Autorità di Regolazione per Energia Reti e Ambiente

Report 306/2020/I

ANNUAL REPORT TO THE INTERNATIONAL AGENCY FOR THE COOPERATION OF ENERGY REGULATORS AND THE EUROPEAN COMMISSION ON THE REGULATORY ACTIVITIES AND FULFILMENT OF DUTIES OF THE ITALIAN REGULATORY AUTHORITY FOR ENERGY, NETWORKS AND ENVIRONMENT

31 July 2020

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1 FOREWORD

This document was written by the Italian Regulatory Authority for Energy, Networks and Environment, and contains a report on the accomplished activities and fulfilment of the regulating duties pursuant to articles 59.1.i) and 41.1.e) of the 2019/944/EU and 162 directives respectively, to be submitted to the Agency for Cooperation between Energy Regulators (ACER) and the European Commission yearly.

The consolidated structure of the report was submitted to the ACER and the DG Energy of the European Commission, so that the Italian situation illustrated in this document can be easily compared with the similar reports of the other Member States.

The main elements of structural evolution of the two Italian markets, electricity and natural gas, are analysed below, concerning their regulated activities and competition state. The report also includes the description of the recent legislation and regulatory evolution of the activities carried out on the energy market, both in matters of consumer protection and security of supplies, the latter within the competence of the national regulator.

The evolution of the European context requires a progressive adjustment of regulation, both with regard to the regulation of public infrastructure and the functioning of markets and instruments designed to encourage investment and ensure the efficient functioning of the system. This adjustment is part of an evolving European regulatory framework that changes the regulator's duties, particularly on cross-border issues, while at the same time redefining the scope of regulatory leverage available at national level.

The regulator's choices must therefore increasingly take into account the technical and economic impact on the future system, also taking into account the speed with which technological innovation changes the cost dynamics of investments.

The regulator's action takes place in a pro-competitive and rapidly changing environment of digital and communication technologies and requires close coordination with the European institutions and other independent authorities, in particular the competition and market authorities.

Milan, 4 August 2020

THE CHAIRMAN

Stefano Besseghini

2 MAIN DEVELOPMENTS IN THE ELECTRICITY AND NATURAL GAS MARKETS

2.1.1 Evaluation of market development and regulation

Main changes in Italian legislation

During 2019, various regulatory interventions concerned the sectors regulated by the Regulatory Authority for Energy Networks and Environment (hereinafter the Authority); the most important are Law no. 117 of 4 October 2019, Law no. 160 of 27 December 2019 and Decree Law no. 162 of 30 December 2019.

Law No. 117 of October 4, 2019, setting forth the *Delegation to the Government for the Transposition of European Directives and the Implementation of Other Acts of the European Union - European Delegation Law 2018*, contains, among the provisions of particular importance to the Authority, provisions for the implementation of European directives that constitute the so-called Package of measures on the circular economy, provisions for the adaptation of national legislation to the European regulation on measures for the security of gas supply and provisions for the implementation of the new common European standards for the natural gas internal market .

In particular, Article 24 of Law no. 117/2019 delegated responsibility to the Government to adopt one or more legislative decrees for the purpose of adapting national legislation to Regulation (EU) 1938/2017 of the European Parliament and Council of 25 October 2017, concerning measures to safeguard the security of gas supply and repealing Regulation (EU) 994/2010. This Regulation identifies mechanisms and instruments to ensure the security of gas supply within the European Union by ensuring the proper and continuous functioning of the natural gas internal market, including to deal with any shortage caused by disruptions in supply or exceptionally high demand, and thus to ensure continuity of supply in the countries of the Union. The adaptation of national legislation must refer to: firstly, to the implementation of the solidarity mechanisms provided for, including the assignment of specific tasks to the transmission system operators and gas operators concerned; secondly, to the identification of guiding criteria in terms of economic compensation between Member States and stakeholders, for activities related to the implementation of the mechanisms themselves, also in coordination with the Authority for the aspects managed by it; finally, to the competence to intervene to ensure security of supply measures also in emerging and isolated areas.

Article 25 of Law no. 117/2019, which identifies the guiding principles and criteria for the implementation of Directive 2019/692/EU, amending Directive 2009/73/EC concerning common rules for the natural gas internal market, has defined the derogations (provided for in art. 14 and Art. 49bis of the amended directive) with regard to transmission pipelines between a Member State and a third country completed before 23 May 2019, for sections of transmission pipelines located on national territory and in Italian waters.

The provisions subject to derogation concern:

- the separation of transmission systems and transmission system operators;
- the designation and certification of transmission system operators;
- certification in relation to third countries;
- third party access;

- methodologies set by regulatory authorities for: (i) connection and access to national networks, including transmission and distribution tariffs and the terms, conditions and tariffs for access to LNG facilities; (ii) the provision of balancing services; (iii) access to cross-border infrastructures, including capacity allocation and congestion management procedures;
- incentives, both short and long term, to improve efficiency, promote market integration and security of supply and support related research activities, to be offered by regulators to transmission and distribution system operators;
- changes - which the regulatory authorities shall be entitled to request from transmission, storage, LNG and distribution system operators, if necessary - in terms and conditions, including tariffs and calculation methodologies, so that they are proportionate and applied in a non-discriminatory manner.

Finally, Annex A to this law provides for the transposition of Directive 2018/2002/EU of the European Parliament and of the Council of 11 December 2018 amending Directive 2012/27/EU on energy efficiency without specifying specific guiding principles and criteria.

Article 1, paragraphs 291 to 295 of **Law no. 160 of 27 December 2019**, concerning the "State Budget for the 2020 financial year and multi-annual budget for the three-year period 2020-2022" (Budget Law 2020), established provisions on incorrect billing for the supply of electricity, gas and water and for the provision of telephone, television and internet services. In detail, paragraph 291 provides that public utility service operators and telephony, television network and electronic communications operators must send users the communications with which they contest, in a clear and detailed manner, any non-payment of bills and announce the suspension of supplies in case of failure to settle, with adequate notice, not less than 40 days, by registered letter with acknowledgement of receipt. Paragraph 292 established that, from the date of entry into force of the law, in electricity, gas and water supply contracts, if payable bills are issued that the competent authority ascertains - or duly documented by means of a special declaration, submitted independently also by telematic means - the illegality of the operator's conduct, for violations relating to the methods of recording consumption, making adjustments or billing, as well as for charges of unjustified expenses and consumption costs, unnecessary services or goods, the user has the right to receive, in addition to the reimbursement of any sums paid, the payment of a penalty equal to 10% of the amount contested and not due and, in any case, an amount not less than 100 euros. Paragraph 293 provides that the operator concerned shall reimburse the amounts unduly received or in any case unjustifiably charged and pay the penalty by crediting them in subsequent bills or by making an appropriate payment, at the user's choice, within a period in any case not exceeding 15 days from the ascertainment or positive response to the declaration independently submitted by the user.

The provisions of paragraphs 85 to 100 on the *Green New Deal* are also highlighted. In particular, paragraph 85 establishes a Fund in the Ministry of Economy and Finance's statement of estimates, a part of which (not less than 150 million per year) is earmarked for interventions aimed at reducing greenhouse gas emissions, developing renewable energies, encouraging the environmentally safe capture and geological storage of CO_2, encouraging the transition to low emission forms of public transport, financing research and development of energy efficiency and clean technologies. The Fund is made up of proceeds from the auctioning of CO_2 emission allowances from the portion pertaining to the Ministry of the Environment and Protection of Land and Sea, for an annual amount of 150 million euros.

Finally, paragraph 295 repealed the rule[1], which provided that the provisions for consumer protection in the field of billing adjustment for the supply of electricity, gas and water services would not apply if the failure to collect or erroneous collection of consumption data were proven to be the user's fault.

Finally, **Decree Law no. 162 of 30 December 2019** was adopted on 31 December 2019, later converted, with amendments, by Law no. 8 of 28 February 2020, setting forth *Urgent provisions on the extension of legislative deadlines, the organisation of public administrations and technological innovation*. This decree decided (art. 12, paragraph 3) to postpone the termination of the standard offer regimes in favour of electricity and gas customers until 1 January 2022. In addition, it has regulated, in detail, the requirements for registration on the List of entities authorised to sell electricity to end customers[2]. After consultation with the Authority, by decree of the Minister of Economic Development, to be adopted within ninety days from the date of entry into force of the provision, the criteria, methods and technical, financial and honourability requirements for registration and continued inclusion in the aforementioned List are established. These requirements must ensure the long-term reliability of the registered party and enable effective action to be taken against possible conduct that may conflict with the general principles, legal and regulatory, which oversee the smooth running of markets and consumer protection.

Developments in the electricity market

Main changes to regulation

Following a complex consultation process, in December 2019 the ***Integrated text of the output-based regulation of electricity distribution and metering services*** **was approved for the period 2020-2023.** The main changes adopted in relation to the continuity of the electricity distribution service are:

- the optional "special regulation" of the number of interruptions, featuring additional bonuses and penalties with respect to the ordinary regulation, for areas still far from the target level, with a postponement of the target year for the achievement of the target levels depending on the distance from the target level and the critical structural issues present in the interconnection between the distribution network and the NTG or in the distribution network;
- the "regulation for experiments" to encourage the improvement of service continuity, in areas identified by the companies, through technological innovation; in this regard, distributors may be authorized to derogate, under certain conditions, from the Authority's regulation, with particular reference to the paths for improving the duration and number of interruptions;
- for companies with more than ten territorial areas, the reduction of premiums against "repeated" penalties incurred by the same territorial area.

Following an extensive consultation process, in December 2019 the Authority also approved the **provisions concerning the regulation of tariffs and the quality of electricity transmission, distribution and metering services for the years 2020-2023**, as well as the provisions concerning the economic conditions for connection, which came into force on 1 January 2020. The Authority has continued to apply the regulatory criteria adopted in 2015, confirming the dual tariff regime based

[1] Established by paragraph 5 of Article 1 of Law no. 205 of 27 December 2017.

[2] Amending paragraphs 81 and 82 of article 1 of Law no. 124 of 4 August 2017 (the so-called Competition Law).

on the size of the companies subject to regulation. In particular, an individual tariff regime has also been confirmed for the Transmission System Operator and for distribution companies serving at least 25,000 withdrawal points, based on rate of return mechanisms for capital costs and price cap mechanisms for operating costs, while a parametric tariff regime is foreseen for the remaining distribution companies. The update concerned, in particular, the revision of the criteria for determining the recognised cost, with reference to setting the initial operating cost levels for the year 2020 and subsequent updates for companies under individual tariff regimes, and some issues to refine the current regulation.

With specific reference to the transmission service, the procedures for recognising costs relating to activities connected with the integration of electricity markets at European level and the implementation of European network codes - including participation in ENTSO-E (European Network of Transmission System Operators for Electricity) - as well as other similar costs have been streamlined, generally providing for a price cap for the costs of activities related to EU subjects that can be made more efficient, and therefore "compressible", essentially linked to personnel costs, and for the recognition outside the price cap mechanism of costs of a "non compressible" nature, such as, for example, fixed costs for participation in transnational associations or projects.

The annual reduction rate of the recognised unit costs has been set at:

- 0.4% for the transmission service;
- 1.3% for the distribution service (including the service marketing costs);
- 0.7% for the metering service;

As regards the connection service, the deadline for the conclusion of the procedure for the overall streamlining of the rules on connection for active and passive points and for the revision of the cost allocation criteria, launched in November 2017, has been extended until the end of 2021, in order to take account of any regulatory changes that might also be necessary for the transposition of European Directives 2018/2001/EU and 2019/944/EU.

Once the tariff criteria were defined, the Authority also approved the tariffs for the provision of electricity transmission services for the year 2020 on the basis of the economic and balance sheet data communicated by the Transmission System Operator, for the purpose of updating the reference revenues to cover the costs of transmission and dispatching activities. As of 2020, moreover, the scope of the transmission tariff also provides for coverage of costs linked to Terna's participation in the Inter-TSO Compensation mechanism, previously covered by the dispatching service fees, so as to align national regulation with the provisions of Regulation (EU) no. 943/2019.

At the end of 2018, the Authority ordered a second postponement of the completion of the **reform of tariff fees to cover general system charges for domestic customers**, which began on 1 January 2017, due to the extension of the effects of the extraordinary measures implemented in the second half of 2018; as a result of this postponement, the two-tier tariff structure already in force in 2018 was maintained until 31 December 2019. In December 2019, the Authority found that there were no further impediments to the completion of the reform and therefore a single rate for all levels of consumption, in relation to all elements of the A_{SOS} and A_{RIM} tariff components, would apply from 1 January 2020. In support of this last step, there was also a legal provision[3] that introduced the automatic application of the electricity bonus (i.e. without the need for a request) from 1 January

[3] Decree-Law No.124 of 26 October 2019, converted into Law No.157 of 19 December 2019.

2021, which the Authority has suggested several times. Consistent with these protection purposes, the Authority also updated the amount of **compensation for the cost of electricity supply to economically disadvantaged customers (electricity bonus)**, taking into account the different effects that the completion of the reform has on each consumer profile (small, medium and large households): the criterion set by the Ministry of Economic Development, according to which the bonus must be determined in such a way as to result in a reduction in expenditure, before tax, of about 30%, has been applied to each profile.

As already illustrated in previous *Annual Reports*, with the implementation of the new network tariff structure, **measures have been taken to make it easier for domestic end customers to choose the level of committed power** that best meets their needs (introduction of contractually committed power levels with greater granularity, i.e. choosing between incremental levels of 0.5 kW, see also below) and reduction for 24 months of the costs associated with each contract change from 1 April 2017). At the end of 2018 the validity of these subsidies was extended until 31 December 2019 in order to promote greater use by customers. However, as also suggested in the consultations held in 2019 with a view to updating the tariff criteria applicable in the 2020-2023 regulatory period, the Authority has arranged for a further extension until 31 December 2023.

The Authority's guidance on updating the **guidelines for the recognition of investments in second-generation (2G) smart metering systems** was expressed in the March 2019 consultation, following which, in July 2019, the guidelines for the recognition of the costs of 2G smart metering systems for the metering of low voltage electricity were updated. The Authority's proposals stemmed from the need to avoid the risk of a two-speed country, i.e. maintaining, even for the second generation of smart metering systems, the same time lag (about 5 years) between different operators that had characterised the first generation; in fact, this would have meant that part of the users would have benefited from 2G smart metering systems with a considerable delay compared to the users served by the new systems in the initial phase. With this in mind, the deadline by which the start of the commissioning plans for 2G smart metering systems must take place, valid for all electricity distribution companies with more than 100,000 customers, has been set at 2022 at the latest; the massive step of replacing the existing meters must be completed by 2026 for 95% of the meters (the same percentage used for the first generation). A target of 90% of replacements by 2025 has also been set.

Finally, in October 2019, the Authority concluded the procedure started in 2017 to define version 2.1 of the 2G smart meters. In light of the positive results of the monitoring carried out, the Authority closed the procedure without changing the functional requirements of the 2G smart meters previously set, but inviting the operators to carry out, during the technical standardisation, a feasibility check of innovative solutions (so-called smart terminal cover) to accommodate the new opportunities of electronic communication technologies, with particular reference to the licensed band communication protocol (so-called *Narrow-Band Internet of Things* - NB-IoT).

The **regulation of the dispatching service is currently undergoing a comprehensive reform**, which must be defined in accordance with European regulations (Capacity Allocation and Congestion Management - CACM, Electricity Balancing Guideline - EB GL, new electricity regulation and new electricity directive). As part of this process, in July 2019 a complete and organic representation of the expected developments was placed under consultation, with two objectives:

- the identification of the main lines of action for the evolution of the dispatching service in the new context of rapid and continuous change, also with a view to achieving European targets by 2030, due to the spread of non-programmable renewable sources and distributed generation, as well as the gradual disappearance of programmable plants that have historically made resources available to ensure the balance between electricity supply and demand;

- the completion of the integration of Italian markets with those of other European countries, taking into account the EU regulatory framework, with particular reference to the coupling of intraday markets, characterised by continuous trading (possibly integrated with auction mechanisms) and the shifting of the gate closure to the hour before the hour to which the negotiation refers, as well as the harmonisation and sharing of services necessary to ensure the security of the system (ancillary services).

The Authority has therefore proposed separating commercial negotiations from the physical programming of the licensed and unlicensed units, considering this intervention appropriate in order to preserve the security of the electricity system as it allows maximum freedom of market participation.

In relation to the valorisation of imbalances, the consultation reaffirmed the intention to value them as consistently as possible with the dimensions of time, space and product type that characterise the value of energy in real time (also using nodal prices, with due graduality). In addition, initial guidance has been given on the evolution of the role of distributors in a context where distributed generation plants are no longer negligible and therefore require a more active management of distribution networks.

In July 2019, the Authority expressed its opinion to the Minister of Economic Development on the proposals for amendments to the Integrated Text on Electricity Market Regulation and Natural Gas Market Regulation, formulated by the Energy Markets Operator (GME) regarding the **integrated management of guarantees in the spot markets for electricity and natural gas**. The proposals were drawn up by the GME with the aim of introducing a single guarantee to cover the individual operator's net exposure to these markets in the day-ahead market, the intraday electricity market and the spot gas market. In October 2019, therefore, the Authority approved the proposals to amend the regulations of the Forward Energy Accounts Platform (PCE) and the related Technical Operating Provisions (TDF) formulated by the GME in order to adapt their content to the innovations introduced in the electricity and natural gas markets with regard to the integrated management of guarantees.

During 2019, the Authority was involved in the **implementation of the market codes at both pan-European and regional level**.

With regard to the regulation on Forward Capacity Allocation (which describes the requirements and criteria for the issuance and allocation of long-term transmission rights (with a time horizon of up to one year) between market areas within the European Union), the Authority has approved[4] the methodology for the allocation of congestion rents emerging from the allocation of transmission rights and participated in the regional round tables aimed at defining how the available capacity on each border between market areas is calculated for the long term (annual and monthly) and how this capacity is allocated to products with annual and monthly allocation.

With regard to the CACM GL regulation (which defines the procedures for the implementation of market coupling at European level on daily and intraday time horizons), it should be noted that Italy's entry into Single Intra Day Coupling is expected for the fourth quarter of 2020. The CACM GL regulation also provides for the development of regional methodologies. In this respect, 2019 was a particularly successful year for the Italy North CCR, as the methodologies for countertrading and redispatching and for calculating capacity on daily and intraday horizons were approved: these are

[4] Resolution 25 June 2019, 274/2019/r/eel.

significant steps towards full integration of the national market in the European context. At the regional level, the Authority also continued the process of implementing the intraday market on the Italian borders: in May 2019, the design of the complementary intraday auctions (Greece-Italy and Italy North), which will accompany the intraday coupling based on continuous trading, was definitively approved.

During 2019, the Authority was involved, together with all European regulators, in a challenging decision-making process concerning a package of six methodologies for the implementation of the BAL GL Regulation (which sets out how to implement the European balancing market), developed and sent by European TSOs at the end of 2018. These methodologies constitute the main structure of the future European balancing market and provide the implementation specifications of common energy trading platforms, pricing rules and settlement between TSOs. The main decisions made by European regulators regarding BAL GL and the Authority's related measures are illustrated below.

The Authority **assessed the consistency between the Ten Year National Transmission Grid Development Plan and the EU Ten Year Network Development Plan** (TYNDP) in its contributions to ACER's opinion no. 11-2019 on the draft TYNDP 2018 and to ACER's opinion no. 13-2019 on electricity projects in National Development Plans and TYNDP 2018. Monitoring shows that a significant percentage (about one third) of projects, both at Italian level and more generally at European level, are lagging behind, mainly due to authorisation problems.

Wholesale and retail markets

According to provisional data released by Terna, in 2019, **electricity demand** (301.4 TWh) decreased by 1% (compared to +0.5% in 2018), mainly due to the drop in consumption in the agricultural and industrial sectors (-2% each), partially offset by domestic consumption (+1%). The decline affected the agricultural and industrial sectors (-2%), while domestic consumption grew by 1% and tertiary sector consumption remained virtually unchanged. About 88% of national demand for electricity was met by domestic production (up from 2018) and the remainder by the foreign balance.

Gross **domestic production** reached 291.7 TWh from 289.7 TWh in 2018. The weak recovery (+0.7%) follows a decline of around 2% in 2018, which had interrupted growth at rates above 2% in the previous two years. The increase occurred both in thermoelectric production, up from 173.6 to 175.1 TWh (+0.9%), and in production from renewable sources, up from 114.4 to 114.8 TWh (+0.4%). In 2019, as in the previous year, 40% of gross electricity was generated from renewable sources, while 60% was generated by thermoelectric power plants; among these, natural gas accounted for almost half (49%) of total gross generation, an increase compared with the previous year (44%). In fact, thermoelectric production has returned to the levels of 2015, after the collapse of 2018, with the gradual replacement of coal and oil products with gas. The share of gross generation of the top three corporate groups (Enel, Eni and Edison), C3, was slightly down (33.7% compared with 35.7% in 2018), while those of A2A and EPH, which are respectively the fourth and fifth largest groups in Italian electricity generation, increased slightly. Enel group's share was 17% (19.4% in 2018), still declining. For the first time Enel is no longer the top operator in thermoelectric generation, as Eni's production was higher, despite a lower installed power. **The amount of electricity incentivised** remains unchanged at 63 TWh, for a system cost also stable at 11 billion euros, out of total general charges of about 15 billion euros.

Consistent with the reduction in demand, the **foreign balance** also fell by 13.1% to 38.2 TWh. As a result, the share of domestic demand covered by the foreign balance has returned to 11.9%, the same level as in 2016 and 2017. The sharp reduction in imports (44 TWh) was accompanied by a marked increase in exports (5.8 TWh; +78%). Maintenance campaigns and, consequently, the difficulties of French nuclear plants in meeting foreign demand, are at the root of both the phenomena outlined above for Italy, namely the reduction in our imports and the increase in our exports.

The quantity of **electricity traded by Sistema Italia** was 295.8 TWh (+0.1 compared to 2018). Against an overall stable demand (+0.2%), volumes offered also remained close to 2018 levels (-0.8%), with slight reductions in all areas except the Centre-South where there was a significant increase (+12.8%). The increase in volumes traded directly on the stock exchange (213.3 TWh, +0.2%) is down, although it remains slightly positive, and accounts for 72% of total day-ahead market trading. Programmes deriving from registration of bilateral over-the-counter trade on the PCE remain stable (82.6 TWh, -0.1%). The **average electricity purchase price (PUN)** in 2019 was €52.32/MWh, down from last year (-14.7%), albeit in line with the price trend of the main European power exchanges. This decrease reflects the lower cost of gas raw material (16.28 €/MWh; -34%) partly offset by the significant increase in CO2 emissions permit prices (+56%). The European market is also seeing a drop in electricity prices, which is essentially distributed in two macro-regions: a northern region, made up of France, the Scandinavian countries and Germany, with prices in the region of €39/MWh and a Mediterranean band, with Italy, Spain and Slovenia with prices between €48 and €52/MWh. In particular, coupling mechanisms have allowed the substantial alignment of prices in the two macro-regions.

On the **forward market**, for standardised products with physical delivery, a total of 1.6 TWh was traded in 2019, up on 2018 (+38%). Total volumes traded on the **intraday market** in 2019 (26.4 TWh) were up compared with the previous year (+1 TWh, +4%).

The results of the Annual Survey (provisional) show that in 2019 **256 TWh were sold in the retail market to just under 37 million customers**, of which 29.5 million domestic and 7.2 million non-domestic. Compared to 2018, total electricity consumption remained substantially stable with a slight downward trend (-0.1%), while consumers increased by 0.4%. The contraction in consumption occurred in the non-domestic sector (-0.3%), while household consumption substantially held up (+0.6%); conversely, the increase in customers was higher in the non-domestic sector than in the domestic sector. As has been the case for a long time now, the standard offer service has lost further ground to the free market. Furthermore, in 2019 the **safeguarded service** also shrunk further. 80.1% of domestic customers are resident with an average consumption of 2,184 kWh. An analysis of the distribution data shows that the electricity consumption of Italian households is rather low: 54.5% of domestic customers are in the annual consumption class of less than 1,800 kWh and withdraw a quarter of all electricity distributed to domestic customers, while the remaining 46.5% (with average consumption exceeding >1,800 kWh) withdraw 73.8% of the total. Households consume around 22% of all distributed energy.

Household **switching** increased in 2019 compared to 2018 (14.3% compared to 9.1% in 2018 in terms of delivery points and 16.9% compared to 10.2% in 2018 in terms of volumes). Looking at the final sales market data, 49.4% of domestic customers are in the free market (up from 46.6% in 2018). The difference in average consumption between households in the free market, which averages 2,063 kWh/year, and in the standard offer market, 1,869 kWh/year, is narrowing, a sign that while previously the domestic customers with higher consumption switched, the process is now spreading to other households.

On the supply side, **the number of suppliers on the retail market** (which reached the significant number of 723 operators thanks to an increase of 88 in the free market, of which only 36 are active) grew sharply again in 2019, confirming a growing trend that has continued unabated since liberalisation in 2007. Regardless of the electricity consumption trend, every year there is an increase in the number of companies with sales of less than 1 TWh, but whose overall market share has been at a standstill at around 15% for years.

The average number of **commercial offers** that sales companies can make to their potential customers was 16.3 for domestic customers and 23.4 for non-domestic customers. Of the 16.3 offers made available to domestic customers on average, 5.1 can only be purchased online, but their success remains very limited: only 4.4% of domestic customers (corresponding to 4.2% of electricity purchased in the free market) have signed a contract offered through this method (the percentage is still up on 2018). With regard to the preferred type of price, 84.7% of domestic customers signed a fixed price contract in the free market, while only 15.3% chose a variable price contract. There are different types of indexing modes for variable price contracts: 37% signed a contract that provides a fixed discount on one of the components established by the Authority for the standard offer regime; 58% of the customers chose a contract that provides the indexing to the PUN and 6% of the customers have chosen one indexed with Brent. Approximately 37% of domestic customers signed a contract with a rebate or discount. Finally, out of the domestic customers who chose a fixed price contract, concerning the presence of additional services in subscribed contracts, one can find a clear preference, among other things an increase, for the guarantee to purchase electricity produced by renewable sources (44% of customers), and for the participation to a points programme, through their electric power contract, that can be from the sales operator as well as from other parties (e.g. points that can be used for payments in a supermarket): 38.2% of the customers chose a contract that offers this additional service. 12.4% of customers, however, preferred a contact without additional services. On the other hand, more than half of the customers who signed a variable price contract chose one without additional services. Even among these customers, however, there is a high interest in the guarantee of purchasing electricity produced from renewable sources (28% of cases). The second preference goes to the possibility of obtaining accessory energy services alongside electricity (10.5%).

In 2019 the level of **concentration in the retail market** decreased, whether measured by the amount of energy sold by corporate groups or by the number of customers served. The dominant player in the entire Italian electricity market remains the Enel group, with a slightly downward market share this year, falling from 37.6% in 2018 to 36% of volumes sold, followed at great distance by Edison (up to 5.4% and Hera, up to 4.9 from 4.3%. Overall, the top five operators hold 82.5% of the domestic sector (84.7% in 2018), although overall, compared to 2018, there is a slight decrease in the level of market concentration, with the share of the top three operators increasing from 46.8% to 46.3% of total sales.

In 2019, the **average price of electricity** (weighted with quantities sold), net of taxes, charged by sales companies to domestic customers was 21.50 c€/kWh in the standard offer service and 24.21c€/kWh in the free market. The difference between the two markets, which can be explained in part by large differences in the types of contracts available on the two markets was therefore 2.7 euro cents, which drops to 2.6 euro cents if we only consider the cost component for energy (10.19 €cents/kWh in the standard offer market against 12.81 €cents/kWh in the free market).

For 2019, due to the epidemiological emergency caused by COVID-19, the available data on **complaints received from electricity suppliers** are partial and not comparable with the previous data. On the basis of the available data, however, the actual average response times for electricity suppliers, in the case of complaints and billing adjustments, are slightly below the minimum standards set by the Authority, equal to 30 calendar days for both complaints and requests for information. The average response times for information requests and billing adjustments recorded in 2019 are also below the general standard. Overall, in 2019, there were 51,986 cases of non-compliance with standards, which led to the right to compensation for services related to the commercial quality of the sale; 2.2 million euros was actually paid in compensation, more concentrated in the free market.

As part of the measures for the effective promotion of competition in 2019, the Authority placed the first guidelines on the regulation of the **safeguard service for small customers** under consultation, adopted voluntary guidelines for the promotion of electricity and natural gas offers in favour of **purchasing groups** (aimed at domestic final customers and small businesses assimilated to domestic final customers) and established the *Portale dei consumi di energia elettrica* (**Electricity and Natural Gas Consumption Portal)**, an institutional website accessible to users from 1 July 2019, where consumers can access, in a simple, secure and free manner, data relating to their electricity and natural gas supplies, including historical consumption data and key technical and contractual information.

<u>Consumer protection and dispute resolution</u>

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 solution of problems and disputes that may arise between customer and service provider (second level). The activities related to the basic level are carried out on a national scale by the Acquirente Unico (single buyer), on behalf of the Authority, through the *Sportello per il consumatore energia e ambiente* (**Energy and Environment Consumer Help Desk**) which responds to calls to the call centre, written requests for information, requests for activation of special information procedures and second level complaints.

In 2019, 483,082 calls (+19% compared to 2018) were received at the Help Desk call centre during service hours; of these, 461,672 were handled and 21,410 were abandoned by customers or end users without waiting for the operator to respond. Compared to 2018, both the average waiting time (149 seconds versus 131) and the average conversation time (200 seconds versus 178) increased slightly. 87% of calls handled by the call centre (403,126) concerned the electricity and gas sectors. With regard to **requests for written information**, in 2019 the Help Desk received 10,768 requests, more than half of which can be traced back to just two topics: " billing" (29%), for which the majority of requests concern "incorrect estimated consumption", and the "market" (25%), for which requests concerning "change of supplier" and "alleged unsolicited contracts" were predominant. The **special information procedures** make it possible to provide information without the need to speak to the Help Desk staff. They have been operational since 1 January 2017 only for some specific issues in the energy sectors; in 2019 requests for activation of special information procedures increased by 43%, for a total of 28,837 cases. Finally, the Help Desk also received 1,568 **second-level complaints** (i.e. those for which the dispute was not resolved with the first complaint), for which it informed the client about the conciliation tools that could be used to resolve the dispute, i.e. the Authority's Conciliation Service or other conciliation bodies.

The activities related to the second level of the protection system concern the **resolution of problems and disputes** arising in the relationship between the customer and the supplier of the regulated service. They can be settled through the Help Desk's special resolution procedures or conciliation procedures. The latter may be carried out using the Authority's Conciliation Service or ADR entities on the Authority's special list.

The **Authority's Conciliation Service** is a dispute resolution procedure, which can be activated by end customers of electricity and natural gas for problems arising with energy operators (suppliers and distributors), in the event of failure to respond or an unsatisfactory response to the complaint. The procedure is undertaken entirely online and in the presence of a third-party, impartial conciliator, expert in mediation. The eventual final agreement is effective as a settlement between the parties, according to Art. 1965 of the Civil code. Moreover, with the approval of Article 141, paragraph 6, letter c) of the Consumer Code, an attempt at conciliation has become a condition for bringing an action before the judiciary for disputes arising in the areas regulated by the Authority (with the exception of tax or fiscal issues), unless urgent and precautionary judicial measures are taken. In 2019, customers and end users of the energy sectors submitted 14,465 requests to the Conciliation Service. The sectoral breakdown of requests received by the Service in 2019 confirms the prevalence of electricity, with a 56% share of requests submitted (8,165 requests); followed by the gas sector, with 36% (5,167 requests). On the other hand, the percentage of dual fuel customers and prosumers out of the total number of requests submitted (995 and 138 requests respectively) is stable. With regard to the approximately 8,500 procedures concluded by agreement, in most cases the value of the dispute did not exceed €5,000 (small claims threshold). Net of the waived procedures (about 1% of the admitted requests), the agreement rate is 69% of the total, up 3% compared to 2018. The parties took an average of 55 days to close a procedure. 78% of the procedures ended in less than two meetings. The agreements signed before the Conciliation Service, relating to procedures initiated in 2019 and concluded, produced over 10.4 million euros in compensation.

As an alternative to the Conciliation Service of Authority, final customers can also fulfil the obligation to attempt conciliation for judicial purposes by turning to other bodies. In December 2015, in implementation of art. 141-decies of the Consumer Code, the Authority established the **List of bodies appointed to manage ADR (Alternative Dispute Resolution) procedures** pursuant to Title II-bis of Part V of the Code. At 31 December 2019, 19 ADR bodies were registered in the Authority's List. Of these, 7 are sectoral joint conciliation bodies - based on specific memoranda of understanding between consumer associations and businesses - and 12 are cross-cutting bodies, which also operate in sectors other than those for which the Authority is responsible. The information sent by ADR bodies reveals a slight decrease in conciliation requests compared to 2018. Out of a total of 1,819 requests (2,167 in 2018), 35% concern the electricity sector. In most cases (56%) requests are submitted by the customer through a consumer association.

Since January 2009, a protection mechanism was activated for the electricity supplies, specifically referring to domestic customers whom find themselves in situations of economic difficulties or in serious health conditions, that receive a **bonus, i.e. a discount on the electricity and/or gas supply.** In June 2019, the Authority submitted a report to Parliament and the Government in which it stressed the need to adopt mechanisms for the automatic allocation of social bonuses to potential recipients. In fact, despite the efforts made to raise awareness of the means to obtain these benefits among those who are entitled to them, the use of these benefits is not yet particularly widespread, even in the presence of situations of serious economic difficulties in the country. The proposals put forward by the Authority in the report were transposed by Decree-Law no. 124 of 26 October 2019, which provided for the automatic recognition of national social bonuses to eligible families from 1 January 2021, eliminating the need to submit an application to municipalities and/or tax assistance centres. Based on the evolution of the national consumer price index for blue- and white-collar households, the Authority has raised the ISEE[5] threshold allowing access to benefits from 8,107.5 to 8,265 euros,

[5] Equivalent Economic Status Indicator: this tool measures the economic status of households in Italy. It is an indicator that takes into account the income, assets and characteristics of a household unit (by number and type).

with effect from 1 January 2020. Thanks to this increase, it is estimated that in 2020 around 200 thousand new customers will be able to benefit from social bonuses.

In 2019, the number of citizens who applied for and obtained the social bonus for electricity supplies was distributed as follows: 870,277 families had access to the electricity social bonus, of which 829,209 for economic hardship and 41,068 for physical hardship. The total amount of bonuses paid for the electricity sector (for economic and physical hardship) was approximately 135.5 million euros. 558,514 households in a state of economic hardship benefited from the social bonus for gas supplies, an increase of 2.9% compared to 2018. The total amount of bonuses paid for the gas sector was approximately 76.2 million euros.

Developments in the gas market

Main changes to regulation

In 2019, the additional services provided by small scale regasification plants, so-called **small-scale LNG** (SSLNG), were regulated. In detail, in May 2019 the Authority defined the criteria for regulating the conditions, including economic conditions, for access to and provision of services offered through LNG storage depots and the provisions on accounting separation for SSLNG services. These criteria apply to regasification terminals that offer, in addition to the regasification service, SSLNG services and LNG storage facilities considered strategic (under national legislation).

With regard to the more general regulation of the liquefied natural gas regasification service, in November the Authority approved the **tariff regulation criteria for the 2020-2023 regulatory period (5PR LNG)**. With this measure, the Authority, acting with substantial continuity with respect to the criteria for determining the recognised cost, which provide for price cap-type incentive regulation schemes for operating costs and rate of return-type regulation schemes for capital costs, has provided, among other things: the phasing out of input-based incentive criteria, without prejudice to the recognition of the portion of revenue attributable to the additional remuneration for investments that came into operation in previous regulatory periods; the provision that a portion equal to one third of the revenue item covering input-based incentives (relating to investments made in previous regulatory periods) be considered within the revenues subject to coverage according to the regasification capacity allocated through tender procedures.

After the consultation, in October the Authority defined the **tariff regulation criteria for the natural gas storage service (RTSG) for the fifth regulatory period (5PRS) 2020-2025**. Also in this case, the new regulation has established the substantial continuity of the criteria for determining the recognised cost, which provide for price cap-type incentive regulation schemes limited to operating costs and rate of return-type regulation schemes applied to capital costs. However, the innovations introduced include: the extension of the duration of the regulatory period to 6 years, with an inter-period review of the level of efficiency gains; the introduction of a mechanism to monitor expected storage performance, designed to ensure consistency between the level of service provided to users and the level of remuneration paid; the phasing out of tariff incentives for the creation of additional capacity, against a strengthening of mechanisms to promote the availability and flexibility of storage performance; the definition of the details of these mechanisms is postponed to a later provision.

In March 2019, the Authority also defined the **tariff regulation criteria for the natural gas transmission and metering service (RTTG) for the period 2020-2023 (fifth regulatory period - 5PRT)**. The new criteria, which implement Regulation (EU) 460/2017 on the harmonisation of gas transmission tariff structures (so-called TAR Code), was published as a result of an extensive public consultation process launched in 2017 and takes into account the findings of ACER's Report entitled "Analysis of the consultation document on the gas transmission tariff structure for Italy", published in February 2019 in response to the final guidelines on the reference price methodology and the cost allocation criteria submitted for consultation in October 2018.

Once again, in a context of substantial continuity with respect to the criteria for determining the recognised cost, which provide for price cap-type incentive regulation schemes limited to operating costs and rate of return-type regulation schemes applied to capital costs, the main new features of the tariff regulation criteria for the transmission service concern in particular:

- the introduction of preparatory tools for the approaches based on the recognition of total expenditure (totex) and greater output orientation, such as greater coordination between tariff regulation and the assessments of the 10-year transmission network development plans;
- the monitoring of investments and the provision of incentives to increase the efficiency of investment expenditure, according to a gradual approach;
- the gradual phasing out of input-based investment incentives;
- the phasing out of the determination of fees according to the so-called matrix methodology, in favour of the Capacity-Weighted Distance (CWD) methodology, identified as the reference methodology within the TAR Code;
- the elimination of the "postage stamp" fee applied to redelivery points on the national territory to cover regional transmission costs, since the costs of transmitting gas on the regional networks are included in the costs to be recovered through the entry and exit tariffs defined through the tariff methodology; this inclusion also entails - without prejudice to the transitional period January-September 2020 - the phasing out of capacity allocations at exit points from the national network to the delivery areas.

Finally, in May, October and November 2019, the Authority published its **guidelines for the definition of tariff regulation criteria and the quality of gas distribution and metering services** in the fifth regulatory period (2020-2025). In confirming a six-year regulatory period, divided into two half-periods of three years each (as already envisaged for the fourth regulatory period ending in 2019), the Authority proposed to give substantial continuity to the criteria for the recognition of operating costs (application of the price cap method), with the aim of achieving full convergence of operating costs between operators of different sizes, with consequent differentiation of the X-factor (linked to the different density of customers served). In addition, in relation to the criteria for recognising the capital costs of the distribution service, it has been proposed to give continuity to the criteria adopted based on revalued historical cost and the hypothesis of introducing incentive regulation schemes for new investments. Also for the metering service, the Authority has proposed to continue the process of gradual elimination of cost recognition approaches based on the recognition of actual expenditure, with full implementation of regulatory criteria based on incentive-based approaches. The Authority has also proposed the possibility of introducing specific incentives for aggregations between operators with less than 50,000 customers, with the aim of promoting competition for the market. As part of the energy transition process, the Authority has suggested the introduction of regulatory instruments to support innovation (such as pilot projects), in particular for: i) interventions aimed at increasing the input of green gas into the networks; ii) interventions to integrate electricity and gas networks; iii) interventions aimed at reducing methane emissions into the atmosphere.

In its October 2019 consultation, the Authority further specified the guidelines on tariff regulation criteria for gas distribution and metering services to be applied from 2020.

The Authority's guidelines were presented in the November 2019 consultation, specifically on: updating the obligations to put smart meters into service for general users in the natural gas sector, increasing metering frequencies, improving performance and developing tariff regulation.

In December 2019, **the new version of the Gas Distribution and Metering Tariffs Regulation for the 2020-2025 regulatory period (RTDG)**, in force for the three-year period 2020-2022, was approved. With reference to the incentives for aggregations between operators, taking into account the results of the consultation, the Authority considers it necessary to carry out an in-depth analysis to assess the tender aspects reported, simultaneously assessing the possibility of envisaging both specific measures to strengthen operators in the individual minimum territorial areas and measures for generalised aggregations, envisaging possible adjustments according to the size of the parties involved in aggregation operations, with a view to adopting, by 30 June 2020, a measure also applicable to aggregations concluded in 2019. It also decided to initiate a procedure aimed at introducing incentive regulation schemes for capital costs relating to the distribution service, based on standard cost recognition approaches and providing incentives with comparable strength to that of the price cap mechanism used to update operating costs, envisaging that it could be applied starting from the investments made in 2022, also taking into account the need to adapt the accounting systems in order to support the hypothesised incentive schemes.

With reference to the tariff regulation of isolated networks fuelled with liquefied natural gas (**isolated LNG networks**), the Authority has established that the costs associated with cryogenic storage depots and local regasification plants, in the case of interconnection with the national transmission system, if not yet fully amortised from a regulatory point of view, are not recognised in the tariff, as these assets are not included among those necessary for the distribution of natural gas in networks interconnected with the national transmission system; Furthermore, in line with certain requirements that emerged in consultation, it has provided that for isolated LNG networks (as for isolated compressed natural gas networks) and provided that there is an authorised interconnection project and in any case for a period not exceeding five years, the general rules laid down for interconnected networks may be applied and that, after the expiry of the five-year period, isolated LNG networks are managed as separate tariff areas limited to the individual plant (tariff areas of isolated LNG networks). On the occasion of the reform of the tariff system for the second half regulatory period, the Authority will assess whether, once this area has started to be managed, it will be possible to assimilate isolated LNG networks to interconnected networks.

With regard to the definition of the tariff system for the natural gas distribution service, the Authority decided to confirm the assumptions made in the October consultation, stressing the fact that the gas service, unlike the electricity service, does not have irreplaceable service characteristics, since it addresses needs and types of use that can be satisfied by means of other energy sources, also with a comparable environmental impact, with the consequence that, in the case of the gas distribution service, the universality of the service is expressed in its availability at transparent cost conditions, while the widespread use of the service, which would increase the cost of satisfying the country's energy needs, does not seem justified.

With regard to **balancing**, in May 2019 the Authority approved a series of provisions, effective as of 1 January 2020, on the activities of Snam Rete Gas to purchase on the market the resources needed to operate the system, i.e. the quantities to cover the difference between the quantities injected into the distribution system by suppliers and those withdrawn by end customers, self-consumption, leaks, unaccounted gas and scheduled line pack changes, in accordance with the provisions of the Tariff

Regulation for the natural gas transmission and metering service for the fifth regulatory period 2020-2023 (RTTG).

<u>Cross-border issues</u>

Under the Capacity Allocation Mechanism Regulation, some **changes have been made to the national regulation for the creation of new capacity** at points in the national network not connected to an EU country. These amendments are designed to harmonise the timing of the national and European procedures in order to ensure a coordinated development of the national transmission network.

In July 2019, only for 2020, a second annual capacity allocation session (in addition to the one held on 1 July) was arranged in September, made necessary by the ongoing negotiations with Algeria and Tunisia to renew the expiring contracts for the purchase and transmission of gas through the TTPC-TMPC international gas pipelines with a landing point in Mazara del Vallo, in view of the fact that Mazara represents a strategic connection point with a natural gas producing country outside the European Union. Following this provision, in July 2019 the Authority **proposed** to carry out a more general **update** of the **current rules**, which date back to July 2002, on the **allocation of annual capacity at the points interconnected with non-European countries** or, more precisely, other than the points interconnected with countries belonging to the European Union and with Switzerland (i.e. Mazara del Vallo, for the connection with Algeria, and Gela, for the connection with Libya). The aim is to reconcile the issues related to the purchase of annual capacity resulting from negotiation/authorisation processes not regulated by European regulations with the need to protect the system from the point of view of security of supply.

With regard to **access to the TAP** (Trans-Adriatic Pipeline) **pipeline**, the procedures proposed by TAP AG for the first ("non-binding") phase of the market test to be carried out in 2019 were approved in June 2019 together with the regulators of Albania and Greece (ERE and RAE). The market test was carried out in compliance with the CAM regulation.

In April 2019, **the processes for allocating transmission capacity at the redelivery points of the transmission network connected to the distribution networks and the corresponding exit points were also reformed**. The reform has become necessary not only because the current procedures appear unnecessarily expensive, but above all because, by favouring those who supply a large number of customers with different delivery characteristics at a city gate, they constitute a barrier to new entrants and hinder the contestability of customers. However, the implementation of the intervention is foreseen following a special evaluation of the implementation aspects carried out on an experimental basis by the Balancing Manager, i.e. the main transmission company, ensuring the involvement of the stakeholders.

On 21 January 2019, the Authority launched the **public consultation on the 2018 Natural Gas Transmission Network Development Plans**. As part of this consultation, which ended on 29 March 2019, it entrusted the largest transmission company to organise a workshop to present the main interventions of the 2018 Plans falling within the scope of the cost-benefit analysis (CBA), as well as the proposal of its application criteria. Subsequently, the Authority **approved** the proposal made by the largest natural gas transmission company on the **criteria for the application of the CBA methodology for the development of the transmission network**.

Finally, in July 2019, the Authority expressed its **assessment on the Ten-Year Development Plans for the natural gas transmission networks** for the years 2017 and 2018 and extended the deadline for submitting the Plans for 2019 to 31 December 2019.

Wholesale and retail markets

On the basis of the preliminary results issued by the Ministry of Economic Development, in 2019, the net consumption of natural gas rose by 1.6 G(m^3), reaching 71.9 G(m^3) from 70.3 G(m^3) in 2018. In percentage terms, consumption grew by 2.2%, thus recovering part of the previous year's loss (-3.2%). The growth was driven by electricity generation consumption, which rose sharply (+11%). On the other hand, consumption for other uses was stable (+0.2%), particularly for motor vehicles, while civil consumption (residential and tertiary) decreased by -3.1% compared to 2018, mainly due to an unfavourable climate trend for heating. Finally, industrial consumption also fell (-1.7%).

In the face of higher consumption, **net imports** consistently showed an increase of 4.6%. The volumes of gas imported from abroad increased by 3 G(m^3) compared to 2018, reaching 70.9 G(m^3); exports fell by 66 M(m^3). There was still a heavy reduction in **domestic production** (-10.9%), albeit less than that recorded in 2016, which was the most important (-14.6%) of the last decade. However, part of the imported gas went to increase stocks: the volumes in storage at the end of the year, in fact, were 1.1 G(m3) higher than the quantities at the beginning of the year. Taking system consumption and network losses into account, gross domestic consumption in 2019 was 74.3 G(m^3), 2.3% higher than in 2018. The level of **dependency from abroad**, measured as the ratio of gross imports to the gross value of domestic consumption, rose again to 95.4%, the highest value ever recorded.

With the exception of volumes from Algeria, which decreased by 25.6% compared to 2018, imports increased from all other countries from which Italy imports gas. The gas that was not imported from Algeria (4.6 G(m^3)) was more than offset by the higher volumes from other traditional countries from which Italy imports gas. In fact, in 2019 we imported: 3 G (m^3) more from Norway, 1.2 G (m^3) more from Libya, 0.5 G (m^3) more from Holland and 0.2 G (m^3) more from Russia; volumes from other areas also increased by around 2.7 G (m^3) (i.e. by 125%). In particular, significant LNG shipments from Trinidad & Tobago, amounting to 1.4 G(m3), and 1.6 G(m3) from the United States, delivered to the Livorno terminal, should be noted. 6% of the gas provisioned abroad is purchased at the European Exchanges.

The corporate groups that hold a share of more than 5% of the overall gas supplied (i.e. produced or imported) are therefore Eni, Edison and Enel. Together they imported 54 of the 69.1 G(m^3), 78.1% of the natural gas entering the Italian market. Considering the quantities produced within the national borders, these three groups account for 78.4% of all the natural gas supplied. This share is down (it was 83.4% in 2018), due to the decrease in Eni's share which was not offset by the increase in Enel's share. The three groups are also the only groups that each hold a share of more than 5% of the available gas (which includes stored gas, as well as imports and production), with an overall share for all three (79.9%) that is slightly higher than that of gas supplied. An analysis of import contracts (annual and multi-annual) active in 2019 in terms of **residual life** shows that 37% of contracts will expire within the next ten years (this was 55.4% in 2018) and 28.4% will expire within the next five years. 35.2% of the contracts in force today have a residual life of more than 15 years. This percentage, which had been increasing since 2014, declined slightly in 2019 as it was 36.6% in 2018.

In 2018, the **total demand of the natural gas sector**, understood as the sum of the volumes of natural gas sold on the wholesale market (including reselling) and retail market plus self-consumption grew by 15%, reaching 329.2 G(m3) (Table 4.3). Overall, the gas sold in the total sales market (wholesale and end market) reached 313.6 G(m^3), an increase of 14.8% compared with the same figure in 2018. The **wholesale market** handled 255.6 G(m^3), an 18.2% increase compared to

2018; the retail market handled 58 G(m^3), recording an increase of 1.9% compared to 2018, while self-consumption totalled 15.6 G(m^3), also with an increase (7.7%). 5 industrial groups served a share of more than 5% of the total demand in 2019, one more than in 2018. In 2019, the number of companies operating in the wholesale market increased, although the volume of gas sold grew more than proportionally. In fact, 195 suppliers, 11 more than 2018, sold a total of 39.4 G(m^3) more than in 2018. As a result of these trends, the average unit volume increased significantly (+11.5%), from 1,175 to 1,311 M(m^3) in the market as a whole. In 2019 the market concentration level remained substantially unchanged: in fact, the share of the top three companies (Eni, Engie Global Markets and Eni Trading & Shipping) was 34.3%, practically the same as the 34.1% calculated in 2018.

The main trading platform in the wholesale market in Italy is the **Virtual Trading Point** (VTP), operated by the leading transmission network operator, Snam Rete Gas. The sales that can be registered are the ones carried out with bilateral contracts and the ones carried out in the regulated markets managed by the GME. The number of VTP subscribers did not grow compared to the previous year, having reached 226 units. However, the number of subscribers who carried out transactions increased by 20 units (12%) compared to 2018, as well as a sharp increase (+5 units) in the number of pure traders (i.e. subscribers who are not users of the transmission system) from 42 to 47. After a year of decline, in 2019, thanks to the increase in overall gas consumption demand, OTC volumes traded at the VTP recovered sharply and increased by 15.6%, from about 86 G(m^3) to just under 100 G(m^3). The volumes traded on the Stock Exchange also showed a significant increase of 14% and reached almost 14 G(m^3), thanks to a particularly significant increase in volumes handled on centralised markets, while energy traded through a clearing house decreased sharply compared with 2018. The churn rate rose to 3.3 after stabilising around 3.1 in the past three years.

With regard to the **gas markets operated by the GME**, it should be noted that, in order to promote the liquidity of the spot market for natural gas by expanding the range of products available for trading and flexibility for the parties operating in it, the Authority has expressed a favourable opinion to the Ministry of Economic Development for the introduction of the weekend product in the Day-Ahead Market (MGP-GAS). The new product, approved by the decree of the Ministry of Economic Development of 12 December 2019, is tradable from 1 January 2020. In 2019, a total of 79.0 TWh of gas was traded in the gas markets operated by the GME, up 45% from the volumes traded in 2018.

The most liquid market is the Intraday Market (MI-GAS) (41 TWh; +47%), thanks in part to trading between third-party operators (other than the Balancing Manager), which reached an all-time high of 24.1 TWh (+80% on 2018), surpassing for the first time the movements of Snam Rete Gas for balancing purposes (17 TWh). **There was a sharp increase in volumes traded on the Day-Ahead Market** (MGP-GAS) (24.6 TWh; +89%), particularly in the second half of the year. Trading on the Gas Forward Market (MT-GAS) also increased, with 726 matches for a total of 3.2 TWh, traded mainly on monthly products (69%). Trading also took place on the Regasification Capacity Allocation Platform (PAR) for a total of 80 slots related to the product "Capacity no longer transferable at auction", amounting to 8.1 M(m^3) liquefied. On average, prices recorded on the various spot platforms in 2019 were around 16 €/MWh, in line with the average annual OTC prices at the VTP of the day-ahead product (16.28 €/MWh). In particular, the average prices of the two sectors of M-GAS - respectively 16.06 €/MWh for MGP-GAS and 16.13 €/MWh for MI-GAS - showed an intra-annual trend that faithfully reflects that of the day-ahead product at the VTP, confirming an average differential between the latter and the System Average Price (SAP)[6] of -20 c€/MWh since last year.

[6] SAP is the average of the prices recorded on the MGP–GAS and MI–GAS weighted for the respective volumes traded.

The provisional results of the Annual Survey showed that, in 2019, 58 G(m^3) were sold to the free or regulated end market, in addition to the 197 M(m^3) supplied through last resort and default services. Overall, the end sales therefore amounted to almost 58.2 G(m^3), with an increase of 1.1 G(m^3) compared to 2018. In order to obtain data that can be compared with the end gas consumption data published by the Ministry of Economic Development mentioned above, commented in the previous pages, we must however consider the volumes related to self-consumption, 15.6 G(m^3), that bring the value of overall consumption given by the Annual Survey to 73.8 G(m^3), which is comparable to the 71.9 G(m^3) reported by the Ministry. The two sources classify the volumes of gas handled over the year in different ways. In any case, the increase in final consumption that emerges both in the annual survey data (3.1%) and in ministerial data, albeit to a lesser extent (2.2%), appears to be linked to a clear recovery of the production sectors, or rather, of the thermoelectric sector, compared with that of civil consumption, which, on the other hand, was still down. The quantities of gas sold on the free market showed an increase of 4.6%, while the sales on the standard offer market fell by 14.3%.

In 2019 the number of active suppliers in the retail market, 446 subjects, rose again (+29 active units), after the break in 2018, the year in which this number had fallen for the first time. Since the increase in the number of suppliers was much larger than the increase in the gas sold, the average unit sales volume decreased by more than 6 M(m^3) compared to 2018, to 130 M(m^3). Ten years ago, before the economic crisis, average sales were almost twice as high at 237 M(m^3). 6.7% of companies active in the final market, i.e. 30 out of 446, sold more than 300 M(m^3) in 2019. In 2018 this share was 7.4%, given that 31 out of 417 companies had exceeded this threshold. Overall, the 30 companies that sold more than 300 M(m^3) account for 82% of all gas sold in the retail market.

There was no change in the top three positions in the end market, where the Eni, Edison and Enel groups remain strong. Compared with 2018, the shares of all three groups were substantially stable or increased slightly, with Eni Group's share rising from 19.2% to 19.4%, Edison Group's share rising from 13.2% to 13.3% and Enel's share rising from 11% to 11.7%. The distance between Eni and Edison remained substantially stable (from 6 to 6.2%), while the distance between Edison and Enel fell from 2.2% to 1.5%. In 2019 the level of **concentration in the retail market** increased slightly, whether measured by the amount of energy sold by corporate groups or by the number of customers served. Using the measures calculated on kWh sold, it can be seen that the number of groups with a total market share above 5% has increased to 4 (there were 3 in 2018). Nevertheless, in 2019 the top three groups controlled 44.4%, while in 2018 the share was 43.4%. The Herfindahl-Hirshman Index (HHI) calculated on the sales market was 810, slightly higher than the 757 of 2018. However, the index level remained well below the value of 1,000, under which concentration is normally judged to be low. When measured in terms of the customers served, concentration tends to increase in almost all sectors: the only exceptions are industrial and public service activities, as well as the non-domestic sector as a whole.

As mentioned above, net of the last resort and default supplies, 73.6 G(m^3) were sold in 2019 - of which 15.6 were for self-consumption and 58 for sales - to 21.7 million redelivery points. In 2019, customers in the gas market as a whole increased by around 65,000 redelivery points. The increase is almost entirely attributable to households (+102,300 points), whose shift towards the free market continued in 2019, among other things, probably driven in part by the end of the standard offer service, originally scheduled for 1 July 2019 and now postponed to 1 January 2022.

If we consider sales in its strict sense and therefore exclude self-consumption, 88% of the gas was purchased on the free market and the remaining 12% on the standard offer market. In terms of customers, 41.4% turned to the standard offer market, while 58.6% bought on the free market. Considering only the **domestic sector**, we can observe that the share of volumes purchased on the free market in 2017 reached 56% for the families and 81.3% for central heating (both shares are calculated from the sales total in the strict sense of the word, i.e. net of self-consumption). In 2018 these values were 50.6% and 78.4%, respectively. In terms of delivery points, in 2019 the share of households that purchased gas in the standard offer service fell to 44.1%, after falling below half (49.9%) for the first time in 2018. A breakdown of sales to the end market (net of self-consumption) by consumer sector and customer size shows that 98% of the volumes sold to the domestic sector are purchased by households with an annual consumption that does not exceed 5,000 m^3: in fact, this share is 98% for both households that purchase in the standard offer market and those that purchase in the free market.

