are treated as equivalent to interconnected networks pursuant to Article 19(2) of the RTDG, for five years from the date on which the relevant applications are approved, with an obligation to inform final customers promptly of any potential change in the applicable tariff conditions at the end of the five-year period if the networks have not been interconnected with the national transmission network;
- recognition of the capital and operating costs incurred by distribution system operators in implementing Regulation (EU) 2024/1787 on the reduction of methane emissions in the energy sector, through the tariff mechanisms already provided for under the regulation or through specific cost-recognition mechanisms where appropriate, with the detailed implementation arrangements to be determined following further analysis.

In January 2025, the interest rates to be appliedi[255] in determining the reimbursement to outgoing operators of the amounts covering tender costs, pursuant to Decree No. 226 of 12 November 2011 of the Minister for Economic Development, in agreement with the Minister for Relations with the Regions and Territorial Cohesion, were approved for 2025, following the update [256]of the WACC for the 2025-2027 period.

In July 2025, the Authority concluded [257]the proceedings launched [258]in April 2024 to implement the provisions of Article 22 of Decree-Law No. 69 of 13 June 2023 (as converted by Law No. 103 of 10 August 2023), with reference to municipalities falling within climate zone F and classified as mountain areas pursuant to Law No. 1102/1971, as well as municipalities that had submitted, within the prescribed deadlines, applications for funding for completion of the programme for the methanization in Southern Italy, pursuant to Interministerial Committee for Economic Planning (CIPE) Resolution 5/2015. To this end, specific rules were established for applying the cap on the amount of recognised capital costs in localities where service is being launched (pursuant to Article 33 of the RTDG), while ensuring full recognition of the costs actually incurred for works designed to enable

[254] Resolution of 28 December 2021, 634/2021/R/gas.

[255] Resolution of 14 January 2025, 3/2025/R/gas.

[256] Resolution of 28 November 2024, 513/2024/R/com

[257] Resolution of 8 July 2025, 321/2025/R/gas.

[258] Resolution of 23 April 2024, 55/2024/R/gas.

renewable gases to be injected into the network.

In December 2025, the Authority approved[259], for 2026, the mandatory tariffs applied to final customers for natural gas distribution, metering and commercial services under Article 42 of the RTDG, the tariff options for gases other than natural gas under Article 69 of the RTDG, and the amounts of the bimonthly advance equalisation payments relating to natural gas distribution services under Article 47 of the RTDG. At the same time, it approved the maximum amount eligible for recognition in respect of additional costs arising from concession fees under Article 59 of the RTDG for distribution operators that had submitted an application and provided appropriate supporting documentation.

4.1.4 Quality of facility services

Quality of gas storage system

At the beginning of April 2025, the Authority established [260]the tariff and service quality regulation criteria for natural gas storage services for the sixth regulatory period (6PRS) – Amendments to the RQTG 6PRT and the RAST – effective from 1 January 2026, broadly maintaining continuity with the previous criteria. The main changes introduced concern:

- service safety: strengthening the provisions on gas leaks through the introduction of additional obligations, including the reading and reporting of the volumes of gas leaked; the reading and reporting of the number of events giving rise to gas emissions and the related volumes, broken down by type and emission source; publication of the methodology used to estimate emissions; and alignment with the provisions of Regulation (EU) 2024/1787 of the requirements concerning the frequency of non-invasive inspections of connecting flow lines;
- service continuity: discontinuation of the penalty mechanism for failure to comply with contractual obligations and the simultaneous introduction of an information requirement to compare the overall withdrawal or injection capacity available to users with the capacity specified in the performance curves established by ministerial decree.

Quality of gas transmission system

In December 2023, following consultation, [261]the Authority approved [262]the quality regulation criteria for natural gas transmission services (RQTG) for the 2024–2027 period (sixth regulatory period – 6PRT), broadly maintaining continuity with the previous regulation. In particular, it provided for:

- in the field of odorisation, to update the Odorisation Plan annually, instead of every six months, and to postpone to a subsequent specific measure the evaluation of a possible recommendation to Parliament and the Government on the need for a regulatory reorganisation in this field;

[259] Resolution of 23 December 2025, 574/2025/R/gas.

[260] Resolution of 1 April 2025, 137/2025/R/gas,

[261] Consultation document of 10 October 2023, 451/2023/R/gas.

[262] Resolution of 12 December 2023, 589/2023/R/gas.

- emissions, that transmission operators publish the methodology used to estimate leakage in a special section of their website;
- to instruct the main transmission operator, within working groups that include other transmission operators, to lead an initiative defining technical and performance requirements for clearly identifying the characteristics of a network fit for hydrogen transport, drawing also on the Asset Health methodology developed at the Authority's instigation[263];
- with reference to the service continuity regulation criteria, to invite the main transmission operator to consider a simplification of the procedure for subscribing to and activating the alternative supply service by means of a tank truck, taking into account the minimum information required to guarantee the alternative service in advance;
- to mandate the main transmission operator to conduct a consultation on the possible functioning of an incentive mechanism of bonuses and penalties based on customer satisfaction, as well as on the perceived usefulness to users of integrating such an incentive mechanism into the regulatory framework.

In September 2024, the Authority amended the [264] Regulation of the measurement service on the natural gas transport network (RMTG[265]) to address issues raised in recommendation papers received in the first months of 2024, specifically including:

- exemption from the application of the economic fee system set out in the RMTG for measuring systems with a Q_{ero} lower than 200 S(m^3)/h;
- the extension of the criterion for determining the charges for non-compliance with service levels in the metering activity, based on the fixed unit cost set by the regulation for Unaccounted Gas, to also include distribution companies (given the introduction of the accountability mechanism for distribution companies on the in-out delta);
- the reduction of the minimum frequency for updating quality data for entities subject to legal metrology with measuring installations having flow rates lower than 4,000 S(m^3)/h and connected to pressures higher than 5 bar, thus falling under the scope of indicator D, from monthly to quarterly, with a transitional period of three years, until 31 December 2026, with a minimum semi-annual frequency.

At the same time, the proposed amendments to the Snam Rete Gas Network Code and SGI, in line with the aforementioned changes, were approved.

In June 2025, the Authority amended [266] the Regulation of metering services on the natural gas transmission network (RMTG[267]), following an analysis of monitoring data on service levels and the

[263] Resolution of 3 May 2022, 195/2022/R/gas

[264] Resolution of 24 September 2024, 377/2024/R/gas.

[265] The RMTG was approved in 2021 (512/2021/R/gas) and defines: (i) the responsibilities and scope of metering and meter reading activities; (ii) minimum and optimal requirements for plant, performance, and maintenance; (iii) predefined service quality levels; (iv) an incentive system to ensure compliance with these quality levels; (v) a system to monitor the quality level requirements.

[266] Resolution of 12 June 2025, 252/2025/R/gas.

[267] The RMTG was approved on 23 November (Resolution 512/2021/R/gas) and defines: (i) the responsibilities and scope

charges applied in 2024 for failure to meet those levels (the first year of application), as well as reports received from plant owners. In particular, the amendments provided for:

- a cap on the total charges applied, equal to five times the service charge, including in respect of charges already applied in 2024;
- the possibility of extending the deadline for requesting the transfer of a plant from 31 December 2024 to 31 July 2025, with exemption from the charges for 2024 and 2025;
- exemption from the charges for 2025 only for requests for the transfer of a plant submitted after 31 July 2025 and by 31 December 2025;
- where gas delivery (and metering) facilities are decommissioned, termination of the transmission operator's easement over the relevant area, which therefore reverts to the customer's full ownership;
- in the event of non-payment, the possibility for the transmission operator to remit only the amounts actually collected, subject to providing evidence of the action taken to recover the amounts due;
- a requirement for the major transmission system operator to assess the introduction of a system for promptly notifying failures to meet service levels;
- the possibility for interested parties to submit comments on the measure.

Also in light of the comments received on the above amendments [268]to the RMTG, in October 2025 the extraordinary and urgent measures [269]adopted in June [270]2025 concerning metering on the gas transmission network were confirmed. The major transmission system operator was therefore instructed both to organise meetings with users to discuss possible improvements to the operation of the Metering Portal and to verify that the implementing procedure concerning third-party causes (published on its website) ensures that, where the plant owner demonstrates that it has taken the necessary steps to fulfil the relevant service requirement, the failure to meet that requirement is not attributed to the plant owner.

Safety and continuity of gas distribution services

At the end of May 2025, proceedings were launched [271]to extend the current Consolidated Gas Distribution Code (TUDG) to 2026 and 2027 and to establish the sixth regulatory period.

As part of these proceedings, in September 2025 the Authority set out[272] its proposed approach to extending the safety and quality regulation to 2026 and 2027, also in light of the entry into force of Regulation (EU) 2024/1787. With regard to quality aspects, pending the designation of the

of metering and meter reading activities; (ii) minimum and optimal requirements for plant, performance, and maintenance; (iii) predefined service quality levels; (iv) an incentive system to ensure compliance with these quality levels; (v) a system to monitor the quality level requirements.

[268] Resolution 252/2025/R/gas.

[269] Resolution of 7 October 2025, 443/2025/R/gas.

[270] Resolution 252/2025/R/gas.

[271] Resolution of 27 May 2025, 221/2025/R/gas.

[272] Consultation document of 23 September 2025, 419/2025/R/gas.

competent authorities and the adoption of the delegated acts provided for under the Regulation, the Authority considered it appropriate to retain the provisions of the Gas Distribution Quality Regulation (RQDG) on a transitional basis, with the exception of the frequency of inspections of low-pressure networks, which was aligned with the 36-month interval already applicable to high- and medium-pressure networks, in accordance with the minimum requirements established by the EU Regulation.

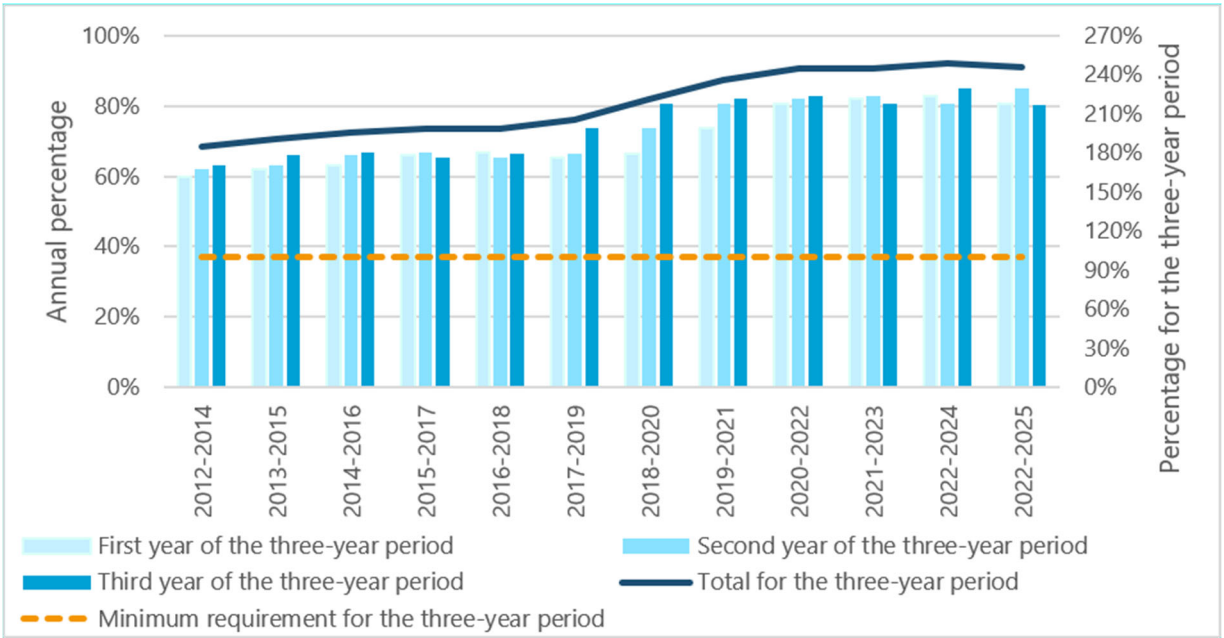
This approach, which was supported by industry operators, was adopted [273]in December 2025, with the 2020–2025 RQDG being extended, with minor amendments, to 2026 and 2027, in line with the approach taken for the regulation of gas distribution and metering tariffs. At the same time, it was emphasised that the primary objectives of the quality regulation established by the Authority are, on the one hand, to ensure the safety and continuity of distribution services in order to protect public health and safety and, on the other, to establish commercial quality standards that ensure an adequate and efficient service for final customers and consumers connected to distribution networks. EU regulation, by contrast, has the primary objective of implementing important environmental policies affecting the public at large and the environment. In this context, specifically as regards methane emissions, the provisions of Regulation (EU) 2024/1787, while constituting a separate and independent set of rules, will need to be appropriately harmonised and coordinated, when implemented, with those established by the Authority, so as not to undermine the service safety requirements pursued through quality regulation, which, when balancing the interests at stake, must be regarded as taking precedence.

As noted above, the RQDG governs activities relevant to the safety of gas distribution services. These include emergency service, inspection of the distribution network, locating leaks following inspection or recommendation by third parties, and gas odorisation. The regulation of these aspects has the aim of minimising the risk of explosions, outbreaks and fires caused by distributed gas and, therefore, it has as its ultimate goal the safeguarding of persons and property from damage resulting from accidents caused by distributed gas. The graphs and tables below illustrate the safety trend in the gas sector in recent years.

The inspection of the network first and foremost aims at intercepting the phenomenon of gas leaks and thus enhancing the safety of citizens. Since 2014, regulation has introduced a minimum inspection obligation of 100% of the network over the three-year period (high/medium pressure network, HP/MP) or the four-year rolling period (low pressure network, LP). Figure 4.1 and Figure 4.2 represent the percentage of the network inspected in each three/four-year period by means of a histogram, while the line represents the total percentage for the period.

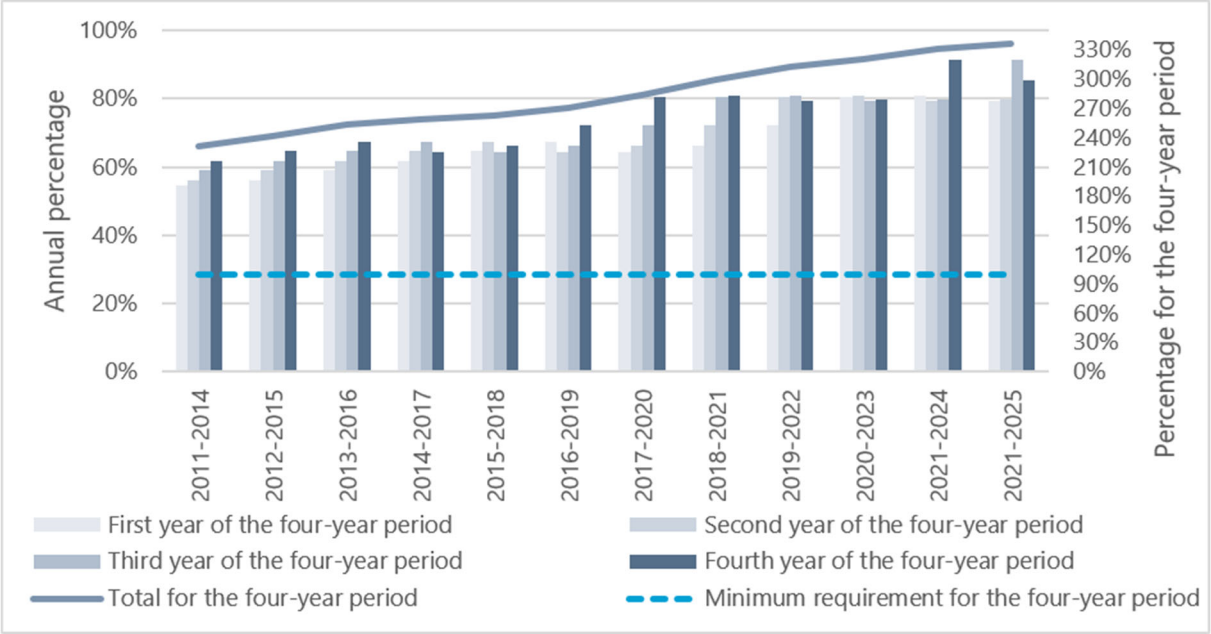
[273] Resolution of 2 December 2025, 532/2025/R/gas.

Figure 4.1 Percentage of high/medium pressure network inspected, by three-year period



Source: Distributing companies' declarations to ARERA.

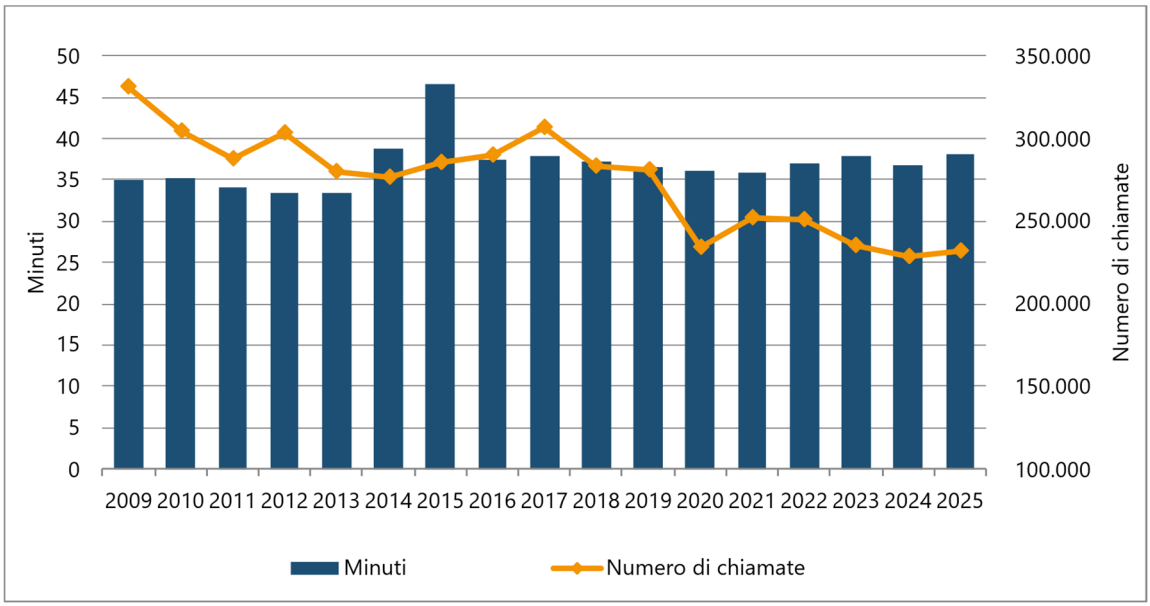
Figure 4.2 Percentage of low-pressure network inspected, by four-year period



Source: Distributing companies' declarations to ARERA.

Compared with 2024, the percentage of high-/medium-pressure (HP/MP) and low-pressure (LP) networks inspected decreased in 2025. Over the reference period as a whole, the percentage, which remains well above the mandatory minimum, increased for the LP network, while decreasing slightly for the HP/MP network.

Figure 4.3 Emergency service on distribution system



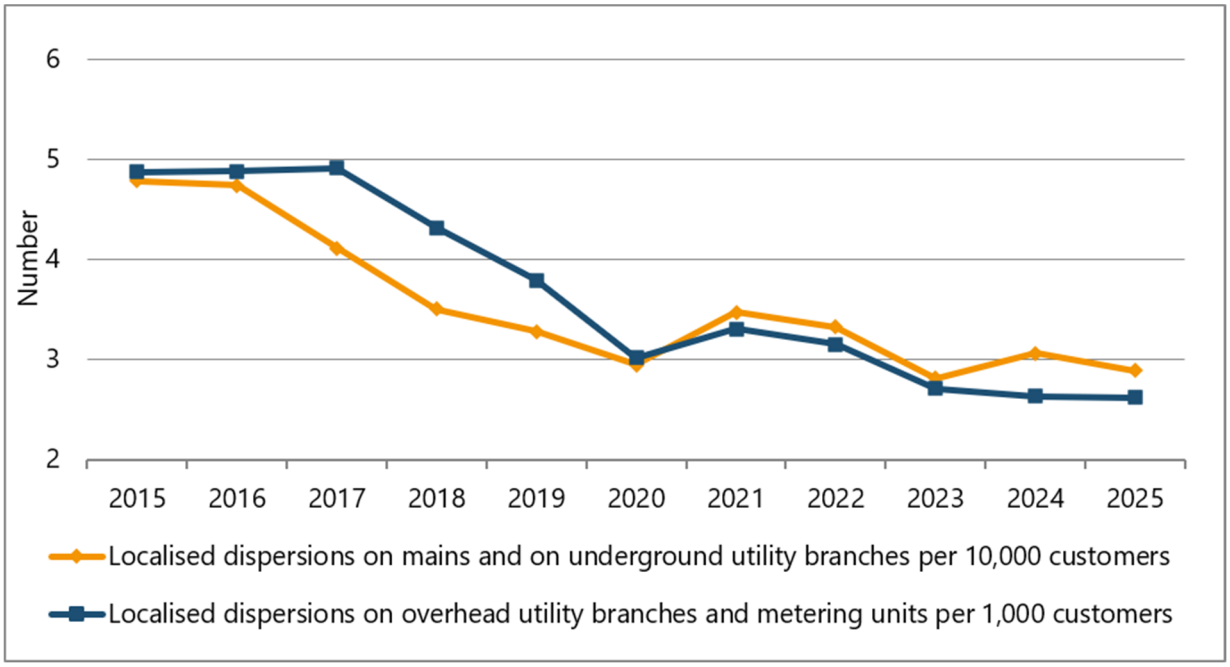
Source: Distributing companies' declarations to ARERA.

