EU Strategy for the Adriatic and Ionian Region
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Roadmap for an electricity market and natural gas hub of the Adriatic-Ionian region

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EU Strategy for the Adriatic and Ionian Region

June 2023

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EXECUTIVE SUMMARY

Scope and objectives of the project

The project *Roadmap for an electricity market and natural gas hub of the Adriatic-Ionian region* was launched in the context of the EU Strategy for the Adriatic and Ionian Region (EUSAIR), a macro-regional approach adopted by the European Commission and endorsed by the European Council in 2014.

The participating countries are 4 EU Member States Croatia, Greece, Italy, Slovenia and 6 Non-EU countries: Albania, Bosnia and Herzegovina, Montenegro, Serbia, North Macedonia and San Marino.

Figure 1 The Adriatic-Ionian region

The objective of the project is identifying actions that may promote the convergence and integration of energy markets in the Adriatic-Ionian Region. The project aims at assessing the merit of, identify the preconditions and develop a roadmap for an integrated market for electricity and gas for the Adriatic-Ionian Region. Greater integration of markets in the Adriatic-Ionian region would be:

- beneficial in itself for the participating countries; and
- an intermediate step before full integration of Adriatic-Ionic countries in the pan-European energy markets.

The preconditions for a successful integration of energy markets include:

- an infrastructure endowment such that that energy may be moved across neighbouring regions; and
- an adequate market design and regulatory framework, supporting cross-border trading.

While we focus on the latter topic, a parallel project *EUSAIR Master Plan on Energy Networks* focuses on the expected development of energy infrastructures, as well as on energy demand and supply scenarios in the Adriatic-Ionian region. We drew from that workstream the information on the fundaments of the energy sectors in the EUSAIR area, that we recall next.

Energy supply and demand in the EUSAIR countries

In 2021, the Adriatic-Ionian region consumed 408 TWh of electricity and 679 TWh of natural gas, accounting for 14% and 17% of the total European consumption respectively.

The countries that have already implemented, in full or to a large extent, the EU legislative and regulatory framework on energy markets account for 81% of the region electricity total consumption and 94% of the region’s gas consumption. These are the EU Member States of the region: Italy, Greece, Slovenia and Croatia.

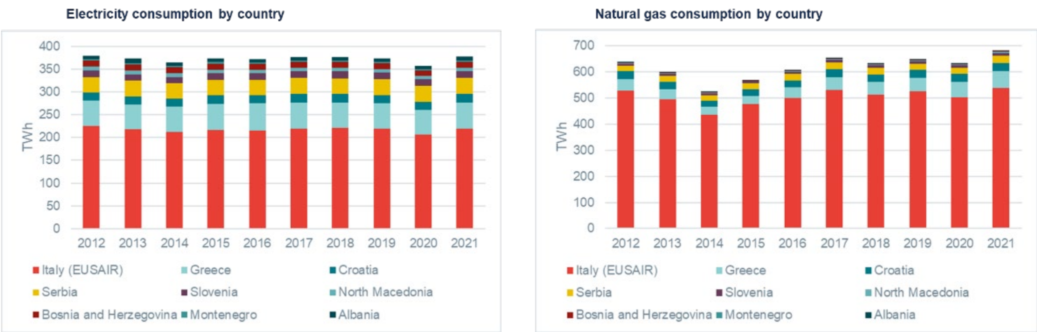
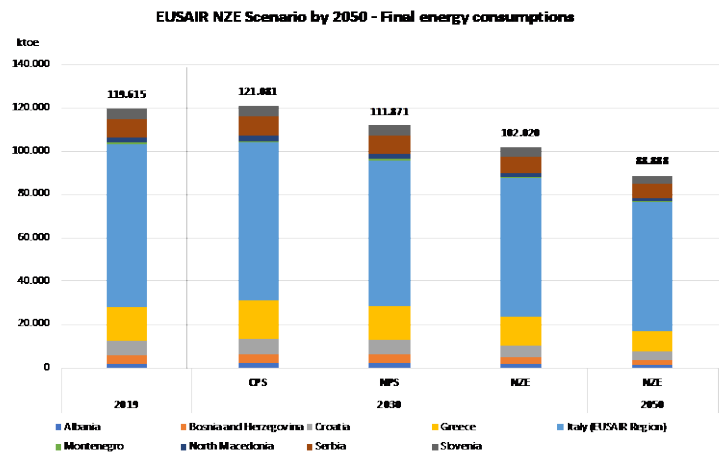


Figure 2 Electricity (left) and natural gas (right) consumption per country in the Adriatic-Ionian region in the period 2012-2021. Source: Eurostat

On the pathway to 2050, final energy consumption is expected to decrease in the region, in line with the European trends driven by energy efficiency. Electricity consumption in the Adriatic-Ionian region is expected to grow substantially, in line with the European electrification trend. Natural gas consumption is expected to remain quite steady until 2030 and then decline for all countries, down to negligible levels in 2050. In some countries, increases in the gas consumption until 2030 mainly reflects substitution of other fossil fuels (such as coal and oil) by natural gas in electricity generation[1].



1 See the parallel study *EUSAIR Master Plan on Energy Networks*

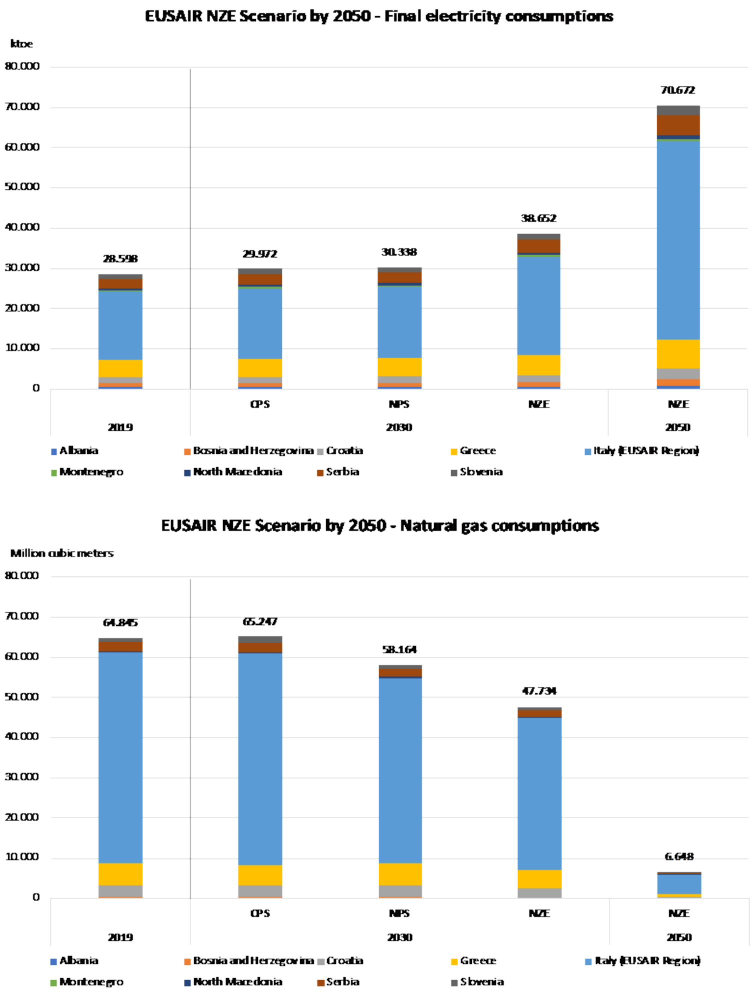
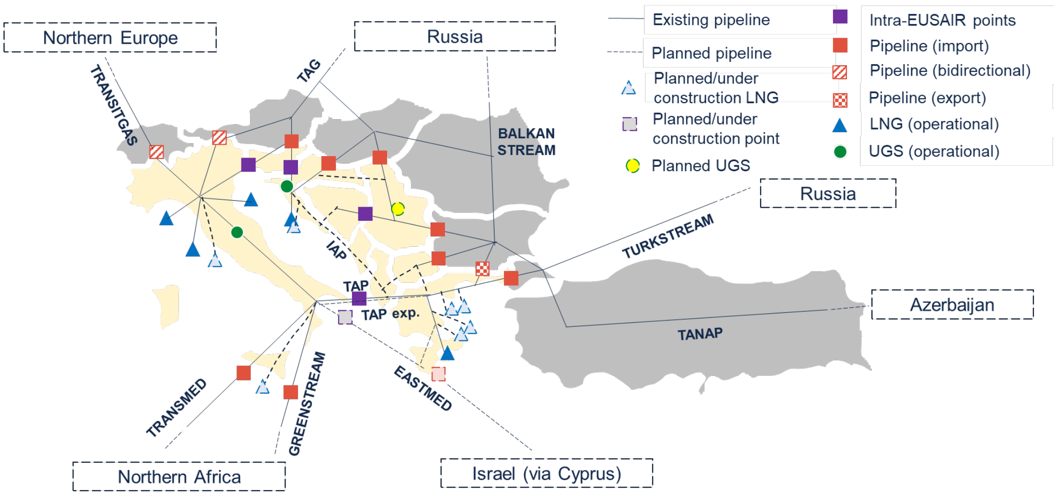


Figure 3 Final energy consumption (top), electricity consumption (middle) and natural gas consumption (bottom) consumption forecasts in the Adriatic-Ionian region. Source: NE Nomisma Energia, *EUSAIR Master Plan on Energy Networks*

Electricity and gas transmission networks

The electricity transmission networks of Adriatic-Ionian countries are highly interconnected. Interconnection capacity is further expected to increase as a result of network investments. Annex C reports the main investments planned in the electricity sector.

The degree of interconnection of the gas sector in the Adriatic-Ionian region, and particularly in the Western Balkans, is lower than for electricity. However, if all foreseen investments are implemented the degree of interconnection might materially increase, as shown in the following figure (see also Annex C).



In particular, two main network investments are being considered or developed that would materially increase the degree of interconnection in the region, as well as reverse flow capabilities. These are: the Ionian-Adriatic Pipeline (IAP) interconnecting Albania to Croatia via Montenegro, and the Greece-North Macedonia interconnector that would enable reverse flows in the south-north direction in the Balkan region. In addition, the Greece-Bulgaria interconnector recently entered in operation, enabling gas flows from Greece to Bulgaria and from there to North Macedonia and Serbia.

The European framework for the internal energy market provides for effective and efficient integration of EUSAIR energy sectors

Market integration is at the heart of the European policy framework for the internal energy market. In particular[2]:

- The Trans-European Networks for Energy (TEN-E) Regulation provides for a comprehensive framework for investment in energy infrastructures at European level, including the identification of 'electricity corridors' (the central-eastern and south-eastern Europe being one of them).
- The gas market design, based on the entry-exit model and explicit allocation of transmission capacity rights via competitive, transparent and open procedures, proved to be effective in ensuring a high degree of market integration across Europe. The gas market design is enshrined in the third energy package[3], with principles for capacity allocation mechanisms being defined in the Commission Regulation (EU) 2017/459 of 16 March 2017 establishing a network code on capacity allocation mechanisms in gas transmission systems (so-called CAM Network Code).
- The Single Day-Ahead Coupling and Single Intraday Coupling mechanisms ensure continuous and seamless integration of 25

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2 Section 2 presents the European energy policy framework in more detail

3 Issued in 2009, see the Third Energy Package webpage by the EU Commission. Note that electricity market rules were adopted as part of the Clean energy for all Europeans package in 2019

countries[4], implementing implicit allocation of transmission capacity on a short-term basis. In the long-term, explicit allocation of transmission capacity is implemented via centralized platforms (such as JAO and SEE CAO).

- Multiple initiatives are underway to integrate EU balancing and ancillary service markets. These are the Trans European Replacement Reserves Exchange (TERRE), Manually Activated Reserves Initiative (MARI), Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO), International Grid Control Cooperation (IGCC) and the Imbalance Netting Cooperation (INC) platforms.

All countries in the Adriatic-Ionian region have committed to implement European energy policy framework and most of them have made progress in that direction

For Adriatic-Ionian countries that are EU Member States, the market integration model is provided by the EU framework, so that the implementation strategy cannot deviate from that already underway and – to a large extent – already implemented.

Non-EU countries of the Adriatic-Ionian region are either already fully integrated with EU markets (San Marino) or Energy Community Contracting Parties (EnC CPs). These are Bosnia and Herzegovina, Serbia, Montenegro, Albania, North Macedonia).

In December 2022 the Energy Community adopted the Clean Energy for All Europeans package, which includes the European market model for electricity and gas. This decision sets the strategy for market integration also in Adriatic-Ionian countries that are not EU Member States. The implementation of the third energy package (for gas) and Clean energy for all Europeans package (for electricity) is underway in EnC CPs; we report below the current state of implementation of energy markets in the Adriatic-Ionian region.

Country	Electricity					
	Market operator established?	Day-ahead market?	Intraday market?	Appointed as NEMO?	Competitive balancing market?	EU Platforms for balancing?
Italy	Yes	Yes	Yes	Yes	Yes	Yes
Greece	Yes	Yes	Yes	Yes	Yes	Yes
Slovenia	Yes	Yes	Yes	Yes	Yes	Yes
Croatia	Yes	Yes	Yes	Yes	Yes	Yes
Serbia	Yes	Yes	No	No	No	No

[4] These include all EU Member States. Countries not included in the market coupling scheme are Switzerland, Great Britain, San Marino and Western Balkan countries (Serbia, Bosnia and Herzegovina, Montenegro, North Macedonia, Albania, Kosovo)

North Macedonia	Yes	No	No	No	Yes	No
Bosnia and Herzegovina	No	No	No	No	Yes	No
Montenegro	Yes	No	No	No	No	No
Albania	Yes	Yes	No	No	Yes	No

Country	Natural gas	
	VTP established?	Efficient allocation of capacity?
Italy	Yes	Yes
Greece	Yes	Yes
Slovenia	Yes	Yes
Croatia	Yes	Yes
Serbia	No	No
North Macedonia	No	No
Bosnia and Herzegovina	No	No
Montenegro	No gas market	
Albania		

The market integration objectives in the Adriatic-Ionian Region overlap with those of the Energy Community

Given that:

- EU Member States already implement the European market model, providing for full market integration;
- Energy Community Contracting Parties already adopted, in December 2022, the European market model as part of the Clean Energy for All Europeans package;
- Deviations from the European market model in any given country would jeopardize integration, since harmonisation of market principles and rules is necessary to guarantee a competitive and efficient participation in the integrated market;
- The EU framework is highly flexible, in that its implementation can be tailored to the specific features of each Country's energy sectors;

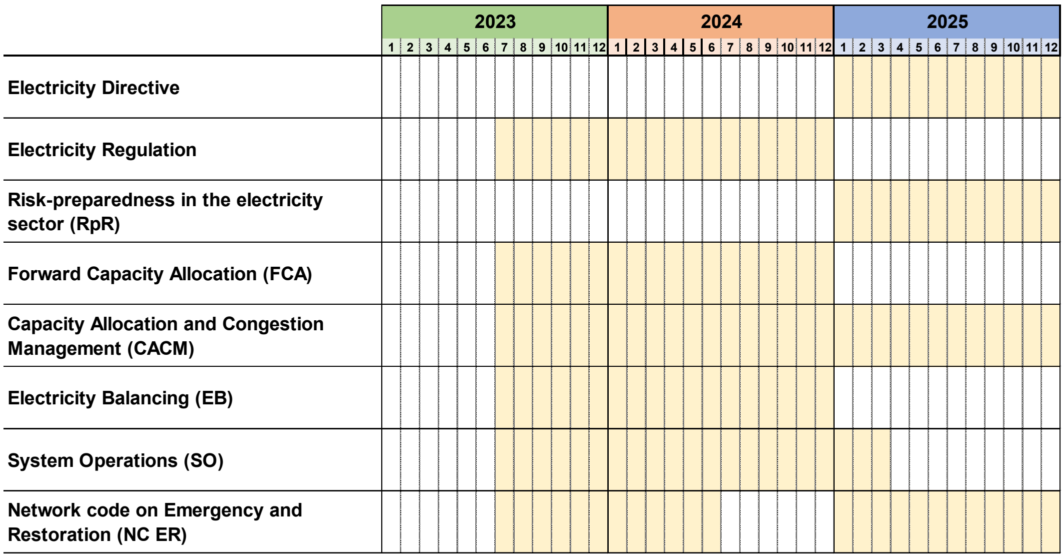
we submit that achieving integration of EUSAIR's energy sectors as a byproduct of integration in the EU market is more efficient than a two-stage approach based on: (i) a first stage, consisting in some form of regional integration of Adriatic-Ionian countries and (ii) a second stage consisting in the integration of the region in the overall EU market.

Roadmap for market integration

We develop a roadmap for the integration of the electricity and natural gas markets, based on the implementation of the European framework.

The integration of gas markets is relatively simpler than for electricity, since the entry-exit model is based on explicit allocation of transmission capacity. This requires each country to implement provisions to ensure the efficient and effective allocation of transmission capacity (in the EU framework, this provided by the CAM Network Code).

Additionally, in the gas sector the merger of national markets into larger balancing zones may be considered. This could bring the benefits of higher liquidity in the commodity markets, but would require the implementation of complex inter-TSO compensation mechanisms – something that in the European experience proved to be very challenging, and often unsuccessful[5].



[5] However, inter-TSO compensation mechanisms proved particularly challenging in the electricity sector but might result in a less complex implementation in the gas sector – see A. Pototschnig, I. Conti, *An inter-TSO compensation mechanism for renewable and low-carbon gases*, Policy Briefs, 2022/53, Florence School of Regulation

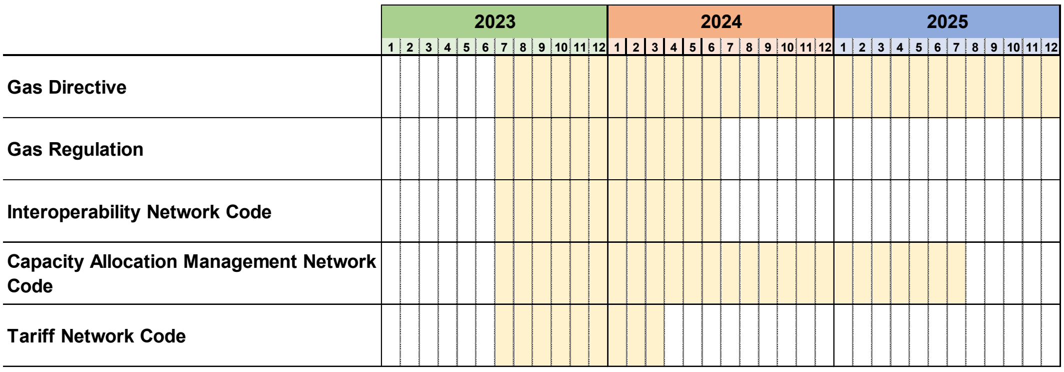


Figure 4 Market integration roadmap for electricity (top) and gas (bottom) markets in the Adriatic-Ionian region

1. OBJECTIVE AND STRUCTURE OF THE ROADMAP FOR INTEGRATION

1.1. Introduction to the Adriatic-Ionian region

The Adriatic-Ionian region is defined in the context of the EU Strategy for the Adriatic and Ionian Region (EUSAIR), one of the four EU macro-regional strategies together with the EU Strategy for the Baltic Sea Region (2009), the EU Strategy for the Danube Region (2011) and the EU Strategy for the Alpine Region (2016).

The general objective of the EUSAIR is to promote economic and social prosperity and growth in the region by improving its attractiveness, competitiveness and connectivity.

The Adriatic-Ionian region is a functional area defined by the Adriatic and Ionian Seas basin, home to more than 70 million people and including the following countries:

- EU Member States: Croatia, Greece, Italy, Slovenia
- Non-EU countries: Albania, Bosnia and Herzegovina, Montenegro, Serbia, North Macedonia and San Marino

Figure 5 The Adriatic-Ionian region. Source: EUSAIR, https://www.adriatic-ionian.eu/about-eusair/

1.2. Integration strategy and Roadmap

With four EU members and six non-EU countries, EUSAIR is expected to contribute to the further integration of the energy markets in the region, as well as with the wider European internal energy market.

The final objective of the integration effort promoted by EUSAIR is the increase competitiveness and connectivity of the energy markets in the whole region – particularly for countries that are not EU Member States and have not yet implemented the European market design for electricity and gas.

The main purpose of this report is to identify the strategy for the implementation of market integration both within the Adriatic-Ionian region and with the wider European region, for both the electricity and gas sectors. In identifying the integration strategy, we shall discuss possible alternative options together with the associated benefits, downfalls and preconditions.

After identifying the implementation strategy, we develop an "implementation Roadmap" identifying all the necessary actions for market integration, as well as the corresponding timetable.

1.3. Structure of the document

The remainder of this document is structured as follows:

- In section 2 we present the main elements of the European framework for the electricity and gas sectors, since the integration of the Adriatic-Ionian markets is part of the wider process of the evolution of the European internal energy market
- In section 3 we discuss the perspectives and RoadMap for the integration of electricity markets in the Adriatic-Ionian region
- In section 4 we discuss the perspectives and RoadMap for the integration of natural gas markets in the Adriatic-Ionian region
- In section 5 we discuss the perspectives for sector-coupling in the Adriatic-Ionian region
- In section 6 we discuss the perspective evolution of the retail energy sector
- In section 7 we discuss support schemes for electricity renewable energy sources (RES)

Finally, this report contains three Annexes:

- Annex A presents a country-level analysis of the electricity sector fundamentals in the Adriatic-Ionian region;
- Annex B presents a country-level analysis of the gas sector fundamentals in the Adriatic-Ionian region;
- Annex C presents new energy infrastructures currently planned or under development in the Adriatic-Ionian region.

2. THE EUROPEAN POLICY FRAMEWORK FOR THE INTERNAL ENERGY MARKET

2.1. European policy framework

2.1.1. Liberalisation of the energy markets: for the First Energy Package to the 'Fit For 55' package

During the 1990s, when most national electricity and natural gas markets were still monopolies, the European Union and the Member States decided to open these markets gradually to competition. The first liberalisation directives (First Energy Package) were adopted in 1996 (electricity) and 1998 (gas), to be transposed into Member States' legal systems by 1998 (electricity) and 2000 (gas).

The Second Energy Package was adopted in 2003, with its directives to be transposed into national law by Member States by 2004, and some provisions entering into force only in 2007. Industrial and domestic consumers were now free to choose their own gas and electricity suppliers from a wider range of competitors.

In April 2009, a Third Energy Package seeking to further liberalise the internal electricity and gas markets was adopted, amending the Second Energy Package and providing the cornerstone for the implementation of the internal energy market.

In June 2019, a Fourth Energy Package consisting of the Electricity Directive[6] and three regulations[7] was adopted. The Fourth Energy package introduced new electricity market rules for renewable energies and for attracting investments. This provided incentives for consumers and introduced a new eligibility limit for power plants to receive subsidies as capacity mechanisms. It required Member States to prepare contingency plans for potential electricity crises and increased the Agency for the Cooperation of Energy Regulator (ACER) competences for cross-border regulatory cooperation in cases involving risk of national and regional fragmentation.

The Fifth Energy Package, referred to as 'Fit For 55', was published on 14 July 2021 with the aim of aligning the EU's energy targets with the new European climate ambitions for 2030 and 2050[8].

The debate on the evolution of the Fit For 55 package is ongoing. After Russia's invasion of Ukraine in February 2022 the EU decided to rapidly phase out all Russian fossil fuels imports, introduce energy-saving measures, diversify its energy imports, adopt structural measures in electricity and gas markets and accelerate the introduction of renewables.

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6 Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast)

7 Electricity Regulation 2019/943/EU, Risk-Preparedness Regulation 2019/941/EU and EU Agency for the Cooperation of Energy Regulators (ACER) Regulation 2019/942/EU

8 Delivering the European Green Deal (europa.eu).

2.1.2. The current policy framework

As announced in the Energy Union strategy[9], in order to give consumers secure, sustainable, competitive and affordable energy, the Commission put forward the 'Clean Energy for all Europeans'[10] package on 30 November 2016. The fourth energy package, currently in force, implements the Energy Union, covering energy efficiency, renewable energy, the design of the electricity market, security of electricity supply and governance rules for the Energy Union. To complete the internal energy market, the Commission adopted measures in the Electricity Directive, Electricity Risk-Preparedness Regulation and the ACER Regulation.

The Regulation (EU) 2019/943 on the internal electricity market revises the rules and principles of the internal electricity market in order to ensure its proper functioning and competitiveness. It supports the decarbonisation of the EU's energy sector, removes barriers to cross-border trade in electricity and enables the EU's transition to clean energy, honouring the commitments made in the Paris Agreement. The regulation defines a set of market-based principles for the operation of electricity markets: prices will be formed on the basis of demand and supply; customers will benefit from market rules and will be active market participants; incentives for decarbonised electricity generation will be market-based; barriers to cross-border electricity flows will be progressively removed; producers will be directly or indirectly responsible for their electricity sales; new conditions under which Member States could set up capacity mechanisms and the principles for their creation will be set out.

The directive on common rules for the internal market in electricity (Directive (EU) 2019/944) focuses on the Member States and consumers, defining a set of different provisions that put the consumer at the centre of the clean energy transition. Suppliers are free to determine the price at which they supply electricity to customers. The Member States ensure market-based price competition between suppliers; protection of energy-poor and vulnerable household customers; and entitlement for final customers to electricity provided by a supplier, subject to the supplier's agreement, regardless of the Member State in which the EU-compliant supplier is registered. Consumers are able to request the installation of smart electricity meters at no additional cost; household customers and microenterprises have access, free of charge, to at least one tool comparing the offers of suppliers, including offers for dynamic electricity price contracts; to switch suppliers free of charge within a maximum of three weeks and to participate in collective switching schemes. End consumers with smart meters are able to request dynamic electricity pricing contracts with at least one large supplier; they have the right to act as active customers, for example by selling self-generated electricity, without being subject to disproportionate or discriminatory technical requirements, and to have summarised clear contractual conditions.

9 Communication COM(2015)0080 from The Commission to the European Parliament, the Council, the European Economic and Social Committee, the Committee of the Regions and the European Investment Bank: A Framework Strategy for a resilient Energy Union with a forward-looking climate change policy

10 Communication COM(2015)0080 from The Commission to the European Parliament, the Council, the European Economic and Social Committee, the Committee of the Regions and the European Investment Bank: Clean Energy for all Europeans

The Risk-Preparedness Regulation (Regulation (EU) 2019/941) strengthens risk preparedness by encouraging cooperation between transmission system operators in the EU and neighbouring countries and ACER. It also aims to facilitate the cross-border management of electricity grids in case of an electricity crisis through the new regional operating centres, which were introduced in the related regulation on the internal electricity market (Regulation (EU) 2019/943). The European Network of Transmission System Operators for Electricity (ENTSO-E) will develop and propose a common methodology for risk identification in cooperation with ACER and the Coordination Group for Electricity, which will subsequently be approved by ACER. Four sets of measures have been proposed:

- Common rules on how to prevent and prepare for electricity crises to ensure cross-border cooperation;
- Common rules for crisis management;
- Common methods to assess risks related to security of supply;
- A common framework for better evaluation and monitoring of security of electricity supply.

The debate on the energy aspects of the fifth energy package initially took place in the context of high energy prices driven by the post-pandemic recovery. In July 2021, the Commission published the first part of the 'Fit For 55' package, which aimed to achieve greenhouse gas emission reductions of at least 55% and a climate-neutral Europe by 2050. In December 2021, the fifth energy package was followed by the publication of the hydrogen and decarbonised gas market package. The debate on the fifth energy package changed radically after the Russian invasion of Ukraine and the ensuing energy crisis, which resulted in Russia unilaterally turning off the gas supply from Russia to EU Member States and extremely high gas and electricity prices in Europe.