Again, in the gas sector, as already described for electricity, the Annual Survey asked suppliers certain questions aimed at assessing the quantity, types and the methods of supply that companies offer customers who have chosen the free market. The average number of **commercial offers** that each gas supplier is able to offer to its potential customers is equal to 10.9 for domestic customers, 6.6 for central heating and 18.2 for non-domestic customers; compared to 2018 data, the number of offers available decreased slightly (previously 11.7 for domestic customers, 7.3 for central heating and 26.7 for non-domestic customers). Of the 10.9 offers made available to domestic customers on average, 4.9 can only be purchased online; households' interest in such offers grew in 2019, but remains, for now, a fairly niche phenomenon, as it turned out that only 6.9% of customers signed a contract offered through this method (in 2018 this share was 2.6%). Concerning the preferred type of price, it was found that 69.9% of households subscribed to a fixed price contract on the free market (i.e. with the price that doesn't change for at least one year from the time of the subscription), while only 30.1% chose a variable price contract, with the price that changes according to the timing and methods established by the contract itself. These values are essentially identical to those of 2018. There are different types of indexing modes for variable price contracts. 47.8% (the same value as 2018) of the customers who subscribed to a variable price contract signed a contract that provides a fixed discount on one of the components established by the Authority for the standard offer regime; 11.4% (18.8% in 2018) of the customers chose a contract that provides the indexing of the Brent and 25.8% (20.4% in 2018) of the customers have chosen one indexed on the PUN. Only a small proportion of customers (2% in 2019 and 0.7% in 2018) chose to index the price of gas to the VTP or GME managed markets (1.2% in 2019 and 0.3% in 2018). The remaining 11.8% (11.9% in 2018) of the contracts provide alternative forms of indexing, often with a combination of those mentioned above. 33.1% of domestic customers have signed a contract with a rebate or discount; on average, the discount is applied to 36.2% of customers who have chosen a fixed price contract and 26% of customers who have chosen the variable price. The presence of additional services in contracts signed by households is more widespread in fixed-price contracts than in variable-price contracts: 47% of customers who have chosen a fixed-price offer sign a contract that also provides an additional service, while this percentage falls below 24% in variable-price contracts; in fixed-price contracts that provide an additional service, there is a clear preference (33%) for those contracts that provide for participation in a points programme.

Based on data provided by transmission operators and data from the SII, the **switching** percentage, i.e. the number of redelivery points that changed supplier in the calendar year 2019, was 9.1% overall, or 30.7% if evaluated on the basis of the consumption of the customers who made the change. These percentages are up slightly compared to 2018. The increase in domestic and central heating switching rates may have been affected by the imminent end of the standard offer regime (although it has been further delayed). Non-domestic users (excluding public service activities) who switched their supplier in 2019 accounted for 13.3% of the total in terms of redelivery points and 37% in terms of volume, again showing a marked revival.

The analysis of data gathered in the *Annual Survey* shows that, last year, the **average price of gas** (weighted by the quantities sold), net of sales taxes, set by the sales companies operating on the end market, was of 39.2 c€/m^3. This price was 40.0 c€/m^3 in 2018. Overall, therefore, the average final price of gas in Italy shows a decrease of 0.8 c€/m^3, corresponding to 1.9%. There is a clearly differentiated trend between the largest consumers (over 20 million m^3/year), which show a sharp drop (-6.8 cent€/m^3, -23.3%) and all other classes, which show increases, ranging from a minimum of one cent (+2.2%), for the intermediate class with consumption between 50 and 200 thousand m3, to 5.2 cent€/m^3 (+8.8%) in the smallest class (consumption up to 5,000 m^3/year). This means that the price gap between smaller and larger customers, stable until 2018 at around 29 c€/m^3, rose to 41 c€/m^3 in 2019. The difference is due to the fact that the fixed costs are shared over greater amounts, in the presence of higher consumption. In particular, the effect of the distribution tariffs is much higher on smaller consumption, while, for larger customers that are directly connected to the transport network, this component is not even present. We can state that the ability to obtain more convenient supply conditions is directly proportioned to the size of the customer, in relation to the greater knowledge of the market and higher attention to contract conditions.

For 2019, due to the epidemiological emergency caused by Covid-19, the available data on the **commercial quality of the gas sales service are partial and refer to 64% of customers, therefore not comparable with previous years.** From the analysis based on partial data, it appears that the actual average time taken to respond to complaints and billing corrections is 24 and 15 calendar days, respectively, well below the minimum standards set by the Authority. On the other hand, with regard to double billing adjustments, compared to the standard set at 20 calendar days, the actual average adjustment time is 32 calendar days. The actual average response time to requests for information is well below the general standard. In 2019, there were 15,982 cases of non-compliance with the standards set for services related to the commercial quality of sales in the gas sector, which determined the right for customers to obtain compensation, of which 91.2% was attributable to customer complaint responses; in particular, the market segment with the highest number of non-standard responses to written complaints is the segment relating to domestic customers in the free market, which accounts for 78.2%. During the year, compensation payments totalling almost 725,000 euros were made. The first three topics complained about concerned: in 47% of cases, problems with billing and everything related to consumption and billed fees, self-reading, billing periodicity, including the closing bill, making payments and refunds; in 13.5% of cases, the terms of the contract, such as withdrawal, change of name, transfer and take-over (completion and costs of transfer and take-over); in 11.8% of cases, issues related to the market, such as how to conclude new contracts, switching timescales and the economic conditions proposed by the supplier during the offer compared to those provided for in the contract and applied.

Consumer protection and dispute settlement in the gas sector are common to those in the electricity sector in the sense that they are regulated in a unified way. On this point, therefore, reference is made to what has already been said about the system of safeguards in the context of developments in the electricity sector.

2.1.2 Report on the implementation of the Clean Energy Package

Clean Energy for all Europeans

In 2019, the work of the European institutions on energy and infrastructure development saw the adoption by the Council and Parliament of the legislative proposals put forward by the European

Commission and included in the so-called Clean Energy for all Europeans (CEP) package. In particular, the Council and Parliament adopted the Regulation on risk preparedness (Regulation (EU) 941/2019), the new Regulation for the operation of ACER - Agency for the Cooperation of Energy Regulators (Regulation (EU) 942/2019, which replaced Regulation (EC) 713/2009), the new Regulation for the internal market in electricity (Regulation (EU) 943/2019, which replaced Regulation (EC) 714/2009) and the new Directive on the electricity sector (Directive 2019/944/EU, which replaced Directive 2009/72/EC with effect from 1 January 2021). The new regulatory provisions complement the directives on energy efficiency and renewable energy sources already approved at the end of 2018 (Directives 2018/2001/EU and 2018/2002/EU; see Annual Report 2019).

Under Regulation (EC) 1999/2018 on the governance of the Union, already approved in December 2018, in 2019 Member States submitted an initial proposal for their Integrated National Energy and Climate Plans (NECPs) to the European Commission. The Commission published its assessments and recommendations on the individual Plans in June 2019 on the basis of which the Member States revised the Final Plans, which were then notified to the Commission by 31 December 2019. The Commission will also assess the Final Plans in the light of the new objectives announced in the communication on the Green Deal for the European Union, a new set of multi-sectoral policy initiatives to be implemented in the coming years by the Commission, with the overall objective of making Europe the first climate neutral continent by 2050, through a so-called green transition. In the meantime, the contents of the Italian NECP are illustrated below.

Integrated National Energy and Climate Plan

The *Italian Integrated National Energy and Climate Plan (NECP)*, published on January 21, 2020, contains the objectives, policies and measures that Italy intends to adopt in the coming years to achieve the European energy and climate targets by 2030.

At the end of 2018, the first NECP proposal had been submitted, subject to a public consultation. 513/2019/I/com, the Authority provided the Production Activities Commission of the Chamber of Deputies with its observations in relation to the new version of the *Integrated National Energy and Climate Plan for Italy 2021-2030* (NECP), i.e. with reference to the text submitted for consultation on 20 March 2019 by the Minister of Economic Development.

In its statement, the Authority expressed the need for the NECP, in defining the concrete lines of action to be implemented for the achievement of the European energy and climate targets, to maintain a clear distinction between objectives, which pertain to the role of general political guidance of Parliament and the Government, and regulatory instruments, avoiding defining excessively detailed solutions and leaving it to the regulator to identify the specific technical-economic measures best suited to achieving the objectives at minimum cost. The Authority stressed the importance of defining market and regulatory instruments that allow investments to be made with a view to efficiency and sustainability, selecting those that are most useful for the system through an analysis of the cost/benefit ratio of the infrastructure.

In the Authority's view, it is necessary for the NECP to provide, first of all, clear guidance on the chosen decarbonisation path, in order to allow for a proper assessment of the necessary infrastructure investments, given that the latter have very long useful lives (which can be up to 60 years in the case of natural gas, for example). It is also essential that the planning and subsequent infrastructure development of the different sectors of the energy chain (production, storage, transmission, distribution, sales and demand flexibility) take place in a coordinated manner, both in terms of timing and the choice between the different infrastructures and their location, always in order to ensure the pursuit of the objectives at minimum cost.

This coordination is necessary, and will be increasingly so in the future, also with regard to the synergistic development of the gas and electricity sectors. In fact, with a view to the decarbonisation of the energy sectors and the development of green gas, the electricity and gas sectors will tend to be much more interdependent (through so-called sector coupling), also considering the progressive penetration of the electric vector in end uses that were traditionally the prerogative of fossil fuels (for example, heat pumps for heating and electric or hydrogen vehicles for transport).

The Authority has, however, noted that the policies and instruments identified by the NECP do not always seem to meet the criteria of efficiency, coordination and selectivity mentioned above, as, for example, in the case of the development of accumulation in the electricity sector or the network in the gas sector.

The Authority has also highlighted the need to develop and promote, in the European context, market-based instruments that ensure long-term risk sharing between operators and the system in order to support the substantial investments needed for decarbonisation and to ensure their efficiency and the necessary coordination.

In this regard, it was pointed out that Italy has already developed and included in the NECP the capacity market instrument to support investments in electricity generation, which is now being implemented. It is important that this instrument is adequately supported in the coming years, as it has been so far, including in the context of new European legislation.

The main targets for 2030 of the NECP are:

- 33% reduction in greenhouse gas emissions compared to 2005 for non-ETS sectors[7];
- 30% increase in the share of energy from renewable sources in gross final energy consumption;
- increase in energy efficiency, with a 43% reduction in primary energy consumption compared to the PRIMES 2007 scenario.

Other important targets are the phasing out of coal by 2025 and the increase in the level of electrical interconnectivity by 10% by 2030. For the electricity sector, the NECP estimates an increase in gross domestic electricity consumption to 339 TWh in 2030, 22% more than in 2017, and of this 187 TWh (55% of the total) from renewable sources. This increase is due to the growth in electrification in the transport and thermal sectors. The demand for natural gas in the gas sector is expected to be around 60 GS(m^3) in 2030, with consumption peaking around 2025 due to the removal of coal from the electricity generation mix.

To achieve these objectives, the NECP envisages a series of infrastructure investments in various sectors at a cost of around 1,200 billion euros, 18% more than would be the case under current policies. The main investments illustrated for the electricity sector include the following: the increase in the power of renewable energy plants to 95.2 GW in 2030 (when wind capacity is expected to reach 19.3 GW and solar capacity 52 GW); the increase in centralised storage by 6 GW and distributed storage by about 4 GW; a new gas production capacity for about 3 GW (about 50% of which is essentially related to coal phase-out); a new Adriatic gas pipeline for at least 1 GW of transmission

[7] The EU has set an overall greenhouse gas reduction target of 40% from 1990 levels. The target is divided into two parts: for sectors covered by the ETS (the European Emissions Trading Scheme), the European target is 43% compared to 2005 and there are no national targets as the scheme already ensures that the target is met (Directive 2018/410/EU); for non-ETS sectors, the European target is 30% compared to 2005 and is shared between Member States (Regulation (EU) 842/2018).

capacity by 2025; the installation of at least 3,000 MVAr of new synchronous compensators and, still under evaluation, a new Sardinia-Sicily-continent electricity interconnection.

For the gas sector, the importance of LNG as a complementary supply source to pipeline supplies is highlighted, so new LNG capacity could be developed. As regards the construction of a methane supply network in Sardinia, the NECP indicates that the possible measures to be implemented will be decided according to the cost/benefit analysis undertaken by RSE on behalf of the Authority. Moreover, in order to pursue security and flexibility targets, the NECP emphasises the possibility of an increasing integration of electricity and gas network infrastructures, also through solutions involving hydrogen production and power-to-gas technologies. In order to facilitate the integration of these technologies, pilot projects may be developed and appropriate changes to the market and regulatory regime analysed.

In order to achieve its targets, the NECP provides for a number of policies and measures in the energy sector, some of which are described below. With regard to the promotion of renewable energy, for small plants there is provision, among other things, for an incentive through support for self-consumption or the use of incentive tariffs where self-consumption is not feasible. For the development of collective self-consumption, especially in cases where the use of existing public networks is preferred, the possibility of introducing forms of direct support will be examined with regard to the benefits of distributed generation in terms of, for example, reduced use of the network. For large plants (larger than 1 MW), the NECP foresees two main instruments: auction mechanisms and Power Purchase Agreements. The NECP also considers the possible use of ad hoc tools for new plants based on innovative technologies still far from being economically competitive in the national context and also provides for the simplification of the authorisation process for the repowering of existing renewable plants.

With regard to the electricity market, among other proposals, it is worth mentioning that it will be assessed whether the single national price (PUN) will be phased out in the medium term, the development of market coupling will continue, and negative prices will be introduced, as required by Regulation (EU) No. 943/2019. The NECP reaffirms that it remains a central objective to maintain the conditions of adequacy of the system, which requires instruments such as the remuneration of capacity, which Italy has already adopted. With regard to services markets, the PNIEC stresses the importance of enabling distributed renewable generation to participate in services markets and fully exploiting demand and other flexibility resources (including accumulation systems), according to principles of technological neutrality and cost minimisation and through new organisational forms. In this respect, it is considered necessary to accelerate the reform process in the dispatching services market. In order to increase energy efficiency, the NECP mainly plans to strengthen measures and instruments already operational at national level, including the white certificate mechanism, tax deductions, the *Conto Termico* (scheme to support the production of thermal energy from renewables) and the National Energy Efficiency Fund. With reference to energy poverty, the Plan establishes, among other measures, the creation of an institutional Observatory on energy poverty and the strengthening of the gas and electricity bonus by introducing an automatic mechanism for granting the benefit to those entitled.

3 THE ELECTRICITY MARKET

3.1 Infrastructure regulation

3.1.1 Unbundling

In 2015 the Authority renewed[8]the provisions relating to functional unbundling for the electricity and natural gas sectors, approving the Integrated text on functional unbundling (TIUF), in compliance with the provisions of the Legislative Decree of June 1st, 2011, n. 93, and of the Directives 2009/72/CE and 2009/73/CE. The TIUF, effective since January 1st, 2016, introduced new unbundling requirements in relation to communication and brand policies for all electricity and natural gas distributors, regardless of their size or corporate form, imposing a complete separation, without any risk of confusion, between the electricity and natural gas sales and distribution activities.

In 2019 the Authority[9] ordered a number of companies operating in the electricity and gas sectors to send the mandatory communications required by the TIUF. With the same resolution, the Authority ordered some electricity suppliers to send information aimed at verifying the correct application of the rules provided by the TIUF on debranding, with regard to the management of commercially sensitive information and the separation of databases between sales activities to final customers in the free market and sales activities to the standard offer market.

3.1.2 Network expansion and optimisation

In Italy, **electricity transmission** takes place through about 73,600 km of electricity lines and circuits and around 900 sorting stations. The national Transmission System Operator (TSO) is the company Terna. Terna's controlling interest, equal to 29.85% of the share capital, is held by CDP Reti, a company in turn controlled by Cassa Depositi e Prestiti[10]. Another important partner is Lazard Asset Management LLC, an American financial institution, which owns 5.12% of Terna. The remaining 65.03% of the capital belongs to the market.

In 2019, the number of companies that own assets of the National Transmission Grid (NTG) rose to 11, two more than the previous year. Until 2018, in addition to Terna - Rete elettrica nazionale and Rete, the Terna Group company into which the infrastructure purchased from Ferrovie dello Stato (Italian State Railways) merged, the following were also present in the electricity transmission: Megareti (formerly Agsm Distribuzione, which incorporated Agsm Trasmissione) of the Agsm Verona group, Edyna Transmission, which is part of the Edyna group operating in South Tyrol, Arvedi Trasmissione, which operates in the Cremona area, Seasm of the A2A group, El.It.E., Nord Energia and Eneco Valcanale, the company that built a high-voltage trunk line connecting to the Austrian Power Grid (APG). From 2019 two new businesses have been added: Terna Crna Gora and Monita Interconnector. Both these companies are 100% owned by Terna and were set up for the construction

[8] Resolution of 22 June 2015, 296/2015/R/com which replaced the previous resolution of 18 January 2007, no. 11.

[9] Resolution of 8 October 2019, 405/2019/E/com.

[10] CDP Reti is 59.1% owned 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.

of the Italy-Montenegro power line, which came into operation on 28 December 2019, more than 10 years after the project was launched. The new interconnection consists of a connection, the first in direct current for the Balkan State, 445 km long between the electrical stations of Cepagatti, in the province of Pescara, and Lastva, in the municipality of Kotor, with a capacity of 600 MW. The original "Villanova-Lastva" project involves the construction of two direct current power lines (HVDC - High Voltage Direct Current) with a total nominal power of 1,200 MW: the exchange power inaugurated last December represents the completion of the first phase of the project. Following the Authority's positive opinion, issued in September 2019, the Ministry for Economic Development granted an exemption from third party access on part of the capacity of the Italy-Montenegro line, which is reserved for energy-intensive users under the Interconnector mechanism. More precisely, the exemption was requested and granted for 200 MW to Monita Interconnector, whose assets total 300 MW functional to the Italy-Montenegro link. The Ministerial Decree also established that, at the end of the exemption period, ownership of the portion of the grid subject to exemption and falling within Italian territory will be transferred to Terna.

Therefore, considering the assets of all the companies belonging to the corporate group, in 2019 the Terna group owned 73,355 km of cables, i.e. 99.7% of the national power lines, as well as 99.3% of the 902 electricity stations that are part of the NTG.

As at 31 December 2019, 127 **electricity distribution** companies were registered in the Authority's Registry of Operators, of which only 10 serve more than 100,000 customers. There are four companies with more than 500,000 delivery points: e-distribuzione (Enel group), Unareti (A2A group), Areti (Acea group) and Ireti (Iren group): all of them changed their names in 2016 to comply with the provisions on functional unbundling, which obliged distribution companies belonging to a vertically integrated corporate group, also engaged in marketing activities, to distinguish themselves from other group companies in terms of identity, brand and communication policies.

Overall, in Italy, electricity distribution takes place through 1,273,000 km of networks, most of which (69%) are low voltage. In 2019, electricity distribution networks grew by about 5,000 km, most of which are low voltage (+3,700 km). The length of medium voltage networks has increased by 1,350 km, while that of high voltage networks is substantially unchanged. e-distribuzione is the leading operator, with a dominant share of 86.2%. These are followed, in the same order as in 2018, by: Unareti with 4.1%, Areti with 3.6%, Ireti with 1.2%. All other distributors have a share of distributed volumes of less than 1%.

Output-based regulation of electricity transmission, distribution and metering services for the 2020-2023 half-period

In April 2019, the Authority launched[11] the intra-period update of the regulation of tariffs and the quality of electricity transmission, distribution and metering services.

Following a complex consultation process[12], in December 2019 the Integrated text of the output-based regulation of electricity distribution and metering services was approved[13] for the 2020-2023

[11] Resolution 9 April 2019, 126/2019/r/eel.

[12] Documents for consultation: 2 July 2019, 287/2019/R/eel (for the distribution service); 30 July 2019, 337/2019/R/eel (for the transmission service); 12 November 2019, 457/2019/R/eel (for the quality of transmission and distribution services); November 22, 2019, 481/2019/R/eel (for other elements of output-based regulation of the transmission service).

[13] Resolution 23 December 2019, 566/2019/r/eel.

half-period.

In relation to the continuity of the electricity distribution service, the new provisions include:

- the optional "special regulation" of the number of interruptions, featuring additional awards and penalties with respect to the ordinary regulation, for areas still far from the target level, with a postponement of the target year for the achievement of the target levels depending on the distance from the target level and the critical structural issues present in the interconnection between the distribution network and the NTG or in the distribution network;
- the "regulation for experiments" to encourage the improvement of service continuity, in areas identified by the companies, through technological innovation; in this regard, distributors may be authorized to derogate, under certain conditions, from the Authority's regulation, with particular reference to the paths for improving the duration and number of interruptions;
- for companies with more than ten territorial areas, the reduction of premiums against "repeated" penalties incurred by the same territorial area.
- improvements aimed at removing some disproportion in the size of the compensation to which users affected by long term outages are entitled;
- updating some of the outage recording rules and the related SRI indicator for the overall adequacy of the outage recording system;
- the establishment of the "Fund for Exceptional Events, Resilience and Other Special Projects" to finance premiums to incentivise the increased resilience of distribution networks and to cover the accumulated debt of the Fund for Exceptional Events.

As regards the continuity of the electricity transmission service, as a result of the above-mentioned consultations, the Authority considered that the conditions for an update of the regulation from 2020 were not met.

Resilience of the electricity distribution system

In implementation of the provisions of the Integrated Text on Electrical Quality, in December 2019 the companies[14] selected the first interventions to be submitted to the mechanism of premiums and/or penalties aimed at increasing the resilience of the electricity distribution networks in terms of greater resistance to the stresses caused by critical risk factors, with particular reference to the formation of ice sleeves due to snow or wind, heat waves, flooding and the falling of plants due to excessive snow load.

The premiums and penalties are valued as follows:

- the premium for an intervention is equal to 20% of its net benefit (benefit minus cost), if it is completed no later than the date of completion indicated by the distributor when the intervention was first included in the plan (original completion date); the premium is halved if the intervention is completed six months later than the original completion date;
- the penalty for an intervention is 10% of its cost if it is completed two half-years later than the original completion date, while it is 25% if the delay is three or more half-years.

[14] Resolution 17 December 2019, 534/2019/r/eel.

Quality of electricity distribution: duration and number of outages

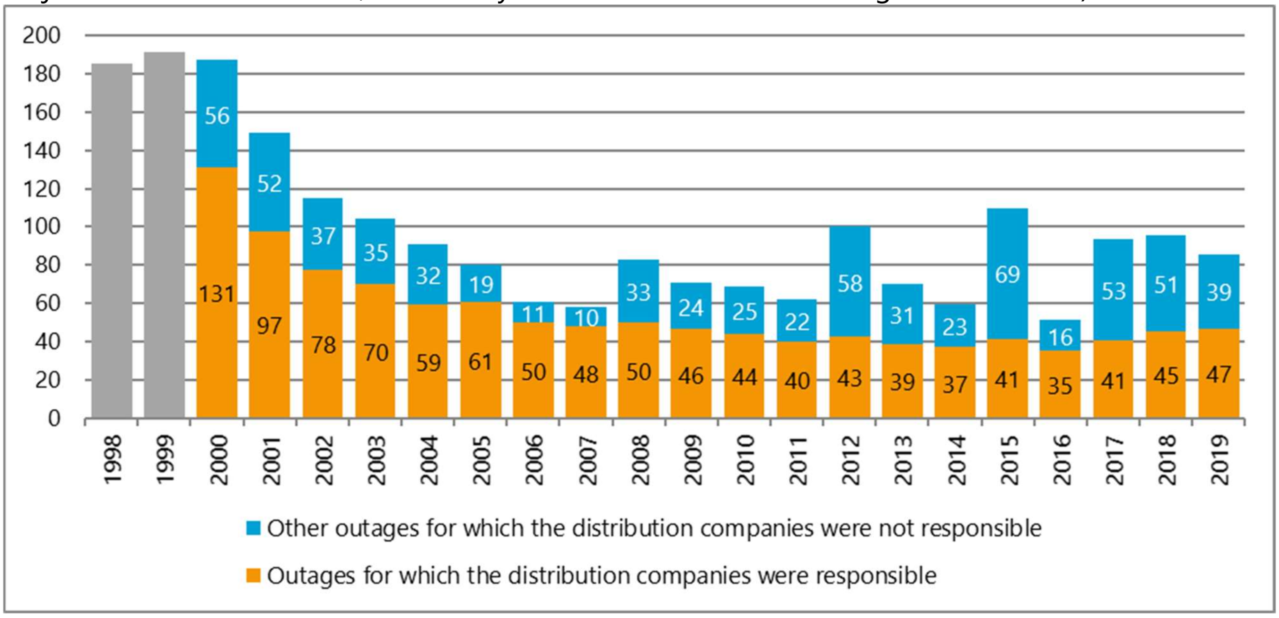
2019 confirms the worsening trend in the duration and number of outages for which distributors were responsible from 2017 onwards.

Analysing the indicators in detail, the duration of unannounced outages is 47 minutes nationally (Figure 3.1) and the number of long and short unannounced outages (between one second and three minutes) is 3.53 interruptions per low voltage customer nationally (Figure 3.2). The following are excluded from the calculation of these values:

- the outages that originated on the NTG and on the high voltage grid;
- exceptional outages, which occurred in periods of disrupted conditions (identified on the basis of a statistical method);
- Outages due to exceptional events, acts of public authority and thefts.

Figure 3.1 Average annual duration of outages per low voltage customer

Minutes lost per customer per year(A); referred to e-distribuzione and other distributors (excluding major incidents on the NTG, defence system interventions and outages due to theft)

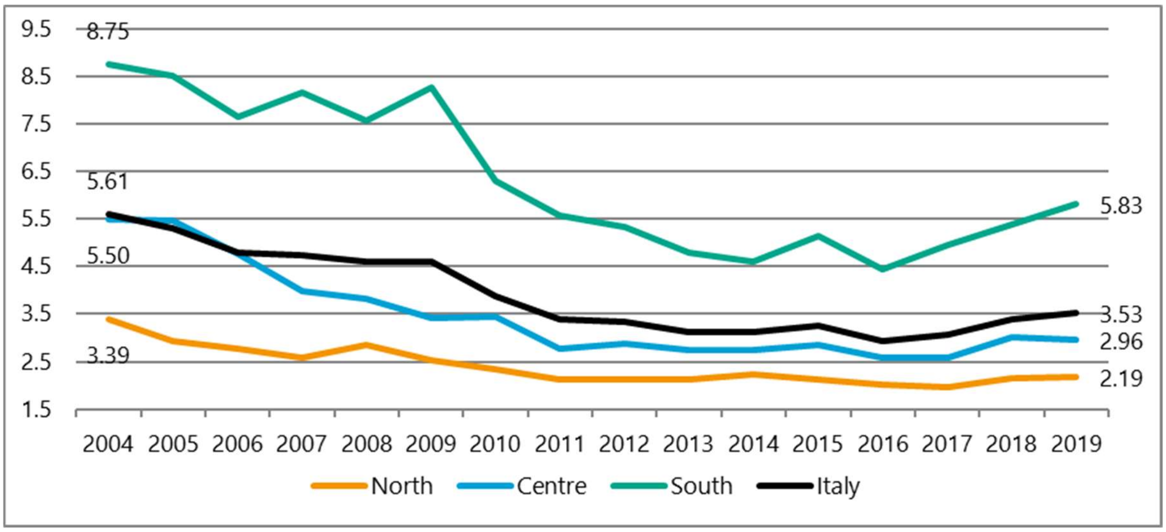


(A) The values for the 2019 are still subject to verification by the Authority.

Source ARERA. Processing of operators' declarations.

Figure 3.2 Average annual number of long and short unannounced outages per low voltage customer for which distributors were responsible

Referred to e-distribuzione and other distributors(A)



(A) The share of minutes of outage for which distributors were responsible for the year 2018 is still subject to verification by the Authority.

Source: ARERA. Processing of operators' declarations.

Network connection times

The Integrated Text of the output-based regulation for the distribution and metering services (TIQE)[15]currently in effect for the regulation period 2016-2023, establishes specific standards for connections with the MV and LV electricity distribution networks. The regulations provide:

- a maximum estimated time for the execution of works on the LV network equal to 20 work days and on MV network equal to 40 work days;
- a maximum time for the execution of simple works equal to 15 working days for the LV network and 30 work days for the MV network;
- a maximum supply activation time equal to 5 work days;
- a maximum supply deactivation time, upon request of the final customer, equal to 5 work days for the LV network and 7 work days for the MV network;
- a maximum supply reactivation time after a suspension due to non-payment equal to 1-week day.

The data related to the connections of active and passive users is reported below. The “active connections” are those requested by the electricity production plants to the transmission or distribution networks, mainly to allow these plants to input energy into the electric system. “Passive

[15] Approved with the Resolution 646/2015/R/eel of 22 December 2015.

connections", are those requested by the consumers to the distribution or transmission networks in order to allow to withdrawal of energy from the electricity system.

The data related to the connection of active users with the transmission network (Table 3.1), refers to the activities that were carried out by Terna, while the data related to the connections of active users with the distribution networks exclusively refers to the activities that were carried out by distribution companies with over 100,000 clients[16]. The numbers related with the connection of passive clients were collected by Terna and by the distribution companies in the context of the customary Survey on Regulated Sectors, carried out annually by the Authority.

Table 3.1 Connection of active users

Power in GW and average time in working days

	TERNA			DISTRIBUTORS		
REQUESTS, QUOTES AND CONNECTIONS	NUMBER	POWER	AVERAGE TIME	NUMBER	POWER	AVERAGE TIME
REQUESTS FOR CONNECTION TO HIGH OR VERY HIGH VOLTAGE NETWORKS						
Requests received	1,037	57.8	-	194	3.7	-
Quotes provided	633	30.9	78	95	2.2	63
Accepted quotes	329	12.9	-	50	1	-
MTR requests	1	0.9	-	0	-	-
Connections made as at 31/12/2019	1	0.9	-	0	-	-
REQUESTS FOR CONNECTION TO MEDIUM AND LOW VOLTAGE NETWORKS						
Requests received				40,653	6.4	-
Quotes provided				35,866	4.3	-
- for power up to 100 kW						17
- for power from 100 to 1,000 kW						36
- for power over 1,000 kW						56
Accepted quotes				31,214	1.9	-
Connections made as at 31/12/2019				20,253	0.3	-
- for simple connections						17
- for complex connections						56

Source: Declarations from Terna and distributors to ARERA.

In relation to requests for connection to high or very high voltage networks, in 2019 Terna received 1,037 connection requests for electricity generation plants, corresponding to a total power of approximately 57.8 GWe and, in the same year, Terna provided 633 quotes for these requests, corresponding to a total power of approximately 30.9 GW, with average delays for the availability of the quotes (net of the allowed interruptions) equal to 78 working days. During the year, 329 quotes were accepted out of the total provided, corresponding to a total power of approximately 12.9 GW. For only one of these, corresponding to a power of 86 MW, the request for the provision of the

[16] All the distribution companies with over 100,000 customers, (AcegasApsAmga, Areti, Deval, e-distribuzione, Edyna, Inrete, Ireti, Megareti, SET Distribuzione and Unareti), sent the Authority the information concerning 2019, relative to the connection of the electricity producing plants by April 2020.

Minimum Technical Requirements (MTR) was submitted and subsequently the corresponding connection was made and activated by 31 December 2019.

The distributors e-distribuzione and Edyna also received requests for electricity production systems to be connected with high voltage networks. In 2019 they received 194 connection requests, corresponding to a total power of approximately 3.7 GW; the distributors provided 95 quotes in the same year, corresponding to a total power of approximately 2.2 GW, with average delays to provide the quote, net of the allowed interruptions, equal to 63 work days. 50 of the provided quotes, corresponding to a power slightly lower than 1 GW, were accepted in 2019; none of these required the MTR availability request. Therefore, also in 2019 (as in the two previous years) distributors did not make any high-voltage connections to electricity generation plants that applied for a connection in the same year.

As regards requests for active connection to medium and low voltage networks, in 2019 the distributors[17] received just over 40,600 connection requests for electricity generation plants, corresponding to a total power of around 6.4 GW. In relation to the latter, during the year the distributors provided just under 35,900 quotes, corresponding to a total power of just under 4.3 GW, with average timescales for the provision of the quote, net of permitted interruptions, of:

- 17 working days, for input power requests up to 100 kW;
- 36 working days, for input power requests higher than 100kW and up to 1,000 kW;
- 56 working days, for input power requests higher than 1,000 kW;

Of all the quotes provided during the year, just over 31,200 were accepted, corresponding to a total power of approximately 1.9 GW.

In relation to the requests received in 2019, just over 20,000 connections were made, corresponding to a little under 0.3 GW, with average connection times, net of the permitted interruptions, equal to:

- 17 working days, for simple jobs[18],
- 56 working days, for complex jobs[19],

while the average timescales for the activation of the connection, net of permitted interruptions, is of 8 work days.

Concerning passive client connections in 2019(Table 3.2), the collected data shows that 233,000 connections with distribution networks were carried out in 2019, nearly all in low voltage. For 76% of them, the supply was activated during the year. The average time to connect clients is 7.9 work days. In particular, the average timescale for making low voltage connections is 6.6 work days. The average time to obtain a medium voltage connection is slightly longer, equal to 12.3 work days.

The data show a higher number of requests than in 2018 (when there were about 231,000, i.e. 1% less), but at the same time, there was a marked deterioration in connection times: in 2018, an average

[17] With reference to the connection of electricity production plants to the distribution networks, it should be noted that the data reported refer exclusively to the activities carried out in 2018 by distributors with more than 100,000 customers.

[18] Simple jobs consist of the professional construction, modification or replacement of the grid operator's system, which is carried out with a limited intervention at the outlet and, if necessary, at the metering unit.

[19] Complex jobs consist of the professional construction, modification or replacement of the network operator's system in all cases not covered by the definition of simple jobs.

of 5.7 working days were required to obtain a passive connection on the low or medium voltage network, while in 2019 there was an increase of 2.2 working days, 39% longer. As ever, it is important to specify that the number of indicated days doesn't include the time to obtain the eventual authorisations and the time needed for obligations required from the consumer. The longer time was especially noticeable for low-voltage customers, who in 2019 were connected two working days later (on average) than in 2018: the waiting time therefore increased by 43%. Medium voltage users also experienced greater delays: compared to the 9.6 days required in 2018, in 2019 they were connected on average in 12.3 days (+ 29% longer).

Each distributor carried out an average of 1,849 connections during the year. If we exclude the operators that didn't carry out any connections (45 parties) from the calculation, the average number of connections carried out by each distributor during the year is equal to 2,877.

In 2019 Terna connected no new passive clients in high and very high voltage.

Table 3.2 Passive user connections to distribution networks

VOLTAGE LEVEL	NUMBER OF CONNECTIONS		AVERAGE TIME (WORK DAYS)(A)	
	2018	2019	2018	2019
Low voltage	229,331	231,597	4.6	6.6
Medium voltage	1,290	1,409	9.6	12.3
TOTAL	230,621	233,006	5.7	7.9

(A) Value calculated net of operators that did not make connections, excluding the time needed to obtain the eventual authorisations and the time needed for any obligations required from the final customer.

Source: ARERA. Annual survey on regulated sectors

Modernisation of old building risers

Building risers are the terminal portion of the electricity distribution network located inside the buildings and make it possible to reach the meters located at the individual housing units.

The discussion with the distributors revealed possible critical issues in the functionality of the risers due to their age, with particular reference to:

- the difficulties for companies in obtaining permits to carry out work on condo households, and thus to comply with the obligation to maintain the risers and at the same time ensure safe operation.
- the risks to the safe operation of the distribution network, following the progressive deterioration of the insulation of the risers;
- the risk of not being able to cope with users' requests for increased power, due to the sizing of the risers carried out with contemporaneity coefficients of use estimated under very different electrical load conditions.

In order to overcome the critical issues outlined above, as a result of specific consultations[20], the Authority has ordered[21] the launch of an experimental regulation, lasting three years, designed:

- to acquire information and elements useful for the implementation of a stable and sustainable regulatory framework, starting from 1 January 2023;
- to carry out a census of the old risers, by each distributor;
- to verify the effectiveness and efficiency of the involvement of the condo households in carrying out the riser modernisation works;
- to strengthen the regulatory framework in relation to the commitment required of the distributors to ensure the supply of electricity also in the face of the changed and future delivery conditions.

More specifically, the Authority introduced the possibility of intervening on the risers built before 1970 and, in case of critical operating conditions, on those built between 1970 and 1985. Since 1986, following a specific provision on the subject[22], the buildings should have been built with the meters located in centralised rooms and no longer in the housing units. In order to overcome the critical issues that have emerged, the responsibility for the building works has been placed in the hands of the condo households and a capped reimbursement has been envisaged for these works, depending on the level of quality of the finishes prior to the modernisation.

The measure in question also encourages the centralisation of meters, where technically possible and subject to agreement between the distribution company and the building. In this case, both construction and electrical works are carried out by the building owner and the maximum reimbursement, again depending the quality level of the finishes, has been increased to also take into account the replacement of the power lines.

3.1.3 Network tariffs for connection and access

New tariff regulation period for transmission, distribution and metering services

In April 2019, the Authority launched[23] the procedure for the intra-period update of the regulation of tariffs and the quality of electricity transmission, distribution and metering services for the years 2020-2023 (NPR2).

Following the consultation process[24] , in December 2019 the Authority approved[25] both the provisions relating to the tariff regulation and the provisions relating to the economic conditions

[20] Consultation documents 331/2018/R/eel of 14 June 2018, and 318/2019/R/eel of 23 July 2019.

[21] Resolution 12 November 2019, 467/2019/R/eel, the annex of which is included in the Integrated Text on Electrical Quality.

[22] Order of the Interministerial Price Committee (IPC) of 30 July 1986, No. 42.

[23] Resolution 09 April 2019, 126/2019/r/eel.

[24] Documents for consultation: 23 July 2019, 318/2019/R/eel; 30 July 2019, 337/2019/R/eel; 21 November 2019, 481/2019/R/eel.

[25] Resolution 27 December 2019, 568/2019/r/eel.

relating to connection, which entered into force on 1 January 2020.

Following the intra-period update approach, the Authority has continued to apply the regulatory criteria adopted in 2015[26], confirming the dual tariff regime based on the size of the companies subject to regulation. In particular, for NPR2 an individual tariff regime has also been confirmed for the Transmission System Operator and for distributors serving at least 25,000 delivery points, based on rate of return mechanisms for capital costs and price cap mechanisms for operating costs, while a parametric tariff regime is foreseen for the remaining distributors. The intra-period update concerned, in particular, the revision of the criteria for determining the recognised cost, with reference to setting the initial operating cost levels for the year 2020 and subsequent updates for companies under individual tariff regimes.

In general, for all infrastructure services, for the purposes of determining the eligible operating costs, the Authority has excluded cost items for which coverage is already implicitly guaranteed by regulatory mechanisms (for example, through risk remuneration) or in relation to which recognition is incompatible with a monopoly activity (for example, advertising and marketing costs that do not reflect specific regulatory obligations). The initial level of operating cost recognised for the year 2020 for transmission, distribution and metering services was determined starting from the actual cost incurred in 2018, taking into account the residual value, not yet reabsorbed through the productivity recovery factor (X-factor), of the increased efficiencies achieved in NPR1 (2016-2019), divided equally between operators and final customers.

Limited to the distribution service, with specific reference to costs relating to exceptional weather events, which in recent years have shown a significantly irregular trend, in determining the initial levels of the operating eligible cost for the distribution service, reference was made to the average value assumed by these specific costs over the last three years available (2016-2018) and it was considered appropriate to exclude these costs from the calculation of efficiency gains. For the distributors, further regulatory interventions are possible, limited to the case of exceptional weather events, the management of which involves charges representing a percentage of at least 15% of the admissible revenue relating to the distribution service, identified as a threshold worthy of intervention in order to preserve the economic-financial equilibrium of the companies.

With specific reference to the transmission service, the procedures for recognising costs relating to activities connected with the integration of electricity markets at European level and the implementation of European network codes - including participation in ENTSO-E (European Network of Transmission System Operators for Electricity) - as well as other similar costs have been streamlined, generally providing for a price cap for the costs of activities related to EU subjects that can be made more efficient, and therefore "compressible", essentially linked to personnel costs, and for the recognition outside the price cap mechanism of costs of a "non compressible" nature, such as, for example, fixed costs for participation in transnational associations or projects.

In addition, the Authority has introduced changes in the method for recognising costs resulting from operating leases, as a result of the introduction of the new international accounting standard IFRS 16, which provides, as from 1 January 2019, for the recognition of the right to use the asset covered by the lease contract under fixed assets, effectively equating the accounting treatment of operating leases to their financial treatment.

With regard to the treatment of net revenues from the use of the electricity infrastructure for purposes other than those specific to the electricity service, a symmetrical sharing of these revenues

[26] Resolution 23 December 2015, 654/2015/r/eel.

was applied for the transmission service, consistent with what was already done in the half-period 2016-2019. In this regard, it should be noted that, unlike the previous half-period, the Authority has decided to update the operating costs recognised, in addition to the effect of the price cap, on an annual basis, also in order to take into account the annual change in net revenues recognised by the Transmission System Operator, for the purpose of adjusting the portion of sharing implicitly considered in the previous year's tariffs.

As regards the annual update of the costs recognised to cover operating costs in NPR2, the Authority has envisaged that it will confirm the possibility of determining the X-factor with the aim of gradually absorbing, by the end of NPR2 (i.e. by the end of 2023), part of the productivity gains achieved in NPR1.

For NPR2, the annual reduction rate of the recognised unit costs has been set at:

- 0.4% for the transmission service;
- 1.3% for the distribution service (including the service marketing costs);
- 0.7% for the metering service;

With reference to the general criteria for determining the cost of capital recognised for transmission, distribution and metering services, the methodology for NPR2 is expected to be substantially in line with the criteria adopted in the previous regulatory period, based on rate-of-return recognition formulas, limiting modification interventions to:

- a review of the work in progress (WIP) recognition mechanisms for the transmission service;
- the introduction of incentive mechanisms for the aggregation between distributors.

In order to cover the costs borne by distributors due to exceptional arrears situations that jeopardise the collection of network tariffs, a mechanism for the recovery of bad debts, managed by the Cassa per i Servizi Energetici e Ambientali (Energy and Environmental Services Fund - CSEA) on an annual basis, has been introduced using the model for the recognition of bad debts linked to the failure to collect the general system charges regulated in February 2018[27].

As regards the connection service, the deadline for the conclusion of the procedure for the overall streamlining of the rules on connection for active and passive points and for the revision of the cost allocation criteria, launched in November 2017, has been extended until the end of 2021, in order to take account of any regulatory changes that might also be necessary for the transposition of European Directives 2018/2001/EU and 2019/944/EU.

Finally, the Authority confirmed[28] its intention to gradually adopt the totex approach, through a specific consultation phase with operators, and to introduce, starting from NPR2, the necessary preparatory tools for a regulatory system based on a forward looking and output-based approach. The Authority has also expressed its intention to trial, from the last year of NPR2, the approach of

[27] Resolution 01 February 2018, 50/2018/r/eel.

[28] Resolution 09 April 2019, 126/2019/r/eel.

recognising the total cost to the transmission company and then to extend its application, from the next regulatory period, to larger electricity distributors.

Tariffs for the transmission, distribution and metering services

As a result of the process of defining the tariff criteria for NPR2, the Authority also approved[29] the tariffs for the provision of electricity transmission services for the year 2020 on the basis of the economic and balance sheet data communicated by the Transmission System Operator, for the purpose of updating the reference revenues to cover the costs of transmission and dispatching activities.

The Authority accepted Terna's request for partial readmission of the Italy-Montenegro interconnection to the list of strategic interventions for the 2012-2015 regulatory period, with consequent remuneration of assets under development in the 2016-2018 period and express waiver of the incentives introduced in 2015[30]. At the same time, it was planned to recover the economic items relating to previous recognitions received, and no longer due, by Terna. As of 2020, moreover, the scope of the transmission tariff also provides for coverage of costs linked to Terna's participation in the Inter-TSO Compensation mechanism, previously covered by the dispatching service fees, so as to align national regulation with the provisions of Regulation (EU) no. 943/2019. The transmission tariff also includes the costs relating to Terna's metering activities incurred as a result of the new responsibilities assigned to the company from 2017 and previously assigned to the distributors.

Finally, in December 2019, the tariffs for the transmission service applied to final customers (so-called compulsory tariffs) for the year 2020 were determined[31].

With regard to distribution and metering services, also in NPR2, consistently with the previous half regulatory period, the decoupling between the single tariff applied to final customers (the so-called compulsory tariff) and the reference tariffs defined to set the constraints on the revenues of each distributor continues to be applied. In December 2019, the compulsory tariffs applied to final customers for 2020 were determined[32].

Completion of the tariff reform for domestic customers

As described in the Annual Report 2019, last year the Authority ordered[33] a second postponement of the completion of the reform of tariff fees to cover general system charges for domestic customers, which began[34] on 1 January 2017, due to the extension of the effects of the extraordinary measures implemented in the second half of 2018; as a result of this postponement, the two-tier tariff structure already in force in 2018 was maintained until 31 December 2019. In December 2019, the Authority found that there were no further impediments to the completion of the reform and therefore a single rate for all levels of consumption, in relation to all elements of the A_{SOS} and A_{RIM} tariff components, would apply from 1 January 2020.

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[29] Resolution 27 December 2019, 568/2019/r/eel.

[30] Art. 20 of Annex A of Resolution 654/2015/R/eel.

[31] Resolution 27 December 2019, 568/2019/r/eel.

[32] Resolution 27 December 2019, 568/2019/R/eel.

[33] Resolution 05 December 2018, 626/2018/R/eel.

[34] Resolution 22 December 2016, 782/2016/R/eel.

In support of this last step, there was also a law provision[35] that introduced the automatic application (i.e., without the need for a request) of the electricity supply cost compensation amount to economically disadvantaged customers, the so-called electricity bonus, as of January 1, 2021, an innovation suggested several times by the Authority to the Government and Parliament, also in order to protect economically disadvantaged customers with low electricity consumption from the cost increases caused by tariff changes related to the completion of the reform. Consistent with these protection purposes, the Authority also updated[36] the amount of the electricity bonus, taking into account the different effects that the completion of the reform has on each consumer profile (small, medium and large households): the criterion set by the Ministry of Economic Development[37], according to which the bonus must be determined in such a way as to result in a reduction in expenditure, before tax, of about 30%, has been applied to each profile.

Subsidies for changes in committed power

As already illustrated in previous *Annual Reports*, with the entry into full force of the new network tariff structure, as of 1 January 2017, measures were implemented to facilitate domestic final customers in optimising their electricity supply expenditure, by searching for the level of committed power that best meets their needs (introduction of a broader range[38] of contractually committed power levels and reduction of the costs associated with each contract change for 24 months as of 1 April 2017). At the end of 2018 the validity of these subsidies was extended[39] until the end of the first half regulatory period (i.e. 31 December 2019) in order to promote greater use by customers.

As part of the aforementioned consultations held in 2019 for the purpose of updating the tariff criteria applicable in the second half regulatory period (2020-2023), the vast majority of stakeholders supported the proposal made by the Authority to extend the applicability of the subsidies for the entire four-year period, believing that full awareness of these opportunities among domestic final customers requires intense and protracted communication campaigns for extended periods. Consequently, the Authority ordered[40] a further extension until 31 December 2023 and, at the same time, the activation during 2020 of the equalisation mechanism (already provided for previously[41]) to offset the effects resulting from the non-application of the fixed contributions not due, in the period between 1 April 2017 and 31 December 2019, from domestic users who, during the same period, have requested changes in the committed power.

[35] Decree-Law No.124 of 26 October 2019, converted into Law No.157 of 19 December 2019.

[36] Resolution 27 December 2019, 572/2019/R/com.

[37] Decree of the Minister of Economic Development of 29 December 2016.

[38] Before this intervention, it was possible for domestic customers to obtain the following predetermined committed power values: 1.5, 3, 4.5 or 6 kW. From 1 January 2017, households can instead select the power value that best suits their needs, as it is now possible to choose from a much larger number of power levels, with steps of 0.5 kW for the most populated areas of domestic users, compared to the past. The customer can therefore choose: from 0.5 kW to 6 kW of committed power in 0.5 increments (0.5 - 1 - 1.5 - 2 - 2.5 - 3 - 3.5 -... - 6 kW) and in 1 kW increments from 6 to 10 kW (7 - 8 –9 - 10 kW); for higher values the power increases in 5kW increments.

[39] Resolution 18 December 2018, 671/2018/R/eel.

[40] Resolution 27 December 2019, 568/2019/R/eel.

[41] Resolution 22 December 2016, 782/2016/R/eel.

Tariff provisions in matters of second generation 2G smart metering systems

The Authority's guidance on updating the framework for the recognition of investments in second generation (2G) smart metering systems was expressed in the March 2019 consultation[42]. Subsequently, in July 2019, the guidelines for the cost recognition of 2G smart metering systems for metering low voltage electricity were updated[43].

The proposals presented in the March 2019 consultation stemmed from the need to avoid the risk of a two-speed country, i.e. maintaining, even for the second generation of smart metering systems, the same time lag (about 5 years) between different operators that had characterised the first generation; in fact, this would have meant that part of the users would have benefited from 2G smart metering systems with a considerable delay compared to the users served by the new systems in the initial phase. With this in mind, the following timeframes have been defined, valid for all electricity distributors with more than 100,000 customers:

- the commissioning plans for the 2G smart metering systems must start in 2022 at the latest;
- the phase of mass replacement of existing meters must be completed by 2026 for 95% of the meters (same percentage used for the first generation). A target of 90% of replacements by 2025 has also been set;
- a new calculation method for the so-called conventional plan (PCO2, used as a reference for modulating cost recognition) has been defined, which has the effect of shortening the time gap implicit in the previous mechanism defined[44] in November 2016 by three years.

In addition, taking into account the comments received, the Authority followed up the proposals regarding cost recognition mechanisms and penalties for failure to implement the commissioning plan or for failure to meet the expected performance levels of 2G smart metering systems. Among other things, it has been planned that, starting from the fourth year of each commissioning plan, tariff penalties will be introduced for failure to meet the expected performance levels of 2G smart metering systems, while monitoring will be carried out in the first three years of the plan. To this end, the operating procedures for calculating the service levels relating to remote reading and remote management, which are relevant for the possible application of penalties, have been defined[45].

Finally, in October 2019, the Authority concluded[46] the procedure started in April 2017[47] to define version 2.1 of the 2G smart meters. During this procedure, the Authority collaborated with a Technical Unit of the Communications Guarantee Authority (AGCOM), organising a technical seminar to present the results of the monitoring of communication performance between smart meters and interoperable user devices (chain 2) thanks to the standardised communication protocol prepared by the Italian Electrotechnical Committee (CEI). In light of the positive results of this monitoring, the Authority closed the procedure without changing the functional requirements of the 2G smart meters previously set[48], but inviting the operators to carry out, during the technical standardisation, a

[42] Document for consultation 100/2019/R/eel of 20 March 2019.

[43] Resolution 16 July 2019, 306/2019/R/eel.

[44] Resolution 10 November 2016, 646/2016/R/eel.

[45] Determination of the Directorate for Energy Infrastructure and Unbundling (DIEU) 23 December 2019, 7/2019.

[46] Resolution 15 October 2019, 409/2019/R/eel.

[47] Resolution 28 April 2017, 289/2017/R/eel.

[48] Resolution 08 March 2016, 87/2016/R/eel.

feasibility check of innovative solutions (so-called smart terminal cover) to accommodate the new opportunities of electronic communication technologies, with particular reference to the licensed band communication protocol (so-called *Narrow-Band Internet of Things* - NB-IoT).

State of incentives for renewable and assimilated energy sources

Table 3.3 summarises the general charges charged to the A $_3$ account in 2019 (preliminary data) compared with those of 2018. The values of the individual components in 2019 took into account, among other things, the revenue requirements for the A_3 account, also in the light of the extraordinary rate reduction decided in December 2018.

Table 3.3 Detail of charges charged to the A_3 account

Millions of euros

CHARGES	2018		2019	
	VALUE	SHARE	VALUE	SHARE
Purchase and sale of renewable electricity CIP6[(A)]	104	0.90%	20	0.18%
Withdrawal of green certifications	106	0.92%	6	0.05%
Conversion of GCs into incentives	3,006	25.96%	2,633	23.00%
Photovoltaic	5,806	50.15%	5,924	51.77%
Dedicated withdrawal	6	0.05%	28	0.24%
All-inclusive rate	1,823	15.74%	1,908	16.68%
On-site exchange	92	0.79%	136	1.19%
ERF administered incentives	462	3.99%	565	4.94%
Other (including ESO operation)	3	0.03%	3	0.03%
TOTAL RENEWABLES	11,408	98.53%	11,223	98.08%
Purchase and sale of assimilated electricity CIP6	159	1.38%	168	1.47%
Assimilated CO_2 costs	20	0.17%	49	0.43%
Recoveries/refunds of previous items CIP6 (CO_2 costs and other)	-9	-0.08%	3	0.02%
TOTAL ASSIMILATED	170	1.47%	220	1.92%
TOTAL COSTS A_3	11,578	100%	11,443	100%

(A) For simplicity, the portion relating to the energy produced by non-biodegradable waste is also included.

Source: ARERA. ARERA processing on ESO data.

Review of the methods for allocating costs relating to the energy efficiency certificates mechanism

In September 2019, the Authority launched[49] a consultation process, in which it explained the advisability of introducing some corrections to the way in which natural gas consumption is subject to the RE and RET[50] additional tariff components to cover the costs resulting from the Energy

[49] Document for consultation 375/2019/R/eel of 17 September 2019.

[50] These are the tariff components, respectively, for distribution for customers connected to the distribution networks and transmission for customers connected directly to the transmission network, expressed in euro cents/standard cubic meter,

Efficiency Certificates (EEC) mechanism. The appropriateness of these corrections stems from the fact that the price that thermoelectric producers offer in the electricity markets takes into account the costs incurred for production, including the RE and RET components applied to natural gas. As a result, there is a (physiological) reversal of the RE/RET components in the sales prices of electricity offered by gas-fuelled thermoelectric power plants (often leading to an increase in the National Single Price - PUN), resulting in an increase in the costs incurred by electricity customers. Moreover, the imposition of the above mentioned components on the gas consumed by gas-fuelled thermoelectric plants makes the latter less competitive compared to production plants using the same technology in other European countries, where the RE and RET components are not included, or even compared to national plants fuelled by other, even less efficient, sources; this effect, in addition to determining inefficient market outcomes, could favour production from sources with a higher environmental impact such as coal, which is paradoxical, since the RE and RET additional tariff components are specifically aimed at promoting energy efficiency and environmental sustainability.

For the reasons explained above, the Authority has proposed the adoption of new methods to set the tariff components applicable to the consumption of natural gas by thermoelectric power plants and to manage the related revenues. In short, the proposed solution consists in avoiding the application of the RE and RET components to the gas consumed for thermoelectric purposes for the part relating to Energy Efficiency Certificates, recovering the revenue lost by directly applying an increase in the A_{RIM} tariff component of the system charges to end electrical customers.

3.1.4 Regulation of network security and reliability

Dispatching regulation reform process

The regulation of the dispatching service is currently undergoing a comprehensive reform, which must be defined in accordance with European regulations (Capacity Allocation and Congestion Management - CACM, Electricity Balancing Guideline - EB GL, new electricity regulation[51] and new electricity directive[52]). As part of this process, a consultation[53] was carried out in July 2019 in which two macro-objectives were identified:

- the identification of the main lines of intervention for the development of the dispatching service as a result of the proliferation of non-programmable renewable sources and distributed generation, as well as the progressive disappearance of programmable plants that have historically made resources available to ensure a balance between electricity supply and demand;
- the completion of the integration of Italian markets with those of other European countries, taking into account the EU regulatory framework, with particular reference to the coupling of intraday markets, characterised by continuous trading (possibly integrated with auction mechanisms) and the shifting of the gate closure to the hour before the hour to which the negotiation refers, as well as the harmonisation and sharing of services necessary to ensure the security of the system (ancillary services).

to cover the charges borne by the Fund for Energy Saving Measures and Interventions and the Development of Renewable Sources in the Natural Gas Sector, as defined in the Integrated Text of the provisions regulating the quality and tariffs of gas distribution and metering services.

[51] Regulation (EU) 943/2019.

[52] Directive 2019/944/EU.

[53] Document for consultation 322/2019/R/eel of 23 July 2019.