With regard to emergency service obligations, Figure 4.3 shows the arrival time at the place of (telephone) call updated to 2025. The national average was approximately 38 minutes, up from 2024. Moreover, the percentage of cases in which the maximum arrival time of 60 minutes was met stood at 99.9%, against a requirement of at least 90%. This percentage excludes calls for which the response time exceeded 60 minutes due to force majeure or causes attributable to third parties.

The mandatory voice recording of calls, introduced by the RQDG from 1 July 2009 and accompanied by the regular control campaign on companies' gas emergency services, carried out with the support of the *Guardia di Finanza*, encourages companies to record data accurately, which is why data is presented starting from that year. Furthermore, it should be added that the number of companies forced to participate in the bonus-penalty regulation concerning safety recoveries has gradually increased, and compliance with the emergency service is a prerequisite for bonus recognition. For this reason, the emergency gas service is an essential service for the safety of citizens. Early intervention can prevent gas accidents that could have very serious consequences. Compliance with the emergency service requirements, which apply to all distribution operators regardless of the number of final customers served, is therefore an essential condition for the recognition of rewards under the reward/penalty regulation governing safety improvements. It should be noted, however, that almost half of the calls received by emergency service centres ultimately prove to be false alarms.

Figure 4.4 shows, as of 2014, for all plants for which distribution companies have communicated data to the Authority, the number of localised dispersions on overhead utility branches and metering units per 1,000 customers and those localised on mains and on underground utility branches per 10,000 customers (considering in total both localised dispersions following inspection and those localised following a call by third parties or their own personnel). In 2025, leaks detected on the network and on the underground sections of service lines, which are generally the most hazardous, decreased both in absolute terms and as a percentage of customers.

Figure 4.4 Number of localised dispersions with respect to customers



Source: Distributing companies' declarations to ARERA.

Connection times to transmission and distribution networks

Connection data differ depending on whether they relate to connections between gas pipelines and transmission networks or connections to distribution pipelines (Table 4.1). For each of these types, data is shown on the number of connections made during the year and the average time elapsed to obtain them, net of the time needed to acquire any authorisations and/or fulfilments on the part of the final customer requesting the connection. The average time is given in the number of working days taken to set up the point and any other works required to make the transmission capacity available, as established in the connection contract stipulated.

In 2025, 120 connections to transmission networks were made, of which 116 were high-pressure pipelines and 4 medium-pressure pipelines. On average, a waiting time of 206.8 working days was recorded for high-pressure connections and 8.3 days for medium-pressure connections. Compared with the previous year, the number of high-pressure connections increased markedly, while the number of medium-pressure pipeline connections decreased marginally. As regards the average time required to complete connections, there was a significant increase for high-pressure pipelines (approximately 65 additional working days), while the time required for medium-pressure pipelines decreased (by 6 days). Just over 30% of the 120 connections completed overall resulted in the activation of supply during the year (more specifically, 35 of the 116 high-pressure connections and 2 of the 4 medium-pressure connections).

For local distribution networks, there was a slight decrease in the number of connections completed, to 42,873 compared with 59,236 in 2024. As in previous years, the vast majority of connections were to low-pressure pipelines (96.1%), with the remainder involving medium-pressure pipelines, while no connections were made to high-pressure distribution pipelines, as has also been the case in recent years. Waiting times for connections to medium-pressure pipelines decreased from 11.8 to 8.6 working days, while those for connections to low-pressure pipelines increased from 36.7 to 43.1

working days.

On average, each distributor completed 224 connections to low-pressure pipelines during the year. If those distributors who did not make a single connection are excluded from the calculation (30 subjects), the average rises to 268 connections per distributor.

Table 4.1 Connections to electricity networks and average connection time

PRESSURE	2024		2025	
	NUMBER	AVERAGE TIME(A)	NUMBER	AVERAGE TIME(A)
CONNECTIONS TO TRANSMISSION NETWORKS				
Medium pressure	6	14.4	4	8.3
High pressure	58	139.8	116	206.8
TOTAL	64	128.0	120	200.2
CONNECTIONS TO DISTRIBUTION NETWORKS				
Low pressure	55,771	11.8	41,209	8.6
Medium pressure	3,465	36.7	1,664	43.1
High pressure	0	-	0	-
TOTAL	59,236	13.2	42,873	9.9

(A) It excludes the time spent in obtaining any authorisations and the time needed for any fulfilment by the final customer.

Source: ARERA. Annual Survey of Regulated Sectors.

4.1.5 System balancing

Regulation of balancing services

In June 2025, the Authority updated [274]the provisions governing the valuation of gas volumes exceeding the limits established in agreements between operators of interconnected facilities and the balance responsible entity, referred to in Article 4.2 of the *Consolidated Gas Balancing Code* (TIB[275]), in order to align them with the provisions of the Gas Transmission Tariff Regulation (RTTG). In addition, with a view to improving the efficiency of balancing services and ensuring that charges better reflect the costs of providing them, it was decided that volumes other than linepack variations, leakages, own-use gas and unaccounted-for gas should be valued at the daily System Average Price (SAP), rather than the monthly average.

The balancing regulation set out in the TIB provides for a "dual" imbalance price, under which the price for users with a "long" position differs from that for users with a "short" position. It also provides that these prices must be, respectively, no lower and no higher than the SAP – calculated as the volume-weighted average of prices recorded on wholesale natural gas markets – increased or decreased by a "small adjustment". In November 2024, the Authority had provided [276]for the "small adjustment" to be calculated daily as a percentage of the SAP. In July 2025, the Authority

[274] Resolution of 10 June 2025, 244/2025/R/gas.

[275] Resolution of 16 June 2016, 312/2016/R/gas.

[276] Resolution of 19 November 2024, 482/2024/R/gas.

amended[277]this provision, to specify the procedures for updating the percentage applied to the SAP. The percentage is updated every six months by the balance responsible entity on the basis of changes in interest rates. At the same time, the Authority also supplemented, on a transitional basis, the TIB provisions governing the procurement of system gas to take account of the provisions of the Snam and Italgas recertification decision concerning biomethane production and marketing. Under the recertification decision, as a transitional measure, biomethane produced and injected into the network is to be used as a priority by the two operators for their own consumption, without being sold to third parties, in order to assess its compatibility with the existing regulatory framework. Accordingly, the provisions adopted in July 2025 also established[278] that, until 30 June 2027, the balance responsible entity (RdB) is to procure, on the trading platform specified in the TIB, the quantity of gas required for system operation, net of consumption covered by gas volumes relating to the transfer of biomethane. The costs associated with purchasing biomethane for own use are included within the neutrality mechanism under Article 8 of the TIB. Finally, also in July 2025, the Authority clarified [279]the provisions governing the management of adjustments arising from the settlement session, aligning the provisions of the RTTG with the implementation arrangements established in the Consolidated *Regulation on the physical and financial settlement of natural gas balancing services* (TISG) [280]and set out in the Snam Network Code. These provide that the net balance of adjustments relating to variable and capacity-based transmission charges is to be settled by transmission operators through the relevant accounts held by the Energy and Environmental Services Fund (CSEA).

In November 2025, the Authority regulated [281]the treatment of receivables not collected by the Balance responsible entity relating to balancing transactions arising between 1 December 2011 and 23 October 2012. It therefore provided for the Energy and Environmental Services Fund (CSEA) to pay Snam the balance between the amounts not yet recognised and those subsequently recovered as a result of the actions undertaken, together with the related interest, using the fund covering costs associated with the gas system balancing mechanism.

Settlement framework

In July 2025, the Authority proposed [282] revising the timetable for adjustment sessions, starting with the 2021–2024 multi-year session, with the aim of ensuring that they are completed more quickly and within more predictable timeframes. The proposal followed a number of reports from operators and reflected the need to address the objective lengthening of the time required to carry out settlement sessions, including through the adoption of new provisions designed to streamline the process. One example, among others, is the procedure allowing a balancing user (UdB) to request corrections to daily withdrawal data calculated by the Integrated Information System Operator (SII).

[277] Resolution of 15 July 2025, 328/2025/R/gas.

[278] Resolution 328/2025/R/gas.

[279] Resolution 328/2025/R/gas.

[280] Resolution of 16 April 2019, 148/2019/R/gas.

[281] Resolution of 18 November 2025, 490/2025/R/gas.

[282] Consultation document of 3 July 2025, 306/2025/R/gas.

These data relate to distribution redelivery points that have not successfully passed the consistency checks performed by the SII Operator against the data in its possession. The proposed revision of the timetable presented in July 2025 drew on a report submitted by the Balance responsible entity (RdB) at the request of the Director of the Authority's Energy Markets Directorate. The report contains operational proposals for possible measures covering the adjustment process as a whole, aimed at shortening the current timeframe for carrying out the sessions, with particular reference to activities falling within the Balance responsible entity's remit. The SII Operator, which was also consulted, agreed to revise its own timetable in line with the Balance responsible entity's proposals, subject to limited changes.

Also in July 2025, the Authority approved [283]a number of provisions concerning the alternative natural gas supply service for temporarily isolated gas networks, following the consultation launched [284]in April 2024. The consultation had set out a solution for accounting for this service for the purposes of determining transmission balances, i.e. gas settlement procedures. The service is managed by the distribution operator to ensure continuity of supply during emergencies or network maintenance, i.e. where service is interrupted or reduced. The main issue discussed and broadly supported during the consultation concerned the relationship between the transmission and distribution operators, with particular attention being drawn to complexities associated with implementation and management costs, as well as potential tax-related issues. Accordingly, while broadly confirming the approach set out at the start of the consultation[285], the Authority decided to introduce the following provisions to take account of the comments received:

- the financial adjustment is recognised by the Balance responsible entity (RdB) to the distribution user (UdD) through its balancing user (UdB), rather than through the distribution operator (including where the distribution network is interconnected with transmission networks operated by smaller transmission operators), once the distribution operator has provided the necessary information;
- the adjustments are determined in dedicated sessions held annually, with the first session covering the 2020–2024 period.

For this purpose, distribution operators, including those not directly interconnected with the transmission network of the major transmission system operator, are required to submit annually to the RdB data on the volumes injected into their networks through the alternative natural gas supply service, broken down by day and by each UdB–UdD relationship, in accordance with the procedures and timetable established by the RdB.

In 2024, an incentive mechanism [286]for gas distribution operators entered into force, designed to support settlement procedures and encourage operators to correct, as promptly as possible, withdrawal data that fail the consistency checks carried out during balancing or adjustment sessions. The amount of the penalty is determined by the Energy and Environmental Services Fund (CSEA) on the basis of data submitted by the Integrated Information System Operator (SII). The amounts are charged to the gas settlement account, with separate records maintained and the Authority duly

[283] Resolution of 22 July 2025, 341/2025/R/gas.

[284] Consultation document of 4 June 2024, 221/2024/R/gas.

[285] Consultation document 221/2024/R/gas.

[286] Resolution of 8 November 2022, 555/2022/R/gas.

informed. During 2025, the results of the publication of data from the multi-year adjustment session (covering 2020–2023) revealed significant penalty amounts, particularly for redelivery points (PdRs) equipped with metering units of class G6 or below. In a small number of cases, however, the calculated penalty exceeded the maximum amount applicable to penalties that may be imposed by the Authority. Reports were also received from distribution operator associations concerning cases in which the procedures adopted by the SII Operator had not allowed withdrawal data to be corrected, consequently resulting in the application of the penalty provided [287]for under the incentive mechanism. Given that the number of such cases could entail a particularly burdensome and complex identification and verification process, in August 2025 the Authority identified [288]measures aimed at mitigating the adverse effects of the requirements imposed by the regulation. Exclusively for the multi-year adjustment session covering 2020–2023, it introduced a tolerance threshold based on the total number of PdRs served by the distribution operator over the same period, which CSEA took into account when calculating the penalty. This tolerance threshold did not apply to PdRs equipped with metering units of class G10 or above, since, given the high consumption associated with these points, it was considered important to obtain more detailed information, with a proportionate burden on the distribution operator responsible for correcting the withdrawal data. For this category of PdRs, and for cases involving PdRs equipped with metering units of class G6 or below exceeding the tolerance threshold, the distribution operators concerned were required to submit a specific notification to CSEA to enable identification of the type of error that could not be corrected by the operators themselves. Finally, also in August 2025, the incentive mechanism [289]was amended to provide that the penalty may in no circumstances exceed 10% of the distribution operator's turnover, in order to prevent the mechanism from producing manifestly disproportionate effects, such as where the penalty amount would even exceed the maximum amount of penalties that may be imposed by the Authority.

Making distribution companies responsible for the difference between gas injected and withdrawn (Delta^{IO})

In August 2022, the Authority introduced [290]a simplified accountability mechanism for distribution operators, aimed at encouraging them to improve the efficiency of their operations by reducing network losses and improving the collection and quality of metering data.

The so-called delta in-out is a parameter that summarises the overall quality of distribution activity, representing the daily difference between what is measured entering the network and what is measured (or estimated) exiting, a difference that ideally tends towards zero.

The regulation stipulates that the delta in-out is not allocated to balancing users but is provided by Snam, with the related costs being borne by the system. The mechanism is supplemented by Operating Instructions for the Balance responsible entity (RdB) to calculate any penalty P applicable to each city gate. These procedures are updated by decision of the Director of the Authority's Energy Markets Directorate, also taking into account requirements raised by operators. With reference to

[287] Article 3 of resolution 555/2022/R/ gas.

[288] Resolution of 5 August 2025, 383/2025/R/gas.

[289] Resolution 383/2025/R/gas.

[290] Resolution of 2 August 2022, 386/2022/R/gas.

2025, following publication of the physical results of the multi-year adjustment session, three sessions were scheduled: the first covering the three-year period 2020–2022; the second covering 2021–2023; and the third covering 2022–2024, based on the results of the multi-year adjustment session for 2022 and 2023 and, for 2024, on the results of the annual adjustment session. In December 2023, [291]with regard to the allocation criterion for interconnected distribution operators based on the number of PdRs, the Authority proposed that, where interconnection metering data are unavailable, any penalty should be allocated on the basis of the volumes attributable to each distribution operator as determined in the adjustment sessions, with Snam Rete Gas, in its capacity as Balancing Operator (RdB), being responsible for the calculation. As this approach was favourably received during the consultation, in early February 2025 the Authority established[292] that the RdB should allocate the penalty among interconnected distribution operators on the basis of the volumes resulting from the adjustment sessions, as transmitted with the relevant breakdown by the Integrated Information System (SII), while giving priority to interconnection metering data where available. In the latter case, the reference distribution operator, in agreement with the downstream distribution operators, determines and submits to the RdB the allocation of the penalty among each of the operators present at the city gate, in accordance with the procedures and timetable established by the RdB in the Operating Instructions. At the same time, the Authority introduced [293]amendments to the mechanism adopted in August 2022 to clarify the regulation applicable in the event of a change of operator managing a facility following a tender for the award of the service. More specifically, it was clarified that any penalty is attributed to the distribution operator managing the facility at the time of the adjustment session following which the penalty is calculated. Exceptions apply to changes of operator already completed by the date of publication of the above amendments or where, by that date, participants had already submitted their bids. In such cases, any penalty is determined by the RdB for each distribution operator on the basis of the period for which it was responsible. Furthermore, in connection with the measures planned by the SII Operator concerning gas settlement processes affecting the calculation of the in-out delta, in February 2025 transitional provisions were introduced[294], pending full implementation of the measures described above, allowing distribution operators to notify the RdB of expected gas withdrawal (OUT) values for city gates connected to PdRs to which an incorrect withdrawal value had been attributed in the transmission balance and which could not be corrected using the procedures currently applicable to adjustment sessions. For this purpose, the RdB was instructed to treat these OUT data in the same way as data relating to identified leakages and fraudulent withdrawals, thereby replacing the value resulting from the adjustment session with the expected OUT value reported by the distribution operator and recalculating the penalty accordingly. Also in February 2025, interested parties were given [295]the opportunity to submit any comments and reasoned proposals on the new provisions by 21 February 2025. Following this ex-post consultation, in March 2025 it was established that[296], in cases involving a change of operator following a tender, the RdB is to allocate any penalty among the distribution operators concerned on the basis of their respective periods of responsibility. This

[291] Consultation document of 5 December 2023, 573/2023/R/gas.

[292] Resolution of 4 February 2025, 28/2025/R/gas.

[293] Resolution 28/2025/R/gas.

[294] Resolution 28/2025/R/gas.

[295] Resolution 28/2025/R/gas.

[296] Resolution of 25 March 2025, 111/2025/R/gas.

constitutes an exception to the general rule under which the penalty is attributed to the distribution operator managing the facility when the calculation is performed. That general rule is based on the principle of continuity in legal relationships and is consistent with the statutory framework governing other cases in which one operator succeeds another, including following corporate transformation, merger or demerger, or the acquisition of a business.

At the beginning of July 2025, the Operating Instructions were updated [297]to implement the measures described above.

Finally, also in July 2025, it was established that[298], when performing the calculations required to correctly determine the in-out delta under the accountability mechanism introduced in [299]August 2022, the RdB should take into account the volumes injected at each city gate by tank trucks.

4.1.6 International coordination

International gas cooperation

With regard to collaborations with foreign countries and international bodies on gas matters, please refer to the section "International Coordination on Electricity and Natural Gas" within the electricity sector chapter of this Annual Report.

4.2 Competition and the functioning of markets

4.2.1 Wholesale markets

According to provisional data published by the Ministry of the Environment and Energy Security, gross natural gas consumption increased by almost 2% in 2025, rising from 61.8 to 63 bcm (Table 4.2). Following the sharp declines recorded in 2022 and 2023 (both -10%) and the modest recovery in 2024 (+1.2%), this increase represents a further positive signal for the sector. Final consumption nevertheless remained at its lowest level of the past thirty years.

In 2025, domestic production recorded a solid recovery, increasing from 2.6 bcm in 2024 to 3 bcm. The non-domestic balance also increased slightly (by 1%), reflecting higher imports, which rose from 59.5 to 61.6 bcm, partly offset by a recovery in exports, which returned to 2.1 bcm, in line with their 2023 level. As the volumes held in storage at year-end were approximately 0.6 bcm higher than at the beginning of the year, gross domestic consumption in 2025 amounted to 63 bcm, as noted above, almost 2% higher than in 2024. Consequently, the level of import dependency, measured as the ratio of net imports to gross domestic consumption, decreased slightly: in 2025, 94.3% of the gas available in Italy came from abroad, compared with 95.2% in 2024 (Table 4.2). Taking into account system consumption and network losses, net gas consumption in 2025 is estimated at approximately

[297] Decision 7/2025 of the Director of the Energy Markets Directorate of 3 July 2025.

[298] Resolution of 22 July 2025, 341/2025/R/gas.

[299] Resolution 386/2022/R/gas.

62 bcm.

Table 4.2 Gross natural gas consumption in Italy

AVAILABILITY (M(m^3))	2024	2025(A)	CHANGE
Domestic production	2,595	3,012	16.1%
Imports	59,461	61,584	3.6%
Exports	620	2,136	244.8%
Stock variation	381	561	47.2%
GROSS DOMESTIC CONSUMPTION	61,817	63,020	1.9%

(A) Provisional data.

Source: Ministry of the Environment and Energy Security.

Production

Data collected through the Authority's Annual Survey of the Energy Sectors, which since 2022 have also included biomethane production, likewise show an increase in domestic gas production in 2025, to 3,301 mcm, compared with 2,674 mcm in 2024. The increase in gas production volumes was significant for some of the major operators.

In 2025, Eni group companies produced approximately 135 mcm more than in 2024, representing an increase of 7.8%. The group remains dominant in this segment, with a clear majority share (56.7%), well ahead of the second-largest group, Royal Dutch Shell. Indeed, the gap between the two leading operators widened further in 2025, as Royal Dutch Shell's production fell by approximately 30 mcm compared with 2024, a decrease of 6.7%. The same trend was recorded by the Total group, whose production fell by 7% compared with 2024, from 62 mcm to 58 mcm. By contrast, Gas Plus recorded a substantial increase, with production more than doubling from 81 mcm to 179 mcm.

Biomethane production slightly exceeded 268 mcm, accounting for 8.1% of domestic production and representing an increase of 20% compared with the previous year. The leading companies in this segment are Società Estense Servizi Ambientali (S.E.S.A.), which produced 36 mcm; Società Agricola Agriman, whose production reached almost 31 mcm; Finam group company Bioman, which produced 17 mcm; A2A group companies A2A Ambiente and Agripower, which together produced 15.9 mcm; and Vallette group company Sant'Ilario Bioenergia, which produced 14.6 mcm. Slightly lower production was recorded by Herambiente and Biorg, both part of the Hera group, which together produced 10.7 mcm.