Reacting to the escalating world energy crisis, the EU put forward several proposals for profound structural changes to its energy markets. In March 2022, the REPowerEU communication (COM/2022/108) immediately stated the EU's intention to phase out its dependency on Russian fossil fuels. In May 2022, the communication was followed by the REPowerEU plan (COM/2022/230), which put forward additional actions to save energy, diversify supplies, increase security of energy supply and replace fossil fuels by accelerating the roll-out of renewable energy. In July 2022, the Commission proposed new rules on coordinated demand reduction measures for gas and published the 'Save gas for a safe winter' communication (COM/2022/360). New Council Regulation (EU) 2022/1369on coordinated demand-reduction measures for gas entered into force on 9 August. On 14 September 2022, the Commission proposed a new regulation on an emergency intervention to address high energy prices (COM/2022/473) and reduce energy bills for European citizens and businesses. The proposal introduces measures to reduce electricity demand, a temporary revenue cap on electricity producers using technologies with lower costs, such as renewables, nuclear and lignite, and a temporary solidarity contribution on excess profits in the oil, gas, coal and refinery sectors, which will be passed on to energy consumers.

2.1.3. The role of ACER

ACER has been operational since March 2011 (see Regulation (EC) No 713/2009). ACER is mainly responsible for promoting cooperation between national regulatory authorities at regional and European level and for monitoring development of the network and the internal electricity and gas markets. It also has the competence to investigate cases of market abuse and to coordinate the application of appropriate penalties with the Member States.

In June 2019, the Commission adopted the ACER Regulation (2019/942/EU) to reform ACER to recast legal acts and strengthen its main role as a coordinator of the action of national regulators, especially in those areas where fragmented national decision-making on issues with cross-border relevance would lead to problems or inconsistencies for the internal market. ACER’s duties in the field of wholesale market supervision and cross-border infrastructure have been increased in order to give it more responsibility in elaborating and submitting the final proposal for a network code to the Commission and in influencing the regional electricity market (bidding zone) review process (laid down in the recast of the Electricity Regulation (2019/943/EU). The ACER Regulation introduces fees as an additional source of funding to cover the costs of REMIT-related activities (‘REMIT fees’) performed by ACER. On 15 July 2020, DG Energy and ACER presented a proposal for a fee structure. On 17 December 2020, the Commission adopted Decision (EU) 2020/2152 on fees, which aims to cover the expenses for the operations such as collecting, handling, processing and analysing information performed by ACER.

As a further step, two regulations were adopted, creating structures of cooperation for European Network Transmission Systems Operators (ENTSOs): one for electricity (Regulation (EC) No 714/2009) and one for gas (Regulation (EC) No 715/2009) amended by Commission Decision 2010/685/EU. The ENTSOs, together with ACER, create detailed network access rules and technical codes, and ensure the coordination of grid operation through the exchange of operational information and the development of common safety and emergency standards and procedures. ENTSOs are also responsible for drafting a 10-year network investment plan every two years, which are then in turn reviewed by ACER.

In addition, Regulation (EU) 2016/1952 improves the transparency of gas and electricity prices charged to industrial end-users by obliging Member States to ensure that these prices and the pricing systems used are communicated to Eurostat once or twice a year. In October 2011, the EU adopted Regulation (EU) No 1227/2011 on wholesale energy market integrity and transparency (REMIT) aiming to guarantee fair trading practices on European energy markets.

2.1.4. Security of supply

Regulation (EU) No 2019/941 establishes measures aimed at safeguarding the security of electricity supply, to ensure the proper functioning of the internal market for electricity, an adequate level of interconnection between Member States, an adequate level of generation capacity, and balance between supply and demand. In light of the crucial importance of gas for the EU’s energy supply and as a response to the Russian-Ukrainian gas crisis during the winter of 2008-2009, Regulation (EU) 2017/1938 concerning measures to safeguard the security of gas supply was adopted in 2010 and revised in 2017. The regulation aims to strengthen prevention and crisis response mechanisms. With the aim of ensuring a secure oil supply, Directive 2009/119/EC obliges Member States to maintain minimum oil stocks, corresponding to 90 days of average daily net imports or 61 days of average daily inland consumption, whichever of the two quantities is greater. In response to concerns regarding the delivery of Russian gas via Ukraine, the Commission released its Energy Security Strategy in May 2014 (COM(2014)0330). The strategy aims to ensure a stable and abundant supply of energy for European citizens and the economy. It lays out measures such as increasing energy efficiency, promoting energy production within the EU, and completing missing infrastructure links to redirect energy to where it is needed during a crisis.

In May 2019, the Commission adopted a targeted revision of the 2009 Natural Gas Directive (Directive (EU) 2019/692). This would make key provisions of the Gas Directive immediately applicable to cross-border gas pipelines with third countries, or more specifically, to those parts of the pipelines in EU territory. This would help to ensure that no current, planned and future gas infrastructure project between a Member State and a third country distorts the single market for energy or weakens security of supply in the EU.

In December 2021, the Commission proposed a revision (COM/2021/803, COM/2021/804 and COM/2021/805) of Gas Directive 2009/73/EC and Gas Regulation (EC) No 715/2009, which establish the regulatory framework for competitive decarbonised gas markets. The proposals include the design and development of the new EU hydrogen market and a new regulation on reducing methane emissions in the energy sector.

On 23 March 2022, following Russia's invasion of Ukraine the Commission proposed a new gas storage regulation (Regulation (EU) 2022/1032), requiring EU countries to fill their gas storage facilities to 80% of their capacity by 1 November 2022 and to 90% in the following years. It also published the communication entitled 'Security of supply and affordable energy prices: Options for immediate measures and preparing for next winter' (COM/2022/138). On 27 June 2022, the co-legislators agreed on the gas storage regulation.

2.1.5. Infrastructures

TEN-E is a policy focused on linking the energy infrastructure of the Member States. As part of the policy, nine priority corridors (four electricity corridors, four gas corridors and one oil corridor) and three priority thematic areas (smart grids deployment, electricity highways and a cross-border carbon dioxide network) have been identified.

Regulation (EU) No 347/2013 lays down guidelines for trans-European energy networks that identify projects of common interest (PCIs) and priority projects among trans-European electricity and gas networks. PCIs for energy and cross-border renewable energy projects are funded by the Connecting Europe Facility for Energy (CEF-E). This is a funding instrument with a total budget of EUR 5.84 billion for the 2021-2027 period allocated in the form of grants managed by the Climate, Infrastructure and Environment Executive Agency. Between 2014 and 2020, a total CEF-E budget of EUR 4.8 billion financed 149 energy cross-border infrastructure actions in 107 PCIs in eight priority corridors (four in the electricity sector and four in the gas sector). The Commission establishes the list of PCIs via a delegated act, which enters into force only if Parliament or Council express no objection within a period of two months from its notification.

On 5 April 2022, the revised TEN-E Regulation was adopted to better support the modernisation of Europe's cross-border energy infrastructure and achieve the objectives of the European Green Deal.

2.1.6. Decarbonisation targets and infrastructure integration

Over the last years, the European Union has committed to increasingly ambitious energy and climate targets for 2030. More specifically:

- the Clean Energy for All Europeans package, proposed by the European Commission in 2016 and adopted between 2018 and 2019, set, *inter alia*, the following targets to be achieved by 2030: (i) a 40% greenhouse gas emission reduction target with respect to 1990 levels; (ii) a 32% target for renewables in final energy consumption; and (iii) a 32.5% improvement in energy efficiency;
- as part of the European Green Deal[11], presented in December 2019, in September 2020, the European Commission proposed to raise the 2030 greenhouse gas emission reduction target, including emissions and removals, to at least 55% compared to 1990. This more ambitious target was enshrined in legislation, together with 2050 climate neutrality goal, by the 2021 EU Climate Law[12].
- to support the achievement of the more ambitious 2030 greenhouse gas emission reduction target, in July 2021 the European Commission proposed the Delivering on the European Green Deal package, which included an increase in the 2030 renewable penetration target to 40% and an additional reduction of energy consumption of 9% by 2030 compared to the reference updated baseline projections made in 2020 (corresponding to 39% and 36% energy efficiency targets for primary and final energy consumption, respectively).
- in May 2022, as part of the EU's response to the Russia-Ukraine conflict, the European Commission launched the REPowerEU Plan[13], which included a proposal to increase the renewable penetration target to 45%14, as well as an increase in the energy consumption reduction target from 9% to 13%.

[11] See: https://commission.europa.eu/strategy-and-policy/priorities-2019-2024/european-green-deal_en.

[12] Regulation (EU) 2021/1119 of the European Parliament and of the Council of 30 June 2021 establishing the framework for achieving climate neutrality and amending Regulations (EC) No 401/2009 and (EU) 2018/1999.

[13] https://commission.europa.eu/strategy-and-policy/priorities-2019-2024/european-green-deal/repowereu-affordable-secure-and-sustainable-energy-europe_en.

[14] The European Parliament is favouring the increase of the 2030 renewable penetration target to 45%, while the Council has so far only agreed to support the 40% target set as part of the measures to deliver the European Green Deal.

With the Energy System Integration Strategy of July 2020[15], the European Commission proposed an action plan to accelerate the clean energy transition. This plan is based on six pillars:

1) A more circular energy system, with ‘energy-efficiency-first’ at its core;
2) Accelerating the electrification of energy demand, building on a largely renewables-based power system;
3) Promote renewable and low-carbon fuels, including hydrogen, for hard-to-decarbonise sectors;
4) Making energy markets fit for decarbonisation and distributed resources;
5) A more integrated energy infrastructure:
6) A digitalised energy system and a supportive innovation framework.

The fifth pillar focuses specifically on infrastructure, stressing the need for an integrated approach, meaning that the planning and operation of the infrastructure of the different energy vectors should be closely coordinated[16]. The first three pillars define a hierarchy of measures to promote decarbonisation: (i) energy efficiency; (ii) electrification; and (iii) the use of decarbonised gases for the hard-to-abate sectors (and processes).

This hierarchy impacts on the demand for the different energy vectors and therefore the corresponding infrastructure needs. More specifically:

- Energy efficiency improvements should reduce the demand for energy, not necessarily to the same extent for the different vectors;
- Electrification will increase the demand for electricity, while reducing the demand for other vectors (mainly natural gas);
- The move towards renewable and low carbon fuels in the hard-to-abate sectors will increase the demand for these fuels – mostly hydrogen and biogas – at the expense of fuels of fossil origin.

The net effect of these policy trends on the demand for the different energy vectors would be:

- Most likely positive for electricity;
- Negative for natural gas[17];
- Positive for renewable and low-carbon gases, including hydrogen.

[15] Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, Powering a climate-neutral economy: An EU Strategy for Energy System Integration, Brussels, 8.7.2020, COM(2020) 299 final.

[16] It is worth noting that, despite the 2020 Energy System Integration Strategy calls for “a more integrated energy infrastructure”, the Commission’s 2021 proposal for the recast of 2009 gas Regulation (Proposal for a Regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen (recast) Brussels, 15.12.2021, COM(2021) 804 final) still envisages three separate EU-wide ten-year network development plans for electricity, gas and hydrogen, albeit based on common scenarios.

[17] At least in the longer term. In the short- to medium-term, natural gas could replace coal in hard-to-abate processes as a step towards full decarbonisation, while the availability of decarbonised vectors is developed.

However, the available infrastructure and the way and speed with which it can be expanded or repurposed, affect the way in which the above-mentioned hierarchy can be implemented.

2.1.7. Energy Community

The Energy Community Ministerial Council adopted the Clean Energy for all Europeans package together with 2030 targets to reduce primary and final energy consumption, accelerate the uptake of renewables and reduce greenhouse gas emissions to achieve climate neutrality by 2050 on 15 December 2022. The ministers also adopted a new electricity package, enabling full market integration of Energy Community Contracting Parties into the European market, based on the principle of reciprocity, that will support the large-scale integration of renewables and coal-phase out.

We recap below the main steps of the integration pathway followed by the Energy Community Ministerial Council and ministers.

On 30th November 2021, the Ministerial Council adopts the Clean Energy package, covering legislation in the area of energy efficiency, renewables, governance, electricity market design and electricity security of supply rules.

In the course of 2022, The European Commission completed a study on the *'Extension of the EU energy and climate modelling capacity to include the Energy Community and its nine Contracting Parties'*. Its findings formed the basis for negotiations with the Contracting Parties on the energy and climate targets.

On 15th December 2022, with Decision 2022/02/MC-EnC, the ministers adopted the 2030 energy and climate targets. The targets put the Contracting Parties on a path towards achieving climate neutrality of their economies by 2050 and decreasing dependence on fossil fuels in the shorter term.

On 15 December 2022, the Energy Community Ministerial Council adopted Decision 2022/03/MC-EnC on the incorporation of the European Union's electricity market acquis in the Energy Community together with Procedural Act 20221/01/MC-EnC on fostering regional energy market integration in the Energy Community. As a result, the Contracting Parties obliged themselves to bring into force the laws, regulations and administrative provisions necessary to comply with the new provisions by 31 December 2023.

The adopted electricity package enables full market integration of Energy Community Contracting Parties into the single European market for electricity, based on the principle of reciprocity. Encompassing nine acts, the package aims at making the markets fit to deliver on cost-efficient clean energy transition while ensuring secure and affordable electricity supply to the citizens.

There are four acts which are part of the Clean Energy for all Europeans package:

- Electricity Directive (EU) 2019/944 (recast);
- Electricity Regulation (EU) 2019/943;
- Risk-preparedness Regulation (EU) 2019/941 (recast);
- ACER Regulation (EU) 2019/942.

The five Network Codes and Guidelines establish detailed rules related to different market segments and system operation:

- Forward Capacity Allocation Guideline;
- Capacity Allocation and Congestion Management Guideline;
- Electricity Balancing Guideline;
- System Operation Guideline;
- Network Code on Emergency and Restoration.

3. ELECTRICITY SECTOR

This section discusses the perspectives and RoadMap for the integration of electricity markets in the Adriatic-Ionian region.

The remainder of the section is structured as follows:

- In section 3.1. we review the structure and organisation of the European electricity markets;
- In section 3.2. we discuss the preconditions for integration of electricity markets in the Adriatic-Ionian region;
- In section 3.3. we review the current state of electricity market development in Europe and in the Adriatic-Ionian region;
- In section 3.4. we review the fundamentals of the electricity sector in the Adriatic-Ionian region;
- In section 3.5. we draw the conclusions and implications for the integration of the electricity markets in the Adriatic-Ionian region, including a RoadMap for integration.

Finally, Annex A presents a detailed country-level of the electricity sector fundamentals in the Adriatic-Ionian region; while Annex C presents the main electricity infrastructures currently planned or under development in the region.

3.1. The European electricity markets

In this section we review the structure and organisation of the European electricity markets in the different time horizons.

3.1.1. Long-term markets

Given the non-storable nature of electricity, the establishment of wholesale spot electricity markets, where electricity is traded on an hourly basis, and increasingly on shorter market time units, results in the emergence of volatility in the electricity spot prices. In turn, spot price volatility creates risk for generators selling their production onto the market and large consumers and suppliers procuring electricity from the market.

Long-term, or forward, markets have been established in the electricity sector in Europe to allow market participants to hedge the risk stemming from the volatility of spot prices. The long-term market model in Europe comprises:

- Markets for derivative products on electricity ("future markets"); and
- Markets for derivative products on the transmission rights for (the value of) the capacity between market areas (long-term transmission rights, or LTTRs)

Both forward and futures contracts provide hedging on the price volatility risk for the underlying commodity – in this case, electricity or transmission capacity. The difference between forward and futures contracts relates mainly to their level of standardisation, the way in which they are traded and their execution guaranteed.

The electricity futures markets are regulated by the European financial market regulation that covers derivatives trading, not specifically related to energy. Financial market regulation sets capital, organisational and transparency requirements for participants in the markets for commodity derivatives (MiFID II[18] and MiFIR[19]), as well as requirements for counterparties that enter into derivative contracts (EMIR[20]).

The electricity transmission rights market is governed by the Forward Capacity Allocation Regulation[21], which establishes the rules for capacity calculation and defines different options for cross-zonal transmission risk hedging.

Long-term contracts for electricity are traded similarly to those for most other commodities. In Europe, long-term wholesale electricity contracts are traded in over-the-counter markets, that is, directly between the counterparties, as well as through organised power exchanges where products are standardised, and clearing is centralised. The two most important exchanges for long term electricity products with delivery in Europe are the European Energy Exchange (EEX) and Nasdaq Commodities (running the Nordpool exchange).

Allocation of LTTRs is performed via explicit allocation of transmission capacity (as in the case of natural gas, see section The European gas markets4.1.). Exchanged LTTRs are (mostly, excluding non-EU borders such as Switzerland) of financial nature, and serve as hedging tools for market participants. The efficiency in the use of capacity in the short-term is instead guaranteed by the ‘market-coupling’ mechanism implemented in the day-ahead and intraday markets, described in the next sections.

Allocation of financial LTTRs is nowadays implemented by a pan-European platform (the Joint Allocation Office, JAO) that centralises all trading operations; as of 2022, JAO runs more than 18.000 auctions per year, allocating cross-border capacity between 41 bidding zones among about 400 market participants. Also, liquid secondary markets for the exchange of LTTRs are established.

We remark that the institution of a pan-European allocation office is today mandated by European legislation[22], but started out in 2008 as an independent project in Central-Western Europe[23] to set up the Capacity Allocation Service Company (CASC). Central-Eastern European markets[24] followed shortly after by setting up the Central Allocation Office (CAO) in 2009. Following the inclusion of Switzerland, Austria, Slovenia, Italy and Greece into CASC in 2010, as of 2015 the CAO and CASC companies merged into JAO, which was then appointed as the Single Allocation Platform pursuant to EU legislation.

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[18] Directive 2014/65/EU of the European Parliament and of the Council of 15 May 2014 on markets in financial instruments and amending Directive 2002/92/EC and Directive 2011/61/EU.

[19] Regulation (EU) No 600/2014 of the European Parliament and of the Council of 15 May 2014 on markets in financial instruments and amending Regulation (EU) No 648/2012.

[20] Regulation (EU) No 648/2012 of the European Parliament and the Council of 4 July 2012 on OTC derivatives, central counterparties and trade repositories.

[21] Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation.

[22] *Ibid*., see Articles 48, 49 and 50

[23] Countries involved in CASC were Belgium, France, Germany, Luxembourg and the Netherlands

[24] Countries involved in CAO were Germany, Austria, Czech Republic, Slovenia, Hungary, Slovakia and Poland

Finally, we note that for long-term markets to be established, 'spot' price signals need to be established and robust. This is because products exchanged in the long-term markets are financial in nature, so that a spot index underlying is needed to settle these contracts. In most cases, the hourly day-ahead price index is used as underlying price – so that following the establishment of the day-ahead market, commodity derivatives and LTTRs can be defined and exchanged.

3.1.2. Day-ahead markets

Trading in the day-ahead timeframe in Europe mostly takes place in organized power exchanges. An exchange collects buy bids (or 'bids') and sell offers (or 'offers') from market participants and clears the market. Besides the core bid matching function, some exchanges also perform the activities of a clearing house; for instance, this has historically been the case in Italy, on the first markets to open a power exchange. In other cases, the clearing house is a separate entity; for instance, this is the case at the largest power exchange in Europe, the European Power Exchange (EPEX), clearing the day-ahead market for more than ten countries in Europe and whose clearing house is the European Commodity Clearing (ECC).

The clearing house acts as the contractual counterparty to market participants in all transactions and settles the market participants' positions by netting out their credits and debits. Furthermore, the clearing house is responsible for invoicing, collection of and management of the collateral mechanism. Note that the clearing house may clear also transactions executed outside of the power exchange.

Trading outside the exchange (commonly referred to as bilateral or 'over-the counter', OTC, trading), is generally allowed in all markets.

Starting in the mid-2010s, substantial effort has been made by national authorities to integrate day-ahead markets by effectively creating one single pan-European cross-zonal market. This project falls under the name of Single Day-Ahead Coupling (SDAC) and integrates (as of 2022) the entire EU block, with the notable exception of non-EU countries – including EUSAIR countries[25].

[25] Countries excluded are Great Britain, following Brexit, Switzerland, and EUSAIR countries that are not part of the European Union (but are Contracting Parties of the Energy Community)

Figure 6 Under the SDAC mechanism, the entire EU block is integrated into a single pan-European day-ahead market. Source: ENTSO-E

The SDAC builds upon the national day-ahead markets, implementing the integration between neighbouring zones via implicit allocation of transmission capacity.

The term ‘implicit allocation’ refers to the fact that when maximising the value of the transactions the rights to use transmission capacity are never allocated directly to market participants, who submit bids and offers in their respective local markets. The main advantage of this approach is that implicit allocation ensures that transmission capacity is always used efficiently by design.

The regulatory framework that defines the procedures for market coupling via the SDAC (and SIDC, see next section) mechanism are provided in the so-called Capacity Allocation and Congestion Management regulation[26] (CACM, see section 2 for more details).

The opposite model, ‘explicit allocation’ of transmission capacity, is instead the reference one used for the allocation of transmission rights in the gas sector (see section 4.1.).

The SDAC project historically developed by transposing national markets into a single EU-wide market – thus having the benefit of accommodating many, if not all, the national specificities into the pan-EU model. In particular, the Euphemia algorithm at the heart of SDAC (acronym for EU Pan-European Hybrid Electricity Market Integration Algorithm) also includes complex orders (block bids, flexible hours bids etc.). This may be beneficial in view of the integration of electricity markets in the Adriatic-Ionian region, because the SDAC mechanism could easily accommodate national specificities in the model.

The fact that SDAC formed as the result of integration of national markets is also made evident by the governance structure of the mechanism. SDAC’s governance model is in fact based on the idea that, despite the fact that all bids and offers are cleared simultaneously in all market zones, a central pan-European power exchange is not established. Rather, individual market operators (so-called

26 Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management

Nominated Electricity Market Operators, NEMOs) run a local instance of the SDAC algorithm, collecting bids and offers from all other exchanges. Results from each NEMO are then reconciled, to ensure consistency, and are then published by each national exchange.

Further, transmission system operators (TSOs) also play a crucial role in the operation of the SDAC mechanism since they are responsible for the calculation of the transmission capacities available between zones, as well as all operations regarding electricity flows across market zones.

In terms of decision-making, all NEMOs appointed by the national regulators collaborate via a joint committee (the ‘All NEMO Committee’), for instance to discuss possible evolutions of the market algorithm or extensions of the committee to new members.

3.1.3. Intraday markets

Intraday markets allow market players to update their contract positions as the expected price at the time of delivery change; intraday markets are open for trade generally up to an hour or even half-hour before real-time.

As in the case of the day-ahead timeframe, European intraday markets are nowadays coupled via the so-called SIngle IntraDay Coupling (SIDC) mechanism.

SIDC is based on a combination of continuous trading market sessions – mandated by European regulation in all zones participating in the SIDC mechanism – and sealed-bid marginal-pricing auctions termed Complementary Regional IntraDay Auctions (CRIDA)[27] – that are not compulsory but are implemented by some markets (such as Italy and Spain, for instance). Starting in 2018 and as of 2022, the entire EU block has joined the SIDC mechanism, with the notable exception of non-EU countries (which include EUSAIR countries that are Contracting Parties of the Energy Community).

[27] *Ibid.*, Article 63

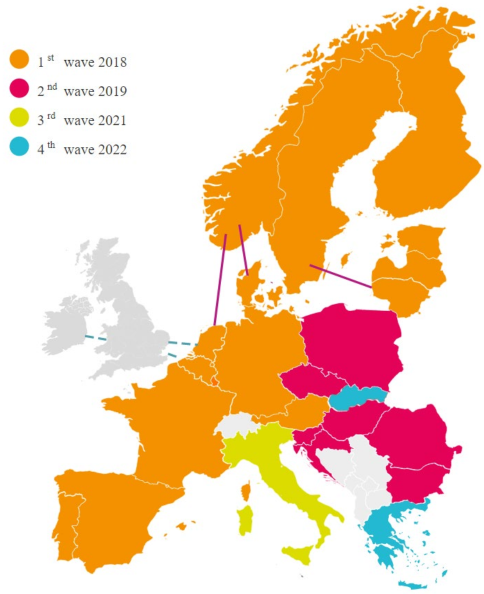


Figure 7 Markets that joined the SIDC mechanism as of 2022. Source: ENTSO-E

Note that as in the case of SDAC, the integration of all European intraday markets requires the harmonisation of market rules and gate closure times. In particular, in order to allow the execution of CRIDAs, the continuous trading sessions are halted and resumed after gate closure of the auctions. The last market session to execute transactions for hour *h* is the continuous trading one, closing one hour before delivery.

The SIDC mechanism is based on the XBID platform, managed and operated by Deutsche Börse AG. The XBID platform collects all bids and offers by national market operators in real-time, execute the transactions and (if necessary) updates the transmission capacity available after a cross-border transaction. XBID is also responsible for defining the so-called 'order book' that each participant, depending on its market zone, can access given the most up-to-date network constraints.

As in the case of the SDAC mechanism, the 'all NEMO Committee' oversees the decision-making process regarding any evolution of the SIDC design in Europe.

3.1.4. Balancing markets

Following the closure of the 'commercial' market sessions (long-term, day-ahead and intraday), system operators need procure services to ensure that the electricity system is balanced and operated securely at real-time.

Such services include:

- Ancillary services to ensure the secure and efficient operation of the power system, including e.g., voltage control, black start capability, frequency regulation.
- Balancing services to ensure that at real-time, the injections and withdrawals into the grid are balanced

In particular, balancing services are essential to the secure operation of the electricity system as the continuous equilibrium of demand and supply is required to ensure the stability of the entire grid frequency (50 Hz in Europe).

Balancing services include balancing reserves, i.e., capacity to provide balancing energy by selected generators and load-serving entities, and balancing energy, i.e., modulations in the generators and load-serving entities from their scheduled set-points.

The design of ancillary services and balancing markets display a lower level of standardisation across Europe, given the technical nature of the services provided which may require for tailored market solutions in different contexts. However, for balancing services the procurement mechanisms adopted by most system operators are similar and recently a harmonisation and integration effort has led to the development of pan-European platforms for the procurement of balancing services. The most relevant platforms are related to the so-called manual frequency restoration (mFRR) and automatic frequency restoration restoration (aFRR):

- The Manually Activated Reserves Initiative (MARI) project for the creation of a pan-European mFRR platform
- The Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO) project, aimed at developing a pan-European aFRR platform.

The development of the MARI and PICASSO platforms, having pan-European relevance, is led by the association of European TSOs (ENTSO-E).

Note that as in the case of SDAC, SIDC and JAO, the development of balancing platforms is mandated by European legislation (in this particular case, by the Electricity Balancing Guidelines[28]).

The integration of balancing markets, as in the case of SDAC and SIDC, requires the harmonisation of products and market operations, as well as cooperation across TSOs for the exchange of information (such as submitted bids and offers, as well as those accepted and the corresponding prices). The integration of balancing market is still progressing, a more detailed timeline is presented in section 3.3.1.

3.2. Preconditions for integration

Market integration allows consumers in one 'downstream' region or market to access generation assets located in another, 'upstream', region or market, at cheaper prices than they could access in their region.

In order for this to occur, two preconditions must be fulfilled:

- Flows of electricity must be physically possible between the 'upstream' market and the 'downstream' market. This requires sufficient

[28] Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing. In particular, See article 19

interconnection capacity between the two regions to transport the electricity

- Market arrangements must be such that transmission capacity is allocated efficiently, so that generation assets are dispatched ito maximise the total welfare in both the ‘upstream’ and ‘downstream’ regions while meeting all transmission constraints.

In terms of infrastructures, there is little uncertainty that new investments will be needed to meet the ambitious electrification targets at European and regional level. These electrification targets are a crucial element of Europe’s decarbonization strategy, based on the substitution of fossil fuel with electricity generated by renewable energy sources such as sun and wind.