In the consultation the Authority proposed separating commercial trading from the physical programming of the authorised and unauthorised units, considering this intervention appropriate in order to preserve the security of the electricity system as it allows maximum freedom of market participation. Participation in the day-ahead market (MGP) and the intraday market (MI) could take place for individual units or portfolios of units (authorised and unauthorised, distinguishing production units from consumption units) characterised by a geographical perimeter not exceeding the market area. The physical programming of individual units, on the other hand, would no longer derive (as is currently the case) from the results of trading on MGP and MI, but would be carried out separately, taking into account their technical characteristics and in different ways depending on whether or not the unit itself is authorised to participate in the dispatching services market (MSD). The reconciliation between the units' programming and the commercial position would be carried out by the Energy Market Operator (GME) at hour H-1, for each hour and for each portfolio held in the name of each market operator, and the resulting commercial balance could be valued at the imbalance price of the unauthorised units.

Pending the full definition and implementation of the regulatory changes described above, in July 2019 the Authority provided[54] transitional instructions to Terna and the GME in order to implement the measures strictly necessary to join the European continuous intraday market (XBID - Cross Border Intraday project), expected by the end of 2020, and for its coordination with the MSD.

With regard to the development of dispatching regulation, the consultation indicates the guidelines aimed at streamlining the criteria on the basis of which Terna - subject to the principles of neutrality, impartiality and efficiency and taking into account the results of the pilot projects[55] - will be called upon to:

- review the definition of ancillary services necessary for the security of the electricity system and the minimum performance requirements to be met in order to provide them;
- determine the reference perimeter of each ancillary service, defined as the boundary within which the service can be provided indiscriminately by production and/or consumption units (single or aggregated) without compromising the security of the electricity system;
- transparently define the requirements for each reference perimeter of each ancillary service;
- to ensure maximum participation in the provision of ancillary services by all potentially suitable (production or consumption) units (including production units powered by renewable sources, storage systems, distributed generation in general and consumption units), including in an aggregate manner; for this purpose, the definitions of 'unauthorised unit' and, above all, of 'authorised unit', including their perimeters and aggregation methods, are revised;
- review the ways in which ancillary services resources are procured and remunerated in the most efficient way, taking into account the time and logistical constraints that characterise the operation of the electricity system.

In relation to the valorisation of imbalances, the consultation reaffirms the intention to value them as consistently as possible with the dimensions of time, space and product type that characterise the

[54] Resolution 30 July 2019, 350/2019/R/eel.

[55] Launched with Resolution 5 May 2017, 300/2017/R/eel.

value of energy in real time (also using nodal prices, with due graduality). In this respect, the Authority proposes to provide for: a time dimension of 15 minutes also for the unauthorised units; a spatial dimension consistent with the new definition of units; the construction of imbalance prices based on nodal prices (the latter aspect, however, is still lacking in final proposals, both because usable nodal prices are not yet available and because European evaluations are under way in the context of the definition of implementing provisions of the European Balancing Regulation[56]).

In addition, initial guidance has been given on the evolution of the role of distributors in a context where distributed generation facilities are no longer negligible and therefore require more active management of distribution networks: as also provided for by Directive 2019/944/EU, distribution companies will have to assume not only the role of neutral facilitator for Terna's supply of ancillary services, but also that of buyer of resources for local ancillary services in contexts where the need arises (for example, contexts characterised by the presence of generation plants with critical issues in maintaining the correct voltage profile or those characterised by congestion caused by the growth in withdrawals to supply electric car recharging points or air conditioning systems). An experimental phase has been outlined which will precede the Authority's final guidance on the matter.

Finally, the consultation presents the Authority's guidance for the simplified regulation of dispatching in special contexts, with particular reference to non-interconnected islands, extending to these islands what has already been defined for Italian distribution networks only interconnected with foreign networks (in short, no programmes are defined and all the regulation of economic items takes place ex post within the framework of the regulation of imbalances on the basis of average prices). The aim of this simplified regulation is to avoid distortions arising from the absence of interconnections with the remaining parts of the national network, ensuring efficiency and transparency, and to implement simplified solutions that are suited to isolated realities.

The consultation in question will be followed by multiple actions aimed at completing the new regulation, which will replace the current one[57] and will update the related chapters of Terna's Network Code.

Changes to the electricity market regulations and updating of the Agreement between the Energy Market Operator and Terna

In July 2019, the Authority expressed[58] its favourable opinion to the Minister of Economic Development on the proposals for amendments to the Integrated Text on Electricity Market Regulation and Natural Gas Market Regulation, formulated by the Energy Markets Operator (GME) regarding the integrated management of guarantees in the spot markets for electricity and natural gas.

The above proposals were drawn up by the GME with the aim of introducing a single guarantee to cover the individual operator's net exposure to these markets in the day-ahead market, the intraday electricity market and the spot gas market. In addition, as part of the launch of integrated guarantee management, the GME proposed to reduce the guarantee models to be used in the electricity and gas markets in order to simplify their operation.

[56] Regulation (EU) 2195/2017.

[57] Introduced with Resolution of 6 June 2006, 111/06.

[58] Opinion of 16 July 2019, 309/2019/I/com.

In October 2019, therefore, the Authority approved[59] the proposals to amend the regulations of the Forward Energy Accounts Platform (PCE) and the related Technical Operating Provisions (DTF) formulated by the GME in order to adapt their content to the innovations introduced in the electricity and natural gas markets with regard to the integrated management of guarantees.

Moreover, in November 2019, the outline of the agreement between the GME and Terna was positively evaluated[60] and sent to the Authority in the version that takes into account the above-described amendments to the electricity market regulations and the regulations of the Energy Accounts Platform.

Finally, in November 2019, the Authority delivered an opinion to the Minister of Economic Development on the GME proposal to repeal the provisions governing the operation of the Energy Derivatives Delivery Platform (CDE). This platform, active since November 26, 2009, was born from the collaboration between GME, Borsa Italiana and Cassa di compensazione e garanzia, with the aim of allowing the physical delivery of Borsa Italiana's financial contracts concluded on the electricity derivatives market (IDEX - Italian Derivatives Energy Exchange).

In view of the lack of recourse to physical delivery, Borsa Italiana, after carrying out a specific consultation procedure with its operators, has informed the GME that it wishes to remove this delivery option from the contracts concluded on the IDEX. This necessitated, inter alia, an adaptation of the electricity market regulation aimed at repealing the provisions related to the functioning of the CDE platform, which the Authority welcomed[61] in November 2019. In the following month, the Authority approved[62] the proposals for amendments to the regulation of the Energy Accounts Platform put forward by the GME as a result of the interruption of the CDE platform's operations.

3.1.5 Monitoring balance of electricity supply and demand

The monitoring balance of electricity supply and demand is not part of the Authority's competences: according to Art. 1 of the legislative Decree n. 93/11 this competence was attributed to the Ministry for Economic Development (MSE).

3.1.6 Monitoring of investments in generation and storage capacity from a security of supply perspective

According to the Legislative Decree n. 93/11, the following functions in matters of monitoring of the capacity investments have been attributed to the MSE:

- network operating security (Art. 7 of Directive 89/2005/CE);
- investments in the interconnection capacity in the next 5 years or more (Art. 7 of Directive 89/2005/CE);
- expected demand and supply for the next 5 years and 1-15 years (Art. 7 of Directive 89/2005/CE).

[59] Resolution 15 October 2019, 411/2019/R/eel.

[60] Resolution 19 November 2019, 477/2019/R/eel.

[61] Opinion of 26 November 2019, 496/2019/I/com.

[62] Resolution 17 December 2019, 550/2019/R/eel.

3.1.7 Implementation of Network Codes and guidelines

Integration of wholesale electricity markets and implementation of European regulations

European regulations relating to the electricity market are technical regulatory measures functional to the completion of the internal energy market. Regulation (EC) 714/2009, in line with the regulation for the electricity market of the so-called Third Package, has defined its areas of intervention and indicated the development and approval procedures that ended in 2017. Informally, the regulations can be grouped into three main families: market, connection and network management. The complete list is reported in Table 3.4.

The regulations are divided into Network Codes (NC) and Guidelines (GL): the former primarily identify rules that can be directly implemented at a national level while the latter focus on general indications on the basis of which implementing provisions, called Terms and Conditions or Methodologies, must be prepared. It follows that the publication of the regulations does not end the development and publication of secondary legislation; on the contrary, each regulation in the form of a guideline foresees, within it, the preparation of specific rules (the methodologies, precisely) by the network operators (Transmission System Operator - TSO) and/or the designated market operators (Nominated Electricity Market Operator - NEMO) that the regulatory authorities of each Member State of the European Union are required to assess and approve; the development of methodologies is also envisaged within the network codes, albeit to a lesser extent and limited to detailed aspects or the specification of certain parameters at national level.

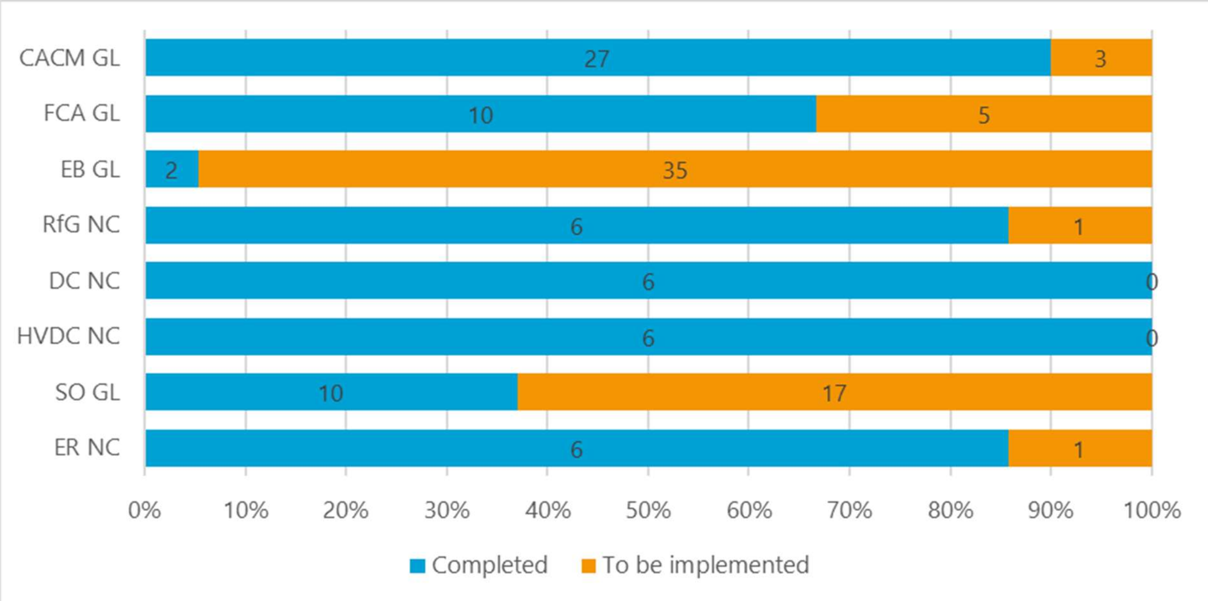
Table 3.4 Table 3.8 Network Codes and guidelines provided by the Regulation (EC) 714/2019

CODE	REGULATION	ABBREVIATION (ACRONYM)	ENTRY INTO FORCE
Market codes	(EU) 2015/1222	Capacity allocation and congestion management guideline (CACM GL)	15 August 2015
	(EU) 2016/1719	Forward capacity allocation guideline (FCA GL)	17 October 2016
	(EU) 2017/2195	Electricity balancing guideline (EB GL)	18 December 2017
Connection codes	(EU) 2016/631	Requirements for generators network code (RfG NC)	17 May 2016
	(EU) 2016/1388	Demand connection network code (DCC)	07 September 2017
	(EU) 2016/1447	High voltage direct current network code (HVDC NC)	28 September 2016
Network management codes	(EU) 2017/1485	System operation guideline (SO GL)	14 September 2017
	(EU) 2017/2196	Emergency and restoration network code (ER NC)	18 December 2017

Source: ARERA.

The methodology development process was started in 2015 with reference to the CACM GL regulation, and then extended between 2016 and 2017 to all other guidelines and network codes. Figure 3.3 summarises the state of implementation at the end of 2019: most methodologies concern the regulations adopted in the form of guidelines, while the network codes use this instrument of further standardisation to a lesser extent. It is also clear that the state of implementation is substantially different for the various regulations. On the market side, most of the work concerns the EB GL Regulation, which entered into force in December 2017, for which only two methodologies were approved at the end of 2019 and 35 remain pending, three of which were however approved by ACER in early 2020. On the network management side, the pathway of the SO GL regulation is about halfway through, while the pathway of the ER NC regulation is almost complete. On the side of the connection codes, the implementation is almost finished: in fact, only the methodology with the criteria of the cost/benefit analysis for the retrofitting of existing plants is missing, which will be developed only when the Authority actually intends to evaluate measures in this sense.

Figure 3.3 State of implementation of the forecasts of network codes and guidelines in Italy



Source: ARERA.

The geographical scope for the adoption of the methodologies is quite varied, as they can have a pan-European, regional or national dimension. Until the adoption of Regulation (EU) 942/2019 on the operation of ACER, decisions at pan-European level involved all EU regulators and were taken in the framework of a cooperation platform called the Energy Regulators' Forum (ERF). With the new Regulation, the Agency has been made responsible for these decisions. Several methodologies related to the CACM GL and FCA GL regulations refer to the so-called Capacity Calculation Regions (CCR), approved[63] by ACER in November 2016. Italy is part of the CCR Italy North, which includes the borders with France, Slovenia and Austria, and of the CCR Greece-Italy, which includes the border with Greece and those between the internal areas of the national territory; but it is also attentive to developments in methodologies concerning the CCR Core (which includes Central Europe from France to Romania), as the CACM GL regulation envisages the merger of the CCR Italy North with the CCR Core. For the decisions taken with reference to the CCR Italy North and Greece-Italy the Authority has promoted the establishment (in 2017) of regional cooperation platforms (respectively INERRF - Italy North Energy Regulators' Regional Forum and GIERRF - Greece-Italy Energy Regulators' Regional Forum). The SO GL Regulation foresees some methodologies referring to the

[63] Decision No. 06-2016 of 17 November 2016.

CCRs (which will then be evaluated in the INERRF and GIERRF regional forums), while other methodologies are specific to each synchronous area, i.e. the portion of the European network sharing the same frequency. In this regard, Italy is included in the Continental Europe synchronous area. Finally, the EB GL regulations operate with highly variable geometry depending on the involved methods: it goes from perimeters that include only the Member States that are meant to use balancing produced data, to perimeters coinciding with the CCRs, to perimeters that consider the agreements for the exchange of specific resources. The cooperation for synchronous areas and specific perimeters provided for in the EB GL regulation is usually defined from time to time by the regulatory authorities involved, without the use of any specific cooperation platform.

Integration of wholesale electricity markets: market codes

During 2019, the Authority was involved in the implementation of the market codes at both pan-European and regional level. The main interventions for 2019 are presented below, separate for each code, together with an overall framework for the integration of electricity markets at European level.

Forward capacity allocation (FCA)

The FCA GL regulation describes the requirements and criteria for the issue and allocation of long-term transmission rights (with a time horizon of up to one year) between market areas within the European Union. For Italy, the Regulation in question applies on the borders with France, Austria, Slovenia and Greece; similar provisions to those in the FCA GL Regulation are also in force on the border with Switzerland as a result of bilateral agreements, while for areas within the national territory the Authority continues to rely on the coverage products in force to date (CCC and CCP), in line with what was decided in 2017. During 2019 the Authority approved[64] the methodology for the allocation of congestion rents emerging from the allocation of transmission rights and participated in the regional round tables aimed at defining how the available capacity on each border between market areas is calculated for the long term (annual and monthly) and how this capacity is allocated to products with annual and monthly allocation. As far as CCR Greece-Italy is concerned, the activity was concluded in November 2019 with the TSOs sending the final version, which was then approved by the regulatory authorities at the beginning of 2020; on the side of CCR Italy North, on the other hand, preliminary interactions with the region's TSOs took place in 2019. Finally, the year 2019 saw ACER update the harmonised rules for the allocation of transmission rights valid throughout Europe[65]. These rules were then also implemented on the Italian-Swiss border, in continuity with existing practices and the fact that the allocation of transmission rights on this border is carried out by the same allocation platform (JAO) used at European level; the preliminary investigation in this regard took place in the last months of 2019, while the approval measure was adopted in early 2020[66].

Capacity allocation and congestion management (CACM GL)

The CACM GL regulation defines the methods for implementing market coupling at European level over the daily (with capacity allocation through implicit auctions within so-called Single Day Ahead Coupling - SDAC) and intraday time horizons (with capacity allocation through continuous trading in so-called Single Intra Day Coupling - SIDC, accompanied by specific capacity enhancement mechanisms and voluntary regional implicit auctions).

[64] Resolution 25 June 2019, 274/2019/r/eel.

[65] ACER decision no. 14-2019 of 4 November 2019.

[66] Resolution 28 January 2020, 21/2020/R/eel.

Prior to the entry into force of the CACM Regulation, voluntary market coupling initiatives were developed in regional areas, both for the day-ahead and intraday markets. In particular, as regards the latter, European network and market operators have implemented the Cross Border Intraday (XBID) project, which has been taken as the basis for the implementation of the SIDC referred to in the CACM GL. The project, which started within an initial cluster of countries of the Union, is gradually being extended to all Member States. The project became operational in 15 countries on 12 June 2018[67]; subsequently a further 7 countries were added on 19 November 2019[68]. Italy's entry into the SIDC is expected for the fourth quarter of 2020. The recent geographical expansion of coupling has brought to light some critical issues inherent in the transfer of net positions (shipping) between central counterparties (CCPs). In particular, the shipping model adopted by the project participants provides that CCPs not operating in neighbouring areas must use the intermediation of CCPs operating in transit areas in order to settle economic items. As the project participants did not reach an agreement on how to regulate the service provided by the intermediary (transit shipping agent), in February 2020 they informed the European regulators, asking them to take a decision in accordance with Article 68(6) of the CACM. The regulators' decision is expected in 2020.

As far as the market of the day before is concerned, the regional initiatives have given rise to two major projects:

- Multi Regional Coupling (MRC), following the merger of the regional projects of central-western Europe, northern Europe, south-western Europe and the Italian borders;
- Four Markets Market Coupling (4M MC), comprising the borders between Romania, Hungary, the Czech Republic and Slovakia.

Following the merger of the two projects, expected for the second half of 2020, the SDAC will start. The merger process involves the Austrian, Polish and German regulators directly on behalf of the MRC project and all the regulators from the countries of the 4M MC project.

With the entry into force of Regulation (EU) 942/2019, the task of approving pan-European methodologies under the CACM and related amendments has been transferred to ACER. On 1 August 2019, the NEMO submitted an amendment to the so-called Algorithm Methodology to ACER in order to include a procedure to manage changes to the coupling algorithms (Change Control Methodology) and a procedure to monitor their performance (Monitoring Methodology), as well as to implement the requirements of the TSOs to determine the capacity price in the intraday market. In January 2020 ACER approved[69] the amendment.

The CACM GL regulation also provides for the development of regional methodologies. In this respect, 2019 was a particularly successful year for the Italy North CCR, as the methodologies for countertrading and redispatching and for calculating capacity on daily and intraday horizons were approved: these are significant steps towards full integration of the national market in the European context.

[67] Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Latvia, Lithuania, Luxembourg, Norway, Holland, Portugal, Spain, Sweden.

[68] Bulgaria, Croatia, Poland, Czech Republic, Romania, Slovenia, Hungary.

[69] Decision No. 04-2020 of 30 January 2020.

Also at the regional level, the Authority also continued the process of implementing the intraday market on the Italian borders: in May 2019, the design of the complementary intraday auctions (Greece-Italy and Italy North), which will accompany the intraday coupling based on continuous trading, was definitively approved[70].

In addition to the implementation of the different methods, the CACM regulations also govern the review methods of the configuration of the market areas at European, regional (CCR) and national levels.

On the European side, the entry into force of Regulation (EU) 943/2019 provided for a new[71] attempt at review: in this respect, the regulatory authorities are required to unanimously approve the methodology setting out the analysis criteria and alternative configurations being assessed. In October 2019, the TSOs sent a first proposal to the regulators, but it was considered incomplete because it lacked sufficient alternative configurations.

The reviews launched at European level also absorbed review projects of regional interest. At the national level, on the other hand, the Authority and Terna have promoted a project to review the areas within the Italian territory, to be conducted in accordance with the principles of the CACM regulation and with the aim of achieving a zonal configuration capable of more effectively reflecting the actual state of the markets and the national electricity system than the previous review, approved back in 2012. In particular, the review process, which began at the beginning of 2018, saw Terna send, in May of the same year, the final proposal for the repeal of the limited production hubs of Foggia, Brindisi and Priolo, the transfer of Umbria from the Centre-North area to the Centre-South area and the replacement of the limited production hub of Rossano with a new physical area of Calabria. In March 2019, the process was completed: the review of the market areas was completed, with full approval[72] of the proposal sent by Terna in May 2018, with effect from January 1, 2021.

Balancing (BAL GL)

Regulation (EU) 2195/2017 establishes the modalities for the implementation of the European balancing market, with regard to trade in balancing capacity and balancing energy, as well as criteria for the harmonisation of settlement mechanisms between TSOs and the criteria for calculating the value of imbalances.

During 2019, the Authority was involved, together with all European regulators, in a challenging decision-making process concerning a package of six methodologies for the implementation of the BAL GL Regulation, developed and sent by European TSOs at the end of 2018. These methodologies constitute the main structure of the future European balancing market and provide the implementation specifications of common energy trading platforms, pricing rules and settlement between TSOs. The main decisions made by European regulators regarding BAL GL and the Authority's related measures are illustrated below.

Within the package of methodologies discussed, the most controversial proposals, which engaged much of the debate in the first half of 2019, were, on the one hand, the proposal for a framework for the implementation of a platform for the exchange of balancing energy from frequency restoration reserves with manual activation (mFRR) frequency restoration reserves with automatic activation

[70] Resolutions 7 May 2019, 174/2017/R/eel, and 28 March 2019, 210/2018/R/eel.

[71] A first attempt at zonal review ended in 2018 without introducing changes (it was suggested to maintain the current configuration), due to the difficulties both in identifying alternative zonal configurations and in implementing an analysis that took into account all the criteria provided for in the CACM regulation.

[72] Resolution 19 March 2019, 103/2019/R/eel.

(aFRR) and, on the other, the proposal for determining the price of balancing energy, formulated, respectively, pursuant to Articles 20, 21 and 30 of the BAL GL. Due to diverging views on some crucial issues, European regulators could not reach unanimity for a decision on these issues and therefore the process ended with the transfer of the decision to ACER, accompanied by an opinion paper in which regulators outlined their views on the content of the methodologies.

Contrary to the outcome of the first three proposals, the European regulators reached unanimity in their request for amendments to:

- methodologies relating to the settlement of intentional exchanges between TSOs (art. 50.1 of the BAL GL);
- the classification of the activation purposes (art. 29.3 of the BAL GL);
- harmonisation of imbalance settlement (art.52.2 of the BAL GL).

The Authority formalised these decisions in July 2019[73]. The proposals amended according to the instructions of the European regulators were sent by the TSOs, as required by the Balancing regulation, within two months of the regulators' decision; however, following the entry into force of Regulation (EU) 942/2019, the task of approving the pan-European methodologies and the related amendments has been transferred to ACER, therefore the final decision will be taken by the European Agency during 2020, by a vote in the Board of Regulators.

In addition to the package of six pan-European methodologies outlined above, the Authority has been asked to comment on two regional methodologies, whose perimeter coincides with the European synchronous area, to define the settlement criteria for unintentional exchanges and exchanges due to ramping and the primary reserve, between the synchronous area systems. The decision-making process ended with a unanimous request for amendments to the proposals, formalised by the Authority in December 2019[74].

Finally, in January 2019, the Authority adopted two measures relating to methodologies sent by the TSOs in June 2018. The first concerns the approval[75] of the methodology for an implementation framework for a platform for the exchange of balancing energy from replacement reserves, while the second[76] concerns instructions to Terna to amend the proposed methodology for an implementation framework for an imbalance clearing platform. The amended proposal for this second methodology was sent during 2019 and in July 2019 the Authority formalised[77] a new request for amendments for further improvements and corrections. The new amended proposal was approved by the TSOs in October, but, following the entry into force of Regulation (EU) 942/2019, as for the other methodologies mentioned above, the final decision will be taken by the European Agency in the course of 2020, by a vote in the Board of Regulators.

[73] Resolutions 30 July 2019, 348/2019/R/eel, 30 July 2019, 349/2019/R/eel and 16 July 2019, 310/2019/R/eel.

[74] Resolution 17 December 2019, 545/2019/R/eel.

[75] Resolution 15 January 2019, 8/2019/R/eel.

[76] Resolution 15 January 2019, 7/2019/R/eel.

[77] Resolution 23 July 2019, 323/2019/R/eel.

Connection codes

The connection codes define the requirements to be met by the various users connected to the electrical system, from generators (RfG NC), to demand response service providers (DCC NC), to operators operating direct current connections (HVDC NC). These codes are implemented at national level without the need for any form of coordination at European level.

In the course of 2016, the European Commission, by various acts, based on the provisions of Regulation (EU) 714/2009[78], issued Regulation (EU) 631/2016 (RfG Regulation - Requirements for Generators), Regulation (EU) 1388/2016 (DCC Regulation - Demand Connection Code) and Regulation (EU) 1447/2016 (HVDC Regulation - High Voltage Direct Current). These regulations, binding in their entirety and directly applicable in each of the Member States, were implemented during 2019. They help to ensure a level playing field in the internal electricity market, to ensure system security and integration of renewable energy sources and to facilitate trade in electricity within the European Union.

The RfG Regulation entered into force on 17 May 2016, applies in the Member States from 27 April 2019 and establishes a network code on the requirements for the grid connection of power-generating facilities, (synchronous power-generating modules, power park modules and offshore power park modules), to the interconnected system.

The DCC Regulation entered into force on 7 September 2016, applies in Member States from 18 August 2019 and establishes a network code laying down the requirements for the grid connection of transmission-connected demand facilities, transmission-connected distribution facilities, distribution systems including closed distribution systems (SDC), and demand units used by a facility or closed distribution system to provide demand management services to relevant system operators and TSOs.

The HVDC Regulation entered into force on 28 September 2016, applies in Member States as of 8 September 2019 and establishes a network code laying down the requirements for the grid connection of high voltage direct current (HVDC) systems and direct current-connected power generation parks.

In order for the three above-mentioned regulations to be fully implemented in Italy from the dates indicated, it was necessary to update the current regulation, with particular reference to the technical conditions for connection, which is the essential issue they deal with. In particular, it was necessary to update the Integrated text of active connections[79], as well as Terna's Network Code and the CEI 0-16 and 0-21 standards, in the parts that relate to the technical conditions for connection.

[78] Regulation (EU) 714/2009 establishes non-discriminatory rules governing access to the network for cross-border exchanges in electricity in order to ensure the proper functioning of the internal market in electricity. The Regulation, inter alia, points out that, in order to ensure the security of the interconnected transmission system, it is essential to establish a common interpretation of the requirements applicable to interconnectors (understood both as production plants and as consumption units). These requirements, which contribute to maintaining, preserving and restoring system security in order to facilitate the proper functioning of the internal market in electricity within and between synchronous areas and to achieving cost efficiency, should be considered as cross-border network and market integration issues. This makes it appropriate to define harmonised rules on network connection, in order to establish a clear legal framework, facilitate trade in electricity within the European Union, ensure system security, facilitate the integration of renewable energy, foster competition and enable more efficient use of the network and resources, to the benefit of consumers.

[79] Annex A to resolution 23 July 2008, ARG/elt 99/08

Following the Authority's approval of the amendments to Terna's Network Code for the implementation of the RfG, DCC and HVDC regulations, the Italian Electrotechnical Committee (CEI) published the new editions of CEI standards 0-16 (concerning connections to medium and high voltage distribution networks) and 0-21 (concerning connections to low voltage distribution networks). The Authority also mandated[80] Terna to amend the Network Code and its annexes in order to integrate them with the new provisions. In fulfilling this mandate, Terna revised several parts of the Network Code, streamlining its various chapters and annexes, and standardising some technical prescriptions that differed according to the different types of electricity production plants.

The Authority approved[81] the amendments to the Network Code proposed by Terna, stipulating that they are already applicable to new plants or units or systems, as well as to existing plants or units or systems, if they are subject to significant changes or partial refurbishment.

Network operation codes

The regulations on network operation, which came into force in the second half of 2017, contain provisions on the operation of the transmission network, both in normal and alert states (SO GL) and in emergency and recovery conditions (ER NC).

With regard to the SO GL Regulation, in 2019 the methodologies for the Continental Europe synchronous area were approved, namely the criteria for the sizing of the primary frequency reserve and for the definition of the limits for the sharing and exchange of secondary and tertiary reserves with neighbouring synchronous areas[82] and the modalities for the cost-benefit analysis aimed at determining the delivery period for primary frequency regulation for devices with reduced energy availability[83]. The Authority then began evaluating the methodologies prepared by Terna with regard to the Load-Frequency Control block (LFC block) Italy, with reference to actions aimed at containing frequency deviations and the criteria for sizing the secondary reserve. Terna has been given[84] specific instructions in this regard.

The ER NC regulation, as a network code, makes limited use of terms, conditions and methodologies subject to scrutiny by regulatory authorities. The regulator's intervention is, in fact, limited only to national implementation, with reference to the contractual conditions that govern the performance of system users involved in the power system's defence and recovery plans, the rules for the suspension of market activities in emergency and recovery conditions, the economic remuneration of balancing services and the valuation of imbalance fees in the event of suspension. The proposals, sent by Terna at the beginning of 2019, were approved by the Authority at the end of the year[85].

[80] Resolutions 592/2018/R/eel and 82/2019/R/eel.

[81] Resolution 17 December 2019, 539/2019/R/eel.

[82] Resolution 16 April 2019, 156/2019/R/eel.

[83] Resolution 02 April 2019, 120/2019/R/eel.

[84] Resolution 21 May 2019, 198/2019/R/eel.

[85] Resolution 17 December 2019, 546/2019/R/eel.

Assessment of coherence between the Ten-Year National Transmission Grid Development Plan and the Community-wide TYNDP Development Plan

The Authority has assessed the coherence between the Ten-Year National Transmission Grid Development Plan and the Community Ten Year Network Development Plan (TYNDP) in their contributions:

- to ACER opinion No. 11-2019 of 25 March 2019 on the draft TYNDP 2018;
- to ACER opinion No. 13/-2019 of 22 May 2019 on the electricity projects of the national development plans and in the TYNDP 2018;

In opinion no. 11-2019 it is noted that some projects - in line with the Authority's opinion[86] of December 2018 - must be considered "under evaluation" (i.e. without implementation activities within the ten-year horizon of the Plan) and excluded from the so-called TYNDP reference network (basic network structure), when applicable. Specifically, these are the projects:

- second pillar of the Italy-Montenegro project;
- Italy-Tunisia interconnection;
- Italy-Slovenia HVDC;
- merchant line Castasegna (CH)-Mese;
- 220 kV Lienz (AT) -Veneto project.

Opinion no. 13-2019 highlights that two investments with cross-border relevance - present in the Italian Development Plan - are not included in TYNDP 2018:

- the project with code 252-N, Dobbiaco-Lienz (AT);
- the project with code 206-P, Volpago station.

Moreover, the same opinion calls for the elimination of the 380 kV Lienz (AT)-Veneto investment from the TYNDP project with code 325, as the investment is no longer present in the Austrian and Italian plans.

Previously, the Authority had provided its contributions to ACER's monitoring of the European TYNDP, the results of which are reported in ACER Opinion No 6-2019 of 15 January 2019. Monitoring shows that a significant percentage (about one third) of projects, both at Italian level and more generally at European level, are lagging behind, mainly due to authorisation problems.

[86] Opinion of 18 December 2018, 674/2018/I/eel.

3.2 Competition and market functioning

3.2.1 Wholesale markets

Table 3.5 shows the balance for electricity in Italy in 2019 compared with the previous year; the data are from Terna sources and are provisional for 2019. Electricity demand decreased by 1% in 2019. The decline affected the agricultural and industrial sectors (-2%), while domestic consumption grew by 1% and tertiary sector consumption remained virtually unchanged. About 88% of national demand for electricity was met by domestic production (up by 1% from 2018) and the remainder by the foreign balance. Imported energy decreased by 7%, while exported energy increased (78%), recording a balance of energy exchanged with foreign countries up by 13%.

Table 3.5 Terna's balance of electricity in Italy

GWh

	2018	2019(A)	VARIATION
Gross production	289,708	291,693	1%
Auxiliary services	9,864	8,853	-10%
Net production	279,845	282,840	1%
Received from foreign suppliers	47,170	43,980	-7%
Sold to foreign customers	3,271	5,817	78%
Destined to pumping	2,312	2,412	4%
Availability for consumption	321,431	318,591	-1%
Network losses	17,988	17,177	-5%
Consumption net of losses	303,443	301,414	-1%

(A) Provisional data.

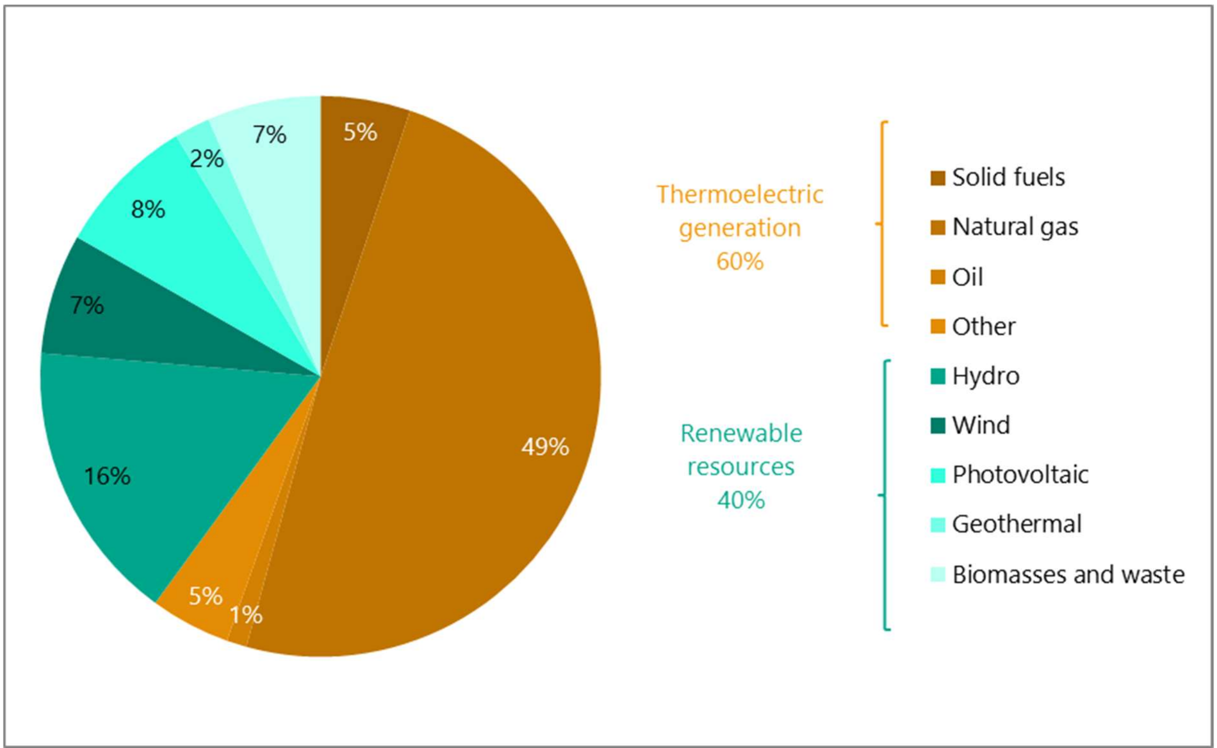
Source: ARERA processing on Terna data.

In 2019 gross domestic production reached 291.7 TWh from 289.7 TWh in 2018. The weak recovery (+0.7%) follows a decline of around 2% in 2018, which had interrupted growth at rates above 2% in the previous two years. The increase occurred both in thermoelectric production, up from 173.6 to 175.1 TWh (+0.9%), and in production from renewable sources, up from 114.4 to 114.8 TWh (+0.4%).

In 2019, as in the previous year, 40% of gross electricity was generated from renewable sources, while 60% was generated by thermoelectric power plants; among these, natural gas accounted for 49% of total gross generation (Figure 3.4), an increase compared with the previous year (44%). In fact, thermoelectric production has returned to the levels of 2015, after the collapse of 2018, with the gradual replacement of coal and oil products with gas.

Table 3.6 shows, for thermoelectric and renewable sources, the number of producers, available power and related production in 2019, using data collected by the Annual Survey on Regulated Sectors carried out by the Authority, which this year covers 95% of the generation indicated by Terna. The table shows that operators holding about half of the power, for a total of 50,600 MW, represent about 2% (336) of the total (14,297) and are mixed producers, with both thermoelectric and renewable generation. While the number of these entities and their available power relative to the total remain stable over time, the percentage contribution to total production, currently about 40% of gross generation (106.6 GWh out of 276.5 GWh), appears to be down from the levels of 2016 and 2017 (when it was about 50%). More than half of this power (52%) is held by 99 companies, for which the renewable source accounts for between 30% and 60% of gross power; the number of operators guaranteeing this share of power is up on the previous year (89 in 2018).

Figure 3.4 Gross production by source in 2019



Source: Terna, provisional data.

Table 3.6 Electricity producers, plants and generation in 2019

PRODUCERS, PLANTS AND GENERATION BY SOURCE	THERMOELECTRIC	RENEWABLE	MIXED	TOTAL
Number of producers	440	13,521	336	14,297
Gross power (MW)	19,546	35,046	50,625	105,216
Gross generation (TWh)	83.2	86.7	106.6	276.5

Source: ARERA. Annual Survey on Regulated Sectors.

The share of gross generation of the top three corporate groups (Enel, Eni and Edison), C3, was slightly down (33.7% compared with 35.7% in 2018), while those of A2A and EPH, which are respectively the fourth and fifth largest groups in Italian electricity generation, increased slightly. Except for the significant decrease (two and a half points) in the Enel group's contribution, the differences from one year to the next are marginal, less than 1%, for all corporate groups with a share of more than 1.5% compared to Terna's total. Overall, the changes offset each other, as they are attributable to a slight redistribution of market shares. The largest, albeit small, increases are recorded for the groups in which the share of hydroelectric production is significant. The share of the other smaller producers is unchanged compared to the previous year.

Table 3.7 Development of the wholesale market

YEAR	REQUIREMENT(A) (TWh)	PEAK DEMAND (GW)	NET INSTALLED CAPACITY (GW)	CORPORATE GROUPS WITH >5% SHARE IN NET GENERATION	SHARE% OF THE FIRST 3 GROUPS IN NET GENERATION
2001	304.8	52.0	76.2	4	70.7
2002	310.7	52.6	76.6	3	66.7
2003	320.7	53.4	78.2	4	65.9
2004	325.4	53.6	81.5	5	64.4
2005	330.4	55.0	85.5	5	59.4
2006	337.5	55.6	89.8	5	57.1
2007	339.9	56.8	93.6	5	54.7
2008	339.5	55.3	98.6	5	52.0
2009	320.3	51.9	101.4	5	50.6
2010	326.2	56.4	106.9	5	48.2
2011	332.3	56.5	118.4	4	43.6
2012	325.5	54.1	124.2	3	41.2
2013	316.0	53.9	124.7	3	39.1
2014	308.2	51.6	121.8	3	41.2
2015	315.0	60.5	118.3	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(B)	317.2	58.8	116.1	5	33.4

(A) Net of the energy destined to pumping and gross of network losses.
(B) Provisional data.

Source: ARERA processing on Terna data and Annual Survey on Regulated Sectors.

The other power generation concentration indices were also down: the C5 on gross generation fell from 46.5% to 45.2%, as did the Herfindahal-Hirschman Index (HHI) on gross generation, which stood at 546 in 2019, down from 615 in 2018. The number of corporate groups with at least 5% of net generation has increased to 5, one more than in 2018.(Table 3.7). The C3 calculated on net generation also drops by two percentage points compared to 2018, reaching 33.4%.

In Italy there are many incentive mechanisms for power generation plants powered by renewable sources, ranging from all-inclusive incentivising feed-in tariffs[87] to incentivising premium feed-in tariffs[88]. All in all, in 2019, the incentive instruments enabled an amount of electricity equal to just over 63 TWh (preliminary data) to be incentivised, almost the same amount incentivised in 2018. In 2018, 33% of the 63.3 TWh of incentivised renewable energy was produced by photovoltaic plants, 27% by wind farms, 25% by biomass, 13% by water plants and, finally, 2% by geothermal energy.

[87] Feed-in tariff means that the incentive recognised for the electrical energy input in the network includes the sale of electricity that is therefore no longer available for the producer. The electricity input into the network is withdrawn at a price that includes the incentive.
[88] Feed-in premium means that the incentive recognised for the electricity produced doesn't include the sale of electricity, which is still available for the producer.

According to preliminary data, these shares will not change substantially in 2019: 34% come from solar, 26% from wind and 25% from biomass, 12% from water and 3% from geothermal.

With the abolition (in 2016) of the green certificate mechanism, the costs deriving from the incentive of renewable sources is generally covered with a tariff component called A_{SOS}. In addition to the costs mentioned above, this component[89] also allows for the provision of special commercial schemes (minimum guaranteed prices and on-site exchange) and the provision of incentives for cogeneration (also for plants combined with district heating systems powered by non-renewable sources). For the year 2019, it is estimated that, at the end of the year, the costs resulting from the incentives for renewable sources alone will amount to approximately 11 billion euros, while the total costs (including, therefore, the additional commercial regimes described above) borne by the A_{SOS} tariff component will be just under 11.4 billion euros.

As mentioned above, electricity demand decreased slightly (-0.6%) compared with the previous year, falling to 319.6 TWh from 321.4 TWh in 2018. Consistently, the foreign balance also decreased by 13.1%, because in 2019 Italy imported 38.2 TWh compared to 43.9 TWh in 2018. As a result, the share of domestic demand covered by the foreign balance has returned to 11.9%, the same level as in 2016 and 2017. The decrease in the foreign balance is due to a sharp reduction in imports, which fell to 44 TWh in 2019 from 47.2 TWh in 2018, accompanied by a marked increase in exports (78%), which were 2.6 TWh higher than in 2018. In fact, exports reached 5.8 TWh compared to 3.3 TWh in the previous year. Maintenance campaigns and, consequently, the difficulties of French nuclear plants in meeting foreign demand, are at the root of both the phenomena outlined above for Italy, namely the reduction in our imports and the increase in our exports.

As ever, Switzerland is the country from which the greater part of our foreign balance (56%) arrived. Another 38% of the net imported electricity came from France, and 13% from Slovenia. Only 3% came from Austria. Market coupling has been operative towards Slovenia, France and Austria for a long time.

In 2019 the total net power was 116 GW (Table 3.7; provisional figure), which is divided between 47% renewable and 53% thermoelectric. Peak demand occurred on 25 July, when power requirements at the peak reached 58.8 GW (57.6 GW on 31 July 2018). The summer peak for 2019 remained below the absolute maximum peak for the Italian electrical system, recorded in summer 2015 (equal to 60.5 GW).

There are three groups with a net installed capacity share of more than 5%: Enel (23.7%), A2A (7.8%) and Edison (5.9%); in 2018 there were four and also included the Eni group, whose share in 2019 dropped to 4.9%. The percentage of capacity reached by the first three groups is 37.4%, essentially unchanged from the 37.6% in 2018. The HHI index related to the installed net capacity outlines a slight decrease of the market concentration; the value of 2019 is equal to 723, when it was equal to 738 in the previous year.

The structure of the electricity market

The Energy Markets Operator (GME) works to manage the energy markets, divided into Spot Energy Market (MPE) – articulated in the Day Ahead Market (MGP), the Intra-day Market (ME) and in the Dispatching Services Market (MSD) – and the Forward Electricity Market (MTE) which requires the mandatory physical delivery of the electricity.

[89] See also note 35.

The Day Ahead Market (MGP) is concerned with energy trading with reference to the 24 hours of the delivery day, which is managed through hourly auctions at equilibrium price (system marginal price). The MGP is a zonal market: the territory is divided into zones representing portions of the transmission network with limited exchange capacity between them. If flows exceed the maximum transit limit allowed by interconnections between zones, the price is recalculated in each zone as if each zone were a separate market from the others (market splitting). While bids for sale are valued every hour at the relevant zonal price, bids for purchase are valued every hour at a Single National Price (PUN) for purchase, defined as the average of the zonal prices weighted by the value of purchases in each zone, net of pumping and foreign zone purchases. In this market, the GME acts as a central counterparty for operators. As of 1 January 2019, the map of geographical exchange zones has been simplified. In addition, as of 28 December 2019, the new interconnection between Italy and Montenegro entered into operation with explicit allocation of transmission capacity.

The intraday market (MI) is also a zonal market, divided into seven separate sessions, two of which are managed in coordination with the two corresponding intraday market sessions in Slovenia, as part of the intraday market coupling project, which has enabled efficient allocation of cross-border capacity on the Slovenian border.

In February 2015 the Multi-Regional Coupling (MRC) was launched on the northern Italian border with France, Austria and Slovenia. The MRC is a market coupling process that introduces implicit auction models to replace the daily explicit auctions, coordinating the allocation of the capacity and the sale of the energy, therefore facilitating the integration of several markets thanks to an excellent exploitation of the interconnection capacity (Net Transfer Capacity – NTC) and the cancellation of uneconomical flows[90].

As a result of the integration of the spot markets (MGP and MI) into the European coupling projects, it became necessary to reduce payment deadlines from two months to one week. In view of the need reported by many operators to be able to continue trading daily products, maintaining payment in the second month following the month of trading, the Daily Products Market (MPEG) was established in 2016, where all operators in the electricity market can trade daily contracts of different profiles (baseload and peakload) on a continuous basis. On this market operators can offer volumes with prices expressed only as differentials with respect to the effective average PUN for the delivery date of the product being traded.

The Market for Dispatching Services (MSD) is aimed at supplying Terna with the resources necessary for the safe management of the system through the resolution of congestion between areas, the creation of reserve capacity and real-time balancing; unlike other markets, in this case Terna acts as the central counterparty of the authorised operators.

The Forward Electricity Market (MTE) managed by the GME was established to allow operators to manage their energy portfolio more flexibly. It consists of trading forward contracts with obligation to deliver and take back energy. Trading is conducted on a continuous basis and concerns two types of contracts, baseload and peakload, tradable with monthly (three products listed at the same time), quarterly (four products listed at the same time) and annual (one product) delivery periods. At the end of the trading phase, contracts with a monthly delivery period are recorded in corresponding transactions on the Energy Account Platform (ECP), subject to adequacy checks provided for in the

[90] Hours in which the flow goes from the more expensive zone to the least expensive one, in the opposite direction to the one that the price differential would suggest.

platform's regulations. The "cascade" mechanism is provided for contracts with a delivery period equal to the quarter and year[91].

The operators can sell and buy energy not only through the market organised by the GME, but also by stipulating sales/purchase contracts concluded outside the supply system. Starting from May 2007 the PCE came into operation, introducing high flexibility for the operators in the optimisation of their own contract portfolio in the medium-long term. The quantities contained in the bilateral term contracts are recorded on the PCE (generally negotiated on brokerage platforms) and, until the end of 2019, the quantities negotiated on the Electricity Derivatives Contracts (CDE) platform, in relation to which operator has requested to exercise the option of physical delivery on the electricity market underlying the contract itself, are recorded[92]. In fact, in November 2008, the Italian Stock Exchange launched the Italian Electricity Derivatives Market (IDEX), dedicated to the trading of financial derivative tools, with the underlying PUN. The physical execution of these contracts took place on the CDE platform. In November 2019, the GME proposed to the Ministry of Economic Development that the CDE platform cease to operate, following the elimination by Borsa Italiana of the physical delivery option in contracts concluded in the financial derivatives market. The proposal was approved[93] and took effect from 1st January 2020.

Lastly, in July 2019, the Authority issued a favourable opinion[94] on the proposals for amendments to the Consolidated Law on the Electricity Market (TIDME) and the MGAS Regulations, which were prepared by the GME, considering them functional to the introduction of a single guarantee to cover the operator's net exposure to these markets in the MGP, MI and MP GAS natural gas markets.

There are around 280 operators admitted to the electricity market in 2020.

Stock exchange negotiation and bilateral negotiation

In 2019, the amount of electricity traded in the Italian System (Table 3.8) was 295.8 TWh (+0.1% compared with 2018), with increases in January (+2.7%) and July (+3.6%). More specifically, on an annual basis, there was a sharp increase in foreign demand (+38.6%) and a modest increase in demand in the southern zone alone (+1.7%), while in Sardinia (-0.4%), Centre-South (-0.5%) and Centre-North (+0.2%) the levels of last year were confirmed and in all other zones there were slight drops. Against an overall stable demand (+0.2%), volumes offered also remained close to 2018 levels (-0.8%), with slight reductions in all areas except the Centre-South where there was a significant increase (+12.8%). There was also a drop in imports (-6.1%) and an increase in exports, the second highest ever (6.8 TWh, +82.6%).

[91] Procedure whereby quarterly and annual forward contracts (futures, forwards and contracts for differences) at maturity are replaced by an equivalent number of contracts with shorter durations. New positions are opened at a price equal to the final settlement price of the original contracts.

[92] For further information on the evolution of the wholesale electricity market, please refer to the GME Annual Report and the Monitoring Report on spot and forward electricity markets and dispatching services published by the Authority.

[93] By decree of 12 December 2019 of the Ministry of Economic Development, following the positive opinion expressed by the Authority with Resolution 496/2019/I/com of 26 November 2019.

[94] With Resolution 16 July 2019, 309/2019/I/com.

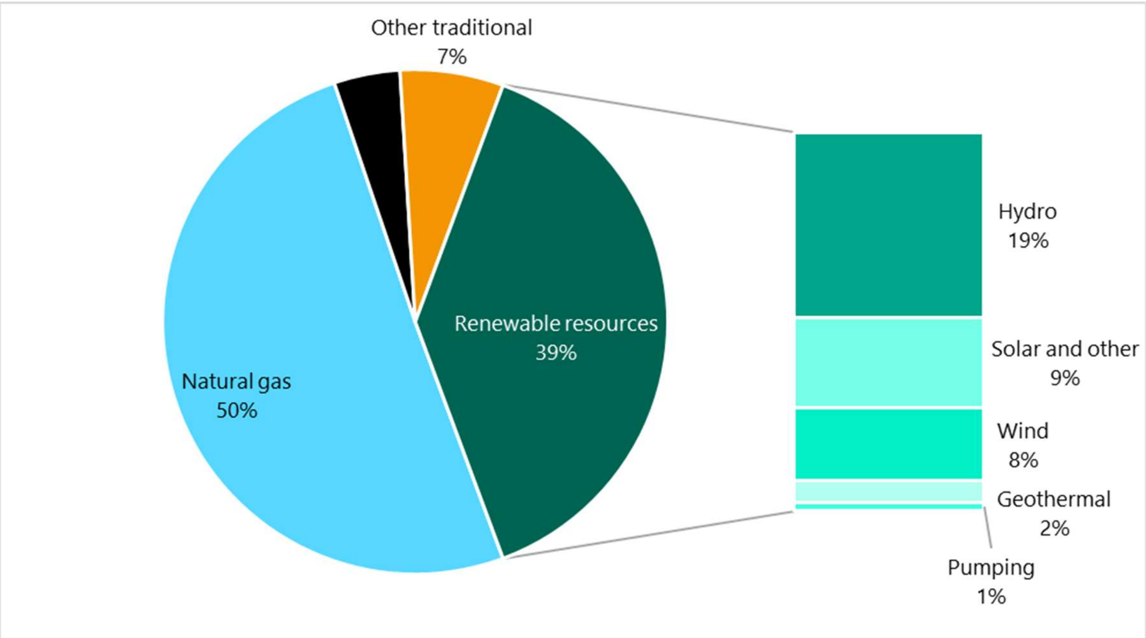
Table 3.8 Electricity market

TWh

YEAR	NEGOTIATIONS ON THE MGP		
	Total	*of which stock exchange*	*of which bilateral*
2004	231.6	*67.3*	*164.3*
2005	323.2	*203.0*	*120.2*
2006	329.8	*196.5*	*133.3*
2007	330.0	*221.3*	*108.7*
2008	337.0	*232.6*	*104.3*
2009	313.4	*213.0*	*100.4*
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*

Source: ARERA processing on GME data.

Figure 3.5 Electricity sales in the MGP by source



Source: ARERA processing on GME data.

With regard to the composition of trade by technology (Figure 3.5), volumes sold by thermal plants stood at 62% (+1% compared to 2018), reflecting strong reductions for coal-fired and fuel oil-fired plants in the North, South and Centre-South and increases throughout the continent for natural gasfired plants; the share sold by renewable energy plants as a whole was also unchanged (39%, -1 % compared to 2018), with a sharp drop in sales of solar plants in the Centre-North alone (-27%).

The increase in volumes traded directly on the stock exchange (213.3 TWh, +0.2%) and equal to 72% of total MGP trading is on the decline, although it remains slightly positive; this liquidity was favoured in sales by exports (+82.6%) and in purchases by non-institutional operators (+9%); the volumes purchased by the Acquirente Unico (single buyer) (-4.4%), which met its entire demand on the stock exchange, are down. Programmes deriving from registration of bilateral over-the-counter trade on the PCE remain stable (82.6 TWh, -0.1%) (Table 3.9).

Table 3.9 Bilateral contracts

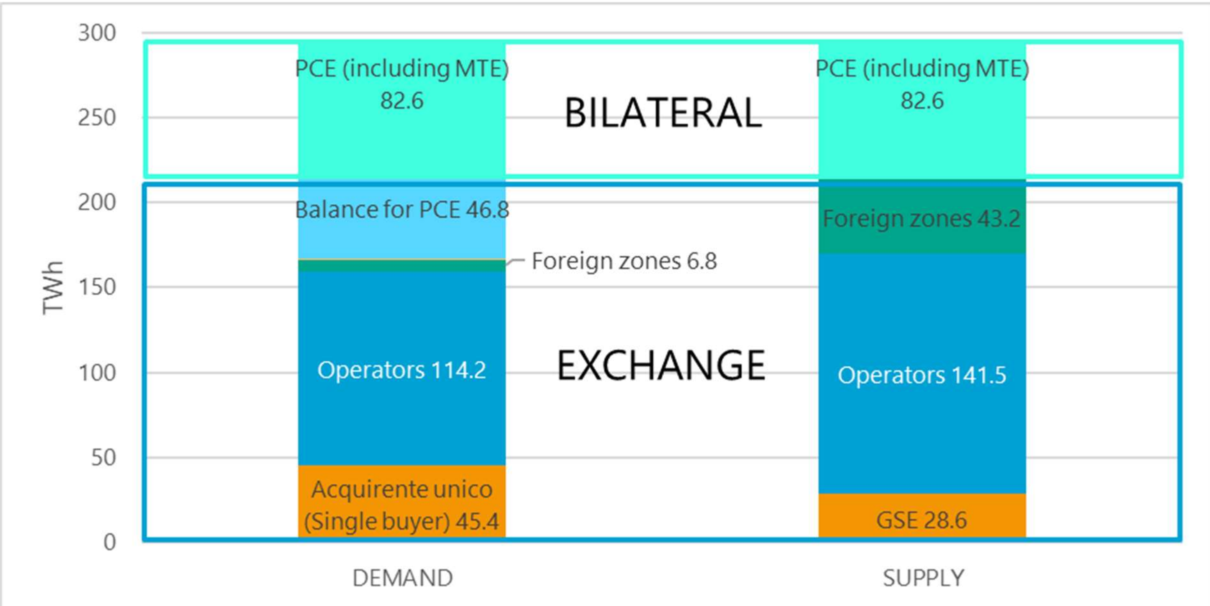
TWh

CONTRACTS	2011	2012	2013	2014	2015	2016	2017	2018	2019
Bilateral contracts	131.1	120.0	82.3	96.1	92.5	86.9	81.3	82.6	82.6
National	148.8	146.9	156.8	162.5	143.5	134.9	125.7	136.9	129.4
Acquirente Unico (single buyer)	*36.8*	*38.8*	*43.9*	*37.9*	*29.1*	*17.6*	*3.7*	*2.5*	-
other operators	*112.0*	*108.1*	*112.9*	*124.6*	*114.4*	*117.3*	*122.0*	*134.4*	*129.4*
Foreign	0.4	0.5	0.1	28.5	0.1	0.03	0.07	0.0003	-
Final balance for PCE(A) programmes	-18.1	-27.4	-74.6	-66.5	-51.0	-48.0	-44.5	-54.2	-46.8

(A) In each relevant period it is the difference between the sum of the emission programmes and the sum of the withdrawal programmes, coming from the PCE, registered on the MGP. The final balance of the PCE programmes is equal to the algebraic sum of the physical balances of the energy accounts (in emission and withdrawal).

Source: ARERA processing on GME data.

Figure 3.6 Composition of electricity supply and demand in 2019



Source: ARERA processing on GME data.