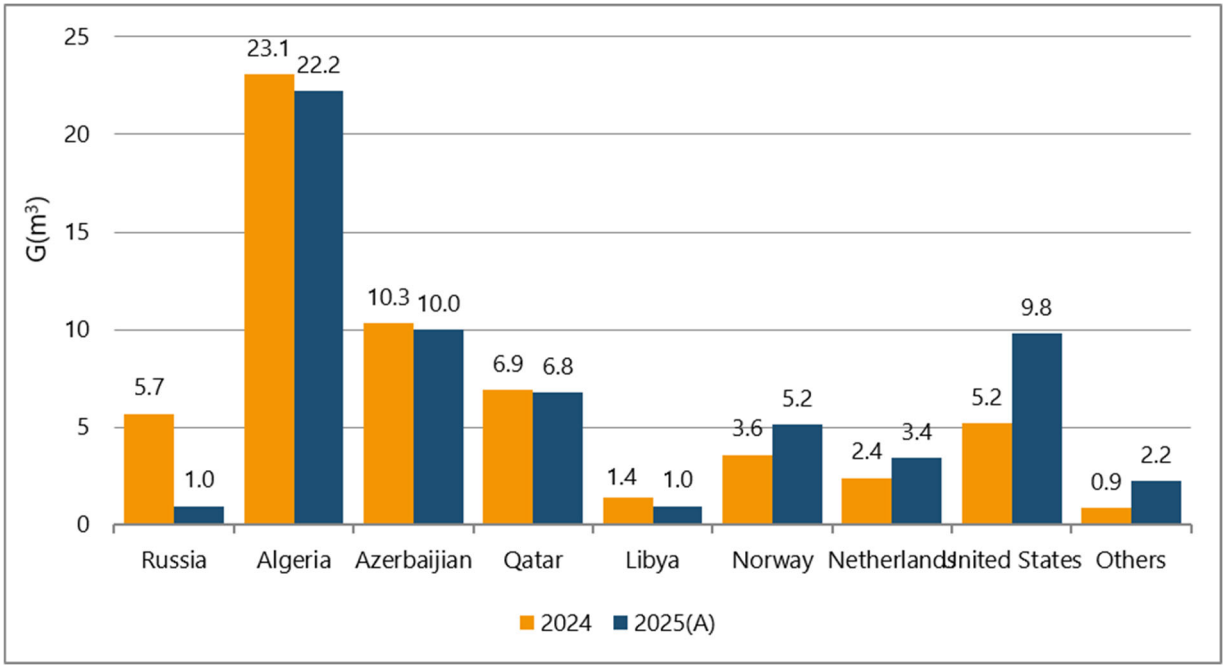
Imports

As noted above, according to preliminary data published by the Ministry of the Environment and Energy Security, Italy imported 2.1 bcm more natural gas in 2025 than in 2024. Gross imports rose from 59.5 to 61.6 bcm, an increase of 3.6%. Following the low recorded in 2024, gross import volumes therefore returned to broadly the same level as in 2023.

The increase was driven primarily by imports from the United States, which almost doubled in 2025, rising from 5.2 to 9.8 bcm. Flows from Northern Europe also increased, with imports from both Norway and the Netherlands up 43%, as did those from countries that have entered Italy's supply mix more recently, rising from 0.9 bcm to 2.2 bcm (+163%). These included, in particular, Trinidad

and Tobago (501 mcm), Equatorial Guinea (353 mcm), Nigeria (328 mcm), Mauritania and Senegal (248 mcm each). Imports from Algeria (-890 mcm), Azerbaijan (-307 mcm), Qatar (-108 mcm) and Libya (-448 mcm) declined. Volumes statistically attributed to Russia, associated with higher withdrawals from Austrian storage facilities transiting through Tarvisio, also fell sharply (-83%), from 5.7 bcm in 2024 to 972 mcm (Figure 4.5).

Figure 4.5 Gross gas imports according to origin



(A) Preliminary data.

Source: Ministry of the Environment and Energy Security.

The increase in Italy's gas imports was driven largely by liquefied natural gas (LNG). In 2025, LNG imports increased by 44%, rising from 14.7 to 21.2 bcm. As a result, LNG accounted for just over one-third of total imports, compared with around one-quarter in 2024. This trend also changed the geographical composition of supplies: the share of the three main supplier countries – the United States, Qatar and Algeria – fell from 94% to 88% of total LNG imports, while cargoes from Trinidad and Tobago (2.4%), Equatorial Guinea (1.7%) and Nigeria (1.5%) gained in importance.

Considering total import volumes, both by pipeline and by sea, Algeria remained Italy's leading supplier in 2025, with a share of 36.1%, followed by Azerbaijan (16.2%) and the United States (15.9%). Qatar's share declined slightly, from 11.6% to 11.0%, while the share of Northern European suppliers (Norway and the Netherlands), traditionally important sources of supply, increased from 10.1% to 14.1%.

According to the provisional data collected through the Authority's Annual Survey of the Energy Sectors, Italy imported 58.8 bcm of natural gas in 2025, 1.2 bcm more than the 57.6 bcm imported in 2024[300]. The increase, equal to 2%, was therefore slightly lower than that indicated by the Ministry's

[300] Data also sourced from the Annual Survey of the Energy Sectors.

data[301]. Of the total gas sourced from abroad, 3.1%, or just over 1.8 bcm, was purchased on European gas exchanges. This share fell significantly from 8% in 2024.

The list of the top twenty importers shows no change in the top three positions. As always, Eni is in first place, having imported 16.8 G(m^3) in 2025, almost 1 G(m^3) less than the previous year. As a result of the decline in Eni's imports (-5.4%), the company's market share fell from 30.9% in 2024 to 28.6% (27.3% if calculated using the Ministry's import data). Volumes purchased abroad by Edison, which ranked second, also decreased by almost 1.2 bcm (-11.5%); as a result, its share fell from 17.6% to 15.3%, although the gap with Eni remained broadly unchanged compared with 2024, at just over 13 percentage points. Imports by Azerbaijan Gas Supply Company, which markets Azerbaijani gas delivered to Melendugno through the TAP, also decreased slightly (-2.8%). With imports of 8.9 bcm, approximately 300 mcm less than in 2024, the company nevertheless consolidated its third-place position, with a share of 15.2% (15.9% in 2024). Vitol moved up to fourth place from sixth in the previous year, with its imported volumes more than doubling from 2.4 bcm to 5.4 bcm. This strong growth pushed Enel Global Trading down to fifth place, despite the latter also recording a marked increase in imports (+19.4%) compared with 2024, from 3.6 bcm to 4.3 bcm.

Table 4.3 Development of the wholesale gas market

Year	Demand Total(A) G(m^3)	Peaking demand(B) M(m^3)/g	Production G(m^3)	Import capacity via tube M(m^3)/g	no. of groups with supply quota >5%(C)	no. of groups with available gas quota >5%(D)	C3 of major groups on total demand
2010	173.5	459	8.3	296.2	3	5	42.3%
2011	178.9	401	8.4	296.2	3	3	42.1%
2012	178.3	464	8.6	298.6	3	3	40.5%
2013	180.8	360	7.7	298.6	3	3	42.7%
2104	210.9	330	7.1	298.6	3	3	51.4%
2015	244.5	340	6.8	293.8	3	3	50.6%
2016	267.4	384	5.8	296.4	3	3	46.3%
2017	285.7	425	5.5	294.0	3	3	44.4%
2018	287.5	396	5.4	293.8	4	4	47.2%
2019	329.4	394	4.9	293.8	3	3	46.8%
2020	386.4	366	4.0	291.4	4	4	42.1%
2021	361.6	391	3.2	297.8	5	5	39.1%
2022	281.3	377	3.1	298.4	5	5	39.1%
2023	269.0	333	2.7	294.4	5	5	37.6%
2024	286.6	339	2.6	294.4	5	5	33.8%
2025	291.7	354	3.0	294.4	5	5	30.3%

(A) Volumes of gas sold on the national wholesale and retail market; it includes resales and fuel gas.
(B) The indicated volume includes inputs, releases from storage, leakage and internal network consumption.
(C) Number of companies with a share of gas produced and/or imported of more than 5%.
(D) Number of companies with a share >5% of available gas volumes, including production, net imports and storage.

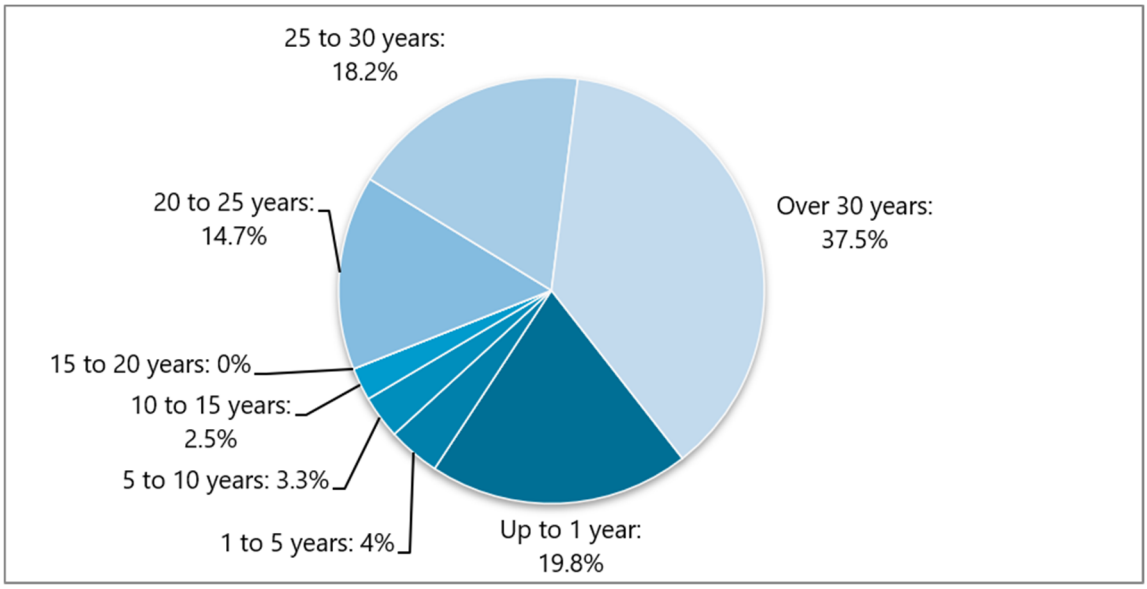
Source: ARERA processing of Snam Rete Gas data and on operators' declarations.

[301] The differences compared with the Ministry's data are partly attributable to the number of companies responding to the Authority's Annual Survey and partly to differences in the classification of import data. It is likely that some quantities, which in the ministerial data are classified as imports, are considered as "Purchases at the Italian border" in the Authority's Survey, in view of the customs clearance procedures.

Five groups [302]each accounted for more than 5% of total gas sourced, i.e. produced or imported: Eni, Edison, Azerbaijan Gas Supply Company Limited, Vitol and Enel (the same as in 2024, except that Vitol replaced Royal Dutch Shell) (Table 4.3). Together, the five groups imported 44.4 bcm of the 58.8 bcm of gas imported into the Italian market. Considering also the quantities produced within national borders, the five groups account for 74.6% of all the gas supplied. These five groups are also the only ones each accounting for more than 5% of available gas (which, in addition to imports and production, includes gas held in storage) and together account for 74.3% of the total, slightly below their combined share of gas sourced.

The structure of import contracts (annual and multi-year) in force in 2025, based on their full duration (Figure 4.6), remained broadly unchanged compared with 2024. Indeed, the share of short-term imports, i.e. those under contracts with a duration of less than five years, decreased slightly from 24.9% in 2024 to 23.8%. By contrast, the share of medium-term contracts (5–20 years) increased somewhat, from 3.4% to 5.8%, while the share of long-term imports (over 20 years) decreased from 71.6% to 70.4%. The share of spot imports[303], i.e. those under contracts with a duration of less than one year, remained broadly unchanged at just under 20%. It is important to note, however, that over the last four years the annual contract quantities (ACQs) underlying the shares shown in the figure have been increasing slightly. This contrasts with the trend observed in almost every year from 2010 to 2021, when older long-term import contracts gradually expired and were not renewed or replaced with contracts of a similar duration.

Figure 4.6 Structure of active import contracts in 2025, according to full term



Source: ARERA. Annual Survey of Regulated Sectors.

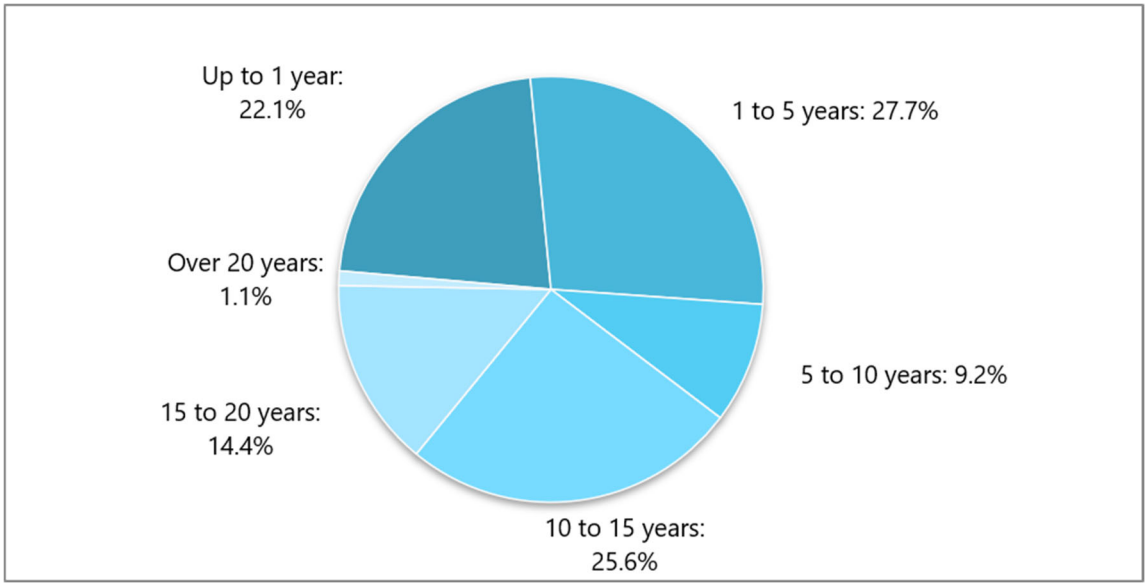
In terms of remaining contract duration, import contracts in force in 2025 (Figure 4.7) show that 49.7% will expire within the next five years (compared with 50.5% in 2024), while 58.9% will expire

[302] For the purposes of the gas market survey, membership of a corporate group is defined in accordance with Article 7 of Law No 287 of 10 October 1990. In essence, an undertaking is considered part of a group even where the parent exercises de facto control over the investee.

[303] The share is calculated, as in previous years, excluding the annual contract quantities of spot contracts that did not result in imports into Italy because the gas was resold directly abroad by the operator active in Italy that had purchased it.

within the next ten years (59% in 2024). Contracts with a remaining duration of more than 15 years account for 15.5% of those currently in force. This share has increased marginally from 14.8% in the previous year.

Figure 4.7 Structure of active import contracts in 2025, according to remaining duration



Source: ARERA. Annual Survey of Regulated Sectors.

In 2025, **total demand in the gas sector**, defined as the sum of gas volumes sold on the wholesale market (including resales) and the retail market, plus own consumption, increased by 1.8% to 291.7 bcm (Table 4.3). This was due to the broad stability of gas traded on the wholesale market and a slight recovery in retail market sales, although own consumption also made a significant contribution.

The wholesale market handled 232.1 bcm, compared with 232.6 bcm in 2024 (-0.2%). The retail market, where 46.6 bcm were sold, 0.5 bcm more than in 2024, recorded a small increase (+1.1%). Own consumption also contributed to the increase in total demand, standing almost 1 bcm higher than in 2024 (+7.5%). In 2025, five industrial groups accounted for more than 5% of total demand, compared with four in 2024. More specifically, these were Eni (11.4%), Engie (10.3%), Edison (8.6%), Royal Dutch Shell (7.2%) and Enel (5.5%). Enel was not included in 2024, when its share stood at 4.7%. Together, the top three groups accounted for 30.3% of total demand, down from 33.8% in the previous year (Table 4.3).

4.2.1.1 Monitoring of wholesale market prices

As in previous years, the data on the wholesale gas market derive from the preliminary processing of information gathered through the Annual Survey on Regulated Sectors, carried out by the Authority on the state of the electricity and gas markets. Questionnaires were distributed to companies listed in the operator registry that had declared wholesale gas or retail sales activity in the previous year, even if only for part of the year.

The number of companies that declared to be engaged in gas sales was 930. 712 companies (77%) responded to the *Annual Survey*, of which 64 stated they were affiliated with a natural gas distribution

company and 14 with a transmission operator.

Of the 776 companies that participated in the survey, 98 stated that they had remained inactive during the year. Of the remaining 678 active ones, 185 sold gas only to the wholesale market and were classified as **pure wholesale suppliers**, 342 sold gas only to final customers and were classified as **pure suppliers**. The remaining 151, which operated on both the wholesale and the end market, were classified as **mixed operators**.

Table 4.4 Sales and prices in the wholesale market in 2025

Operators	Number	Sales M(m^3)	Price c€/m^3
Pure wholesale suppliers	185	158,370	42.2
Mixed operators	151	73,685	44.3
TOTAL WHOLESALE	336	232,056	42.9

Source: ARERA. Annual Survey of Regulated Sectors.

The wholesale market was supplied 68% by pure wholesale suppliers and the remaining 32% by mixed operators. In 2025, the number of companies operating in the wholesale market increased significantly to 336, compared with 2024. However, it should be noted that the number of market participants - which is based on the companies responding to the Authority's Annual Survey - is the indicator most affected by year-to-year variations in the survey response rate. The volume of gas sold on the wholesale market declined by 0.5 bcm (-0.2%), resulting in a 9.1% reduction in the average sales volume per company, from 760 mcm to 691 mcm.

The level of concentration in the wholesale market decreased in 2025: the combined share of the three largest companies (Shell Energy Europe, Engie Global Markets and Edison) was 21.1%, compared with 23.6% in 2024. The combined market share of the five largest companies (the three above together with Eni and Vitol) declined from 35.1% to 31.6%. The Herfindahl-Hirschman Index (HHI) for the wholesale market also fell, from 427 to 377.

The average price charged on the wholesale market in 2025 was 42.9 c€/m^3, up 2.9% from 41.7 c€/m^3 in 2024. The increase in prices was consistent with international commodity price trends, with increases recorded across all European markets during 2025. The price charged by mixed operators was 44.3 c€/m^3, which is 2.12 euro cents higher than that charged by pure wholesale suppliers (42.2 c€/m^3).

Virtual exchange point

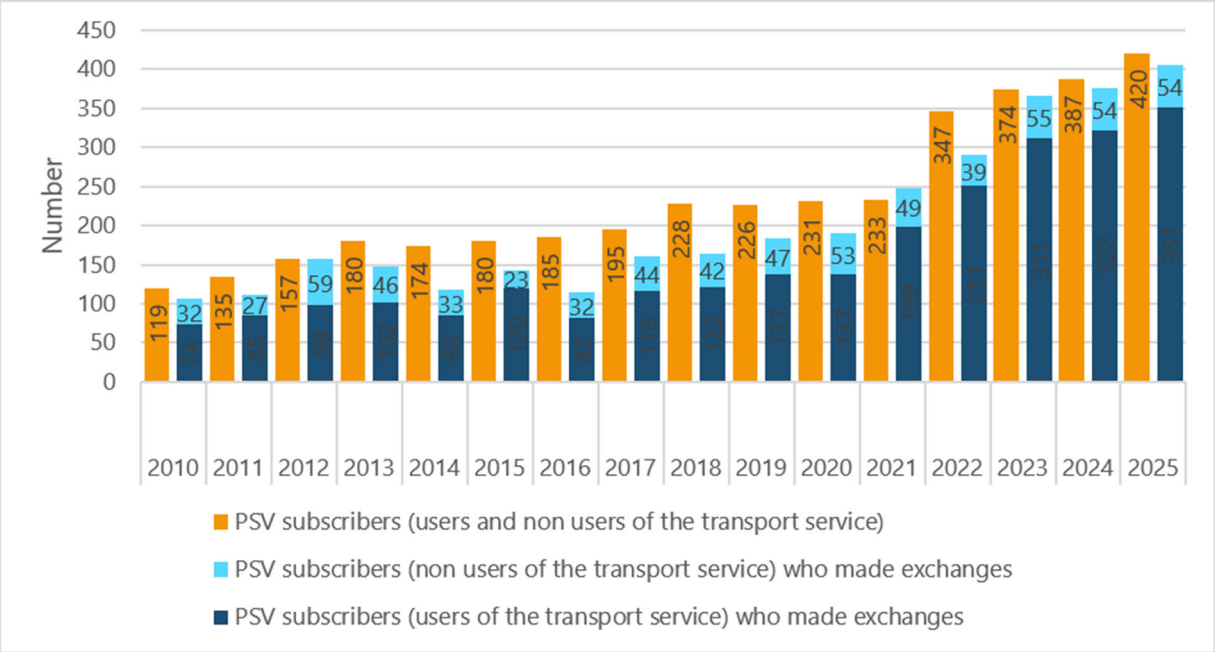
The main trading platform in the wholesale market in Italy is the Virtual Trading Point (PSV), operated by the transmission network operator, Snam Rete Gas. Alienations that can be registered are both those that take place through bilateral OTC contracts and those that take place within the regulated markets managed by the GME. Since September 2015, contracts managed by third-party exchanges [304]may also be registered at the PSV, thereby broadening the range of forward products providing

[304] A third-party exchange means the operator of a foreign regulated market on which derivative financial instruments providing for physical delivery are countertraded and where the clearing and guarantee arrangements for transactions concluded on that market are handled through a clearing house (i.e. the third party that assumes counterparty risk); alternatively, it means the clearing house itself where, either directly or through companies it controls or in which it holds an interest, it is responsible for the obligations relating to the physical delivery of the products offered.

for physical delivery of gas at the PSV. To operate at the PSV, market participants must be registered members, i.e. they must meet the relevant requirements and have signed an application form or access agreement under which they undertake to comply with the conditions approved by the Authority[305].