Looking at the policy and market framework, the preconditions identified above are addressed explicitly by the regulatory framework. In particular:

- **70% rule**. TSOs are required to ensure that at least 70% of the transmission capacity is offered for cross-zonal trade, while respecting operational security limits. This requires intensive market monitoring by ACER, that implements a harmonised approach to monitor the achievement of the minimum level of available cross-zonal capacity (so-called MACZT)
- **Implicit allocation of transmission capacity**. As described in the previous section, implicit allocation of cross-zonal transmission in the short-term timeframe (day-ahead and intraday) ensures the efficient use of transmission capacity by design. Market participants can hedge against fluctuations in the price difference between neighbouring markets, resulting from congestions in the network, via Long term Transmission Rights (LTTRs)

3.3. Current state of market development

In this section we review the current state of market development in Europe and in the Adriatic-Ionian region.

3.3.1. European markets

Spot markets

As already anticipated in sections 3.1.2 and 3.1.3, the European design provides for pan-European implementations of the day-ahead (SDAC) and intraday (SIDC) markets, as well as the platforms for mFRR (MARI) and aFRR (PICASSO).

Looking at SDAC, ENTSO-E reported that as of 2022, 98.6% of EU consumption is coupled, resulting 1.530 TWh/year exchanged in what is effectively a single internal market for the entire EU block. On average, 200 M€ of transactions are matched daily. The SDAC algorithm is executed in about 17 minutes to select bids and offers, determine the optimal use of transmission capacity and calculate market prices in each market zone.

Figure 8 SDAC quarterly market clearing volume in the period Q1 2014-Q2 2021. Source: ENTSO-E

Regarding the SIDC mechanism, at the end of 2022 the roadmap for inclusion of all markets has been completed with the go-live of Greece and Slovakia. Since the launch of the SIDC, volumes exchanged through the XBID platform have been tripled from about 4 TWh/month in 2019 up to more than 12 TWh/month exchanged in January 2023.

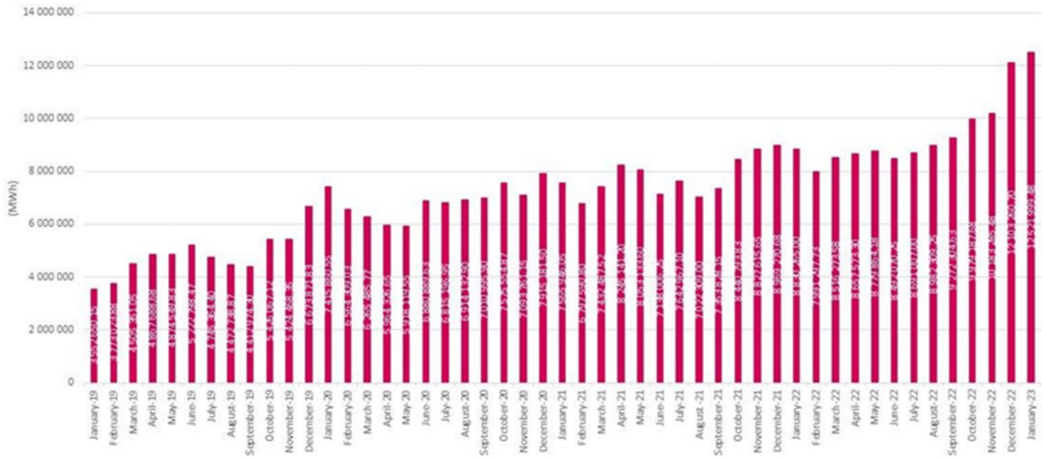


Figure 9 SIDC monthly exchanged volume in the period January 2019 – January 2023. Source: ENTSO-E

At the time of writing, all countries in the EU block have already entered the day-ahead and intraday market coupling mechanisms. Moving on to the balancing platforms, the process is still ongoing but well defined. In particular, an "accession roadmap" has been developed by ENTSO-E to target the inclusion of all markets into the platform by the end of 2024.

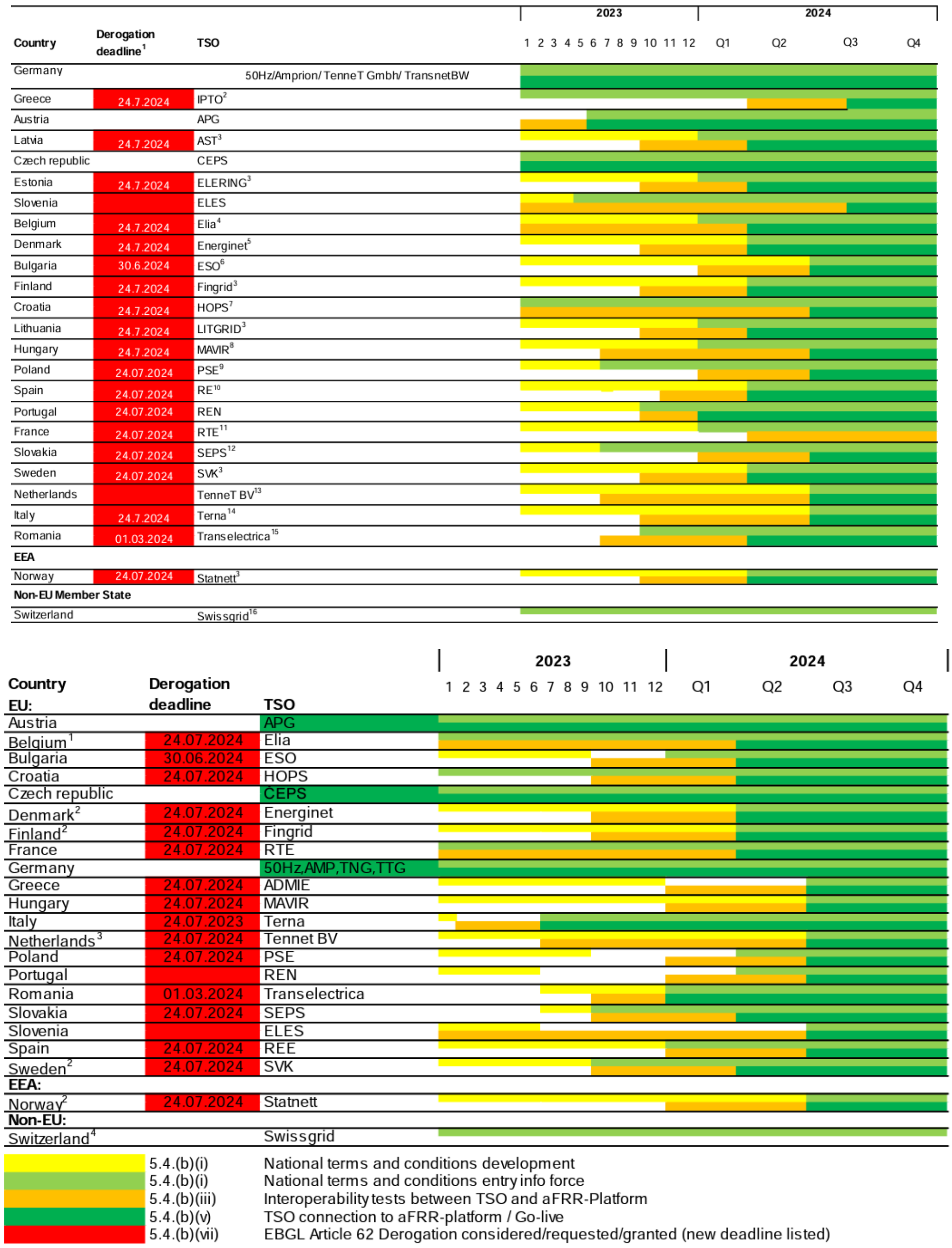


Figure 10 MARI (upper panel) and PICASSO (lower panel) accession roadmaps – April 2023

Long-term markets

Electricity long-term markets feature a high degree of harmonisation and integration at European level. In particular, the European Energy Exchange (EEX) and European Commodity Clearing (ECC) centralise trading and clearing operations for many European markets. National markets, Nasdaq and the Intercontinental Exchange (ICE) complete the picture for electricity long-term products trading in Europe, as presented in **Figure 11**.

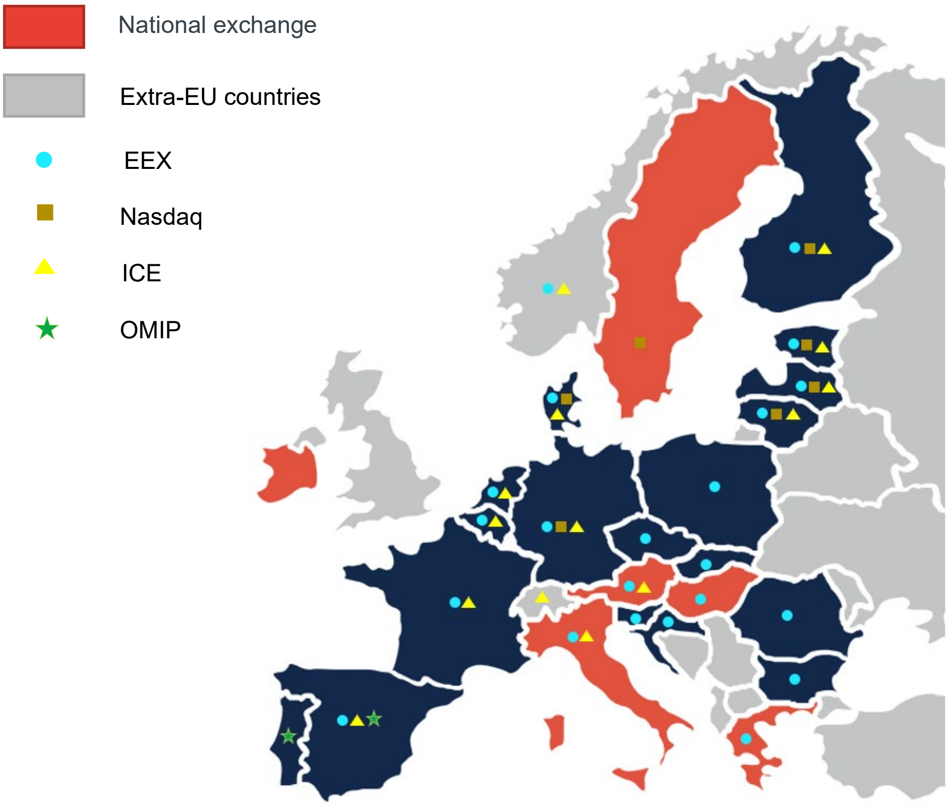
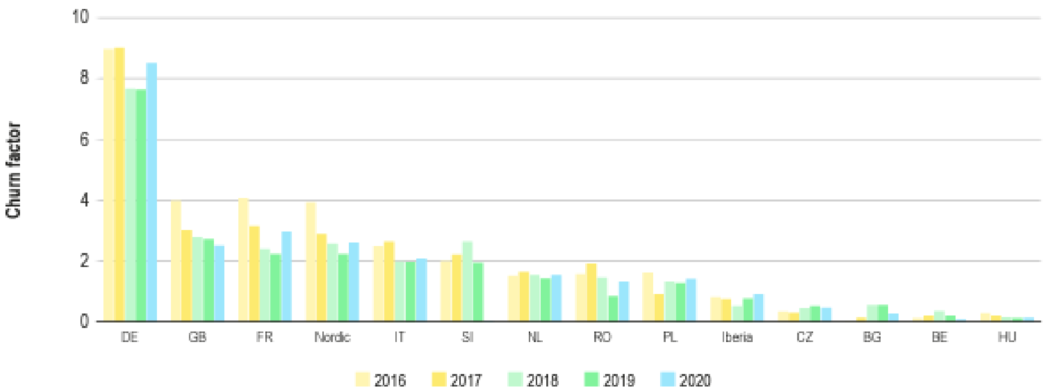


Figure 11 Venues for electricity long-term trading in Europe

At present, liquidity is concentrated in selected markets, or 'hubs', in particular the German market acts as reference market for European electricity futures by featuring the highest degree of liquidity.



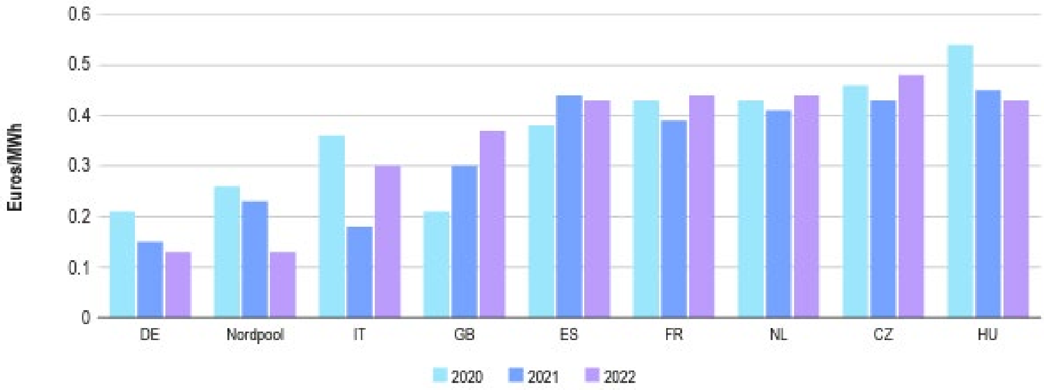


Figure 12 Churn factors (top) and bid-ask spreads (bottom) of the main European futures markets. Source: ACER and CEER, *"Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets – Electricity Wholesale Market Volume"*, October 2021

Concerning the long-term market for transmission rights, the Joint Allocation Office (JAO) operates a pan-European platform that performs explicit allocation of LTTRs on all European borders and for several delivery periods. At present, 26 financial transmission rights (FTR-options)[29] and 7 physical transmission rights (PTRs)[30] on 33 borders are allocated via auctions spanning intraday, daily, weekly, monthly, quarterly, seasonal and yearly maturities. **Figure 13** shows on which borders LTTRs are allocated by JAO.

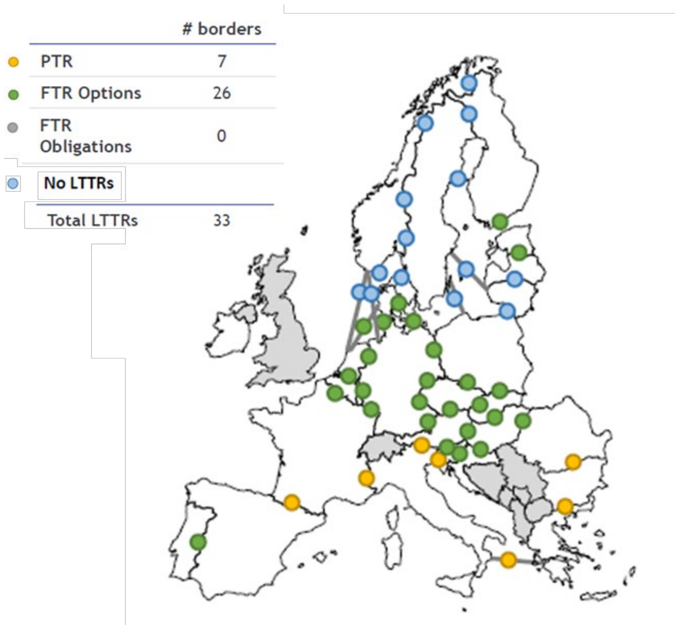


Figure 13 LTTRs products allocated in Europe in 2023. Source: ENTSO-E

[29] These are contracts that give the holder the right to receive the hourly day-ahead price difference between two neighbouring market zones.

[30] These are contracts that give the holder the right to physically use the infrastructure to transport electricity between neighbouring market zones.

3.3.2. Adriatic-Ionian markets

While sharing the common European ‘target’ model, electricity markets in the Adriatic-Ionian region feature very different degrees of development.

Countries that are part of the EU block (Italy including San Marino, Slovenia, Croatia and Greece) fully implement the European policy framework and are part of the SDAC and SIDC mechanisms. This implies that available transmission capacity is efficiently allocated at the borders with these countries with other EU member states, and market integration is fully achieved. From a governance perspective, market operators of these markets are part of the All NEMOs Committee.

For these markets, long-term markets are also established and (while lacking liquidity in smaller markets), provide participants with effective and efficient hedging opportunities. Note that as already discussed in section 3.1.1, long-term markets can be established in all those countries where a day-ahead price is defined and sufficiently robust to act as underlying price index for futures and LTTRs.

Finally, being part of the EU block, these countries are also in process of joining the balancing platforms with end-2024 as the target date.

Looking at non-EU countries (Serbia, North Macedonia, Bosnia and Herzegovina, Montenegro and Albania), the state of development is less advanced. Market operators are established in all countries but Bosnia and Herzegovina. Looking at countries where a market operator is established, the day-ahead market is operating only in Serbia and Albania (although Montenegro and North Macedonia made public statements regarding the launch of national day-ahead markets). Serbia is planning to launch the intraday market in the course of 2023[31].

The following table recaps the status of electricity market development in the Adriatic-Ionian region, identifying for each country:

- The share of electricity consumption of that country;
- Whether a national day-ahead market (DAM) is established;
- Whether national intraday market (IDM) is established;
- Whether long-term markets are established;
- Whether the country joined SDAC/SIDC (market coupling);
- Whether the country joined (or plans to join according to the accession roadmap) the MARI and PICASSO platforms.

Country	%	DAM	IDM	Long-term	SDAC & SIDC	Balancing platforms
Italy	57%	Yes	Yes	Yes	Yes	Yes
Greece	15%	Yes	Yes	Yes	Yes	Yes

[31] Source: Energy Community implementation reports 2022

Croatia	5%	Yes	Yes	Yes	Yes	Yes
Slovenia	4%	Yes	Yes	Yes	Yes	Yes
Serbia	10%	Yes	No (announced)	No	No	No
Bosnia and Herzegovina	3%	No	No	No	No	No
North Macedonia	2%	No (announced)	No	No	No	No
Albania	2%	Yes	No	No	No	No
Montenegro	1%	No (announced)	No	No	No	No

Table 1 Status of electricity market development in the Adriatic-Ionian region

3.4. Electricity sector fundamentals in the Adriatic-Ionian region

This section presents some fundamentals indicators of the electricity sector fundamentals in the Adriatic-Ionian region. More detailed country-level analyses are presented in Annex A.

With a 58% share of the entire region's consumption, Italy is the largest consumer in the Adriatic-Ionian region. Following countries in terms of consumption share are Greece (15%), Serbia (10%), Croatia (5%), Slovenia (4%), North Macedonia (2%), Albania (2%) and Montenegro (1%).

The following **Figure 14** and **Figure 15** display the electricity consumption by country in the period 2012-2021 and the average consumption shares over the entire period, respectively.

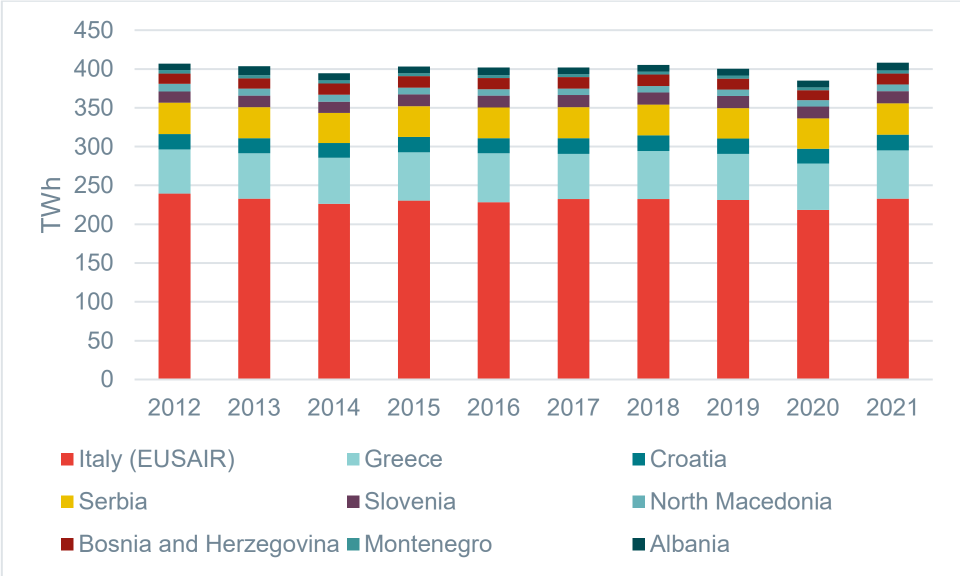


Figure 14 Electricity consumption by country in the period 2012-2021. Source: Eurostat

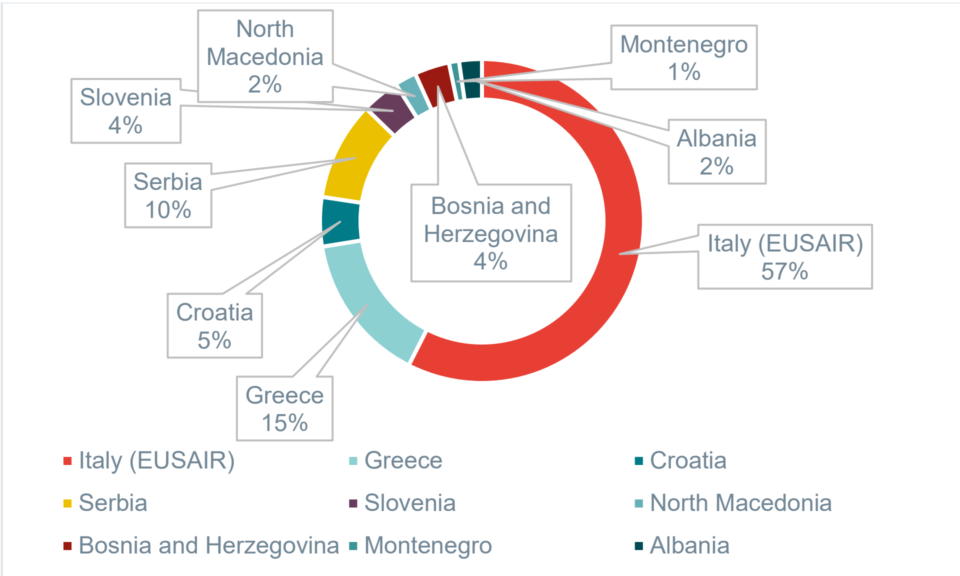


Figure 15 Share of electricity consumption by country (average 2012-2021). Source: Eurostat

These consumption shares reflect material differences in the sizes and demographics of each country: looking at the consumption of electricity per-capita, EUSAIR countries displayed a relatively uniform level of consumption (average: 5,336 kWh) – **see Figure 16**.

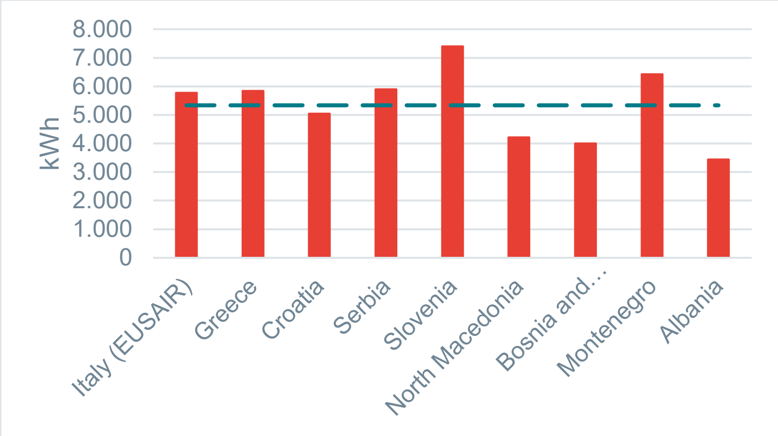


Figure 16 Electricity consumption per capita in the Adriatic-Ionian region. The dashed line indicates the average value. Source: Eurostat

While solar and wind source increasingly gained share in the past years, fossil fuels still play an important role in the generation mix. Natural gas accounts for 36% of the total electricity generation in the Adriatic-Ionian region, followed by coal (15%). Hydropower generation accounts for about 23% of the total generation. Overall, in 2022 renewable sources accounted for 42% of the total electricity generation in the Adriatic-Ionian region.

The following **Figure 17** and **Figure 18** display the electricity production by country and source in 2021 and the corresponding percentage shares, respectively. **Figure 19** provides a representation of the electricity production by source in the entire Adriatic-Ionian region, while **Figure 20** recaps the share of renewable vs. non-renewable electricity generation in the region in 2021[32].