Electricity generation concentration operations in

In 2019, several corporate operations were carried out in the context of electricity generation: this sector is particularly dynamic, with many plant divestitures and acquisitions between the operators, although they are mostly small in size.

Among the main groups the Iren Group's incorporations in 2019 of some solar and photovoltaic generation companies appear significant. There have also been important acquisitions by the A2A group which, continuing its expansion strategy in the green energy sector, from 1 January 2020 acquired new plants powered by renewable sources (in solar and wind energy) with the objective - stated in the presentation of the Development Plan for the period 2020-2024 - of reaching (M&A and greenfield developments) 500 MW by 2024 and over 1.5 GW by 2030, to reach a 40% share of renewables in its generation portfolio.

It should also be noted that the data collected through the Authority's annual survey showed for the first time that the Enel group is no longer the leading operator in thermoelectric generation, as the Eni group's output was higher, despite a lower installed capacity. Conversely, the share of small producers in total gross national production remained at 38.7% (same value in 2018). Small-scale producers are responsible for 96.1% of the generation from photovoltaic sources and the predominant contribution in bioenergy production (76.7%) as well as wind power, where they account for 67.5%. In 2019, production shares among the various operators were affected by the decrease in hydroelectric power plants, with operators owning this type of facility seeing their shares decrease slightly.

3.2.1.1 Monitoring the price levels of the wholesale market

The day ahead market

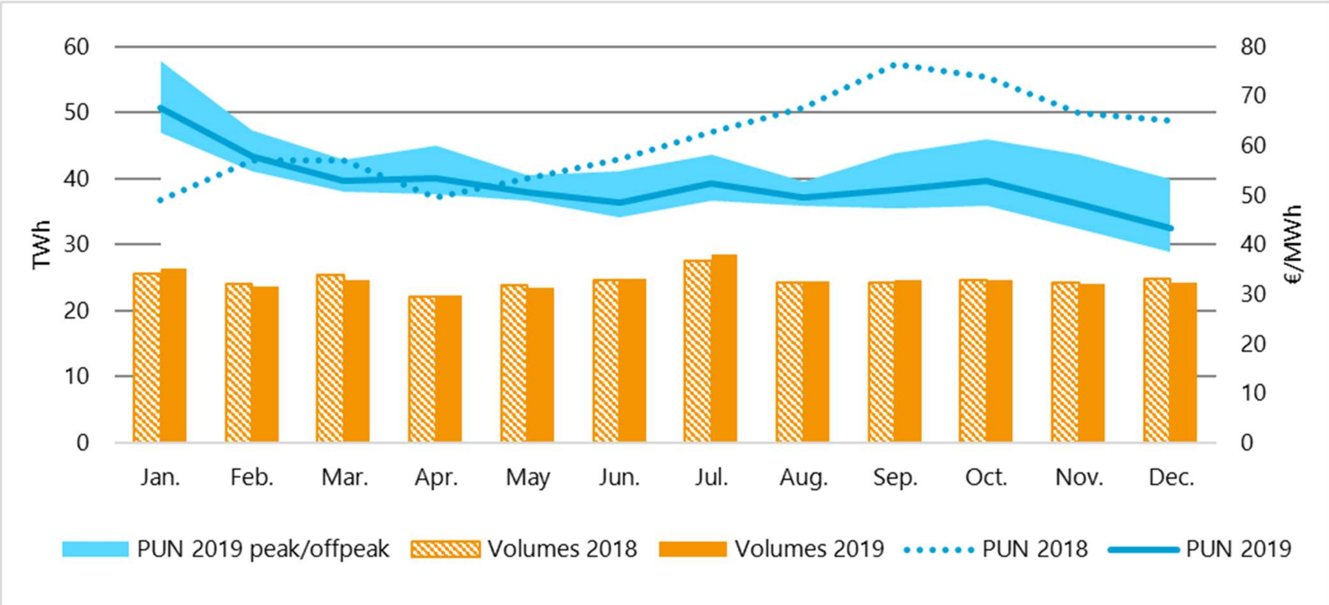
The average of the national single electricity purchase price (PUN) in 2019 was €52.32/MWh (Figure 3.7), down from last year (-14.7%), albeit in line with the price trend of the main European power exchanges (Figure 3.9). This decrease reflects the lower cost of gas raw material (16.28 €/MWh; -34%) partly offset by the significant increase in CO2 emissions permit prices (+56%). The above dynamics were homogeneous in all groups of hours: 59.12 €/MWh (-14%) during peak hours[95], 50.57 €/MWh (-14%) during off-peak hours on working days and 46.63 €/MWh (-16%) on public holidays. The daily dynamics of the relative price differentials between different groups of hours remained substantially stable, with a slight reduction in the differential in the morning hours offset by an equally slight increase in the differential in the evening hours.

The evolution of prices at a zonal level was characterised by decreases of between 10% and 16% compared to 2018, with values between 50 €/MWh in the South zone, which for the eleventh consecutive year was the zone with the lowest price, and 63 €/MWh in Sicily, which recorded the highest zonal price for the thirteenth consecutive year. The Sicily zone also continued to record an increase in its price differential with the North zone (11.5 € / MWh compared to 7–8 € / MWh in the previous two years), while the differential between the Sardinia zone and the North zone remained below 1 €/MWh.

[95] The peak hours concern only working days and are between 8:00 and 20:00, i.e. the relevant periods from 9 to 20.

Figure 3.7 Monthly trend of the PUN (national single price) and the total traded volumes for the Italian System

Volumes in TWh; PUN (average, peak and off peak) in €/MWh



Source: GME.

In its third year of full operation, the Daily Products Market (MPEG) recorded 1,049 transactions (-56% compared to 2018), for a total of 701 GWh (-78%) traded, with a mainly baseload profile (99%). Trade was concentrated in the first three quarters of the year and less than 1% of volumes were purchased by the Acquirente Unico (single buyer); in the previous two years, the Acquirente Unico (single buyer) was the main counterparty in purchases. The average price of daily products on the baseload type fell to 0.10 €/MWh (-0.08 €/MWh), with no particular variations between years.

Forward electricity market

On the forward market managed by the GME, for standardised products with physical delivery, a total of 1.6 TWh was traded in 2019, up on 2018 (+38%) (Table 3.10). Considering the type of products traded, the preference for the baseload profile remained stable (94%; +3%), while the duration of contracts decreased, with more trades for products with monthly maturity (44%, +9%) compared to those with quarterly (36%) and annual maturity (20%). On average there were sixteen matches per month, which are more concentrated in March and May. For the fifth consecutive year, no bilateral transaction was recorded for clearing purpose only.

Looking at the trend in the prices of the generally more liquid forward product, i.e., the monthly baseload expiring in the month immediately following (M+1), operators indicated prices ranging between €49/MWh (August) and €71/MWh (January) for 2019. This trend is in line with the trend recorded during the course of the year by the underlying PUN, the largest difference being in the last 2 months of the year, in correspondence with the greater reductions in the latter (Figure 3.8).

Table 3.10 Volumes traded on the MTE

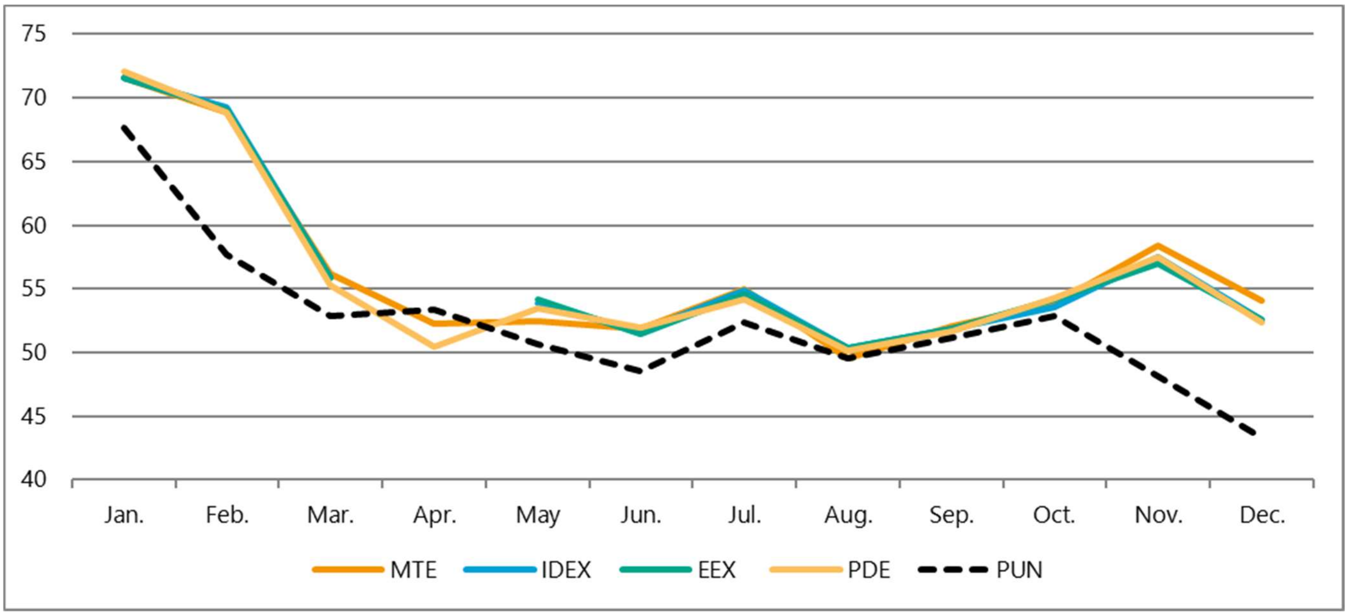
MWh

DURATION	2013	2014	2015	2016	2017	2018	2019	VARIATION 2019/2018	SHARE
CONTRATCTS (MW)	2,171	2,944	1,004	411	518	391	596	52%	145%
Baseload	679	2,829	899	323	449	357	561	57%	94%
Peakload	1,492	115	105	88	69	34	35	3%	6%
VOLUMES (GWh)	7,996	18,402	5,087	1,069	1,356	1,191	1,641	38%	100%
Baseload	3,618	18,356	5,007	1002	1,335	1,155	1,602	39%	98%
Peakload	4,379	46	79	67	21	36	38	6%	2%

Source: ARERA processing on GME data.

Figure 3.8 Average prices of the monthly baseload product in 2019, with maturity in the subsequent month on the different trading platforms

€/MWh



Source: ARERA processing on data from different sources.

Intraday market

Total volumes traded on the intraday market in 2019 (26.4 TWh) were up compared with the previous year (+1 TWh, +4%). Although the clear majority of volumes were traded in the first 3 sessions (81%), particularly on MI1 (48%), it is noted that the highest percentage increase compared to 2018 was recorded for sessions between MI3 and MI7, underlining a greater preference to trade close to real time. The prices recorded remain strongly correlated to the values of the Day Ahead Market, both in terms of time and zonality, in particular monthly average prices[96] are down from a high of 66-76 €/MWh in January to a low of 44-52 €/MWh in December. The prices of the first three sessions were strongly aligned, while MI6 and MI7 sessions recorded average price differentials of up to 23% in the

[96] The values refer to the average prices in the national zones only.

months between April and August. Prices also reflect the dynamics of the MGP on a zonal basis, with the lowest average price[97] in the South macrozone (€52/MWh) and the highest in Sicily (€71/MWh).

The integration of the Italian market in the European context

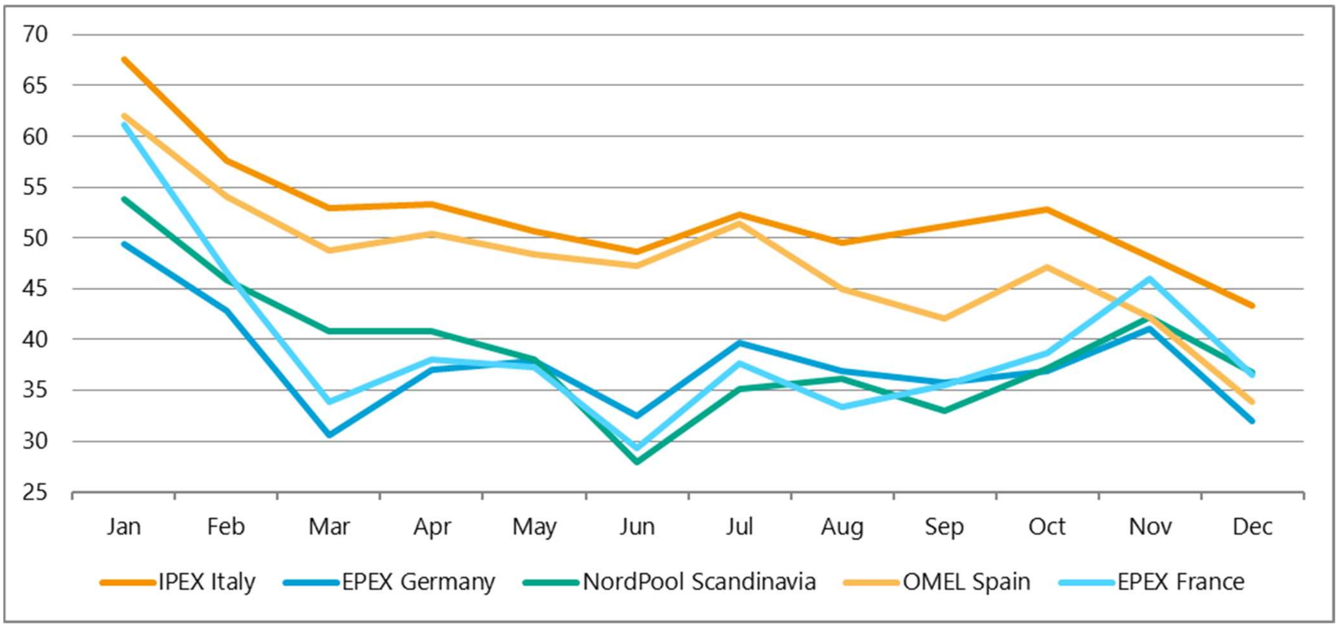
The European market is also seeing a drop in electricity prices, which is essentially distributed in two macro-regions: a northern region, made up of France, the Scandinavian countries and Germany, with prices in the region of €39/MWh and a Mediterranean band, with Italy, Spain and Slovenia with prices between €48 and €52/MWh.

In particular, the coupling mechanisms made it possible to substantially align[98] the prices of the two macro-regions in 102 hours (+24 compared to 2018), concentrated in the latter part of the year and, unlike the previous year, distributed throughout the day. As regards the northern Italian border, the same coupling mechanism has allocated a capacity of 2.8 GWh in import (-71 MWh compared to 2018) and 1.2 GWh in export (+130 MWh) on average every hour; in particular, the share of total capacity allocated in implicit auction is about 90% on the French and Austrian borders.

Figure 3.9 Average monthly price trend in the main European Stock Exchanges in 2019

Average baseload values; €/MWh

Source: ARERA processing on European power exchanges data.



[97] The values refer to the average price of the seven sessions.

[98] Alignment is understood as a price differential of less than 1 €/MWh in a single hour between the following borders: North–France, France–Germany, Germany–Scandinavian area.

3.2.1.2 Monitoring the level of transparency, including compliance with transparency obligations, and the level and effectiveness 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 to assess the structure of the markets and their proper functioning, as well as the behaviour of operators and the adequacy of the system. In the electricity sector, the Authority has therefore adopted[99], since 2008, the Integrated Text on the monitoring of the wholesale electricity market and the dispatching service market (TIMM), in order to strengthen its monitoring function in the sector.

The importance of the monitoring function performed by the regulatory authorities at the national level - and already envisaged for ARERA by the law establishing it - has also been recognised at the European level: in addition to the directives on energy markets and Regulation (EU) 1227/2011 on wholesale energy market integrity and transparency (REMIT), in fact, the monitoring powers of the national regulatory authorities have been strengthened and expanded. In particular, the monitoring function envisaged by REMIT is aimed at increasing overall market transparency and promoting a more level playing field between operators by intercepting abusive conduct relating to market manipulation and insider dealing, including cross-border and cross-product practices (spot and futures products, physical and financial); this important function is therefore coordinated at European level by the Agency for the Cooperation of Energy Regulators (ACER).

At the national level, the monitoring activities that the ARERA is entrusted with under the REMIT extend the scope of more traditional monitoring activities aimed at identifying anomalies (not necessarily of an abusive nature) in the behaviour of wholesale market participants, and extend to all electricity and natural gas trading with delivery in Italy, including through cooperation with other national regulatory authorities and with foreign operators of organised markets. On the operational level, the monitoring function assigned to ARERA under REMIT overlaps with the traditional one, largely sharing information, procedures and analysis tools.

In 2019, analysis continued on the historical data input to the resolution algorithm of the market programming phase for the dispatching service. These analyses focused in particular on defining the constraints on the integrated and non-integrated network, which are aimed at securing the resources to meet the reactive power reserve requirements for voltage regulation (primary and secondary). With these developments, it has been possible to historically reconstruct the market structure in which the proceedings initiated in the past[100], concerning the supply strategies adopted by some dispatching users who own production units authorised for the dispatching service market, were framed. These proceedings were concluded in 2019 with a decision to close the case and a sanctioning procedure in relation to the non-diligent programming strategies in the electricity dispatching service.

Moreover, in order to increase the effectiveness of the monitoring tools available to the Authority, last year the scope of data relating to the dispatching service market, organised in dedicated data warehouses, was extended.

[99] With Resolution of 5 August 2008, ARG/elt 115/11 and subsequent amendments.

[100] With Resolutions 24 June 2016, 342/2016/E/eel, 4 August 2016, 459/2016/E/eel, and 6 October 2017, 674/2017/E/eel

Lastly, coordination continued with ACER in monitoring wholesale electricity markets, pursuant to the REMIT regulation.

Implementation of REMIT

In 2019, preliminary investigation activities resulting from reports of abnormal orders and/or transactions on the wholesale markets for electricity and natural gas, which are potentially abusive pursuant to Article 5 of the REMIT Regulation, were carried out. In two cases, the investigation phase was closed with a decision to close the case, since the conditions for the opening of a formal investigation under Article 2(2) and (3) of the REMIT, which define 'market manipulation' and 'attempted market manipulation' respectively, were not met.

The Authority also confirmed its proactive contribution to the working groups both within the Agency for the Cooperation of Energy Regulators (ACER) and the Council of European Energy Regulators (CEER), in order to promote a coordinated approach in the implementation of REMIT, by participating:

- in the preparation of ACER guidelines dedicated to the identification of specific cases of manipulation, with particular reference to the retention of generation capacity in the electricity market;
- in the constant update of the Market Monitoring Handbook, user manual for the internal use of ACER and the regulators, to promote the cooperation and coordination in the management of cases envisaged by REMIT;
- in the sharing of tools, methods and means for the surveillance of the wholesale market and of the issues related to the coordination of the potential violations in the cross-border market;
- in the monitoring of the evolution of the financial regulations and the contribution to the training for the CEER-ACER positions in the relevant contexts for the correct functioning of the energy markets.

Finally, in order to ensure a unified view of financial markets and wholesale energy product markets, strengthening cooperation with the *Commissione nazionale per le società e la Borsa* (National Commission for Companies and the Stock Exchange - CONSOB), a public workshop was organised in June 2019 on the regulatory regime applicable to energy undertakings following the entry into force of Directive 2014/65/EU of the European Parliament and of the Council of 15 May 2014 on markets in financial instruments (so-called MiFID II, Markets in Financial Instruments Directive).

3.2.2 Retail market

According to the provisional data published by Terna, in 2019 total consumption (net of losses) was approximately 301 TWh, with a decrease of 0.7% compared to that of 2018. Table 3.11 3.14 describes its distribution per final sector of use.

In the context of the Authority's Operators Registry, 123 parties in the standard offer market, 3 in safeguarded category market and 723 in the free market, declared they had sold electricity in 2019 (also for a limited period of the year). In 2018 there were 127 suppliers in the standard offer market, 2 in the safeguarded category market and 635 in the free market. The number of parties exercising the standard offer regime has therefore decreased by four compared to 2018, as a result of corporate transactions involving the sale of the business. On the contrary - and as usual - the number of companies selling electricity in the free market has instead decidedly increased (by 88 units). 123 parties that carry out the standard offer regime (all of them) and 551 companies that sell electricity in the free market (that is 76% of 723) responded to the Authority's annual survey. Among these, 74 declared they were inactive throughout the whole year. Consequently, 477 companies that responded to the annual survey were active in the free market.

Table 3.11 Distribution of national electricity consumption per final sector

TWh

PRODUCTION SECTOR	2015	2016	2017	2018	2019(A)	VARIATION 2018/19
Domestic	66.2	64.3	65.5	65.1	65.7	0.9%
Agriculture	5.7	5.6	6.0	5.8	5.7	-1.7%
Industry	122.4	122.7	125.5	126.4	123.9	-2.0%
Tertiary	102.9	102.9	104.9	106.0	106.1	0.1%
TOTAL	297.2	295.5	301.9	303.4	301.4	-0.7%

(A) Provisional data.

Source: Terna.

Table 3.12 shows the distribution of the end sales of electricity (net of self-consumption and network losses) together with the total number of customers[101] per market type, determined on the basis of the Authority's annual survey data supplied by the electricity operators: producers, those exercising the standard offer services, wholesalers and free market suppliers. The sales data collected by the Authority (considered with the self-consumption data) is representative of a population that reflects 91%[102] of the final consumption estimated by Terna, the Electricity Transmission Grid Operator.

According to the results of the annual survey (to be considered provisional for 2019, as usual) 256 TWh were sold on the retail market to fewer than 37 million customers. Compared to 2018, total electricity consumption remained substantially stable with a slight downward trend (-0.1%), while consumers increased by 0.4%. The contraction in consumption occurred in the non-domestic sector (-0.3%), while household consumption substantially held up (+0.6%); conversely, the increase in customers was higher in the non-domestic sector than in the domestic sector. As has been the case for a long time now, the standard offer service has lost further ground to the free market. Furthermore, in 2019 the safeguarded service also shrunk further.

In 2019 there were 29.6 million domestic customers, of which 15 served under standard offer and 14.6 million in the free market. In a context of overall growth (+78,000 domestic delivery points compared to 2018), the movement of consumers towards the free market continued: against the 1,690,000 domestic delivery points lost in the standard offer market compared to 2018, the free market recorded an increase of 1,768,000. Households purchasing energy on the free market grew by 13.2%, while those served under standard offer fell by 8.7%. Evaluating the shares of the two markets in terms of customer numbers, it can be seen that in 2019 the free market reached 49.4%.

[101] Approximated by the number of delivery points counted using the pro die criteria (counted using the fractions of year for which they were supplied).

[102] To obtain the indicated percentage you must add the data collected from the Survey for self-consumption and group self-consumption, to the end consumption of the Survey shown in Table 3.14, as well as the sales to final customers who aren't connected to distribution networks and are not included in the table.

Twelve years after the complete opening of the electricity market on 1 July 2007, the standard offer service still serves just over half of domestic customers.

Table 3.12 Electricity retail market

Net of self-consumption and losses

	VOLUMES (GWh)			DELIVERY POINTS (thousands)		
	2018	2019	VARIATION	2018	2019	VARIATION
Standard offer service	45,273	40,648	-10.2%	19,705	17,607	-10.6%
Domestic	30,660	27,982	-8.7%	16,660	14,969	-10.1%
Non-domestic	14,613	12,666	-13.3%	3,046	2,638	-13.4%
Safeguarded category market	4,269	3,643	-14.7%	80	76	-5.6%
Free market	206,844	211,831	2.4%	17,019	19,254	13.1%
Domestic	26,581	30,102	13.2%	12,821	14,590	13.8%
Non-domestic	180,262	181,729	0.8%	4,198	4,664	11.1%
FINAL MARKET	256,386	256,123	-0.1%	36,805	36,937	0.4%

Source: ARERA. Annual Survey on Regulated Sectors.

The average consumption per unit of households in the standard offer market is lower than that of households who purchase energy on the free market: 1,869 kWh/year versus 2,063 kWh/year. This differential, however, is decreasing over time: in 2019 it dropped to 194 kWh, halving compared to 414 kWh five years earlier. This is because at the beginning of market opening the first domestic consumers to move to the free market were those with high consumption, while households with lower consumption also moved to the free market as the transition to the free market was completed.

If we consider not only households but also non-domestic low-voltage customers served under the standard offer regime, we can see that the volumes intermediated in the standard offer regime now represent a rather small share, 16%, of the entire Italian electricity market (but account for 47.7% of total delivery points). In 2019, 83% of all electricity purchased in Italy was sold on the free market (and served 52.1% of delivery points). The safeguarded section, which is also decreasing, was worth 1.4% of sales volumes and 0.2% of delivery points in 2019. In a final market that shrunk overall by 0.3 TWh compared to 2018, the sales volumes of the standard offer market fell by 9.3 TWh (-10.2% compared to 2018), while the free market gained 9.7 TWh compared to the previous year (+2.4%) and sales fell by 0.7 TWh (-14.7%) in the safeguard regime.

The total number of consumers increased in 2019 by 132,000 to 36.9 million: the standard offer regime lost just over 2 million points, the number of safeguarded service customers decreased by another 4,000 units, while in the free market customers increased by 2 million and 235,000 points compared to 2018.

Switching

On the basis of data provided by distributors in the annual survey and - for the first time - data from the SII[103], it can be observed that in 2019 household switching increased significantly compared to

[103] Integrated Information System (SII): an information system established with the Single Buyer with the Law n. 129/10, of August 13th, 2010, with the goal of managing the information flows between the subjects (mainly distributors and

the previous year, whether measured in terms of delivery points or in terms of volumes (Table 3.13). 14.3% of domestic customers - 4.2 million households - changed suppliers at least once during the year. The volumes corresponding to this portion of customers are about 16.9% of the total energy distributed to the domestic sector, while the volumes corresponding to the 9.1% of households that changed supplier in 2018 corresponded to 10.2% of the energy delivered. The greater dynamism in household switching may have been driven by the advent of the complete deregulation of the electricity market, which, until December 2019, was expected to take place on 1 July 2020 and was then postponed to 1 January 2022 by Decree Law No. 162 of 30 December 2019[104].

After the slowdown of the previous year, the first since 2011, switching by non-domestic customers also recovered again in 2019, from 17.3% to 23.1%. Overall, around 1.7 million delivery points changed supplier in 2019. In terms of underlying volumes, the increase compared to the previous year is lower, by 3.1 percentage points. The split by voltage level shows that the resumption of switching activity by non-domestic customers is primarily attributable to low-voltage connected customers, 23.1% of which changed supplier during 2019 (6% more than in 2018) and for a share of underlying volumes of 35.2%. Here, too, a stimulus to switching could probably be derived, at least in part, from the fact that, from 1 January 2021, small and medium-sized enterprises will no longer have the right to purchase energy in the standard offer service.

Table 3.13 Switching rates of final customers

TYPE OF CUSTOMER	2018		2019	
	VOLUMES	DELIVERY POINTS	VOLUMES	DELIVERY POINTS
Domestic	10.2%	9.1%	16.9%	14.3%
Non-domestic	28.5%	17.3%	31.6%	23.1%
of which:				
- low voltage	27.9%	17.1%	35.2%	23.1%
- medium voltage	36.5%	31.7%	33.3%	28.6%
- high and very high voltage	9.9%	21.6%	21.2%	23.1%
TOTAL	24.6%	10.7%	28.4%	16.1%

Source: ARERA. Annual Survey on Regulated Sectors.

During 2019, however, other non-domestic customers also maintained a fair rate of switching: in fact, 28.6% of customers connected to medium voltage (for a total of 33.3% of energy) and 23.1% of customers connected to high or very high voltage, for a volume of approximately the same magnitude, changed supplier. Only medium voltage delivery points showed a slight decrease in switching activity compared to 2018.

suppliers) that participate in the electricity and natural gas markets, according to the rules and procedures established by the Authority. It is based on a data bank that contains the whole list of the national delivery points and the fundamental data needed to manage the related processes called the Central Official Registry or RCU.

[104] Converted, with amendments, by Law No.8 of 28 February 2020.

Standard offer service

Low-voltage connected households and small companies[105] that did not stipulate a free market sales and purchase contract use the **market with standard conditions** or **standard offer regime**. Service is guaranteed by appropriate sales companies or distribution companies with less than 100,000 customers connected to their own network, on the basis of the financial conditions and commercial quality indicated by the Authority.

More precisely, under the standard offer regime, Acquirente Unico, a single buyer, is responsible for the supply of electricity on the wholesale market which sells it to standard offer operators at a price that reflects the costs sustained, including those for energy. The standard offer prices are established by the Authority on the basis of the wholesale market prices in order to cover the supply costs incurred by the companies appointed to provide this service. As regards the component covering marketing costs, the criterion used by the Authority reflects the costs incurred by a hypothetical new entrant to access the market segment of electricity sales to households. In summary, the energy component of the standard offer prices is set according to a market-based methodology, 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 consumers supplied under the standard offer regime without distinction according to location.

In 2019, 40.6 TWh were sold in the service at standard conditions, to around 17.6 million delivery points (calculated on a pro die basis). Compared to 2018 consumption fell to 4.6 TWh (-10.2%), while the supplied delivery points decreased by 2.1 million units (-10.6%). The decrease in delivery points confirms a long term trend: this service was born, in a transitional way, at the time of the complete liberalisation of the market in order to support households and small companies that were still not in a position to choose a supplier and will disappear in time, also because of the regulatory provisions in this matter (i.e. from 1 January 2022, according to the latest legislative provisions). Last year 1,7 million domestic customers left the standard offer regime (-10.1%) and so did 0.4 million non-domestic customers (-13.4%). In the context of households, the decrease in residents (1.3 million, -10.2%) is proportionally lower than non-residents (0.4 million, -9.9%). There are smaller variations in public lighting, for which there is a 6.8% decrease in the number of points served and an 8.2% decrease in energy sold; but this is a fairly marginal consumption sector.

The shares of the different categories of total consumption changed little compared to 2018. 68.8% of the volumes was purchased by domestic customers (28 TWh) that, in terms of numbers (15 million delivery points), represents 85% of the total. The remaining 31.2% of the energy (12.7 TWh) was purchased by non-domestic customers which, in terms of delivery points (2.6 million), represent 15% of the points served under standard conditions.

In the context of **domestic customers** (Table 3.14), residents represent 78.4% of the delivery points and 89% of consumption. 91.6% of residents have a contract with power up to 3 kW. In 2019 the average unit consumption of domestic customers was 1,869 kWh/year, slightly higher than the 1,840 kWh recorded in 2018. Considering that most (75.5%) of domestic customers are resident and have a contract with power up to 3 kW, the average consumption of the Italian households is 1,965 kWh/year, a value that is 19 kWh higher than recorded in 2018. Higher, equal to 3,850 kWh, and also rising slightly, is the average consumption of residents with power over 3 kW, which last year was

[105] According to the Decree-Law of June 18th, 2007, n. 73, amended by Law n.125 of August 3rd, 2007, "small companies" are final customers different from domestic clients with less than 50 employees and an annual turnover or a balance sheet no higher than 10 million Euro.

3,792 kWh; also rising slightly is the average consumption of non-residents, which rose from 918 kWh in 2018 to 950 kWh in 2019. 89.2% of households served under standard conditions, however, consume less than 3,500 kWh per year.

The most prevalent contract conditions in the standard offer regime are, as usual, the mandatory two-tier tariff and time-of-use tariff that concern 97.3% of delivery points. Nearly all domestic customers (97.2%) pay the mandatory two-tier tariff, an economic condition that varies at hourly bands during the day and that, since July 1st, 2010, is automatically applied to the customers equipped with a re-programmed smart meter; only 1.8% of the customers pays the voluntary time-of-use tariff, that is the one explicitly requested by the customers even before July 1st, 2010; the old non time-of-use tariffs is applied to the remaining 1% of domestic delivery points.

Table 3.14 Domestic customers with standard condition service per type and consumption class in 2019

Volumes in GWh; number of delivery points in thousands; average consumption in kWh

TYPE OF CUSTOMER AND ANNUAL CONSUMPTION CLASS	VOLUMES	SHARE	DELIVERY POINTS	SHARE	AVERAGE CONSUMPTION
0-1,000 kWh	1,973	7.0%	4,596	30.7%	429
1,000-1,800 kWh	5,090	18.2%	3,618	24.2%	1,407
1,800-2,500 kWh	5,985	21.4%	2,801	18.7%	2,136
2,500-3,500 kWh	6,883	24.6%	2,342	15.6%	2,939
3,500-5,000 kWh	4,744	17.0%	1,163	7.8%	4,080
5,000-15,000 kWh	2,867	10.2%	436	2.9%	6,581
> 15,000 kWh	441	1.6%	13	0.1%	33,310
TOTAL DOMESTIC	27,982	100%	14,969	100%	1,869
OF WHICH:					
Domestic residents up to 3kW	21,137	75.5%	10,756	71.9%	1,965
Domestic residents over 3kW	3,775	13.5%	980	6.5%	3,850
Domestic non-residents	3,070	11.0%	3,233	21.6%	950

Source: ARERA. Annual Survey on Regulated Sectors.

Table 3.15 highlights the consistency by consumption class of the delivery points (approximately 2.6 million) and volumes (12.7 TWh) relating to **non-domestic uses** served under standard conditions, by consumption class. As in 2018, approximately one fifth (19.5%) of the energy destined to other uses was sold to customers of the first consumption class (<5 MWh/year) that makes up 81% of the entire range of non-domestic consumers. The second class of customers with an annual consumption between 5 MWh and 10 MWh, includes 8.6% of the delivery points and absorbs 12.5% of the electricity sales. Therefore 89.6% of the non-domestic customers who purchase electricity in the standard offer service have annual consumptions that do not exceed 10 MWh.

The delivery points with power lower than 16.5 kW represent 93% of the non-domestic consumers supplied in standard offer and 52% of the consumption. The delivery points with power greater than 16.5 kW, although representing only 7% of these consumers, absorb 48% of sales, as they are characterised by higher annual consumption: half of their delivery points fall in the classes with consumption between 20 and 500 MWh.

Table 3.15 Non-domestic customers with standard condition service per type and consumption class in 2019

Volumes in GWh; number of delivery points in thousands; average consumption in kWh

TYPE OF CUSTOMER AND ANNUAL CONSUMPTION CLASS	VOLUMES	SHARE	DELIVERY POINTS	SHARE	AVERAGE CONSUMPTION
0-5 MWh	2,468	19.5%	2,136	81.0%	1,155
5-10 MWh	1,587	12.5%	226	8.6%	7,007
10-15 MWh	1,074	8.5%	88	3.3%	12,227
15-20 MWh	867	6.8%	50	1.9%	17,315
20-50 MWh	3,025	23.9%	99	3.7%	30,591
50-100 MWh	1,873	14.8%	28	1.0%	67,874
100-500 MWh	1,638	12.9%	10	0.4%	159,726
500-2,000 MWh	115	0.9%	0	0.0%	724,070
2,000-20,000 MWh	18	0.1%	0	0.0%	4,150,560
20,000-50,000 MWh	1.6	0.0%	0	0.0%	25,089,477
TOTAL NON DOMESTIC	12,666	100.0%	2,638	100.0%	4,802
OF WHICH:					
Non-domestic up to 16.5 kW	6,385	50.4%	2,436	92.3%	2,622
Non-domestic over 16.5 kW	5,922	46.8%	184	7.0%	32,180
Public lighting	359	2.8%	18	0.7%	19,785

Source: ARERA. Annual Survey on Regulated Sectors.

Among non-domestic consumers the most prevalent economic condition is time-of-use, as well: it is, in fact, applied to 97.7% of the delivery points and 95.8% of the volumes sold. The alternative is the non-time-of-use tariff, which concerns 2.1% of the delivery points and 4% of the energy. Even more marginal are the shares of the two-tier tariff, with which 0.2% of customers and the energy purchased are billed.

Safeguarded category market

The safeguarded category market is composed of the non-domestic customers who have no sales and purchase contract in the free market, even only temporarily, but who are not qualified to access the standard offer market. These consumers are admitted to the safeguard service when they remain in arrears.

Since 2008 this service has been provided by suppliers selected by auction[106], obtaining the right to provide the service for two consecutive years. The safeguard service for the two-year period 2019-2020 was awarded to three suppliers at the end of 2018: Enel Energia and Hera Comm, already awarded in the previous two years, to which A2A Energia has been added. The new award, however, led to changes in the areas served.

[106] As established by decree of the Ministry of Economic Development of 23 November 2007.

According to the data received from the three safeguard operators in 2019, the service has further shrunk compared to the previous year. More precisely, 75,988 delivery points were supplied under this regime last year (calculated with the "pro die" criterion, meaning they were counted for the fractions of year for which they were supplied), compared to the 80,457 in 2018 (91,345 in 2017). Overall, 3,643 GWh were withdrawn compared to 4,269 in 2018. The safeguard market shrunk by approximately 5.6% in terms of delivery points and 15% in terms of consumed energy, compared to 2018 (Table 3.16).

In the safeguard service, almost all customers (93%) are connected at low voltage, 7% are served at medium voltage and only 0.03% of the delivery points are connected at high voltage. The incidence of these customers in terms of energy purchased is obviously very different: considering the volumes sold, the incidence of low voltage is only 37% (but it has increased compared to 33% in the previous year), that of high voltage customers is 4% (in 2018 it was 6%), while medium voltage purchases almost two thirds of the total energy sold in this service (although its weight is down from 61% in 2018 to 58% in 2019).

Table 3.16 Safeguard service by type of customer

TYPE OF CUSTOMER	VOLUMES (GWh)			DELIVERY POINTS (thousands)		
	2018	2019	VARIATION	2018	2019	VARIATION
Public lighting	478	421	-12.0%	19.3	17.3	-10.6%
Other uses	946	939	-0.7%	55.4	53.3	-3.8%
TOTAL LV	1,424	1,360	-4.5%	74.8	70.6	-5.5%
Public lighting	21	33	57.9%	0.11	0.15	29.8%
Other uses	2,571	2,088	-18.8%	5.6	5.2	-6.4%
TOTAL MV	2,592	2,121	-18.2%	5.7	5.4	-5.7%
Other uses	253	162	-35.8%	0.03	0.03	-0.3%
TOTAL HV	253	162	-35.8%	0.03	0.03	-0.3%
TOTAL SAFEGUARD	4,269	3,643	-14.7%	80.5	76.0	-5.6%

Source: ARERA. Annual Survey on Regulated Sectors.

Overall, the delivery points related to public lighting served under the safeguard service in 2019 fell to about 17,000 units from 19,000 in 2018, thus recording a decrease of 10.4%, while the energy purchased by them also fell from 499 to 454 GWh (-9.1%). The other uses, on the other hand, showed an overall reduction from around 61,000 to 59,000 points served (-4%) and a reduction in consumption of 15.5%, that is from 3,770 to 3190 GWh.

Enel Energia's share in the safeguard market drastically decreased in 2019: due to the results of the auctions, the company served eight regions in 2018, but served only two in 2019. Therefore, its incidence in terms of volumes sold fell from 45.9% to 22.1%. On the other hand, Hera Comm went from 12 to 15 regions served and consequently its share rose from 54.1% to 72.1%; the new entry A2A Energia, with three regions served in 2019, has accumulated a share of 5.8%.

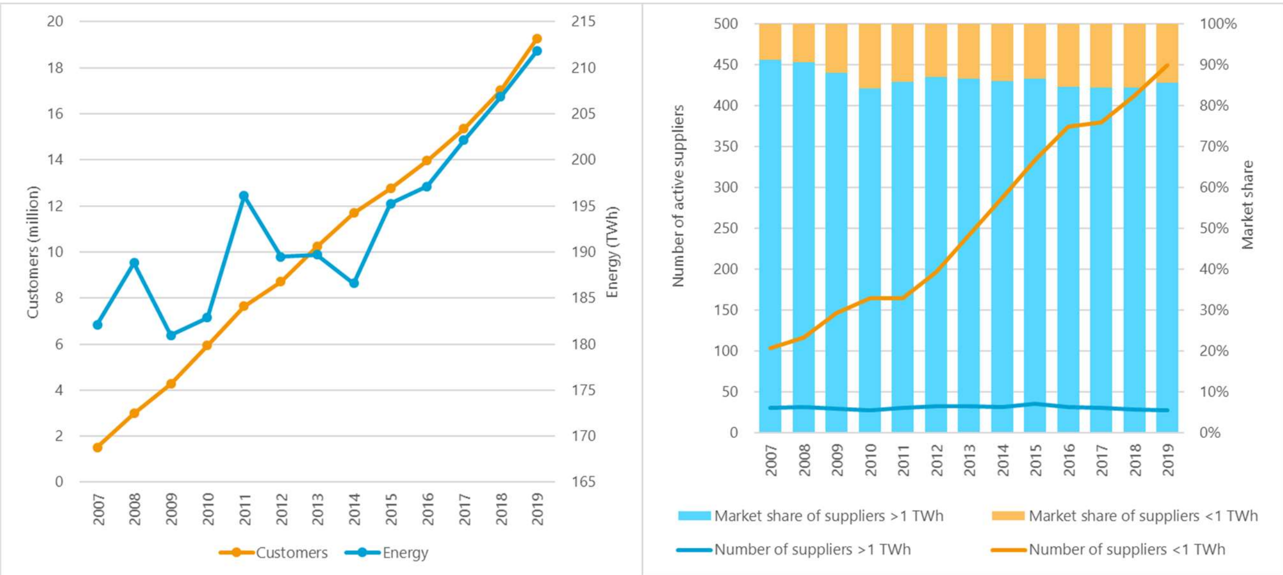
Free market

As seen in the previous pages, according to the (provisional) data collected in the annual surveys on the regulated sectors, 211.8 TWh were sold in the free electricity market in 2019, almost 5 TWh more than in 2018, to 19 million customers, with an increase of 13.1% compared to 2018.

Since its opening in 2007, the free market has been steadily expanding both in terms of customers and in terms of energy sold, even though the growth in sales volumes has suffered some setbacks over time and has occurred at a slower pace than that of customers. Regardless of the quantities sold, there has been a steady increase in the number of active companies or, more precisely, those among them with sales of less than 1 TWh, whose market share, however, has been at a standstill for years at around 15% (Figure 3.10).

In 2019, in fact, the growth in the number of operators proved to be dynamic: according to the responses obtained from the annual survey on regulated sectors, 36 new active companies entered the free market (+8.2%). The concomitant market expansion, which is lower in percentage terms (+2.4%), led to a further decline in the average unit sales volume of companies operating in this market, as in previous years. In 2019, in fact, the average unit sales volume of companies operating in the free market was 444 GWh, 5.3% lower than the 469 GWh recorded in 2018, thus reaching a new low point in the historical series. In fact, it dropped to a third of that observed in 2007 (1,349 GWh), the year of complete market opening.

Figure 3.10 Evolution of the free electricity market



Source: ARERA. Annual Survey on Regulated Sectors.

The corporate composition of the share capital of companies operating in the sale to free end-customers as at 31 December 2019, limited to direct first level holdings, shows a low foreign presence, with only 4.6% held by persons of foreign origin. Only 21 companies (out of the 455 that provided this data) have a non-Italian majority shareholder. Foreign direct shareholders are mostly German, Luxembourg or Spanish companies, but there are also majority shareholders from other countries (Albania, Austria, Belgium, Finland, Malta, Portugal, United Kingdom, Romania, Slovenia, United States of America and Switzerland).

Of the 477 active suppliers that responded to the annual survey, 32% sell energy in 1 to 5 regions; 91 companies, or 19%, sell electricity all over Italy; the remaining 232 companies (49%) operate in 6 to 19 regions.

The details of the customers per type and voltage (Table 3.17) shows an increase of nearly 2.2 million points served, mainly from the standard offer market. This result is due almost exclusively to low-voltage customers and in particular to domestic customers, despite a sharp increase in other low-voltage connections (+12.2%). Households served in the free market increased by 1,768,000, or 13.8%, compared to 2018; 472,000 new delivery points purchased electricity in the free market for other low-voltage uses. On the other hand, there was a drop in medium voltage customers, which fell by about 10,000 units (-8.6%); this drop is mainly attributable to other uses, although the public lighting points also fell by 218 units compared to 2018. The high/very high voltage delivery points showed a slight increase (1.3%), reaching almost 1,000 units.

As in 2018, purchases of low-voltage electricity increased (5.9%), while medium and high voltage purchases remained substantially stable (more precisely, an increase of +1.3% for high voltage purchases and a drop of -0.01% for medium voltage purchases). The domestic sector recorded an increase of 13.2% in the electricity purchased, public lighting delivery points reduced their consumption by 6.1%, while the other uses, which saw a sharp increase in the number of points served (11.6%), showed a more modest increase (1%) in the energy purchased.

Table 3.17 Free market by type of customer

TYPE OF CUSTOMER	VOLUMES (GWh)			DELIVERY POINTS (thousands)		
	2017	2018	VARIATION	2017	2018	VARIATION
Low voltage	84,287	89,273	5.9%	16,906	19,151	13.3%
Domestic	26,581	30,102	13.2%	12,821	14,590	13.8%
Public lighting	4,114	3,913	-4.9%	225	230	2.1%
Other uses	53,591	55,259	3.1%	3,859	4,331	12.2%
Medium voltage	96,249	96,241	0.0%	112	102	-8.6%
Public lighting	322	255	-21.0%	0.98	0.76	-22.2%
Other uses	95,927	95,986	0.1%	111	102	-8.5%
High and very high voltage	26,308	26,317	0.0%	0.99	1.00	1.3%
Other uses	26,308	26,317	0.0%	0.99	1.00	1.3%
TOTAL	206,844	211,831	2.4%	17,019	19,254	13.1%

Source: ARERA. Annual Survey on Regulated Sectors.

As always, among **domestic customers**, the most important class in terms of delivery points is the one with consumption between 1,000 and 1,800 kWh, which includes 24.2% of consumers. However, the neighbouring classes also have a similar weight. If we consider the purchase volumes, the most important class is the one with consumption between 2,500 and 3,500 kWh/year, in which 25.1% of all the energy purchased by the domestic sector in the free market is sold. In fact, 87% of delivery points have a consumption level that doesn't exceed 3,500 kWh/year. The average consumptions that emerge from the data relative to the free market is very similar to that of domestic customers supplied under standard offer, except in the case of customers who consume up to 1,000 kWh/year for whom average consumption in the free market (5077 kWh) is 18.2% higher than customers under standard offer, equal to 429 (Table 3.18).

13.4% of domestic customers, over 1.9 million, subscribed to a dual fuel contract in 2019. The number of domestic customers with this type of contract[107] has increased slightly (in 2018 it was 1.8 million), but their incidence on the total number of electricity customers has slightly decreased compared to that recorded in 2018 (which was 13.9%). The total consumption of dual fuel customers is 4 TWh, 13.2% of all energy sold to domestic customers on the free market. The portion of domestic customers who buy dual fuel contracts maintains a fairly constant trend over time, with small shifts both downwards and upwards. In this case, too, average consumption is very similar to that shown by customers who sign contracts for electricity alone.

Table 3.18 Domestic free market in 2019 by consumption class

Volumes in GWh and number of delivery points in thousands

CONSUMPTION CLASS	VOLUMES	SHARE	DELIVERY POINTS	SHARE	AVERAGE CONSUMPTION
< 1,000 kWh	1,793	6.0%	3,536	24.2%	507
1,000-1,800 kWh	5,156	17.1%	3,664	25.1%	1,407
1,800-2,500 kWh	6,259	20.8%	2,930	20.1%	2,136
2,500-3,500 kWh	7,561	25.1%	2,576	17.7%	2,935
3,500-5,000 kWh	5,442	18.1%	1,335	9.2%	4,076
5,000-15,000 kWh	3,515	11.7%	532	3.6%	6,605
> 15,000 kWh	375	1.2%	15	0.1%	24,455
TOTAL DOMESTIC	30,102	100.0%	14,590	100.0%	2,063
of which with dual fuel contract					
< 1,000 kWh	212	5.3%	411	21.0%	517
1,000-1,800 kWh	745	18.7%	528	27.1%	1,410
1,800-2,500 kWh	920	23.1%	431	22.1%	2,135
2,500-3,500 kWh	1,057	26.5%	361	18.5%	2,930
3,500-5,000 kWh	670	16.8%	165	8.5%	4,059
5,000-15,000 kWh	349	8.8%	54	2.7%	6,517
> 15,000 kWh	34	0.8%	1	0.1%	24,194
TOTAL WITH DUAL FUEL CONTRACT	3,987	100.0%	1,950	100.0%	2,044

Source: ARERA. Annual Survey on Regulated Sectors.

In contrast with what happens on the market with standard conditions, where the two-tier tariffs are predominant as they became compulsory from a certain date onwards, the unbundling of the customers by applied rate in the free market shows a substantial preference for the non-time-of-use contract mode, which has been chosen by 61.6% of all customers (equivalent to 60.3% of consumption). 29% of customers chose the two-tier modality and only 9.5% the time-of-use modality. The elements that make the non-time-of-use price more attractive are probably due to the simplicity of calculation and control of the tariff bill, as well as the absence of a constraint on consumption times.

[107] Dual fuel customers are the ones who receive one bill for both electricity and natural gas supplies; customers who have a contract with the same supplier for electricity and natural gas services, but receive two bills for the supplies, are excluded from this.

Concerning **non-domestic** customers, the sales in terms of volumes are concentrated in the consumption classes that range from 100 to 20,000 MWh/year, which together include 58.5% of the energy purchased by the non-domestic sector altogether. However, 63.4% of customers belong to the first class, meaning that they consume less than 5 MWh per year.

Dual fuel contracts have not spread widely among the non-domestic customers in 2019: the delivery points that preferred this type of supply are around 85.000 on the nearly 4.7 million total and almost all connected at low voltage; the purchased energy is just below 1.8 TWh on the total 181.7.

Available offers in the free electricity market

This year the Annual Survey of Regulated Sectors asked electricity and natural gas suppliers certain questions to assess the quantity, types and the methods of supply that companies offer customers who have chosen the free market.

The panorama of commercial offers available on the free market is a very complex and varied reality, enriched in 2018 by the presence of the PLACET (Free Price Under Equivalent Protection Conditions) offers, described in detail in paragraph 3.3.4. The data provided below on the types of offers available and actually chosen by customers in 2019, however, do not include a separate category for PLACET offers. In the electricity sector, the number of customers who preferred this type of offer in 2019 was 9,639, in the case of domestic customers, and 2,602, in the case of non-domestic low voltage customers. The objective of the questions asked to suppliers on the quantity and quality of commercial offers was, as in previous years, aimed at classifying the numerous offers on the market, although not completely exhaustive of reality. Therefore, please accept with caution the results presented in these pages. What's more, since the supply of the non-domestic customers traditionally introduces more complex and varied necessities compared to households, this year's distribution of collected results is also practically only concentrated on the latter.

The average number of commercial offers that suppliers can make to their potential customers was 16.3 for domestic customers and 23.4 for non-domestic customers. The latter, of course, has a greater choice, as this customer generally consumes more volumes and has more differentiated needs (multi-site, more varied hourly consumption profiles, etc.) than households. The supplier is surely able to offer more personalised services and individual contracts to this type of customer. Compared to 2018, the number of offers available to domestic customers has remained substantially unchanged. The number of offers available to non-domestic customers, however, decreased compared to 2018, when it was 39.6. The drop could be due, at least in part, to the fact that the free market for non-domestic customers is certainly more mature than that for households and could therefore find itself in a phase of streamlining of the offers addressed to this specific customer. Part of the drop, however, could also be explained by the better categorisation of offers by suppliers, as this is the fourth edition of the Survey asking for data on commercial offers. However, 21% of suppliers offer only one contract to their domestic customers, almost a third of them (29%) offer up to 3 contracts and the remaining half of suppliers offer their customers a range from 4 offers upwards. Compared to 2018, there has been a decrease in the number of suppliers offering only one type of contract, while there has been an increase in both those offering 2 or 3 and those offering up to 8.

Of the 16.3 offers made available to domestic customers on average, 5.1 can only be purchased online (5.9 in 2018), i.e. only through the internet, which is now an alternative sales channel through which the company can illustrate its offer with all the necessary details while saving on management costs. However, 20.8% of the suppliers don't provide on-line offers. The number of online offers is equal to the total number of offers proposed to customers in 17.4% of the cases, while the number of online offers is lower than the total offers in the remaining 82.6%. The success of online offers among households remains very limited: only 4.4% of customers (corresponding to 4.2% of electricity purchased in the free market) have signed a contract offered through this mode. The result is however higher than that of 2018, when 3.3% of households chose to subscribe to an electricity offer online.

Concerning the preferred type of price, 84.7% of households subscribed to a fixed price contract on the free market (i.e. with a price that does not change for at least one year from the time of the subscription), while only 15.3% chose a variable price contract, i.e. with a price that changes according to the times and methods established by the contract itself. Again, the figures have increased slightly compared to the previous year, when the variable price was chosen by 14.1% of domestic customers. In addition, 2.7% of customers have signed a contract with a minimum contractual term clause, meaning that the customer is not permitted to change supplier for a minimum time stipulated in the contract as a condition for the application of the set price. The percentage is higher with variable price contracts where the minimal contractual duration is applied to 9% of customers, while this figure is 1.6% in the case of fixed price contracts. There are different types of indexing modes for variable price contracts. 32% of customers who signed a variable-price contract signed a contract that provides for a fixed discount on one of the components established by the Authority for the standard offer service (they were 41% in 2018); 58% of customers chose a contract that provides for indexation to the trend of the PUN and 6% of customers chose one that is indexed to the trend of Brent (the previous year the values were more similar: 35% for the contract indexed to the PUN and 18% for that indexed to Brent). Finally, only 3% of the customers chose a contract that provides a different form of indexing from the ones mentioned above (7% in 2018).

Approximately 37% of domestic customers have signed a contract that provides for a rebate or discount of one or more free periods or a fixed sum in cash or volume, which may be one-off or permanent, possibly subject to the occurrence of a specific circumstance (for example, a discount for contracts signed by friends of the customer, a discount for direct automatic bank payments, etc.). More in detail, it turns out that the discount is applied to an average of 30% of the customers who chose a fixed price contract and to 78% of the customers who chose the variable price contract. However, the proportion of contracts purchased with a rebate or discount has fallen significantly since 2018, when it was 42%.

Finally, out of the domestic customers who chose a fixed price contract, concerning the presence of additional services[108] in subscribed contracts (Table 3.19), one can find a clear preference, among other things an increase, for the guarantee to purchase electricity produced by renewable sources (44% of customers), and for the participation to a points programme, through their electric power contract, that can be from the sales operator as well as from other parties (e.g. points that can be

[108] More specifically, the additional services envisaged in the questionnaire to the suppliers were:
- guarantee of energy from renewable sources (total or percentage green offer);
- points collection programme (own or others);
- ancillary energy services (for example, digital and collaborative tools to control energy consumption and costs, tools to increase energy efficiency, professional services such as telephone assistance, plant maintenance, insurance, etc.);
- gifts or gadgets;
- advantages over the purchase of other goods or services (for example, discounts on petrol supplies, magazine subscriptions, etc.);
- other not included among the previous items.

used for payments in a supermarket): 38.2% of the customers chose a contract that offers this additional service. 12.4% of customers, however, preferred a contact without additional services.

Table 3.19 Contracts for the supply of electricity by type of price and by type of additional services

Percentage of customers who signed the indicated contracts

CONTRACTS	2016	2017	2018	2019
Fixed price	84.6%	83.9%	85.9%	84.7%
Variable price	15.4%	16.1%	14.1%	15.3%
Additional services of fixed price contracts				
No additional services	n.a.	n.a.	12.2%	12.4%
Guarantee of energy from renewable sources	49.6%	45.7%	39.1%	44.3%
Points collection programme (own or others)	42.2%	45.0%	36.0%	38.2%
Accessory energy services	3.9%	5.7%	7.4%	2.6%
Gifts or gadgets	n.a.	1.4%	0.2%	0.4%
Advantages on buying other goods or services	2.6%	0.5%	0.3%	0.7%
Other	1.8%	1.7%	4.7%	1.5%
TOTAL	100.0%	100%	100%	100%
Additional services of variable price contracts				
No additional services	n.a.	n.a.	53.0%	52.3%
Guarantee of energy from renewable sources	60.9%	48.9%	27.5%	28.0%
Points collection programme (own or others)	5.8%	6.9%	2.5%	3.4%
Accessory energy services	22.0%	16.1%	8.5%	10.5%
Gifts or gadgets	n.a.	23.1%	3.1%	1.3%
Advantages on buying other goods or services	4.1%	3.6%	1.4%	2.4%
Other	7.2%	1.4%	4.1%	2.1%
TOTAL	100.0%	100%	100%	100%

Source: ARERA, Annual Survey on Regulated Sectors.

On the other hand, more than half of the customers who signed a variable price contract chose one without additional services. Even among these customers, however, there is a high interest in the guarantee of purchasing electricity produced from renewable sources (28% of cases). The second preference goes to the possibility of obtaining accessory energy services alongside electricity (10.5%). Point collection programmes and gift/gadget schemes collect a fairly modest share of preferences, 3.4% and 1.3% respectively.