In 2025, 351 market participants traded, sold and purchased gas at the PSV (Figure 4.8). Only 54 qualified as standalone traders, since they were not transport system users. The number of VTP subscribers increased compared with the previous year, reaching 420, up from 387 in 2024 (+9%). The number of subscribers who carried out trades increased by the same amount (+9%), from 322 entities to 351. Unlike in previous years, however, the number of pure traders remained unchanged at 54 (the same as in 2024).

Figure 4.8 PSV subscribers



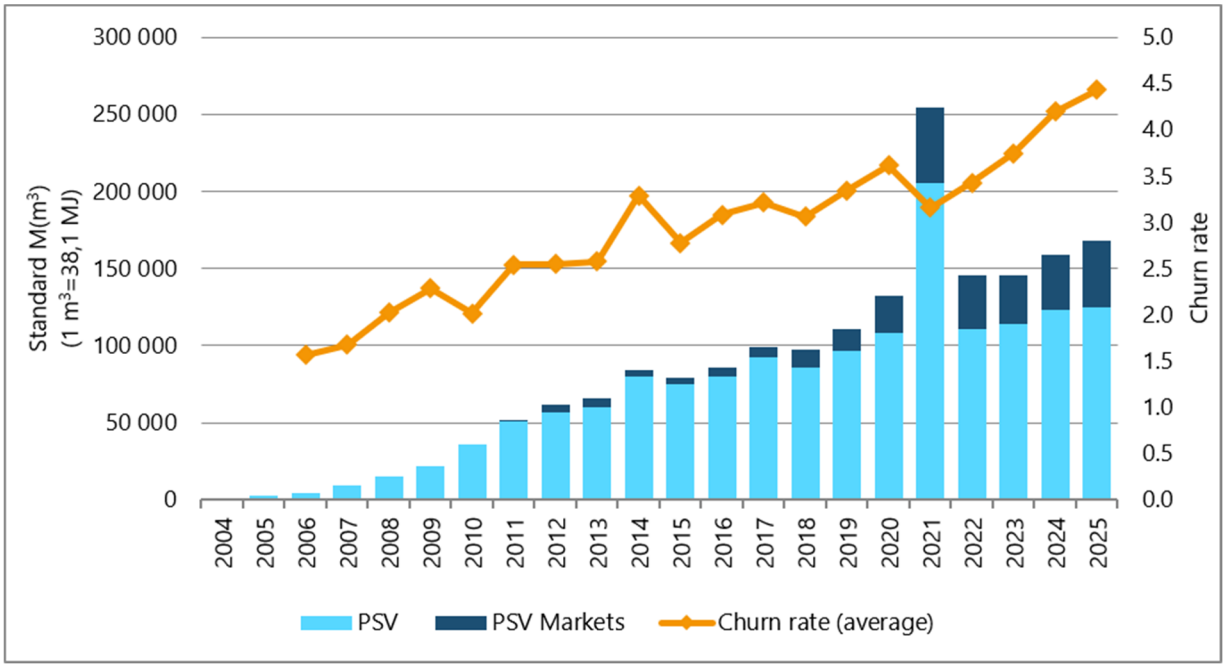
Source: ARERA. Annual Survey of Regulated Sectors.

Figure 4.9 shows the development of trades registered at the PSV. In the graph, the label "PSV" groups together redeliveries from daily OTC transfers, multi-day OTC transfers, and forced LNG transfers, while "PSV-Markets" includes trades at the PSV arising from transactions on centralised markets and those processed through a clearing house.

In 2025, OTC volumes increased by 1.5%, from 123 bcm to almost 125 bcm; by contrast, volumes subject to compulsory delivery at the PSV fell by 40%, from 183 mcm to 109 mcm. As a result, total deliveries at the VTP increased only marginally, by 1.4% compared with 2024. Volumes arising from trades on organised markets, however, recorded strong growth (+19%), following the already substantial increase (+13%) seen in the previous year. Volumes traded on organised markets rose to 42.8 bcm, a level not far below the peak of 49.3 bcm reached in 2021. This was driven by an increase in volumes handled on centralised markets (+14.1%), accompanied by strong growth in gas traded through clearing houses (+56.6%).

[305] By resolution of 16 March 2017, 147/2017/R/gas.

Figure 4.9 Transaction volumes at PSV and churn rate



Source: ARERA processing of Snam Rete Gas data.

Of course, the growth also occurred in the average number of daily transactions, which increased by 15% in 2024, from around 1,100 to nearly 1,300. This was due to the increase in transactions in the markets (+13.8%), but especially to those carried out OTC (+15.7%). The average number of daily transactions also increased overall by 6.4% in 2025, from approximately 1,270 to 1,355, driven by an increase in transactions on organised markets (+5.5%) and, above all, in OTC transactions (+7%).

The rise in trading activity and underlying volumes accounts for the increase in the churn rate from 4.2 to 4.4, an aggregate indicator showing the average number of times gas is traded between its initial sale and physical delivery. The indicator can be calculated in different ways. That illustrated in the figure is obtained by relating the total volumes traded at the PSV to the value of records that result in physical delivery. The more liquid the market, the higher this figure. This rate increased greatly between 2006 and 2014, declined sharply in 2015 and then stabilised in the years 2016 to 2018 at around 3.1. Since 2022, it has shown a sustained upward trend. The 4.4 reached in 2025 is the highest value since the inception of the PSV.

Gas stock exchange

The Italian gas exchange was launched in 2007 with the introduction of an obligation for importers and concession holders to offer or sell specified volumes of gas on regulated platforms. Responsibility for managing the market was subsequently entrusted to GME, which, from 2010 onwards, progressively developed the main gas markets: the P-GAS platform; the M-GAS spot market, comprising Day-Ahead market-GAS and Intra-day market-GAS; and, subsequently, the MV-GAS forward market.

Since 2015, operators have been able to extend registration at the PSV to transactions concluded on exchanges operated by entities other than GME. In particular, the GME was commissioned to register at the PSV the transactions executed on the platforms operated by ICE Endex and Powernext (PEGAS

platform of the EEX group), which had already launched futures products with delivery at the PSV in April 2015.

Since 2016, following implementation of the European balancing regulation, market participants and Snam Rete Gas have had access to the same spot markets to procure the resources required to balance the system. New dedicated segments were also introduced, such as the market for gas in storage and the market for locational products, which were subsequently integrated into M-GAS.

In the following years, measures were introduced to increase market liquidity, including liquidity providers (market makers that, in return for financial compensation, undertake to maintain simultaneous buy and sell orders on the market within a predefined bid-ask spread), integration with the Trayport platform, the weekend product and the AGS segment, through which the Balance responsible entity procures the resources required for the operation of the system.

As of 20 July 2023, the GME introduced the Italian Gas Index (IGI), a price index based on the prices of transactions concluded in the Natural Gas Market (MGAS), i.e. for "title transfer" products with automatic appointment to the PSV. It is, in essence, an index drawn up daily on the basis of the trades that have taken place in the MGAS with the aim of serving as a reference for the definition of contracts. The index is calculated for each gas (delivery) day as the mathematical average of the prices of all completed trades:

- in the PGM-GAS segment in continuous trading;
- in the hourly band 17:15-17:30;
- on the working day preceding the delivery date (for daily product), or on Friday (for the weekend product);
- with a price within the range (±30%) of the mathematical mean of the prices recorded in the previous five transactions.

Legislative Decree No 14 of 2 February 2021, which aligned national legislation with the provisions of Regulation (EU) 2017/1938, provided that GME is to make available dedicated trading platforms for the implementation of the provisions of each intergovernmental solidarity agreement concluded between the Government of the Italian Republic and an EU Member State or a third country, in accordance with the terms of the relevant agreement. From 30 December 2025, GME introduced the Market for the Management of Voluntary Solidarity Measures (MVS) within the gas market, designed to manage at national level any request for market-based solidarity measures pursuant to Article 13 of Regulation (EU) 2017/1938.

Prices and Volumes

A total of 210.4 TWh was traded on the natural gas markets operated by GME in 2025, up 16% compared with 2024 (Table 4.5).

The Day-Ahead Market continued to account for the largest share of liquidity (78%, up 3 percentage points on 2024), with traded volumes increasing to 165 TWh (+20% compared with 2024). The largest share of these volumes (81%; -1%) was traded via continuous trading (133.8 TWh; +20%). Monthly trading patterns also showed higher volumes during the first two months of the year. The AGS segment of the Day-Ahead Market (MGP) recorded total trading volumes of 30.8 TWh, up 22% on 2024.

Table 4.5 Annual volumes for each of the gas markets managed by the GME (GWh)

MARKETS	2019	2020	2021	2022	2023	2024	2025
P-GAS							
Rates	444,292	-	2,216,982	2,031,021	629,548	957,915	826,082
M-GAS							
MGP-GAS	24,794,256	55,782,408	79,292,760	127,159,680	106,451,328	136,987,608	164,646,984
MGP-Continuous	24,676,608	30,043,296	45,593,472	75,780,648	78,522,624	111,713,568	133,824,000
MGP-AGS	117,648	25,739,112	33,699,288	51,379,032	27,928,704	25,274,040	30,822,984
MI	41,052,864	51,064,320	45,932,952	43,126,512	44,544,312	40,207,512	39,495,816
MI-Continuous	41,052,864	46,701,360	44,325,192	40,528,008	44,385,336	39,202,152	38,875,320
MI-AGS	-	4,362,960	1,607,760	2,598,504	158,976	1,005,360	620,496
MGS	13,365,494	6,449,968	5,084,077	5,133,885	3,274,177	3,515,669	5,425,160
MPL	-	-	-	-	-	-	-
MT-GAS	3,192,048	478,272	22,320	-	-	-	-
TOTAL	79,656,906	113,296,696	132,526,771	177,451,098	154,899,365	181,668,704	210,394,042

Source:GME

As in 2024, the share of volumes traded on the Intraday Market continued to decline, falling from 22% in 2024 to 19%. Total traded volumes amounted to 39.5 TWh, down 2% on the previous year. Continuous trading remained the dominant mechanism, accounting for 98% of the market, with traded volumes of 38.9 TWh (-1%), while volumes traded in the AGS segment, at 0.6 TWh, were slightly less marginal than in the previous year.

In 2025, trading in the Gas Storage Market (MGS) also increased, with transactions totaling 5.4 TWh (+54%), while, as before, Snam did not activate any sessions in the Locational Products Market.

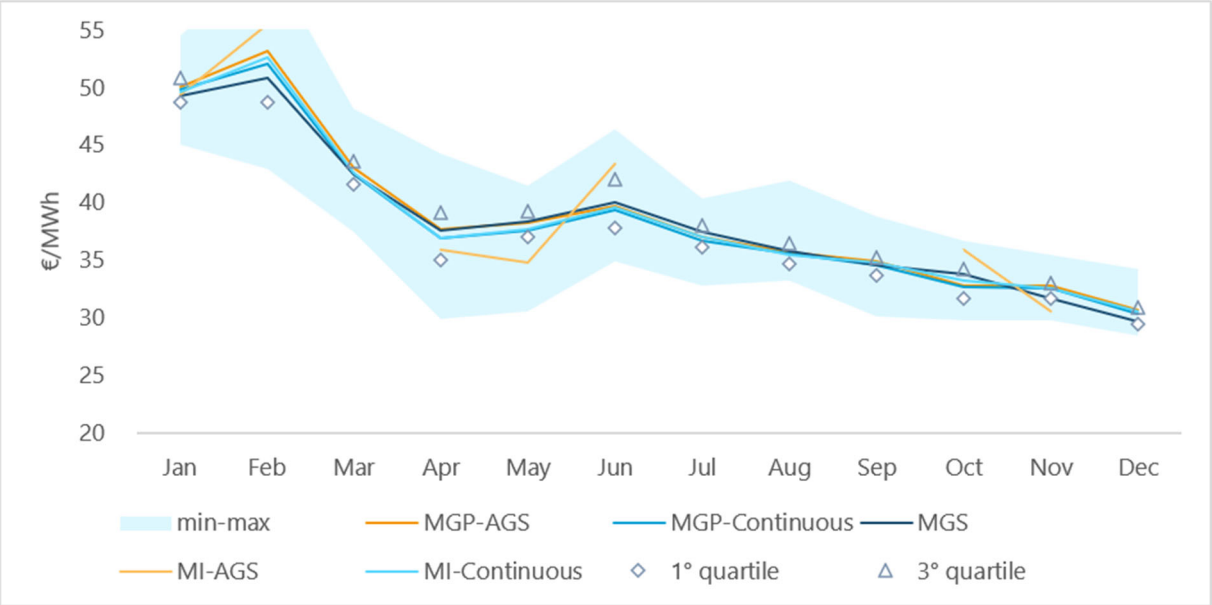
Regarding the forward products traded on the MT-GAS, there were no recorded trades, while allocations in the Royalties sector of the P-GAS amounted to 0.8 TWh (-14%).

Finally, 119 slots were allocated on the Regasification Capacity Allocation Platform (PAR), 99 more than in 2024, for a total of 14.5 mcm of LNG, an increase of 12.8 mcm compared with 2024.

As regards prices recorded on the various trading platforms, these can all be approximated to an annual average of around €38.35/MWh (Figure 4.10), up 5% compared with 2024 and in line with the annual average price of over-the-counter transactions at the PSV (€38.56/MWh), which likewise increased by 5% compared with the previous year. In particular, the average prices in the two continuous trading segments of the M-GAS market, €37.95/MWh for the Day-Ahead Market (MGP) and €38.47/MWh for the Intraday Market (MI), followed an intra-year pattern closely mirroring that of VTP prices.

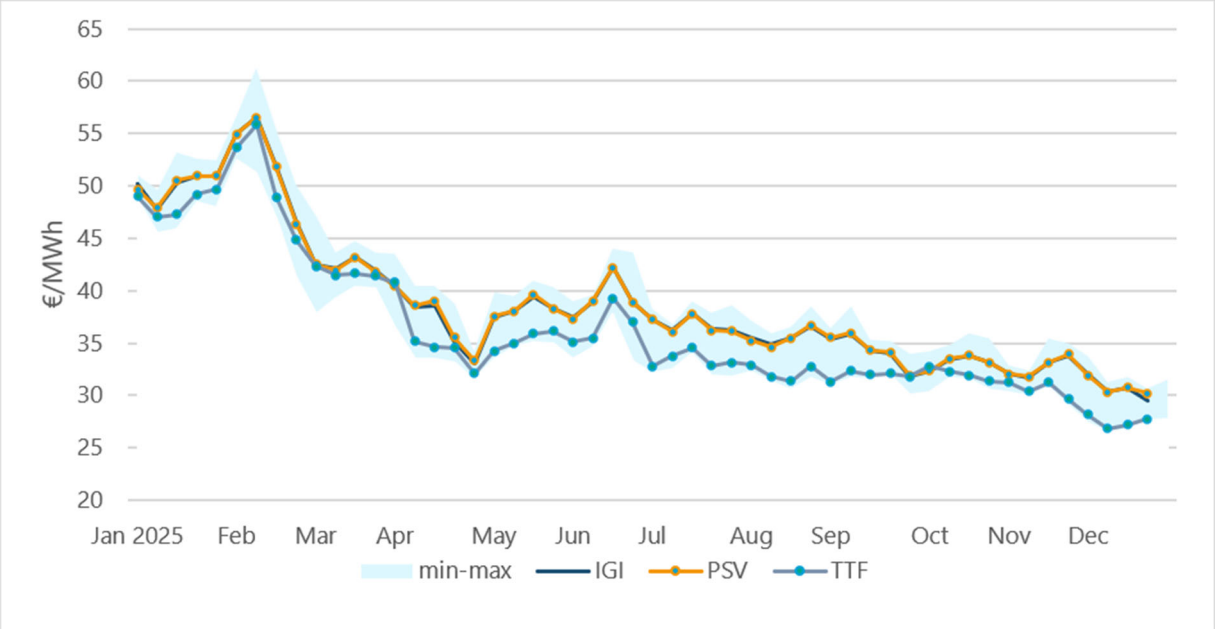
The annual average of the IGI price index calculated by GME () is €38.53 /MWh, and its trend throughout the year was in line with the average price recorded at the PSV (from ICIS) for the day-ahead and weekend products (€38.56 /MWh). The graph also includes the average TTF price (sourced from LSEG Data & Analytics) for the day-ahead product.

Figure 4.10 Prices in M-GAS markets and minimum and maximum values in 2025



Source: GME

Figure 4.11 Comparison of price indices by flow day (weekly arithmetic averages)



Source: ARERA, analysis based on GME (IGI) and Refinitiv (PSV and TTF) data.

4.2.1.2 Monitoring of the level of transparency, including compliance with obligations on transparency and on the degree and on the efficiency of market opening and competition

Monitoring of the wholesale market

At the end of 2018, the Authority adopted the [306] Integrated Text of Natural Gas Wholesale Market Monitoring (TIMMIG) in order to strengthen its monitoring function in the sector[307]

The TIMMIG commissioned the GME to monitor the competitive dimension and the largest transmission operator company, Snam Rete Gas to monitor the structural dimension. In addition, the largest transmission operator company has to collect and organises data on monitoring activities in a database, the "Core Data Database". This database is accessible to the Authority and to the GME. The outline of the Convention, as well as the subsequent updates, are approved by the Authority, based on a recommendation by SRG and the GME.

As in each year, therefore, in accordance with the relevant provisions, approval was given to the actual costs incurred by the major transmission operator in 2024 for monitoring the wholesale natural gas market[308], as well as to the Activity Plan and corresponding cost budget submitted by the major transmission operator for wholesale gas market monitoring activities in 2026[309].

Following the Russia-Ukraine crisis and the sharp increase in gas prices, Article 7(5) of Decree-Law No 21 of 21 March 2022 established that, for monitoring purposes, holders of contracts for the supply of gas volumes to the Italian market are required to submit to the Ministry of the Environment and Energy Security and the Authority the contracts for the supply of gas intended for the Italian market, together with any amendments thereto. The Authority subsequently established [310]the operating procedures: contracts with a duration of at least one year must be submitted in full, together with the relevant details, while for contracts lasting less than one year it is sufficient to provide key information, such as volumes injected into the national system and prices, while ensuring the confidentiality of commercially sensitive data.

4.2.2 Retail market

According to the provisional results of the Annual Survey, which traditionally underpin the analysis in these pages, 46.4 G(m^3) were sold on the retail market in 2025, in addition to 186 M(m^3) provided via last-resort and default services. Overall, final sales amounted to 46.5 bcm, an increase of 0.5 bcm compared with 2024 (Table 4.6). However, to obtain a figure comparable with the final gas consumption figure published by the Ministry of the Environment and Energy Security and discussed in the preceding pages, own consumption volumes of 13.1 bcm must also be taken into account.

[306] By Resolution of 5 December 2018, 631/2018/R/gas.

[307] For more details on the structure, purpose and provisions of the TIMMIG, please refer to the 2019 *Annual Report*.

[308] By Resolution of 13 May 2025, 200/2025/R/gas.

[309] By Resolution of 25 November 2025, 505/2025/R/gas.

[310] By Resolution of 30 March 2022, 143/2022/R/gas.

This brings total consumption as reported in the Annual Survey to 59.6 bcm, a figure comparable with the Ministry's 62.1 bcm. As usual, there are differences between the two sources, which classify the volumes of gas handled during the year differently. According to the Annual Survey data, total gas consumption recovered in 2025, increasing by 2.4% compared with 2024.

Table 4.6 Final consumption of natural gas

	VOLUMES M(m^3)			WITHDRAWAL POINTS (thousands)		
	2024	2025	CHANGE	2024	2025	CHANGE
Retail sales	45,807	46,363	1.2%	21,717	21,640	-0.4%
Last resort and default supplies	243	186	-23.3%	31	27	-13.0%
TOTAL MARKET	46,050	46,550	1.1%	21,748	21,667	-0.4%
Fuel gas	12,181	13,100	7.5%	1.6	1.2	-27.1%
END CONSUMPTIONS	58,231	59,650	2.4%	21,750	21,668	-0.4%

Source: ARERA. Annual Survey of Regulated Sectors.

Of the 46.5 G(m^3) of gas sold in the retail market, 13.7 G(m^3) were sold by pure suppliers, while the remaining 32.8 G(m^3) were brokered by suppliers also operating in the wholesale market (Table 4.7).