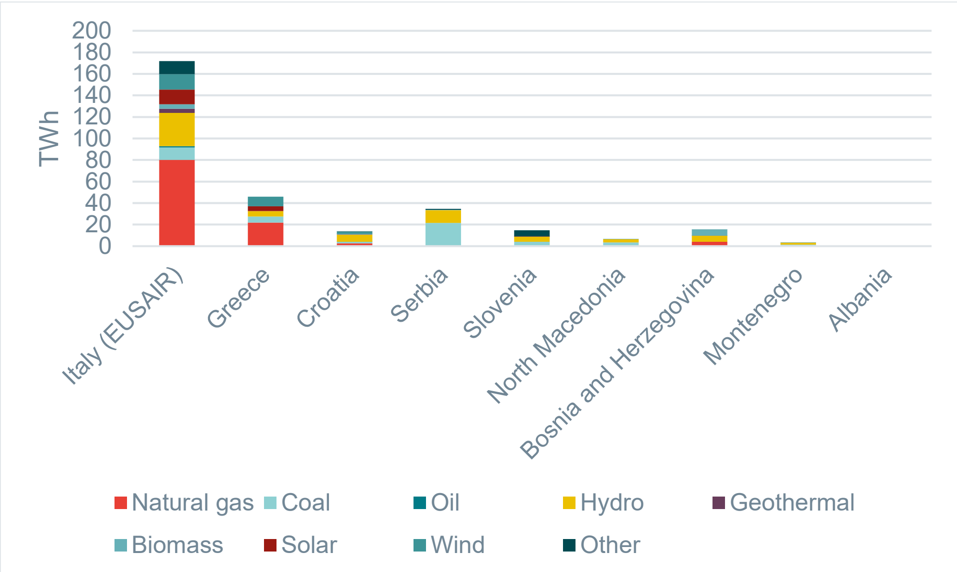


Figure 17 Electricity production by country and source in 2021. Source: ENTSO-E Transparency Platform

[32] Includes generation from hydroelectric, solar, wind, biomass and geothermal sources. Non-renewables include natural gas, coal, oil and other sources

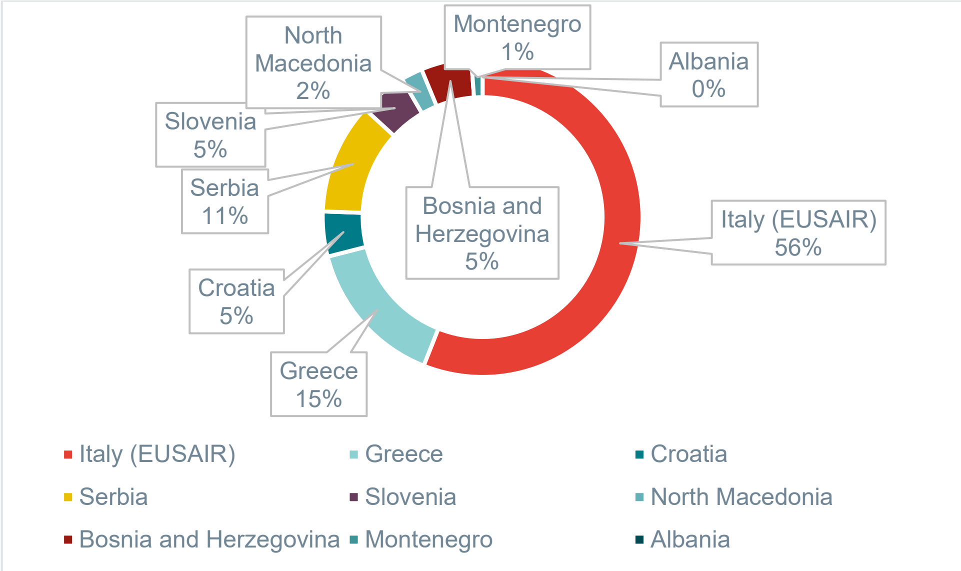


Figure 18 Electricity production by country in 2021. Source: ENTSO-E Transparency Platform

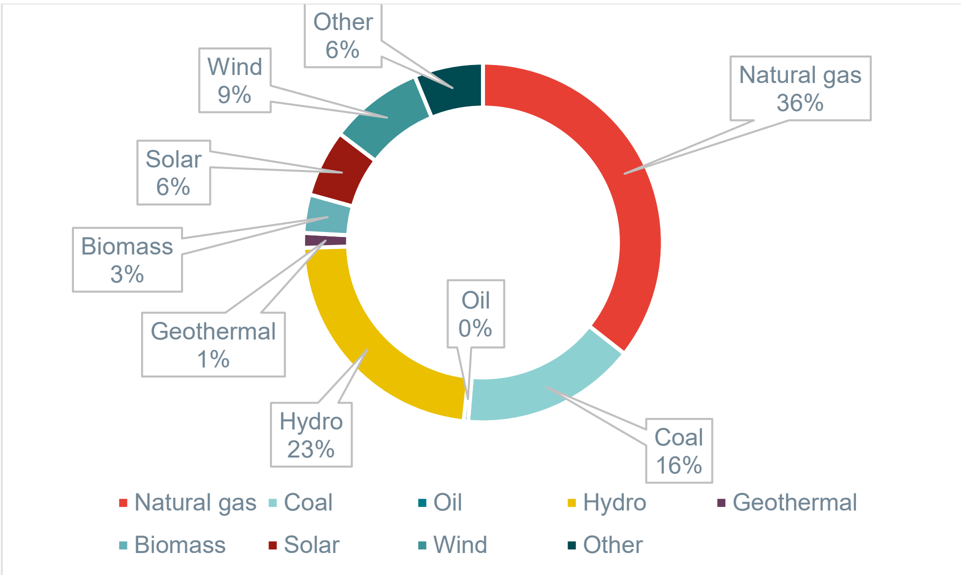


Figure 19 Electricity production by source in the Adriatic-Ionian Region (2021). Source: ENTSO-E Transparency Platform

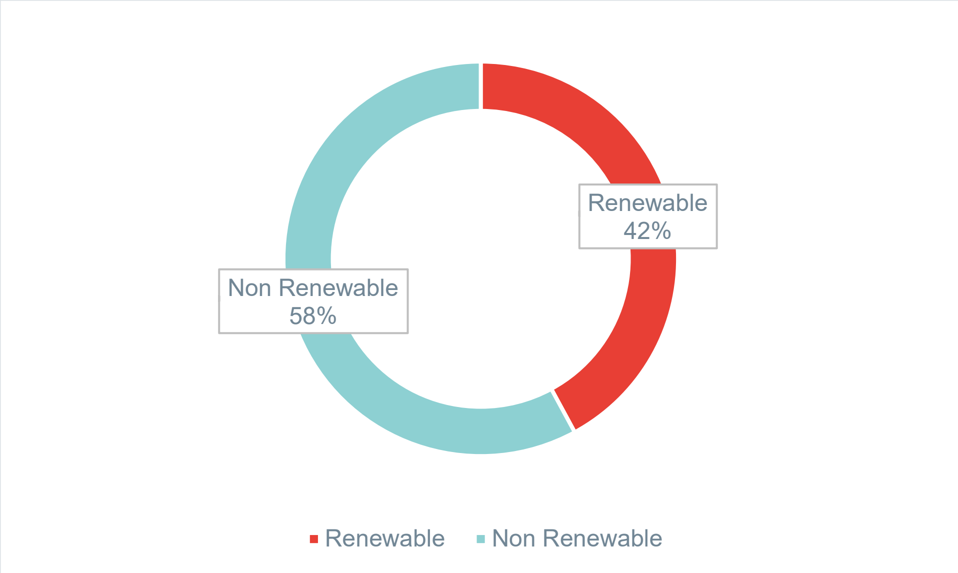
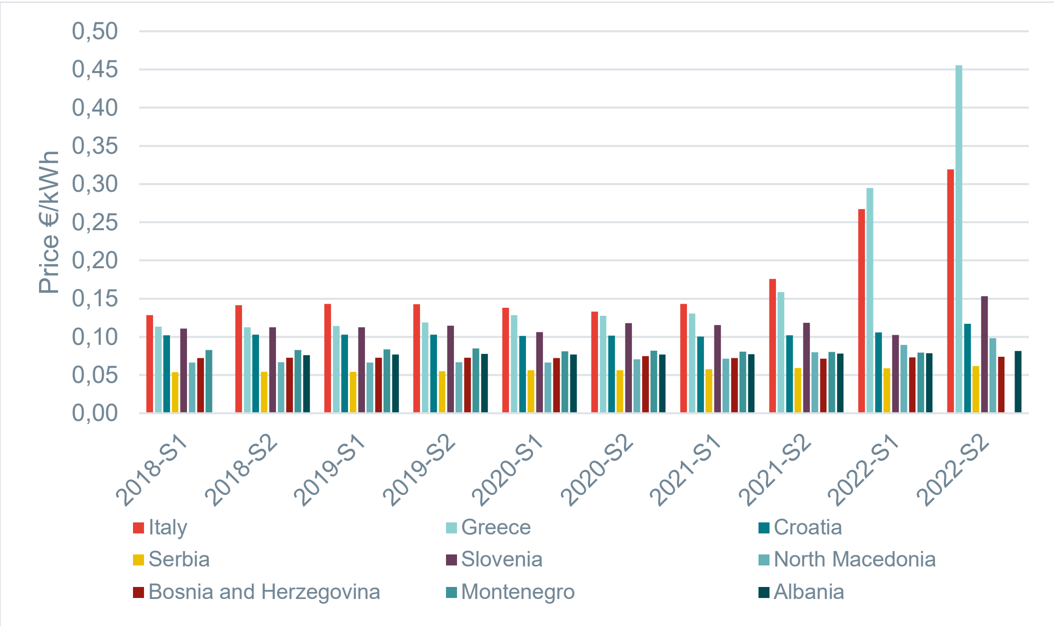


Figure 20 Share of renewable sources in the electricity mix in the Adriatic-Ionian region. Source: ENTSO-E Transparency Platform

Finally, electricity prices for final consumers have been relatively stable in the Adriatic-Ionian region, with Italy and Greece displaying the highest prices at around 15 c€/kWh (in the non-household segment) in the pre-2022 period. Prices in the non-household segment are usually higher in the 10-20 c€/kWh range.

Following the energy price crisis started in the last months of 2021, responses by each country in the region has been rather diversified. In most Western Balkan countries, policy intervention appears to have maintained prices (particularly for the household segment) relatively low – below the 15 c€/kWh level. Italy and Greece displayed materially higher prices, up to 45-50 c€/kWh in the household and non-household sector in Greece, respectively.



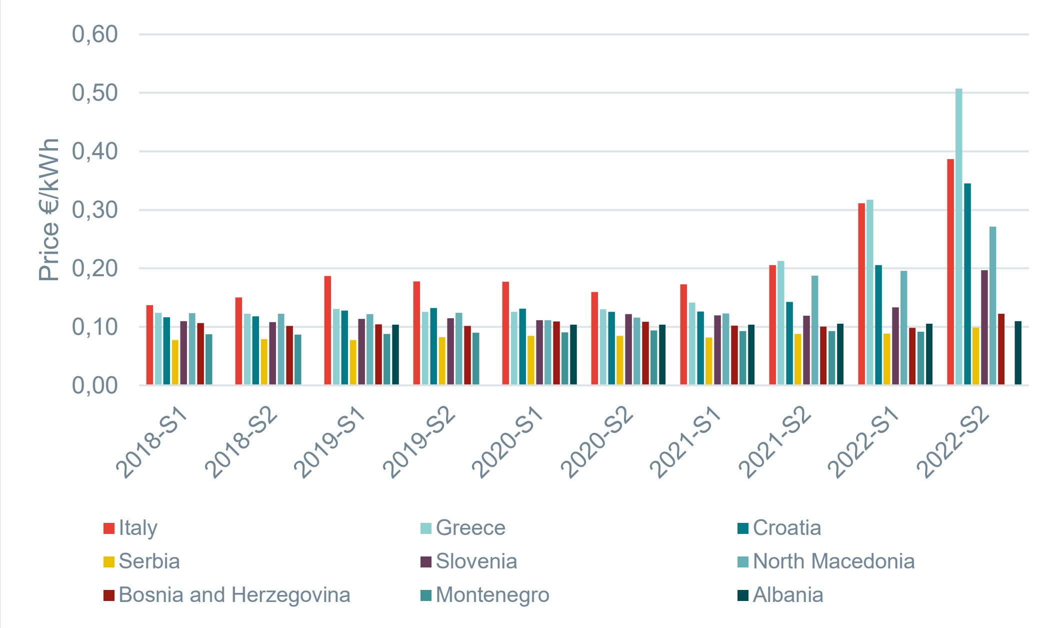


Figure 21 Electricity prices in the household (top panel) and non-household (bottom panel) segments in the Adriatic-Ionian region. Source: Eurostat

3.5. Electricity market integration

Building on the material presented above we discuss in this section the necessary steps, as well as the RoadMap for implementation, for the integration of electricity markets in the Adriatic-Ionian region.

3.5.1. Integration strategy

The most crucial result from sections 3.1. , 3.2. and 3.3. is that substantial deviations from the pathway to market integration already set at European level are not realistic. Otherwise stated, there is only one viable model for integration of the markets in the Adriatic-Ionian region, namely the implementation of the Clean Energy Package and – for Contracting Parties of the Energy Community – the transposition to national law of the EU electricity market framework, inclusive of networks codes and guidelines.

We discuss this topic in more detail below.

The integration of Adriatic-Ionian markets is a by-product of the implementation of the European target model.

Looking at **Table 1**, the first crucial step towards market integration involves the inclusion of all EUSAIR countries into the SDAC and SIDC mechanisms. This would ensure market integration within the Adriatic-Ionian region as well as with the wider European internal market. The establishment of spot markets in the Adriatic-Ionian region would also pave the way for the opening of long-term markets in the region.

The geographical coverage of the SDAC and SIDC mechanism nowadays extends to the entire Europe, excluding non-EU countries such as Switzerland, the UK and – most notably – the following EUSAIR countries:

- Serbia
- Bosnia and Herzegovina
- Montenegro
- Albania
- North Macedonia

We remark that while these countries do not fall within the perimeter of EU, they are Contracting Parties of the Energy Community. As the Energy Community adopted the Electricity Package in 2022, these countries entered binding commitments regarding the transposition of the European framework to national laws and provisions. This sets the pathway for market development in the entire Adriatic-Ionian region, from which it is not possible to deviate. Once this path has been completed, all markets in the Adriatic-Ionian region (both those that are EU Member States and Energy Community Contracting Parties) will share the same European market design.

Specifically, the implementation of the European electricity market framework requires to transpose the provisions included in the following acts:

- Electricity Directive[33],
- Electricity Regulation[34]
- Forward capacity allocation (FCA) Regulation[35]
- Capacity allocation and congestion management (CACM) Regulation[36]
- Electricity balancing (EB) Regulation[37]
- System operations (SO) Regulation[38]
- Network codes for emergency and restoration (NC ER) Regulation[39]

The RoadMap presented in the next paragraph is based on the transposition to national law of this set of documents, referred to as the 'electricity package' in the following.

From a technical perspective, implementing the electricity package above will also ensure full market integration as a by-product, because the European market design (based on implicit allocation) ensures that interconnection capacity is used efficiently.

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[33] Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity.

[34] Commission Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity.

[35] Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation.

[36] Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management.

[37] Commission Regulation (EU) 2017/2195 establishing a guideline on electricity balancing.

[38] Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation.

[39] Commission Regulation (EU) 2017/2196 establishing a network code on electricity emergency and restoration.

However, it is important to bear in mind that not only technical issues need to be addressed but, importantly, also legal and compliance ones. For instance, even if a national day-ahead market is established and operating the appointment of a national market operator as NEMO is done in the context of the CACM regulation, which is aimed at EU Member States. The importance of this fact is illustrated by the case of the UK, who successfully participated in SDAC and SIDC until Brexit. After Brexit, the market operator lost its NEMO status and, while market coupling was fully functional from a technical point of view, it was stopped at the UK border.

In the case of the Adriatic-Ionian region, this issue has been resolved in December 2022 when the Energy Community Ministerial Council adopted Decision 2022/03/MC-EnC on the incorporation of the European Union's electricity market acquis in the Energy Community, together with Procedural Act 20221/01/MC-EnC on fostering regional energy market integration in the Energy Community. The Procedural Act has a particular relevance in this context, since it institutes the role of 'Energy Sector Stakeholder' (including TSOs and NEMOs) and it establishes the principle of 'reciprocity' by which[40] (emphasis added):

> Where a Decision adopted by the Ministerial Council under both Title II and Title III of the Treaty provides that energy sector stakeholders from Contracting Parties apply terms, conditions and methodologies already adopted in accordance with procedures of European Union law, **the relevant energy sector stakeholders from the European Union**, in particular transmission system operators and nominated electricity market operators **shall treat the energy sector stakeholders from Contracting Parties in the same manner as energy sector stakeholders from the European Union**

This provision sets the legal ground for Energy Community Contracting Parties to join the SDAC and SIDC mechanism and achieve market coupling with the rest of the EU block, as well as within the Adriatic-Ionian region.

3.5.2. Implementation Roadmap

Given the discussion in the previous paragraph, we conclude that the Roadmap for integration of electricity markets in the Adriatic-Ionian region largely overlaps with the RoadMap for market development of EUSAIR countries that are Contracting Parties of the Energy Community. No actions towards further integration are needed for other EUSAIR countries that are EU Member States, apart from those that have already been defined as part of the existing European integration pathway (in particular, with respect to the development of balancing platforms).

Commitments in this direction has already been taken by Energy Community Contracting Parties[41], and a roadmap for implementation of the electricity package has been defined for the next three years – see

Figure 22, where for illustrative purposes the RoadMap has been reported separately for years 2023, 2024 and 2025. Note that as a part of this RoadMap, steps related to the integration of each Contracting Party (CP) into the Adriatic-Ionian region as well as the wider European internal market are clearly identified

[40] See the Procedural Act 20221/01/MC-EnC, article (3)

[41] For more information, see https://www.energy-community.org/implementation/package/EL.html

(see in particular the CACM section for the steps necessary to join the SDAC and SIDC mechanisms).

		2023											
		1	2	3	4	5	6	7	8	9	10	11	12
Electricity Directive													
Art. 5	CPs to report to EnCS on public intervention in market based supply prices												
Art.12	Technical process of switching supplier <24h and shall be possible on any working day												
Art. 16/33	CPs to establish rules i.a. for citizen energy communities, electromobility and energy storage												X
Art. 69	EnCS to review the implementation of this Directive and submit a report to the Ministerial Council												
Electricity Regulation													
Art. 6	TSOs to publish current system status, estimated imblanance prices and balancing energy prices latest 30min after delivery												X
Art. 8	Imbalance settlement period = 15min (or derogation)	X											
Art. 10	Measures and actions to prevent wholesale market price limitation	X											
Art. 11	Estimation of VoLL							X					
Art. 14	Bidding zone review												X
Art. 16	TSOs to make availabe 70% cross-zonal capacities (or action plan/derogation, if applicable)												X
Art. 18	ECRB to report on tariffs for transmission and distribution system										X		
Art. 19	TSOs to report on usage of congestion income; NRAs to inform ECRB and publish			X									
Art. 22	CPs to ensure that capacity mechanisms exclude generation with more than 550gCO2/kWh	X											
Art. 22	CPs to ensure that capacity mechanisms exclude generation with more than 550gCO2/kWh and 350kg Co2/y/kWe												
Art. 36	TSOs to participate in RCC(s)												
Annex IV	Establishment of RCCs												X
Annex IV	RCCs to present to NRAs their set-up (incl. plan for operations)												
Annex V	Establishment of SORs												X
Risk-preparedness in the electricity sector (RpR)													
Art. 3	Designate national governmental or regulatory authority as competent authority	X											
Art. 10	Competent authorities to adopt and publish first risk-preparedness plan												
Forward Capacity Allocation (FCA)													
Art. 4	TSOs to apply harmonised allocation rules						X						
Art. 4	TSOs to apply pan-EU TCMs (majority)												X
Art. 10	TSOs to submit methodology for calculating cross-zonal capacity (regional TCM)												
Art. 16	TSOs to submit rules on splitting of cross-zonal capacity (regional TCM)												
Art. 21	TSOs to develop operational rules for LT calculation timeframes supplementing rules for merging IGMs (regional TCM)												
Art. 31	TSOs to submit regional design of LTTRs (regional TCM)												
Art. 36	TSOS to submit nomination rules for electricity exchange schedules between bidding zones (regional TCM)												
Art. 48	TSOs to conclude bilateral agreements with TSOs of EU MSs on usage of allocation platform												X
Art. 49	TSOs to submit requirements for regional allocation platform						X						

Art. 59	TSOs to submit methodology for cost sharing for establishing, developing and operating regional allocation platform
Capacity Allocation and Congestion Management (CACM)	
Art. 4	NEMO designation
Art. 5	CPs to inform EnCS in case of monopoly for day-ahead and intraday trading services (NEMO)
Art. 7	NEMOs of EU MSs and CPs to develop MCO integration plan
Art. 9	NEMOs and TSOs to apply pan-EU TCMs for SDAC and SIDC (majority)
Art. 20	TSOs to submit methodology for calculating cross-zonal capacity for day-ahead and intraday (regional TCM)
Art. 35	TSOs to submit methodology for coordinated RD/CT (regional TCM)
Art. 35	TSOs to report on progressive coordination and harmonisation per CCR
Art. 44	TSOs to submit methodology for fallback (regional TCM)
Art. 74	TSOs to submit methodology for RD/CT cost sharing (regional TCM)
Annex I	TSOs to conclude cooperation agreements with neighbouring EU TSOs per CCR
Electricity Balancing (EB)	
Art. 5	TSOs to apply pan-EU TCMs (majority)
Art. 18	TSOs to submit national terms and conditions related to balancing
Art. 19	TSOs to adhere to TERRE (if applicable)
Art. 20	TSOs to adhere to MARI (if applicable)
Art. 21	TSOs to adhere to PICASSO (if applicable)
Art. 22	TSOs to adhere to IN (if applicable)
Art. 37	TSOs to submit methodology for calculating cross-zonal capacity (regional TCM)
System Operations (SO)	
Art. 6	TSOs to apply pan-EU TCMs
Art. 6	TSOs to apply key organisational requirements, roles and responsibilities in relation to data exchange
Art. 6	TSOs to submit regional TCMs
Art. 6	TSOs to submit national TCMs
Art. 15/16	TSOs to provide data for ENTSO-E's annual reports on operational security indicators and load-frequency control
Art. 17	RCCs to provide annual report on regional coordination assessment to ENTSO-E
Art. 24	TSOs to develop business continuity plans (which shall be reviewed annually)
Art. 26	TSOs to develop security plans (which shall be reviewed regularly)
Art. 40	TSOs to agree with DSOs on data exchange
Art. 118	TSOs to develop synchronous area operational agreements (SAFA)
Art. 155	TSOs to develop FCR prequalification process
Art. 159	TSOs to develop FRR prequalification process
Art. 162	TSOs to develop RR prequalification process
Network code on Emergency and Restoration (NC ER)	
Art. 4	TSOs to submit terms and conditions for defence and restoration service provider (national legal framework or contractual basis)

Art. 6	TSOs to notify RCCs on the measures within system defence and restoration plan												■
Art. 11/23	TSOs to submit system defence plan and system restoration plan												■
Art. 12	TSOs to implement measures of the system defence plan												
Art. 24	TSOs to implement system restoration plan												
Art. 36	TSOs to submit rules concerning suspension and restoration of market activities												■
Art. 39	TSOs to submit rules for imbalance settlement and settlement of balancing capacity/energy in case of market suspension												■
Art. 43	TSOs to define test plan in consultation with DSOs, SGUs, defence service providers and restoration service providers												

		2024											
		1	2	3	4	5	6	7	8	9	10	11	12
Electricity Directive													
Art. 5	CPs to report to EnCS on public intervention in market based supply prices												
Art.12	Technical process of switching supplier <24h and shall be possible on any working day												
Art. 16/33	CPs to establish rules i.a. for citizen energy communities, electromobility and energy storage												
Art. 69	EnCS to review the implementation of this Directive and submit a report to the Ministerial Council												
Electricity Regulation													
Art. 6	TSOs to publish current system status, estimated imblanance prices and balancing energy prices latest 30min after delivery												
Art. 8	Imbalance settlement period = 15min (or derogation)												■
Art. 10	Measures and actions to prevent wholesale market price limitation												
Art. 11	Estimation of VoLL												
Art. 14	Bidding zone review												
Art. 16	TSOs to make availabe 70% cross-zonal capacities (or action plan/derogation, if applicable)												
Art. 18	ECRB to report on tariffs for transmission and distribution system												
Art. 19	TSOs to report on usage of congestion income; NRAs to inform ECRB and publish			■									
Art. 22	CPs to ensure that capacity mechanisms exclude generation with more than 550gCO2/kWh												
Art. 22	CPs to ensure that capacity mechanisms exclude generation with more than 550gCO2/kWh and 350kg Co2/y/kWe												
Art. 36	TSOs to participate in RCC(s)						■						
Annex IV	Establishment of RCCs												
Annex IV	RCCs to present to NRAs their set-up (incl. plan for operations)						■						
Annex V	Establishment of SORs												
Risk-preparedness in the electricity sector (RpR)													
Art. 3	Designate national governmental or regulatory authority as competent authority												

Art. 10	Competent authorities to adopt and publish first risk-preparedness plan
Forward Capacity Allocation (FCA)	
Art. 4	TSOs to apply harmonised allocation rules
Art. 4	TSOs to apply pan-EU TCMs (majority)
Art. 10	TSOs to submit methodology for calculating cross-zonal capacity (regional TCM)
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Art. 31	TSOs to submit regional design of LTTRs (regional TCM)
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Art. 9	NEMOs and TSOs to apply pan-EU TCMs for SDAC and SIDC (majority)
Art. 20	TSOs to submit methodology for calculating cross-zonal capacity for day-ahead and intraday (regional TCM)
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Art. 6	TSOs to submit regional TCMs
Art. 6	TSOs to submit national TCMs

Art. 15/16	TSOs to provide data for ENTSO-E’s annual reports on operational security indicators and load-frequency control			■									
Art. 17	RCCs to provide annual report on regional coordination assessment to ENTSO-E			■									
Art. 24	TSOs to develop business continuity plans (which shall be reviewed annually)						■						
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		2025											
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Electricity Directive													
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Art.12	Technical process of switching supplier <24h and shall be possible on any working day												■
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Art. 69	EnCS to review the implementation of this Directive and submit a report to the Ministerial Council												■
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Art. 19	TSOs to adhere to TERRE (if applicable)

Art. 20	TSOs to adhere to MARI (if applicable)	
Art. 21	TSOs to adhere to PICASSO (if applicable)	
Art. 22	TSOs to adhere to IN (if applicable)	
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Art. 6	TSOs to submit national TCMs	
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Art. 162	TSOs to develop RR prequalification process	
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Art. 4	TSOs to submit terms and conditions for defence and restoration service provider (national legal framework or contractual basis)	
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Art. 24	TSOs to implement system restoration plan	
Art. 36	TSOs to submit rules concerning suspension and restoration of market activities	
Art. 39	TSOs to submit rules for imbalance settlement and settlement of balancing capacity/energy in case of market suspension	
Art. 43	TSOs to define test plan in consultation with DSOs, SGUs, defence service providers and restoration service providers	

Figure 22 Roadmap for electricity market integration in the Adriatic-Ionian region. Source: Energy Community Secretariat

4. NATURAL GAS SECTOR

This section discusses the perspectives and RoadMap for the integration of natural gas markets in the Adriatic-Ionian region.

The remainder of the section is structured as follows:

- In section 4.1. we review the structure and organisation of the European gas markets;
- In section 3.2. we discuss the preconditions for integration of gas markets in the Adriatic-Ionian region;
- In section 4.3. we review the current state of gas market development in Europe and in the Adriatic-Ionian region;
- In section 4.4. we review the fundamentals of the gas sector in the Adriatic-Ionian region;
- In section 4.5. we draw the conclusions and implications for the integration of the gas markets in the Adriatic-Ionian region, including a RoadMap for integration.

Finally, Annex B presents a detailed country-by-country analysis of the natural gas sector fundamentals in the Adriatic-Ionian region; while Annex C presents the main gas infrastructures currently planned or under development.

4.1. The European gas markets

In this section we discuss the structure and organisation of the European natural gas market, based on the entry-exit model.

4.1.1. Point-to-point transmission rights, hubs, and trading points

The European gas network sector developed in the 1960's under the point-to-point capacity allocation and tariffication model (PTP, see **Figure 23**).

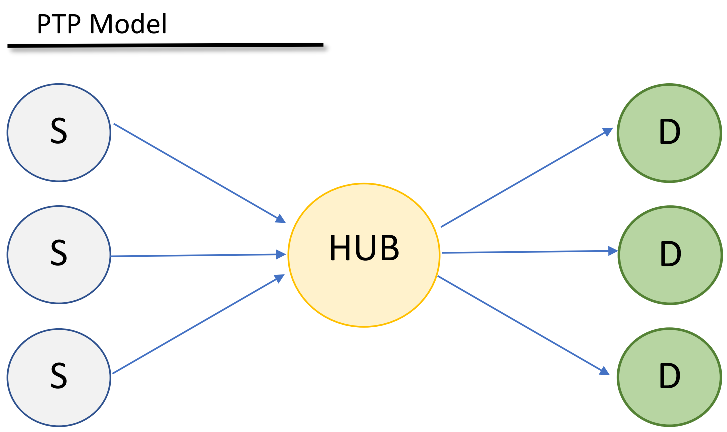

Figure 23 The point-to-point model

Under the PTP model transmission rights are defined as the rights to flow gas through a certain physical pipeline. In case the source points (**S** in the figure) and the destination points (**D** in the figure) are connected to different interconnected pipelines, the shipper has to buy a chain of transmission rights, corresponding to the physical path that the gas will follow.

In the PTP model 'hubs' are physical infrastructures that connect to multiple pipelines, and that make it possible to route gas entering the hub from one pipeline to another pipeline connected to the hub.

The largest physical hubs operating in Europe were located at Baumgarten (AT) and Zeebrugge (BE). In the Netherlands, hub-services in the context of a PTP model were provided by the transmission system operator (Gasunie) without a specialised physical infrastructure, buy by dispatching the highly inter-connected Dutch transmission network; these arrangements are referred to as 'virtual hub'.

The hub location is the obvious reference for wholesale trading because, on the one side, multiple suppliers may deliver gas to the hub through the pipelines bridged by the hub; on the other side consumers located at different locations may are directly or indirectly connected to the pipelines bridged by the hub.

Indeed, the most liquid European traded market is the one in which transactions entail delivery and collection of gas at the virtual Dutch hub, namely via the Title Transfer Facility (TTF). In 2019, volumes exchanged at TTF amounted to 40,390 TWh, or 79% of the total volumes traded in Europe, with a churn rate of 97.1[42]. Volumes traded at TTF have been constantly growing through the years, with a 43% year-on-year (YoY) growth rate between 2008 and 2019.