Concentration in the retail electricity market

The classification (provisional, given the preliminary nature of the collected data) of the first twenty groups for total sales to the final market in 2019 (Table 3.20) has changed compared to the previous year, due to a shuffle in suppliers from the fourth position upwards. In fact, the top three positions have not changed compared to 2018. The dominant player in the entire Italian electricity market, as always, remains the Enel group, with a declining share of 36% this year (it was 37.6% in 2018), but still way ahead of the second group. In second place is the Edison group, with an overall share of 5.4%, an increase compared to 4.9% in 2018, thanks to the clear growth in medium and high voltage sales. The Hera group also maintained its third position in 2019, with an increase of 4.9% compared to 4.3% in 2018, mainly achieved in the domestic sector and in high voltage customers. The changes in the 2019 rankings, on the other hand, concern the fourth and sixth position, in which there are the same groups as in 2018, but in reversed position: the A2A group, which in 2018 was in sixth place, rose to fourth, while the Eni group was in fourth place and fell to sixth. The Axpo group remained in fifth position. In addition, the E.ON, Alperia, Egea and Engie groups gained several positions, while the Iren, Duferco, CVA and Repower groups fell in the rankings. The growth in sales of the A2A group, totalling 26%, occurred mainly in the non-domestic segment and, in particular, in sales to non-domestic low voltage customers. Conversely, the Eni group has lost a lot of ground among non-domestic customers, especially high voltage ones, while it has increased its sales among households; overall, however, the quantities of electricity it sold in 2019 are 5% lower than in 2018.

The Enel group maintains its position in the total market primarily thanks to its substantial dominance in the mass market, consisting of the domestic sector and low-voltage connected non-domestic customers: just over half of this market - 50.7%, to be precise - is, in fact, served by Enel, while Hera and Eni, in second and third position, have much smaller shares (4.2% and 3.7% respectively). Since 2016, the Enel group has also firmly maintained its first position in the segments of non-domestic customers in medium and high/high voltage, which it had lost in 2013 and regained in 2016.

In 2019, 67% of the energy consumed by households was sold by the Enel group (70% in 2018); with a share of 6.4%; the second group is Eni, while Acea has maintained its third position with 3.3%. Overall, the top five operators (in addition to those already mentioned, Hera and A2A) hold 82.5% of the domestic sector (84.7% in 2018). In the case of sales to low-voltage powered non-domestic customers, the share of the Enel group, equal to 37.7% (down from 39.3% in the previous year), also remains well behind the 5.2% of the second in the ranking, which is the Hera group (in second place also in 2018). These are followed by A2A with 4.5%, which was in fourth place in 2018, Edison (in third place in 2018) and E.ON (in eleventh place in 2018), both with 3.2%.

In 2019, the Edison Group, which traditionally followed the incumbent, maintained its fifth position in the mass market, which, as mentioned above, is the segment comprised of households and non-domestic customers supplied with low voltage. In sales to non-domestic customers supplied with high and very high voltage, Edison returned to third place (it was fourth the previous year) with a 13.7% share, just as it remained in third place, with a 6.7% share, for medium voltage customers.

In the medium voltage segment, the Hera Group maintained second place with 6.8%. The A2A group is in fourth position, with 5.8% (it was sixth in 2018), and the Axpo group is in fifth position with 5.3%. The Eni group, which in 2018 was in fourth place with a 5.2% share, fell to sixth with 4.8% in 2019.

In sales to high or very high voltage customers, after Enel the second group has become Axpo, with a share not too far from the incumbent: 14.7% against 18.5% of Enel. In 2018 the Axpo group was third with 12.6%. The Duferco group fell to fourth position, with a 12.3% share (in 2018 it was second with 13.8%), followed by Green Network (10.3%).

Table 3.20 Top twenty groups for sales on the final market in 2019

GWh

GROUP	DOMESTIC CUSTOMERS	NON-DOMESTIC CUSTOMERS LV	MV	HV/VHV	TOTAL	POSITION IN 2018
Enel	38,955	27,602	20,844	4,898	92,299	1st
Edison	1,155	2,344	6,635	3,626	13,760	2nd
Hera	1,760	3,772	6,711	302	12,544	3rd
A2A	1,548	3,293	5,751	792	11,384	6th
Axpo Group	75	1,899	5,196	3,893	11,063	5th
Eni	3,719	1,190	4,682	874	10,465	4th
Green Network	290	1,347	3,041	2,729	7,407	7th
E.On	462	2,321	3,959	356	7,099	11th
Iren	1,373	1,938	2,778	301	6,389	8th
Acea	1,918	1,773	2,127	275	6,093	10th
Duferco	77	799	1,831	3,263	5,970	9th
Alperia	331	1,150	3,394	220	5,094	15th
Egea	78	1,176	3,118	183	4,555	16th
CVA	121	1,290	2,622	99	4,131	12th
Repower Ag	0	2,022	1,997	67	4,086	14th
Engie	437	160	1,387	2,033	4,017	22nd
Dolomiti Energia	641	1,483	1,597	36	3,757	17th
Sorgenia	288	1356	1383	32	3,058	19th
Agsm Verona	297	1,003	1,611	101	3,012	23rd
Nova Coop SC	147	976	1,658	8	2,790	21st
Other operators	4,412	14,306	16,039	2,393	37,150	-
TOTAL OPERATORS	58,084	73,198	98,361	26,480	256,123	-

Source: ARERA. Annual Survey on Regulated Sectors.

In 2019 the level of concentration in the retail market decreased, whether measured by the amount of energy sold by corporate groups or by the number of customers served. In fact, the indicators normally used to evaluate concentration all show an improvement compared to 2018. Table 3.21 highlights the detail of the concentration measures, also distinguished by voltage levels. In the first part of the table, the measures are calculated from the volumes sold by corporate groups in the retail market, while in the second part of the table, the measures are calculated on the basis of the customers (delivery points) served by the corporate groups themselves.

Using the measures calculated on the kWh sold, the C3, that is the share of the first three operators (corporate groups) fell to 46.3% of the total sales, while it was at 46.8% in 2018. The HHI index also fell to 1,465 from 1.557 in 2018, falling below the first attention threshold of 1,500[109]. Finally, the number of groups with a market share above 5% rose to two: the Enel group, this year with a 36% share (in 2018 it held 37.6%), and the Edison group with a 5.4% share. It should be noted, moreover,

[109] An HHI value between 1,500 and 2,500 indicates a moderately concentrated market, while a value higher than 2,500 indicates a strongly concentrated one (the maximum index value is 10,000).

that in 2019 the Hera group, in third position, reached a share of 4.9%, therefore only just falling outside the number of groups with more than 5% of the market. However, the concentration of the Italian electricity market has two opposing sides: in the household segment it is high, albeit decreasing sharply, while in that of non-domestic customers it is very low and stable.

Using the indicators calculated on the delivery points, the concentration values are higher than those indicated by the volumes of energy sold, except - obviously - those relating to non-domestic customers served at high and very high voltage. However, in comparison with 2018, the data confirm a reduction in concentration in all market segments and especially in that of low-voltage connected non-domestic customers.

Table 3.21 Concentration measures in the retail electricity market

Measures calculated on corporate groups

VOLTAGE LEVEL	2018			2019		
	GROUPS >5%	C3	HHI	GROUPS >5%	C3	HHI
MEASURES CALCULATED BASED ON THE ENERGY SOLD BY THE CORPORATE GROUPS						
Domestic customers	2	79.4%	4,977	2	76.8%	4,581
Non-domestic customers	2	38.8%	985	4	38.8%	943
Low voltage	1	47.1%	1,651	2	47.4%	1,551
Medium voltage	4	33.6%	706	5	34.8%	721
High and very high voltage	5	48.6%	1,137	6	46.9%	1,098
TOTAL MARKET	1	46.8%	1,557	2	46.3%	1,465
MEASURES CALCULATED BASED ON THE CUSTOMERS SUPPLIED BY THE CORPORATE GROUPS						
Domestic customers	2	81.3%	5,293	2	77.5%	4,744
Non-domestic customers	1	68.8%	3,965	1	62.3%	3115
Low voltage	1	69.4%	4,032	1	62.6%	3,158
Medium voltage	3	46.8%	1,136	2	42.7%	1,064
High and very high voltage	4	44.8%	910	4	40.9%	763
TOTAL MARKET	1	78.6%	5,019	2	74.0%	4,385

Source: ARERA. Annual Survey on Regulated Sectors.

3.2.2.1 Monitoring of the retail market price level, the level of transparency, the level and effectiveness of market opening and competition

Monitoring of the retail market price level

The Authority collected two sets of data for the sales prices in the retail electricity market:

- that of *Average prices applied in the electricity and natural gas market* carried out according to the Resolution of 29 March 2018, ARG/elt 167/08, in which the quarterly data relative to the charges billed[110] by the suppliers to the domestic and non-domestic customers is recorded at

[110] More precisely, these are average unit costs obtained from the relation between the payments received and the quantity of energy invoiced in the reference quarter period.

half-yearly intervals, divided into consumption classes and market types;

- the other carried out within the context of the Annual Survey on Regulated Sectors, in which the data for the previous year is recorded and divided according to several retail categories (type of market, sector and consumption classes, type of contract).

The prices collected on the basis of Resolution 168/2018/R/ com are also included in the monitoring of the retail market carried out by the Authority pursuant to the *Integrated text of the monitoring of the retail markets for electricity and natural gas* (TIMR)[111], which, in addition to prices, carries out the analysis of a number of indicators relating to operators making final sales of electricity with more than 50,000 delivery points served (see below). Based on an institutional agreement, all the data collected according to the Resolution 168/2018/R/com are sent on a half-yearly basis to the Ministry of Economic Development, who sends them to Eurostat, in order to fulfil the obligation on statistics of the end prices of electricity and natural gas. These obligations were amended in 2016, with the adoption of *Regulation (EU) 2016/1952 on European statistics on natural gas and electricity prices and repealing Directive 2008/92/EC*. The Authority therefore updated[112] its systems for recording prices charged by electricity and natural gas suppliers to final customers to adapt them to the requirements of the new European Regulation. Since Italy has obtained an extension for the application of Regulation 2016/1952, these new price reporting systems have been applied starting from the price communication referring to the first half of 2019.

The data from the Annual Survey present a greater detail, useful for preparing the annual report to the national and European authorities.

Table 3.22 Average prices to domestic customers in 2019

€/MWh; provisional data.

CONSUMPTION CLASS (kWh/year)	QUANTITY OF ENERGY (GWh)	DELIVERY POINTS (thousands)	PRICE NET OF TAXES	OF WHICH: SUPPLY COSTS
< 1,000 kWh	3,766	8,132	554.5	191.2
1,000-1,800 kWh	10,246	7,283	243.1	125.7
1,800-2,500 kWh	12,244	5,732	208.8	114.2
2,500-3,500 kWh	14,444	4,918	198.3	108.0
3,500-5,000 kWh	10,186	2,498	192.3	102.8
5,000-15,000 kWh	6,382	968	188.6	97.2
> 15,000 kWh	816	29	176.8	88.1
TOTAL DOMESTIC CUSTOMERS	58,084	29,559	229.1	115.5

Source: ARERA. Annual Survey on Regulated Sectors.

Within the Annual survey on the regulated sectors, the sales operators have been requested to transmit the data relative to the end price practised to their customers, net of taxes, for the part connected to the single supply costs, which are obtained from the sum of the components relative to the energy, the dispatching, the network losses, the imbalance and the marketing costs of the sale.

[111] Approved with Resolution 3 November 2011, ARG/com 151/11.

[112] Precisely with Resolution 168/2018/R/com which also repealed the previous Resolution of 20 November 2008, ARG/elt167/08, relating to the same collection of prices.

The analysis of the prices transmitted by the operators has shown an extreme variability of the unit cost for the customers. This result can be found in all consumption classes, with certain differences. As we can see in Table 3.22, which shows the averages of the prices applied to domestic customers divided by consumption classes, the values are between a minimum of 177 €/MWh, for the larger customers (over 15,000 kWh/year) and a maximum of 555 €/MWh, relative to the smaller class (0-1,000 kWh). The price constantly drops as the size of the customers increases. This is due to the gradual phasing out, established by the Authority starting from 2017, of the progressive structure of network tariffs and system charges. The cost of supply, as always, also decreases continuously as consumption increases.

As already highlighted in the analysis of the free market, the number of offers available to final customers has increased over the years. Some of these offers include fixed prices for a predefined period (one or two years), in which the updating mechanisms of the costs are not therefore influenced by market dynamics of energy prices, but mainly depend on the date of subscription of the contracts and in particular on the expectations of the existing price trend of the energy at that moment, as well as the duration of these contracts (the longer it is, the more the negotiated price must take the risks of market changes into account). Other offers have variable prices. Some of these provide discounts on the raw material component, others offer advantages for the purchase of other goods or services (like discounts at the supermarket, or on fuel, or telephone services, maintenance and insurance services, etc.). Other offers are bound to the respect of defined consumption thresholds, and when they are exceeded, the additional price components are applied. These elements may explain the differences in average unit fee levels between the free market and the standard offer service (Table 3.23).

Table 3.23 Average prices to domestic customers in 2019 by consumption class and market type

€/MWh

CONSUMPTION CLASS (kWh/year)	SUPPLY COSTS			AVERAGE TOTAL PRICE (NET OF TAXES)		
	STANDARD OFFER	FREE MARKET	DIFFERENCE	STANDARD OFFER	FREE MARKET	DIFFERENCE
< 1,000 kWh	186.3	196.6	10.3	564.6	543.4	-21.1
1,000-1,800 kWh	110.1	141.1	31.0	222.0	263.9	41.9
1,800-2,500 kWh	98.7	129.1	30.3	189.6	227.1	37.5
2,500-3,500 kWh	92.7	122.0	29.3	180.0	214.9	35.0
3,500-5,000 kWh	88.2	115.5	27.3	175.1	207.3	32.3
5,000-15,000 kWh	83.9	108.0	24.2	173.0	201.3	28.3
> 15,000 kWh	80.2	97.3	17.1	165.9	189.6	23.7
TOTAL DOMESTIC CUSTOMERS	101.9	128.1	26.2	215.0	242.1	27.1

Source: ARERA. Annual Survey on Regulated Sectors.

Table 3.24 shows the prices relating to non-domestic customers (including those served under the safeguard service), broken down by voltage level. The amount of the unit fees shows, as usual, an inverse relationship with the voltage level. Table 3.25 shows the breakdown of low voltage non-domestic customers by type of market. The lowest average fees are found in the free market, which also has the highest quantities of energy.

Within the supply cost component, the first consumption class (up to 1,000 kWh/year) shows the smallest difference between the two markets, while larger differences, both in absolute terms and as a percentage, are shown by the three central classes (consumption between 1,800 and 5,000 kWh/year). The comparison shows a similar trend in the final price (net of taxes), except for lower differentials in percentage terms, as well as the counter-trend behaviour of the first consumption class, for which the free market has a lower price level, which can be attributed to a different incidence of resident customers, burdened to a lesser extent by system charges.

Table 3.24 Average prices to non-domestic customers in 2019

€/MWh; provisional data.

VOLTAGE LEVEL	QUANTITY OF ENERGY (GWh)	DELIVERY POINTS (thousands)	PRICE NET OF TAXES	OF WHICH SUPPLY COSTS
Low voltage	73,198	7,269	210.8	94.8
Medium voltage	98,361	108	138.4	73.3
High and very high voltage	26,480	1	81.7	62.7
TOTAL NON-DOMESTIC CUSTOMERS	198,039	7,378	157.6	79.8

Source: ARERA. Annual Survey on Regulated Sectors.

Table 3.25 Average prices to low voltage non-domestic customers in 2019, by type of market

VOLTAGE LEVEL	QUANTITY OF ENERGY	DELIVERY POINTS	PRICE NET OF TAXES	OF WHICH SUPPLY COSTS
Standard offer	12,666	2,638	244.9	101.0
Safeguarded	1,360	71	205.9	100.2
Free market	59,171	4,561	203.6	93.3
LV NON-DOMESTIC CUSTOMERS	73,198	7,269	210.8	94.8

Source: ARERA. Annual Survey on Regulated Sectors.

Table 3.26 Final average prices net of taxes per type of hour tariff in 2019

€/MWh; excluding the safeguarded category market; provisional data.

HOUR TARIFF	QUANTITY OF ENERGY (GWh)	DELIVERY POINTS (thousands)	PRICE NET OF TAXES	OF WHICH SUPPLY COSTS
Non time-of-use	18,394	9,126	251.9	135.6
Two-tier	36,724	19,053	218.5	105.9
Time-of-use	2,966	1,380	217.9	108.4
Domestic customers	58,084	29,559	229.1	115.5
Non time-of-use	29,026	1,363	142.72	77.85
Two-tier	51,737	948	158.06	82.50
Time-of-use	113,632	4,992	153.15	76.87
Non-domestic customers	194,396	7,302	150.95	78.03

Source: ARERA. Annual Survey on Regulated Sectors.

Table 3.27 Average prices for the purchase of electricity in the free market applied for domestic customers with dual fuel contracts in 2019

Quantity of energy in GWh; delivery points in thousands; prices in €/MWh; provisional data

CONSUMPTION CLASS (kWh/year)	QUANTITY OF ENERGY	DELIVERY POINTS	PRICE NET OF TAXES	OF WHICH SUPPLY COSTS
Domestic customers				
< 1,000 kWh	212	411	597.1	279.9
1,000-1,800 kWh	745	528	278.9	168.8
1,800-2,500 kWh	920	431	228.5	141.6
2,500-3,500 kWh	1,057	361	210.1	126.7
3,500-5,000 kWh	670	165	194.7	113.5
5,000-15,000 kWh	349	54	185.9	102.2
> 15,000 kWh	34	1	170.7	155.5
TOTAL DOMESTIC CUSTOMERS	3,987	1,950	242.8	142.1
Low voltage	1,075	85	178.6	82.7
Medium voltage	733	1	66.7	35.9
High and very high voltage	5	0	69.8	29.8
TOTAL NON-DOMESTIC CUSTOMERS	1,813	85	133.1	63.6

Source: ARERA. Annual Survey on Regulated Sectors.

Table 3.26 shows the value of prices, also net of taxes, subdividing electricity customers by type of hourly tariff and excluding the safeguard market, while the following table shows the electricity prices paid by free market customers who have signed a dual fuel contract. For domestic customers, the electricity prices that emerge from dual fuel contracts are more expensive compared to purchasing electricity with a specific contract in case of low consumption. The tables show the reduced consistency of the number of these customers and the energy they purchased.

Monitoring the level of transparency, the level and effectiveness of market opening and competition

The **monitoring system of the retail markets** allows the Authority to accomplish the regular and systematic observation of the sale conditions, including the degree of liberalisation, market competitiveness and transparency, and the level of participation of the consumers and their degree of satisfaction.

Legislative Decree n. 93, of 1 June 2011, in implementation of Directives 2009/72/CE and 2009/73/CE, has established that the Authority must carry out the monitoring of the retail markets, with reference to the electricity and natural gas sectors. This activity was launched, for both mass customers market sectors, with the *Integrated text of the electricity and natural gas retail sales markets monitoring system* (TIMR), as mentioned in the previous paragraph.

At the end of 2019, the Report illustrating the main results of retail market monitoring activities with reference to 2018[113] was published, describing, where possible, the evolution of the relevant

[113] Report 10 December 2019, 527/2019/I/com.

phenomena in the first seven years (2012-2018). Consistently with the previous Reports, the Report of 2018 analyses the data collected in matters of:

- structure of the offer and competitive dynamics in the sector of mass customer sales;
- the frequency with which customers change their supplier (switching) or renegotiate their contract with their current supplier;
- organisational processes and mechanisms to support the functioning of the sales market;
- arrears, as estimated by the analysis of the requests for supply suspension and based on financial indicators, such as invoices and un-paid amounts.

The results of the retail monitoring activity for 2018, firstly confirm the absence of specific significant issues for customers in the medium voltage - other uses sector. In particular, the increase in concentration is limited and customer dynamism is sustained. Therefore, for that year as well, it can be stated that the functioning of the market, with reference to the medium voltage - other uses customer segment does not require any specific regulatory intervention.

For customers connected to the low-voltage - other uses service the evidence on the competitive dynamics and structure of the sales market shows, on the one hand, some encouraging signs of dynamism but, on the other hand, also aspects that require further verification. In the monitoring activities to come, therefore, particular attention will be paid to these latest results, also in order to confirm them with further findings, with particular reference to the evolution of concentration levels and the dynamism of final customers.

On the other hand, despite the signs of improvement that have emerged with regard to residential customers, in the electricity sector, and residential customers and central heating, in the natural gas sector, the critical issues that historically characterise these market segments, and which still persist, suggest that greater care should be taken in the process of accompaniment, including regulatory, towards the complete liberalisation of the market. In detail, particular attention should be paid, first and foremost, to the high levels of concentration and the continued competitive advantage of the standard offer operators. Other elements likely to be examined further in the monitoring activity to come are:

- the impact on final prices of the greater differentiation of offers in the domestic and non-domestic customer segments;
- how changes in supply prices in wholesale markets may or may not be reflected in the offers available to final customers in downstream markets and in the prices paid by customers.

For both sectors, the above elements, relating to the configuration of the markets and the difficulty for final customers to navigate the offers present in the free market, must be taken into account in the process of complete liberalisation provided for by Law no. 124/2017, which provides for the removal of protection regimes from 1 January 2021 for small businesses and from 1 January 2022 for domestic customers and micro-enterprises[114]. This is in order to avoid customers not being able

[114] Pursuant to art. 2 of Directive (EU) 944/2019 this category includes companies with a maximum of 10 employees and an annual turnover or balance sheet total not exceeding 2 million euros.

to take full advantage of all the opportunities offered by the free market in the forthcoming context of full liberalisation.

The retail monitoring system continues to evolve in order to fully exploit the potential of the SII: for this reason, in May 2019 the Authority started a procedure[115] aimed at expanding and updating the phenomena monitored, increasing the detail of the information available and defining new publication and reporting methods, which allow greater timeliness and usability of the monitored data.

Complaints relating to the commercial quality of the electricity sales service and compensation

The Integrated text of the regulation of the quality of electricity and natural gas sales services (TIQV)[116], has established a series of rules to protect final customers and commercial quality indicators, which all electricity and gas sales companies are required to comply with. There are two types of indicators: general and specific. Written complaints, billing corrections and double billing corrections are subject to specific minimum standards on service time, while written requests for information are subject to general standards.

In the event that the supplier does not comply with the specific commercial quality standards, the customer automatically receives compensation on the occasion of the first bill. The automatic basic compensation (starting from 2017, equal to 25 euros) doubles if the performance of the service subject to compensation takes place beyond twice the standard time and triples if the performance of the service takes place beyond triple the time of the standard or even longer. Regardless of the expected escalation, the compensation must in any case be paid to the customer within 6 months by the supplier who received the written complaint or the request for billing or double billing correction. Compensation is not due if compensation has already been paid to the customer in the calendar year for non-compliance with the same quality standard and in the case of complaints for which the customer cannot be identified (because the complaint does not contain the minimum necessary information). Furthermore, the supplier is not obliged to pay automatic compensation if the failure to comply with the specific quality standards is due to force majeure - understood as acts of public authority, exceptional natural events for which a state of emergency has been declared, strikes called without the notice required by law, failure to obtain authorisation - or to causes attributable to the customer or third parties, or damages or impediments caused by third parties.

For 2019, due to the epidemiological emergency caused by COVID-19, the data available and illustrated below are partial and refer to 88% of electricity customers, therefore not comparable with previous years. On the basis of the available data, however, the actual average response times for electricity suppliers, in the case of complaints and billing corrections, are slightly below the minimum standards set by the Authority, equal to 30 calendar days for both complaints and requests for information. The average response times for information requests and billing corrections recorded in 2019 are also below the general standard (Table 3.28).

[115] With Resolution of 7 May 2019, 173/2019/A.

[116] Annex A to Resolution of 21 July 2016, 413/2016/R/com.

Table 3.28 Standards for the electricity sales service and actual average times in 2019

In calendar days and percentage values

SERVICES	SPECIFIC STANDARDS	GENERAL STANDARDS	AVERAGE ACTUAL TIMES(A)
Maximum time for reasoned response to written complaints	30	-	28.0
Maximum time for billing corrections	60 or 90(B)	-	28.5
Maximum time for double billing corrections	20	-	27.0
Minimum percentage of responses to written requests for information sent within the maximum period of 30 calendar days	-	95%	9.2%

(A) Partial data and referring to 88% of electricity customers.
(B) 90 calendar days in the case of quarterly frequency bills.

Source: supplier declarations to ARERA.

Overall (Table 3.29), the companies that served customers in the electricity sector and that reported data up to 3 April 2020 received a total of 225,853 written complaints: 55.6% of complaints came from customers in the free market, while 40.1% came from customers in the standard offer market. As regards the requests for information received, partial data from 2019 show that 66.5% of the requests come from domestic customers and 25% from non-domestic customers. 73.5% of requests for information are from customers in the free market and, in particular, domestic customers, while customers in the standard offer market account for 12.9%. Multi-site customers contribute 7.6% to total requests, while medium voltage customers contribute a residual share (0.8%). Billing corrections, which follow written complaints on already paid bills whose content is disputed, mainly concerned the free market (74.9%) and, in particular, domestic customers (45.3%), followed by non-domestic customers also in the free market (29.6%). 51.1% of billing corrections come from domestic customers, while 34.9% from non-domestic customers.

The data communicated by the suppliers also include the average actual response time to a double billing correction request, calculated on the basis of the actual response time both in cases where the specific or general quality standard has been met and in cases where this standard has not been met for reasons attributable to the supplier. From 1 January 2019 the standard has dropped to 60 calendar days. Double billing corrections, which are caused by errors in switching procedures (i.e., for the same consumption period, the final customer receives a bill from both the old supplier and the new supplier), were a largely residual phenomenon in 2019 (1,796 cases), which mainly affected domestic and non-domestic customers in the free market (70.4%).

Table 3.29 Complaints, requests for information and billing corrections received by electricity suppliers

	2017	2018	2019(A)
Number of complaints	323,572	284,507	225,853
Number of requests for information	211,619	147,167	152,493
Number of billing corrections	19,006	9,245	5,869
Number of double billing corrections	3,798	2,191	1,796

(A) Partial data and referring to 88% of electricity customers.

Source: ARERA processing of data from the Help Desk for the energy consumer.

As far as the subjects of the complaints are concerned, the first three concerned: for about 44% of the cases, billing and everything related to consumption and fees billed, self-reading, billing periodicity, including the closing bill, making payments and refunds; for 15.56% the events of the contract, such as withdrawal, change of name, transfer and take-over (completion and costs of transfer and take-over); for 10.5% the procedures for the conclusion of new contracts, switching timescales and the economic conditions proposed by the supplier at the time of the offer compared to those provided for in the contract and actually applied.

Overall, in 2019 there were 51,986 cases of non-compliance with the standards, which led to the right to compensation for services relating to the commercial quality of the sale; the largest number of automatic compensation payments accrued in the market segment relating to domestic customers (both in the free market and in the standard offer service) and is mainly related to the failure to comply with the time limits for responding to written complaints; this was followed, in terms of number, by compensation to non-domestic customers in the standard offer market and to non-domestic customers in the free market.

A situation very similar to that for accrued compensation is evident for the compensation actually paid out, more concentrated in the free market, which in 2019 was paid out for more than 2.2 million Euros (in 2018 automatic compensation was paid out for almost 2.8 million Euros).

3.2.2.2 Recommendations on final sales prices, investigations, inspections and measures to promote effective competition

Investigation and inspections

Enforcement of the provisions laid down by the Authority is carried out by monitoring the conduct of operators, identified from time to time on the basis of planning documents prepared on an annual basis or following reports or evidence in the possession of the Offices. For this reason, the Authority performs surveys, inspections and document verification of plants, processes and services related to the Authority’s interest sectors.

With reference to 2019, the surveillance activity was carried out according to the methods already consolidated in previous years, through:

- fact-finding and reconnaissance; in particular, the last part of the survey on investments declared by companies was completed during the reporting period and a survey of retail electricity and gas sales companies was launched;
- on-site inspections, related to a wide range of topics, with particular attention to priority topics such as consumer protection, service quality, correct operation of the markets and control of the distributed incentives and the costs items recognised in the tariff;
- documental checks, in particular relating to: the correct application of brand unbundling obligations and communication policies of electricity sales companies; the correct contribution, by regulated companies, of the Authority's operating charges; the correct disbursement of incentives to energy-intensive companies.

In cases where the monitoring activities reveal cases of non-compliance with regulatory provisions, the consequent sanctions and/or prescriptive measures are taken against operators. The results of this activity are also relevant to the implementation or updating of the regulatory framework, with a view to its continuous improvement and effectiveness, in the regulatory cycle process adopted.

With regard to sanctioning measures, in 2019 the conclusion of a procedure resulting from the multi-year fact-finding survey on the investments of regulated companies, launched in 2014, should be noted[117]. At the end of 2018, in fact, the gas distribution plants of the company CO.M.E.S.T. were included in the above-mentioned multi-year survey[118]. The activities related to this last extension were completed during 2019 and the results were approved by Resolution 314/2019/E/gas of 16 July 2019: numerous construction deviations, even significant ones, were found in the company's distribution network, of which both the Municipal Administrations concerned and the Prefecture and the Court of Palermo were informed.

In compliance with the indications of the Strategic Framework, in 2019 the monitoring activity was expanded, with a greater number of inspections carried out than in previous years and, in particular, with a further increase in the regulatory areas subject to investigation and control, also in relation to the dynamics taking place in the regulated sectors.

In 2019, a total of **110 inspections** were carried out in **the electricity and gas sectors**, an increase compared to the previous year with a broad spectrum of topics addressed compared to the past. During the year, in fact, inspections were carried out in two new fields of investigation, i.e. on the functional unbundling of electricity sales, that is on the provisions concerning the methods for separating the companies' brand and communication policies, as well as on gas settlement, that is to say on the provisions regarding the physical and economic items of the gas balancing service. Inspection activities were also carried out in the other areas considered to be priorities, in order to ensure adequate coverage of the monitoring activities with respect to the panel of operators present and users served, with particular attention paid to the quality of electricity and gas services.

Measures for the effective promotion of competition: safeguarded service for small customers

In 2017, the Competition Law was approved (Law No. 124 of 4 August 2017), which introduced rules relating to the retail electricity and natural gas market, aimed in particular at: (i) the cessation of the transitional price regulation (standard offer service) defined by Law no. 125, and (ii) the introduction of interventions to support the further development of the retail markets. During 2019, the Authority continued its interventions to support the further development of retail markets within the regulatory framework outlined by the Competition Law.

The deadline provided for by Law no. 124/2017 (subsequently amended by Law no. 108 of September 21, 2018, converting Decree Law no. 91 of July 25, 2018) for phasing out the standard offer service was postponed: the law provided for the abolition of the service as of 1 July 2020 and assigned the Authority the task of regulating a safeguard service, to be assigned through competitive procedures and to be provided at conditions that would encourage customers to switch to the free market, aimed at customers without a supplier in the aftermath of the abolition of the standard offer service. The Authority set out its first guidelines on the regulation of the **safeguard service for small customers** in consultation document 397/2019/R/eel of 27 September 2019.

[117] With Resolution 6 June 2014, 256/2014/E/com.

[118] With Resolution of 11 December 2018, 642/2018/E/gas.

After issuing this document, Law no. 124/2017 was further amended by the Decree-Law of 30 December 2019, No. 162, converted, with amendments, by Law of 28 February 2020, No. 8 and on this occasion the phasing out of the service was postponed to 1 January 2021 for small companies and 1 January 2022 for domestic customers and micro-enterprises[119]; at the same time, a service of last resort "with gradual protections", regulated by the Authority, was provided for customers not supplied in the free market.

The measures outlined in consultation document 397/2019/R/eel concern, in particular: i) the requirements for access to the safeguard service by final customers; ii) the structure of the service; iii) the economic conditions of supply; iv) the contractual conditions applied to final customers.

With reference to the conditions of access to the service indicated under i), the consultation document provides that the service is provided automatically (*ex lege*) to small customers without a contract under free market conditions, whether they are customers still supplied under the standard offer service, whether they are customers whose free market contract will be terminated (for example, by withdrawal from the supplier or by an expired and not renewed contract) and who have not signed another contract in time. Furthermore, unlike what happens today with the standard offer service, there is no possibility for customers with delivery points supplied in the free market to request the activation of the safeguard service.

With reference to the structure of the service (under ii), two possible options are proposed:

- *model 1*, which provides for the assignment of responsibility for supplying the electricity needed to provide the service to the Single Buyer, and the marketing activity to the operators, respectively[120];
- *model 2* , with a structure similar to that of the current last resort services in the electricity and natural gas sector (in which operators are also responsible for the supply of electricity).

In relation to the economic conditions of the safeguard service for small customers (point iii), the following measures are envisaged:

- application to the customer of a price for energy that has the same structure as the fees for the standard offer service (variable over time and undifferentiated at territorial level);
- adoption of rules for the quantification of fees to cover supply costs differentiated by type of customer, based respectively on the expected values of wholesale market prices (so-called ex ante method of determination), with reference to domestic customers, and on the actual values that are determined in that market (so-called ex post method), with reference to non-domestic customers;
- application of a marketing fee determined on the basis of the results of the auctions in such a way, on the one hand, as to guarantee the protection of the final customer against sudden changes in the price paid in the standard offer service and, on the other hand, not to disrupt or create interference with free market offers; to this end, the final customer is expected to pay, for

[119] Pursuant to art. 2 of Directive (EU) 944/2019 this category includes companies with a maximum of 10 employees and an annual turnover or balance sheet total not exceeding 2 million euros.

[120] The marketing activity includes the provision of the supply by signing a transmission contract with the distribution company and managing the contractual relationship with the customer. By way of example, marketing includes billing, payment and insolvency management, complaint handling and customer information services in general.

an initial period, a price in line with what he would pay under the standard offer service and, subsequently, a price determined on the basis of the results of the competitive procedures;

- an adequate remuneration of the service operators compared to the price offered in competitive procedures.

With regard to the contractual conditions for the provision of the service (point iv), it is proposed to apply to final customers the same conditions provided for by the regulation of the so-called PLACET offers (i.e. free price at equivalent protection conditions)[121], so as to ensure continuity with the contractual provisions currently in force.

The consultation document also outlines possible measures to promote the selection of reliable operators to whom the service in question should be assigned by identifying strict requirements for participation in competitive procedures and the results of competitive tendering.

Measures for the effective promotion of competition: purchasing groups

With Resolution No. 59/2019/R/com of 19 February 2019, the Authority adopted Voluntary Guidelines for the promotion of electricity and natural gas offers in favour of purchasing groups aimed at final domestic customers and small businesses assimilated to final domestic customers, i.e. low voltage connected businesses and those with annual consumption up to 200,000 S(^{3}), in implementation of Article 1, paragraph 65, of Law No. 124/2017. The purchasing groups to which the above Guidelines are addressed (so-called energy purchasing groups) are associative entities established with the aim of selecting one or more suppliers for the supply of electricity and/or natural gas to the final customers included in the group. The group's organiser typically manages the process of customers joining the group, negotiates the supply conditions with selected suppliers and assists customers if they end up signing an offer, without becoming a counterparty to the energy supply contract.

There are two potential advantages of purchasing groups. Firstly, groups are potential instruments for transition to the free market, especially for smaller customers who have so far been more reluctant to abandon standard offer regimes because of perceived differences in negotiation with suppliers. This is because the aggregation of a large customer base allows small users to rebalance their bargaining position with the supplier in order to obtain offers that are more cost-effective and better suited to their consumption needs. Secondly, these groups can arouse the interest of final customers in understanding and evaluating market offerings through the savings opportunities they offer. In light of the above, the Authority, with the aforementioned Guidelines, has intended to establish uniform rules of conduct with which energy purchasing groups that decide to adhere to them must comply, in order to ensure the necessary transparency for its members on collective purchasing campaigns, correctness in the use of the various forms of communication to the customer right from the promotional phase of the initiatives in question, completeness of the information provided on how to join the group, on the commercial offers proposed as well as on the criteria for choosing them, as well as adequate information assistance to the customer, especially in the phase of joining the group and the suggested offer. Adherence to the Guidelines implies full compliance by accredited purchasing groups with the customer care and information obligations established for a period of at least 24 months. In 2019, the Authority established and published the list of purchasing groups that undertake to comply with the Guidelines (so-called accredited purchasing groups) on its

[121] See Resolution 27 July 2017, 555/2017/R/com.

website. At 31 December 2019, 8 purchasing groups were accredited for the promotion of commercial electricity and gas offers for small customers.

Measures for the effective promotion of competition: PLACET offers

The advance in the understanding of commercial offers by consumers is a fundamental prerequisite for their active participation in the market. This participation is essential in order to reach a structure where the free market is also the normal method of electricity and gas purchase for smaller customers, above all, in view of the end of the standard condition services. The Authority has therefore introduced[122] the PLACET offers (free price offers under uniform contractual conditions), for both electricity and natural gas, described later in this chapter.

Measures for the effective promotion of competition: establishment of the Consumption Portal

To facilitate the choice of their supplier, it is essential that the customer knows the trend of their consumption in detail. This is why, since July 2019, the **Electricity and Natural Gas Consumption Portal** has been available. It is an institutional website where consumers can access, in a simple, secure and free manner, data relating to their electricity and natural gas supplies, including their historical consumption data and the main technical and contractual information (described in detail in the following paragraph).

3.3 Consumer protection and dispute resolution in the electricity sector

3.3.1 The protection system: the handling of final customer complaints (basic level)

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 solution of problems and disputes that may arise between customer and service provider. The activities related to the basic level, described below, are carried out on a national scale by the Single Buyer, on behalf of the Authority[123], through the Energy and Environment Consumer Help Desk (Help Desk). The activities relating to the basic service are represented by the Help Desk's responses to:

- calls to the Call Centre,
- written requests for information,
- requests for activation of special information procedures,
- second level complaints.

An overview of the volumes handled by the protection system in 2019 and, in particular, those that reached the Help Desk is illustrated in Table 3.30.

[122] With Resolution of 27 July 2017, 555/2017/R/com.

[123] Renewed from the end of 2019 for the three-year period 2020-2022, with Resolution of 10 December 2019, 528/2019/E/com.

Table 3.30 Protection system: volumes reaching the desk and second level activities

ACTIVITIES	YEAR 2019
Basic level	
Calls to the call centre 800.166.654 (received during service hours)	483,082[(A)]
Written requests for information	10,768[(B)]
Requests for activation of special information procedures	28,837
Second level complaints redirected with information on conciliation	1,568
Second level	
Applications to the Conciliation Service (compulsory conciliation)	14,465
ADR entities registered in the Authority's List (compulsory conciliation)	1,451
Requests for activation of special resolution procedures	9,198

(A) The value also includes calls relating to the water sector.
(B) Of which 407, classified as complex, have been redirected to the Conciliation Service because they are related to potential disputes.

Source: Energy and Environment Consumer Help Desk processing.

In 2019, 483,082 calls (+19% compared to 2018) were received at the Help Desk call centre during service hours; of these, 461,672 were handled and 21,410 were dropped by customers or end users without waiting for the operator to respond. Compared to 2018, both the average waiting time (149 seconds versus 131) and the average conversation time (200 seconds versus 178) increased slightly. 87% of calls handled by the call centre (403,126) concerned the electricity and gas sectors. The topics dealt with in the phone calls received at the Help Desk concerned, in particular, social bonuses (41%), dispute resolution (24%), rights and regulation (10%), practices at the Help Desk (12%) and in the remaining 12% of cases other aspects *Tutela Simile* (a sort of standard offer for the free market), *Offerte PLACET* (free price offers under uniform contractual conditions), *Portale Offerte*, purchasing groups). Lastly, there were 22,141 contacts in which information was provided on the issue of phasing out price protections in the energy sectors, both on specific request ("rights and regulation" channel), and during a conversation on related issues.

With regard to **requests for written information**, in 2019 the Help Desk received 10,768 requests for the energy sectors, which were divided into two categories: simple and complex. Over half of simple information requests (10,361 in total) can be traced back to just two topics: " billing" (29%), for which the majority of requests concern "incorrect estimated consumption", and the "market" (25%), for which requests concerning "switching" and "alleged unsolicited contracts" were predominant. The topics of "connections and technical quality" and "contracts", on the other hand, covered 14% and 11% of written requests for information respectively. 407 of the written requests (3.8%) were classified as "complex", because, in addition to the information on regulation relating to the problem highlighted by the customer, they also entailed indicating the out-of-court dispute resolution tools available in the event that the first complaint is not resolved. In more than half of the cases complex requests for information concerned the topic of "billing".

The **special information procedures** make it possible to provide information without the need to speak to the Help Desk staff. They have been operational since 1 January 2017, but ì only for certain issues in the energy sectors. By means of information encoded in centralised databases (Integrated Information System, Compensation System) and "automatically applicable" regulations, the Help Desk provides final customers or their delegates with the required information. Compared to the previous year, in 2019 requests for the activation of special information procedures increased by 43%, for a total of 28,837 cases, broken down as follows: 70.5% in the electricity sector, 21% in the gas sector and 8.5% in both sectors. The share of the electricity sector decreased by 5.5%, while the share of gas increased by 3%. The strong overall increase in requests is mainly due to those concerning the identification of the operator responsible for the RP/PoD (Redelivery Point for gas/Point of Delivery for electricity) concerned in case of transfer ("unknown supplier") and those aimed at knowing the current commercial counterparty and the switching date (up by 45% and 58%, respectively, for each type, from one year to the next).

Finally, the Help Desk also received 1,568 **second-level complaints** (i.e. those for which the dispute was not resolved with the first complaint), for which it informed the client about the conciliation tools that could be used to resolve the dispute, i.e. the Authority's Conciliation Service or other conciliation bodies. Overall, 2,112 customers or users were redirected towards conciliation, directly or indirectly, which decreased by 62% compared to the same figure in 2018. The 1,568 cases redirected directly to conciliation also mainly concerned "billing" (49%).

3.3.2 The protection system: out-of-court dispute resolution (second level)

The activities related to the second level of the protection system concern the resolution of problems and disputes arising in the relationship between the customer and the provider of the regulated service. They can be settled through the Help Desk's special resolution procedures or conciliation procedures. The latter may be carried out using the Authority's Conciliation Service or ADR entities on the Authority's special list.

Special resolution procedures

In the same way as for the special information procedures (relating to the basic level of the protection system), the Help Desk also accesses information encoded in centralised databases for resolution procedures. In contrast to the information procedures, the special resolution procedures make it possible to determine the outcome of the dispute and involve a discussion with the Help Desk staff if further information is required to consult the databases or to verify the correct fulfilment of the regulations following the resolution of the dispute.

In 2019, the Help Desk received 9,198 requests for the activation of resolution procedures, an increase of 27% compared to 2018. The majority of requests concerned the special "bonus" procedure (89%); the remaining percentage is divided between requests on "C^{MOR} cases" (verification of the conditions for its cancellation, in 8% of the total), on "double billing" (2%) and on "voluntary restoration procedure"[124] (1%). Finally, there were only 6 cases of activation of the special resolution procedure for "failure to pay automatic compensation" due within the maximum time limits set by the regulation. While in terms of the percentage incidence of each procedure on the total, there were no significant deviations compared to 2018, an analysis of the individual procedures shows that the most significant change, in absolute terms, is attributable to the special "bonus" procedure, for which there were almost 2,000 more requests; in percentage terms, on the other hand, it is the "double billing" procedure that shows the largest increase (+ 38%) compared to the previous year.

The gas sector accounted for 55% of the requests, the electricity sector for 36% and both sectors for 9%: compared to 2018, the weight of the gas share increased by 5% to the detriment of the electricity

[124] Procedure governed by the Integrated text on preparatory measures for the confirmation of the contract for the supply of electricity and/or natural gas and voluntary restoration procedure, TIRV, adopted by Resolution No. 228/2017/R/com of 6 April 2017.

sector. In 93% of cases, the special resolution procedures involved domestic customers, while e-mail was the most commonly used method of access.

The Authority's conciliation service

The Authority's Conciliation Service is a dispute resolution procedure, which can be activated by final customers of electricity and natural gas for problems arising with energy operators (suppliers and distributors), in the event of failure to respond or an unsatisfactory response to the complaint. The procedure is undertaken entirely online and in the presence of a third-party, impartial conciliator, expert in mediation. The eventual final agreement is effective as a settlement between the parties, according to Art. 1965 of the Civil code. Moreover, with the approval of Article 141, paragraph 6, letter c) of the Consumer Code[125], an attempt at conciliation has become a condition for bringing an action before the judiciary for disputes arising in the areas regulated by the Authority (with the exception of tax or fiscal issues), unless urgent and precautionary judicial measures are taken.

In 2016, the Authority approved[126] a comprehensive and organic text of the provisions on the subject, which were brought together in the Integrated Text on Conciliation (TICO)[127], which also identifies the conciliation procedures available to parties other than the Authority.

In June 2018 the Authority carried out[128] a review of the TICO, in order to incorporate the evidence that emerged in the first year of operation and to provide clarification on its application for the benefit of stakeholders. The Authority, in implementation of Article 141-sexies of the Consumer Code, has provided for specific information obligations for energy suppliers, towards final customers.

In 2019, customers and end users of the energy sectors submitted 14,465 requests to the Conciliation Service. The sectoral breakdown of requests received by the Service in 2019 confirms the prevalence of electricity, with a 56% share of requests submitted (8,165 requests); followed by the gas sector, with 36% (5,167 requests). On the other hand, the percentage of dual fuel customers and prosumers out of the total number of requests submitted (995 and 138 requests respectively) is stable. The sector that recorded the greatest increase in requests from one year to the next, in absolute terms, is the electricity sector, with around 2,000 more requests than in 2018.

The main method of submitting requests has become the use of delegates other than consumer associations (41%, compared to 36% in 2018), while the proportion of requests submitted through consumer associations registered with the CNCU[129] (27%, compared to 29% in 2018) and those submitted directly by customers (32%, compared to 36% in 2018) has decreased. 74% of requests received by the Service concerned a domestic final customer, consistent with the previous year. With regard to the subject of disputes, the prevalence of billing remains (53%), followed by contracts (12%) and compensation for damages (10%). Breaking down the data on the energy sectors, different percentages can be identified: in the electricity sector, "billing" is 48% and "damage" is 16%; in the

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[125] The legislative decree n. 130/15 has transposed Directive 2013/11/UE of the European Parliament and the Council of May 21st, 2013, in the Italian legislation, concerning the ADR for the consumers, that amends the regulation (EC) 2006/2004 and the Directive 2009/22/CE (Directive on ADR for consumers).

[126] Resolution of 05 May 2016, 209/2016/E/com.

[127] Annex A of Resolution of 5 May 2016, 209/2016/E/com.

[128] Resolution 28 June 2018, 355/2018/R/com.

[129] The Consiglio Nazionale dei Consumatori e degli Utenti (National Council of Consumers and Users - CNCU) is the representative body of consumer and user associations at national level. It is based at the Ministry of Economic Development and is composed of consumer associations recognised according to the criteria established by the Consumer Code (Legislative Decree 206/2005, art. 137) and a representative designated by the State - City and Local Authorities Unified Conference (Legislative Decree 281/1997, art. 8).

gas sector, the weight of "billing" increases to 62%; for dual fuel customers, "billing" is 51% and "contracts" 21%.

As regards the response to requests received by the Service, 79% were admitted to the procedure (a percentage substantially in line with the previous year). 69% of procedures concluded with an agreement between the parties, an increase compared to the previous year (66%). The parties took an average of 55 days (2 more than in 2018) to reach the agreement and, in 78% of cases, less than two meetings.

With regard to the approximately 8,500 procedures concluded by agreement, in 2019 the value of the dispute was declared by the activator in 56% of cases; of these, 54% were in the range from 0 to 1,000 euros, while 85% did not exceed 5,000 euros (threshold of small claims pursuant to Regulation (EC) 861/2007 of 11 July 2007, as amended and supplemented). The rate of agreement on concluded procedures (195 procedures pending as at 17 March 2020) recorded in 2019 by the Conciliation Service, net of waived procedures (equal to about 1% of admissible requests), is 69% of the total, up 3% compared to 2018. The parties took on average 55 days to close a procedure (56 days for agreements and 52 days for non-agreements). 78% of the procedures ended in less than two meetings. The agreements signed before the Conciliation Service, relating to procedures initiated in 2019 and concluded, produced over 10.4 million euros in compensation. This value is given by the algebraic sum of the economic consideration (in the form of value recovered also with respect to the value of the dispute or refunds, indemnities, recalculation of erroneous bills, waiver of expenses and default interest, etc.) obtained by customers or end users through the aforementioned agreements. Of the approximately 3,900 questionnaires completed at the end of the conciliation procedure, 98% of the activators were satisfied with the Service.

Other conciliation services

As an alternative to the Conciliation Service of Authority, final customers can also fulfil the obligation to attempt conciliation for judicial purposes by turning to other bodies. In December 2015, in implementation of art. 141-decies of the Consumer Code, the Authority established the List of bodies appointed to manage ADR (Alternative Dispute Resolution) procedures pursuant to Title II-bis of Part V of the Code.

At 31 December 2019, 19 ADR bodies were registered in the Authority's List. Of these, 7 are sectoral joint conciliation bodies - based on specific memoranda of understanding stipulated between consumer associations and companies - and 12 are transversal bodies, which also operate in sectors other than those falling within the Authority's competence; among the latter, 11 are mediation bodies and, as such, also registered in the Register of mediation bodies kept by the Ministry of Justice[130].

The information sent by ADR bodies reveals a slight decrease in conciliation requests compared to 2018. Out of a total of 1,819 requests (2,167 in 2018), 35% concern the electricity sector. In most cases (56%) requests are submitted by the customer through a consumer association.

Also with this channel, the main issue of the disputes is billing (60%), followed at a great distance by contracts (12%), while problems related to arrears and suspension appear in third place (9%). As in the previous year, the percentage of requests admitted is very high (85%); the related procedures were completed in 78% of cases in 2019, largely (73%) with an agreement. Finally, as regards the average time taken to conclude procedures, there is a difference depending on the outcome: on

[130] Legislative Decree 4 March 2010, No. 28 and Ministerial Decree 18 October 2010, No. 180.

average, 50 days in case of agreement (as in 2018) and 54 days in case of non-agreement (65 days in 2018).

3.3.3 Protection of vulnerable domestic consumers and energy poverty

Initiatives for customers in economic hardship and with serious health conditions: social bonuses

Since January 2009, a protection mechanism was activated for the electricity and gas supplies, only for domestic customers who find themselves in situations of economic difficulties or in serious health conditions, that receive a bonus, i.e. a discount on the electricity and/or gas supply.

Decree-Law No. 4 of 28 January 2019, on "Urgent provisions on the subject of citizenship and pensions"[131], provides that the 'Citizens' Income' (CI) may be granted to households with certain characteristics, in particular an equivalent economic situation indicator (ISEE) of less than € 9,360, and that, for households consisting exclusively of one or more members aged 67 years or more, the CI takes the name of Citizens' Pension (CP). The decree also establishes that the subsidies relating to electricity tariffs for economically disadvantaged families and those relating to compensation for the supply of natural gas are extended to beneficiaries of CI or CP. In May 2019 the Authority implemented[132] the Decree-Law n. 4/2019, through changes to the regulation contained in the Integrated text on the methods for applying the compensation schemes for expenses incurred by disadvantaged domestic customers for the supply of electricity and natural gas - TIBEG[133], allowing recipients of CI and CP to have access to the electricity and gas bonus due to economic hardship. Such access was allowed in the manner already provided for the other bonus recipients, in terms of start date and duration of the bonus period.

In June 2019, the Authority submitted a report[134] to Parliament and the Government in which it stressed the need to adopt mechanisms for the automatic allocation of social bonuses to potential recipients. In fact, despite the efforts made to raise awareness of the means to obtain these benefits among those who are entitled to them, the use of these benefits is not yet particularly widespread, even in the presence of situations of serious economic difficulties in the country. In order to maximise the distribution of bonuses, in its report, the Authority proposed to the Government and Parliament to introduce a digital exchange of the data already contained in the public databases of INPS (National Social Security Institute) and SII (Integrated Information System), in compliance with the regulations on the protection of personal data, so as to automatically award social bonuses to all citizens with ISEE certification below the threshold provided for by the regulations in force, without the latter having to submit an application. The proposals put forward by the Authority in the report were transposed by Decree-Law no. 124 of 26 October 2019[135], which provided for the automatic recognition of national social bonuses to eligible households from 1 January 2021, eliminating the need to apply to municipalities and/or tax assistance centres. More in detail, the Decree-Law establishes that bonuses are automatically granted to all subjects whose ISEE is within the limits established by the legislation in force and that the Authority, with its own measures, after consulting

[131] Converted, with amendments, into Law 28 March 2019, No. 26.

[132] Resolution 07 May 2019, 165/2019/R/com.

[133] Annex A to Resolution of 26 September 2013, 402/2013/R/com.

[134] Report of 25 June 2019, 280/2019/I/com.

[135] Converted, with amendments, into Law of 19 December 2019, No. 157 (so-called Fiscal Decree).

The Italian Data Protection Authority, shall define the methods of transmission of useful information by the INPS to the SII (managed by the Single Buyer). Furthermore, the Authority must define the methods of application for the distribution of the bonus as well as, after consulting The Italian Data Protection Authority the methods of sharing the information relating to those entitled to bonuses between SII and SGAte (Management System for energy tariffs facilities), in order to ensure the full recognition to the citizens of the other social benefits provided.

In December 2019 the Authority ordered[136] the update of the ISEE threshold value, as required by the decree of the Ministry of Economic Development of 29 December 2016 (article 1, paragraph 3). Based on the evolution of the national consumer price index for blue- and white-collar households, the Authority has raised the ISEE threshold allowing access to benefits from 8,107.5 to 8,265 euros, with effect from 1 January 2020. Thanks to this increase, it is estimated that in 2020 around 200 thousand new customers will be able to benefit from social bonuses.

The bonuses in numbers

In 2019, the number of citizens who applied for and obtained the **social bonus for electricity supplies** was distributed as follows: 870,277 families had access to the electricity social bonus, of which 829,209 for economic hardship and 41,068 for physical hardship. The total amount of bonuses paid for the electricity sector (for economic and physical hardship) was approximately 135.5 million euros.

Since 2017 there has been a growth in the number of beneficiaries of the subsidies, after two years of substantial stability; growth is confirmed in 2019. This phenomenon is mainly attributable to the increase in the reference ISEE threshold, which rose[137] from €7,500 to €8,107.5 on 1 January 2017; the new increase in the threshold to €8,265 will hopefully lead to a further increase in the number of beneficiaries in 2020.

Starting from the introduction of the subsidy in 2008 and until 31 December 2019, the number of households who have benefited, for at least one year, from the electricity bonus due to economic hardship, including the beneficiaries of the Purchase Card (see below), was equal to approximately 3.1 million households, more than 50% of which are located in the macro-areas of the South and the Islands.

During 2019, the number of households that took advantage of the Purchase Card scheme fell dramatically, from over 23,000 to around 8,300, a decrease of 64% compared to the previous year. This radical drop in subsidies for Card holders could be the result of the introduction of Citizenship Income, which replaced the Card system for many families, even if the two measures can be combined. Furthermore, as already noted in the past, the automatic method of accessing the electricity bonus provided for the Purchase Card continues to present issues. The absence of the obligation to include the PoD as one of the elements to be communicated when submitting the application for the Purchase Card makes it impossible to identify the supplies to be subsidised.

There were 41,068 households with an active bonus for the use of life-support electrical equipment (bonus for physical hardship) as at 31 December 2019; this figure increased significantly compared to the previous year, by 23%. The bonus for physical hardship is divided into three bands, in order to

[136] Resolution 03 December 2019, 499/2019/R/com.

[137] Ministerial Decree of 29 December 2016.

consider the type of used equipment, the average hourly consumption of each type of equipment and the average hours of daily use. On the basis of these elements, certified by the ASL (local health authority), the customer is assigned to one of the three provided bands of compensation. The three bands are then further differentiated according to the committed power (up to 3 kW and from 4.5 kW)[138].

Charges associated with the payment of the electricity bonus for economic and physical hardship are included among the components of general charges relating to the electricity system and are covered by the A_{SRIM} component, which is included in the bill for final customers in the A_{RIM}[139] component, which is paid by all customers who do not enjoy the electricity bonus.

At 31 December 2019, 558,514 households benefited from the **social bonus for gas supplies** due to economic hardship, with a 2.9% growth compared to 2018. In total, more than 1.9 million households have benefited from the subsidy at least once since its entry into force. The total amount of bonuses paid for the gas sector was approximately 76.2 million euros in 2019. To cover the charge 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 GST components, which are charged to customers other than domestic customers. In addition to the funds raised from customers, there are also funds from the State Budget. As in the electricity sector, the value of the compensation is defined annually at the same time as the tariff update.