Table 4.7 Gas retail sales and prices in 2025

Operators	Number	Sales M(m^3)	Price c€/m^3
Pure suppliers	342	13,747	92.6
Mixed operators	151	32,802	63.2
TOTAL RETAIL	493	46,550	71.9

Source: ARERA. Annual Survey of Regulated Sectors.

The average price charged to retail market customers by suppliers operating on that market was 71.9 c€/m^3, around 0.7 cents higher (+1%) than in 2024. As usual, this price was higher than that charged to final customers by operators active in both the wholesale and retail markets, which stood at 63.2 c€/m^3. The reason for the positive differential is primarily due to the nature of the customers served and their characteristics. Suppliers in the retail market mainly serve household customers connected to the distribution networks, who, while numerous, tend to have relatively modest consumption levels. The final customers of companies that also operate on the wholesale market are typically large consumers, particularly in the industrial sector. Their high consumption levels enable them to obtain more favourable prices, and they are often directly connected to the transmission network, meaning that they do not incur distribution costs.

Unlike in the previous two years, the number of suppliers active on the retail market began to increase again [311]in 2025, reaching 493, 11 more than in 2024. As gas sales volumes also increased (+1.1%), average sales per supplier decreased slightly, from 96 mcm to 94 mcm (-1.2%). For many years, the growing number of suppliers has driven this figure steadily down from the historical high of 237 mcm recorded in 2010; the decrease in 2025 was broadly in line with the trend observed over the last ten years, with the exception of 2024. Of the 493 companies active in the end market, 27

[311] As noted in the section on the wholesale market, 776 of the 994 companies that had declared in the Authority's Registry of Operators that they carried out wholesale or retail gas sales activities during 2025 (even if only for a limited part of the year) responded to the Annual Survey. Apart from the 98 companies that declared to have remained inactive, out of the remaining 678 there are 185 that sold gas exclusively in the wholesale market. Of these, 493 operated on the retail market.

(5.5%) sold more than 300 mcm in 2025. Together, these companies accounted for 85.4% of all gas sold in the retail market.

34.3% (i.e. 169 companies) of the 493 active suppliers who responded to the Annual Survey serve customers in a large part of the national territory, i.e. in at least 17 Italian regions; 52.5% (259 companies) sold gas in between 6 and 16 regions; the remaining 65 companies (13.2%) operated in between 1 and 5 regions. The share of companies operating throughout or across a large part of Italy (17 to 20 regions) increased slightly compared with 2024, when it stood at 33.4%. The share capital composition of gas suppliers, restricted to direct participations, indicates a low level of foreign presence: only 30 enterprises have a majority shareholder who is not Italian. Direct foreign participants are mainly British, Swiss, Slovenian and Luxembourg companies, although companies from a further 13 countries are also present.

As already noted, 59.6 bcm were sold in 2025, of which 13 bcm were for own consumption and 46.6 bcm for sale, to just under 21.7 million customers (redelivery points) (Table 4.8). Overall, compared with 2024, gas consumption increased by 2.4%. Own consumption, which is concentrated mainly in the industrial and electricity generation sectors, increased by 7.5%. Gas sold on the free market, amounting to 44.7 bcm, rose modestly by 0.9%, while sales under the Vulnerability Protection Service for household customers and through Supplier of Last Resort services, totalling 1.8 bcm, increased by 4.8%.

Consumption in the household sector (households and apartment buildings) remained broadly stable at 13.7 bcm, while consumption in the productive sectors (industry and thermoelectric generation) increased from 37.6 bcm to 39.6 bcm (+5.5%). By contrast, consumption in the tertiary sector (the commercial and services sectors together with public service activities) declined by 10%, falling from 7.0 bcm to 6.3 bcm.

More specifically, in 2025 gas sales:

- to the household sector remained broadly stable at 11.7 bcm (-0.1%); sales under the vulnerability protection service increased from 1.5 bcm to 1.6 bcm (+9.4%), while those on the free market decreased to 10.1 bcm (-1.5%);
- to condominiums increased by 4.2% (+4.9% on the free market, while sales under last-resort services halved);
- to the industrial sector increased from 14.6 bcm to 15.1 bcm (+3.5%), while own consumption decreased by 4.6%; overall, therefore, industrial consumption increased by 3.1% in 2025;
- to the thermoelectric sector increased by 5.8% (+0.6 bcm), while own consumption rose by 8.5%; taking both components into account, total consumption in the sector increased from 22.2 bcm to 23.8 bcm, 7.2% higher than in 2024;
- to the trade and services sector decreased by 12.2%; own consumption also fell sharply and, overall, consumption in the sector declined from 6.3 bcm in 2024 to 5.6 bcm, a decrease of 12.1%;
- to public service activities increased from 669 mcm to 734 mcm, up 9.6%.

Table 4.8 End natural gas market by customer sector

CUSTOMER SECTOR	2024				2025			
	VULNERABILITY PROTECTION AND DEFAULT	FREE MARKET	SELF CONSUMP-TION	TOTAL M(m³)	VULNERABILITY PROTECTION AND DEFAULT	FREE MARKET	SELF CONSUMP-TION	TOTAL M(m³)
VOLUMES (M(m³))								
Household	1,478	10,268	0	11,771	1,616	10,138	0	11,754
Condo households	25	1,868	7	1,901	12	1,961	7	1,980
Trade and services	126	6,169	39	6,333	100	5,429	35	5,565
Industry	2	14,603	784	15,389	5	15,106	749	15,860
Power generation	0	10,818	11,350	22,167	0	11,449	12,309	23,758
Public service activities	91	578	0.4	669	69	664	0.2	734
TOTAL VOLUMES	1,721	44,330	12,181	58,231	1,803	44,747	13,100	59,650
REDELIVERY POINTS (thousands)								
Household	2,641	17,727	0	20,367	2,760	17,535	0.0	20,295
Condo households	2	171	0.4	174	1	166	0.4	168
Trade and services	20	976	1.0	996	18	969	0.6	988
Industry	1	152	0.1	153	1	152	0.1	153
Power generation	0	1	0.1	1	0	1	0.1	1
Public service activities	9	50	0.0	59	7	55	0.0	62
TOTAL REDELIVERY POINTS	2,672	19,077	1.6	21,750	2,787	18,879	1.2	21,668

Source: ARERA. Annual Survey of Regulated Sectors.

Average annual consumption amounted to 579 m³ for households, 11,787 m³ for apartment buildings with domestic use, 5,635 m³ for the commercial sector, 103.5 thousand m³ for industry, 20.4 mcm for electricity generation and 11,746 m³ for public service activities. On the free market, average household consumption (578 m³) was slightly lower than that recorded under the Vulnerability Protection Service (586 m³).

On average, 75% of volumes are purchased on the free market, 3% through the vulnerability protection service and last resort services, and 22% are self-consumed. Considering retail sales only, and therefore excluding own consumption, 96.1% of gas was purchased on the free market, while the remaining 3.9% was supplied under the Vulnerability Protection Service and Supplier of Last Resort services. Measured by customer numbers, 87.1% purchased gas on the free market.

Considering the **household sector** alone, the share of volumes purchased on the free market decreased slightly to 86.2% for households, while it reached 99.4% for condominiums (both shares are calculated on total sales excluding own consumption). In 2024, the corresponding figures were 87.4% and 98.7%. Measured by delivery points, 13.6% of households were supplied under the Vulnerability Protection Service, compared with 13.0% in 2024.

The breakdown of sales to final customers (excluding own consumption) by consumption sector and customer size (Table 4.9) shows that, on average, customers with annual consumption of up to 5,000 m³ account for 27.6% of all gas sold on the retail market. Customers consuming between 5,000 and 50,000 m³/year account for 9.4%, those in the third consumption band (50,000–200,000 m³/year) for 4.2%, those in the fourth band (200,000–2,000,000 m³/year) for 9.9%, those in the penultimate band (2–20 million m³/year) for 17.4%, and those in the highest band (over 20 million m³/year) for 31.5%. 98.5% of the volumes sold to the household sector are purchased by families whose annual consumption does not exceed 5,000 m³. The largest share of volumes sold to condominiums is concentrated in the annual consumption class between 5,000 and 50,000 m³, which accounts for

74.4% of the total. 67% of all the gas purchased by the commercial sector is concentrated in the first three classes. Conversely, the classes with the highest annual consumption are particularly significant for industrial and thermoelectric generation consumption. The consumption of public service activities is concentrated among the intermediate classes: 38% is consumed by customers with annual consumption between 5,000 and 50,000 m^3, 19.9% by those with consumption between 50,000 and 200,000 m^3, 24.3% is consumed by customers with annual consumption between 200,000 and 2,000,000 m^3, another 10.6% is sold to customers consuming between 2 and 20 M(m^3)/year.

Table 4.9 Natural gas end market in 2025 by customer type and size

SECTOR	CUSTOMERS DISTRIBUTED BY ANNUAL CONSUMPTION CLASS (m^3)						TOTAL M(m^3)
	<5,000	5.000-50.000	50.000-200.000	200.000-2,000,000	2.000.000-20,000,000	>20,000,000	
PROTECTION OF VULNERABILITY AND LAST RESORT	1,611	104	32	40	16	-	1,803
Household	1,587	29	0.1	-	-	-	1,616
Condo households	0.8	9.5	2.0	0.0	-	-	12
Trade and services	16	36	16	18	14	-	100
Industry	0.8	2.2	0.3	0.2	1.1	-	5
Power generation	-	-	-	-	-	-	-
Public service activities	6.4	26.5	13.7	21.7	1.0	-	69
FREE MARKET	11,236	4,294	1,938	4,566	8,065	14,648	44,747
Household	9,989	145	3	1	-	-	10,138
Condo households	133	1,458	320	48	3	-	1,961
Trade and services	927	1,855	854	1,200	419	175	5,429
Industry	140	583	615	2,823	5,735	5,210	15,106
Power generation	0	2	14	338	1,831	9,263	11,449
Public service activities	47	252	132	157	77	-	664
TOTAL	12,847	4,398	1,969	4,606	8,081	14,648	46,550

Source: ARERA. Annual Survey of Regulated Sectors.

Switching

The analysis of switching activity in the natural gas sector this year also includes data collected from transmission and distribution operators through the Annual Survey on the energy sectors and data from the Integrated Information System (SII), managed by the Acquirente unico. Based on the sources indicated, the switching rate – measured by the number of customers [312]who changed supplier during the 2025 calendar year – was 18.8% overall, rising to 19.4% when measured on the basis of the consumption of customers who switched (Table 4.10).

The switching rate among household customers was unchanged compared with 2024, confirming the significant level of activity reached in recent years. More specifically, just over 4.2 million customers changed supplier at least once during the year, representing 18.7% of all household customers and accounting for 25.3% of household consumption volumes. Household switching

[312] For ease of reference, the term "customers" is used generically throughout the text. It should be noted, however, that we are talking about the number of redelivery points in the case of transmission users and the number of metering units in the case of distribution users.

probably continued to benefit, at least in part, from the impetus provided by the end of access to the regulated price conditions set by the Authority for household customers, which – it is worth recalling – have been reserved for vulnerable household customers since 1 January 2024[313]. Indeed, it is likely that changing contract after leaving the regulated price regime prompted some consumers to seek information and look for better supply terms.

Table 4.10 Final gas customer switching rates

CUSTOMERS BY SECTOR	2024		2025	
	CUSTOMERS	VOLUMES	CUSTOMERS	VOLUMES
Household	18.6%	24.1%	18.7%	25.3%
Condo households	24.1%	30.0%	24.4%	31.0%
Public service activities	35.8%	54.7%	30.3%	50.0%
Other uses	18.1%	22.4%	19.9%	16.8%
TOTAL	18.7%	23.5%	18.8%	19.4%

Source: ARERA. Annual survey of regulated sectors and the SII.

An equally large proportion, amounting to 24.4%, of domestic-use condominiums switched to a different supplier, corresponding to 31% of the consumption volume in that sector. These customers lost the right to access the regulated service in 2023, but their switching rate remained high.

A total of 30.3% of entities carrying out public service activities, representing 50% in volume terms, chose to switch to a new supplier. This is a high rate, although this is one of the "hybrid" categories encompassing very different types of customers: not only small municipal premises, whose consumption levels are similar to those of commercial establishments, but also large hospital complexes with very high annual consumption, which can therefore significantly increase the volumes involved in switching. Finally, "other uses" that changed their supplier accounted for 19.9% of the total in terms of customers, and 16.8% in terms of volumes (corresponding to about 7.6 G(m^3)).

Available offers and sales contracts in the free gas market

As already highlighted in Chapter 3 (see Section 3.2.2), this year the Annual Survey of the Energy Sectors once again asked electricity and natural gas suppliers a number of questions aimed at assessing the number of offers that companies make available to customers choosing to purchase energy on the free market and, above all, the distribution of their customers across the different types of contract they actually selected[314]. Here again, as already mentioned in Chapter 3, it is reiterated that the objective of the questions on the quantity and quality of commercial offers is to classify the numerous offers on the market, albeit not completely exhaustive of reality. The results presented in these pages should be treated with caution.

In 2025, natural gas suppliers offered household customers an **average** of 33.5 **retail offers**, of which 3.2 were available exclusively through online channels. For non-household customers, the average

[313] Vulnerable household customers are individuals falling into the following categories: persons aged over 75; recipients of the gas social bonus on the basis of their equivalent economic status indicator; persons with disabilities pursuant to Law No 104/1992; and users living in emergency accommodation following natural disasters.

[314] The data discussed in the section on contract types chosen by customers also take into account PLACET Offers (free-price offers under standardised contractual conditions).

number of available offers was 18.1, including 1.9 that could be purchased exclusively through digital channels. For apartment buildings with domestic use, the average number of available offers stood at 8.1, of which an average of 1.3 were available exclusively online. As observed in previous years, the natural gas free market displays marked differences between customer categories: the greater variety of offers available to households reflects the more intense commercial competition in this segment.

In the natural gas sector, the use of **digital channels** for entering into contracts appears to have become more widespread than in previous years, particularly among non-household customers. In 2025, contracts concluded online accounted for 13.5% of the total for household customers and 22.9% for non-household customers, both up from 2024, when the corresponding shares were 9.7% and 20.6%. The increase was particularly marked in the household segment, where the share of contracts concluded online rose by almost four percentage points in a single year.

As regards the preferred **pricing structure** (Table 4.11), variable-price contracts are clearly predominant across all market segments, confirming the trend observed in recent years. Among household customers, 67.9% of contracts are variable-price contracts, while the remaining 32.1% provide for a fixed price. There is also a significant difference between the two types in terms of price: the supply component for variable-price contracts stands at 75.0 c€/m³, around 8% lower than the 81.2 c€/m³ recorded for fixed-price contracts. The preference for indexed-price contracts is considerably more pronounced among condominiums for residential use, where 94.1% of customers have subscribed to variable-price offers. Here too, the average price of variable-price offers (61.1 c€/m³) is slightly lower than that of fixed-price offers (62.5 c€/m³). The share of variable-price contracts is also very high among non-household customers, accounting for 86.2% of the total. Unlike in the household segments, however, the average price of variable-price contracts (50.2 c€/m³) is broadly in line with that of fixed-price contracts (48.9 c€/m³).

Table 4.11 Contracts for the supply of natural gas in the free market in 2025 by price type and average price

CONTRACTS	HOUSEHOLDS		CONDOMINIUMS		NON-HOUSEHOLDS	
	SHARE	PRICE(A) c€/m³	SHARE	PRICE(A) c€/m³	SHARE	PRICE(A) c€/m³
Fixed-price contracts	32.1%	81.2	5.9%	62.5	13.8%	48.9
Variable-price contracts	67.9%	75.0	94.1%	61.1	86.2%	50.2
TOTAL CUSTOMERS	100%	76.9	100%	61.2	100%	50.1

(A) Supply cost component.

Source: ARERA, Annual Survey of Regulated Sectors.

Analysis of variable-price offers by **indexation method** confirms that the Virtual Trading Point (PSV) is the main benchmark for determining natural gas prices on the Italian free market. In 2025, contracts indexed to PSV prices accounted for by far the largest share across all customer segments: 74.8% of contracts entered into by household customers, 84.2% of those relating to condominiums for residential use and 75.4% of contracts entered into by non-household customers. The average prices associated with these offers were 76.7 c€/m³ for household customers, 61.7 c€/m³ for condominiums and 51.9 c€/m³ for non-household customers, very close to the respective overall average prices for variable-price contracts. A second category of some significance comprises offers providing a discount on components set by the Authority under the regulated services. These were chosen by 13.2% of household customers, 10.0% of condominiums and 9.6% of non-household customers. Offers indexed to TTF (Title Transfer Facility) prices remained relatively uncommon, accounting for 5.4% of household customers and around 7% of non-household customers, while their share among condominiums was below 2%. The average price of these offers was generally higher than that of

PSV-indexed contracts, particularly in the household segment, where it reached 77.5 c€/m³.

A total of 38.9% of household customers entered into a contract providing for a **rebate or discount** in the form of one or more free periods or a fixed amount in cash or volume. Such discounts may be one-off or permanent and may be conditional on a specific event (for example, a discount for contracts entered into by friends of the customer or for payment of bills by direct debit). More specifically, on average, discounts were applied to 63.4% of customers who chose a variable-price contract. Lower percentages were recorded for other customers: 16.6% of condominiums entered into a contract offering a discount, predominantly under variable-price arrangements, while among non-household customers, 17.8% had a contract providing for some form of discount, again predominantly under variable-price arrangements.

The Annual Survey also examined the inclusion of **additional services** in contracts and their extent, using the same methodology as in the previous year[315]. Just like in the electricity survey, the gas one also required suppliers to specify the combination of additional services included in the contracts selected by their customers. Consequently, customers with contracts including several additional services were redistributed pro rata across the individual services indicated by suppliers.

The prevalence of additional services in fixed-price gas supply contracts varies significantly by customer type, with marked differences between household customers, condominiums for residential use and non-household customers. Overall, additional services are more common among household customers, while condominiums and non-household customers tend to favour offers focused primarily on gas supply alone (Table 4.12).

For fixed-price contracts for household customers, the most common additional service is loyalty points programmes, included in 57.6% of contracts entered into by customers. The average price of these contracts (85.6 c€/m³) is higher than the average for fixed-price contracts (81.2 c€/m³).

hese are followed by offers with no additional services (22.7%), which have a below-average price (75.6 c€/m³), and offers including a 100% green energy guarantee (11.7%). The other categories of additional services remain relatively uncommon. Among condominiums for residential use, more than 65% of fixed-price contracts include no additional services. The only additional service with a significant take-up is additional energy services, chosen by 31% of customers, at a price broadly in line with the average, while all other additional services attract little interest. A similar picture emerges among non-household customers, where almost 80% of fixed-price contracts include no additional services. The most significant shares relate to loyalty points programmes (11.5%) and green offers (7.9%).

For variable-price contracts too, the share of contracts with no auxiliary services remains high, although there are significant differences between customer segments. It stands at 55.5% among household customers, 65.6% among condominiums and 95.3% among non-household customers, highlighting the extremely limited role of additional services in the business customer segment. For household customers, variable-price offers are mainly characterised by the inclusion of loyalty points programmes (20.2%) and 100% green energy guarantees (12.9%).

In the condominium segment for residential use, additional energy services continue to be the main category of complementary services, featuring in 31% of variable-price contracts, although at a price above the average. For non-household customers, by contrast, offers with additional services remain marginal: no individual category accounts for more than 2% of contracts entered into, confirming

[315] See the 2022 Annual Report for a detailed description of the methodology.

that the choices of these customers are primarily driven by the economic and contractual terms of supply.

Table 4.12 Natural gas supply contracts in the Italian free market in 2025 by type of additional services and average price (percentage of customers having signed the indicated contracts)

CONTRACTS	HOUSEHOLDS		CONDOMINIUMS		NON-HOUSEHOLDS	
	SHARE	PRICE(A) c€/m³	SHARE	PRICE(A) c€/m³	SHARE	PRICE(A) c€/m³
ADDITIONAL SERVICES OF FIXED-PRICE CONTRACTS						
No additional service	22.7%	75.6	65.6%	59.7	79.8%	48.0
100% green energy guarantee	11.7%	78.7	2.9%	63.7	7.9%	77.3
Auxiliary energy services	3.7%	71.8	31.0%	73.8	0.5%	59.3
Advantages over the purchase of other goods or services	3.0%	69.9	0.0%	62.7	0.1%	66.6
Other products or services offered together with gas	0.2%	78.3	0.1%	57.3	0.0%	77.0
Points collection programme	57.6%	85.6	0.1%	61.8	11.5%	87.2
Free gift or gadget	0.7%	107.8	0.1%	47.6	0.1%	105.6
Other not included in the aforementioned items	0.5%	80.7	0.2%	28.1	0.0%	80.0
TOTAL FIXED-PRICE CONTRACTS	100%	81.2	100%	62.49	100%	48.9
ADDITIONAL SERVICES OF VARIABLE-PRICE CONTRACTS						
No additional service	55.5%	75.0	65.6%	59.65	95.3%	50.1
100% green energy guarantee	12.9%	76.9	2.9%	63.66	1.6%	62.5
Auxiliary energy services	5.3%	75.5	31.0%	73.81	1.0%	52.1
Advantages over the purchase of other goods or services	0.0%	72.4	0.0%	62.71	0.0%	62.8
Other products or services offered together with gas	4.4%	74.5	0.1%	57.27	0.1%	70.8
Points collection programme	20.2%	70.3	0.1%	61.85	1.9%	59.5
Free gift or gadget	0.7%	94.4	0.1%	47.58	0.0%	48.5
Other not included in the aforementioned items	0.9%	59.4	0.2%	28.14	0.1%	44.4
TOTAL VARIABLE-PRICE CONTRACTS	100%	75.0	100%	61.14	100%	50.1

(A) Supply cost component.