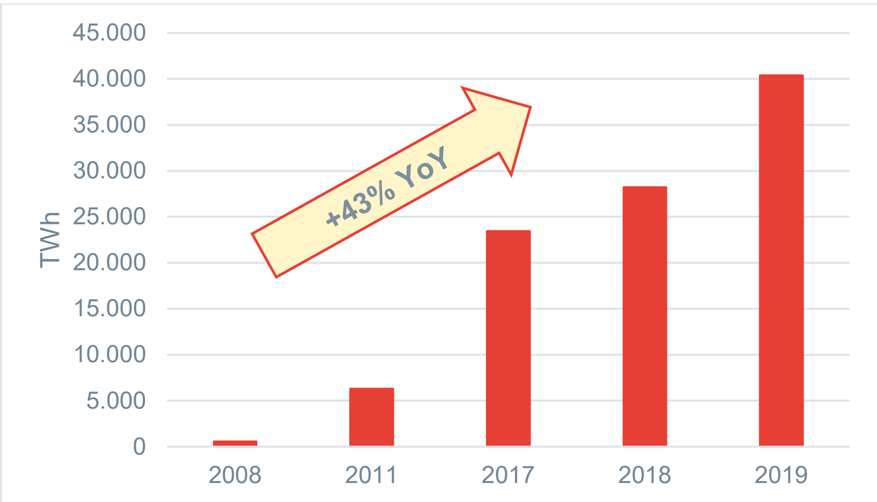

Figure 24 Volumes exchanged at TTF and year-on-year growth rate in the 2008-2019 period. Source: Oxford Institute for Energy Studies

4.1.2. The entry-exit model and trading areas

Since the early 2000s, the European gas sector started evolving from the PTP model into the currently applied transmission capacity allocation and tariffication model, commonly referred to as the entry-exit model (EE model). In the EE model, transmission rights are defined as the right to bring gas into an 'entry/exit zone',

[42] Source: Oxford Institute for Energy Studies, *European Traded Gas Hubs: the supremacy of TTF* (May 2020). The churn rate measures the number of times each MWh 'exchanges hands' in the market before entering into delivery

through a certain entry point, or to withdraw gas from a certain entry/exit zone, through a certain exit point. A market participant wishing to import gas into an entry/exit zone to serve a consumers connected to a distribution network nested in that zone's transmission network, will pay an entry charge – that depends of the interconnection point through which the gas is imported in the entry/exit zone –, and an exit charge – that depends on the interconnection point between the transmission network and the distribution network that connects the consumers.

Note that the market participant that imports gas in the entry/exit zone may sell it to another market participant at any place within the entry/exit zone, without bearing any further transportation cost. More generally, trading within a market zone is not restricted based on transmission constraints; in case one of such constraints is binding, the system operator must socialize the cost of relieving it, via the transmission charges, to all network users of that zone.

The balance of each market participant, i.e. the difference between the volume of gas injected into and withdrawn from the transmission network, is assessed with reference to the entire entry/exit zone; this means that the imbalance equals the (algebraic) sum of the market participant's injections in and withdrawals from all the entry and exit points of the entry exit zone. In other terms the entry/exit zone acts also as a 'balancing area'. Because of this feature, the entry/exit zone is an obvious trading area, commonly referred to as 'virtual trading point' (VTP).

Further, the cost for the transmission network that implements the entry/exit zone are covered by the tariffs paid by market participants for the entry or exit rights at the zone's interconnection points. For this reason, the entry/exit zone is sometimes referred to as 'tariff zone'.

Summing up, the current European market model for natural gas is based on the definition of 'entry/exit zones' that act at the same time as

- 'balancing areas', as they define the perimeter over which the balance of each user is assessed
- 'virtual trading points', as they define the perimeter over which transactions for the delivery of natural gas are concluded
- 'tariff zones', as they define the perimeter for the definition of the tariffs necessary to recover transmission costs between entry/exit areas

Entry/exit zones coincide in almost all European countries with the political borders of member States; therefore the entry/exit points coincide with the cross-border interconnections between national transmission systems[43]. In some cases, entry/exit zones have been identified with smaller geographical regions, to better capture physical congestions in the gas network. This was the case, for instance, in Germany (GASPOOL and NCG entry/exit areas – merged in 2021) and in France (PEG and TRS entry/exit zones – merged in 2018).

We conclude this section with a note on terminology used throughout this report. In the PTP model, it is immediate to identify 'hubs' (since they are associated to physical infrastructures) and 'gas shippers' as the subjects responsible for

[43] Other entry or exit points include the connection points with storage sites, production fields, and distribution networks.

transporting gas from one point to another. In the EE model, all these definitions are no longer associated to physical infrastructures, and the entry/exit area is the geographical perimeter relevant for market design purposes.

In what follows we will use terms such 'entry/exit zone', 'balancing zone', 'tariff zone' and 'trading area' interchangeably, assuming that they apply to the same geographical area. Similarly, we shall use the term 'market participant' it its most ample meaning, including 'shippers', 'balancing responsible party' and 'gas supplier'. We will turn to the more accurate terminology when addressing the possibility that the boundaries of the different institutes do not overlap.

4.1.3. Trading between entry/exit zones and congestions

Trading of natural gas between entry/exit zones can and does take place extensively in Europe. As shown in the next figure, under the EE model the supplier to zone B of gas sourced in zona A, via the interconnection point A→B, is required to hold exit rights from zone A and entry rights in zone B. The cost to transport gas from A is equal to a transmission tariff $T_{A \to B}$ (set at regulatory level, covering exit fees from A and entry fees into B), plus a 'surcharge' $S_{A \to B}$ in case of congestions (see discussion below).

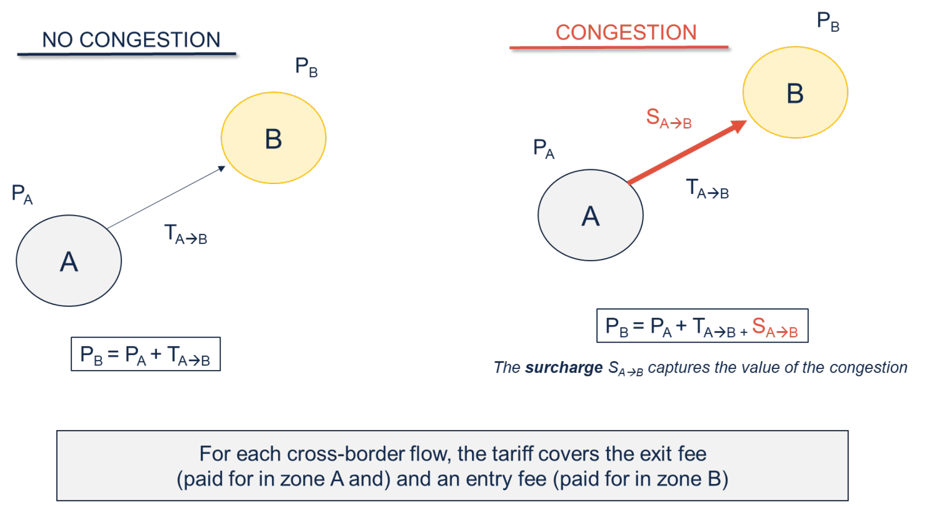

Figure 25 The entry-exit model. In the event of congestions (right panel), a 'surcharge' arises

The market clearing prices in the two areas converge, but for the cost of the entry/exit charges, if the entry and exit capacity are available. When that happens the two trading areas will operate to a large extent as if they were one, and the efficient market outcomes results in a price for gas in zone B equal to the price in zone A, plus the transmission charges (T):

$$P_B = P_A + T_A^{exit} + T_B^{entry} = \mathrm{P_A} + T_{A \to B}$$

In case of insufficient transmission capacity to meet demand in zone B using gas sourced in zone A, a so-called 'congestion' arises. In the case of congestion, the price of gas in zone B shall increase since more expensive sources of gas must be used to supply the zone, as gas cannot effectively be sourced in zone A. This implies that a higher value is associated to the transmission capacity, something that in the jargon is termed a 'surcharge' (S):

$$P_B = P_A + T_A^{exit} + T_B^{entry} + S_{A\to B} = P_A + T_{A\to B} + S_{A\to B}$$

We note that the price formation mechanism discussed in this section implies that, in a highly interconnected system with no congestions, all trading areas feature the same wholesale gas price, net of transmission charges (something that is commonly referred to as the 'price convergence' effect). In case of congestions, prices diverge due to the emergence of surcharges that reflect the difference in costs to supply gas from alternative routes and sources with respect to the most efficient set of routes and sources.

Price convergence requires that the following conditions to hold:

- There is physical capacity between each zone A and zone B to meet the demand to move gas between the two zones expressed by market participants; and
- The arrangements to allocate such capacity are flexible enough to adapt to the need of the market participants, and in particular allow for the emergence of a surcharge.

As discussed in the next sections, these conditions are strongly related to the preconditions for the integration of natural gas markets under the entry-exit model.

4.2. Preconditions for integration

Under the entry-exit model, there are two preconditions for effective integrations of natural gas market areas:

1. The availability of sufficiently ample transmission capacity across market areas; and
2. The efficient allocation of transmission capacity between neighbouring regions

The condition (1) is an obvious physical prerequisite for integration since, in the absence of transmission infrastructures, gas cannot flow between market areas and coupling is therefore impossible.

Condition (2) is instead an 'economic' prerequisite and requires the market design to be such that transmission capacity at all borders is allocated in an efficient manner. This requirement is enforced by requiring that:

- Transmission capacity is allocated via transparent and competitive procedures (e.g., auctions)
- Capacity that is purchased and not used by any given participant must be re-offered to the market ('anti-hoarding' practices, see below)

This guarantees in fact the formation of efficient market prices in each area; with reference to **Figure 25**, suppose for example that there is an excess of supply of relatively cheaper gas in this area (compared to area B) that can supply also area B, until the demand in B is fully met. We assume that transmission capacity is sufficient to accommodate the gas flow between A and B.

If transmission capacity is efficiently allocated, the price in area B must converge to the price P_A, plus the transmission tariff $T_{A \rightarrow B}$, since the same source of gas is used to meet demand both in area A and B.

If instead transmission capacity is not efficiently allocated, the interconnection between A and B may end up not being fully used and the price P_B may form at a level different (and higher) than the price P_A. In such an event, consumers in the area B would not be able to access the gas sourced at price P_A and would need to resort to another (more expensive) source of gas at a price $P_B > P_A$.

This might occur, for instance, in the event of 'hoarding' of transmission capacity by an operator that controls the interconnection capacity between the two areas. By retaining the control (and not using) the transmission capacity between areas A and B, this operator can artificially generate a congestion (also referred to as a 'commercial' congestion) and increase the price in area B to inefficient levels. Anti-hoarding provisions are typically applied precisely to avoid such practices, forcing holders of transmission capacity to make available to the market any quota of the capacity held that is not used[44].

Finally, we remark that while price convergence (i.e., the condition $P_B = P_A + T_{A \rightarrow B}$ in the example above) is an important signal for market integration (see discussion in the next section), it is important to keep the two concepts well separated. In fact, even in an integrated market (where efficient allocation of transmission capacity takes place), prices between neighbouring market areas might deviate by more than the transmission tariff because of congestions in the use of the network. If these congestion events are rare, in fact, it is likely that the cost of developing new infrastructures, or expanding existing ones, to resolve such congestions exceeds the benefits that would be brought by price convergence (i.e., price reductions in the rare events of congestions).

4.3. Current status of market development

In this section we review the current state of market development in Europe and in the Adriatic-Ionian region.

4.3.1. European markets

Efficient wholesale price formation is nowadays ensured by the institution of gas exchanges in all the main European trading zones. **Figure 26** shows the main natural gas trading areas in Europe as of 2019, together with the gas exchange where the majority of transactions for that hub are concluded.

Table 2 displays the active market participants, traded volumes, the number of traded products and the churn rate in the main European trading areas.

[44] This is commonly referred to as a *use-it-or-lose-it* (UIOLI) provision

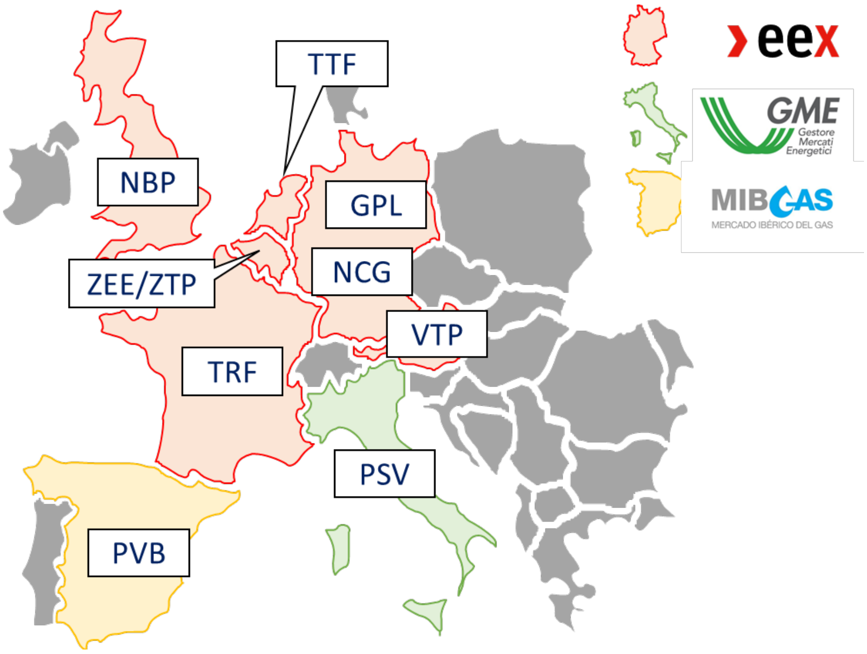

Figure 26 Main natural gas hubs in Europe and corresponding gas exchanges as of 2019. Source: Oxford Institute for Energy Studies

Hub	Active market participants	Traded Products	Traded Volumes (TWh)	Churn Rate
TTF	167	52	40.390	97,1
NBP	135	42	12.480	14,3
NCG	124	25	2.205	4,3
GPL	95	24	1.375	2,9
PSV	94	24	1.440	1,8
VTP	72	17	970	9
TRF	63	16	870	2
ZEE	52	17	380	1,9
ZTP	52	13	190	
PVB	56	11	130	0,3

Table 2 Active market participants, number of traded products, traded volumes and churn rate in the main European natural gas hubs. Source: Oxford Institute for Energy Studies

Allocation of transmission capacity is done (for most interconnection points) by a single central entity (PRISMA Capacity Platform Gmbh[45]), that organizes auctions for the allocation of transmission capacity over different time horizons, interconnecting 19 trading zones and allocating transmission capacity on behalf of more than 42 system operators. As of today, more than 660 shippers are registered to the PRISMA platform.

[45] https://www.prisma-capacity.eu/

As a result, there is ample evidence supporting that price convergence has been reached in many countries in Europe. **Figure 27** displays the evolution of wholesale gas prices for some of the main trading areas in Europe in the period Jan 2005 – June 2021, display a high level of correlation between hubs.

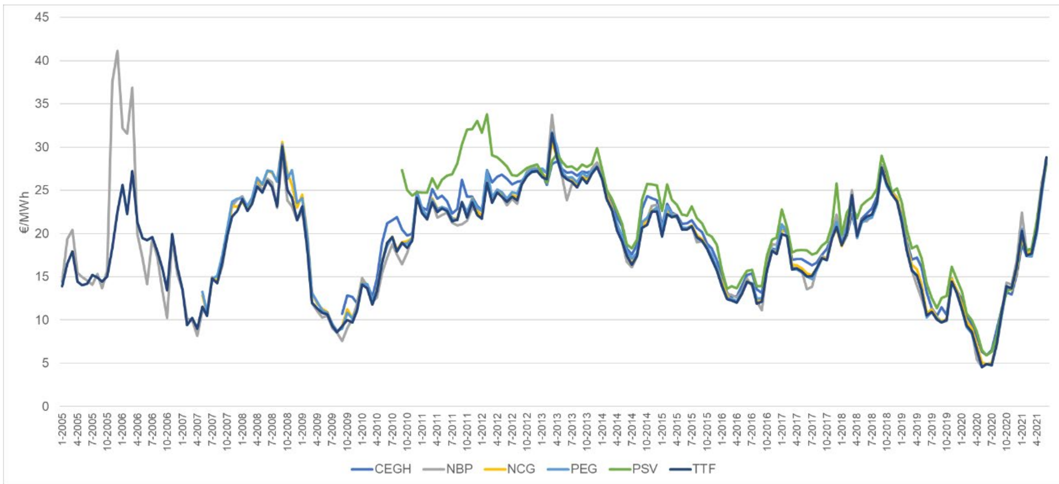

Figure 27 Day-ahead prices for the main European trading areas (TTF, NBP, NCG, PSV, VTP, TRF). Source: ICIS Heren

Performing a quantitative assessment of price convergence is not an obvious task, as it involves detecting congestions and comparing price differentials between trading areas (or 'spreads'), that may depend on a number of market factors, with transmission tariffs, that are defined for different products over different time horizons.

Selecting TTF as benchmark, the European Agency for the Cooperation of Energy Regulators (ACER) analyses the dynamics of price convergence in Europe by counting the number of instances, over a yearly period, in which the price difference against TTF is below a given value. The results are reported in **Figure 28**.

ACER's analysis also groups trading zones into 'macro-areas' (Central-Eastern Europe, North-Western Europe, South-Western Europe) within which congestion arise rarely and, as a result, all trading zones are highly intercorrelated. As it should be expected, macro-areas that are geographically closer to TTF display lower price differentials, since transportation costs (including tariffs and surcharges, where relevant) to reach that market areas from the Dutch "hub" are lower.

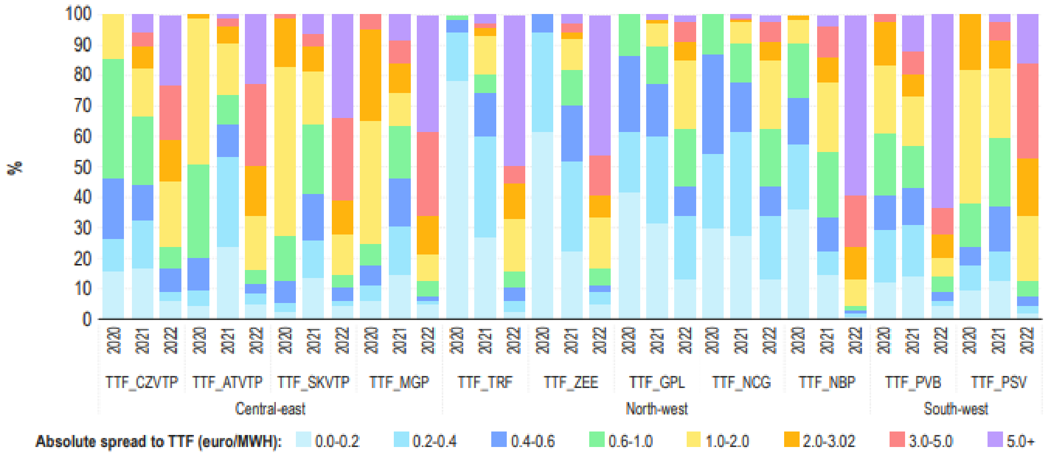

Figure 28 Statistics of the daily price spreads against TTF in 2020, 2021 and 2022. Source: ACER/CEER Market Monitoring Report 2021.

Indeed, these results are confirmed by academic research investigating the topic. For instance, in December 2018 Bastianin, Galeotti and Polo[46] carried out extensive research on price convergence in European gas markets and concluded that

"[…] there is evidence of pairwise price convergence and that this process is associated with key characteristics of the gas market, such as the existence and the maturity degree of development of trading hubs, as well as the degree of interconnection"

Finally, this evidence is also confirmed by analysing gas flows across market zones; **Figures 29**, **30**, **31** and **32** display the net flows[47] of gas at some of the main interconnection points in Europe:

- Tarvisio, at the Austria/Italy border;
- Obergailbach, at the France/Germany border;
- Pirineos, at the Spain/France border; and
- Bacton, at the UK/Netherlands border

together with the corresponding transmission capacity. This analysis show that for most days, the network can accommodate gas flows without congestions emerging (see **Table 3** below for an analysis in the period 2019-2022)

[46] A. Bastianin, M. Galeotti and M. Polo, *Convergence of European Natural Gas Prices*, Working Paper Series IEFE-Università Bocconi, available at https://green.unibocconi.eu/publications/archive/iefe-publications/working-papers/wp_107_cdr_green

[47] Positive values indicate flows in the Austria→Italy, France→Germany, Spain→France and UK→Netherlands directions, respectively. Negative values represent flows in the opposite directions

IP	Tarvisio		Obergailbach		Pirineos		Bacton	
Direction	AT>IT	IT>AT	FR>DE	DE>FR	SP>FR	FR>SP	UK>NL	NL>UK
N° Congestions	57	0	0	0	87	28	307	26

Table 3 Congestions at the selected European interconnection points (IPs). A congestion is identified, for any given direction and day, by the condition that the gas flow is ≥ 90% of the transmission capacity. Source: DFC analysis on ENTSOG data

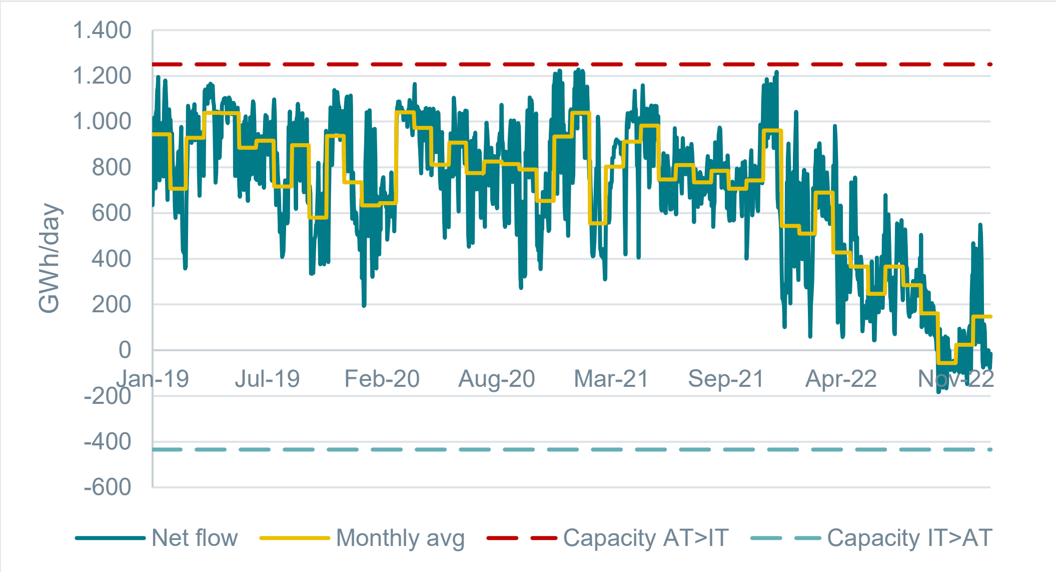

Figure 29 Net flows at Tarvisio IP (Austria/Italy border). Positive values indicate the Austria to Italy direction. Source: ENTSOG

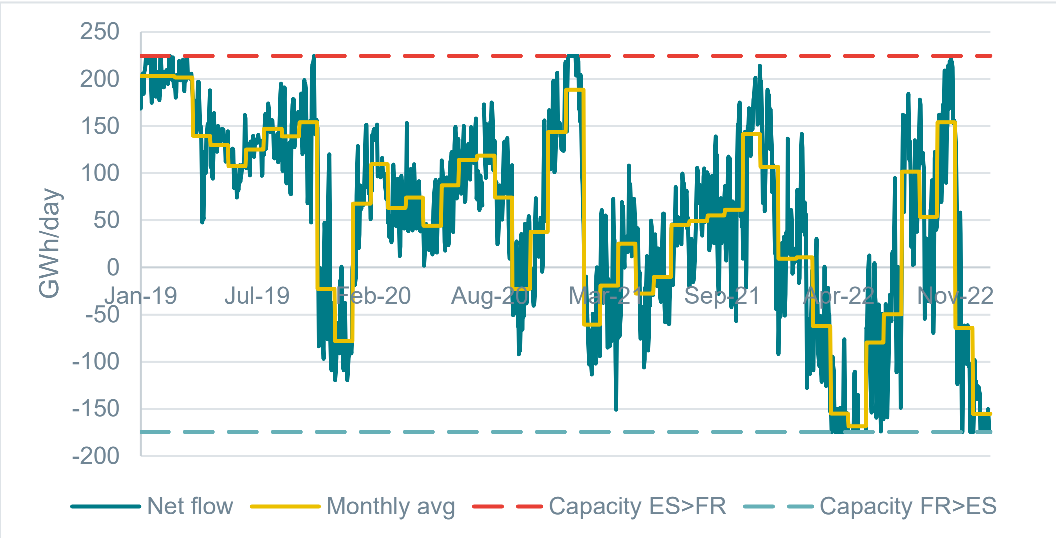

Figure 30 Net flows at Pirineos IP (Spain/France border) Positive values indicate the Spain to France direction. Source: ENTSOG

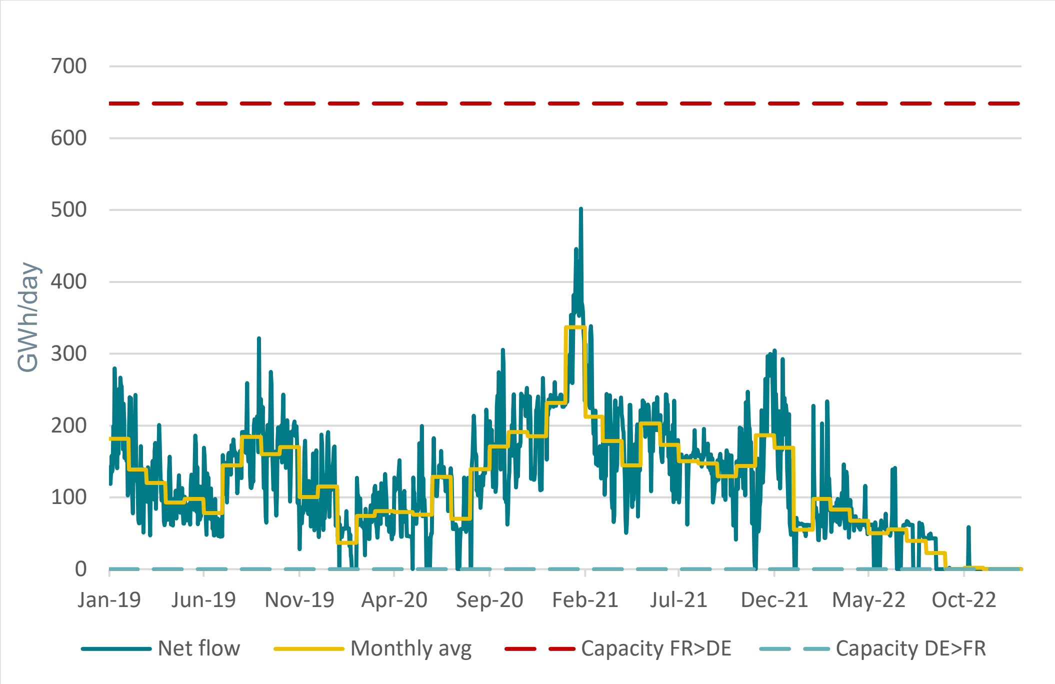

Figure 31 Net flows at Obergailbach IP (Spain/France border). Positive values indicate the France to Germany direction. Source: ENTSOG

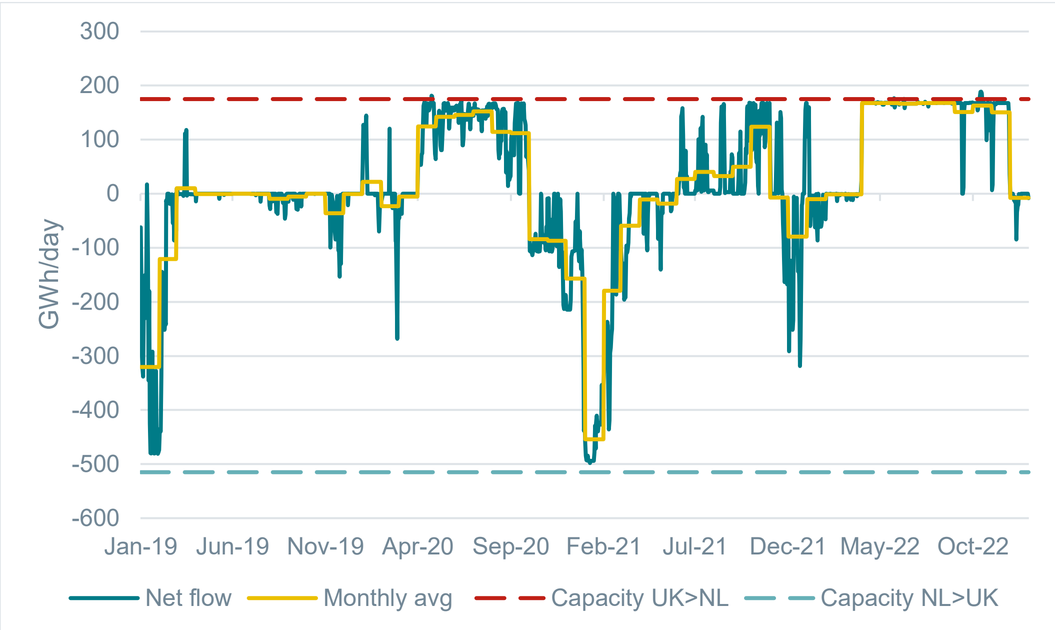

Figure 32 Net flows at Bacton IP (UK/Netherlands border). Positive values indicate the UK to Netherlands direction. Source: ENTSOG

4.3.2. Adriatic-Ionian markets

Natural gas markets in the EUSAIR regions feature very different degrees of maturity. In particular,

- Italy is one of the largest gas markets in Europe, and as such its organisational structure reflects that of a very mature and liquid market[48]. The wholesale price for gas delivered at the *Punto di Scambio Virtuale* (PSV) forms on a liquid market and acts as benchmark for actively traded futures exchanged on EEX. Transmission capacity is allocated via the PRISMA platform. Finally, the retail segment is fully liberalised.
- Slovenia, Croatia and Greece feature a fully liberalised wholesale gas market, implementing the third energy package including the development of natural gas exchanges and the efficient allocation of transmission capacity. With respect to Italy, also given their smaller sizes, these countries lack liquidity and do not have liquid long-term contracts for delivery.
- Serbia, North Macedonia and Bosnia and Herzegovina do not fully implement the provisions of the third energy package. This impacts the efficiency of price formation in the region and the perspectives for an effective integration; for instance, capacity hoarding by the incumbent operator has been reported at the Horgos interconnection point (north border between Serbia and Hungary)[49]
- Albania and Montenegro do not have a gas sector, so that no market is made necessary by the fundamentals.