3.3.4 Interventions in pricing for vulnerable customers

Standard offer and safeguard services

Legislative Decree n. 93/11 does not provide a specific definition of vulnerable customer concerning the electricity sector (as it does with natural gas, see below). However, Article 35 on public service obligations and consumer protection provides that all domestic consumers and small companies (with less than 50 employees and a turnover of less than 10 million Euros) who do not choose a supplier on the free market are served within the framework of the standard offer service established by Law No 125 of 3 August 2007[140]. The standard offer service is regulated by the Authority and ensures, on the one hand, the continuity of supply (universal service function) and, on the other hand, a specific (contractual) quality at reasonable prices; this price regulation is of a transitional nature and will be phased out, by virtue of Law no. 124 of 4 August 2017 (the so-called Competition Law), from 1 January 2021 for small businesses and from 1 January 2022 for micro-enterprises[141] and domestic customers, respectively. Until the date of termination of the transitional price regime, the

[138] See the Annual Report 2013 for the details of the functions of the bonus.

[139] Article 1 of Resolution 922/2017/R/eel of 27 December 2017 provides that, as from 1 January 2018, the A_{SRIM} element of the A_{RIM} component shall be applied without distinction to all users, including those entitled to the electricity bonus. The effects of this application are offset in favour of users entitled to the electricity bonus by increasing the same bonus by the value of the A_{SRIM} element applied to the annual reference consumption for each type of disadvantaged customer provided for by the TIBEG. Since January 2019 this component (formerly the A_S component) represents 2.61% of the average expenditure of the typical user.

[140] Converting Decree-Law No.73 of 18 June 2007.

[141] Pursuant to art. 2 of Directive (EU) 944/2019 this category includes companies with a maximum of 10 employees and an annual turnover or balance sheet total not exceeding 2 million euros.

Authority will regulate the standard offer service in accordance with the principles, identified by the European Court of Justice,[142] of proportionality and timeliness in relation to the market opening process.

Customers who find themselves without a supplier in the free market and who do not have the right to access the standard offer service, since they are different from domestic and small businesses, are supplied, again in accordance with the aforementioned law 125/2007, thanks to the safeguarded category market, aimed at guaranteeing only the continuity of supply. This service is provided by sales companies selected through competitive procedures for territorial areas at economic conditions determined as a result of the same procedures.

Providing information in view of phasing out price protections

Law no. 124/2017 provided for preparatory actions for the termination of the transitional price regime[143]. These interventions include, for example, each supplier sending final customers adequate information on whether price protections have been phased out, in accordance with the procedures defined by the Authority, and a strengthening of the Authority's functions, with specific reference to the disclosure and dissemination of information on the full opening of the market and the conditions under which services are provided, for the benefit of final customers and users.

In this context, in November 2017, the Authority ordered[144], among other things, that, as of January 1, 2018, the standard offer operators send their customers, within the summary bill, a special information note, with content defined by the Authority, regarding the expected phasing out of price protections.

In May 2019, the Authority ordered[145] that the information note should continue to be sent with the bill until the price protections were completely phased out. The wording to be included in the bills issued in 2019 contains, on the one hand, an indication of how simple and free of charge it is to change contract or supplier, with the guarantee of continuity of service, and, on the other hand, the elements to encourage the final customer to take advantage of the Authority's tools aimed at making an informed and aware choice, such as the Offers Portal and PLACET offers (see below). At the same time, the Authority launched a procedure to define new tools for the information and empowerment of final customers in the energy markets, additional and complementary to the information in the bill; the final aim is to involve customers more actively in the evolution of the markets and the tools set up for them and to increase the involvement of customers already served in the free market.

PLACET offers

Increased understanding of commercial offers by final customers is a prerequisite for their active participation in the market and is therefore a key area of action to achieve a structure in which the free market is the normal mode of supply even for small customers.

142 Judgement of the European Court of Justice – Great Chamber, April 20th, 2010, proceeding C-265/08.

143 Article 1, paragraph 69.

144 Resolution 10 November 2017, 746/2017/R/com.

145 Resolution 21 May 2019, 197/2019/R/com.

Consistent with this framework, the Authority has, therefore, promoted actions aimed at increasing the awareness of final customers and the transparency of contractual terms and conditions, in order to allow their wider participation in a competitive market.

With this in mind, in July 2017 the Authority introduced[146] the regulation of offers "at a free price under equivalent protection conditions" (so-called PLACET offers), aimed at increasing customers' ability to evaluate the commercial offers present on the free market, by identifying offer structures that are easy to understand, comparable between suppliers (since they differ only in price) and separable from any proposal for additional services by the same supplier.

The regime of PLACET offers applies to small customers served in the free market, identified, for the electricity sector, as all customers (domestic and non-domestic) connected to the low voltage grid.

In detail, the resolution imposed an obligation on each operator in the free market to include two PLACET offer formulas among its commercial offers - one fixed price and one variable price - characterised by general supply conditions set by the Authority, with the exception, however, of economic conditions, the levels of which are freely defined by the supplier (according to a predefined fee structure). In both cases, the price of energy is divided in a fixed share expressed in €/customer/year and an energy share expressed in €/kWh or €/S (m^3) and therefore proportional to the consumed volumes[147].

Table 3.31 Number of PLACET offers on the Offer Portal at 31 December 2019, distinguished by type of final customer

	FIXED PRICE	VARIABLE PRICE	TOTAL
Domestic customers	228	227	455
Non-domestic customers	228	228	456
TOTAL ELECTRICITY SECTOR	-	-	911
Domestic customers	230	227	457
Non-domestic customers	234	232	466
Central heating	200	202	402
TOTAL GAS SECTOR	-	-	1,325
TOTAL PLACET OFFERS	-	-	2,236

Source: ARERA. Processing on Single Buyer data.

As of 31 December 2019, there are 2,236 PLACET offers on the *Portale Offerte:* 911 relating to the electricity sector and 1,325 relating to natural gas. In particular, of the 911 offers available for electricity customers, 455 are for domestic customers and 456 for non-domestic customers; of the

[146] Resolution 27 July 2017, 555/2017/R/com.

More precisely, the PLACET variable price electricity offers provide, every month, a price indexed with the PUN (Single National Price), expressed in €/kWh, as determined by the GME. The price is divided into hour bands with a remote-managed meter. In particular, for remotely managed domestic customers, the price is divided into F1 and F23 hour bands, and for remotely-managed non-domestic customers, it is divided into F1, F2 and F3 hour bands. For domestic and non-domestic customers, who do not have a remotely managed meter, the price is the same at all hours.

The PLACET natural gas offers at variable prices provide a price indexed with the TTF determined every quarter as the arithmetic average of the OTC forward quarterly prices of the quarter in question, at the TTF hub, found by ICIS-Heren with reference to the calender month preceding the concerned quarter.

1,325 offers for natural gas, 457 are for domestic customers, 402 for central heating and 466 for non-domestic customers (Table 3.31).

The periodic monitoring of PLACET electricity offer prices present in the *Portale Offerte* shows that in the fourth quarter of 2019 for the typical domestic customer[148] the pre-tax average cost of fixed PLACET offers was 15% higher than the pre-tax standard offer cost for the same period, while the pre-tax average cost of the variable PLACET offers was 13% higher than the pre-tax standard offer cost.

3.3.5 Access to consumption data

An initial guarantee of access to consumption data is provided by the billing regulation. In particular, Bill 2.0, which came into force on 1 January 2016 (see Annual Report 2015) must contain data on annual consumption and its breakdown by time bands. Further elements can be found in the detailed bill, available on the website. Through complaints and requests, the customer can request the data from the suppler, who 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 access, via electronic display, to the current consumption data both in terms of energy and power consumption, as well as the consumption values divided into peak/off-peak/mid-level hours used for the last bill.

The right for final customers to have access to their historical consumption data was however made explicit by Legislative Decree no. 102 of 4 July 2014, implementing Directive 2012/27/EU. In 2015[149] and 2017[150], the Authority set out its guidelines in relation to making historical consumption data available to final customers, taking into account both the regulatory changes and developments that have taken place and, in particular, the advent of the 2G metering system in the electricity sector.

In particular, in December 2017, the Authority stipulated[151] that consumption data, understood as historical billing data and historical data of the delivery time profile, must be accessible through the Integrated Information System (IIS), which is already the repository of such information pursuant to Law no. 27 of 24 March 2012. In addition, the Authority deemed it appropriate that the data should be made available digitally through a web portal, set up by the Single Buyer (as manager of the SII) and accessible to the final customer with authentication through the Public Digital Identity System (SPID). Following the consultation, the provisions of the 2018 Budget Law were adopted[152], which specified deadlines for completing the process.

In June 2019, the Authority then defined[153] how final customers can access their consumption data from 1 July 2019 through the dedicated Consumption Portal on the Authority's website[154]. Consumers can access, in a simple, safe and free way, data related to their historical consumption,

[148] For the definition of a typical household user for electricity, see the previous notes.

[149] Document for consultation 186/2015/R/eel of 23 April 2015.

[150] Document for consultation 865/2017/R/efr of 14 December 2017.

[151] Document for consultation 865/2017/R/efr of 14 December 2017.

[152] Law no. 205 of 27 December 2017 on "Budget for the State for the financial year 2018 and multiannual budget for the three-year period 2018-2020".

[153] Resolution 25 June 2019, 270/2019/R/com.

[154] https://www.consumienergia.it/portaleConsumi/

reported in summary documents, numerical tables and graphs, as well as the main technical and contractual information.

Further developments to the Portal are already planned, such as extending the period to which the historical consumption refers from 12 to 36 months, displaying the power withdrawn with an indication of maximum value and, for customers equipped with 2G meters, displaying the historical programming of the bands for the meters and the availability of consumption data with quarter-hour detail.

A further important development is the possibility for so-called third parties to access the data on supplies. This aspect, which is essential in order to disseminate the tools to raise awareness of one's energy footprint, requires further investigation, currently under way, in order to define the parties that can be delegated, ensure adequate protection of personal data and manage authorisation by final customers.

3.3.6 Availability of price comparison tools

As noted above, Law no. 124/2017 provided for preparatory actions for the termination of the transitional price regime. This includes, inter alia, a strengthening of the Authority's functions, with specific reference to disclosure and dissemination of information about the full opening of the market and the conditions under which services are provided. These tools include a price comparison tool for small customers[155].

Within this framework, in February 2018, the Authority adopted the Regulation for the implementation and management, by the Manager of the Integrated Information System (hereinafter referred to as the "Manager"), of a Portal of offers for domestic final customers and small electricity and natural gas companies (so-called Offers Portal).

Currently, free market offers for domestic customers and low-voltage powered companies, including dual fuel offers (electricity and gas) and PLACETs, are published on the Portal. The *Portale Offerte* currently has several filters and options for refining the search (e.g. based on a specific operator, or based on discounted offers, etc.) that allow the user to select the offer that best meets their needs.

During 2019, the offers present on the Portal and the requests from operators to insert and correctly represent the specific characteristics of the various offers on the market were monitored.

Monitoring shows that the total number of visits from 1 July 2018 (start date) to 31 December 2019 consisted of 1,078,824 unique visits. A total of 8,179,045 pages were viewed.

As at 31 December 2019, a total of 2,293 offers were available for the electricity sector, while there were 70 dual fuel offers (Fig. 8.1). 61.3% of offers to domestic customers were fixed price, while for non-domestic customers this percentage was 54.1%.

Periodic monitoring of the electricity offers on the Portal shows that in the fourth quarter of 2019, for a typical domestic customer[156], the average pre-tax cost of the top 10 operators was 11% lower

[155] Article 1, paragraph 61. "... the creation and management ... of a special web portal for the collection and publication in open data mode of the offers in force on the retail market for electricity and gas, with particular reference to domestic users ... low voltage connected companies ...".

[156] A typical domestic electricity user is considered a resident domestic customer, with consumption of 2,700 kWh, two-tier price tariff, power equal to 3 kW and located in Milan (postcode 20132).

than the pre-tax standard offer cost for fixed-price offers and 6% for variable-price offers. Again for the same type of customer, the average pre-tax cost of the top 30 operators was also lower than the standard offer cost, namely 7% for fixed price offers and 3% for variable price offers.

4 THE GAS MARKET

4.1 Infrastructure regulation

4.1.1 Network and LNG tariffs for connection and access

LNG regasification tariffs

In 2019, the additional services provided by small scale regasifiers, so-called **small-scale LNG** (SSLNG), were regulated. In detail, in May 2019 the Authority defined[157] the criteria for regulating the conditions, including economic conditions, for access to and provision of services offered through LNG storage depots and the provisions on accounting unbundling for SSLNG services, in application of the regulatory provisions of articles 9 and 10 of Legislative Decree No. 257 of 16 December 2016. These criteria apply to regasification terminals that offer, in addition to the regasification service, also SSLNG services and LNG storage depots considered strategic (pursuant to Article 9 of the abovementioned Legislative Decree No. 257/2016) and that are connected to the natural gas transmission network and equipped with facilities functional to the regasification process and to input into the natural gas transmission network.

These services envisage, in particular:

- with regard to the regulation of access to infrastructures that provide both the regasification service and the SSLNG services:
  - to apply the provisions set out in the Integrated Text on the adoption of guarantees of free access to the LNG regasification service (TIRG), also for the purpose of regulating the conditions of access to the regasification service provided by LNG depots;
  - in the case of capacity dedicated to SSLNG services in addition to regasification services, that access to these services is based on procedures defined independently by the infrastructure manager, without prejudice to the opportunity for the revenue generated through the provision of the services to contribute to covering the costs for using the part of the infrastructure shared between the regasification service and SSLNG services;
  - in the case of SSLNG services that commit part of the regasification capacity (competing capacity), that the users of SSNLG services participate, for the delivery of LNG to the terminal, in the competitive procedures for the allocation of regasification capacity defined by the Authority pursuant to the TIRG;

- with reference to the tariff regulation criteria:
  - to apply the provisions set out in the LNG Regasification Service Tariff Regulation (RTRG) also to LNG storage and regasification depots, for which SSLNG services are configured as additional services to LNG regasification services;
  - to apply, for existing regasification terminals, a common cost recognition criterion in line with the proposed incremental costs, according to which only costs (capital and operational) directly attributable to the provision of SSLNG services are attributed to SSLNG services;

[157] Resolution 168/2019/R/gas of 7 May 2019.

- to foresee that the coverage of the share of the common costs of the regasification activity and SSLNG services attributable to the SSLNG services themselves is to take place on the basis of the two separate ways of managing the capacity functional to the provision of these services (dedicated or competing capacity); in particular, it is established that (i) in the case of additional and dedicated capacity in addition to the capacity authorised for regasification, a share of the revenues deriving from the provision of SSLNG services shall contribute to reducing the revenue recognised for the regasification service in order to remunerate the common costs; (ii) in the case of capacity competing with the regasification capacity, the users of SSNLG services, for the delivery of LNG to the terminal, shall bear the fee resulting from the competitive procedures for access to the infrastructure, in return for their share of the common costs;
- with regard to revenue coverage mechanisms, to introduce a specific mechanism allowing the LNG depot operator referred to in Article 9 of Legislative Decree no. 257/2016 connected to the transmission network, with reference only to the capacity made available for the purpose of the regasification service, to partially cover the recognised costs limited to the start-up period of the activity, and in any case not exceeding the guarantee level provided for existing regasification terminals; in addition, it is established that the application of this mechanism shall be governed as part of the regulation of the LNG regasification service currently being defined for the fifth LNG regulation period.

With regard to the more general regulation of the service, which was the subject of consultation[158] during September 2019, in November 2019 the Authority approved[159] the tariff regulation criteria for the liquefied natural gas regasification service (RTRG) for the 2020-2023 regulatory period (5PR LNG). With this measure, the Authority, substantially in line with the criteria for determining the recognised cost, which provide for price cap-type incentive regulation schemes for operating costs and rate of return-type regulation schemes for capital costs, has introduced the following main new features:

- the phasing out of input-based incentive criteria, without prejudice to the recognition of the portion of revenue attributable to the additional remuneration for investments that came into operation in previous regulatory periods;
- the introduction, in addition to the Q_{CP} coefficient to cover self-consumption and the losses of the regasification chain, of further fees to cover variable costs, such as the C_{CP} fee to cover the monetary costs associated with the consumption of the regasification chain and the C_{ETS} fee to cover the costs relating to the emission trading system;
- the introduction of the possibility, also for terminals benefiting from the coverage mechanism, to retain a part (40%) of the revenues deriving from the offer of flexibility services, with the remaining part being allocated to the reduction of the burden on the system for covering the corrective factor;
- the provision that a portion equal to one third of the revenue item to cover input-based incentives (relating to investments made in previous regulatory periods) be considered as part of the revenues subject to coverage according to the regasification capacity allocated through competitive procedures;

[158] Document for consultation 391/2019/R/gas of 26 September 2019.

[159] Resolution 474/2019/R/gas of 19 November 2019.

- the completion of the regulatory framework for LNG storage and regasification depots and the provision of SSLNG services:
- with reference to the revenue coverage mechanism for LNG depots equipped with facilities functional to the regasification service, a duration of application of the revenue coverage mechanism of 4 years;
- with regard to the sharing of revenues from SSLNG services to cover the common costs of regasification activity, the introduction of a flat rate sharing criterion that provides for the return to the system of 50% of the revenues from the offer of small-scale LNG services, less the costs directly attributable to those services.

Storage tariffs

After the consultation[160] of July 2019, in October 2019 the Authority defined[161] the tariff regulation criteria for the natural gas storage service (RTSG) for the fifth regulatory period (5PRS) 2020-2025. The regulation provides, in particular:

- the substantial continuity of the criteria for determining the recognised cost, which provide for price cap-type incentive regulation schemes limited to operating costs and rate of return-type regulation schemes applied to capital costs;
- extension of the duration of the regulatory period to 6 years, with intra-period review of the level of efficiency gains;
- the introduction of a mechanism for monitoring expected storage performance, aimed at ensuring consistency between the level of service provided to users and the level of remuneration recognised;
- the phasing out of tariff incentives for the creation of additional capacity, against a strengthening of mechanisms to promote the availability and flexibility of storage services; the definition of the details of these mechanisms is postponed to a later measure;
- The introduction of an optional mechanism to reduce recognised revenues subject to coverage factor, while strengthening the output-based incentives referred to in the Regulation on free access to the natural gas storage service (RAST).

In December 2019, the Authority, following the review of the tariff proposals submitted by storage companies pursuant to RTSG 2020-2025, approved[162] the corporate revenues for the storage service for the year 2020.

Tariffs for the gas transmission service

In March 2019, the Authority defined the tariff regulation criteria for the natural gas transmission and metering service (RTTG) for the period 2020-2023 (fifth regulatory period - 5PRT). The new criteria,

[160] Document for consultation 288/2019/R/gas of 02 July 2019.

[161] Resolution 419/2019/R/gas of 23 October 2019.

[162] Resolution 535/2019/R/gas of 17 December 2019.

which implement Regulation (EU) 460/2017 on the harmonisation of gas transmission tariff structures (so-called TAR Code), was published as a result of an extensive public consultation process launched in 2017[163] and takes into account the findings of ACER's Report entitled “Analysis of the consultation document on the gas transmission tariff structure for Italy”, issued on 14 February 2019 in line with the provisions of the TAR Code, on the final guidelines on the reference price methodology and the cost allocation criteria submitted for consultation in October 2018[164].

The following are the main changes in the tariff regulation criteria for the transmission service for the new period (5PRT), compared to the previous one:

- substantially in line with the criteria for determining the recognised cost, which provide for price cap-type incentive regulation schemes limited to operating costs and rate of return-type regulation schemes applied to capital costs, the introduction of preparatory tools for the approach based on the recognition of total expenditure (totex) and a greater orientation towards output, such as greater coordination between tariff regulation and the assessments of the 10-year transmission network development plans, the monitoring of investments and the provision of incentives to increase the efficiency of investment expenditure, according to a gradual approach;
- with regard to investment incentive measures, the gradual phasing out of input-based incentives (based on additional return on investment);
- the phasing out of the determination of fees according to the so-called matrix methodology, in favour of the Capacity-Weighted Distance (CWD) methodology, identified as the reference methodology within the TAR Code;
- the elimination of the "postage stamp" fee applied to redelivery points on the national territory to cover regional transmission costs, since the costs of transmitting gas on the regional networks are included in the costs to be recovered through the entry and exit tariffs defined through the tariff methodology; this inclusion also entails - without prejudice to the transitional period January-September 2020 - the phasing out of capacity allocations at exit points from the national network to the delivery areas.

In May 2019, following the verification of the tariff proposals submitted by transmission companies pursuant to RTTG 2020-2023, the Authority approved[165] the reference revenues and determined the tariff fees for the natural gas transmission and metering service for the year 2020.

Finally, in December 2019, again as part of the tariff procedure initiated in 2017, the Authority defined[166] objectives and principles to be followed in the process of restructuring the gas metering

[163] The procedure was opened by Resolution No. 82/2017/R/gas of 23 February 2017 and the following documents were published for consultation:

- on 29 March 2018, document 182/2018/R/gas, containing the initial guidance on reference pricing methodology and cost allocation criteria;
- on 21 June 2018, document 347/2018/R/gas, containing the initial guidance on the criteria for determining recognised revenues;
- on 16 October 2018, document 512/2018/R/gas, containing the final guidance on the criteria for determining the revenue recognised for transmission services, the reference price methodology and cost allocation criteria for the transmission service.

[164] Document for consultation 512/2018/R/gas of 16 October 2018.

[165] Resolution 201/2019/R/gas of 28 May 2019.

[166] Resolution 522/2019/R/gas of 10 December 2019.

activity at the entry and exit points of the transmission network, mandating Snam Rete Gas to submit a document with the operational lines of the restructuring for public consultation.

Tariffs for distribution and metering services

In May 2019, the Authority published[167] its guidelines for the definition of tariff regulation criteria and the quality of gas distribution and metering services in the fifth regulatory period (2020-2025), summarised below:

- confirm a regulatory period of six years, divided into two half-periods of three years each (as already foreseen for the fourth period);
- give substantial continuity to the criteria for the recognition of operating costs (application of the price cap method), with the aim of achieving full convergence of operating costs between operators of different sizes, with consequent differentiation of the X-factor (linked to the different density of customers served);
- in relation to the criteria for recognising the capital costs of the distribution service, give continuity to the criteria adopted based on the revalued historical cost, with confirmation of the ceiling on investments in start-up locations introduced in December 2016[168] and the hypothesis of introducing incentive regulation schemes for new investments;
- in relation to the metering service, to continue the process of gradually eliminating cost recognition approaches based on the recognition of actual expenditure, with full implementation of regulatory criteria based on incentive-based approaches, both in relation to the recognition of capital costs and in relation to operating costs;
- assess the possibility of introducing specific incentives for mergers between operators with less than 50,000 customers (in implementation of the provisions of Article 23, paragraph 4, of Legislative Decree no. 93/2011);
- in relation to the criteria for allocating costs to users, the need for a new assessment of the design of the current six tariff areas, taking into account both the need not to hinder competition in the retail market and the impact of the size of the socialisation area on the efficient development of the service (allocative efficiency), with the establishment of a specific and additional tariff area for Sardinia, in order to encourage an efficient development of the service in this area of planned future methanisation;
- initiate in-depth studies for possible reforms of the current binomial tariff structure for the distribution service (weights of fixed and variable shares, breakdown by consumption brackets);
- complete the process of unifying the connection contributions and other services of the distribution companies; in order not to alter the competitive balance between the parties participating in the tenders for service management, it is intended to evaluate the introduction of equalisation mechanisms;
- in relation to the energy transition process, introduce regulatory instruments to support innovation, in particular for the following types: i) interventions aimed at increasing the input of green gas into the networks; ii) interventions aimed at integrating electricity and gas networks; iii) interventions aimed at reducing methane emissions into the atmosphere;

[167] Document for consultation 170/2019/R/gas of 7 May 2019.

[168] Resolution 704/2016/R/gas of 01 December 2016.

- confirm the current framework for regulating gases other than natural gas;
- confirm the approach according to which isolated LNG-fuelled networks are substantially the same as distribution networks for gas other than natural gas; in particular, for these networks, the identification of regional tariff areas, differentiated by distribution company, is envisaged;
- in relation to networks fuelled by tank trucks (compressed natural gas), assess the possibility of revising the current regulatory approach in order to prevent companies from possibly adopting opportunistic behaviour (favouring the supply of isolated networks by tank trucks carrying compressed natural gas, over supplying by carriers carrying liquefied natural gas, only for reasons of tariff affordability).

In its October 2019 consultation, the Authority further specified[169] the guidelines on tariff regulation criteria for gas distribution and metering services to be applied from 2020. In detail, the Authority hypothesised:

- in relation to the design of the tariff system, to provide for: (i) a reference tariff determining the company's permitted revenue; (ii) a compulsory tariff applied to final customers determining actual revenue; (iii) an equalisation mechanism between permitted and actual revenue;
- with regard to the reference tariff, to confirm the building block approach used to determine the recognised cost (operating costs, depreciation and amortisation and return on invested capital);
- as regards the determination of the recognised cost of the distribution service, to confirm the hybrid approach in a first phase with: i) incentive regulation schemes (price cap) for determining operating costs; ii) recognition of centralised capital costs on the basis of parametric criteria; iii) recognition of location capital costs; in a second phase, the application of incentive regulation schemes (introduction of standard costs and efficiency incentive mechanisms) also for capital costs;
- in order to determine the recognised cost of the metering service, to provide for a consolidation of the incentive adjustment schemes for operating costs and capital costs.

The same consultation also proposed the timing for the implementation of the new criteria, with the identification of interventions that will come into force in the first half-period (2020-2022), interventions that will come into force by 2023 and interventions to be implemented in the second half-period (2023-2025). The first group includes: the determination of the initial levels of operating costs and the X-factor for the annual update of the same operating costs; the definition of the parameter β in relation to capital costs; the revision of the weights to be attributed to actual costs and standard costs for calculating the value of new investments in smart meters. In relation to the second group of interventions, to be implemented by 2023, the introduction of efficiency incentives on the capital costs of the distribution service and tools to support innovation in networks and advanced metering functionalities is planned. Finally, in relation to the interventions that will enter into force in the period 2023-2025, it is planned to review the gearing level in line with the TIWACC[170] update timescales and with the duration of the PWACC; assess whether to set higher efficiency

[169] Document for consultation 410/2019/R/gas of 15 October 2019.

[170] Criteria for determining and updating the rate of return on invested capital for infrastructure services in the electricity and gas sectors for the period 2016-2021 (TIWACC 2016-2021), Annex A to Resolution 583/2015/R/com of 2 December 2015 and subsequent amendments.

recovery targets than those envisaged at the beginning of the period for larger companies, on the basis of specific analyses of companies' costs, by carrying out productivity analyses; apply parametric recognition methods to cover the costs of remote reading / remote management systems and concentrators, based on efficiency analyses; implement the reform of the tariff structure of the natural gas distribution service; complete the reform of connection fees.

With respect to decisions effective from 2020, the Authority hypothesised:

- regarding the criteria for determining the recognised operating costs:
    - to consider 2018 as a trial year for the purpose of setting operating costs for the fifth period;
    - to provide for a symmetrical distribution of the greater productivity gains achieved in the fourth regulation period between final customers and businesses;
    - to adopt a gradual approach for defining the convergence process in the recognition of operating costs, currently differentiated according to the size of the companies. In particular, with respect to the unit operating costs related to the distribution service, it is expected that the differences in the recognition will be halved by the end of the regulatory period (instead of the complete reabsorption, initially indicated[171]), both to take into account the observations that emerged from the consultation, and in relation to the proposals relating to the incentives for aggregations;
    - to provide that the X-factor to be applied for the marketing service and the metering service (both in relation to the installation and maintenance functions and in relation to the collection, validation and registration functions) is fixed with the aim of fully extracting any productivity gains achieved in the fourth period;
    - in relation to the recognition of the costs of switch readings, to provide for the halving - from 5 euros to 2.5 euros - of the cost recognised for each reading exceeding those made in 2018;
    - in relation to the recognition of operating costs related to remote reading / remote management systems and concentrators and concerning metrological checks of metering units of classes higher than G6, to confirm the final recognition criterion on the basis of specific data collection;
    - in relation to the coverage of operating costs in relevant operations, to confirm the regulation of the fourth period;
- with the aim of promoting competition for the market (gas tenders), to introduce incentives for aggregations between operators. Specifically, it is proposed to encourage aggregations between small or medium-sized and small businesses from 2019 onwards, by means of surcharges on the recognition of operating costs and by bringing forward the time of revaluation of impaired RABs;
- regarding the criteria for determining the eligible capital costs:
    - to confirm the recognition of centralised capital costs with a parametric approach, the same for all operators;
    - to also confirm the regulation criteria already applied in the fourth regulation period for location assets (final balance approach for the distribution service and incentive schemes for the metering service);

[171] Document for consultation 170/2019/R/gas.

- in relation to the performance of cost/benefit analyses, to make public the guidelines made available by the Control Booth composed of ANCI, the Ministry of Economic Development and ARERA;
- in relation to investment expenditure ceilings, to confirm the level set in 2016[172]. It is proposed, instead, to review the application mechanisms, with the introduction of a gradual approach that avoids penalising simple delays in achieving good levels of methanisation;
- in relation to the treatment of RABs misaligned with respect to sector averages, to consider new investments in the distribution service made from 2018, while, in relation to the metering service, to adopt a solution that takes into account investments in smart meters made in previous years;
- in relation to so-called frozen contributions, to adopt a more gradual "release" process;
- to confirm the regulatory useful lives of the fourth period;
- to introduce a review of the criteria for determining the residual undepreciated portion of traditional meters replaced with smart meters;
- in relation to the setting of the coefficient β used to determine the WACC, to assume a range between 0.40 and 0.43;

- regarding the tariff system for the distribution and metering of natural gas:
  - to confirm the structure of the tariff system in force in the fourth regulatory period;
  - in relation to the proposal of possible future methanisation of Sardinia, to confirm the focus on establishing a Sardinian tariff framework and to carry out an independent study to provide a transparent analytical framework based on precise assessments to support the necessary decisions on the island's energy future;
- with regard to gases other than natural gas, to confirm the approach adopted in the fourth regulation period;
- in relation to isolated networks in which natural gas is distributed:
  - to confirm the possibility of regulating isolated networks fed by LNG as isolated networks of different gases, without equalisation and with the application of a specific territorial tariff to the customers of the service (there is no provision for the application of the mandatory tariff by supra-regional tariff macro-area);
  - in relation to networks powered by a tank truck (compressed natural gas), to confirm the adoption of a transitional solution, with assimilation to the interconnected natural gas networks, subject to verification over a five-year horizon.

The Authority's guidelines were presented[173] in the November 2019 consultation, specifically on: updating the obligations to put smart meters into service for general users in the natural gas sector, increasing metering frequencies, improving performance and developing tariff regulation.

In December 2019, the new version of the Gas Distribution and Metering Tariffs Regulation for the 2020-2025 regulatory period (RTDG), in force for the three-year period 2020-2022, was approved[174].

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[172] Resolution 704/2016/R/gas of 01 December 2016.

[173] Document for consultation 487/2019/R/gas of 26 November 2019.

[174] Resolution 570/2019/R/gas of 27 December 2016.

With respect to the guidelines indicated in the consultation in October, in the final provision, the Authority deemed it appropriate:

- for the purpose of determining the recognised operating cost, to apply equal weight to the actual costs and the costs recognised in the reference year, both in the event that the actual costs are lower than the recognised costs, and in the event that the actual costs are higher;
- to determine the actual cost incurred in 2018 for each activity and function, based on the data reported in the separate annual reports - sent to the Authority by the distribution companies - which reflect recurring costs, excluding the costs whose coverage is already implicitly guaranteed in the regulatory mechanisms (for example through the remuneration of risk) or in relation to which the recognition is not compatible with an activity carried out under a monopoly regime based on the quantification of these unrecognisable costs, as shown in the accounts themselves;
- to provide that, during the infra-period review, the possible effects of environmental policies defined at EU level on the dynamics of the redelivery points served are assessed and to consider how the risk is allocated between final customers and businesses;
- in relation to the recognition of costs relating to switch readings, in view of the observations received, to provide that, for the first half regulatory period, the level of the standard cost recognised for each switch reading that exceeds the number of readings made in 2018 is maintained at €5 and that the review of this standard cost is deferred to the infra-period review, also on the basis of the data relating to the number of switch readings made in the period 2019-2021 and taking into account the trend of smart meter installations;
- With reference to the incentives for aggregations between operators, taking into account the results of the consultation, the Authority considers it necessary to carry out an in-depth analysis to assess the tender aspects reported, simultaneously assessing the possibility of envisaging both specific measures to strengthen operators in the individual minimum territorial areas (ATEM) and measures for generalised aggregations, envisaging possible adjustments according to the size of the parties involved in aggregation operations, with a view to adopting, by 30 June 2020, a measure also applicable to aggregations concluded in 2019[175];
- to carry out further investigations with the distribution companies and the granting local authorities, in relation to the preparation of guidelines for carrying out cost/benefit analyses;
- to launch a procedure aimed at introducing incentive regulation schemes for capital costs related to the distribution service, based on a standard cost recognition approach and providing incentives with a comparable effectiveness to that of the price cap mechanism used for updating operating costs, envisaging that it can be applied starting from the investments made in 2022, also taking into account the need to adjust the accounting systems necessary to support the proposed incentive schemes;
- to assess the possibility of recognising the residual undepreciated costs of the smart meters decommissioned in the first roll-out phase;
- to review the proposal put forward in the October consultation[176] on how to treat the share of the so-called "frozen" contributions, in relation to the need to guarantee greater graduality and tariff stability; to this end, it is deemed appropriate to provide, in particular, for a follow-up to the proposals made during the consultation, which envisage, in order to fully "thaw" the

[175] Document for consultation 410/2019/R/gas.

[176] Document for consultation 410/2019/R/gas.

contributions, the adoption of a time horizon aligned with the time horizon for the return of the contributions subject to deterioration;

- in relation to determining the rate of return on invested capital, taking into account the results of the consultation: to follow up the proposal to align the coefficient β for distribution and metering services, since the regulatory framework envisaged for the two services (unlike what some operators have argued) is homogeneous, with the consequence that differences in the systematic risk recognition, typically considered in tariff regulation, do not appear justified; not to change the level of the coefficient β for the distribution service, in consideration of the fact that the regulatory framework compared has changed little compared to the previous period and therefore, as already decided for other regulated services in the gas sector, it seems reasonable to maintain the level of this coefficient in determining the rate of return on invested capital;
- with reference to the tariff regulation of isolated networks supplied with liquefied natural gas (isolated LNG networks):
  - to provide that the costs associated with cryogenic storage depots and local regasifiers, in the case of interconnection with the national transmission system, if not yet fully depreciated from a regulatory point of view, are not recognised in the tariff, as these assets are not included among those necessary for the distribution of natural gas in networks interconnected with the national transmission system;
  - in line with certain requirements that emerged in consultation, to provide that the general rules laid down for interconnected networks may also be applied to isolated LNG networks (as for isolated compressed natural gas networks) - provided that an authorised interconnection project exists and in any case for a period not exceeding five years - and that, after the expiry of the five-year period, isolated LNG networks are managed as separate tariff areas limited to the individual plant (tariff areas of isolated LNG networks);
  - in cases where the isolated LNG networks are managed by operators who, in the same region, also manage isolated networks powered by tank trucks, to provide for the submission of an application for the unification of the tariff areas of isolated LNG networks and those of isolated networks powered by tank trucks;
  - on the occasion of the reform of the tariff system for the second half regulatory period, assess whether, after the start of the operations in the area, it would be possible to assimilate isolated LNG networks to interconnected networks, since the cost socialisation area would coincide with the concession area and therefore the repercussions in terms of costs of the service would remain within a perimeter for which the granting local authorities and the companies managing the service are informed and responsible;
- with reference to the tariff regulation of isolated networks powered by a tank truck:
  - to provide that, at the request of the company concerned, the general rules laid down for interconnected networks may be applied, provided that there is an authorised interconnection project and in any case for a period of no more than five years, after which the isolated networks powered by tanker trucks subject to the request will be excluded from the tariff areas provided for on the basis of the rules applied until then and will constitute separate tariff areas limited to the portion of the network in which the plant is located (so-called tariff areas for isolated networks supplied by tank truck);
  - to provide specific provisions to protect final customers connected to the isolated networks, which can be applied if the five-year period has elapsed without interconnection; or, in line with what has been indicated for isolated LNG networks, during the reform of the tariff system

for the second regulatory period, to assess whether, after the start of the area operations, it is possible to permanently assimilate the isolated networks supplied by tank trucks to the interconnected networks;

- with reference to the definition of the natural gas distribution service tariff system:
  - to confirm the assumptions made in the October consultation[177], stressing the fact (already clarified by the Authority since December 2000[178]) that the gas service, unlike the electricity service, does not have irreplaceable service characteristics, since it addresses needs and types of use that can be satisfied by means of other energy sources, also with a comparable environmental impact, with the consequence that, in the case of the gas distribution service, the universality of the service is expressed in its availability at transparent cost conditions, while the widespread use of the service, which would increase the cost of satisfying the country's energy needs, does not seem justified;
  - in relation to Sardinia's methanisation prospects, to provide for an independent study to be carried out, planned for July 2019 aimed at a broader assessment, following a cost/benefit analysis approach, of the options available with regard to the infrastructural upgrading of the energy system in the Region of Sardinia, taking into account the various infrastructure projects (launched or planned) and their possible interdependencies, in order to provide a transparent analytical framework based on precise assessments, in support of the necessary decisions on the island's energy future;
  - to confirm the establishment of a specific tariff area for Sardinia, establishing, however, that, in order to take into account the need to guarantee partial and transitory forms of compensation, a specific CE tariff component of the mandatory tariff, expressed in Euro/PoR, applied only to redelivery points served in the Region of Sardinia, should be introduced on a transitional basis, for a period not exceeding three years, and to provide for the lower revenues to be compensated as part of the equalisation mechanisms with coverage through the UG1 component of the same mandatory tariff;
  - to provide that, pending the completion of the independent study mentioned above, parties managing isolated LNG networks or isolated networks powered by tank trucks may request the application of the general rules provided for interconnected networks, even in the absence of an authorised interconnection project, in any case for a period not exceeding five years;
  - to provide that in any case, at the end of the five-year period, if interconnection with the national transmission system is not achieved, tariff solutions are adopted that guarantee the protection of final customers who have connected to these networks and limit the risk borne by final customers;
- to launch a procedure for the reform of the tariff system to be applied in the second half of the fifth regulatory period, assessing: (i) in relation to the determination of the reference tariff (which sets the size of the constraint on the admitted revenues of the distributors), a possible review of the scale variables, considering in particular the possibility that a portion of the constraint may be set according to the volumes distributed; (ii) in relation to the compulsory tariff applied at the redelivery points, a possible review of the structure of the tariff of the distribution service, its breakdown between fixed and variable rates, as well as the current breakdown into tariff brackets; iii) again in relation to the mandatory tariff applied at the redelivery points, a possible review of

[177] Document for consultation 410/2019/R/gas.

[178] Resolution 237/00 of 28 December 2016.

the tariff areas, to be carried out with the aim of encouraging a development of the service based on economic criteria, in order to avoid increasing the cost of meeting the country's energy needs, which will already be affected by decarbonisation policies, and with the aim of making local authorities and companies more responsible for the extension and development of the service, avoiding incentives for behaviour, the costs of which would be covered by other companies and/or the community of users, and also allowing greater flexibility in local choices related to decarbonisation policies; v) the continuation of the reform of connection fees, with a view to making the criteria for the application of such fees on the national territory more homogeneous to the investments made, making the distributors responsible;

- to provide that, in order to integrate the regulatory criteria for the second half-period of the fifth regulatory period, a procedure is launched aimed at defining parametric recognition methods for covering the costs of the remote reading/ remote management systems and concentrators, based on efficiency analyses;
- to adopt transitional rules relating to the application of the tariff regulation on isolated LNG networks and isolated networks supplied by a tank truck, in particular with reference to networks of this type already in operation at 31 December 2019, so as to allow an orderly transition to the new structure; in addition, to provide that the treatment already applied in the previous regulatory period will continue for 2020 and that the distributors that manage the networks in question may, by 30 June 2020, submit an application for assimilation to the distribution networks connected to the national transmission system, limited to a five-year period starting on 1 January 2021.

In December 2019 the mandatory tariffs, for 2020, for the gas distribution, metering and marketing services, as per article 42 of the RTDG, tariff options for other gases, as per article 70 of the RTDG, and the bimonthly equalisation amounts relating to the natural gas distribution service, pursuant to article 47 of the RTDG, were approved[179]. With the same resolution, the maximum amount of recognition of higher charges arising from the presence of concession fees, pursuant to art. 60 of the RTDG, was approved for distribution companies that have submitted a request and provided appropriate documentation.

Infrastructure consistency

In Italy there are nine companies that manage the **national** (10,329 km) **and regional** (24,804 km) **gas transmission network**: three for the national network and eight for the regional network. The largest gas transmission company is Snam Rete Gas, in addition to which two other companies that own and manage small sections also transport gas on the national network: Società Gasdotti Italia - which has also obtained certification as a transmission operator - and Infrastrutture Trasporto Gas. The Snam group owns 93.1% of the networks: 32,726 km of network out of the 35,133 km that makes up the Italian gas transmission system The second operator is Società Gasdotti Italia, which manages a total of 1,665 km of network (4.7%), of which 603 is on the national network. The company Retragas, of the A2A group, is the third with a share of 1.2%, thanks to its 411 km of regional network. The remaining six minor operators, with the exception of Infrastrutture Trasporto Gas own small sections of the regional network.

[179] Resolution 571/2019/R/gas of 27 December 2019.

Liquefied natural gas is input into the Italian national transmission network through the interconnection with the terminals in operation in Panigaglia (in Liguria), Cavarzere (in Veneto) and Livorno (in Tuscany). The Panigaglia plant, owned by the company GNL Italia which belongs to the Snam group, has a maximum regasification capacity of 13 M (m^3) / day and the maximum annual quantity of gas that it can input into the transmission network is 3.5 G(m^3). The Cavarzere terminal is an off-shore structure located in the Adriatic Sea off the coast of Rovigo with an annual regasification capacity of 8 G (m^3) and approximately 26.4 M (m^3)/day. The terminal belongs to the company Adriatic LNG. To date, 80% of the terminal's regasification capacity, i.e. 21 M (m^3)/day, has been allocated to Edison for a period of 25 years (until 2034); the remaining 20%, alongside with any capacity not used by users, is offered on the market through capacity subscription procedures. The Livorno terminal owned by the company OLT Offshore LNG Toscana arose from the conversion of an LNG vessel - the "Golar Frost" - into a floating regasification terminal anchored about 22 km off the coast between Livorno and Pisa. Its maximum daily regasification capacity is 15 M(m^3)/day, while the annual capacity is 3.75 G(m^3).

Natural gas **storage** is carried out on the basis of 15 concessions owned by five companies: Stogit, Edison Stoccaggio, Ital Gas Storage, Geogastock, Blugas Infrastrutture. All active storage sites are built on exhausted gas fields. Stogit, which belongs to the Snam group, is the main storage company which owns 10 of the 15 concessions. The Italian gas storage system has important dimensions: in the thermal year 2019-2020, which ended on 31 March 2020, the storage system offered a total assignment availability in terms of total space for active reserve (so-called working gas) equal to 18.05 G(m^3), of which 4.6 G (m^3) is destined for strategic storage. The space offered at auction has all been assigned. At 31 October 2019 the stores were filled to 13.1 G(m^3). The peak nominal delivery reached in the year was 260.4 million standard cubic meters/day: 251.5 M(m^3)/d in the Stogit stores and 8.9 M (m^3)/d in the Edison stores.

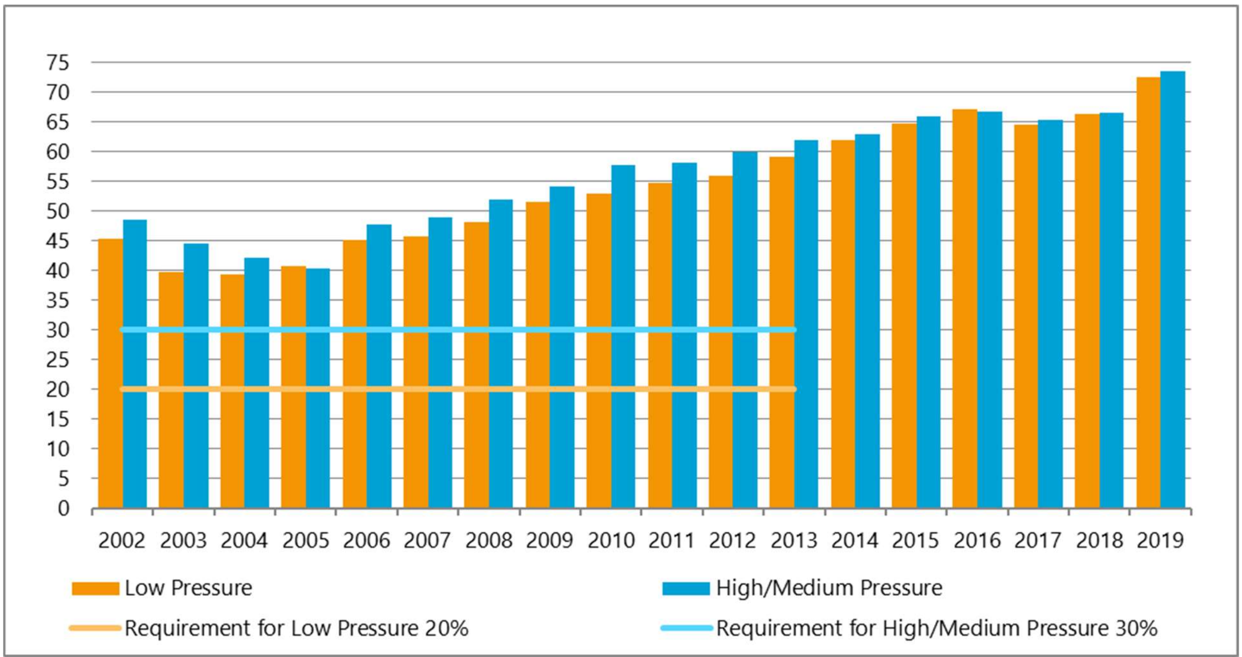
The **distribution** of natural gas in Italy takes place by means of 264,026 km of network (of which 629 not in operation in 2019), 57.7% at low pressure, 41.6% at medium pressure and 0.7% at high pressure. The length of the networks grew by 1,692 km compared to 2018. In addition to the networks, gas distribution takes place through approximately 6,600 stations and 101,000 final reduction stations. 58.2% of the networks (153,220 km) are in the North, 22.8% in the Centre (60,162 km) and the remaining 19% (50,645 km) are located in the South and in Sicily. In 2019, there were 199 gas distribution companies (nine fewer than in 2018) of which seven were very large (with over 500,000 customers), 19 with between 100,000 and 500,000 customers, 21 medium (50,000-100,000 customers), 97 small (10,000-50,000) and 55 very small (less than 5,000 customers). The number of companies with more than 100,000 redelivery points has fallen in recent years (26 from 35 in 2012), but their share has not decreased in terms of gas distributed and has remained substantially stable at around 83% over the years. Medium-sized companies increased slightly both in terms of the number (from 18 to 21) and the incidence of volumes distributed (from 6% to 7.1%), while small and very small companies reduced both their number (from 173 to 152) and their share of volumes distributed (from 11% to 9.6%). Overall, the 199 operators active in 2019 distributed 31.3 G(m^3), 901 million m^3 less than the previous year, to 23.9 million metering units. The service was managed through 6,514 concessions in 7,211 municipalities.

Gas distribution service quality

At the end of 2013, the Regulation of the quality of gas distribution and metering services for the regulation period of 2014-2019 - Part I of the Unified text of the regulation of the quality and tariffs of the gas distribution and metering services for the period of regulation 2014-2019 (RQDG), was approved[180]. The RQDG regulates certain relevant activities for the security of the gas distribution service. Among these we can mention emergency services, the inspection of the distribution network, the activity of locating leaks after inspection or notification by third parties and gas odorisation. The regulation of these matters has the objective of minimising the risk of explosions and fires caused by distributed gas and, therefore, its true purpose is the protection of persons and property from damage resulting from accidents caused by distributed gas. The following diagrams and tables illustrate the development of the security of the gas sector in recent years.

Figure 4.1 shows the number of networks inspected in the period between 2002 and 2019. The regulation provided a minimum annual obligation until 2013, then, in 2014, it introduced an inspection obligation equal to 100% of the network in the three years (high/medium pressure network, HP/MP) or in the rolling four-year term (low pressure network, LP). 2019 registered a decrease compared to 2018, although the percentage of inspected network was higher than the levels recorded before 2014. Network inspections have the general objective of intercepting the phenomenon of leaks, thereby favouring greater citizen safety.

Figure 4.1 Percentage of inspected network since 2002



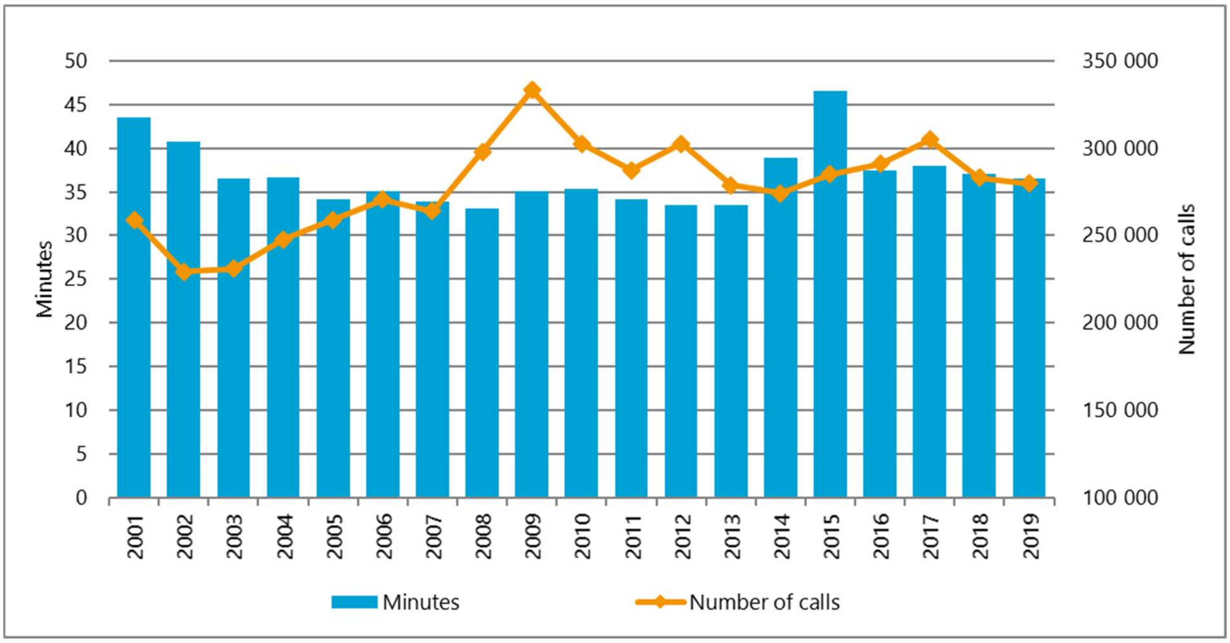
Source: Declarations from distributors to ARERA.

With reference to the obligations regarding emergency services, Figure 4.2 shows the time of arrival to the call site (after a telephone call) in 2019. The national average value is approximately 36.5 minutes, slightly lower than in 2018. The obligation provides an annual minimum percentage of calls with time of arrival on the call site for emergency services within the maximum time of 60 minutes, equal to 90%.

[180] With the Resolution 574/2013/R/gas of 12 December 2013.

Figure 4.2 Emergency services for the distribution system since 2001

Number of calls and time of arrival at the call site (in minutes)

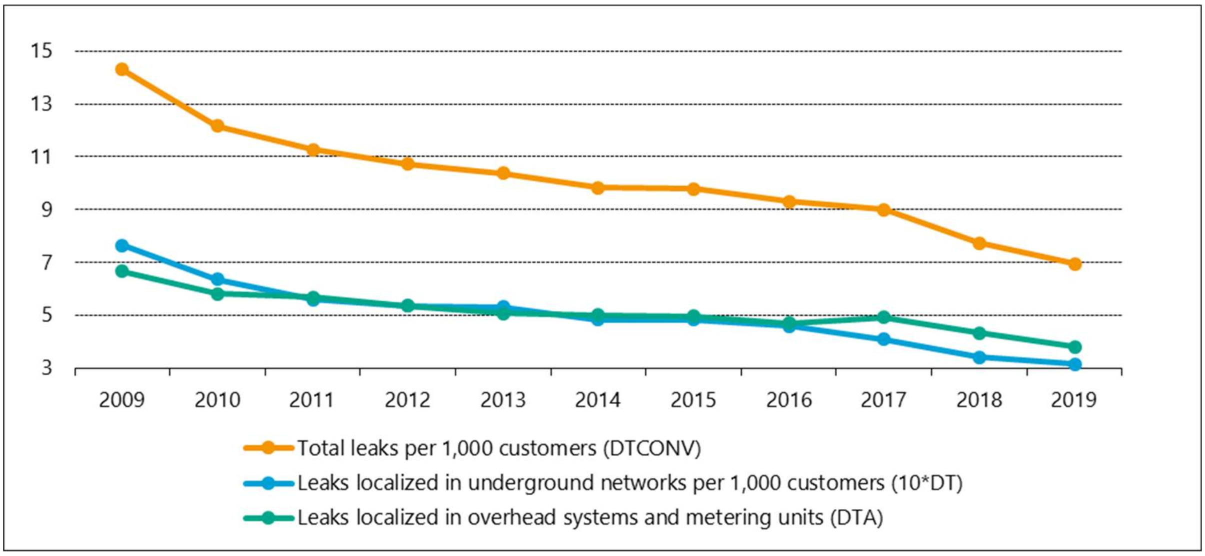


Source: Declarations from distributors to ARERA.

The obligation of recording the calls, introduced on 1 July 2009, accompanied by control campaigns on gas emergency services, and accomplished with the help of the *Guardia di Finanza*, drives companies to record the data precisely. We must also add that the companies obliged to participate in the premium-penalty regulation related to safety recovery has gradually increased and the compliance with the emergency regulation is an essential requirement for the recognition of the premiums.

Figure 4.3 Number of localised leaks following third party notifications every 1,000 customers

Systems subject to incentive regulation - Period 2009-2017



Source: Declarations from distributors to ARERA.

Figure 4.3 illustrates the number of leaks located following third-party reports per thousands of customers for the distribution systems subject to the penalty-premium regulation: there is a decrease for leaks located on the underground network (10*DT), normally more dangerous, and a decrease for those on the above ground network (DTA). The DT_{conv} is constantly decreasing.

Connection times for the transmission and distribution networks

The data related to the connections is divided into connections to natural gas pipelines or connections to distribution pipelines. In each type of system, the data related to the number of accomplished connections and the average time passed in order to obtain them are highlighted, net of the time needed to acquire any administrative authorisations or fulfilment of obligations by the final customer who requested the connection. The average time is indicated in number of working days used for the realisation of the redelivery point and any other works needed to make the transmission capacity available, according to what is provided in the stipulated contract.

In 2019, 80 connections were made to transmission networks, 61 of which to high pressure pipelines and 19 to medium pressure pipelines (Table 4.1). On average, it took 70 working days for high pressure pipelines and 38.3 days for medium pressure pipelines. Compared to the previous year, the number of connections for both types of pipeline has increased and the average time taken to make connections to high pressure networks has fallen sharply: 14 working days less than in 2018. The connection time to medium pressure networks, on the other hand, remained largely unchanged compared to the previous year. Of the 80 connections made overall, 44 activated the supply during the year (more precisely, 37 out of 70 at high pressure and 7 out of 19 made at medium pressure).

Table 4.1 Connections to transmission networks and average connection time

Number and average time in work days

PRESSURE	2018		2019	
	NUMBER	AVERAGE TIME(A)	NUMBER	AVERAGE TIME(A)
High pressure	59	84.0	61	70.0
Medium pressure	18	38.5	19	38.3
TOTAL	77	73.4	80	62.5

(A) Excluding the time takeb to obtain any authorisations.

Source: ARERA. Annual Survey on Regulated Sectors.

Also in the case of local distribution networks there is a significant increase in the number of connections made (Table 4.2) which in 2019 was 117,045 compared to 104,156 in 2018. As always, most of the connections concerned low pressure pipelines (95.8%) and the remaining medium pressure pipelines, as no connection was made by distributors for the high-pressure network, as was the case last year. There was a significant reduction in waiting times for connections to medium pressure networks, from 13.7 to 7.4 working days on average, while the average waiting times for connections to low pressure networks remained substantially unchanged, from 17.6 to 17.3 working days.