Source: ARERA. Annual Survey of Regulated Sectors.

Concentration in the natural gas retail market

Analysing the sales performance of corporate groups rather than individual companies provides a more accurate assessment of market shares and the level of concentration in the final sales market (Table 4.13). However, the ranking changed little compared with 2024, except at the lower end.

Following a 9.7% increase in sales volumes, the Edison Group retained its leading position, with its market share rising from 15.5% to 16.8%. The Eni Group, which lost first place in 2023 but regained second place in 2024, consolidated that position in 2025. Supported by a 7.1% increase in sales, its market share also edged up, from 12.0% to 12.7%. The Enel Group remained in third place despite an 11.5% decline in sales, which reduced its market share from 11.1% in 2024 to 9.7%. A comparison of sales volumes with those recorded in 2024 shows increases for 11 of the 20 groups, while sales declined for nine, in some cases very significantly.

Table 4.13 Top twenty groups for natural gas sales to the end market in 2025

GROUP	VOLUME M(m^3)	SHARE	POSITION IN 2024
Edison	7,811	16.8%	1 °
Eni	5,927	12.7%	2 °
Enel	4,538	9.7%	3 °
A2A	2,747	5.9%	4 °
Hera	2,525	5.4%	5 °
Royal Dutch Shell	2,248	4.8%	6 °
Energeticky a Prumislovy Holding (Eph)	2,152	4.6%	8 °
Iren	2,074	4.5%	7 °
Sorgenia	1,776	3.8%	10 °
Axpo Group	1,101	2.4%	9 °
Engie	1,072	2.3%	11 °
Met Holding	820	1.8%	12 °
Agsm Aim	680	1.5%	14 °
E.On	624	1.3%	13 °
Unoenergy	537	1.2%	16 °
Duferco	519	1.1%	17 °
Estra	496	1.1%	15 °
Dolomiti Energia	443	1.0%	19 °
Solvay	420	0.9%	18 °
Burgo Group	335	0.7%	28 °
Others	7,703	16.5%	-
TOTAL	46,550	100.0%	-

Source: ARERA. Annual Survey of Regulated Sectors.

Given these contrasting trends among the largest groups, concentration in the retail gas market remained broadly unchanged compared with 2024, at least at the aggregate level across all customer segments. Table 4.14 highlights, precisely, the details of the concentration measures, also broken down by consumption sector. In the first part of the table, metering is calculated from the volumes sold by the corporate groups in the retail market; in the second part of the table, metering is calculated from the customers (redelivery points) served by the corporate groups themselves.

Based on sales volumes, the number of groups with a share of the overall market exceeding 5% returned to four. Moreover, in 2025, the top three groups control 44.8%, while in 2024 the share was 43.8%. The Herfindahl-Hirschman Index (HHI) for the retail market was 900, slightly higher than the 2024 figure of 858. However, the index remained below the threshold value of 1,000, below which market concentration is generally considered to be low. The highest level of concentration was observed in sales to industrial customers and electricity generators, where the C3 ratio exceeded 50%, while the lowest was recorded in sales to public service activities and the commercial and services sectors. Compared with 2024, both the C3 ratio and the HHI indicate slight increases in concentration in the apartment buildings, industrial and electricity generation segments, whereas concentration declined in all other segments, particularly in the commercial sector. When calculated based on the customers served, concentration increases in the household sectors and decreases in the non-household sectors.

Table 4.14 Concentration metering in the natural gas retail market

Metering calculated on corporate groups

	2024			2025		
SECTOR	GROUPS >5%	C3	HHI	GROUPS >5%	C3	HHI
METERING CALCULATED ON THE BASIS OF ENERGY SOLD BY CORPORATE GROUPS						
HOUSEHOLDS	4	45.4%	850	4	43.2%	786
Household	4	49.7%	1,000	4	47.7%	935
Condominiums	5	35.8%	664	5	36.8%	661
NON-HOUSEHOLDS	5	46.0%	985	5	48.5%	1,072
Trade and services	5	41.7%	761	5	31.9%	547
Industry	4	56.4%	1,368	4	59.3%	1,494
Power generation	8	52.0%	1,276	8	53.4%	1,306
Public service activities	7	34.9%	677	8	28.7%	582
TOTAL MARKET	5	43.8%	858	4	44.8%	900
METERING CALCULATED ON THE BASIS OF CUSTOMERS SERVED BY THE CORPORATE GROUPS						
HOUSEHOLDS	4	52.7%	1,151	4	50.5%	1,070
Household	4	52.9%	1,159	5	50.7%	1,080
Condominiums	6	37.5%	670	5	34.0%	548
NON-HOUSEHOLDS	4	35.5%	558	4	32.2%	487
Trade and services	4	35.9%	587	4	33.0%	520
Industry	5	34.2%	655	6	32.1%	594
Power generation	4	50.3%	1,034	6	41.1%	818
Public service activities	6	34.5%	649	8	26.8%	518
TOTAL MARKET	4	51.7%	1,104	4	49.5%	1,024

Source: ARERA. Annual Survey of Regulated Sectors.

In general, however, the level of concentration in the Italian natural gas market remains low: with few exceptions, the C3 does not exceed 55%, and most importantly, the values of the HHI index have dropped in all sectors below the first attention threshold of 1,500[316].

4.2.2.1 Monitoring of the level of retail market prices, of the level of transparency and of the degree and of the efficiency of market opening and competition

As already described in detail in Chapter 3 (see section 3.2.2.1, to which reference is made) on the subject of sales prices in the electricity and natural gas retail markets, the Authority has two readings:

- the survey of *Average prices charged in the electricity and natural gas market,* carried out pursuant to Resolution 168/2018/R/com of 29 March 2018, which collects, on a half-yearly basis, quarterly data on the prices billed[317] by suppliers to household and non-household customers, broken down by consumption class and type of market;
- that carried out as part of the *Annual Survey of Regulated Sectors*, in which data is collected for the previous year and broken down according to various categories of detail (type of market,

[316] An HHI value between 1,500 and 2,500 indicates a moderately concentrated market, while a value above 2,500 indicates a highly concentrated one (the maximum value of the index is 10,000).

[317] More specifically, these are average unit revenues calculated as the ratio of revenues collected to the quantities of energy billed in the reference quarter.

sector and consumption classes, type of contract applied).

The data from the *Annual Survey* are used for the statistical analyses carried out by the Authority, especially those presented in the annual reporting to national and European authorities.

Analysis of the data collected in the Authority's Survey for 2025 shows that the average gas price (weighted by volumes sold), excluding taxes, charged by suppliers to final customers was 71.9 c€/m³ (Table 4.15), 1% higher than in the previous year (71.2 c€/m³).

The increase, reflecting higher wholesale gas prices, affected almost all customer categories and, where observed, varied only slightly across consumption bands. The largest increase (+4.8%) was recorded for very large customers (annual consumption above 20 million m³), while the smallest increase (+1.4%) was recorded for customers in the intermediate consumption band of 0.2 - 2 million m³/year. By contrast, the smallest customers (with annual consumption of up to 5,000 m³, consisting mainly of household customers) recorded a slight decrease of 1.3% compared with the previous year.

Table 4.15 Average selling prices (net of taxes) in the gas retail market

ANNUAL CONSUMPTION CLASS	PRICES (c€/m³)										
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Less than 5,000 m³	55.7	51.7	52.1	58.3	63.4	58.1	65.9	103.1	100.2	111.2	109.7
Between 5,000 and 50,000 m³	46.0	42.1	43.1	48.4	50.7	43.7	55.0	117.9	88.5	84.0	87.1
Between 50,000 and 200,000 m³	41.0	37.0	36.2	43.7	44.7	37.3	48.8	113.6	85.0	73.5	75.9
Between 200,000 and 2,000,000 m³	32.5	28.3	26.8	31.4	33.8	27.3	38.5	101.4	71.3	59.0	59.8
Between 2,000,000 and 20,000,000 m³	28.0	24.2	23.0	26.5	28.2	21.9	35.1	93.9	65.3	50.8	51.7
More than 20,000,000 m³	26.5	21.8	24.3	29.2	22.4	16.9	52.8	130.4	56.1	46.0	48.5
TOTAL	38.9	33.8	34.3	40.0	39.2	33.9	52.3	111.2	76.0	71.2	71.9

Source: ARERA. Annual Survey of Regulated Sectors.

Table 4.16 Selling prices (net of taxes) in 2025 in the retail gas market by consumption sector and customer size

SECTOR	CUSTOMERS DISTRIBUTED BY ANNUAL CONSUMPTION CLASS (m³)						TOTAL (c€/m3)
	< 5,000	5.000-50.000	50.000-200.000	200.000-2,000,000	2.000.000-20,000,000	> 20,000,000	
Household	109.8	86.4	84.5	-	-	-	109.5
Condo households	100.3	92.3	86.0	76.2	-	-	91.4
Public service activities	111.7	84.4	76.1	67.3	57.3	-	77.7
Trade and services	109.8	85.0	75.2	61.6	56.9	52.4	79.3
Industry	106.4	82.2	71.7	58.4	50.6	46.8	53.3
Power generation	-	93.8	66.6	58.3	53.7	49.5	50.4
TOTAL	109.7	87.1	75.9	59.8	51.7	48.5	71.9

Source: ARERA. Annual Survey of Regulated Sectors.

Table 4.16 shows the breakdown of average prices in 2025 by size and customer type. Larger-scale production sectors, such as industry and electricity generation, record the lowest average price levels, while sectors with a higher concentration of small and medium-sized enterprises, such as services and trade, show higher values. These nevertheless remain below the price levels recorded for household customers, whether supplied individually or through centralised systems (condominiums). Table 4.17 shows the trend over the past decade in sales prices for household customers (households and, until 2023, condominiums) with annual consumption of up to 5,000 m³, distinguishing between

the two main contractual arrangements under which they were supplied: the regulated service (which, since 2024, has been reserved for vulnerable customers only) and the free market.

Table 4.17 Gas retail market selling prices for customers with domestic uses consuming up to 5,000 m³/year, by market type

Values excluding taxes, in c€/m³

CONSUMPTION CLASS ANNUAL AND MARKET	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015
Standard offer service(A)	52.8	47.7	48.2	55.8	60.4	51.0	62.3	115.7	82.6	90.5	93.5
Free market	61.5	58.4	56.8	60.4	65.9	62.7	67.9	95.3	105.6	114.9	112.4
Difference	16.5%	22.4%	17.8%	8.2%	9.1%	22.9%	9.0%	-17.6%	27.9%	27.0%	20.2%

(A) Until 2023, it included families and condominiums; from 2024, the protection service is reserved for vulnerable household customers only.

Source: ARERA. Annual Survey of Regulated Sectors.

The regulated service recorded lower prices in all years except 2022, when the free market recorded a lower price (-17.6%), owing to the widespread use of fixed-price contracts in that market, which initially limited the pass-through to final customers of the sharp increase in wholesale gas prices following the outbreak of the Russia-Ukraine conflict. This pass-through continued in both 2023 and 2024. In each of those years, prices in the free market increased by around 10 c€/m³, before easing slightly in the most recent year (-3 c€/m³). By contrast, prices under the protection service fell by as much as 33 c€/m³ in 2023, only partly offset by an increase of 11 c€/m³ over the following two years. As a result, the free market became markedly more expensive again in 2023. Over the past three years, prices in the free market have consistently exceeded those under the protection service by between 28% in 2023 and 20% in 2025.

Naturally, the price differences observed between the two markets may also be due to other factors. In particular, reference should be made to the section on the free market, which highlights the presence of commercial offers combining energy supply with the purchase of other goods or services (such as assistance, maintenance, insurance, telecommunications, supermarket discounts, or fuel discounts).

Monitoring of the level of transparency including compliance with transparency obligations and of the degree and of the efficiency of market opening and competition

The retail market monitoring system is common between the electricity and natural gas markets. Reference is therefore made to section 3.2.2.1, which presents the *Annual Report on retail market monitoring activities for 2024*, [318] describing, where possible, developments in the relevant phenomena over all the years in which monitoring has been carried out (since 2012), as well as the *Report on the monitoring of electricity supply conditions applied to non-vulnerable household customers*, [319]which the Authority is required by law to submit to the competent Parliamentary

[318] Report 486/2025/I/com of 11 November 2025 (2024 Report). All the content of the 2024 Report and previous reports, together with retail monitoring data and analyses, is available on the Retail Monitoring page of the Authority's website (https://www.arera.it/rapporti-e-relazioni/monitoraggio-retail).

[319] Report 143/2025/I/com.

Committees by 31 March each year, starting from 2025.

Complaints related to the commercial quality of the natural gas sales service and compensation

The rules for the protection of final customers and the commercial quality indicators that all electricity and natural gas sales companies are required to comply with, and which are monitored by the Authority, are set out in the Integrated Text Regulating the Quality of Electricity and Natural Gas Sales Services (TIQV) as described in section 3.2.2.1. Also in connection with the sale of natural gas, as in the electricity sector, if the supplier does not comply with specific standards, the customer automatically receives compensation, at the time of the first useful billing. The basic automatic compensation (Euro 25) doubles if the performance of the indemnified service takes place beyond twice the standard time and triples if the performance takes place beyond three times the standard time or more.

For 2025, 457 companies submitted data on the commercial quality of natural gas supply services, reporting that they served a total of 19 million customers (1.4 million non-household customers and 17.6 million household customers, 86% of the latter being in the free market).

Table 4.18 Sales service standards and actual average times in the natural gas sector in 2025

PERFORMANCE	SPECIFIC STANDARDS (calendar days)	ACTUAL AVERAGE TIMES
Maximum time for a reasoned response to written complaints	30	16
Maximum time for bill adjustments	60 or 90(B)	15
Maximum time for double bill adjustments	20	25
Minimum percentage of replies to written requests for information sent within the maximum time of 30 calendar days	–	7

(A) 90 calendar days in the case of four-monthly invoices.

Source: ARERA on data declared by operators.

Analysing the data on the actual average response times for customer requests in 2025, responses to written complaints and billing adjustments recorded average times below the set standards (16 and 15 calendar days, respectively), while double billing corrections were typically completed above the standards set by the Authority, similar to what occurred in the electricity sector. In particular, regarding rectifying double billing, the average actual response time is 25 calendar days, compared to the standard of 20 calendar days. By contrast, the actual average response time for requests for information, at 7 calendar days, was well below the general standard (Table 4.18).

Natural gas suppliers received a total of 178,695 **written complaints**, down 11.9% compared with the previous year (Table 4.19); the majority of written complaints (82.5%) were submitted by household customers in the free market. Written complaints relating to household customers served under the vulnerability protection service accounted for 6.5% of the total complaints. Multi-site gas customers accounted for 3.9% of complaints, while complaints from condominiums for domestic use and public service activities accounted for 0.9% and 0.1% of total complaints, respectively.

Table 4.19 Complaints, requests for information and bill adjustments in the gas sector

	2021	2022	2023	2024	2025
Number of complaints	172,004	156,407	167,675	202,784	178,695
Number of requests for information	121,054	133,063	142,153	127,311	437,829
Number of bill adjustments	16,487	11,400	12,498	7,775	12,547
Number of double bill adjustments	849	607	406	274	238

(A) Partial data referring to 64% of gas customers.

Source: ARERA processing of data from the Energy Customer Help Desk.

There were 12,547 written **billing adjustment** requests, a significant increase compared with the previous year (+61.4%); the number of adjustments requested by household customers in the free market was particularly significant (85.2% of the total). These were followed by adjustments requested by non-household customers connected at low pressure in the free market (4.8%), vulnerable household customers under the regulated service (4.7%) and multi-site customers (3.7%). Billing adjustments benefiting condominiums for domestic use accounted for 1.5% of the total, while customers using gas for public service activities accounted for only 0.04%.

As in previous years, in 2025 cases involving **double-billing adjustments** were extremely limited in number (238), particularly when compared with the millions of bills issued by suppliers each year; the overall figure was down 13.1% compared with 2024. Requests from household customers in the free market accounted for a significant share of total double-billing adjustments during the year (77.7%), followed by non-household customers connected at low pressure in the free market (9.7%) and multi-site customers (8.8%).

In 2025, there were a total of 9,961 cases of non-compliance with the standards established for commercial quality services in the gas sector that entitled customers to **compensation**, a significant decrease compared with the previous year (21,134 in 2024). As in the electricity sector, compensation in the gas sector was mainly attributable to failure to meet the standard response time for written complaints (94%) and, to a much lesser extent, the time limits for billing adjustments (5%) and double-billing adjustments. Overall, the market segment recording the highest number of compensation payments was household customers in the free market.

Amounts paid by way of automatic compensation totalled €420,650, almost half the amount recorded in the previous year (€922,000 in 2024); 93.5% of the amounts were paid for failure to comply with the response times for written complaints. In absolute terms, the market segment benefiting most from automatic compensation was household customers in the free market (+74.3%).

In 2025, 102 suppliers reported serving a total of 1.7 million customers with **dual-fuel** contracts (contracts for the joint supply of electricity and natural gas). These customers submitted 27,519 written complaints, down 9.3% compared with the previous year, and 53,041 written requests for information, up 68.3% compared with 2024. Bill and double-bill adjustments amounted to 1,496 (-3.4%) and 29 (-46.3%) respectively.

Overall, for customers with dual-fuel contracts, there were 1,818 cases of non-compliance with the standards for commercial quality services that entitled customers to automatic compensation through their bills (-47.1%). Some 91.4% of cases of non-compliance were attributable to failures to respond to customer complaints within the prescribed time limits, while 7.8% related to delays in billing adjustments.

Also with regard to the amounts paid to customers for automatic compensations, the prevalence of cases is related to failure to comply with response times to complaints (90.6%); to a lesser extent, bill

adjustments (8.5%) and double bill adjustments (0.9%). Overall, compensation amounting to Euro 78,900 was paid to the dual fuel customer segment.

4.2.2.2 Recommendations on final sales prices, investigations, inspections and imposition of measures to promote competition

Measures to promote competition and recommendations on final sales prices

The Authority's activities in analysis and recommendations on final sales prices are common to the electricity and gas sector and have already been described in detail in section 3.2.2.2 (to which reference is made).

Conducting investigations, inspections and imposing measures for the effective promotion of competition

With reference to the activities in 2025, see also section 3.2.2.2.

4.3 Security of supply

The functions and competences referred to this topic (i.e. monitoring the balance between energy demand and supply, forecasting future demand and available supply, additional capacity and measures to cover peak demand or supply shortfalls) are assigned exclusively to the Ministry of the Environment and Energy Security.

5 CUSTOMER PROTECTION AND DISPUTE RESOLUTION

5.1.1 The protection system: handling end-customer complaints (basic level)

The consumer protection system in the sectors regulated by the Authority is structured into two main areas: the first relates to providing customers with information and assistance (basic level), and the second to resolving issues and disputes between customers and service providers.

In 2025, in line with the trend already observed in 2024, there was a further overall decline in the volume of requests – both written and telephone – received by the Energy and Environment Consumer Help Desk of the Authority, managed on its behalf by *Acquirente Unico*, relating to the activation of various services for customers and users in regulated sectors (Table 5.1).

Table 5.1 Protection System: incoming volumes to the Help Desk and second-level activities(A)

ACTIVITY	2024		2025	
Basic level (information and assistance)	ENERGY SECTORS	ALL SECTORS	ENERGY SECTORS	ALL SECTORS
Calls to the call centre (received during working hours)	1,083,236	1,122,521	744,970	786,647
Written requests for information(B)	48,658	52,632	40,398	45,177
Requests for activation of special information procedures	51,423	51,423	42,044	42,044
Second level (dispute resolution)				
Requests for the activation of special settlement procedures	17,326	17,326	13,679	13,679
Requests to the Authority Conciliation Service (mandatory conciliation)	29,180	34,564	22,619	30,235
Conciliation requests to ADR entities on the Authority's List (mandatory conciliation)	1,956	2,300	702	1,066

(A) The Help Desk is also active for environmental sectors regulated by the Authority.
(B) Including written petitions that the Help Desk encountered by providing information on out-of-court dispute resolution tools (referred to as complaints redirected to conciliation).

Source: Energy and Environment Consumer Help Desk processing.

In fact, in 2025 the Consumer Help Desk **call center** received 786,647 calls during operating hours, a decrease of 30% compared with 2024. Just over 700,000 calls relating solely to the energy sectors were actually handled (i.e. excluding calls abandoned by final customers or users before an operator answered): in fact, 95% of requests concerned the electricity and gas sectors. The average duration of calls with the call centre was 214 seconds, 19 seconds less than the 233 seconds recorded in 2024, confirming the downward trend observed over the past two years.