The following **Table 4** recaps the status of market development in the Adriatic-Ionian region, indicating whether a VTP is established, forward products are exchanged, transmission capacity is efficiently allocated and the retail segment is liberalized.

Country	VTP	Forward market	Efficient transmission capacity allocation	Liberalization of retail segment
Italy	Yes	Yes	Yes	Yes
Greece	Yes	No	Yes	Yes
Croatia	Yes	No	Yes	Yes
Slovenia	Yes	No	Yes	Yes
Serbia	No	No	No	Yes

[48] San Marino is fully integrated in the Italian gas market via regulatory and market provisions

[49] Energy Community Secretariat, *Annual Implementation Report*, 1st November 2022 (Serbia)

North Macedonia	No	No	No	Yes
Bosnia and Herzegovina	No	No	No	Republika Srpska: Yes Fed. Bosnia and Herz.: No
Montenegro	No gas market			
Albania	No gas market			

Table 4 Status of gas market development in the Adriatic-Ionian region

Finally, looking at the utilisation of gas infrastructures, there is no evidence of structural congestions – as presented in the next section. This supports the possibility to assess integration models based on the merger of balancing areas, as discussed in section **Error! Reference source not found.**

4.4. Gas sector fundamentals in the Adriatic-Ionian region

This section presents some fundamentals indicators of the natural gas sector fundamentals in the Adriatic-Ionian region. More detailed country-level analyses are presented in Annex B.

With a 82% share of the entire region's consumption, Italy (EUSAIR regions only) is the largest consumer in the Adriatic-Ionian region. Following countries in terms of consumption share are Greece (8%), Croatia (5%), Serbia (4%) and Slovenia (1%). Montenegro features no gas consumption, while Albania has a small consumption met by national production.

The following **Figure 33** and **Figure 34** display the natural gas consumption by country in the period 2012-2021 and the average consumption shares over the entire period, respectively.

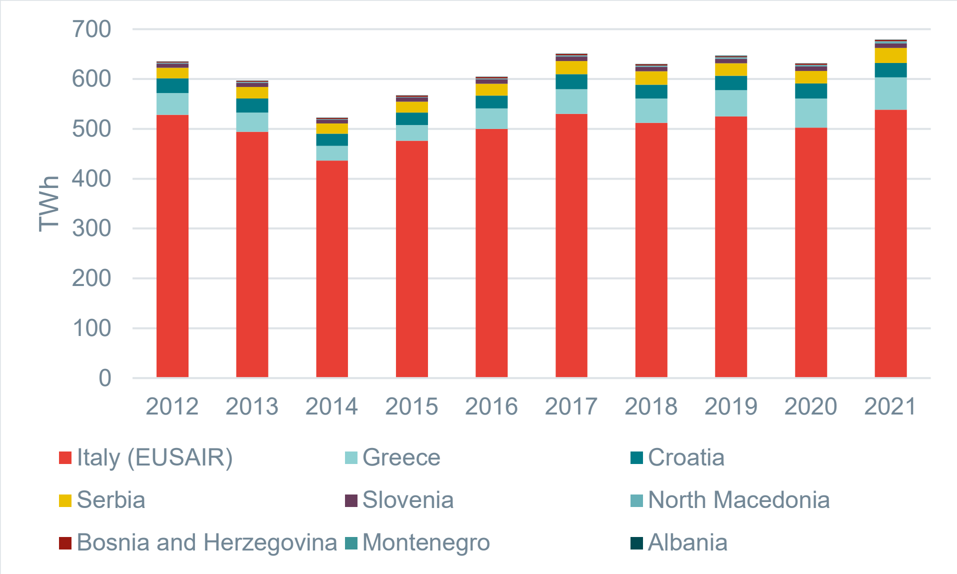

Figure 33 Natural gas consumption by country in the period 2012-2021. Source: Eurostat

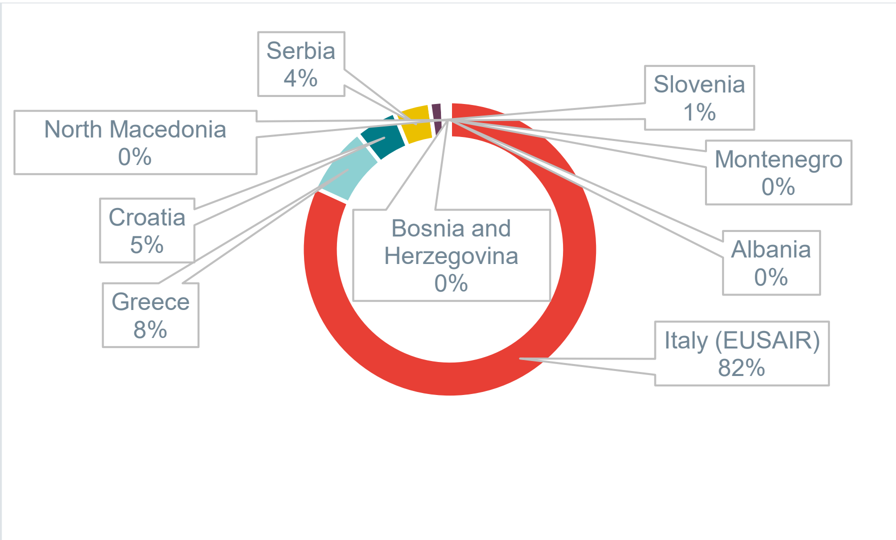

Figure 34 Share of natural gas consumption by country (average 2012-2021). Source: Eurostat

With respect to electricity (see Figure 16 for reference), natural gas consumption is concentrated in countries that have higher industrial consumptions and higher natural gas-fired generation capacity (most notably, Italy). This is evident when looking at the natural gas consumption per capita, see the next **Figure 35**.

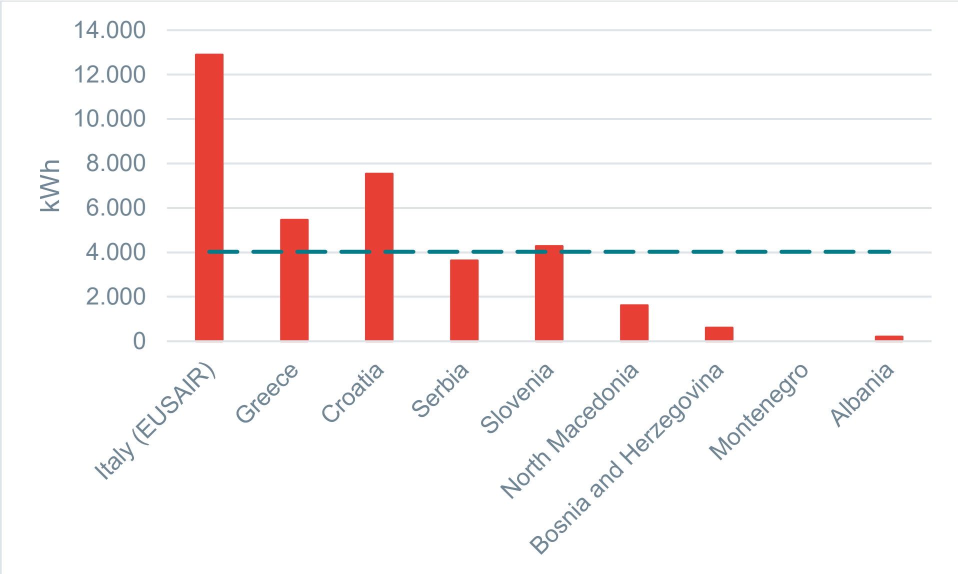

Figure 35 Natural gas consumption per capita in 2021 in the Adriatic-Ionian region. The dashed line indicates the region's average. Source: Eurostat

As of 2021, the Adriatic-Ionian region consumed about 679 TWh of natural gas. Of this, 85% (578 TWh) is imported in the region via pipeline, followed by LNG (11%, or 73 TWh) and national production (4%, or 27 TWh). Russia and Algeria were the main supply sources to the region, followed by Azerbaijan (via the TAP infrastructure) and, to a lower degree, Libya, Norway and Turkey. Looking at LNG, Qatar has been the main supplier, followed by the US, Egypt and Nigeria.

The following **Figure 36** and **Figure 37** display the breakdown of pipeline and LNG imports by source country to the Adriatic-Ionian region.

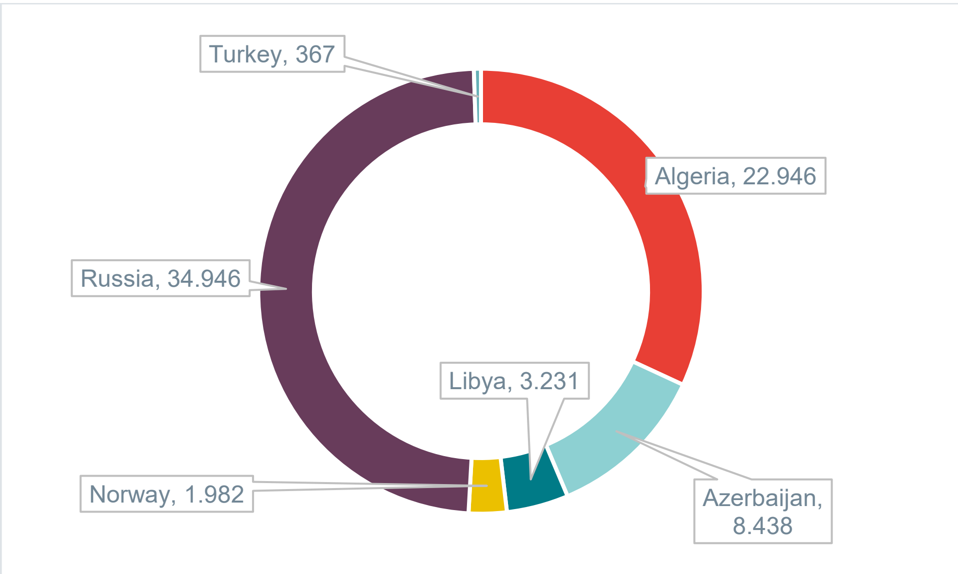

Figure 36 Pipeline imports into the Adriatic-Ionian region by supply country in 2021. Values indicate the import volume in TWh. Source: Eurostat

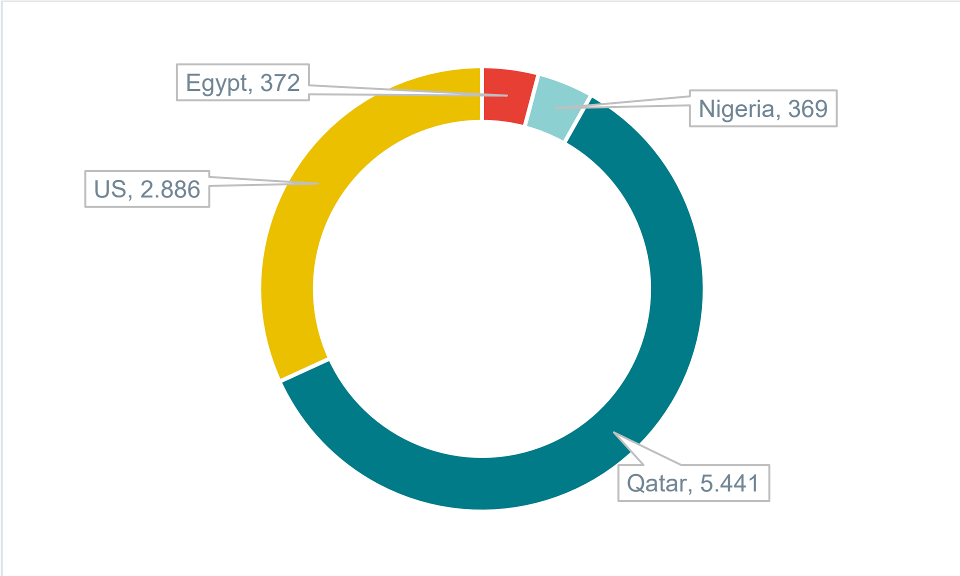

Figure 37 LNG imports into the Adriatic-Ionian region by supply country in 2021. Values indicate the import volume in TWh. Source: Eurostat

Looking at infrastructures, the Adriatic-Ionian region is well interconnected and does not present structural internal congestions. Future developments are being evaluated that could further improve integration in the region as well as additional LNG import capacity and storage capacity, see **Figure 38** and Annex C for additional information.

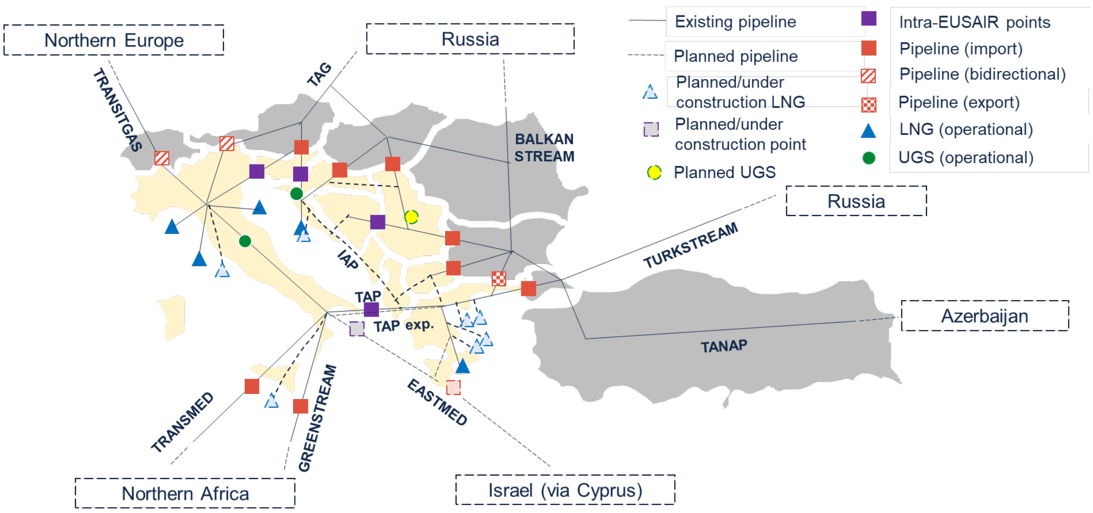

Figure 38 Schematic representation of the gas network in the Adriatic-Ionian region. Source: DFC analysis on ENTSOG data

Finally, the following **Figure 39** displays the natural gas prices in the Adriatic-Ionian region for the household and non-household sectors, in the period 2018-2021. As a general trend, all countries display prices in the non-household sector materially lower than those in the household sector. In the household segment, Italy displays consistently higher prices than other countries.

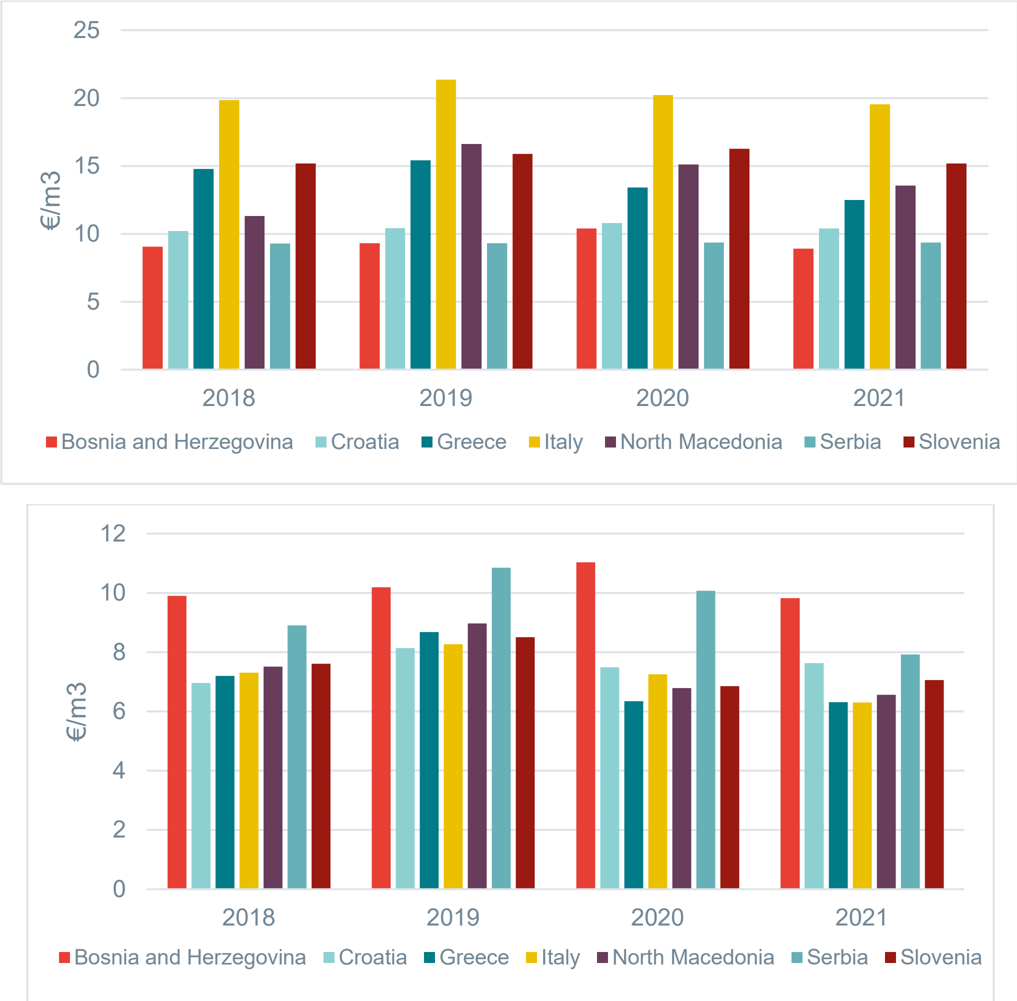

Figure 39 Natural gas prices in the household (top panel) and non-household (bottom panel) segments in the Adriatic-Ionian region. Source: Eurostat

4.5. Natural gas market integration

In this section we build on the results presented in the previous sections to draw conclusions and implications for the integration of the gas markets in the Adriatic-Ionian region.

4.5.1. Integration strategy

Alternative models for market integration may differ along different dimensions, namely:

- The policy framework implemented, including e.g., capacity allocation mechanisms, tariff regulation, unbundling provisions, etc (see section 2);
- The operational aspects related to the design and implementation of the markets, such as product design, trading arrangements, and collateral and credit requirements;
- The geographical perimeter of the market areas, or ‘hubs’, implemented.

However, as in the case of electricity following the European pathway for market integration is expected to be the best strategy also for the Adriatic-Ionian region, as discussed below.

The third energy package provides for a robust reference model in all EUSAIR countries, and leads to market integration as a by-product

As in the case of electricity (see the discussion in section **Error! Reference source not found.**), market integration is obtained as a by-product of market development in the Adriatic-Ionian region, as this is based on the entry-exit model described in section 4.1.

For instance, consider a key element of the regulatory framework regarding market integration for gas, namely the Capacity Allocation Mechanism Network Code (CAM NC)[50]. Among other things, the CAM NC specifies the mechanisms to implement effective and efficient allocation of transmission capacity, together with providing tariffication principles and methodologies under the entry-exit model. Implementing the CAM NC as part of the third energy package fully implements market integration, both within the Adriatic-Ionian region and with the wider European internal market.

Besides the fact that implementing the third energy package would deliver market integration by design, we remark that (as in the case of electricity) both EU and-EU EUSAIR countries are already legally committed to the implementation of the third energy package, including the CAM NC. This is because since all Energy Community Contracting Parties took commitments to implement the third energy package for gas, including its Network Codes.

Alternative options related to implementation and market practices may be considered, but this may not be desirable

The European markets have nowadays reached a high degree of maturity and standardization, which reduces barriers to entry and transaction costs. For instance, forward transactions are centralized in few exchanges, the largest being the European Energy Exchange (EEX) (see section 4.3.1). Centralization of trading reduces financial costs for participants, since they can net out the risk exposure on multiple markets and multiple commodities (e.g., gas, electricity and emissions).

Furthermore, many trading practices are nowadays largely codified and standardised: for instance, the European Federation of Energy Traders (EFET)[51] provides for a standard contract template (termed "Master Agreement") that is commonly used across Europe. This contractual template facilitates market operations, for instance by making the establishment of a new commercial relationship easier and ensuring that all market participants have a 'common ground' – most notably, when it comes to collateral management. EFET plays a crucial role in the standardisation of energy market operations in many areas, including (relevantly to the current project) gas, electricity and renewable certificates.

Implementing alternative options for the development of markets in the EUSAIR region, while technically possible, may therefore be not desirable. Developing

[50] Commission Regulation (EU) 2017/459 of 16 March 2017 establishing a network code on capacity allocation mechanisms in gas transmission systems

[51] https://www.efet.org/#

practices that deviate from what is commonly used across Europe may in fact create frictions to market participation in newly developed EUSAIR markets and, ultimately, jeopardize the effort of market integration.

For instance, consider the case of a new VTP being established in the Adriatic-Ionian region, supporting spot trading of natural gas. The development of the long-term market may follow two different paths: list forward product for delivery of gas at the newly established VTP on an established exchange (the obvious choice being EEX), or list such forward products on a newly instituted national exchange.

The main implication of this choice is that liquidity is expected to remain lower if the forward products are listed on a national exchange – to the detriment of market development. Since market players are already operating on EEX, and they are familiar with all the practices (and risk management procedures) related to operations in that exchange, it will be easier for them to enter transactions into the newly launched long-term products. Furthermore, as discussed earlier the main advantage of trading centralization lies in the reduction of financial costs and collateral requirements for participants – something that would not be achieved in case trading takes place at a national exchange.

As a result, we expect that since the markets to be developed need to be integrated not only within Adriatic-Ionian region, but within the wider European market, adherence to all the mainstream operational practices currently employed in Europe is the best option to achieve market integration.

Geographical perimeter of the VTPs comprised in the EUSAIR region

The last dimension to be considered is related to the geographical perimeter of the entry-exit areas to be developed. With this respect, alternative options may be considered because there is a trade-off between:

- Increasing the liquidity of the hubs to be developed (requiring larger, possibly multi-country areas); and
- Reducing the scope and need for TSO-TSO cooperation and inter-TSO compensations.

Should two or more entry-exit market areas be merged, a market participant holding entry rights at any one of the IPs at the border of the merged entry-exit zone would be entitled to deliver the gas imported through that IP anywhere inside the merged zone. This solution would result in a single market for gas, thus implementing the highest possible level of integration of the markets.

However, such solution would present major implementation issues. This happens because implementing a single entry/exit and balancing area requires that all the countries involved in the merger agree, at least, on a common:

- Transmission capacity computation and allocation system;
- Transmission charging methodology;
- Injections and withdrawals notification system;
- System dispatch;
- Imbalance assessment and charging methodology.

Further, an inter-TSO compensation scheme among transmission system operators would have to be set-up, in order to allocate the revenues from entry/exit charges, which would be collected (only) at the borders between the merged area and the neighbouring areas. This would apply also to any potential increase in total system operations cost resulting from an increase in congestion within the merged area, as a result of greater integration.

Conclusions

Implementing the integration of natural gas markets is somewhat less complex than for electricity, since it does not require setting up the legal and regulatory framework needed for SDAC and SIDC (see section 3.3.). This reduced complexity is ultimately connected to that fact that transmission capacity is allocated explicitly, rather than implicitly. Once transmission capacity is allocated efficiently (e.g., through competitive auctions and avoiding hoarding procedures), the entry-exit model provides for efficient price formation in integrated but institutionally separated markets. In the electricity sector, instead, implicit allocation (while guaranteeing efficient outcomes), requires the establishment of a single European market.

In this context, the European policy framework for gas (via the CAM NC) provides for competitive and transparent capacity allocation procedures. As a result, implementing the third energy package for gas – beside being a commitment already undertaken by all EUSAIR countries – is the most effective way to reach full integration.

In addition to the implementation of the third energy package, zone mergers may be considered, that may bring the benefit of a higher liquidity when merging small market zones into a single entry-exit zone. However, zone merger comes with significant challenges, most notably related to the need for inter-TSO compensation mechanisms.

In the European experience, zone merger processes have been implemented in Germany and France. It is important to note that these unifications proved very complex and took long periods of time despite the zones belonging to the same EU Member State (so that any redistribution effect resulting from the merger did not impact the Member State as a whole).

Another successful experience of market integration achieved by instituting a single market area is given by the "FinEstLat" project, unifying the Finnish, Estonian and Latvian markets. A project to expand the zone to include Lithuania ("FinBalt") is also under discussion, with a go-live no sooner than October 2024.

On the other hand, similar operations in major European neighbouring countries did not prove successfully (for instance, this was the case for Austria and Italy[52]), emphasizing the important role of the EE model in implementing integration of national markets whilst avoiding the need for inter-TSO compensations.

[52] See the study commissioned by ARERA and E-Control on *Italian-Austrian wholesale price formation in the light of market integration* – https://www.arera.it/allegati/pubblicazioni/Italian-Austrian%20Wholesale%20Price%20Formation.pdf – October 2020

4.5.2. Implementation roadmap

The tables below illustrate the implementation roadmap for the natural gas sector in the Adriatic-Ionian region, for years 2023, 2024 and 2025 in separate tables.