Table 4.2 Connections to distribution networks and average connection time

Number and average time in work days

PRESSURE	2018		2019	
	NUMBER	AVERAGE TIME(A)	NUMBER	AVERAGE TIME(A)
Low pressure	0	-	0	-
High pressure	3,707	13.7	4,871	7.4
Medium pressure	100,449	17.6	112,174	17.3
TOTAL	104,156	13.8	117,045	7.8

(A) Excluding the time needed to obtain any authorisations and the time needed for any fulfilment of obligations by the final customer.

Source: ARERA. Annual Survey on Regulated Sectors.

4.1.2 Balancing

Reform of the settlement regulation

In February 2018, the Authority approved[181] the reform of the gas settlement rules, contained in the "Integrated text of the provisions for the regulation of the physical and financial items for the natural gas balancing service" (TISG). This reform, which entered into force on 1 January 2020, is characterised by the following main changes:

- the assignment to the Balancing Manager (RdB), i.e. the main transmission company, of the task of supplying the difference between the quantities introduced into the distribution system by sellers and those withdrawn by final customers (delta^{IO} or Δ_{IO});
- the simplification of the procedures for determining the physical and economic items relating to balancing and adjustment sessions;
- the easing of uncertainty for the balancing user (UdB) with reference to withdrawals destined to Redelivery Points (RP) with a reading frequency lower than monthly; in fact, the quantities to be supplied for these points are forecast by the RdB and these items are not redetermined, thus reducing the risk connected to their settlement;
- the centralisation in the Integrated Information System (SII) of some activities previously under the responsibility of distributors;
- the implementation by the RdB of a methodology for assessing the climatic factor in the determination of daily withdrawals concerning RPs with a detection frequency less than or equal to monthly, as well as the revision of the delivery profiles.

The aforementioned reform provides[182] for the subsequent regulation of the RdB's supply of the volumes covering the delta^{IO}, as well as the consequent supplements to the regulation of balancing and incentives to the RdB. Guidelines on these aspects, aimed at introducing greater efficiency and

[181] Resolution 72/2018/R/gas of 08 February 2018.

[182] Point 9 of the Resolution 72/2018/R/gas of 08 February 2018.

transparency for the benefit of the gas system, were set out in the September 2018 consultation[183]. Following the consultation, in April 2019 a new version of the TISG was approved[184], which:

- implements the new regulation on the determination of daily physical items;
- is consistent with the certification, within the official central register of the Integrated Information System (SII), of the chain of commercial relations between the distribution user and the balancing user, approved in April 2019[185];
- assigns the SII Operator the responsibility for defining, in agreement with the RdB and the other transmission companies, the operating procedures inherent to the information exchanges envisaged regarding the provisional balance.

Also in relation to the September 2018 consultation, in May 2019 the Authority approved[186] a series of provisions functional to the definition of the regulatory framework relating to the market supply, by Snam Rete Gas, from 1 January 2020, of the resources necessary for the operation of the system, i.e. the quantities covering delta^{IO}, self-consumption (C component), leaks (PE component), unaccounted for gas (CNG component) and scheduled linepack changes (ΔLP_P component), in line with the provisions of the Tariff Regulation for natural gas transmission and metering service for the fifth regulatory period 2020-2023 (RTTG). Moreover:

- amendments were made to the Integrated text on gas balancing, also in relation to the neutrality mechanisms of the RdB, as well as the introduction of a new performance indicator;
- it was decided that the Snam Rete Gas balancing equation should be altered so as to be able to distinguish the supply of resources necessary for the operation of the system from activities aimed at balancing the system, also due to the fact that the former do not contribute to the formation of marginal balancing prices;
- the operational procedures for the implementation of the trial ordered in February 2019, regarding the limitation of the use of storage by the RdB, were defined[187].

Following the provisions of May 2019, in September 2019 the Authority set out[188] guidelines on the organisational and management aspects of the supply of the above mentioned quantities at the MGAS digital Platform. Specifically, the Authority proposed that:

- the supply takes place through auctions at marginal price within the MP-GAS sector, in which all the operators admitted to operate on MGAS could participate, with suspension of the market at continuous trading during the auction;
- the auction is of multilateral type, so as to favour the liquidity of the session and the formation of prices aligned to market conditions, especially in case of suspension of continuous trading;

[183] Document for consultation 462/2018/R/gas of 20 September 2018.

[184] Resolution 148/2019/R/gas of 16 April 2019.

[185] Resolution 155/2019/R/gas of 16 April 2019.

[186] Resolution 208/2019/R/gas of 28 May 2019.

[187] Resolution 57/2019/R/gas of 19 February 2019.

[188] Document for consultation 378/2019/R/gas of 17 September 2019.

- Snam Rete Gas participates in the market as a price-taker; consequently, the offer would only indicate the quantity and, therefore, the Authority would have the task of establishing the criterion for defining the maximum and minimum price through which to value, respectively, the purchase and sale offers during the auction session;
- the transactions concluded in the context of the auctions are not excluded from the formation of the self-production system (SAP), mainly for the following reasons: i) the resources necessary for the functioning of the system are part of the daily needs of the system itself and should, therefore, contribute to the formation of the daily price; ii) the exclusion could favour forms of arbitrage that could result in an incorrect valuation of the resources.

On the other hand, with regard to the proposals concerning auction times, the following was taken into account: i) the opportunity to guarantee a first auction at a time when the market has good liquidity, given the possibility that there may be a need to supply high volumes; ii) the advisability of not underestimating the need to minimise the amount of adjustments during the gas day.

In November 2019, further provisions on the supply by the RdB of the resources necessary for the operation of the system were approved[189], starting from the proposal submitted by the RdB under the TIBG. In addition, the organisational structure illustrated in the September 2019 consultation was supplemented[190], taking into account the comments made by users and Snam Rete Gas and providing, in particular, that:

- supply takes place through auctions at marginal price within the MP-GAS sector, open to the participation of all operators admitted to operate on MGAS, without suspending the market at continuous trading during the auction;
- each auction is bilateral;
- transactions concluded in the auction are excluded from the formation of the System Average Price (SAP);
- the number of auctions for products with delivery on each gas day is limited to two, to be held:
  - on gas day D-1, after a first assessment of the quantities to be supplied for the management of the delta^{IO} and of the scheduled line pack variation, at 1:30 pm;
  - on day D, at 1:30 pm.

With regard to the purchase and sale prices of the Snam Rete Gas offers, it was established:

- that the purchase prices are equal to the average SAP for the 7 days preceding the trading day increased by 30€/MWh;
- that the sales prices are equal to 0 €/MWh.

It was also ordered that Snam Rete Gas can continue to supply any additional quantities of system gas and, in particular, self-consumption, according to the methods established in May 2019[191]. In the

[189] Resolution 451/2019/R/gas of 05 November 2019.

[190] Document for consultation 378/2019/R/gas.

[191] Point 7 of the Resolution 208/2019/R/gas of 28 May 2019.

event of unforeseen and significant variations in market conditions, Snam Rete Gas, if it deems it necessary and urgent in order to supply the system gas, may define a purchase price higher than that mentioned above, notifying the Authority and the GME. Finally, it was foreseen:

- that the outcome of the September 2019 consultation[192] is also functional to the GME's changes to the gas market regulation;
- to give a mandate to the largest transmission company and the GME to develop, within their area of competence, a proposal to update the Data Lists, indexes and reports indicated by the TIMMIG (Integrated text of the monitoring of the wholesale natural gas market), which makes it possible to detect potentially anomalous behaviour by operators;
- that the RdB conducts an analysis of the functioning of the consumption profiling methodology, using the tools and activities envisaged by TIMMIG, starting from 1 January 2020.

In December 2019, the proposals to update the Network Code transmitted by Snam Rete Gas in application of the gas settlement reform were approved[193], within the scope of competence, and provisions were adopted for the launch of the new regulation from 1 January 2020. In particular, it was established:

- to provide, in continuity with the regime in force until 31 December 2019, for transitional regulation for the application of the charges for deviation from the transmission capacity required to supply the delivery points at the city gates and to limit the risks connected to the possible incorrect assessment of the transmission capacity required due to the uncertainties in the forecasting of the delivery points in the first phase of the settlement reform;
- to extend, until 19 February 2020 inclusive, the validity of the numerical parameters of the incentives referred to in Article 9 of the TIBG, defined[194] in September 2018;
- that Snam Rete Gas can improve, also on the basis of updated data made available by the SII Manager and after reporting to the Authority, the methods for determining the standard profile correction parameter with the W_{kr} temperature, also in order to reduce the daily variability of the portion of delta^{IO} to be supplied with respect to its average value and the possibility that critical situations may arise in the management of the balancing resulting from uncertainties in estimating the volumes to be supplied, both for the part of consumption that is forecast by the balancing users themselves (i.e. consumption at the redelivery points of the distribution network read at least monthly or more frequently), and for the extent and variability of the volumes to be supplied by Snam Rete Gas, in particular for the portion covering the delta^{IO}.

Finally, with regard to the settlement of previous years, following the Authority's provisions[195] in October 2017 in regulating the management of adjustment sessions for the 2013-2019 period, in March 2019 the Authority issued[196] instructions to the Energy and Environmental Services Fund for

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[192] Document for consultation 378/2019/R/gas.

[193] Resolution 538/2019/R/gas of 18 December 2019.

[194] Resolution 480/2018/R/gas of 27 September 2018.

[195] Resolution 670/2017/R/gas of 05 October 2017.

[196] Resolution 91/2019/R/gas of 12 March 2019.

the payment to Snam Rete Gas, as the Balancing Manager, of the amounts relating to the results of the second adjustment session[197]. At the same time, it was also established that transmission companies shall pay users the amounts of the adjustments of the deviation fees determined in application of the provisions[198] of April 2018 in accordance with methods and timeframes similar to those established[199] in December 2018. Subsequently, at the end of October 2019, similar provisions were adopted[200] in relation to the outcomes of the third adjustment session, envisaged[201] for October 2017 and covering the years 2014-2017.

4.1.3 Cross-border issues

Access and development of the transmission system

Regulation (EU) 459/2017 (Capacity Allocation Mechanism - CAM), which establishes a network code relating to capacity allocation mechanisms in gas transmission systems, regulates, among other issues, the creation of new capacity at interconnection points between the countries of the European Union. On these points, the Regulation provides for a harmonised procedure at European level for the creation of new capacity and introduces directly applicable obligations on transmission system operators and national regulatory authorities. Under the CAM regulation, the first procedure for creating new capacity was launched by transmission system operators in 2017. In light of the experience gained in the aforementioned procedure and in view of the start of the new procedure on 1 July 2019, in April 2019 the Authority deemed it appropriate to amend[202] some provisions of the national regulation relating to the creation of new capacity at points of the national network not connected with a country of the European Union. These amendments, in particular, are designed to harmonise the timing of the national and European procedures in order to ensure coordinated development of the national transmission network. Although the two procedures affect different access points of the national network (European and non-European), they have an impact on the development of the transmission system itself and it is therefore important that they are coordinated.

As regards, however, the interconnection points between countries outside the European Union, in the first months of 2019, several Italian operators entered negotiations with Algeria and Tunisia to renew the expiring contracts for the purchase and transmission of gas through the international TTPC-TMPC gas pipelines with a landing point in Mazara del Vallo. Due to the prolongation of the negotiations, the operators involved submitted a report to the main transmission company, to express their interest in acquiring annual capacity at the input point of Mazara del Vallo, but the inability to participate in the manner and the times indicated in the Transmission Code. In order to take into account the exceptional circumstances described above and in consideration of the fact that Mazara represents a strategic link point with a non-European Union natural gas producer, in July

[197] Resolution 670/2017/R/gas of 5 October 2017.

[198] Resolution 223/2018/R/gas of 5 April 2018.

[199] Resolution 676/2018/R/gas of 18 December 2018.

[200] Resolution 433/2019/R/gas of 29 October 2019.

[201] Resolution 670/2017/R/gas of 5 October 2017.

[202] Resolution 245/2019/R/gas of 16 April 2019.

2019[203] the Authority ordered a derogation from the current regulation and gave a mandate to the main transmission company to introduce, only for 2020, a second session for the assignment of annual capacity (in addition to that of 1 July) in September. Following this provision, in July 2019 the Authority proposed[204] to carry out a more general update of the current rules, which date back to July 2002[205], on the allocation of annual capacity at the points interconnected with non-European countries or, more precisely, other than the points interconnected with countries belonging to the European Union and with Switzerland (i.e. Mazara del Vallo, for the connection with Algeria, and Gela, for the connection with Libya). The aim is to reconcile the issues related to the purchase of annual capacity resulting from negotiation/authorisation processes not regulated by European regulations with the need to protect the system from the point of view of security of supply.

With regard to access to the TAP (Trans-Adriatic Pipeline) pipeline, the procedures proposed by TAP AG for the first ("non-binding") phase of the market test to be carried out in 2019 were approved[206] in June 2019 together with the regulators of Albania and Greece (ERE and RAE). The market test was carried out in compliance with the CAM regulation, which provides that, at least in all odd years, the TSOs (*Transmission System Operator*) carry out a coordinated process for offering incremental capacity at interconnection points with the countries of the European Union. If successful, the capacity of the pipeline is increased compared to the initial capacity, as the necessary investments are covered by the capacity booking commitments resulting from the test, up to the limit of the technical possibilities.

Finally, with regard to the output points located on national territory, in April 2019[207] the process launched[208] with the March 2018 consultation on the reform of the processes for the allocation of transmission capacity at the redelivery points of the transmission network connected with the distribution networks and the corresponding output points was concluded.

The reform has become necessary not only because the current procedures appear unnecessarily expensive, but above all because, by favouring those who supply a large number of customers with different delivery characteristics at a city gate, they constitute a barrier to new entrants and hinder the contestability of customers.

The resolution defines the main aspects relating to the determination of the capacities associated with the redelivery points and the related information flows. However, the implementation of the intervention is foreseen following a special evaluation of the implementation aspects carried out on an experimental basis by the Balancing Manager, i.e. the main transmission company, ensuring the involvement of the stakeholders. In this perspective, the Authority's measure[209] of February 2019, which incentivised the completion of the delivery profiling methodology by adding a dynamic component, a function of temperature, and a broad sharing of the new methodology with market operators, in advance of its entry into force, takes on importance. This methodology makes it possible

[203] Resolution 308/2019/R/gas of 16 July 2019.

[204] Document for consultation 344/2019/R/gas of 30 July 2019.

[205] Resolution 137/02 of 17 July 2002.

[206] Resolution 267/2019/R/gas of 25 June 2019.

[207] Resolution 147/2019/R/gas of 16 April 2019.

[208] Document for consultation 114/2018/R/gas of 1 March 2018.

[209] Resolution 57/2019/R/gas of 19 February 2019.

to allocate the peak capacity use at the city gates more closely to the contribution of each delivery point and therefore also to share the costs more fairly.

A further aspect that was discussed in depth before the implementation of the reform concerns the so-called z-factor, which reproportions the conventionally calculated capacities of each delivery point so that their sum coincides with the capacity used at the city gate. In this regard, it was found that capacity should not be calculated with reference to individual city gates, but to an aggregation of them by geographical or climatic zones, in order to avoid significant differences in transport costs for final customers belonging to different city gates, even if geographically close.

The measures[210] of April 2019 provided for a large period of time from the date of their adoption to that of their entry into force, both to allow the necessary further study described above, and to allow operators adequate implementation time, given the profound impact on commercial relations and on consolidated positions in the market structure due to the long duration of the pre-existing regulation.

Evaluation of the 10-year transport network development plans and cost/benefit analysis

On 21 January 2019, the Authority launched the public consultation on the 2018 Natural Gas Transmission Network Development Plans. As part of this consultation, which ended on 29 March 2019, it mandated the largest transmission company to organise a workshop to present the main interventions of the 2018 Plans falling within the scope of the cost-benefit analysis (CBA), as well as the proposal of its application criteria[211].

The workshop, organised by Snam Rete Gas in coordination with the other transmission system operators and with the Authority's Offices, was held on 13 March 2019 and saw the participation of a varied range of stakeholders (companies in the sector and consumers).

Subsequently, the Authority approved the proposal[212] made by the main natural gas transmission company on the criteria for the application of the CBA methodology for the development of the transmission network. The measure, which implements the provisions[213] of September 2018 on the minimum requirements for the preparation of the Plans, in relation to both the completeness and transparency of information and the CBA methodology, is part of the process aimed at adopting a methodology that makes it possible, on the one hand, to assess the consistency of the infrastructure development choices identified by the operators with the criteria of cost-effectiveness and efficiency of investments, and, on the other, to selectively identify the interventions that can bring greater utility to the system. In view of the necessary testing phase of the application of the CBA methodology, when approving Snam's plan, the Authority highlighted the appropriateness and effectiveness of the Application Criteria after their first application in the 2019 and 2020 Plans, in order to identify any need to revise the minimum requirements and/or the Application Criteria themselves.

Finally, in July 2019, the Authority expressed its assessment[214] on the Ten-Year Development Plans for the natural gas transmission networks for the years 2017 and 2018 and extended the deadline

[210] Resolution 147/2019/R/gas of 16 April 2019.

[211] The proposal for CBA application criteria was drawn up by the main gas transmission company (Snam Gas Network) pursuant to the provisions of Resolution 27 December 2018, 468/2018/R/gas.

[212] Resolution 230/2019/R/gas of 11 June 2019.

[213] Resolution 468/2018/R/gas of 27 September 2018.

[214] With the Resolution 335/2019/R/gas of 30 July 2019.

for submitting the Plans for 2019 to 31 December 2019. When assessing the Plans, the Authority noted, in particular:

- the lack of information or the failure to present CBAs made it impossible to express a complete assessment of some development interventions, including the expansion of methane pipelines for new imports from the South, the Larino-Biccari pipeline and the Piombino-Isola d'Elba connection;
- the absence of the conditions to express a positive assessment of the development interventions presented by Energie Rete Gas, both because the relevant CBAs do not present sufficient evidence of the efficiency and usefulness of the interventions for the gas system, and in view of the lack of evidence of adequate coordination with the interconnected network operators;
- With reference to the Sardinia methanisation project, given its strategic importance and the size of the investment, the Authority has deemed it appropriate to postpone its assessment until the publication of a CBA (see the section on Tariffs for distribution and metering services).

4.1.4 Implementation of network codes and guidelines

Approval and updating of service codes

The regulations governing access to and supply of natural gas transmission, storage and regasification services, contained in Legislative Decree no. 164 of 23 May 2000, provide that the companies providing these services must define their own codes in accordance with the criteria established by the Authority, which approves them once it has verified their consistency with these criteria.

During 2019, a number of codes for transmission, storage and regasification services were updated in order to implement new regulatory provisions, Authority provisions or management methods to improve service provision.

In particular:

- in March 2019, the proposal to update the Storage Code submitted by Edison Stoccaggio was approved[215], introducing the flexibility services referred to in Article 1, paragraph 9, of the Ministerial Decree of 15 February 2019, as well as the provisions concerning the establishment of the cash collateral on gas deposited in storage in favour of third-party creditors;
- in April 2019, the proposal to update the Storage Code presented by Stogit was approved[216], with which: short-term storage capacity booking processes were improved, for example through the introduction of a second daily capacity booking session at 3:30 pm on the day before the gas day and the integration of guarantee management methods; a service was introduced that provides for the possibility of reducing the minimum monthly filling profile in the storage filling phase; the procedures for switching from normal operating conditions to general emergency

[215] Resolution 80/2019/R/gas of 05 March 2019.

[216] Resolution 153/2019/R/gas of 16 April 2019.

conditions and the timing of processes for the allocation of additional supply services were defined[217];

- in November 2019, the proposal to update the Storage Code presented by Stogit was approved[218], which incorporates a number of simplified procedures for the allocation of so-called fortnightly supply capacity: in particular, intertemporal transfers of user-owned capacity are facilitated, according to criteria of economic merit, without forcing the user to participate in the allocation procedure for both purchase and sale;
- In December 2019, two proposals to update the Storage Code presented by Edison Stoccaggio were approved[219]: the first concerns the methods by which capacity and gas sales and purchases are regulated; the second concerns the allocation of capacity for short-term storage services and the consequent integration of the renaming acceptance criteria.

4.2 Competition and market functioning

4.2.1 Wholesale markets

On the basis of the preliminary results issued by the Ministry of Economic Development, in 2019, the net consumption of natural gas rose by 1.6 G(m^3), reaching 71.9 G(m^3) from 70.3 G(m^3) in 2018 (Table 4.3). In percentage terms, consumption grew by 2.2%, thus recovering part of the previous year's loss (-3.2%).

Table 4.3 Natural gas balance in Italy

M (m^3); provisional data for 2019

	2018	2019	VARIATION
National production	5,448	4,852	-10.9%
Imports	67,873	70,912	4.5%
Exports	391	325	-16.7%
Change in stocks	-264	-1,121	325.4%
GROSS DOMESTIC CONSUMPTION	72,667	74,319	2.3%
System consumption and losses	-2,328	-2,403	3.2%
NET CONSUMPTION	70,338	71,916	2.2%

Source: Ministry of Economic Development

In 2019, industrial gas consumption fell by 1.7%, while thermoelectric generation consumption benefited from a reduction in electricity imports, recording a sharp rise (+11%). On the other hand, consumption for other uses was stable (0.2%), particularly for motor vehicles, while civil consumption (residential and tertiary) decreased by 3.1% compared to 2018, mainly due to an unfavourable

[217] Resolution 612/2018/R/gas of 27 November 2018.

[218] Resolution 461/2019/R/gas of 12 November 2019.

[219] Resolution 555/2019/R/gas of 19 December 2019.

climate trend for heating: 2019 was once again a hot year. Compared to the peak of 85.3 G (m^3) that gas consumption reached in 2005, in 2019 final gas demand was therefore equal to 84%.

In the face of higher consumption, net imports consistently showed an increase of 4.6%. The volumes of gas imported from abroad increased by 3 G(m^3) compared to 2018, reaching 70.9 G(m^3); exports fell by 66 M(m^3). There was still a heavy reduction in domestic production (-10.9%), albeit less than that recorded in 2016, which was the most important (-14.6%) of the last decade. However, part of the imported gas went to increase stocks: the volumes in storage at the end of the year, in fact, were 1.1 G(m3) higher than the quantities at the beginning of the year. Taking system consumption and network losses into account, gross domestic consumption in 2019 was 74.3 G(m^3), 2.3% higher than in 2018.

The level of foreign dependence, measured as the ratio of gross imports to the gross value of domestic consumption, rose again to 95.4%, the highest value ever recorded.

Production

According to the data collected in the customary Annual survey on the regulated sectors carried out by the Regulatory Authority for energy networks and the atmosphere, in 2019 altogether 4,669 M(m^3) were extracted by 14 companies belonging to 9 corporate groups (in 2018 there were 18 companies in 13 corporate groups). Since last year's production was 5,268 M(m^3), in 2019 the decrease measured in the survey data was 11.4%.

The share of domestic production held by Eni group companies also fell slightly in 2019, reaching 75.2% from 76.2% in the previous year (it was still 81.5% in 2016). In 2019, in fact, the companies of the Eni group extracted about 500 M(m^3) less than 2018, thus recording a 12.6% decrease. The group remains the dominant operator of this segment with a decisive majority share, far ahead of the second corporate group, Royal Dutch Shell, which owns 11.3%. In contrast to the two previous years, in 2019 production of the latter slightly decreased by about 50 M(m^3) (-7%) but, due to the higher overall reduction, its share rose to 14.6% from 13.9% in 2018. The production of the Edison Group, whose companies extracted about 14 M(m^3) less gas than in 2018, also fell slightly (-4%). The share of the Edison group therefore rose to 7.4% from 6.8% last year. Gas Plus remained in fourth position, this year with a share slightly up to 2.3% from 2% in 2018.

Imports

In 2019, gross imports of natural gas into Italy reached 70.9 G(m^3), an increase of 4.5% compared to 2018. Exports, on the other hand, fell from 391 to 325 M(m^3). The foreign balance therefore rose from 67,482 to 70.587 M(m^3). Italy's dependence on foreign supplies started to rise again, reaching a historical peak of 95.4% (93.4% in the previous year).

Figure 4.4 shows the amounts of gas supplied in the last two years per country of origin[220] of the gas. With the exception of volumes from Algeria, which decreased by 25.6% compared to 2018, imports increased from all other countries from which Italy imports gas. The gas that was not imported from Algeria (4.6 G(m^3)) was more than offset by the higher volumes from other traditional countries from which Italy imports gas. In fact, in 2019 we imported: 3 G (m^3) more from Norway, 1.2 G (m^3) more from Libya, 0.5 G (m^3) more from Holland and 0.2 G (m^3) more from Russia ; volumes from other areas also increased by around 2.7 G (m^3) (i.e. by 125%). In particular, significant LNG shipments from

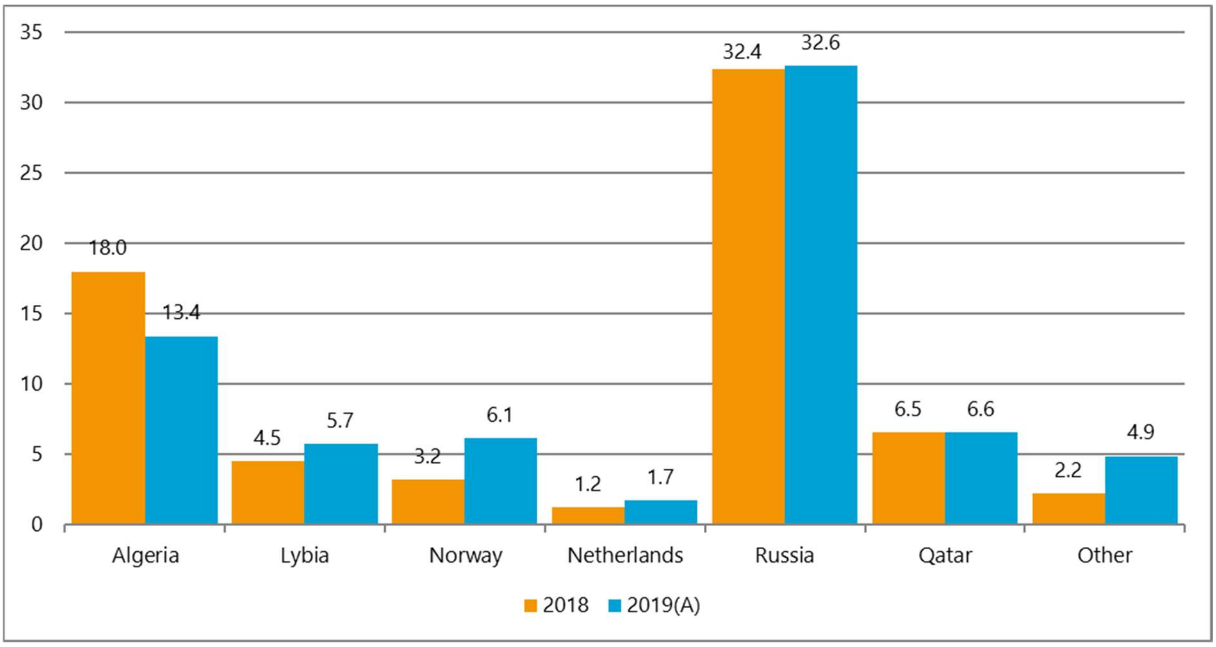
[220] Imports are divided by Country of physical origin of the gas, not by contract. The gas imported under swap regimes is also accounted for according to its Country of physical origin.

Trinidad & Tobago, amounting to 1.4 G(m3), and 1.6 G(m3) from the United States, delivered to the Livorno terminal, should be noted.

In 2019, therefore, the weight of Russia among the countries exporting to Italy fell slightly to 46% (it was 47.7% in 2018), while Algeria's share fell from 26.5% to 18.8%. The third most important country is Qatar, which accounts for 9.2% of the total gas imported into Italy (9.6% in 2018), followed by Norway, whose share is 8.7%, and Libya, 8%. In 2019, 6.8% of Italian imports came from all the other countries together. Thanks to the significant increase in the Norwegian share, the incidence of imports from Northern Europe (i.e. from Norway and the Netherlands together) rose to 11.1% from 6.5% in 2018.

Figure 4.4 Gross gas imports according to its origin

M(m^3); estimates made according to the input point of the gas



(A) Preliminary data.

Source: Ministry of Economic Development

According to the (provisional) data collected with the annual survey on the sectors regulated by the Authority, 69 G(m^3) were imported into Italy in 2019, 2 more than in 2018[221]. The increase was, therefore, 3.1%, slightly lower than the figure reported by the Ministry of Economic Development[222]. 6% of the total gas supplied abroad, approximately 4.1 G(m^3), is purchased at the European Exchanges. The latter value almost doubled compared to 2018, when 2.9 G(m^3) reached the European stock exchanges.

As always, Eni is in first place in the ranking of importing companies, whose quantities purchased abroad in 2019, equal to 32.5 G(m^3), decreased by 2.5 G(m^3) compared to 2018. The significant

[221] Data from Annual surveys on regulated sectors.

[222] The differences compared to the Ministry data are due, in part, to the number of companies who respond to the Authority's Annual survey, and also due to the discrepancies in the classification of the import data. In other words, it is possible that some of the quantities that are classified as import by the Ministry, will be considered as "Purchased at the Italian border", due to the Customs clearance procedures.

reduction in Eni's imports (down 7.2%), compared to an overall increase in total domestic imports, caused the company's market share to fall sharply to 47.1% (45.9% if calculated on the value of imports from ministerial sources), from 52.3% in 2018. This share is down from 2014, but remains well above the trough reached in 2010, when, due to the antitrust ceilings established by Legislative Decree No.164[223] of 23 May 2000, the portion of foreign gas supplied by Eni had fallen to 39.2%. Edison's imports, second in the ranking as in 2018, instead remained substantially unchanged, having increased from 14.6 to 14.7 G(m^3); its share in the import market therefore fell to 21.3% from the previous 21.8% and the distance from Eni was shortened by five percentage points, although only due to the decrease in Eni's share. A significant increase (+7.4%) was instead seen in Enel Global Trading's imports, which rose from about 6.3 G(m^3) in 2018 to 6.7 G(m^3). Therefore Enel Global Trading remained in third place with a its share increasing slightly from 9.4% to 9.8%. As in 2018, DXT Commodities SA (formerly Dufenergy Trading) is in fourth place in the ranking of importers in 2019, whose quantities imported just exceeded 2 G(m^3) and represent 42% of those of the third importer.

Table 4.4 Development of the wholesale market

Year	Demand Total[(A)] G(m^3)	Peak demand[(B)]M(m^3)/d	Production G(m^3)	Import capacity G(m^3)/y	No. companies with supply share >5%[(C)]	No. of companies with available gas share >5%[(D)]	C3 of the main groups on total demand
2001	125.1	n.a.	15.5	n.a.	n.a.	2	68.2%
2002	111.8	n.a.	14.3	84.0	3	3	67.4%
2003	123.6	n.a.	13.9	84.8	3	3	63.8%
2004	127.3	386	12.9	88.7	3	3	62.4%
2005	138.3	421	12.0	90.6	3	3	66.7%
2006	134.3	443	11.0	92.3	3	3	66.5%
2007	136.1	429	9.7	98.4	3	3	63.8%
2008	151.5	410	9.3	100.3	3	3	57.1%
2009	147.2	436	8.0	110.9	3	4	49.2%
2010	173.5	459	8.3	116.0	3	5	42.3%
2011	178.9	401	8.4	116.3	3	3	42.1%
2012	178.3	464	8.6	116.9	3	3	40.5%
2013	180.8	360	7.7	122.1	3	3	42.7%
2104	210.9	330	7.1	121.7	3	3	51.4%
2015	244.5	340	6.8	120.3	3	3	50.6%
2016	267.4	384	5.8	120.1	3	3	46.3%
2017	285.7	425	5.5	121.7	3	3	44.4%
2018	287.5	396	5.4	120.4	4	4	47.2%
2019	328.9	394	4.9	120.2	3	3	46.9%

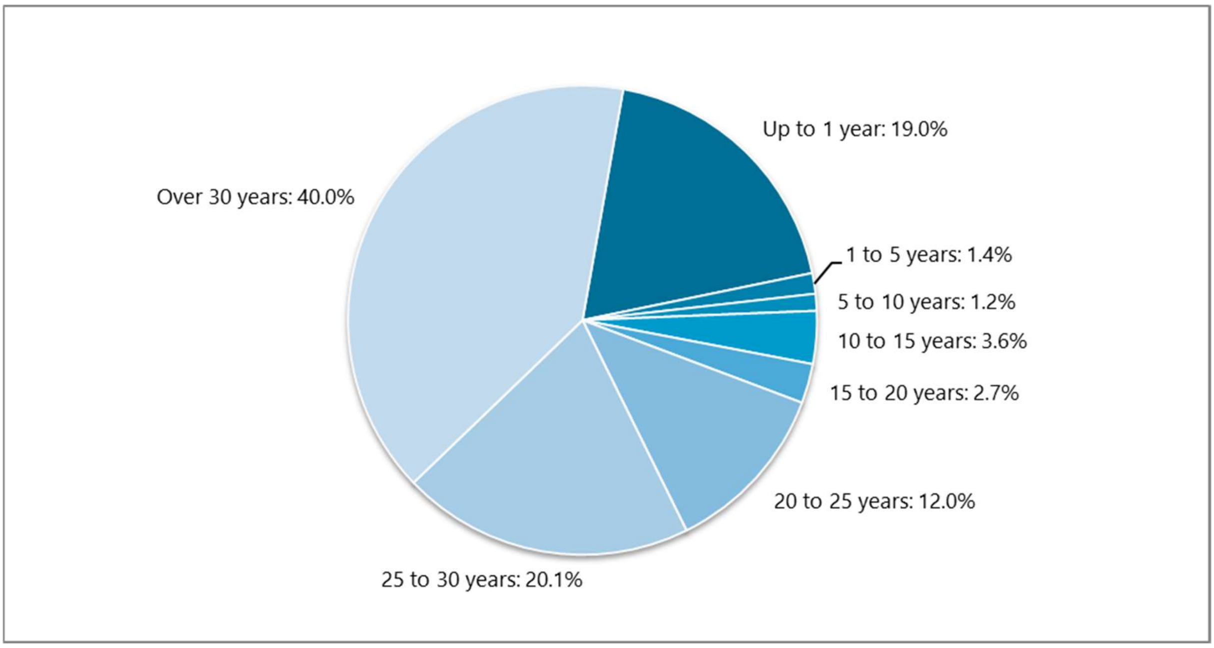
(A) Gas volumes sold in the national wholesale and retail markets; including resale and self-consumption.
(B) The volume indicated includes inputs, storage supplies, leaks and internal network consumption.
(C) Number of companies with a production share and import capacity greater than 5%.
(D) Number of companies with a >5% share of the volumes of gas available, which include production, net imports and stored gas.

223 This decree provided, among other measures, the imposition of maximum limits for the import and sales on the end market of natural gas by a single operator (75% of the imports in 2002, which reaches 61% in 2010), with the objective of defining the conditions for the entry to the market of gas imported by subjects other than Eni and the other two subjects historically present on the gas import market, even if their shares are small.

Source: ARERA processing on Snam Rete Gas data and on declarations from operators.

The groups[224] that hold a share of more than 5% of the overall gas supplied (i.e. produced or imported) are therefore Eni, Edison and Enel (Table 4.4). Together they imported 54 of the 69.1 G(m^3), 78.1% of the natural gas entering the Italian market. Considering the quantities produced within the national borders, these three groups account for 78.4% of all the natural gas supplied. This share is down (it was 83.4% in 2018), due to the decrease in Eni's share which was not offset by the increase in Enel's share. The three groups are also the only groups that each hold a share of more than 5% of the available gas (which includes stored gas, as well as imports and production), with an overall share for all three (79.9%) that is slightly higher than that of gas supplied.

Figure 4.5 Structure of import contracts active in 2019, according to their entire duration



Source: ARERA. Annual Survey on Regulated Sectors.

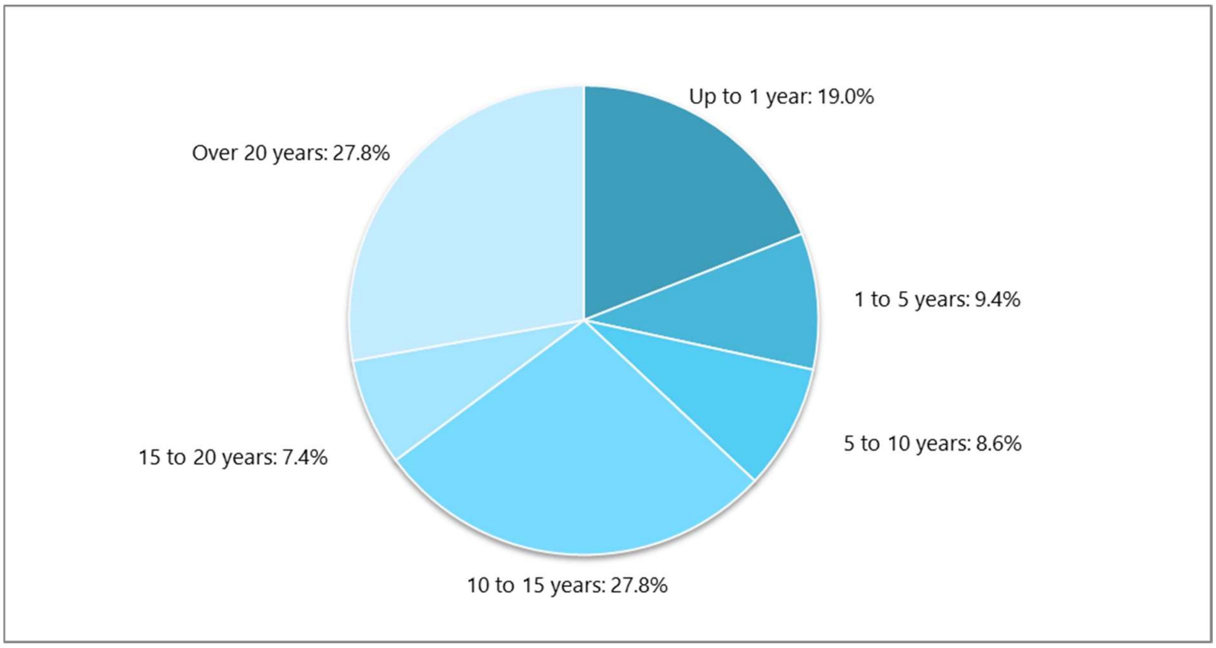
The analysis of the import contracts (annual and multi-year) active in 2019 according to the entire duration (Figure 4.5) also highlights a rather long structure for 2019. The share of long-term contracts, those whose entire duration exceeds 20 years, is in fact equal to 72.1%, although a decrease compared to last year (when it was 76.2%). The incidence of short-term import contracts, i.e. those with a duration of less than five years, grew further and was just over 20% (13.9% in 2018), while that of medium-term contracts (5-20 years) decreased by 2.5 percentage points compared to last year (7.5% instead of 10% in 2018). The annual contract quantities underlying the shares expressed in the figure have, however, increased for the first time since 2016: in 2019, in fact, the volumes contracted totalled 86.3 G(m^3), compared to an average of 84.7 G(m^3) over the last three

[224] In the survey on the gas market participation in a corporate group is defined according to what is specified in art. 7 of the Law of October 10th, 1990, n. 287: in brief, belonging to a group is established even when there is a de facto control of the investee in the company.

years. The incidence of spot imports[225], i.e. those with a duration of less than one year, is constantly increasing: in 2019 it rose by 7.5 percentage points to 19%.

In terms of residual life, the import contracts in place as of 2019 (Figure 4.6) show that 37% of contracts will expire within the next ten years (the same share was 55.4% in 2018) and 28.4% will expire within the next five years. 35.2% of the contracts in force today have a residual life of more than 15 years. This percentage, which had been increasing since 2014, declined slightly in 2019 as it was 36.6% in 2018.

Figure 4.6 Structure of import contracts active in 2019, according to their residual duration



Source: ARERA. Annual Survey on Regulated Sectors.

In 2018, the total demand of the natural gas sector, understood as the sum of the volumes of natural gas sold on the wholesale market (including reselling) and retail market plus self-consumption grew by 15%, reaching 329.2 G(m^3)(Table 4.4).

Overall, the gas sold in the total sales market (wholesale and end market) reached 313.6 G(m^3), an increase of 14.8% compared with the same figure in 2018. The wholesale market handled 255.6 G(m^3), an 18.2% increase compared to 2018; the retail market handled 58 G(m^3), recording an increase of 1.9% compared to 2018, while self-consumption totalled 15.6 G(m^3), also with an increase (7.7%). 5 industrial groups served a share of more than 5% of the total demand in 2019, one more than in 2018.

More precisely, the industrial groups and their respective shares, indicated between parenthesis, are: Eni (24.0%), Engie (14.6%), Edison (8.4%), Enel (8.3%) and Royal Dutch Shell (4.5%). The top three groups cover altogether 46.9% of the total demand, a lower share than last year (which was 47.2%).

[225] It is important to remember that, as in past years, this has been assessed excluding the Annual Contract Quantities of spot contracts, which did not create imports in Italy, because the gas was sold directly abroad by the operator who was active in Italy and who purchased it.

4.2.1.1 Monitoring the price levels of the wholesale market

The data related to the gas wholesale market is, as always, from the first and provisional processing of the data collected in the annual survey that the Authority carries out on the state of the electricity and gas markets in the previous year. The survey was addressed to the 744 accredited companies of the Operators Registry, concerning the gas sales sector, which declared they sell gas on the wholesale or end market in 2019 (even for a short period of the year). Of these, 583 companies replied (78%), 87 of which stated that they were companies affiliated to a natural gas distribution company and 11 to a transmission company.

Of the 583 companies that participated in the survey, 63 said they remained inactive during the year. Of the remaining 520 active ones, 74 sold gas only on the wholesale market and were classified as pure wholesalers, 325 sold gas only to consumers and were classified as pure suppliers. The remaining 121, who operated on both the wholesale market and end market, were classified as mixed operators.

Table 4.5 Sales and prices in the wholesale market in 2019

M(m^3); c€/m^3

Operators	Number	Sales	Price
Pure wholesalers	74	131,904	20.91
Mixed operators	121	123,700	22.04
TOTAL WHOLESALE	195	255,604	21.45

Source: ARERA. Annual Survey on Regulated Sectors.

The wholesale market, which handled a total of 255.6 G(m^3), is supplied for 52% by pure wholesalers, and 48% by mixed operators. Unlike what has happened in the previous two years, in 2019, the number of companies operating in the wholesale market increased, although the volume of gas sold grew more than proportionally. In fact, 195 suppliers, 11 more than 2018, sold a total of 39.4 G(m^3) more than in 2018. As a result of these trends, the average unit volume increased significantly (+11.5%), from 1,175 to 1,311 M(m^3) in the market as a whole.

During the year, 12 companies started selling natural gas wholesale and two purchased it; two companies ceased operations and one went out of business, while seven companies changed corporate group. There have been six mergers between companies that already belonged to the same corporate group. In 2019 the market concentration level remained substantially unchanged: in fact, the share of the top three companies (Eni, Engie Global Markets and Eni Trading & Shipping) was 34.3%, practically the same as the 34.1% calculated in 2018. The combined market share of the top five companies (the three mentioned above plus Enel Global Trading and Edison) fell from 50% to 48%. The HHI index calculated only on the wholesale market also fell from 628 to 614, remaining however below the value of 1,500, considered the first symptom of concentration.

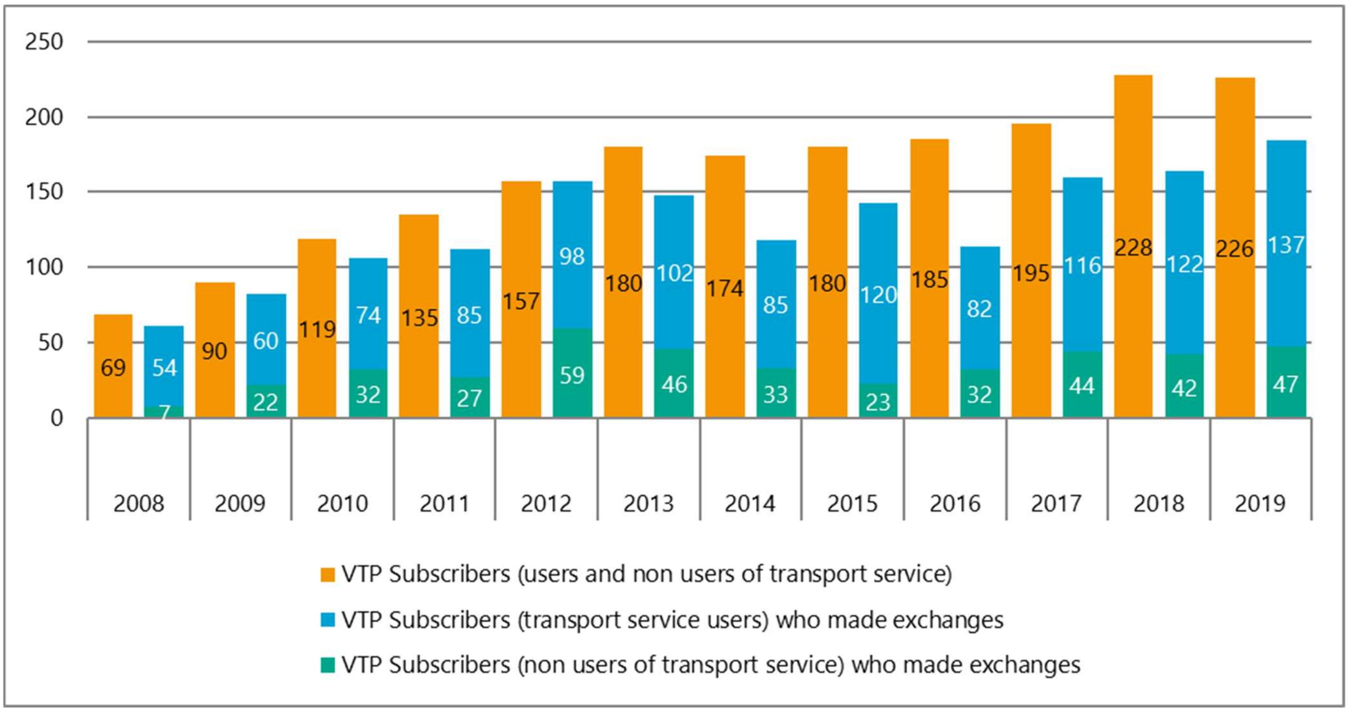
In 2019 the average wholesale market price was 21.45 c€/m^3, well below the 24.05 c€/m^3 (-10.8%) charged in 2018. This is in line with the VTP price trend which in 2019 dropped by 34% compared to the 2018 average. The mixed operator price was 22.04 c€/m^3, that is 1.13 cents higher than the price charged by pure wholesalers (equal to 20.91 c€/m^3).

Virtual trading point

The main trading platform in the wholesale market in Italy is the Virtual Trading Point (VTP), operated by the leading transport network operator, Snam Rete Gas. The sales that can be registered are the ones carried out with bilateral contracts and the ones carried out in the regulated markets managed by the GME. Since September 2015 it is also possible to register contracts managed by third party[226] Stock exchanges to the VTP, thus increasing the offer of futures products with physical gas delivery to the VTP. In order to operate at the PSV it is necessary to be a subscriber, i.e. to be in possession of the required requirements and to have signed a membership form or an access contract, by which one undertakes to comply with the conditions set by the Authority[227].

In 2019, 184 entities performed the trade, sale and purchase of gas on the VTP. Only 47 of these were pure traders, as they were not transmission system users. Despite a slight increase in demand for natural gas, the number of VTP subscribers did not increase compared to the previous year, having reached 226. However, the number of subscribers who carried out transactions (Figure 4.7) increased by 20 units (12%) compared to 2018, as well as a sharp increase (+5 units) in the number of pure traders (i.e. subscribers who are not users of the transmission system) from 42 to 47.

Figure 4.7 VTP Subscribers since 2008



Source: ARERA. Annual Survey on Regulated Sectors.

Figure 4.8 shows the evolution of the trades recorded at the VTP. The figure shows the redeliveries to the VTP and, with the indication "VTP-GME", all the exchanges recorded at the VTP resulting from trading on the markets managed by the GME, i.e. those that took place on the Gas Balancing Platform

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[226] By third party Stock exchange we mean the manager of a foreign regulated market, in which financial derivatives are exchanged which provide for the physical delivery and whose clearance and guarantee activities for the transactions carried out in this market are regulated through a clearing house (the third party that accepts the counterparty risk); or it is the same clearing house that is responsible for the fulfilment of the physical delivery of the purchased products, directly or through subsidiaries or investees.

[227] With the Resolution 147/2017/R/gas of 16 March 2017.

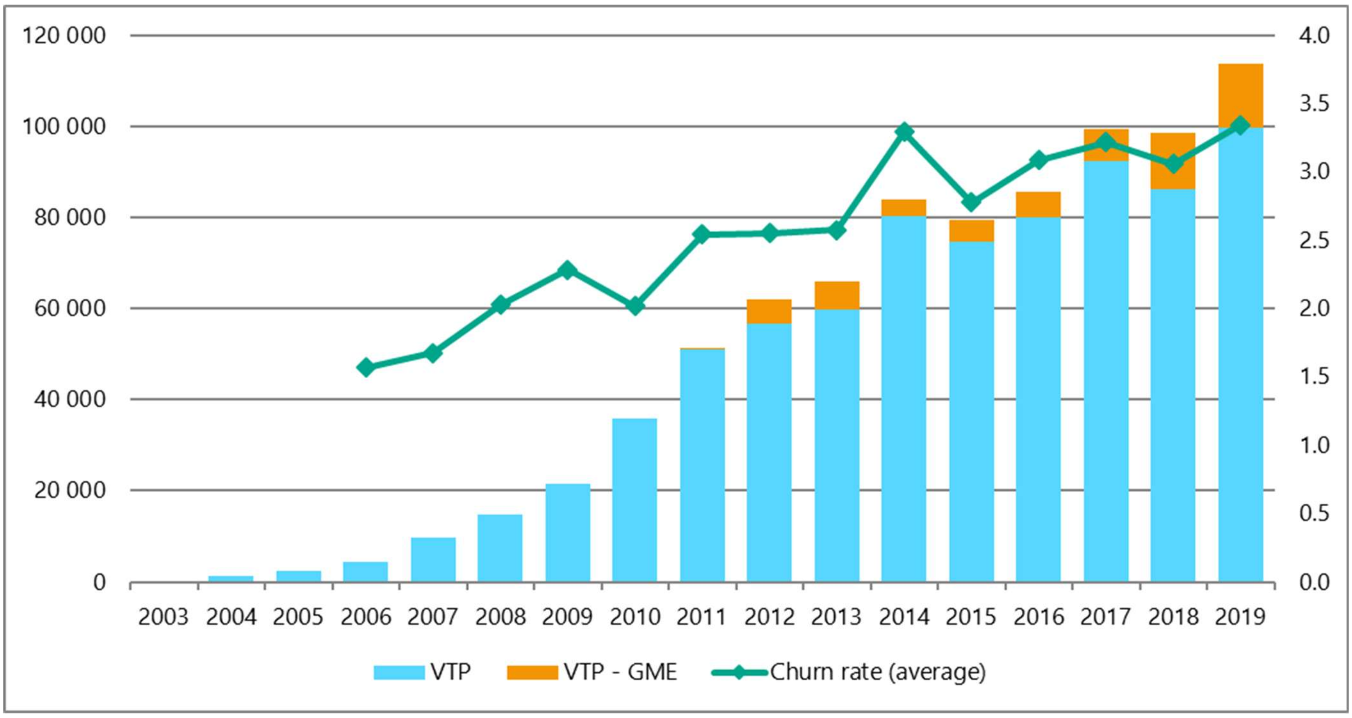
(PB-GAS) until September 2016, but also those in the M-GAS and, lastly, those managed as clearing houses.

The VTP has grown considerably over time, both in terms of the number of transactions and the volumes exchanged, thanks to the increase in the available purchasing methods described. Beginning in the autumn of 2015, the transactions recorded on the VTP, which acts as clearing house, have been notably increasing. As will be seen in the next paragraph, the launching of the new balancing market (fourth quarter of 2016), that brought a net increase in the exchanges on the several M-GAS platforms, was useful to support this continuous increase.

After a year of decline, in 2019, thanks to the increase in overall gas consumption demand, OTC volumes traded at the VTP recovered sharply and increased by 15.6%, from about 86 G(m^3) to just under 100 G(m^3). This in particular thanks to the strong increase in LNG volumes with forced delivery to the VTP. The volumes traded through the stock exchange also showed a significant increase, equal to 14%, although less than the 77% jump recorded in 2018. Volumes traded on the exchange almost reached 14 G(m^3) from 12.3 the previous year, thanks to a particularly significant increase in volumes managed in centralised markets, while energy traded as a clearing house fell sharply compared to 2018.

Figure 4.8 VTP transaction volumes and churn rate

M(m^3) standard 38.1 MJ



Source: ARERA processing on Snam Rete Gas data.

The churn rate is a synthetic indicator that measures the average number of times that the commodity (gas) is exchanged between the time of the initial sale and that of its physical delivery. The indicator can be calculated in different ways. The one shown in the figure is obtained by dividing the total volumes subject to trading at the VTP by the value of the registrations that result in physical delivery. The more liquid the market, the more this value increases. This rate grew significantly between 2006 and 2014. In the last three years it had stabilised around 3.1 and in 2019 with the increase in activity highlighted it reached the value of 3.3. However, it still remains well below 10 which is the threshold value of the churn rate often used in literature to judge the liquidity and maturity of a market.

Gas exchange

The creation of a gas exchange in Italy began in 2007 with the obligation for holders of natural gas production concessions to surrender the rates of gas produced in Italy due to the State and, for importers, to offer a share of the gas imported on the regulated capacity market. In 2009, the financial management of the gas market was exclusively entrusted to the GME, which manages the sale and purchase offers (and all the connected services) according to financial criteria.

The first core of the Stock Exchange was created in March 2010, with the creation of the negotiation Platform for the exchange of imported gas shares, called P-GAS. With the birth of M-GAS, in October 2010, the spot natural gas market was launched, in which GME plays the role of central counterparty. On this market, operators qualified to perform transactions on the VTP can buy and sell volumes of spot natural gas. It is divided into:

- MGP-GAS (day ahead gas market), in which the dealings occur with sale and purchase offers related to the next-day gas. The negotiation modality is continuous with closing auction price;
- MI-GAS (intra-day gas market), in which the dealings occur with gas negotiations related to the actual gas-day. The negotiation modality is continuous.

PB-GAS, in operation from the end of 2011 until September 2016, replaced the "storage" balancing system with a "market" balancing system, where the price is no longer set by the Authority, but determined by the intersection of supply and demand for stored gas. Those who had storage capacity were required to participate in this mechanism. The compulsory participation, added to the presence of Snam Rete Gas as Balancing Manager (RdB), has allowed higher gas handling in this market, compared to the others managed by the GME.

Until the end of September 2016, the PB-GAS was divided into two sections: Section G-1, a real day-ahead market (where, on a voluntary basis, several flexible resources could be called to respond to Snam Rete Gas's offers to cover the system's forecast imbalance) and Section G+1, a day-after market (where operators offered storage resources at their disposal on a daily basis, for purchase and sale).

Following the approval of the European Balancing Regulation[228], a balancing system was introduced on 1 October 2016, which puts all available flexible resources such as storage, import or regasification of LNG into competition during the day. In this system, the users and Snam Rete Gas access these spot market products to stock the necessary resources to balance the individual position and the aggregated position of the system, respectively. This reform also introduced imbalance prices that lead the single users to balance their own positions, so that the network, in its entirety, is also balanced. In this context, the Snam Rete Gas system operator supplies the users with real-time information on the state of the network so that the users can balance the system efficiently, limiting, vice versa, its purchase and sales actions on the market to what is strictly necessary to supply "price signals".

Beyond the existing MGP-GAS and MI-GAS, the following markets of spot products useful for balancing purposes have been activated since 1 October 2016:

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[228] (EU) 312/2014 Regulation approved by the European Commission on 26 March 2014.

- the storage gas Market (MGS) allows all the users to exchange, in one single marginal price auction session, the ownership of the stored gas; Snam Rete Gas can access this market in order to safely manage possible network deviations, as well as for other operations;
- the locational products Market (MPL) is carried out according to auction negotiation methods and only at the request of Snam Rete Gas. In this market, Snam Rete Gas obtains the amounts of gas that are necessary to manage the physical requirements inside the balancing zone, or possible expected deviations between total network inputs and withdrawals, from the qualified users.

The negotiations of both the aforementioned sections, organized in a transitional way in the context of the balancing Platform (PB-GAS), are part of the Gas Market organisation (MGAS), since April 2017.

Since 2015, the operators can also extend the VTP registration for the transactions concluded at Stock Exchanges managed by subjects other than the GME[229]. The GME has been instructed to record the transactions performed on the platforms managed by ICE Endex and Powernext (PEGAS platform of the EEX group) on the VTP, which had already launched futures products with delivery to the VTP, in April 2015.