In 2025, the top two topics in terms of callers' initial queries remained unchanged, although their ranking was reversed compared with 2024. The largest share of calls concerned "dispute resolution procedures" (39%, +13% compared with 2024), which also ranked first when considering calls relating solely to the energy sectors; 36% of calls concerned the "social bonus" (-6%), including 233,790 calls specifically relating to the social bonus for the electricity and gas sectors. Lastly, the percentages relating to "rights and regulation" and "gradual standard offer service and vulnerable customers" (energy sectors only) were essentially reversed compared with 2024: the former accounted for 14% of calls (7.5% in 2024), while the latter accounted for 7% (14% in 2024). Compared with 2024, the number of calls in 2025 concerning the phasing-out of price protection mechanisms in the energy sectors more than halved: approximately 69,000 calls were recorded in 2025, compared with around

158,000 in the previous year.

As regards **written requests for information**, the Helpdesk received 45,152 requests, of which 40,398 related to the energy sectors, down 17% compared with the previous year. Excluding complaints redirected to conciliation, which accounted for approximately 10% of the total, the main topics addressed remained broadly in line with the previous year. The social bonus remained the most prevalent topic, accounting for 32% of requests, up 8% compared with 2024; in almost all cases, requests concerned the mechanism for the automatic award of the benefit. Requests relating to the "market" (17%, +5%), "billing" (15%, +1%) and "contracts" (13%, +2%) also increased. For the latter, the main sub-topics concerned switching supplier (70%), estimated consumption (46%) and unilateral changes (42%). Among the other recurring topics, "market" and "billing" remained among the most frequent subjects of written requests for information, each accounting for 14%, down 3 and 1 percentage points respectively compared with 2024, while "non-payment of bills and disconnection" accounted for 11%, up 2 percentage points. Requests were also received concerning vulnerable customers in the energy sectors, accounting for 5% of the total, down 4.5 percentage points compared with 2024; these requests mainly concerned the statutory eligibility requirements for recognition as a vulnerable customer, in the context of the phasing-out of price protection mechanisms.

Special information procedures make it possible to provide information without the need for interaction with Helpdesk staff (the consumer completes an online request form). They have been operational since 1st January 2017, only for certain specific issues in the energy sectors, which are codified in centralised databases (Integrated Information System, Compensation System). For this reason, and due to regulation of the "automatically applied" case, the Desk provides the requested information to final customers or their delegates. In 2025, the Consumer Help Desk received 42,044 written requests requiring the initiation of a special information procedure, down 18% compared with 2024. Of these requests, 60.5% concerned the electricity sector, 31.5% the gas sector, and the remaining 8.0% both sectors. The most frequently used procedure concerned switching and the identification of the commercial counterparty, accounting for 42% of the total (-8% compared with 2024), followed by the C^{MOR} procedure at 39% (+12%) and the procedure relating to an unknown supplier for change of account holder at 19% (-4%). In 2025, as in the previous year, the special procedure relating to C^{MOR} recorded the largest increase, both in percentage terms (+20%) and in absolute terms (+2,804 requests).

5.1.2 The protection system: out-of-court dispute resolution (second level)

Activities relating to the second level of the protection system concern the resolution of issues and disputes arising in the relationship between the customer and the regulated service supplier. These issues may be resolved through the Consumer Help Desk's special settlement procedures or through conciliation procedures. The latter may be brought before the Authority Conciliation Service or ADR entities registered on the Authority's special list.

Special settlement procedures

Special resolution procedures are applied for specific types of problems in the energy sectors. Similarly to what happens for special information procedures (relative to the basic level of the protection system), also for settlement procedures, the Help Desk accesses information encoded in

centralised databases. In contrast to information procedures, special settlement procedures allow the outcome of the dispute to be determined and imply assistance of the Help Desk staff, in case further information is needed to consult databases, or to verify the correct fulfilment of the regulation following the resolution of the dispute. If the customer's request is considered well-founded, on the basis of the documents sent by the customer and the checks on the Integrated Information System, the Help Desk sends a notice to the operator concerned, requesting that the facilitation be paid in the invoice and informing the final customer. Only once the disbursement has been made within the regulatory time limits is the case submitted to the Help Desk closed. If, on the other hand, the application turns out to be unfounded, the Help Desk sends a communication to the final customer, providing the appropriate clarifications and explaining why the facilitation cannot be paid.

In 2025, a total of 13,679 applications resulted in the activation of special settlement procedures, down 21% compared with 2024. The social bonus procedure remained the most widely used, accounting for 80% of the total (-2% compared with 2024). In one case out of three, the issue concerned the payment of the social bonus itself. The special C^{MOR} procedure, which concerns verification of the conditions for the possible cancellation of the compensation amount, accounted for 19%, up 2 percentage points compared with 2024. The other procedures recorded negligible volumes (for example, those concerning double billing accounted for around 1% of the total).

As regards the average overall time taken by the Help Desk to process special settlement procedures, the figures for 2025 were unchanged from 2024, except for the bonus procedure, for which an increase of 3 working days was recorded (to a total of 20), and the procedure relating to compensation, which took 6 fewer days (10 compared with 16 in 2024). The average time taken to close C^{MOR} cases remained unchanged at 14 working days.

Overall, 59% of special settlement procedures concerned the electricity sector, whose share increased further from 49% in the previous year. In the remaining cases, the issues concerned both sectors or dual-fuel customers.

The household sector was involved in 94% of the special settlement procedures, and 85% of the requests were submitted by end customers without the assistance of delegates. The principal method for triggering these procedures was via email, used in 58% of cases.

The Authority's conciliation service

The Authority's conciliation service is a dispute resolution tool that can be activated by final customers of electricity and natural gas for issues arising with energy operators (suppliers and distributors), in case of missed or unsatisfactory response to a complaint. The procedure takes place entirely on-line and in the presence of a third-party, impartial mediator experienced in mediation. Any final agreement has settlement effect between the parties pursuant to art. 1965 of the Civil Code. Furthermore, with the adoption of Article 141(6)(c) of the Consumer Code[320], an attempt at conciliation became a prerequisite for bringing legal proceedings in disputes arising in the sectors regulated by the Authority (with the exception of tax-related matters), without prejudice to urgent and interim judicial rulings. The Authority, in implementation of article 141-*sexies* of the Consumer Code, has laid down specific information obligations for energy suppliers towards final customers.

[320] The legislative decree no. 130/15 implemented in the Italian legal system Directive 2013/11/EU of the European Parliament and Council of 21 May 2013, on *Alternative Dispute Resolution* (ADR) for consumers, which amends Regulation (EC) 2006/2004 and Directive 2009/22/EC (Directive on ADR for consumers).

In 2025, final customers and users in the energy sectors submitted 22,619 applications to the Conciliation Service, down 22.5% compared with the previous year. With a 40% share (12,027 applications), broadly in line with 2024, the electricity sector recorded the highest number of applications, followed by gas at 24% (-9%; 7,450 applications). Dual-fuel customers submitted 2,920 applications, accounting for 10% of the total (-1%), while 222 applications were submitted by prosumers – parties that are both producers and consumers of electricity – compared with 217 in 2024.

The main channels used to submit applications were representatives other than consumer associations (42%, corresponding to 12,794 applications, +4% compared with 2024) and direct submission by customers, i.e. without the assistance of a representative, which accounted for 34% of applications (+1%). These were followed by applications submitted through consumer associations registered with the National Council of Consumers and Service Users (CNCU) [321](24%, corresponding to 7,201 applications, down 5% compared with 2024).

As in 2024, 79% of the applications received by the Service concerned household customers, compared with 21% for non-household customers. Considering applications from household customers alone, the electricity sector accounted for the largest share, at 33%, unchanged from 2024, while gas stood at 28%, down 10%. This therefore represents a reversal of the ranking compared with 2024, when gas exceeded electricity by 5 percentage points. The electricity sector also accounted for the largest share of applications submitted by non-household customers, at 64% (-7% compared with 2024).

As regards the subject matter of disputes, billing remained the most common issue (45%, +1% compared with 2024), followed by contractual disputes at 14% (-10%) and claims for damages at 11% (+3%). More than half of the applications submitted by prosumers concerned economic net metering (25%, -11%) and "connections, works and technical quality" (27%, +10% compared with 2024).

In 2025, the admissibility rate for conciliation applications submitted to the Service stood at 80% (-2% compared with 2024); 14% of applications were not completed by the applicants (+4% compared with 2024), while 6% were deemed inadmissible (-2%). In such cases, applicants may resubmit their application once the grounds for inadmissibility have been remedied.

As in previous years, the participation rate in proceedings convened before the Conciliation Service remained very close to 100%, standing at 99.8% in 2025. This reflects the obligation imposed by the Authority on all operators and service providers in the energy, water and district heating sectors to participate in proceedings before the Conciliation Service.

As regards the outcome of applications submitted to the Service, the settlement rate for proceedings concluded in 2025 stood at 74% in the gas sector (+11% compared with the previous year) and 60% in the electricity sector (+1% compared with 2024). In particular, excluding pending proceedings, suppliers recorded a settlement rate of 73% for concluded proceedings (+7% compared with 2024), while the rate for distributors stood at 43% (+11%). It took the parties an average of 56 calendar days to reach agreement, 1 less than in 2024. For proceedings initiated in 2025 and concluded with

[321] The National Council of Consumers and Service Users (CNCU) is the representative body of consumer and user associations at national level. It is based at the Ministry of the Environment and Energy Security and is composed of consumer associations recognised according to the criteria set out in the Consumer Code (Legislative Decree 206/2005, art. 137) and a representative designated by the Unified Conference State - Cities and Local Autonomies (Legislative Decree 281/1997, Art. 8).

a settlement, the overall compensation value exceeded €24 million. This represents the total economic benefit (in the form of amounts recovered or refunds, compensation payments, recalculation of incorrect bills, waivers of charges and default interest, etc.) obtained by customers or users who entered into such settlements, including through a representative.

Based on 11,698 questionnaires completed at the close of proceedings, 96% of applicants expressed an overall positive assessment, with responses ranging from "very satisfied" (53%) to the intermediate level of "satisfied" (16%) and "fairly satisfied" (27%). The conciliator's performance was rated very positively by 65% of these applicants (-2 percentage points compared with 2024).

Other conciliation services

As an alternative to the Authority's Service, the final customer may make a mandatory attempt at conciliation for judicial purposes also with recourse to other parties. The Authority, in implementation of Article 141-decies of the Consumer Code, in December 2015 the Authority established [322]the List of bodies responsible for managing ADR (Alternative Dispute Resolution) procedures pursuant to Title II-bis of Part V of the Code.

At 31 March 2026, 25 ADR entities were registered in the Authority's List. Of these, eight are sector-specific joint conciliation bodies, based on specific memoranda of understanding between consumer associations and companies; one body operates in a single region; and the remaining 16 are cross-sector bodies that also operate in sectors other than those falling within the Authority's remit. Of the latter, 15 are mediation bodies and, as such, are also included in the Register of Mediation Bodies maintained by the Ministry of Justice[323]. One body, including the regional-level one, is responsible solely for the water sector, while the remaining bodies are all competent in the electricity and gas sectors.

Based on the information submitted by ADR bodies, 2025 saw a significant reduction in the total number of applications received compared with the previous year (-53%). Specifically, out of a total of 1,066 applications (2,300 in 2024), 702 concerned disputes arising in the electricity and gas sectors and involving dual-fuel customers (compared with 1,956 in 2024), while 364 concerned the water sector (343 in 2024). No applications concerned the district heating sector (one in 2024).

Across all sectors, 72% of applications submitted (82% in 2024) were handled by joint conciliation ADR bodies. In the energy sectors, billing was confirmed as the predominant subject of disputes (50%, +25 percentage points compared with 2024). Considering the other subjects with shares equal to or above 5%, contracts accounted for 17%, followed, with smaller shares, by market issues (9%), metering (9%), arrears and disconnection (7%) and damages (5%).

The proportion of applications deemed admissible remained high: of the 1,066 applications received by the bodies included in the List, the admissibility rate was 87% in 2024 (90% in 2024, out of 2,300 applications received). The parties reached a settlement in 70% of concluded procedures, compared with 64% in 2024.

Finally, as regards the average time taken to conclude procedures, in 2025, as in previous years, there is a difference depending on whether the procedure was concluded with or without an agreement

[322] Resolutions of 17 December 2015, 620/2015/E/com and of 14 July 2020, 267/2020/E/com.

[323] Legislative Decree no. 28 of 4 March 2010 and Ministerial Decree no. 180 of 18 October 2010.

between the parties. On average, the procedures were concluded in about 64 days in the case of an agreement (57 days in 2024), while, in the case of no agreement, they were closed in 59 days (compared to 58 days in 2024). In all cases examined, the deadlines set by the Consumer Code (90 days potentially able to be extended for a maximum of a further 90 days) were complied with.

5.1.3 Consumer protection: vulnerable household customers and energy poverty

Initiatives in favour of customers in economic hardship and serious health conditions: social bonuses

The electricity and gas social bonuses are social policy measures introduced to reduce energy bills for households experiencing financial hardship. Energy expenditure places a proportionately greater burden on lower-income household budgets, owing to the essential nature of energy services and the limited scope for reducing consumption, other than through energy-efficiency measures, which nevertheless require upfront investment in more efficient appliances. In Italy, through Article 1(375) of Law No 266/2005, the subsequent Interministerial Decree of 28 December 2007 and Decree-Law No 185/2008, the legislator introduced social bonuses to reduce electricity and gas bills for households experiencing financial hardship and, as regards electricity costs only, for persons using specific life-saving electromedical equipment. In particular, the Interministerial Decree of 28 December 2007 and, subsequently, Decree-Law No 185/2008 identified the Equivalent Economic Status Indicator (ISEE) [324]as the means of identifying households experiencing financial hardship and eligible for the bonuses.

Since 2009, a protection mechanism has therefore been in place for electricity and natural gas supplies to household customers experiencing financial hardship or serious health conditions, who receive a bonus in the form of a discount on their electricity and/or natural gas supply.

At first, access to the benefit was made available upon request. This created a significant gap between the potential beneficiaries and the actual recipients of the benefit. In order to bridge this gap, Decree-Law No 124 [325]of 26 October 2019 established that, from 1 January 2021, bonuses would be granted automatically to eligible households, without requiring them to submit a specific application to municipalities and/or tax assistance centres. In February 2021, the implementing arrangements for the automatic granting of electricity, gas and water social bonuses to eligible households experiencing financial hardship were approved[326], entirely replacing the previous application-based system. he electricity social bonus for physical hardship, however, falls outside the scope of the automatic system and continues to be granted upon application by the person concerned.

In 2022, the automatic mechanism was further refined and the pool of beneficiaries was expanded for the period from 1 April to 31 December 2022 by raising the ISEE eligibility threshold for the electricity and gas social bonuses from €8,265 to €12,000. In 2023, in addition to the ordinary bonus,

[324] The Equivalent Economic Status Indicator (ISEE): this is the tool used to measure the economic condition of households in Italy. It is an indicator that takes into account income, assets and the characteristics of a household (in terms of size and type).

[325] Converted with amendments by Law no. 157 of 19 December 2019.

[326] By Resolution of 23 February 2021, 63/2021/R/com.

supplementary compensatory components continued to be provided, funded from the State Budget, in order to contain increases in expenditure resulting from the international price crisis. The legislative amendments provided, on the one hand, for supplementary compensatory components and, on the other, further expanded the pool of beneficiaries by raising the ISEE eligibility threshold for the compensation to €15,000 from 1 January 2023, albeit with different levels of support depending on the ISEE value, and to €30,000 from 1 April 2023 for large families. From 1 January 2024, the eligibility threshold for the bonus returned to the ordinary level, set at €9,530 and at €20,000 for households with at least four dependent children.

Pursuant to Article 1(3) of the Ministerial Decree of 29 December 2016, this threshold was updated in January 2026, in accordance with the prescribed three-year cycle, on the basis of the average value of the national consumer price index used for each relevant three-year period. Accordingly, from 1 January 2026, the eligibility threshold for social bonuses was updated to €9,796[327].

For 2025, the social bonuses for financial hardship were therefore granted to households with an ISEE of up to €9,530, or up to and including €20,000 for households with at least four dependent children. In addition to the ordinary social bonus, Article 1(1) of Decree-Law No 19 of 28 February 2025 provided, for 2025 only, for an extraordinary contribution of €200 towards the electricity bills of household customers with an ISEE of up to €25,000, as a temporary financial support measure (Table 5.2).

Table 5.2 – ISEE thresholds for access to benefits in 2025

TYPE OF CONCESSION	ISEE THRESHOLD (EUROS)	ISEE THRESHOLD (EUROS) FOR LARGE FAMILIES
Electricity and gas bonus	9,530	20,000
Extraordinary contribution (electricity)	25,000	25,000

Source: ARERA.

In order to give prompt and immediate effect to the above legislative provision, in March 2025 the Authority [328]defined the implementing arrangements for granting the extraordinary contribution to household customers already receiving the electricity social bonus. In particular, it provided that the extraordinary contribution was to be paid together with the bonus for the period from 1 April to 31 July 2025. Shortly thereafter, the Authority [329]defined the operational arrangements for granting the extraordinary benefit introduced by the Government, to be applied to electricity bills for 2025, to beneficiaries with an ISEE above €9,530 and up to and including €25,000. In compliance with Regulation (EU) 2016/679 (GDPR) and national data protection legislation, the same measure also provided for the transfer from the National Social Security Institute (INPS) to *Acquirente Unico* of data relating to the household customers concerned, in order to enable the Integrated Information System (SII) Operator to:

- identify, from June 2025, customers holding electricity supply contracts who were entitled to the extraordinary contribution;
- activate the contribution; and enable electricity suppliers to credit the extraordinary contribution

[327] By Resolution of 20 January 2026, no. 2/2026/R/com.

[328] By Resolution of 27 March 2025, 132/2025/R/eel.

[329] By Resolution of 1 April 2025, 144/2025/R/eel.

on the bills of eligible households, in accordance with the same arrangements as those applicable to the electricity social bonus.

Bonuses in figures

The automatic mechanism for granting social bonuses to eligible households, together with the government measures introduced in response to the international price crisis, both increased the amount of the bonuses and expanded the pool of beneficiaries by raising the ISEE thresholds for access to the support. In 2024, by contrast, in the absence of government measures raising the ISEE eligibility threshold, the overall number of beneficiaries of social bonuses for financial hardship decreased compared with 2023 (Table 5.3).

Table 5.3 – Customers receiving electricity and gas social bonuses for financial hardship

YEAR AND SCHEME	ELECTRICITY BONUS		GAS BONUS	TOTAL BONUSES PAID OUT
	FINANCIAL HARDSHIP	PURCHASE CARD HOLDERS	FINANCIAL HARDSHIP	
Application-based access scheme for eligible households				
2020	805,303	8,551	543,963	1,357,817
Automatic granting scheme				
2021	2,487,599	(A)	1,537,884	4,025,483
2022(B)	3,766,105	(A)	2,441,158	6,207,263
2023(C)	4,576,621	(A)	3,005,197	7,581,818
2024	2,801,668	(A)	1,711,068	4,512,736
2025	2,674,030	(A)	1,605,377	4,279,407
Change 2025/2024	-4.6%	(A)	-6.2%	-5.2%

(A) Recipients of the electricity social bonus for financial hardship include *Carta acquisti* (Purchase Card) holders (Law No 190 of 4 December 2008), who have been eligible for the benefit since the relevant provisions were first introduced. These beneficiaries are now included in the new automatic granting scheme for social bonuses for financial hardship.
(B) In 2022, the total bonuses related to benefit classes a), b), c) and d).
(C) In 2023, the total bonuses related to benefit classes a), b), c), d) and b-bis), the latter remaining temporarily in force until 31 December 2023.

Source: Integrated Water Service.

In 2025, the number of beneficiaries falling within the ordinary eligibility thresholds for the social bonus (ISEE of up to €9,530 for households with up to four members and €20,000 for large families) also decreased slightly (-4.6%) compared with the previous year (Table 5.3). Overall, around 2.7 million **electricity social bonuses** were granted during the year, in addition to the 3.4 million households that received the exceptional €200 contribution. More than 1.6 million **gas social bonuses** were also granted, with the number of beneficiaries again declining slightly compared with the previous year (-6.2%).

The estimated amount of the benefits granted (comprising both the ordinary bonus and the extraordinary contribution for 2025) and paid to recipients of social bonuses for financial hardship was approximately €840 million for electricity and approximately €165 million for gas.

As regards the **electricity social bonus**, 2,674,030 bonuses related to classes a) and b), corresponding to households with an ISEE of up to €9,530 and households with an ISEE of up to €20,000 in the case of families with four or more children. Households with up to two members

accounted for 51% of beneficiaries, those with three or four members for 36.3%, and those with more than four members for 12.7%. As regards the extraordinary contribution, 3,417,660 households in classes X, Y and Z [330]received the benefit during the year. The amount paid in respect of the extraordinary contribution granted to these households was €683.5 million.

Beneficiaries of the electricity social bonus are spread regionally as follows: North-West 19.2%, North-East 10.8%, Centre 15.6%, South 35.7%, and Islands 18.7%.

As regards the **gas social bonus**, 1,605,377 bonuses related to households in classes a) and b), namely households with an ISEE of up to €9,530 and households with an ISEE of up to €20,000 and four or more children. Households with up to four members accounted for 86.2% of beneficiaries, while those with more than four members accounted for 13.8%. The number of gas social bonus recipients also decreased compared with the previous year (-6.2%), as indicated above. As with electricity social bonus recipients, this result may be due to the unavailability of definitive outturn data.