		2023											
		1	2	3	4	5	6	7	8	9	10	11	12
Gas Directive													
Art. 9,15	Unundling of gas production from network activities												
Art. 12	Designation of system operators												
Art. 22	Processes for the development of a TYNDP												
Art. 32	Third-party access												
Art. 36	Exemption from TPA provisions for new infrastructures												
Art. 37	Eligibility of consumers and market opening												
Gas Regulation													
Art. 13	Definition of tariff methodologies												
	Establishment of a virtual trading point												
Art. 16	Definition of capacity products												
Art. 16	Definition of capacity allocation mechanisms												
Art. 22	Establishment of harmonised procedures for the exchange of capacity rights												
Regulation 703/2015 (interoperability NC)													
Chapter II	Definition of interconnection agreements												
Chapter IV	Gas quality and odourisation - restrictions to cross-border trading												
Art. 21	Set up of data exchange solutions												
Regulation 2017/459 (CAM NC)													
Art. 6	TSOs to define capacity calculation methodologies												
Art. 9	Definition of standard capacity products												
Art. 8, 11	Definition of auction design												
Art. 19	Definition of bundled capacity products												
Chapter V	Procedures for incremental capacity process												

Chapter VI	Definition of interruptible capacity products												
Art. 37	Offering of capacity rights via the capacity booking platforms (JAO, SEE CAO etc)												
Regulation 2017/460 (tariff NC)													
Art. 5	Cost allocation assessments												
Art. 7	Choice of a reference price methodology												
Art. 13	Definition of multipliers and seasonal factors												
Art. 15	Reference prices for non-standard products												
Art. 16	Reference prices for interruptible capacity												
Art. 21	Pricing for bundled capacity products												

		2024											
		1	2	3	4	5	6	7	8	9	10	11	12
Gas Directive													
Art. 9,15	Unundling of gas production from network activities												
Art. 12	Designation of system operators												
Art. 22	Processes for the development of a TYNDP												
Art. 32	Third-party access												
Art. 36	Exemption from TPA provisions for new infrastructures												
Art. 37	Eligibility of consumers and market opening												
Gas Regulation													
Art. 13	Definition of tariff methodologies												
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Art. 8, 11	Definition of auction design												
Art. 19	Definition of bundled capacity products												

Chapter V	Procedures for incremental capacity process
Chapter VI	Definition of interruptible capacity products
Art. 37	Offering of capacity rights via the capacity booking platforms (JAO, SEE CAO etc)
Regulation 2017/460 (tariff NC)	
Art. 5	Cost allocation assessments
Art. 7	Choice of a reference price methodology
Art. 13	Definition of multipliers and seasonal factors
Art. 15	Reference prices for non-standard products
Art. 16	Reference prices for interruptible capacity
Art. 21	Pricing for bundled capacity products

		2025											
		1	2	3	4	5	6	7	8	9	10	11	12
Gas Directive													
Art. 9,15	Unundling of gas production from network activities												
Art. 12	Designation of system operators												
Art. 22	Processes for the development of a TYNDP												
Art. 32	Third-party access												
Art. 36	Exemption from TPA provisions for new infrastructures												
Art. 37	Eligibility of consumers and market opening												
Gas Regulation													
Art. 13	Definition of tariff methodologies												
	Establishment of a virtual trading point												
Art. 16	Definition of capacity products												
Art. 16	Definition of capacity allocation mechanisms												
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Art. 9	Definition of standard capacity products												
Art. 8, 11	Definition of auction design												

Art. 19	Definition of bundled capacity products	
Chapter V	Procedures for incremental capacity process	
Chapter VI	Definition of interruptible capacity products	
Art. 37	Offering of capacity rights via the capacity booking platforms (JAO, SEE CAO etc)	
Regulation 2017/460 (tariff NC)		
Art. 5	Cost allocation assessments	
Art. 7	Choice of a reference price methodology	
Art. 13	Definition of multipliers and seasonal factors	
Art. 15	Reference prices for non-standard products	
Art. 16	Reference prices for interruptible capacity	
Art. 21	Pricing for bundled capacity products	

4.5.3. The scope for an Adriatic-Ionian gas 'hub'

Recall from the previous sections that once the entry-exit transmission capacity model is implemented over a certain geographic area, that area becomes, by construction, a 'hub'. This happens because market participant can import gas in the area through any of the entry point A and, at the same time, export it through any of the exit points B. In this way, the market participant achieves the same result that he would have obtained, in a point-to-point environment, via the routing service performed by a physical hub.

For this reason, once the entry-exit system is implemented in a given market area, no further institutional arrangements are necessary to establish the corresponding region (that corresponds, in the most common case, to a national country) as a 'hub'.

However, the concept of 'hub' may be extended beyond this technical perspective, to define a market area whose price is a benchmark for transactions occurring in the region. In this sense, the Dutch market area (TTF) acts as a 'hub' for the whole European region, since a large share of contracts (including for delivery to final consumers, and for LNG and pipeline imports) is indexed to the TTF price.

For an entry-exit area to become a 'hub' in this wider sense of the term, is necessary that some conditions related to the market fundamentals and the infrastructure endowment are met. Such conditions include:

- The topology of the transmission network is such that the market area has large interconnections with multiple other market areas in the region;
- The gas that can transit through the area is an inframarginal supply option in some interconnected areas;
- The capacity of the supply sources connected to the areas is adequate to meet the demand from the entire region (including, if relevant exports)

In his perspective, Italy and Greece may be consider as the most suitable candidate to become 'hubs'. In fact, Italy features the largest share of consumption and import capacity in the region. However, interconnection to the Balkan region is relatively limited, since it is only via TAP at the Albania-Italy border (commercial reverse flow) and at the Slovenia-Italy border.

Greece is well positioned geographically to become a 'hub' for the Balkan region, given the size of its regassification capacity (once new investments are factored in), and the possibility to export to the Balkan region via the IGB (Greece-Bulgaria border) and directly to North Macedonia (via a pipeline currently under development).

We note incidentally that, in entry-exit framework, there is no competition among market areas in their role of 'hubs'; instead, alternative transportation routes, through different entry-exit areas, will compete based on the tariff levels, i.e., the sum of the entry and exit tariffs along each of them.

In conclusion, whether one or more 'hubs' (in the wider sense of the term) will emerge to act as benchmark for the EUSAIR region cannot be known at present, but it does not depend on the market integration strategy pursued. Rather, this will depend on the evolution of the sector fundamentals (including the development of new infrastructures), as well as the trading arrangements implemented by the participants operating in the region (e.g., in terms of contract indexing).

5. SECTOR-COUPLING PERSPECTIVES IN THE ADRIATIC-IONIAN REGION

5.1. Sector coupling and P2G technologies

The term *"(smart) Sector Coupling"* entered the EU energy policy debate for the first time as an agenda item of the 31st EU Gas Regulatory Forum in Madrid in October 2018 and has been one of the most widely debated topics since then. Nevertheless, there is no universal or agreed definition of sector coupling as of today. While sector coupling indicates the integration of electricity and gas, the interlinking with more sectors (e.g., heating, transport and industrial production) is more often referred to as "Sector Integration".

To this scope, the possibilities offered by technology and digitalisation are deemed crucial to increase efficiency, reduce waste and optimise electricity and gas infrastructure costs. While gas-to-power, i.e., gas turbines have existed for decades, power-to-gas (P2G) technologies are rather new. P2G technologies can serve the double purpose of converting (curtailed) electricity into renewable or low-carbon hydrogen (depending on the type of electricity used) – for storage or direct use – and even into natural gas after methanization. The figure below illustrates an example of a power-to-hydrogen process and its potential uses.

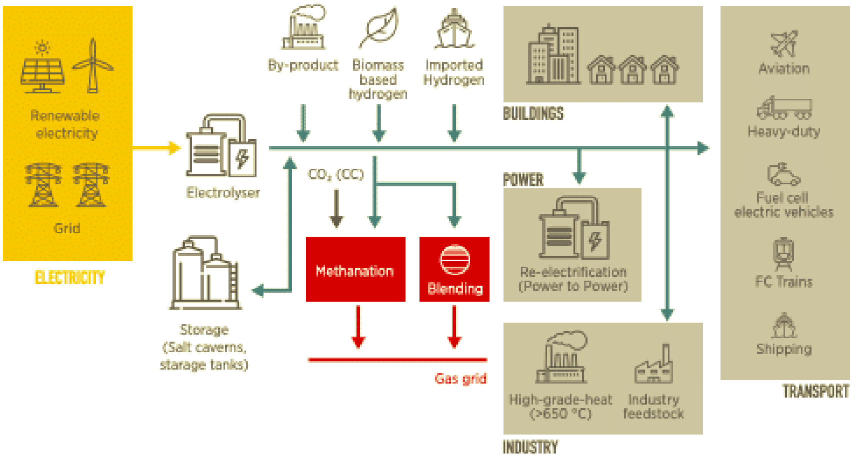


Figure 40 Power-to-gas technology. Source: IRENA, 2018

Hydrogen, and particularly renewable hydrogen, has reached central stage in the European policy debate since the publication of the EU Hydrogen Strategy in 2020[53]. Hydrogen is a versatile energy carrier, that can be produced from multiple feedstocks and can be used across a number of applications. In particular, renewable electricity can be converted to hydrogen via electrolysis, which can couple renewable energy with all the end uses that are more difficult to electrify and decarbonise (so-called 'hard-to-abate' sectors, such as high-grade heat industrial uses).

[53] COM/2020/301 - https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52020DC0301

This coupling also allows electrolysers to provide flexibility to the grid, complementing alternatives such as batteries, demand response and vehicle-to-grid in smart electrification.

We discuss below the hydrogen policy framework and the current state of development of the hydrogen sector in Europe and in the Adriatic-Ionian region.

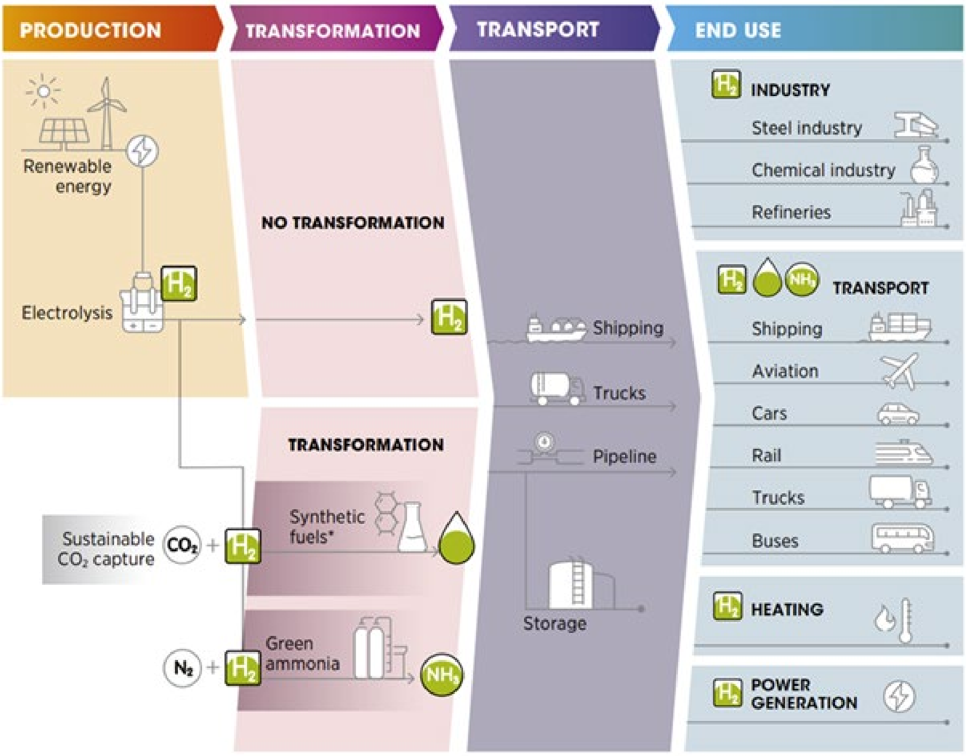


Figure 41 The production and use of renewable hydrogen. Source: IRENA

5.1.1. Hydrogen policy framework

Since the publication of the Hydrogen Strategy, the Fit-for-55 package (July 2021) has put forward a number of legislative proposals that translate the European hydrogen strategy into concrete European hydrogen policy framework. This includes proposals to set targets for the uptake of renewable hydrogen in industry and transport by 2030. It also includes the Hydrogen and decarbonised gas market package[54], which puts forward proposals to support the creation of optimum and dedicated infrastructure for hydrogen, as well as an efficient hydrogen market.

Furthermore, the recovery plan NextGenerationEU has been made available to EU countries to invest in hydrogen projects across the value chain. Investment support has also been provided through the Important Projects of Common European Interest (IPCEIs) on hydrogen. The first IPCEI, called "IPCEI Hy2Tech", which includes 41 projects and was approved in July 2022, aims at developing innovative technologies for the hydrogen value chain to decarbonise industrial processes and the mobility sector, with a focus on end-users.

In September 2022, the Commission approved "IPCEI Hy2Use", which complements IPCEI Hy2Tech and which will support the construction of hydrogen-

[54] COM/2021/803 and COM/2021/804

related infrastructure and the development of innovative and more sustainable technologies for the integration of hydrogen into the industrial sector. Finally, the Clean Hydrogen Partnership was established in November 2021 to support research and innovation in the hydrogen ecosystem.

5.1.2. Hydrogen scenarios

With the publication of the REPowerEU plan in May 2022, the European Commission complements the implementation of the EU hydrogen strategy to further increase the European ambitions for renewable hydrogen as an important energy carrier to move away from Russia's fossil fuel imports. In the Staff Working Document[55] accompanying the plan, the Commission outlines a 'hydrogen accelerator' concept to scale up the deployment of renewable hydrogen, which will contribute to accelerate the energy transition and decarbonising the EU's energy system.

The ambition is to produce 10 million tonnes and import 10 million tonnes of renewable hydrogen in the EU by 2030. In its Ten Year Network Development Plan, the association of electricity and gas TSOs (ENTSO-E and ENTSOG) define the expected scenarios for the development of the hydrogen sector in Europe (on a country-by-country basis). The following **Figure 42** and **Figure 43** display the expected evolution of hydrogen demand in Europe and in EU countries in the Adriatic-Ionian region.

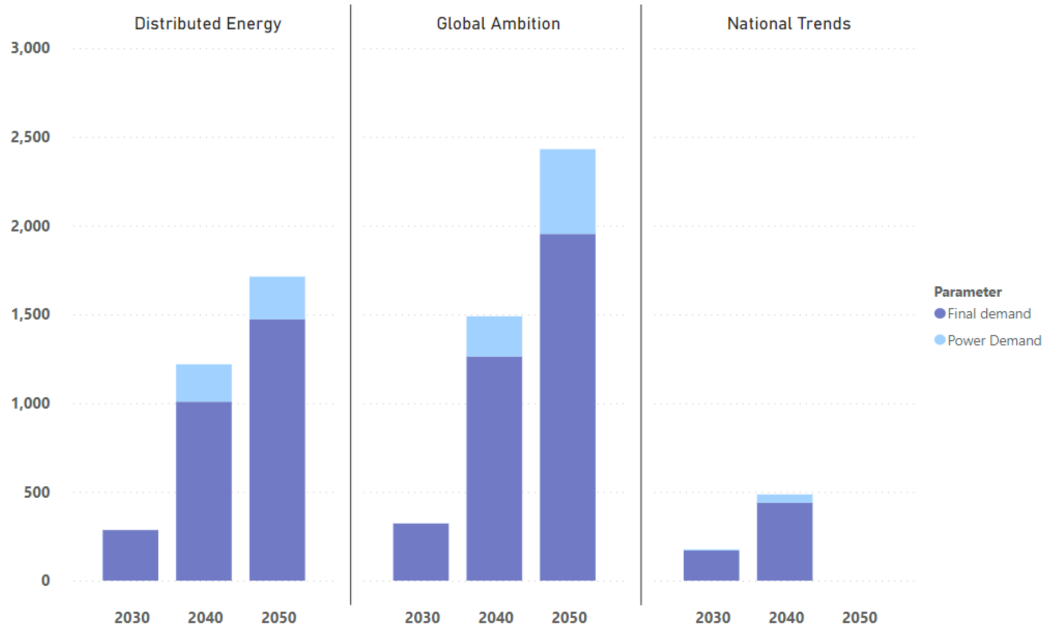


Figure 42 Expected evolution of hydrogen demand in Europe (TWh/y). Source: ENTSO-E and ENTSOG TYNDP 2022[56]

[55] Staff Working Document SWD/2022/230

[56] See the visualization platform at https://2022.entsos-tyndp-scenarios.eu/visualisation-platform/

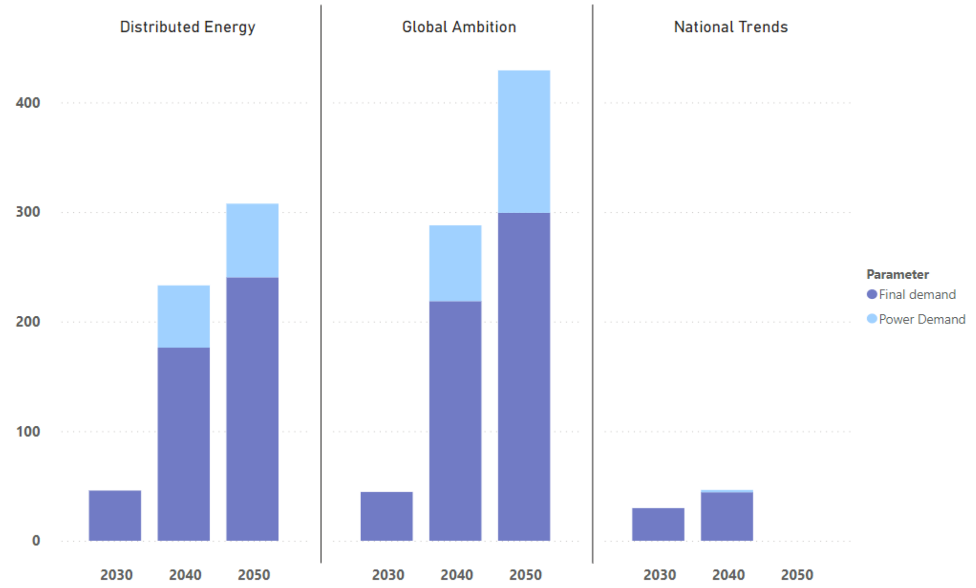


Figure 43 Expected evolution of hydrogen demand in the EU countries that belong in the Adriatic-Ionian region (Italy, Greece, Slovenia and Croatia; data in TWh/y). Source: ENTSO-E and ENTSOG TYNDP 2022[56]

5.2. Perspectives in the Adriatic-Ionian region

The perspectives of the hydrogen sector in the Adriatic-Ionian region are closely interrelated with those of the wider European region, and – at present – still relatively uncertain.

The European strategy for hydrogen envisages a first phase of development in which the current hydrogen production is decarbonised by converting the current fossil-fuel hydrogen production with renewable electricity-based electrolysis. In this phase, electrolysers may be developed close to large industrial sites that currently employ hydrogen as feedstock. It is expected that countries that do not feature large hydrogen consumption levels as of today will be only marginally touched by the hydrogen sector development in this stage.

In a second phase, until 2030 in the strategy envisaged by the Commission, renewable hydrogen is expected to become a structural element of the industrial landscape. This implies the large-scale development of electrolysers, to replace (at least partly) the use of fossil gas in hard-to-abate industries. Countries with large shares of natural gas consumption in the industrial sector are expected to experience higher penetration of hydrogen consumption, although this is largely under the control of national authorities. For instance, decarbonisation in the transportation sector may be obtained both via electrification and by means of synthetic fuels or hydrogen – with support policies largely governing the evolution of the sector.

Finally, in the long-term and targeting 2050 hydrogen is expected to be developed at large scale and transported over long distances (possibly retrofitting the existing gas network where applicable). At this stage the development of the hydrogen sector is still uncertain, and it is expected that national policies will largely shape the penetration of hydrogen and other P2G technologies in the Adriatic-Ionian region. For instance, countries that currently feature coal-fired electricity production may decarbonise the sector by moving to natural gas; in this case, investments in the natural gas sector may be not compatible with additional investments for large-scale hydrogen development.

6. RETAIL MARKETS

Historically, the energy retail sector in Europe was dominated by vertically integrated monopolies, where a single entity controlled the entire value chain, from electricity or gas generation to transmission, distribution and retail supply. However, in the 1990s, spurred by the need for market reforms, several European countries began to introduce liberalisation measures to encourage competition and foster innovation in the sector. The key objective was to dismantle the existing monopolistic structures, introduce new market players, and give consumers the freedom to choose their energy supplier.

The liberalisation process involved unbundling the various segments of the energy market, separating generation, transmission, distribution, and supply functions to promote competition. This separation aimed at removing barriers to entry for new players, including independent power producers, renewable energy developers, and retail suppliers.

One of the significant impacts of the liberalisation of the energy retail sector has been the emergence of consumer choice. In the past, consumers had limited options and were bound to purchase energy from the designated supplier in their region, at regulated prices. However, liberalisation has empowered consumers by offering a wide range of energy providers, tariff options, and contract terms. This competition has created an environment where suppliers must strive to provide affordable prices, enhanced customer service, and innovative products to attract and retain customers.

Retail liberalisation progressed at different rates in Europe, with the UK leading the way; today, the liberalization process is well in its third decade in most European markets. However, retail market liberalisation proved very challenging due to a number of factors, most notably the need for regulators to enhance competition in a sector structurally featuring low consumer engagement, while at the same time ensuring protection for final consumers (particularly, residential consumers[57]). This resulted in many markets still featuring a high concentration, reduced switching rates and (in many cases) a coexistence of regulated-price regimes and free-market offers.

The remainder of this section is structured as follows. In section 6.1. we discuss the main policy intervention tools used to implement consumer protection. In section 6.2. we discuss the energy retail market structure in Europe and in the Adriatic-Ionian region. In section 6.3. we review the issue of consumer engagement. In section 6.4. we discuss new trends in the electricity retail sector.

6.1. Consumer protection measures

Policy intervention plays a fundamental role in shaping the structure and functioning of the energy retail markets in Europe. In this section we review the main instruments and tools used to protect end consumers.

[57] In addition, vulnerable consumers are usually granted regulated conditions to access electricity and natural gas, to protect them from price increases

Regulated tariffs

In some countries regulated tariff options are available to small consumers for a long time since the opening of the market. Regulated tariff options protect customers both directly, to the extent that their level is cost-based, and indirectly, acting as a price ceiling to the market prices.

The use of 'regulated tariffs' entails a tension between customer protection and the objective to promote the development of the market, since too low regulated tariffs might displace genuinely competitive offers. The problem may be relevant at the early stages of retail liberalisation, when competitive entrants are more likely to face higher cost than the incumbent regulated supplier, while being unable to enrich their offers enough, to make them attractive at a price higher than the regulated tariff. The entrants' cost may be higher than the incumbent supplier's, for example, due to customer acquisition expenditures or because of unexploited scale economies. In a frictionless economy, entrants would regard such additional cost as an investment, to be recovered by creating value for customers and appropriating part of it, at a later time. In the policy debate, though, concerns that low regulated tariffs may prevent desirable entry are a common theme.

In Europe tariff regulation for household consumers is implemented in several countries, including France, Spain, Italy.

In the UK, since the market opening all suppliers have to offer a default tariff, named 'standard variable tariff'. The standard variable tariff is paid by consumers that have never selected a market-based tariff and by consumers who have subscribed a definitive-time offer, like typically are fixed-price tariffs, that fail to select a new offer by the time the current one ends. The standard variable tariff has no end date; the 'variable' attribute refers to the possibility for the supplier to change the tariff level at any time, with the condition that, if the price is to be increased, customers must be notified 30 days in advance. In practice, tariff prices have generally changed once or twice a year. Until 2018 the level of the standard offer was not regulated, and standard would generally turn out to be more expensive that the offers addressed to active consumers. Following the government's legislation in January 2019, the regulator introduced a price cap on the 'standard variable tariffs', that are also the default tariffs, paid by around 11 million customers.

Last resort service

The last-resort service, implemented in all markets, protects consumers against the risk of involuntary disconnection by automatically activating a supply contract. This may happen in case the consumer's supplier goes bankrupt, or if the consumer supplied under a definitive-time offer fails to select a new offer by the time the current one ends. The following features concur to shaping the default tariff as a last resort regime. First, consumers cannot voluntarily select to enter the default tariff regime; they just land there in case they are left without supplier. Second, default tariffs are often more expensive than the offers available in the market, in order to incentivise consumers to move back to the market.

The default service in case of bankruptcy of supplier is typically provided by the largest retailer operating in the area (Germany, Norway), or by a firm selected by the public authorities via auction (Italy, Denmark). In the Netherlands, the responsibility for ensuring electricity supply when a retailer defaults is split among retailers in proportion to the demand each retailer serves.

Default tariffs are regulated or subject to close regulatory scrutiny. The providers of the default service are usually required to procure wholesale energy and the balancing services via auctions and pass on the corresponding cost to their default service customers. In this way, the regulator can ensure that customers on the default tariff secure service at a competitive price, at least as regards the wholesale power purchase cost element of the final bill, with the other elements of the bill being controlled via cost-based regulation.

In Italy, the regulator runs an auction were competitive retailers bid to provide the default service consumers in predefined geographic areas; the default service is awarded to the retailers that bid the lowest level for the default tariff for four years.

Restrictions to price discrimination

The obvious profit maximising strategy for a retailer serving a large share of non-responsive demand entails price discrimination and, in particular, charging high prices to inactive customers and targeting active customers with cheaper competitive offers.

Regulators may limit the ability and the incentives for price discrimination by electricity retailers. In the UK, for example, in 2009 geographical price discrimination was prohibited, in order to prevent the former regional monopolists to discriminate against traditional customers for which, since liberalisation, they acted as default suppliers. At that point, the competitive dynamics between the former monopoly suppliers changed: once selective discounts on the standard variable tariffs were banned, fixed-rate options took their place as the competitive acquisition tariffs.

Other measures to limited price-discrimination included limiting the number of tariff options that each retailer could offer and the prohibition of most types of discounts. Those constraints were later relaxed based on the competition authority assessment that their benefits were outweighed by their dampening effect on price competition, caused by limiting the flexibility suppliers to target selective groups of customers and their incentives to tariff innovation.

Provisions on fixed term contracts

Market offers typically have an end to the contract, after which retailers may revert the consumers to another price plan if the consumers do not actively renew or switch to another contract. A business practice that is typically considered unfair and exploitative consists in placing customers on higher tariffs when they fail to make new arrangements at the end of a fixed term contract. Some jurisdictions have implemented requirements around alerting customers when their contacts are coming to an end so that they may make the appropriate arrangements. In the UK, it is requested that consumers that fail to select a new offer at the end of a fixed term contract be placed on the default tariff. In Germany, fixed term contracts are renewed automatically if customers do not cancel them within a given notice period.

Preventive checks

In the Netherlands any new service offering, or change has to be submitted to the regulator at least four weeks before it comes into force. The retailer has to provide a breakdown of the included costs and the regulator uses this information to determine whether the price is excessive. Although censure of prices by the regulator is extremely rare, this may be because retailers think it is a credible threat and act accordingly.

Discipline of selling practices

In some jurisdictions special rules for door-to-door selling of electricity and gas are implemented. For example, in Great Britain the six largest retailers stopped door-to-door solicitations in 2010 and 2011, following new license requirements and standards of conduct, and political pressure opposing doorstep sales. In Spain door-to-door electricity and gas sales are prohibited.

Grace periods, during which the client can cancel a switch, are also implemented in some countries.

Publication of quality-of-service indicators and mandated minimum quality of service standards

In some countries, complaint scorecards are published, which rank retailers by their rate of complaints. In some cases, other quality of service indicators are published, including for example performance indicators of the retailers call center. Sometimes minimum performance standards are mandated.

Price transparency

Microbusiness customers in most countries have more limited access to price comparison tools than residential customers, while presenting similar weaknesses when it comes to participation in the market.

For this reason, suppliers may be required to publish or disclose to their target microbusiness clients aggregate information on prices in recently subscribed contracts.

Dispute resolution

Public intervention on complaint and dispute between customers and retailers is common in liberalised electricity markets. Measures range from regulating the complaint handling process implemented by retailers, to appointing of a third-party who can act as mediator, with the authority of making binding resolutions, or ombudsmen.

Further, consumers retain the usual right to address their complaints to civil courts.