The forward market managed by GME (MT-GAS) was launched on 2 September 2013. This market, which was placed next to the existing spot markets, is carried out according to the continuous negotiation modalities with different negotiation books, one for each type of negotiable product and referring to different delivery periods, where gas purchase and sales offers are selected.

Between January and February 2018, some measures were introduced aimed at promoting the development of the liquidity of the natural gas markets and, in particular, of the spot market. Of particular importance was the creation of market making figures, i.e. liquidity providers who undertake, in return for an economic advantage, to maintain sale and purchase offers contained within a predefined price differential in the market at the same time; liquidity providers operate in the trading of day-ahead products. The GME pays a fixed fee of €160 for each useful session and a fee of € 0.01/MWh for each MWh traded on the MGP-GAS for the daily product G+1 to liquidity providers that have carried out market making activities in compliance with the terms, methods and conditions provided for, per calendar month.

Another measure introduced in 2018 is the integration of the markets managed by the GME within the Trayport platform, where the main foreign markets are already operating; this is a highly anticipated evolution for users because it allows them to optimise trading activities through simultaneous operations on several markets from a single trading platform.

In order to promote the liquidity of the spot natural gas market, expanding the offer of products available for trading and flexibility for the parties operating in the market, the Authority expressed a favourable opinion[230] to the Ministry of Economic Development for the introduction of the weekend product in the MGP-GAS market. The new product, approved by the decree of the Ministry of Economic Development of 12 December 2019, is tradable from 1 January 2020.

Finally, in 2019, the Authority expressed a favourable opinion[231] on the proposals to amend the Integrated Text of the Electricity Market Regulations (TIDME) and the MGAS Regulations, prepared

[229] Resolutions 282/2015/R/gas of 12 June 2015, and 436/2015/R/gas of 10 September 2015.

[230] With Resolution of 26 November 2019, 496/2019/I/com.

[231] With the Opinion of 16 July 2019, 309/2019/I/com.

by the GME, as they were considered functional to the introduction in the MGP, MI and MP GAS natural gas markets of a single guarantee to cover the net exposure accrued by the operator on these markets.

Prices and Volumes

In 2019, a total of 79.0 TWh of gas was traded in the gas markets operated by the GME, up 45% from the volumes traded in 2018 (Table 4.6).

The most liquid market is the Intraday Market (MI-GAS) (41 TWh; +47%), thanks in part to trading between third-party operators (other than the Balancing Manager), which reached an all-time high of 24.1 TWh (+80% on 2018), surpassing for the first time the movements of Snam Rete Gas for balancing purposes (17 TWh). In the Storage Gas Market (MGS) (13.4 TWh; –1%), the main operator is instead the Balancing Manager, both for purchase (6.8 TWh, +84%) and for sale (4.8 TWh, +36%), especially for purposes other than balancing, or for managing neutrality with respect to the quantities recognised in kind to cover consumption, losses and unaccounted for gas (CNG).

Table 4.6 Annual volumes for each of the gas markets managed by the GME

GWh

MARKETS		2011	2012	2013	2014	2015	2016	2017	2018	2019
P-GAS	Import	-	-	-	-	-	-	-	-	-
	Royalties	2,870	2,708	1,801	-	-	-	1,057	2,471	1,290
	Decree-Law No. 130/10	-	-	-	-	-	-	-	-	-
M-GAS	MI-GAS	13	36	4	102	1,009	7,090	23,826	27,862	41,053
	MGP-GAS	149	136	13	-	-	335	3,280	13,006	24,564
	MT-GAS	-	-	-	-	-	-	171	602	3,225
	MGS	-	-	-	-	-	3,269	16,633	13,502	13,365
	MPL	-	-	-	-	-	-	-	-	-
PB-GAS	PB-GAS (G+1)	1,712	34,925	40,833	38,584	40,833	30,568	-	-	-
	PB-GAS (G-1)	-	-	48	2,940	7,326	6,218	-	-	-
TOTAL		4,743	37,805	42,699	41,627	49,199	47,480	44,967	57,443	83,497

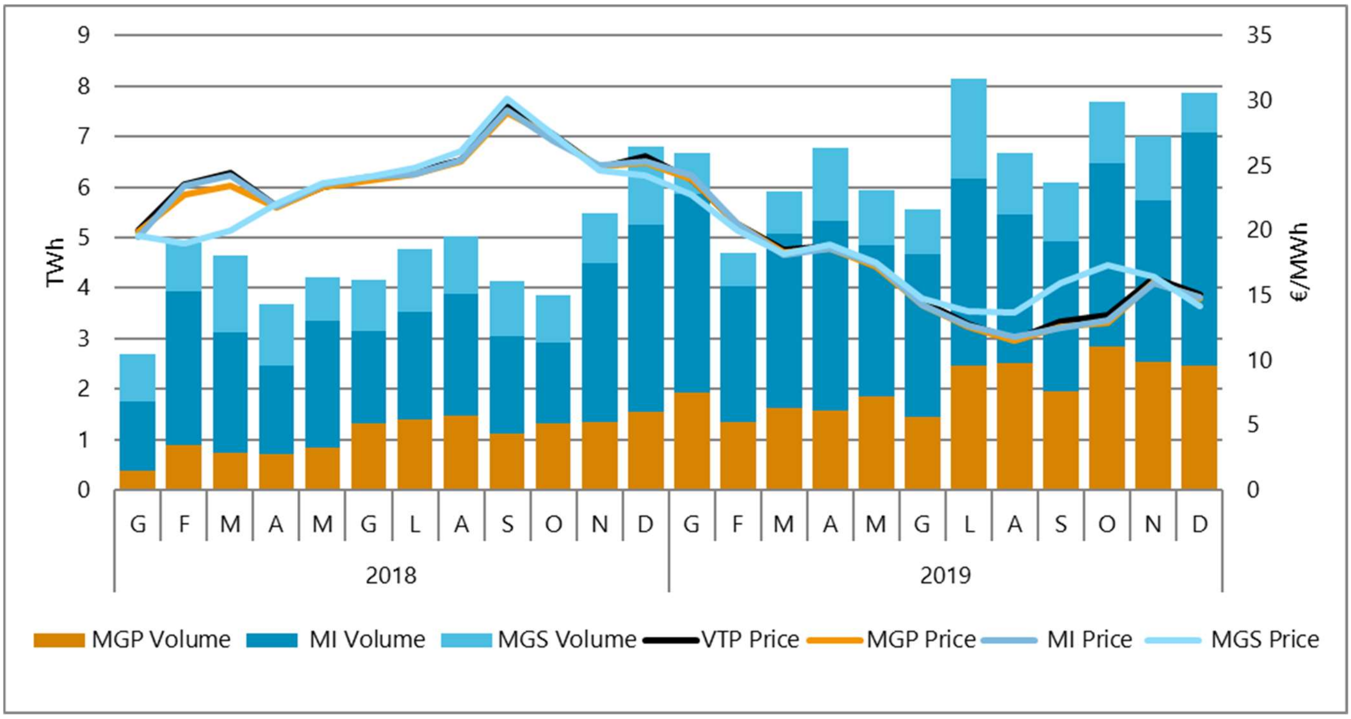
Source: GME.

There was a sharp increase in volumes traded on the Day-Ahead Market (MGP-GAS) (24.6 TWh; +89%), particularly in the second half of the year. This growth was supported by the activity launched by the TSO on an experimental basis on the MGP-GAS, starting from the month of July 2019, pursuant to the resolution of 19 February 2019, 57/2019/R/gas[232], for a total of 2.1 TWh (approximately 8% of the total traded). During the year there was no trading for the Locational Product Market (MPL), while there was a decrease in auction trading in the "Royalties" section of P-GAS, with 0.4 TWh traded in January sessions alone for a total of 1.3 TWh delivered in 2019. Trading on the Gas Forward Market (MT-GAS) also increased, with 726 matches for a total of 3.2 TWh, traded mainly on monthly products (69%). Trading also took place on the Regasification Capacity Allocation Platform (PAR) for a total of 80 slots related to the product "Capacity no longer transferable at auction", amounting to 8.1 M(m^3) liquefied.

[232] Resolution 57/2019/R/GAS initiated an experimental phase to limit the use of storage by the Balancing Manager.

Figure 4.9 Monthly performance of prices and volumes in the markets useful for gas balancing

€/MWh; MWh



Source: GME, Thomson Reuters for the VTP.

On average, prices recorded on the various spot platforms (Figure 4.9) in 2019 were around 16 €/MWh, in line with the average annual OTC prices at the VTP of the day-ahead product (16.28 €/MWh). In particular, the average prices of the two sectors of M-GAS - respectively 16.06 €/MWh for MGP-GAS and 16.13 €/MWh for MI-GAS - showed an intra-annual trend that faithfully reflects that of the day-ahead product at the VTP, confirming an average differential between the latter and the System Average Price (SAP)[233] of -20 c€/MWh since last year. On the other hand, there were some upward variances in MGS prices (up to +4 €/MWh), particularly in the months between July and October, which normally coincide with the injection period at the storage sites.

4.2.1.2 Monitoring the level of transparency, including compliance with transparency obligations, and the level and effectiveness of market opening and competition

Monitoring of the wholesale market

In light of the evolution of the reference international context, as well as the monitoring tasks assigned by Italian legislation, in December 2018 the Authority adopted[234] the Integrated Text on the monitoring of the wholesale natural gas market (TIMMIG), which, starting from a streamlining of the existing one, makes it possible to have more automated analysis, reporting and reporting tools available[235].

[233] SAP is the average of the prices recorded on the MGP–GAS and MI–GAS weighted for the respective volumes traded.
[234] With the Resolution 631/2018/R/gas of 05 December 2018.
[235] For more details on the structure, purposes and provisions of the TIMMIG, see the 2019 Annual Report.

The TIMMIG appointed GME to monitor the competitive dimension and the largest transmission company, Snam Rete Gas (or SRG) to monitor the structural dimension. In addition, it requires the largest transport company to collect and organise data on monitoring activities within a database, called the core data database. This database is accessible to the Authority and GME. In particular, pursuant to TIMMIG, GME's methods of access to the aforementioned database are governed by a special agreement signed by GME itself and by SRG. The outline of the Agreement, as well as subsequent updates, are approved by the Authority, on the basis of a proposal by SRG and the GME. In autumn 2019 the Authority approved[236] an update of the Agreement with which it is expected that SRG, for the performance of the monitoring activities assigned to it, will have access to the data relating to the individual transactions concluded in the continuous trading markets managed by GME, anonymously, as well as the data on the transactions proposed and concluded by the same company.

As required by the TIMMIG, the GME and SRG sent the Authority, for approval, the final balance of the costs incurred for the monitoring activities carried out in the previous year. In 2019, therefore, the Authority approved the final costs incurred by GME in 2018 for monitoring the wholesale natural gas market[237] and the costs incurred by Snam Rete Gas for the aforementioned activity during 2018 and the estimate for 2019[238]. Given the launch of the SRG Monitoring Office, the Authority has at the same time decided to update the unbundling regulation in order to provide for the monitoring of the wholesale natural gas market (in line with what has already been done for the electricity sector). The costs relating to the aforementioned monitoring activities are financed by the Fund to cover the costs associated with the gas system balancing system.

Finally, the TIMMG requires the GME and the main transmission company to send the Authority the cost estimate for the following year for approval, and only the GME to send the preliminary cost estimate for the current year. In line with these provisions, at the end of 2019 the Authority approved the cost estimate for GME's wholesale natural gas market monitoring activities for the year 2020 and the preliminary cost estimate for the same activities carried out in 2019[239] as well as SRG's cost estimate for monitoring activities for the year 2020[240].

Implementation of REMIT in the gas sector

Also in 2019, the Authority continued to coordinate with ACER in the monitoring activities of the wholesale natural gas markets under REMIT. In particular, the Authority has provided for[241] the amendment of Annex A to Resolution no. 502/2016/R/gas of 15 September 2016, containing the rules governing the fund to cover any debt arising from default by market operators for amounts in excess of the guarantees enforced, in order to adjust the provisions in line with the introduction of the integrated system of guarantees for the electricity and natural gas markets, which allows for the unitary management of default, and consequently to standardise the safeguard system in force in these markets.

[236] With the Resolution 392/2019/R/gas of 24 September 2019.

[237] With the Resolution 151/2019/R/gas of 16 April 2019.

[238] With the Resolution 223/2019/R/gas of 04 June 2019.

[239] With the Resolution 452/2019/R/gas of 05 November 2019.

[240] With the Resolution 556/2019/R/gas of 19 December 2019.

[241] With Resolution 376/2019/R/gas of 17 September 2019.

Among the adjustments that became necessary, it should also be noted that in 2019 the Authority:

- expressed[242] its favourable opinion to the Ministry of Economic Development on the proposal to amend the Natural Gas Market Regulation (MGAS), submitted by the GME, related to the way storage resources are made available in case of activation of the measures contained in the Emergency Plan;
- approved[243] a proposed agreement between the GME and Snam Rete Gas that defines the methods by which the Balancing Manager is supplied, through the natural gas market, with the quantities to cover consumption, network losses, line pack variation and unaccounted for gas;
- expressed[244] its favourable opinion to the Ministry of Economic Development on the proposal to amend the Natural Gas Market Regulation (MGAS), presented by the GME, aimed at introducing the integrated system of guarantees for the electricity and natural gas markets, which entailed the need for a unified management of default and the standardisation of the safeguard system in force in the above-mentioned markets;
- approved[245] the proposed agreements between GME and SRG and between GME and Stogit made necessary by the introduction of the integrated system of guarantees for the electricity and natural gas markets and by the changes made to the regulation of the fund to cover the debt resulting from defaults by market operators (for amounts in excess of the guarantees enforced), in order to standardise the safeguard system in force in these markets.

4.2.2 Retail market

The provisional results of the Annual Survey, on which the comments on these pages are traditionally based, show that in 2019 58 G(m^3) were sold to the final market, free or protected, to which must be added 197 M(m^3) provided through the last resort and default services[246]. Overall, the end sales therefore amounted to almost 58.2 G(m^3), with an increase of 1.1 G(m^3) compared to 2018.

In order to obtain data that can be compared with the end gas consumption data published by the Ministry of Economic Development mentioned above, we must however consider the volumes related to self-consumption, 15.6 G(m^3), that bring the value of overall consumption given by the Annual Survey to 73.8 G(m^3), which is comparable to the 71.9 G(m^3) reported by the Ministry. The two sources classify the volumes of gas handled over the year in different ways. In the Annual Survey data, the level of overall consumption in 2019 therefore increased by 2% compared to 2018, although it is still far from the pre-crisis values, which were around 85 G(m^3). In 2019, self-consumption also recorded a good recovery, after the reduction highlighted in 2018. In terms of volumes, the growth compared to the previous year was 1.1 G(m^3), equal to 7.7%, while in 2018 it had decreased by 3.7%. This item has a very strong influence on electricity generation (88% of self-consumption is recorded in this sector). As can be seen below, the increase in final consumption that emerges both in the

[242] With the Resolution 68/2019/R/gas of 26 February 2019.

[243] With the Resolution 266/2019/R/gas of 25 May 2019.

[244] With Resolution 309/2019/R/gas of 16 July 2019.

[245] With Resolution 478/2019/R/gas of 19 November 2019.

[246] The request for data related to the last resort and default supplies can be found in the Annual Survey in simplified form. Therefore, for this kind of supply there are no available details (consumption sector, type of connection, etc.) with which the final sales are usually analysed. So all the detailed analyses are accomplished net of this market component in the rest of this paragraph.

annual survey data (3.1%) and in ministerial data, albeit to a lesser extent (2.2%), appears to be linked to a clear recovery of the production sectors, or rather, of the thermoelectric sector, compared with that of civil consumption, which, on the other hand, was still down.

Table 4.7 Final natural gas consumption

Delivery points in thousands; volumes in M(m^3)

	VOLUMES			DELIVERY POINTS		
	2018	2019	VARIATION	2018	2019	VARIATION
Final sales	56,916	58,021	1.9%	21,616	21,681	0.3%
Last resort and default supplies	183	197	8.0%	120	128	6.7%
TOTAL MARKET	57,099	58,219	2.0%	21,736	21,809	0.3%
Self-consumption	14,473	15,584	7.7%	2.6	2.6	0.0%
FINAL CONSUMPTION	71,572	73,803	3.1%	21,739	21,812	0.3%

Source: ARERA. Annual Survey on Regulated Sectors.

Of the 58 G(m^3) of gas sold in the end market, 11 G(m^3) were sold from pure vendors while the remaining 47 G(m^3) were traded by suppliers who also operate in the wholesale market (Table 4.8). The average price charged to consumers, equal to 39.18 c€/m^3, increased by 0.77 c€, or 1.9% compared to the value of 2018. As usual, this price is higher than the one charged on the end market by the wholesalers (pure and mixed), which was equal to 36.54 c€/m^3. The reason for the positive difference of 2.63 c€, mainly lies in the type of customers supplied and the related characteristics. The companies that operate mostly in the end market mainly address civil customers that are connected to the distribution networks and that, although there are many of them, are characterised by low consumption. Vice versa, the customers supplied by the wholesalers are mainly large consumers, especially industrial, which, thanks to the high levels of consumption, are surely able to obtain more favourable prices. Industrial customers are often directly connected to the transmission network and, therefore, do not pay for distribution costs.

Table 4.8 Sales and prices in the retail market for 2019

M(m^3); c€/m^3

Operators	Number	Sales	Price
Pure suppliers	325	11,042	50.38
Mixed operators	121	46,979	36.54
TOTAL RETAIL	446	58,021	39.18

Source: ARERA. Annual Survey on Regulated Sectors.

The price differential that can be observed in the wholesale market is decidedly lower. In comparison with an average price of 21.45 c€/m^3 charged by pure wholesalers to other resellers, mixed operators (i.e. companies that also operate in the final market) demanded on average 22.04 c€/m^3 for the gas they sold to other resellers, i.e. 0.58 cents more. The price charged to other resellers also dropped significantly compared to 2018 (-9.8%). In 2019, however, price differentials widened: last year the differential on the price charged by wholesalers to end market customers was 2.43 c€/m^3, while the differential on the price charged to other intermediaries was 0.39 c€.

In 2019, the number of active suppliers in the retail market rose again after the break in 2018, the year in which, for the first time, this number experienced a downturn[247]. Since the increase in the number of suppliers was much larger than the increase in the gas sold, the average unit sales volume decreased by more than 6 M(m^3) compared to 2018, to 130 M(m^3). Ten years ago, before the economic crisis, average sales were almost twice as high at 237 M(m^3). 6.7% of companies active in the final market, i.e. 30 out of 446, sold more than 300 M(m^3) in 2019. In 2018 this share was 7.4%, given that 31 out of 417 companies had exceeded this threshold. Overall, the 30 companies that sold more than 300 M(m^3) account for 82% of all gas sold in the retail market.

There were a number of movements between companies in 2019 as well: 55 companies have started selling to final customers; 9 companies in total have ceased operations; 11 companies have acquired or sold their sales activities; 22 companies have changed corporate group; there have been 10 mergers by incorporation, all within the same corporate group.

Of the 446 active suppliers that responded to the Annual Survey, 12.3% (i.e. 55 companies) supply customers throughout the country, i.e. in all 19 Italian regions supplied with methane[248]; 277 companies (62.1%) sold electricity in 6 to 18 regions; the remaining 114 companies (25.6%) operated in 1 to 5 regions. The number of companies operating on all or a large part of the national territory is growing. The corporate breakdown of the share capital of gas suppliers, limiting the analysis to direct holdings, displayed poor foreign presence: only 19 companies (of around 426 that provided this data) have a non-Italian majority shareholder. The direct foreign shareholders are mostly Luxembourg or Swiss companies, but there are also German, British, Austrian and Spanish companies as well as other nationalities.

Net of the last resort and default supplies, 73.6 G(m^3) were sold in 2019 - of which 15.6 were for self-consumption and 58 for sales - to 21.7 million customers (redelivery points).

Overall, gas sales decreased compared to 2018 in all sectors, with the exception of those destined for electricity generation. Self-consumption, which for the most part falls within the same sector, increased by 7.7%, the quantity of gas sold in the free market grew by 4.6%, while sales in the regulated market fell by 14.3%. The regulated market values shown in the table do not include the quantities supplied in the default and last resort services, as they cannot be divided into the different sectors. These were 183 M(m^3) in 2018 and 197 M(m^3) in 2019. If the default and last resort services are also considered, the gas sold in the regulated market increases to 7.1 G(m^3), while the drop compared to 2018 reduces slightly -13.8%.

Consistent with sales, the number of customers who purchased gas in the standard offer service decreased by 11.2%, (taking into account the default and last resort services, the decrease is reduced slightly to -11%); conversely, customers in the free market increased by 10.4% overall.

In 2019, the Italian economy slowed down but remained up by 0.3%; the added value of the manufacturing industry declined again (-0.5%) after six years of growth, and the more gas intensive sectors showed modest or negative results. Again in 2019 the climate was generally hot. These elements explain the 4.2% reduction observed in gas consumption in the domestic sector, which in addition to the domestic sector includes central heating, the tertiary sector and public service

[247] In fact, as seen in the paragraph dedicated to the wholesale market, this year 583 companies responded to the annual survey of the 744 that, in the Authority's Operators' Registry, declared that they were selling gas at wholesale or retail level during 2019 (even if only for a limited period of the year). Excluding the 63 companies that declared they remained inactive, of the remaining 520, there were 74 that sold gas exclusively on the wholesale market. Therefore, 446 entities operated in the retail market, 29 more than in 2018.

[248] In Sardinia the gas service isn't present.

activities. Consumption in the production sector, on the other hand, grew by 7.4%, but this result was due solely to the strong increase in thermoelectric generation, which in 2019 made extensive use of natural gas to make up for lower electricity imports. Sales of gas to the thermoelectric sector, in fact, grew by 23%, while self-consumption increased by 8.3%: taking both items into account, therefore, consumption in the sector was 15.3% higher than in 2018.

Sales of gas to the industrial sector fell by 2.2%, while self-consumption increased by 3.7%: overall, therefore, in 2019 industrial consumption fell by 1.7%. On the other hand, sales to the civil sector fell by 4.2% and self-consumption by 4.8% (but in this sector they are negligible). The rate of change of the civil sector improved if we consider the sales on the free market exclusively, which remained substantially unchanged (+0.2%) as compared to 2018. This stability was guaranteed by the domestic sector: in fact, volumes of gas sold in the free market to households were 6.4% higher than in 2018, those of central heating grew by 0.6%, while those of commerce fell by 3.1% and those of public service activities fell sharply (-20.6%).

Table 4.9 Retail market per consumption sector

Customers in thousands and volumes in M(m^3)

CONSUMPTION SECTOR	2018 STANDARD OFFER SERVICE	2018 FREE MARKET	2018 SELF-CONSUMPTION	2018 TOTAL	2019 STANDARD OFFER SERVICE	2019 FREE MARKET	2019 SELF-CONSUMPTION	2019 TOTAL
VOLUMES								
Domestic	7,542	7,737	0	15,279	6,473	8,232	0	14,706
Central heating	528	1,919	7	2,454	445	1,931	5	2,382
Commerce and services	-	7,420	24	7,445	-	7,193	24	7,217
Industry	-	19,065	1,781	20,846	-	18,648	1,847	20,494
Electricity generation	-	11,506	12,661	24,167	-	14,148	13,708	27,855
Public service sector	-	1,199	0	1,199	-	951	0	951
TOTAL VOLUMES	8,070	48,847	14,473	71,389	6,918	51,103	15,584	73,605
REDELIVERY POINTS								
Domestic	10,040	10,071	0	20,112	8,920	11,294	0	20,214
Central heating	72	127	0	200	60	131	0	191
Commerce and services	-	1,063	1	1,064	-	1,045	1	1,047
Industry	-	182	0	182	-	185	0	185
Electricity generation	-	1	0	1	-	1	0	1
Public service sector	-	59	0	59	-	45	0	45
TOTAL REDELIVERY POINTS	10,113	11,503	2	21,617	8,980	12,701	2	21,682

Source: ARERA. Annual Survey on Regulated Sectors.

In 2019, customers in the gas market as a whole increased by around 65,000 redelivery points. The increase is almost entirely attributable to households (+102,300 points), whose shift towards the free market continued in 2019, among other things, probably driven in part by the end of the standard offer service, originally scheduled for 1 July 2019 and now postponed to 1 January 2022. In 2019, in fact, another 1,133,000 clients left the standard offer service, while the free market recorded 1,198,000 more. A more detailed look, however, highlights that households' exit from the standard offer market was more than offset by the growth in the number of those served in the free market. In the case of central heating the balance is negative: while 12,000 points left the standard offer market, only 4,000 more were recorded in the free market.

Moreover, in 2019, the number of redelivery points in industry increased by about 3,000, while those in electricity generation increased by about 100 points. On the other hand, redelivery points in commerce and services fell by 17,000, as did customers in the public service sector (-14,000 points).

As a result of what has been said so far, it can be observed that in 2019 average unit consumption decreased in the domestic sector, commerce and services, industry and thermoelectricity, while it grew in central heating and public services. More precisely, the average consumption for households increased from 760 to 728 m^3, for central heating from 12,299 to 12,468 m^3, for commerce from 6,997 to 6,896 m^3, for industry from 114.3 to 110.8 thousand m^3, for electricity generation from 30.2 to 29.9 M(m^3) and, finally, for public services from 20,210 to 21,060 m^3. In the free market household average consumption (729 m^3) was practically identical to that found in the standard offer market (726 m^3), while in the case of central heating the average consumption in the free market, equal to 14,786 m^3, was almost double that found in the standard offer service, equal to 7,394 m^3.

The proportion of volumes purchased on average on the free market was 69.4%, that of the standard offer market was 9.4%, while self-consumption amounted to 21.2%. If we consider sales in its strict sense and therefore exclude self-consumption, 88% of the gas was purchased on the free market and the remaining 12% on the standard offer market. In terms of customers, 41.4% turned to the standard offer market, while 58.6% bought on the free market.

Considering only the **domestic sector**, we can observe that the share of volumes purchased on the free market in 2017 reached 56% for the families and 81.3% for central heating (both shares are calculated from the sales total in the strict sense of the word, i.e. net of self-consumption). In 2018 these values were 50.6% and 78.4%, respectively. In terms of delivery points, in 2019 the share of households that purchased gas in the standard offer service fell to 44.1%, after falling below half (49.9%) for the first time in 2018.

Table 4.10 Retail market by customer type and size in 2019

M(m^3)

SECTOR	CUSTOMERS DIVIDED BY ANNUAL CONSUMPTION CLASS (m^3)						TOTAL
	<5,000	5,000-50,000	50,000-200,000	200,000-2,000,000	2,000,000-20,000,000	>20,000,000	
STANDARD OFFER MARKET	6,411	469	39	0.1	-	-	6,918
Domestic	6,352	120	0.7	0.1	-	-	6,473
Central heating	59	348	38	-	-	-	445
FREE MARKET	9,403	5,087	2,386	5,245	9,474	19,508	51,103
Domestic	8,032	164	4	3	29	-	8,232
Central heating	81	1,377	398	74	1	-	1,931
Commerce and services	1,069	2,605	1,130	1,440	737	213	7,193
Industry	180	690	708	3,310	7,560	6,200	18,648
Electricity generation	0	2	10	159	941	13,036	14,148
Public service sector	40	250	136	260	206	59	951
TOTAL	15,813	5,556	2,424	5,246	9,474	19,508	58,021

Source: ARERA. Annual Survey on Regulated Sectors.

A breakdown of sales to the end market (net of self-consumption) by consumer sector and customer size (Table 4.10) shows that 98% of the volumes sold to the domestic sector are purchased by households with an annual consumption that does not exceed 5,000 m^3: in fact, this share is 98% for both households that purchase in the standard offer market and those that purchase in the free market. The largest share of volumes sold for central heating is concentrated in the annual consumption class between 5,000 and 50,000 m^3: this class, in fact, absorbs 78% of the volumes of gas purchased for central heating use in the standard offer market, and 71% of those purchased in the free market. 67% of all gas purchased by the commercial sector is concentrated in the first three classes. Conversely, the classes with the highest annual consumption are particularly prominent for industrial consumption and thermoelectric generation. The consumption of the public service sector is fairly evenly distributed among the intermediate classes.

Switching

Once again this year, the analysis of switching activities in the natural gas sector includes data collected from transmission and distribution operators through the annual survey on regulated sectors and data from the Integrated Information System (SII), managed by the Single Buyer. Based on data provided by transmission operators and data from the SII, the switching percentage, i.e. the number of customers[249] that changed supplier in the calendar year 2019, was 9.1% overall, or 30.7% if evaluated on the basis of the consumption of the customers who made the change (Table 4.11). These percentages are up slightly compared to 2018. The increase in domestic and central heating switching rates may have been affected by the imminent end of the standard offer regime (although it has been further delayed).

Table 4.11 Switching rates of final customers

CUSTOMERS BY SECTOR AND ANNUAL CONSUMPTION CLASS	2018		2019	
	CUSTOMERS	VOLUMES	CUSTOMERS	VOLUMES
Domestic	6.6%	7.7%	8.8%	10.9%
Central heating	9.5%	13.2%	10.1%	12.4%
Public service sector	17.1%	30.4%	15.7%	31.4%
Other uses	11.5%	33.5%	13.3%	37.0%
TOTAL	7.0%	27.1%	9.1%	30.7%

Source: ARERA. Annual Survey on Regulated Sectors.

These percentages are up or stable compared to 2017. The increase in domestic and central heating switching rates may have been affected by the imminent end of the standard offer regime (although it has been further delayed). However, it may be due in part to the change in data source[250].

The changes of supplier to domestic consumers in 2019, which were not required by law, rose by two percentage points, confirming and indeed increasing the already moderate dynamism recorded in 2018, after a certain number of years in which it had somewhat diminished. Last year, in fact, at least

[249] For reasons of editorial convenience, we generally speak of customers in the text. We must however explain that we are speaking of a number of redelivery points in the case of the transmission users and the number of metering units in the case of distribution users.

[250] Since November 2008, in fact, the switching procedures have been entirely operated by the SII and this has led to a decrease in the delays in the procedures.

1.6 million customers changed supplier, equivalent to a share of 8.8% of the total (and corresponding to a 10.9% share of volumes). The fraction of domestic use central heating that switched to another supplier was higher and equal to 10.1%, for volumes corresponding to 12.4% of the related consumption sector. The latter share is slightly lower than in 2018, while the switching rate in terms of customers is higher than in 2018, which means that central heating users with smaller annual consumption are starting to move.

15.7% (equivalent to 31.4% in terms of volumes) of the entities that manage a public service activity chose to turn to a new supplier; this is a high rate, but this is one of the "hybrid" categories that includes very different realities: not only small municipal offices (which have similar consumption values as commercial establishments) but also large hospital complexes, which have very significant consumption annual and which, consequently, can significantly increase the volumes involved in switching. Finally, the "other uses" that have changed their supplier totalled 13.3% of the total in terms of customers, as well as 37% in terms of volumes, once again showing a marked dynamism.

Table 4.12 Switching rates by region and customer type in 2018

Percentage values

REGION	DOMESTIC		CENTRAL HEATING		OTHER USES		PUBLIC SERVICE SECTOR		TOTAL	
	CUSTOMERS	VOLUMES	CUSTOMERS	VOLUMES	CUSTOMERS	VOLUMES	CUSTOMERS	VOLUMES	CUSTOMERS	VOLUMES
NORTH	8.9	10.8	9.7	12.0	13.5	34.4	16.5	35.1	9.3	28.5
CENTRE	9.6	12.0	10.5	13.2	13.3	39.2	15.7	25.9	9.9	31.2
SOUTH AND ISLANDS	7.5	9.9	13.6	18.8	12.0	42.7	13.4	24.5	7.7	37.4
ITALY	8.8	10.9	10.1	12.4	13.3	37.0	15.7	31.4	9.1	30.7

Source: ARERA. Annual Survey on Regulated Sectors.

The switching levels at territorial level, also with detail by type of customer, are shown in Table 4.12. For domestic customers, the percentage of the Centre is equal to 9.6% in terms of customers and to 12% in terms of volumes, against a national average of 8.8% (customers) and 10.9% (volumes). Unlike in previous years, switching levels among central heating users shows a higher level in the South, at least in terms of customers, while in terms of volumes it remains below the national average. In the public service sector, the rates in the North were the highest in terms of customers (16.5% against 15.7% of the national average) and volumes (35.1% against the national average of 31.4%). Finally, in the other uses, there is a fair degree of homogeneity of switching activity between the different areas in terms of customers, 13% of whom change supplier at least once a year everywhere. In terms of volumes, however, there is more movement in the Centre-South.

Available offers in the free gas market

As already mentioned in chapter 3 (paragraph 3.2), this year the Annual Survey of Regulated Sectors asked electricity and natural gas suppliers certain questions to assess the quantity, types and the methods of supply that companies offer customers who have chosen the free market. The range of commercial offers available on the free market is very complex and varied, most recently enriched by the creation of PLACET offers[251]. The data provided below on the types of offers available and actually chosen by customers, however, do not include a separate category for PLACET offers. In the gas sector, the number of customers who chose this type of offer in 2019 was 12,012 in the case of domestic customers, 69 in the case of central heating and 1,744 in the case of non-domestic customers with annual consumption of less than 200,000 m^3.

Here too it is useful to reiterate that the objective of the questions on the quantity and quality of the commercial offers is aimed at classifying the numerous offers on the market, although not completely exhaustive of reality. Therefore, please accept with caution the results presented in these pages. What's more, since the supply of non-domestic customers traditionally introduces more complex and varied necessities compared to households, this year's distribution of collected results is also practically only concentrated on the latter[252].

The average number of commercial offers that each gas supplier was able to offer their potential customers was 10.9 for domestic customers, 6.6 for central heating and 18.2 for non-domestic customers. The latter obviously has a greater possibility of choice, generally being the most important customer in terms of consumed volumes and with more differentiated requirements compared to those of a domestic customer. Compared to 2018 data, the number of offers available has slightly decreased (there were 11.7 for domestic customers, 7.3 for central heating and 26.7 for non-domestic customers); part of the reductions could be due to better categorisation of offers by sellers, as this is the fourth edition of the Survey that has asked for data on commercial offers. However, 16% of suppliers offer a single contract type, 37% offer up to 3 and the remaining 48% of the suppliers propose a range that offers 4 plus contract offers to their customers. Compared to 2018, there has been a decrease in the number of suppliers offering only one type of contract, an increase in those offering two or three, and a decrease in those offering four to ten.

Of the 10.9 offers made available to domestic customers on average, 4.9 can only be purchased online, i.e. only through the internet, a sales channel through which the company can clarify its offer conditions while saving on operating costs (there were 6.5 in 2018). However, 18.1% of the suppliers don't provide on-line offers. In 2% of the cases the number of on-line offers is equal to the total number of offers proposed to customers. Therefore, in most cases, the number of on-line offers was lower than the total offers. Households' interest in online offers grew in 2019, but remains, for the time being, a fairly niche phenomenon, as only 6.9% of clients signed a contract offered through this method (in 2018 this share was 2.6%).

Concerning the preferred type of price, it was found that 69.9% of households subscribed to a fixed price contract on the free market (i.e. with the price that doesn't change for at least one year from the time of the subscription), while only 30.1% chose a variable price contract, with the price that changes according to the timing and methods established by the contract itself. These values are essentially identical to those of 2018, when the variable price was chosen by 29.6% of domestic customers (Table 4.13). There are different types of indexing modes for variable price contracts. 47.8% (the same value as 2018) of the customers who subscribed to a variable price contract signed a contract that provides a fixed discount on one of the components established by the Authority for the standard offer regime; 11.4% (18.8% in 2018) of the customers chose a contract that provides the indexing of the Brent and 25.8% (20.4% in 2018) of the customers have chosen one indexed on the PUN. Only a small proportion of customers (2% in 2019 and 0.7% in 2018) chose to index the

[251] For a description of these offers, see the paragraph relating to the free electricity market, in Chapter 2 of this Volume.

[252] The only result shown for non-domestic customer concerns the number of available offers because the specific question in the supplier's questionnaire obtained a good response rate.

price of gas to the VTP or GME managed markets (1.2% in 2019 and 0.3% in 2018). The remaining 11.8% (11.9% in 2018) of the contracts provide alternative forms of indexing, often with a combination of those mentioned above.

Concerning the length of the contract, 3.8% of domestic customers subscribed to a contract that provides a clause of minimal contractual duration, where the customer can't change supplier for a minimum period of time established by the contract, in order to apply the established price. The percentage is somewhat higher in the case of variable price contracts. However not all the suppliers on the free market apply a contract that provides this type of clause, and those that envisage this possibility also offer customers alternative contracts that do not include this constraint. In 2019, there were a total of 21 suppliers applying contracts with a minimum duration clause, serving a total of just under two million households. The share of these suppliers' customers who purchased a contract with minimal duration clause is equal to 39.1% (43.2% with variable price and 32.8% with fixed price). All figures are slightly up on last year: in 2018 there were 19 suppliers offering a contract clause and the share of their customers who had signed it was 28.7%.

Table 4.13 Contracts for the supply of natural gas by type of price and type of additional services

Percentage of customers who signed the indicated contracts

CONTRACTS	2016	2017	2018	2019
Fixed price	68.5%	68.6%	70.4%	69.9%
Variable price	31.5%	31.4%	29.6%	30.1%
ADDITIONAL SERVICES OF FIXED PRICE CONTRACTS				
No additional services	85.3%	38.3%	45.0%	52.7%
Points collection programme (own or others)	72.0%	51.4%	46.1%	33.0%
Accessory energy services	23.0%	7.1%	6.1%	4.3%
Advantages on buying other goods or services	5.0%	1.4%	0.9%	0.4%
Gifts or gadgets	n.a.	0.2%	0.2%	0.2%
Personalised telephone services	n.a.	0.0%	0.0%	0.0%
Other	1.0%	1.6%	1.8%	9.4%
TOTAL	100.0%	100%	100%	
ADDITIONAL SERVICES OF VARIABLE PRICE CONTRACTS				
No additional services	68.4%	86.5%	82.7%	76.2%
Points collection programme (own or others)	13.3%	2.0%	1.8%	4.0%
Accessory energy services	20.9%	7.0%	6.6%	11.8%
Advantages on buying other goods or services	1.5%	0.4%	0.4%	0.2%
Gifts or gadgets	n.a.	0.3%	0.4%	0.6%
Personalised telephone services	n.a.	0.0%	0.0%	0.0%
Other not included in the above items	64.3%	3.7%	8.2%	7.1%
TOTAL	100.0%	100%	100%	100%

Source: ARERA. Annual Survey on Regulated Sectors.

33.1% of the domestic customers subscribed to a contract that provides a rebate or a discount of one or more free periods or of a fixed sum in money or volume, that can be one-off or permanent, and provided when a certain condition is met (i.e. a discount for contracts subscribed by friends of the customer, discount for direct automatic bank payments, etc.). More in detail, it turns out that the discount is applied to an average of 36.2% of customers who chose a fixed price contract and to 26% of customers who chose the variable price contract. The share of contracts purchased that provide for a rebate or discount decreased compared to 2018, when it was 39.6%.

The presence of additional services (Table 4.13) in contracts signed by households is more widespread in fixed-price contracts than in variable-price contracts: 47% of customers who have chosen a fixed-price offer sign a contract that also provides an additional service, while this percentage falls below 24% in variable-price contracts. In fixed-price contracts that provide an additional service, there is a clear preference (33%) for those contracts that provide for participation in a points programme and a certain appreciation (4%) for contracts that offer an accessory energy service. Appreciation for additional service in customers with a fixed price is decreasing over time, while - on the contrary - it is increasing slightly in customers with a variable price.

Concentration in the retail natural gas market

The analysis of the sales performance of corporate groups, instead of those achieved by individual companies, allows a more correct assessment of market shares and the level of concentration in the final sales market (Table 4.14).

Table 4.14 Top twenty groups for sales on the final market in 2019

Volumes in M(m^3)

GROUP	VOLUME	SHARE	POSITION IN 2018
Eni	11,263	19.4%	1st
Edison	7,690	13.3%	2nd
Enel	6,794	11.7%	3rd
Hera	3,070	5.3%	5th
Iren	2,753	4.7%	4th
A2A	2,216	3.8%	6th
Energeticky A Prumyslovy Holding, A.S.	2,183	3.8%	7th
Sorgenia	1,665	2.9%	8th
Axpo Group	1,515	2.6%	10th
Engie	1,169	2.0%	9th
Royal Dutch Shell Plc	1,134	2.0%	13th
Estra	1,040	1.8%	12th
E.On	971	1.7%	11th
Unogas	752	1.3%	16th
Solvay Energy Services Italia	696	1.2%	17th
Eg Holding Spa	598	1.0%	18th
Dolomiti Energia	498	0.9%	19th
Repower Ag	475	0.8%	21st
ACSM-Agam	472	0.8%	25th
Soelia	434	0.7%	27th
Others	10,634	18.3%	-
TOTAL	58,021	100.0%	-

Source: ARERA. Annual Survey on Regulated Sectors.

There was no change in the top three positions in the end market, where Eni, Edison and Enel remain strong. Compared with 2018, the shares of all three groups were substantially stable or increased slightly, with Eni Group's share rising from 19.2% to 19.4%, Edison Group's share rising from 13.2% to 13.3% and Enel's share rising from 11% to 11.7%. The distance between Eni and Edison remained substantially stable (from 6 to 6.2%), while the distance between Edison and Enel fell from 2.2% to 1.5%. A look at the various positions in the ranking highlights that in 2019 there were no particular changes in the order compared to 2018. The Hera group overtook Iren, but the opposite happened last year. The Royal Dutch Shell and E.On groups switched position compared to last year: in 2019 Royal Dutch Shell is in eleventh place and the E.On group is in thirteenth, in 2018 they were exactly the opposite. On average, groups tend to move up or down two positions at a time.

In 2019 the level of concentration in the retail market increased slightly, whether measured by the amount of energy sold by corporate groups or by the number of customers served. Table 4.15 highlights the detail of the concentration measures, also distinguished by consumption sector. In the first part of the table, the measures are calculated from the volumes sold by corporate groups in the retail market, while in the second part of the table, the measures are calculated on the basis of the customers (delivery points) served by the corporate groups themselves.

Table 4.15 Concentration measures in the retail natural gas market

Measures calculated on corporate groups

	2018			2019		
SECTOR	GROUPS >5%	C3	HHI	GROUPS >5%	C3	HHI
MEASURES CALCULATED BASED ON THE ENERGY SOLD BY THE CORPORATE GROUPS						
DOMESTIC CUSTOMERS	3	45.3%	920	3	48.7%	963
Domestic customers	3	49.5%	1,085	3	53.2%	1,137
Central heating	4	34.1%	553	4	36.6%	620
NON-DOMESTIC CUSTOMERS	3	43.9%	797	5	45.3%	856
Commerce and services	5	28.2%	478	5	30.5%	524
Industry	3	52.6%	1,224	5	58.3%	1,435
Electricity generation	6	51.9%	1,258	6	48.0%	1,183
Public service sector	6	40.2%	800	4	50.9%	1,107
TOTAL MARKET	3	43.4%	757	4	44.4%	810
MEASURES CALCULATED BASED ON THE CUSTOMERS SUPPLIED BY THE CORPORATE GROUPS						
DOMESTIC CUSTOMERS	4	51.9%	1,242	4	55.5%	1,240
Domestic customers	4	52.1%	1,251	4	55.7%	1,301
Central heating	5	37.4%	699	5	40.0%	712
NON-DOMESTIC CUSTOMERS	4	34.7%	551	4	38.3%	607
Commerce and services	4	34.2%	544	4	37.8%	602
Industry	3	46.9%	887	3	43.4%	828
Electricity generation	3	40.0%	726	3	51.3%	1,221
Public service sector	4	30.0%	477	4	29.8%	480
TOTAL MARKET	4	50.8%	1,189	4	54.5%	1,240

Source: ARERA. Annual Survey on Regulated Sectors.

Using the measures calculated on kWh sold, it can be seen that the number of groups with a total market share above 5% has increased to 4 (there were 3 in 2018). Nevertheless, in 2019 the top three groups controlled 44.4%, while in 2018 the share was 43.4%. The Herfindahl-Hirshman Index (HHI) calculated on the sales market was 810, slightly higher than the 757 of 2018. However, the index level remained well below the value of 1,000, under which concentration is normally judged to be low. When measured in terms of the customers served, concentration tends to increase in almost all sectors: the only exceptions are industrial and public service activities, as well as the non-domestic sector as a whole.

However, it should be noted that the level of concentration in the Italian natural gas market is generally quite low: with few exceptions, the C3 does not exceed 55%, but above all the values of the HHI index are below the first attention threshold equal to 1,500[253] in all sectors.

4.2.2.1 Monitoring of the retail market price level, the level of transparency, the level and effectiveness of market opening and competition

As already described in detail in Chapter 3 (see paragraph 3.2.2.1, to which reference is made) on the subject of sales prices in the retail markets of electricity and natural gas, the Authority has two observations:

- that of *Average prices applied in the electricity and natural gas market* carried out according to the Resolution of 29 March 2018, 168/2018/R/com, in which the quarterly data relative to the charges billed[254] by the suppliers to the domestic and non-domestic customers is recorded at half-yearly intervals, divided into consumption classes and market types;
- the other carried out within the context of the Annual Survey on Regulated Sectors, in which the data for the previous year is recorded and divided according to several retail categories (type of market, sector and consumption classes, type of contract).

The data of the Annual Survey is used for the statistical analysis carried out by the Authority, especially those presented in the annual reports to the national and European Authority.

The analysis of data gathered in the survey conducted by the Authority for 2019 shows that, last year, the average price of gas (weighted by the quantities sold), net of sales taxes, set by the sales companies operating on the end market, was of 39.2 c€/m^3 (Table 4.16). This price was 40.0 c€/m^3 in 2018. Overall, therefore, the average final price of gas in Italy shows a decrease of 0.8 c€/m^3, corresponding to 1.9%.

There is a clearly differentiated trend between the largest consumers (over 20 million m^3/year), which show a sharp drop (-6.8 cent€/m^3, -23.3%) and all other classes, which show increases, ranging from a minimum of one cent (+2.2%), for the intermediate class with consumption between 50 and 200 thousand m^3, to 5.2 cent€/m^3 (+8.8%) in the smallest class (consumption up to 5,000 m^3/year). This means that the price gap between smaller and larger customers, stable until 2018 at around 29 c€/m^3, rose to 41 c€/m^3 in 2019. The difference is due to the fact that the fixed costs are shared over greater amounts, in the presence of higher consumption. In particular, the effect of the distribution tariffs is

[253] An HHI value between 1,500 and 2,500 indicates a moderately concentrated market, while a value higher than 2,500 indicates a strongly concentrated one (the maximum index value is 10,000).

[254] More precisely, these are average unit costs obtained from the relation between the payments received and the quantity of energy invoiced in the reference quarter period.

much higher on smaller consumption, while, for larger customers that are directly connected to the transport network, this component is not even present. We can state that the ability to obtain more convenient supply conditions is directly proportioned to the size of the customer, in relation to the greater knowledge of the market and higher attention to contract conditions.

On the other hand, as already seen in the electricity sector, it is necessary to consider that the range of offers from suppliers to consumers has become remarkably wider, with the development of the free market, and now the customers can choose between very different packages. Some of these include accessory services (assistance, maintenance, insurance, etc.), for which the price of gas offered considers additional elements to the single cost of the gas itself. Other offers provide discounts on raw materials, while others offer advantages on the purchase of different goods or services (discounts at the supermarket, on fuel, on telephone services, etc.). Many suppliers also offer fixed price formulas, whose price update mechanisms are not influenced by the economical dynamics of the energy prices, but often depend on the date of subscription to the contracts (and in particular on the current expectations on the future development of the fuel price), and on the duration of the contracts themselves (the longer it is, the more the stipulated price must consider the risks of market changes). Other offers are related to the respect of defined consumption thresholds, after which additional price components are considered.

Table 4.17 shows the breakdown of the average prices per consumption sector. The consumption class with the highest price is the smallest, for the reasons set out above, while the one with the lowest price concerns customers with consumption from 2 to 20 million m^3 , which, as already highlighted, are those who had the lowest increase compared to the previous year. In relation to the different sectors, the total average of each sector (last column on the right) depends on the division of the volumes sold between the size classes. For what has been said above, domestic customers, characterised by the prevalence of lower unit consumption, have a higher average total price, while for the opposite reason industry and electricity generation have lower overall prices. Central heating, public service and commercial activities have an intermediate price.

Table 4.16 Average sales prices net of on the final market taxes

c€/m^3; annual consumption classes expressed in m^3

ANNUAL CONSUMPTION CLASS	2014	2015	2016	2017	2018	2019
Lower than 5,000	58.8	55.7	51.7	52.1	58.3	63.4
From 5,000 to 50,000	46.9	46.0	42.1	43.1	48.4	50.7
From 50,000 to 200,000	41.4	41.0	37.0	36.2	43.7	44.7
From 200,000 to 2,000,000	35.0	32.5	28.3	26.8	31.4	33.8
From 2,000,000 to 20,000,000	34.0	28.0	24.2	23.0	26.5	28.2
Over 20,000,000	32.2	26.5	21.8	24.3	29.2	22.4
TOTAL	42.3	38.9	33.8	34.3	40.0	39.2

Source: ARERA. Annual Survey on Regulated Sectors.

Table 4.17 Retail sales prices on the final market by consumption sector and customer size in 2019

c€/m^3; annual consumption classes expressed in m^3

SECTOR	CUSTOMERS DIVIDED BY ANNUAL CONSUMPTION CLASS						TOTAL
	<5,000	5,000-50,000	50,000-200,000	200,000-2,000,000	2,000,000-20,000,000	>20,000,000	
Domestic	63.5	52.4	45.4	32.3	-	-	63.2
Central heating	57.1	52.4	48.9	40.8	39.1	-	51.6
Public service sector	65.1	50.0	43.9	35.4	28.5	22.1	39.4
Commerce and services	62.6	49.7	44.6	38.1	35.2	30.1	46.4
Industry	63.2	50.2	42.2	31.2	26.5	22.6	27.9
Electricity generation	72.9	50.0	51.9	41.6	35.9	22.2	23.4
TOTAL	63.4	50.7	44.7	33.8	28.2	22.4	39.2

Source: ARERA. Annual Survey on Regulated Sectors.

Monitoring the level of transparency, including compliance with transparency obligations, the level and effectiveness of market opening and competition

The retail markets sale monitoring system (already described in detail in Chapter 3) allows the Authority to accomplish the regular and systematic observation of the sale conditions, including the degree of liberalisation, market competitiveness and transparency, and the level of participation of consumers and their degree of satisfaction.

Reference should be made to paragraph 3.2.2.1 in which the Report 527/2019/I/com illustrates the main outcomes of the monitoring activity describing, where possible, the evolution of the relevant phenomena in the first seven years (2012-2018).

Complaints relating 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 established by the Integrated text of the regulation of the quality of electricity and natural gas sales services (TIQV) as described in paragraph 3.2.2.1.

Also in relation to the sale of natural gas, if the supplier does not meet specific standards, the customer automatically receives compensation on the occasion of the next bill. The automatic basic compensation (25 euros) doubles if the performance of the service subject to compensation takes place beyond twice the standard time and triples if the performance of the service takes place beyond triple the time of the standard or even longer.

For 2019, due to the epidemiological emergency caused by COVID-19, the data available and illustrated below are partial and refer to 64% of customers, therefore not comparable with previous years. From the analysis based on partial data, communicated by operators up to 3 April 2020, it appears that the actual average time taken to respond to complaints and billing corrections is 24 and 15 calendar days, respectively, well below the minimum standards set by the Authority. On the other hand, with regard to double billing adjustments, compared to the standard set at 20 calendar days, the actual average adjustment time is 32 calendar days. The actual average response time to requests for information is well below the general standard (Table 4.18).

Table 4.18 Sales service standards and average actual times in the natural gas sector in 2019

Calendar days and percentage values

SERVICES	SPECIFIC STANDARDS	GENERAL STANDARDS	AVERAGE ACTUAL TIMES 2019(A)
Maximum time for reasoned response to written complaints	30	-	24
Maximum time for billing corrections	60 or 90(B)	-	15
Maximum time for double billing corrections	20	-	32
Minimum percentage of responses to written requests for information sent within the maximum period of 30 calendar days	-	30%	11%

(A) Partial data referring to 64% of gas customers.
(B) 90 calendar days in the case of quarterly frequency bills.

Source: ARERA. Data declared by operators 2019.

In 2109 sales companies serving the standard offer and free natural gas market received a total of 91,429 written complaints, 72.4% of which referred to domestic customers on the free market, 12.6% to domestic customers on the standard offer market and 3% to multi-site customers. Overall, complaints relating to the free market represent 84.3% of the total complaints from gas customers. Thereafter, 12.7% of complaints concern customers in the standard offer market, while a residual share, equal to 2.9%, refers to multi-site gas customers. 62.6% of the 60,381 requests for information from gas customers came from domestic customers on the free market, 19.6% from domestic customers on the standard offer market and 11% from customers with different uses on the free market. Overall, 74.8% of requests concerned customers in the free market. Billing corrections, which overall amount to 12,699, notably include those requested by customers in the standard offer market and, in particular, domestic customers (53.7% compared to 43.4% recorded for customers in the free market). Double billing corrections, equal to 1,703 overall, mainly affected (82.2%) domestic customers on the free market. Although it concerns a limited number of customers, double billing records, for almost all categories of customers (with the exception of central in both the standard offer market and the free market), average correction times are higher than the standard set at 20 calendar days (Table 4.19).

Table 4.19 Complaints, information requests and billing corrections

	2017	2018	2019(A)
Number of complaints	216,704	194,074	91,429
Number of requests for information	99,300	86,728	60,381
Number of billing corrections	44,217	20,587	12,699
Number of double billing corrections	2377,221	2319,389	1,703

(A) Partial data referring to 64% of gas customers.

Source: ARERA processing of data from the Help Desk for the energy consumer.

In 2019, there were 15,982 cases of non-compliance with the standards set for services related to the commercial quality of sales in the gas sector, which determined the right for customers to obtain compensation, of which 91.2% was attributable to customer complaint responses; in particular, the market segment with the highest number of non-standard responses to written complaints is the segment relating to domestic customers in the free market, which accounts for 78.2%. During the year, compensation payments totalling almost 725,000 euros were made.

In the gas sector, the first three topics complained about concerned: in 47% of cases, problems with billing and everything related to consumption and billed fees, self-reading, billing periodicity, including the closing bill, making payments and refunds; in 13.5% of cases, the terms of the contract, such as withdrawal, change of name, transfer and take-over (completion and costs of transfer and take-over); in 11.8% of cases, issues related to the market, such as how to conclude new contracts, switching timescales and the economic conditions proposed by the supplier during the offer compared to those provided for in the contract and applied.

4.2.2.2 Recommendations on final sales prices, investigations, inspections and measures to promote effective competition

Measures for the promotion of competition and recommendations on the final sale prices

The activities in terms of analysis and recommendations on the final sale prices performed by the Authority are common to the sectors of electricity and gas and are already described in paragraph 3.2.2.2.

Investigations, inspections and measures for the effective promotion of competition

With reference to the activities carried out in 2019, please refer to paragraph 3.2.2.2.

4.3 Consumer protection and dispute resolution in the gas sector

4.3.1 Compliance with article 41, paragraph 1, letter o) of EC Directive 2009/73/EC.

Guarantees for effective consumer protection

Article 41, paragraph 1, letter 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 applied.

In Italy, these measures are now fully and widely applied.

Over the course of time, a number of regulatory bodies have been consolidated, which bring together in an organic way all the provisions on some relevant thematic areas, in particular:

- the Code of Commercial Conduct[255];
- the Integrated text on confirmation of the contract for the supply of electricity and/or natural gas and voluntary restorative procedure (TIRV)[256];

[255] Latest version approved with Resolution 366/2018/R/com.

[256] Latest version approved with Resolution 28/2017/R/com.

- the Integrated text on the quality of sales services (TIQV)[257];
- the Integrated Text on Billing (TIF)[258].

The protection system: the handling of final customer complaints (basic level)

The handling of complaints is common to the electricity sector, therefore, please refer to what is indicated in paragraph 3.3.1.

Access to consumer data (art.41, paragraph 1, letter q)

The issue of guaranteeing access to customer consumption data is also common to the electricity sector, therefore reference should be made to paragraph 3.3.5.

Management of gas disputes (art.41, paragraph 11) and investigative powers for the resolution of disputes (art.41, paragraph 4, letter e)

The topic is common to the electricity sector, therefore please refer to what is indicated in paragraph 3.3.2.

4.4 Security of supply

Legislative Decree No. 93/11, in implementing the Third energy package, attributes the functions and competences referring to this paragraph of the annual Report to the EC (i.e. to monitor the balance between energy supply and demand, to forecast the future demand and the available supply, the additional capacity and the measures in order to cover peak demand or supply decrease) exclusively to the Ministry for Economic Development.

[257] Latest version approved with Resolution 413/2016/R/com.

[258] Latest version approved with Resolution 463/2016/R/com.