Gas social bonus beneficiaries were geographically distributed as follows: 26.7% in the North-West, 15.1% in the North-East, 19.5% in Central Italy, and 31.3% in Southern Italy and 7.5% in the Islands.

In order to cover the burden resulting from the application of the gas bonus, the Authority has established, within the mandatory tariff for natural gas distribution and metering services, the GS and GS_T components, charged respectively to households and non-households. In addition to the funds collected from customers, there are also funds from the state budget. As in the electricity sector, the amounts of the bonuses were defined quarterly, at the same time as the tariff update.

As mentioned above, alongside the social bonus designed to alleviate financial hardship among households in Italy, a further bonus is available to support households that use life-sustaining electrical equipment: the **social bonus for physical hardship**. This bonus is divided into three bands to take account of the type of equipment used, the average hourly consumption of each type of equipment and the average number of hours of daily use. On the basis of these elements, certified by the Local Health Authority, the customer is placed into one of three tiers: consumption up to 600 kWh/year, between 600 and 1,200 kWh/year, or above 1,200 kWh/year. The three bands are further differentiated according to the contracted power level, which may be up to 3 kW, 3.5 kW, 4 kW or 4.5 kW[331].

For 2025, the Authority [332]also determined and updated the amounts of the bonus to be granted to customers experiencing physical hardship. The amount granted was set at a level corresponding to the energy costs associated with the additional consumption arising from the use of life-sustaining equipment, differentiated according to the contracted power level and the consumption band associated with the type of equipment used. The amount of the social bonus for physical hardship, as determined by the Authority, ranges from a minimum of €167.90 to a maximum of €543.85 per year per beneficiary. The charges related to the disbursement of the electricity bonus for economic and physical hardship are included amongst the general charges pertaining to the electricity system and are covered by the A_{SRIM} element of component A_{RIM}, which final customers pay in the bill and

[330] Class x) comprises households with fewer than four children and an ordinary or current ISEE above €9,530 and up to €15,000; class y) comprises households with fewer than four children and an ordinary or current ISEE above €15,000 and up to €25,000; and class z) comprises households with four or more dependent children and an ordinary or current ISEE above €20,000 and up to €25,000.

[331] For details on the operation of bonuses, see also the 2013 *Annual Report*.

[332] Resolution of 27 December 2024, 599/2024/R/com

which is applied to all customers who do not benefit from the electricity bonus.

In 2025, 86,010 families benefited from the bonus for the use of electrical devices for life support, marking a 11.4% increase compared to the previous year. In 2025, 64.8% of the bonuses distributed belong to the minimum tier (up to 600 kWh/year), showing a slight increase compared to 2024 (+0.2%); bonuses for the middle tier (consumption between 600 and 1,200 kWh/year) account for 21.3% (compared to 21.4% in 2024), while those for the maximum tier (over 1,200 kWh/year) make up 13.9%, also slightly decreased from 2024 (when they were 14%).

5.1.4 Guarantees for the effective protection of gas consumers: compliance with art. 41(1)(o) of Directive 2009/73/EC

Article 41(1)(o) of Directive 2009/73/EC requires the regulator, also in cooperation with other authorities, to ensure that consumer protection measures, including those in Annex 1, are effective and enforced.

In Italy, these measures are now fully and extensively applied.

Over time, a number of bodies of legislation have been consolidated, bringing together in an organic way all the provisions on a number of relevant subject areas, in particular:

- the Code of Business Conduct[333];
- the Integrated Sales Service Quality Text (TIQV)[334];
- the Integrated Billing Text (TIF)[335];
- The Integrated Text on electricity, gas and water bonuses for financial hardship[336];
- the Integrated Text on Confirmation of the Electricity and/or Natural Gas Supply Contract and Voluntary Restoration Procedure (TIRV)[337];
- the Integrated Conciliation Text (TICO)[338]

5.1.5 Tools available to final customers

Information initiatives to overcome price protections

Since 2017, the Authority has required [339]electricity suppliers under the standard offer service and gas suppliers under the regulated gas service, from 1 January 2018 until the end of regulated price

[333] Resolution 366/2018/R/com.

[334] Resolution 413/2016/R/com.

[335] Resolution 463/2016/R/com.

[336] Resolution 63/2021/R/com.

[337] Resolution 228/2017/R/com.

[338] Resolution 209/2016/R/com

[339] Resolution 746/2017/R/com, as amended by Resolution 197/2019/R/com.

protection (as provided for by the relevant legislation), to include in their customers' bills a specific notice, with content determined by the Authority, concerning the end of regulated price protection.

For 2025, the Authority determined the content of the following notices:

- from 1 January 2023, both free-market suppliers and suppliers providing regulated electricity and natural gas services are required to include information in each bill to raise customers' awareness of their consumption and consumption habits;
- from 1 July 2025, following the introduction of the new regulation on the*"La bolletta dei clienti finali di energia"* ("Energy bill for final customers")[340], information on how to find free-market offers best suited to customers' needs;
- from 1 January 2025, following the introduction of the Gradual Standard Offer Service for non-vulnerable household electricity customers, information for household customers with a free-market electricity contract on the rights of vulnerable customers and the conditions available to them;
- for the natural gas sector, from September 2024, as part of the provisions governing the phase-out of the regulated gas service and the establishment of supply conditions for vulnerable customers, information on the rights of vulnerable customers and the conditions available to them.

Strengthening of the Code of Business Conduct

The Code of Business Conduct for the sale of electricity and natural gas to final customers lays down, in accordance with the provisions of the Consumer Code [341]and the EU energy directives, the rules of conduct that electricity and/or natural gas suppliers (including persons acting on their behalf in any capacity) must comply with in their commercial dealings with final customers (household customers and small non-household customers).

In 2024, with effect from 1 January 2025, the Authority approved [342]measures to update and streamline the pre-contractual and contractual rules laid down in the Code of Business Conduct for the benefit of electricity and natural gas final customers.

- the implementation of the amendments to the Consumer Code introduced by Legislative Decree No. 26 of 7 March 2023 and Law No. 214 of 30 December 2023 (the so-called Competition Law 2022);
- the obligations of suppliers in the event of changes to contractual terms;
- the provisions on telemarketing and telesales, as well as the consequent harmonisation of the rules regarding changes to the contractual terms of PLACET offers and the vulnerability protection service.

In particular, for contracts concluded off-premises or at a distance, suppliers are required to provide household customers, where available, with information on electronic means of communication that allow written messages to be exchanged on a durable medium and that record the date and time of the communication. The period for exercising the right of withdrawal was also extended from 14 to

[340] Resolution of 23 July 2024, 315/2024/R/com

[341] Legislative Decree no. 206 of 6 September 2005.

[342] Resolution 395/2024/R/com

30 days for contracts concluded in the context of unsolicited visits by a supplier to a household customer's home or excursions organised by a supplier for commercial purposes. Furthermore, in the case of contracts concluded by telephone, for consent to enter into the contract to be valid, the customer must confirm that they have received the written document containing all the contractual terms and conditions, provided on paper or on another available and accessible durable medium.

The requirements applicable to changes in contractual terms and conditions were also strengthened, providing, inter alia, that:

- communications must be provided on a durable medium previously accepted by the customer and, in the case of unilateral changes and renewals, their content must comply with the specific regulatory requirements and be kept separate from communications of a different nature, such as commercial communications;
- where communications are sent electronically, the heading of communications concerning contractual changes and renewals must match the subject line, where applicable, of the message used to transmit them;
- unilateral changes and renewals must be communicated with at least three months' notice, reduced to one month only where the unilateral change consists exclusively of a reduction in the charges specified in the contract and determined by the supplier;
- where only the notice periods for communications concerning unilateral changes, automatic changes and renewals are not complied with, the supplier must pay the final customer automatic compensation of €30; where the required communication methods and/or notice periods are not complied with, the unilateral change or renewal does not take effect, except where it is more favourable to the final customer;
- suppliers must also include, in communications concerning changes to contractual terms and conditions, information on the payment of the aforementioned automatic compensation where the applicable notice periods are not complied with.

Decree-Law No 19 of 28 February 2025 also tasked the Authority [343]with defining appropriate measures to achieve the objective, for the benefit of small final customers, of enhancing the transparency and comparability of electricity and natural gas offers on the free market by reducing and simplifying the components of the charges applicable under supply contracts, as well as establishing simplified arrangements for communicating changes to contractual terms and conditions that ensure maximum accessibility of the relevant information.

As a matter of urgency, the Authority adopted a number of initial transitional measures with effect from 1 July 2025. In particular, it:

- amended the way in which charges and related information are presented in the section of supply contracts setting out the economic terms offered;
- required suppliers, for all electricity and natural gas offers aimed at household customers, to divide the section setting out the economic terms offered into separate subsections, clearly distinguishing all charges relating to the cost of electricity and/or natural gas supply from information concerning charges for use of the electricity and/or natural gas network and general system charges;
- required suppliers to publish on their websites, on the relevant offer page and for each current offer aimed at household final customers, the offer code and the related contractual

[343] Which implemented the Decree Law through the Resolutions of 8 April 2025, 156/2025/R/com and 5 August 2025, 386/2025/R/com.

documentation, including at least the section setting out the economic terms as described above and the relevant Summary Sheet. This information must be given appropriate prominence relative to other information provided and be clearly and easily accessible to users.

Furthermore, with effect from 1 April 2026, the Authority provided for:

- the streamlining of charges under electricity and natural gas offers aimed at household customers;
- the introduction of disclosure requirements concerning the drafting of supply contracts, the pre-contractual stage and communications regarding changes to contractual terms and conditions, together with the consequent amendment of the Code of Business Conduct;
- the introduction of provisions concerning suppliers' websites.

In particular, the Authority standardised the pricing structure of free-market electricity and natural gas offers aimed at household customers, providing for a reduction in the number of charges determined by suppliers. Suppliers remain free to set the amount of these charges, in accordance with EU legislation, which expressly grants them the right to determine their supply prices freely. For all offers aimed at household customers, suppliers may set only two charges to cover the cost of electricity and natural gas supply: a single annual fixed charge, expressed in €/year, and a single consumption-based charge, expressed in €/kWh or €/S(m^3). Both charges may be differentiated according to the final customer's consumption characteristics (for example, by time band) or other customer characteristics (for example, registered residence status). These charges are supplemented by network-use tariffs and general system charges, as updated by the Authority, and, for electricity offers only, by a charge covering dispatching costs, which is also set and periodically updated by the Authority.

With specific reference to the cost of supply[344], for offers aimed at household final customers, supplier-defined annual fixed and consumption-based charges (including charges applicable after the initial validity period of the economic terms, where already specified in the contract) must be presented in a standardised table. This enables final customers to locate them easily in the contractual documentation and use them to compare different offers. In addition, for offers aimed at household customers, the Summary Sheet must include the table of supplier-defined charges, replacing the summary price indicators.

Lastly, the Authority introduced a requirement for suppliers to publish on their websites all current offers available on the *Portale Offerte*.

Energy bills for final customers

At the end of 2023, the Authority launched [345]a comprehensive review of *Bill 2.0*, aimed at making bills simpler, easier to understand and more consistent. Given the importance of the review and the need to ensure the broadest possible stakeholder participation, the procedure was made subject to an analysis of the regulation's impact (AIR).

[344] Resolution 386/2025/R/com

[345] Resolution of 7 November 2023, 516/2023/R/com.

The new rules approved by the Authority in 2024[346] introduced a bill structure comprising the following two documents, applicable from 1 July 2025 to electricity customers supplied at low voltage and to natural gas customers comprising households, condominiums for household use, public service activities and other uses with annual consumption of up to 200,000 S(m^3):

- Summary Bill, containing:
  - the *Standardised Front Page*, i.e. a standard first page of the bill for all final customers, containing a limited set of key information specified by the Authority, including final customer identification details, billing and payment information, the total amount payable, telephone contact details for the electricity fault service or gas emergency service, and a dedicated information section for the supplier;
  - the *Energy Receipt*, i.e. a simple and readily understandable format replacing the existing classification of expenditure items "by purpose", which presents the amounts billed according to a quantity-times-price (or "average price") approach;
  - the *Offer Box*, containing information designed to clearly explain the characteristics and application of the offer subscribed to;
  - the *Essential Information*, with information organised into consistently named and readily identifiable boxes;
- the so-called *Detailed Information*, unchanged from the previous Bill 2.0 rules.

In January 2025, the Authority made a number of additions to the new rules[347], adopting the measures without prior consultation given the need to allow the operators concerned sufficient time to adapt their billing systems by the date on which the new rules were due to become operational (1 July 2025). The additions concerned, in particular:

- additional services, information on which may be shown after the bill total;
- the Offer Box, with the addition of two further lines to provide a more detailed breakdown of how the amount payable under the subscribed offer is calculated;
- documents intended for so-called multi-site customers, with a view to making the documentation easier to understand.

For the latter, in February 2025, further specific provisions [348]were introduced, allowing non-household and multi-site final customers, upon explicit request, to receive a Summary Bill that does not include the Energy Statement for all withdrawal and/or redelivery points.

In addition, in March 2025 the Authority launched a consultation [349]on the model Glossary for energy bills for final customers, setting out the terminology and main items used in the Summary Bill and the Detailed Information document. The Glossary was subsequently [350]approved in May.

The new rules have therefore been in force since 1 July 2025 for low-voltage electricity customers and for gas customers (households, condominiums for household use, public service activities and other uses) with annual consumption of up to 200,000 Sm^3, as well as for customers supplied with

[346] Resolution of 23 July 2024, 315/2024/R/com

[347] By Resolution of 21 January 2025, 12/2025/R/com.

[348] By Resolution of 25 February 2025, 64/2025/R/com.

[349] Consultation document of 25 March 2025, 118/2025/R/com.

[350] By Resolution of 13 May 2025, 204/2025/R/com.

gases other than natural gas, although simplified arrangements apply to the latter. The scope of application was also extended to gas services of last resort (from 2025-2026) and to supplies to public administrations.

5.1.6 Access to consumption data

A first guarantee for customers of access to consumption data is provided by the billing regulation. As outlined earlier, the bill should contain details of the annual consumption and its allocation according to hourly bands. Further elements can be found in the detailed bill, which suppliers must make available through the Internet. Customers can also access the data by submitting a complaint or request to their supplier, who in turn will request them from the distributor.

On the other hand, given the widespread use of smart meters, particularly in the electricity sector, the final customer has at his disposal, via an electronic display, the current consumption data in terms of both energy and power consumption, as well as the consumption values broken down into peak/off-peak/mid-level hours used for the last bill.

In December 2017, the Authority established [351]that consumption data, comprising historical billing data and historical data on time-based consumption profiles, should be made accessible through the Integrated Information System (SII), which already holds this information pursuant to Law No 27 of 24 March 2012.

Furthermore, the Authority considered it appropriate that the digital provision of data should take place through a web portal, set up by Acquirente Unico (as SII Operator) and accessible to the final customer with authentication through the Public Digital Identity System (SPID). Following the consultation, the 2018 Budget Law [352]introduced provisions specifying the timeframes and deadlines for completion of the process.

In June 2019, the Authority therefore established [353] the arrangements whereby, from 1 July 2019, final customers can access their consumption data through the dedicated ***Portale dei consumi*** (Consumption Portal)[354]. The *Portale Consumi* is continuously evolving, with the aim of both monitoring and improving its performance and implementing its specifications.

In 2024, in order to implement the 2022 Competition Law (Article 2(3))[355], the Authority defined the general requirements and technical principles enabling final customers to make their metering data securely available to authorised third parties, as provided for by the 2022 Competition Law. In doing so, the Authority took into account the existing operating model of the aforementioned *Portale Consumi*, as well as Opinion No 695/24 of the Italian Data Protection Authority, as required by law.

In order to ensure the highest level of customer protection, provision was made for a gradual

[351] Consultation document of 14 December 2017, 865/2017/R/efr.

[352] Law No 205 of 27 December 2017, containing the "State Budget for the 2018 financial year and multi-year budget for the three-year period 2018–2020".

[353] Resolution of 25 June 2019, 270/2019/R/com.

[354] https://www.consumienergia.it/portaleConsumi/.

[355] Resolution of 26 November 2024, 509/2024/R/com

expansion of the range of entities that customers may authorise. For the first phase of implementation, these comprise electricity or natural gas suppliers, energy service companies certified under UNI 11352, entities or configurations governed by the Integrated Regulation of Distributed Self-Consumption (TIAD) or the Integrated Electricity Dispatching Integrated Text (TIDE), consumer associations represented on the CNCU (National Council of Consumers and Service Users), and business associations belonging to the social partners represented on the CNEL (National Council for the Economy and Labour). For further details on the functionality and content of the *Portale Consumi* and on subsequent features already available in both the private and public areas, reference should also be made to previous Annual Reports. More generally, the model adopted by the Authority provides that final customers must be fully aware of the process involved in selecting the third party to which they decide to make their data available and that such data may be made available solely for the two purposes provided for under EU and national legislation: comparing comparable offers and providing energy-related services. The third-party access model was implemented and has been fully operational since October 2025.

5.1.7 Availability of price comparison tools

Electricity and gas "Portale Offerte"

In February 2018, the Authority adopted [356]the Regulation governing the development and operation, by *Acquirente Unico*, the operator of the Integrated Information System, of a website on which suppliers can publish offers aimed at household customers and small electricity and natural gas businesses, known as the ***Portale Offerte***[357]. It contains fixed and variable offers of the free market, PLACET offers, as well as the expenditure of protection outlines for both electricity and natural gas. In greater detail, offers relating to the supply of electricity are aimed at households and non-households supplied at low voltage; offers relating to the supply of gas to are aimed at households, condominiums with household use and non-households with gas consumption not exceeding 200,000 S(m^3)/year.

The design and implementation of the *Portale Offerte* are aimed at guaranteeing ease of consultation by the end user; for this reason, a usability and ease-of-consultation analysis of the Portale is carried out on a quarterly basis, evaluating its use both via desktop PCs and mobile devices.

Since its start-up on 1 July 2018, the Portale has been the subject of monitoring, as well as consolidation actions and new functionalities.

In 2025, several important measures were introduced to steer non-vulnerable end customers towards the free market, following the withdrawal of safeguarded services. In particular, the following features were developed: access via SPID/CIE, which makes it possible to identify the supplies registered to the individual/legal entity that has authenticated and to make the relevant data available for consultation and for estimating annual expenditure. In particular, the use of historical, and therefore actual, consumption data enables annual expenditure to be estimated on the basis of the customer's actual consumption level, reflecting their consumption habits; calculation of annual expenditure

[356] Resolution of 1 February 2018, 51/2018/R/com, as amended by Resolution of 5 March 2019, 85/2019/R/com.

[357] https://www.ilportaleofferte.it/portaleOfferte/.

under the Gradual Standard Offer Service for non-vulnerable household customers; a new section of the *Portale Offerte* enabling final customers, by authenticating via SPID/CIE or entering the offer code, to view the characteristics and terms and conditions of their offer, even if it is no longer available. Lastly, with a view to making the website easier for final customers to use, the content of the video tutorials available on the *Portale Offerte* website was expanded and enhanced.

Access monitoring data show that the website recorded a total of 1,552,757 unique visitors in 2025. On average, approximately 129,400 unique visitors accessed the Portal each month, with a peak of more than 184,000 users in January.

At 31 December 2025, the Portal database contained 19,355 available offers, comprising 15,861 free-market offers, 2,324 PLACET offers and 1,170 offers for which estimated annual expenditure cannot be calculated due to their specific features and innovative pricing structures. Overall, 10,027 electricity offers and 5,771 natural gas offers are available for which estimated annual expenditure can be calculated, together with 63 dual-fuel offers.

PLACET offers

Increasing final customers' understanding of commercial offers is a prerequisite for their active participation in the market. The Authority has, therefore, promoted interventions aimed at increasing final customers' awareness and the transparency of contractual conditions, in order to allow their widest participation in a competitive market. Against this background, in July 2017 the Authority introduced [358]the rules governing Free-Price Offers under Uniform Contractual Conditions (PLACET offers), which establish offer structures that can be easily compared across suppliers, as they differ only in terms of price, and can be clearly distinguished from any additional services offered by the same supplier. The regulation of PLACET offers applies to small customers served in the free market, identified, for the electricity sector, with all customers (households and non-households) connected to the low-voltage network and, for the natural gas sector, with final customers (household, condominiums for household and other uses) owning points with annual consumption of less than 200,000 S(m^3).

As at 31 December 2025, there were 2,324 PLACET offers in the *Portale Offerte* (Table 5.4).

Table 5.4 Number of PLACET offers present in the *Portale Offerte* as at 31 December 2025, broken down by type of final customer

SECTOR	FIXED PRICE	VARIABLE PRICE	TOTAL
Household customer	234	266	500
Non-household customer	231	251	482
TOTAL ELECTRICITY SECTOR	-	-	982
Household customer	222	314	536
Non-household customer	210	238	448
Condo households with consumption of less than 200,000 m^3	151	207	358
TOTAL GAS SECTOR	-	-	1,342
TOTAL PLACET OFFERS	-	-	2,324

Source: ARERA. Processing of data from Acquirente Unico.

[358] Resolution of 27 July 2017, 555/2017/R/com.