Regulation of minimum terms and conditions for retail market supply

It is common for regulators to discipline non-core terms and conditions of market-based retail supply offers addressed to the smaller consumers. Matters such as i) critical information (and its form) to report on the invoice, ii) frequency and timing of the invoicing and iii) criteria for the drafting of supply contracts are frequently regulated.

Targeted policies for vulnerable customers

Energy is regarded as a ‘necessity good’ in all developed countries, i.e. as an indispensable requirement for the minimum socially accepted standard of living. For the poorest part of the population expenditure on energy is generally the one of the highest items of expenditure; further price elasticity of electricity and gas demand is limited. These features explain the political relevance of energy prices, as their increase has a highly regressive impact.

Various forms of protection are targeted to specific types of customers, commonly referred to as ‘vulnerable’. The definition of vulnerable customer is different in different jurisdictions. Vulnerable customers may include low-income consumers, low-income consumers with average consumption above the average, customers that are less able than a typical customer to protect their interests in the energy market, and customers depending on life-support equipment.

The most common measures to protect vulnerable customers include social tariffs, one-off support to pay for outstanding arrears, payment plans offered to consumers who are in debt to extend their bill payment, exemption from disconnection – due to medical circumstances or weather conditions, installation of pre-payment metering as an alternative to disconnection, a reduction of maximum withdrawable capacity, as an alternative to disconnection, energy efficiency support programmes, to help reduce the consumer’s expenditure on energy.

The cost of the policies for vulnerable customers is typically borne by consumers and, less frequently, paid for out of the general tax system.

6.2. Market structure

6.2.1. European markets

Nowadays, consumers in most EU jurisdictions can choose between multiple types of offers, including for instance fixed-price offers, variable-price offers, offers of renewable energy, as well as offers including a variety of additional services. **Figure 44** displays the number of offers available to household consumers in Europe in 2020 and 2021.

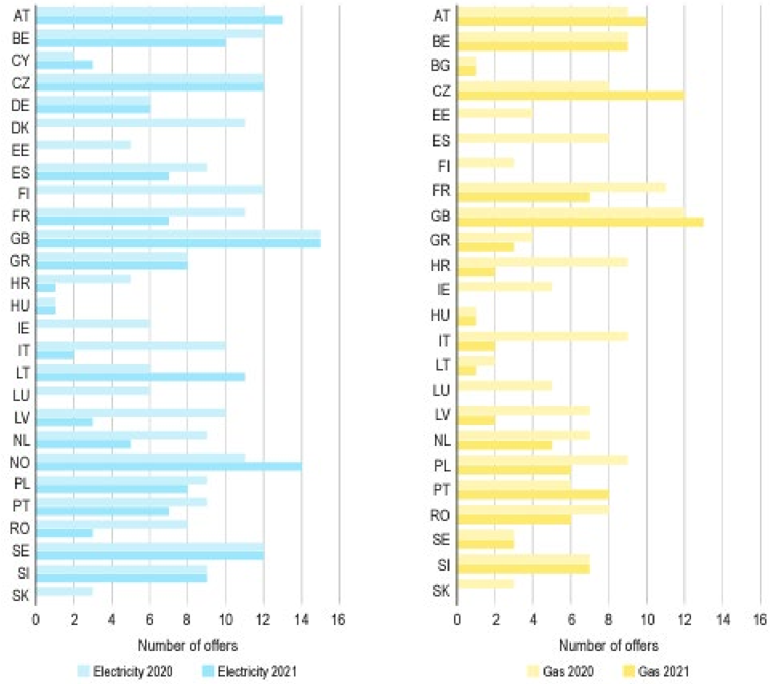
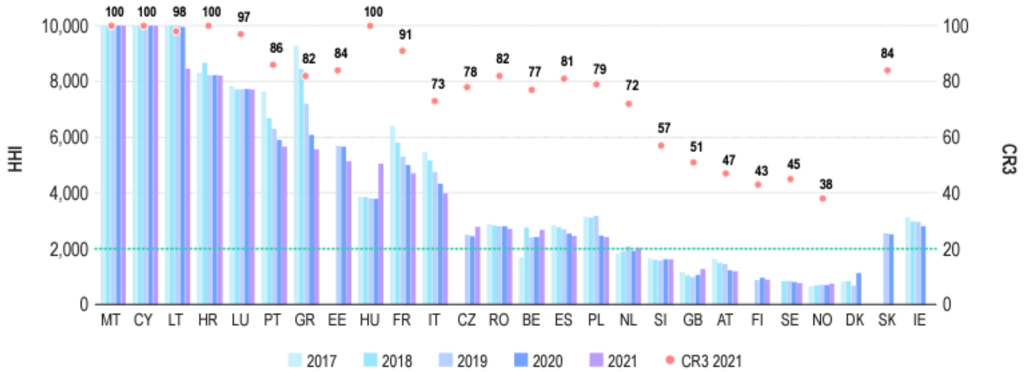


Figure 44 Number of offers available to household consumers in the electricity (left) and natural gas (right) retail sectors in 2020 and 2021. Source: ACER and CEER, Market Monitoring Report 2021, Energy Retail and Consumer Protection Volume

European markets feature very different degree of concentration, depending on the maturity of each market as well as other dimensions (for instance, whether a regulated regime exists or not). **Figure 45** shows the HHI[58] concentration index and the market share of the three largest suppliers (CR3 indicator) for the period 2017-2021 in all EU jurisdictions[59], for the household segment.



[58] The HHI (Herfindahl-Hirschman Index) concentration index is a commonly used measure to assess market concentration or the degree of competition in a particular industry or market. The HHI concentration index is calculated by summing the squares of the market shares of all firms operating in a specific market.

[59] Apart from Germany and Latvia, that do not monitor the HHI index.

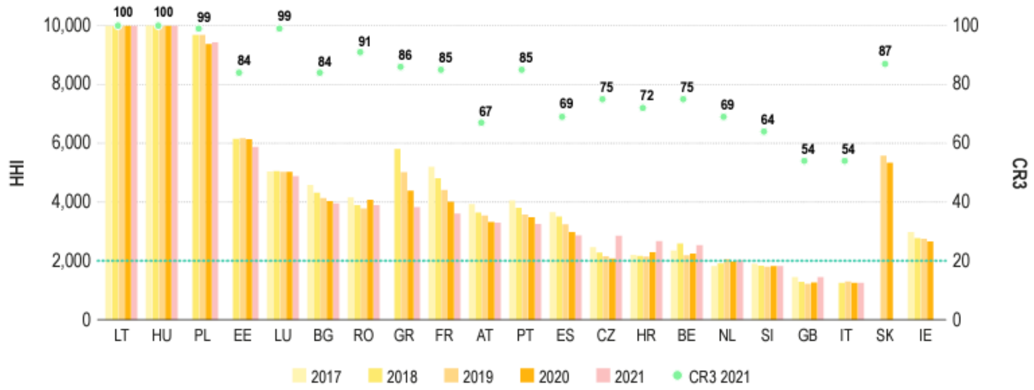


Figure 45 HHI index and CR3 index in the electricity (top) and natural gas (bottom) household retail segment in Europe. Source: ACER and CEER, Market Monitoring Report 2021, Energy Retail and Consumer Protection Volume

6.2.2. Adriatic-Ionian region

Regarding EU Member States that are part of the Adriatic-Ionian region (Italy, Greece, Slovenia and Croatia), the considerations and results presented in the previous section apply.

For all other countries that are Contracting Parties of the Energy Community, the retail liberalisation process is ongoing and, at present, at an earlier stage.

Looking at the incidence of regulated price regimes in the Energy Community, the Energy Community Secretariat reports a material increase in the share of consumers served in the free market – see the next figure.

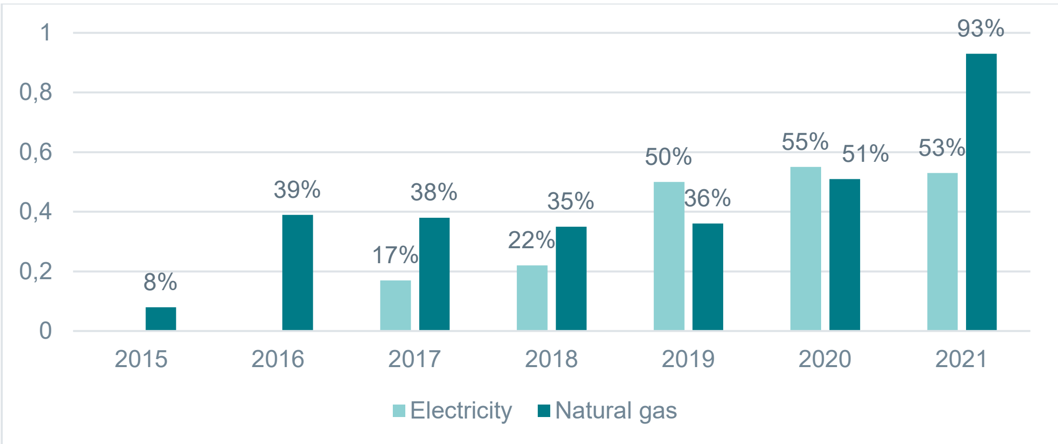


Figure 46 Retail market opening in the Energy Community. Source: Energy Community Secretariat, Implementation Report 2022

However, the retail energy markets in the Energy Community region are still highly concentrated. In some cases, while formally there exist multiple suppliers the entire market is served by the former monopolist (for instance this is the case in Montenegro).

For electricity, the CR3 index is above 90% for the majority of the EnCP countries – and close to 100% when looking at the household segment.

The same result is found in the gas sector, with Bosnia and Herzegovina and North Macedonia featuring a CR3 above 90%, while Serbia stabilized at around 85% in 2021. Albania and Montenegro currently do not feature a gas market.

6.3. Consumer engagement

6.3.1. European markets

Switching rates

The switching rate of consumers is one of the key indicators of well-functioning retail energy markets. Even though switching processes have been facilitated by regulation and the process automation in many markets, there still is a high number of energy consumers (especially household consumers) who remain with their incumbent supplier.

Figure 47 shows the switching rates for electricity and gas household consumers in Europe in 2019, 2020 and 2021. These data show that there is a progressive increase in switching rates across European Member States; moreover, the countries with the highest switching rates are the same for electricity and gas, pointing to the existence of structural factors in those countries favouring switching among energy consumers.

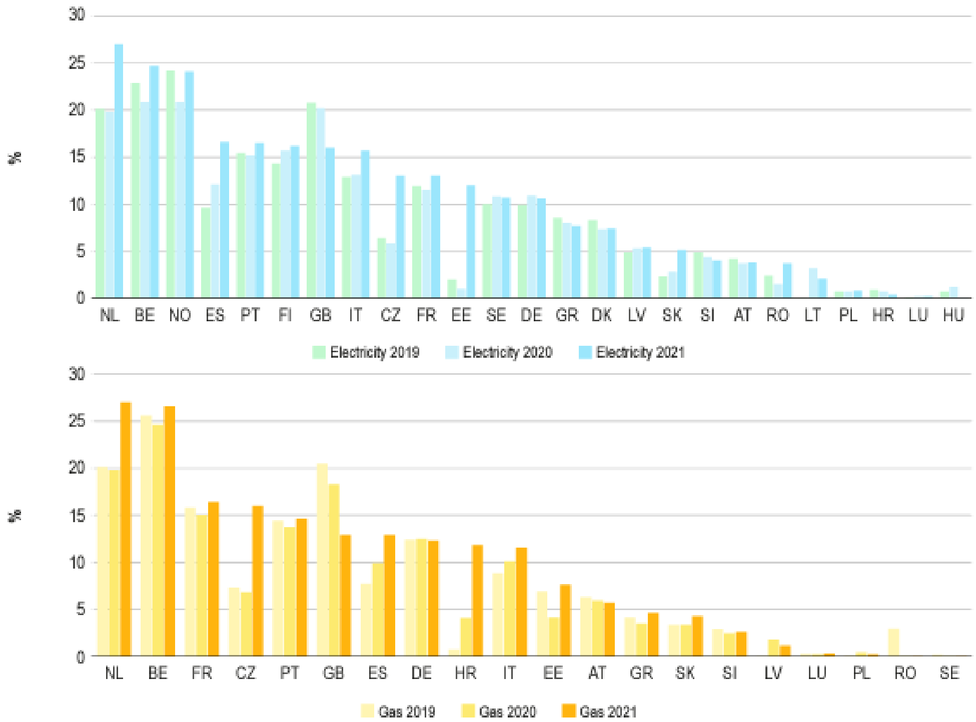


Figure 47 External switching rates of household consumers (by number of metering points) in 2021. Source: ACER and CEER, Market Monitoring Report 2021, Energy Retail and Consumer Protection Volume

In countries featuring both regulated and non-regulated price regimes, switching rates outside of the regulated regime are almost always higher than switching rates to the regulated regime (the only exception being the Polish electricity market). This leads to a progressive "depletion" of the regulated regime consumer's base.

Switching rates	Electricity		Gas	
	Out of regulated regime	To regulated regime	Out of regulated regime	To regulated regime
Spain	4,2%	1,5%	0,3%	0,3%
France	3,0%		22,8%	
Italy	4,2%	0,2%		
Lithuania	21,0%	0,2%		
Poland	2,1%	2,6%	0,2%	0,2%
Portugal	4,1%	0,5%	1,1%	0,1%
Croatia			10,5%	

Table 5 Switching rates in European countries featuring both regulated and non-regulated regimes, 2021. Source: ACER and CEER, Market Monitoring Report 2021, Energy Retail and Consumer Protection Volume

Switching duration

Another important index to monitor consumer engagement is the so-called switching duration, since shorter switching times encourage consumers to actively search for better energy deals and switch supplier. Article 12 of Directive 2019/944 allows a maximum time of three weeks to switch from the date of the request and by no later than 2026, the technical process of switching shall take no longer than 24 hours on any working day.

Figure 48 shows that the legal maximum duration of an electricity or a gas supplier switch meets the respective Directive requirement of three weeks in most MSs, including for EU Member States that are part of the Adriatic-Ionian region. Looking at actual switching times, however, Greece still features more than 15 working days to perform a switch.

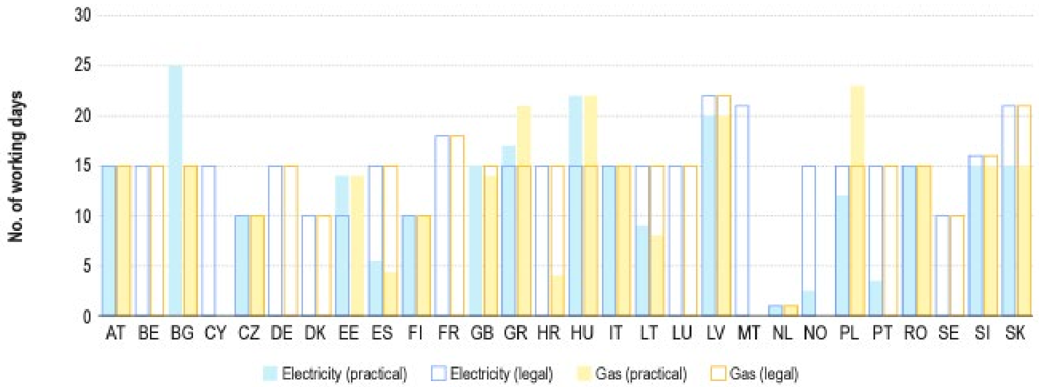


Figure 48 Legal maximum and actual switching duration in European markets in 2021. Source: ACER and CEER, Market Monitoring Report 2021, Energy Retail and Consumer Protection Volume

6.3.2. Adriatic-Ionian region

For Italy, Greece, Croatia and Slovenia the considerations and results presented in the previous section apply. For all other countries that are Energy Community Contracting Parties (Western-Balkan region), low switching rates have been observed.

In the electricity sector, the highest switching rate was observed in North Macedonia and was equal to 1.5%. All other countries displayed a switching rate below 1%.

In the gas sector, only in Serbia a very limited number of consumers changed supplier in the previous year – around 0.01%.

Looking at switching durations, the legal maximum duration of an electricity or a gas supplier switch in most Energy Community Contracting Parties is also in line with the Directive 2019/944 requirements – three weeks. Legal switching durations are reduced to 15 days in Albania and Montenegro for electricity sector.

6.4. New trends in the electricity retail sector

In this section we discuss the two main trends in the development of the electricity retail markets in Europe, that are emerging as part of the decarbonisation process.

- Energy communities
- Power Purchase Agreements (PPAs)
- Aggregation

We review each topic in turn.

6.4.1. Energy communities

The European Commission defines energy communities as follows[60]

> Energy communities organise collective and citizen-driven energy actions that help pave the way for a clean energy transition while moving citizens to the fore. They contribute to increasing public acceptance of renewable energy projects and make it easier to attract private investments in the clean energy transition. At the same time, they have the potential to provide direct benefits to citizens by increasing energy efficiency, lowering their electricity bills and creating local job opportunities.

The underlying rationale of energy communities is that small consumers that are located in geographical proximity (and therefore, connected to the same portion of the network) can benefit from self-consumption of renewable electricity produced locally. The benefit stems from the reduction in transmission and distribution costs and is shared among all members of the energy community. Also, the community can benefit from the reduced cost of the produced electricity, as this is of renewable source.

The energy community is commonly organised as follows: members of the community are supplied according to the 'standard' arrangements of the retail

60 See https://energy.ec.europa.eu/topics/markets-and-consumers/energy-communities_en

market. In particular, they may be supplied by the same entity – but this is not necessary.

Renewable electricity produced by the community members is then accounted ex-post; based on the time of its production and the electricity consumption of the community, tariff reductions are granted to the community. The cost savings are then split among the community members /for instance, based on their total consumption).

The energy community therefore largely acts as a 'virtual' layer on top of the existing retail market arrangements, which has the benefit of not creating overlaps and conflicts with the existing structure. The distinguishing feature of the energy community is that it provides a framework to incentivise and coordinate private citizens to invest in renewable energy generation facilities – creating positive economies of scale and providing a robust regulatory framework. In this context, the concept of energy communities aligns with the broader transition from centralized and fossil fuel-based energy systems to decentralized, renewable, and community-led models.

6.4.2. Power Purchase Agreements

Power Purchase Agreements (PPAs) are contractual agreements between two parties, typically an electricity generator and a buyer, that establish the terms and conditions for the sale and purchase of electricity. PPAs are function to support the development of renewable energy projects in 'market-parity' conditions (i.e., such that renewables are not remunerated under a support scheme, see section 7).

In a PPA, the electricity generator agrees to supply a specified quantity of electricity to the buyer over a defined period. The buyer is typically a utility company, a corporate entity, a government agency, or even a consortium of buyers.

Key elements typically included in a PPA are:

- Quantity and duration: The PPA specifies the quantity of electricity to be supplied and the duration of the agreement, typically ranging from 10 to 25 years. The distinguishing feature of PPAs is that they are long-term, so that the agreed-upon quantity and duration provide clarity and stability to both parties involved.
- Pricing structure: The PPA outlines the pricing structure for the electricity being supplied. This can take various forms, such as a fixed price or variable price. The pricing structure ensures transparency and establishes the financial terms of the agreement.
- Delivery and transmission: The PPA includes provisions regarding the delivery and transmission of electricity from the generator to the buyer. It may specify the point of delivery, the responsibility for transmission infrastructure, and any associated costs or liabilities.
- Operational and technical aspects: The PPA may cover technical requirements, operational standards, and performance indicators that the generator must adhere to. This ensures that the electricity supplied meets certain quality standards and operational criteria.

- Environmental attributes: Many PPAs, particularly those involving renewable energy projects, include provisions related to environmental attributes. These may address the ownership and transfer of renewable energy certificates, allowing the buyer to claim the environmental benefits associated with the electricity consumed.

PPAs provide several advantages for both electricity generators and buyers. For generators, PPAs offer long-term revenue certainty, which reduces investment risks and helps secure financing for renewable energy projects. Buyers benefit from a stable and often predictable cost of electricity over the duration of the agreement, potentially locking in favorable rates and demonstrating their commitment to sustainability and renewable energy procurement goals.

Power purchase agreement (PPA) transactions have nowadays been registered in most European countries, though various markets are at varying stages of development. The PPA market is dominated by five regions: Iberia leads in solar deals, Germany in solar and offshore wind deals, the UK and Benelux in offshore wind agreements, and the Nordics in onshore wind deals. Finland, Portugal, and France are among the developing markets.

A growing number of newcomers have agreed to a PPA: around a quarter of Europe's 33.4 GW of renewable energy installations in 2020 are reported to have signed a PPA[61].

6.4.3. Aggregation of distributed resources

Aggregation, in the context of electricity retail markets, refers to the practice of combining or grouping multiple electricity resources into a single entity for the purposes of providing services to the electricity system.

In the European market model, aggregation of small and distributed resources to provide balancing services is a natural feature of the design, since market participants submit their offers in the market for portfolios of units. As participants bear balancing responsibility for the overall portfolio, and not for each single unit within the portfolio, they can reduce imbalances for the portfolio by dispatching any resource, including distributed ones. This is the so-called ‘self-balancing’ principle.

In addition, most European market designs also support the participation of distributed resources to the ancillary services market – usually to provide (at least) balancing services. Under this design, the aggregated unit (commonly referred to as ‘virtual power plant’, VPP) acts as a virtual entity towards the system operator, submitting offers as an aggregated entity and then dispatching the activations received by the system operator towards the individual resources.

Note that since each resource will belong to both a portfolio (for balancing purposes) and a VPP (for the purpose of submitting offers in the ancillary services markets), complex interactions are required between the party responsible for the imbalances (the Balancing Responsible Party, BRP) and the party responsible for

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61 Source: IHS Markit

offers and activations in the ancillary services market (Balancing Service Provider, BSP – a newly defined institutions specifically related to VPPs).

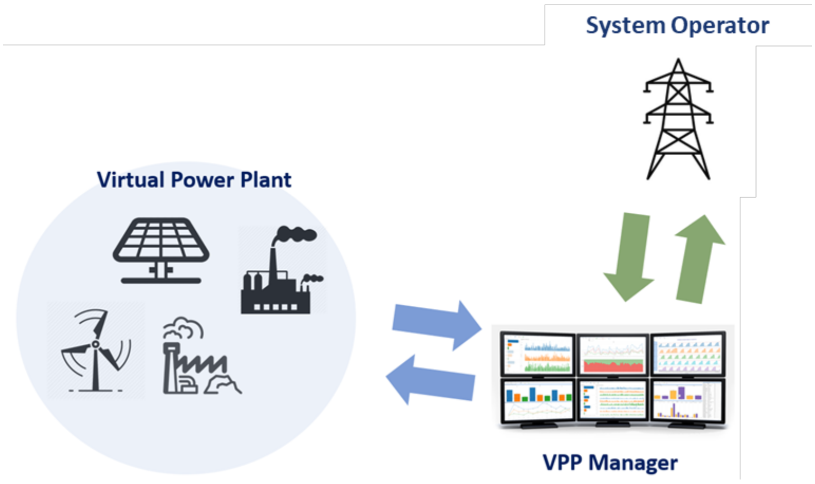


Figure 49 Schematical representation of a virtual power plant (VPP)

Note that aggregating small, distributed resources is usually associated with higher costs, since it requires setting up an IT infrastructure that can monitor and control each individual consumption and injection point. Since this cost is to a large extent fixed per point, the unitary cost of aggregation increases as the size of resources decreases. For this reason, support schemes have been developed in many countries to support the set-up of VPPs and foster the participation of distributed resources to the ancillary services markets.

Finally, as distributed resources are (most commonly) connected to the distribution networks, distribution system operators (DSOs) are emerging as new key players in the flexibility markets for the future, decarbonised electricity sector. Unlocking the full potential of the flexibility of distributed resources will in fact require DSOs to be able to monitor, control and activate resources connected to their network to meet the increasing flexibility needs of the electricity system, also in coordination with TSOs at the transmission network level.

6.5. Perspectives in the Adriatic-Ionian region

In this section we discuss the status and perspectives for the retail sector in the Adriatic-Ionian region. A more detailed discussion of the current status of the retail sector is provided in the Annexes.

Consumer protection measures are widely employed in the region, most commonly via regulated-price regimes aimed at domestic consumers (for both electricity and gas). In some countries, the market is dominated by the incumbent player, supply at regulated price conditions – so that even if retail is formally liberalised and consumers can access free-market offers, competition is limited.

The structure of the market and the organisation of the sector is relatively homogeneous across the region, since all countries implement unbundling provisions and provides for free-market offers. However, there might be less room for competition in small markets for some countries in the Western Balkans, that could result in a relatively lower degree of engagement – measured e.g. in terms of switching out of the regulated-price regime.

In terms of new trends in the retail sector,

- Energy communities may develop in line with is happening in Europe; their evolution is strongly influenced by the choices of national authorities as energy communities require the development of an appropriate policy framework transferring them the benefits of a reduced utilisation of the network
- Regarding PPAs, it appears unlikely that a strong PPA market arises before the development of renewable capacity is at an advanced stage. Looking at the EU experience, renewables growth is first supported by support policies, before moving to market-parity
- Aggregation of distributed resources require the development of advanced ancillary services markets in line with the European framework.

7. SUPPORT SCHEMES FOR RENEWABLE GENERATION CAPACITY

As the deployment of large-scale renewable electricity generation capacity increases in line with the European decarbonisation targets, investment costs shall reduce so that renewable energy projects are expected to become competitive even in the absence of public support.

However, while markets alone can deliver most of the desired level of additional capacities of renewables in the EU, national support schemes are also needed to spur increased investment in renewable energy in view of the increased ambition under the European Green Deal and REPowerEU.

Support schemes aimed at renewable generators pursue a twofold objective:

i) governing the development of the generation fleet, transferring risk from investors to consumers; and

ii) extracting rents from generators.

Moreover, the decarbonisation process poses material challenges associated to the size and urgency of the investments required, as well as the integration of intermittent renewable energy sources into the electricity mix.

A number of different support mechanisms has been designed and implemented to support generation capacity from renewable energy sources in Europe. These fall into three main categories:

- Feed-in-tariffs (FiT), in which the renewable generator receives a flat €/kWh remuneration for each kWh produced, irrespective of the time of production;
- Feed-in-premia (FiP), in which the renewable generator receives an additional remuneration on top of the spot market price (usually, the hourly day-ahead price);
- Contracts for difference (CfD), in which the renewable generator receives an integration on top of the spot market price up to a predetermined strike price.

We discuss these three models in more detail below.

Feed-in tariffs, feed-in-premia and contracts for difference

Alternative variations of the mechanisms listed above have been developed to address the issue of integration renewables into the spot market more effectively. In fact, a key feature of FiT schemes is that they do not provide renewable generators any incentive to produce in the hours when electricity is more valuable, i.e., when demand is higher (since the remuneration is independent on the time of production).

Feed-in-premia (FiP) have been introduced precisely to address this issue: by giving the renewable generator exposure to the spot prices, it provides them with the incentive to generate in higher-price hours. However, the FiP in this context is still “fixed”, i.e., a value in €/kWh that is independent on the market price. This implies that the generator receives an additional revenue on top of the market price (the "premium"), but still he or she may over-recover costs if the market price is high, or under-recover costs if the market price is low.

The same principle as fixed FiP schemes is applied to contract for differences (CfD), but in this case the "premium" on top pf the market price is determined as the difference between a predetermined strike price and the market price. This effectively provides a so-called "sliding" (rather than "fixed") feed-in-premium that guarantees the generator a level of revenues up to the strike price.

In this so-called "one-way" CfD (also referred to as sliding FiP), cashflows are established only in case the market price falls below the strike price. A variation of this mechanism is the so-called "two-way" CfD, in which the renewable generator also returns any revenue in excess of the strike price, effectively stabilizing the revenues at the strike price level.

Figure 50 below shows the four support mechanisms described.

Figure 50 Feed-in-tariffs and feed-in-premia (left panel) and contracts for difference (right panel)

Another relevant dimension to be considered in the design of renewable support mechanisms is the quantity that defines the remuneration of the generator. In the first implementations of the models presented above, the actual production (determined ex-post) was used. An evolution of the model (implemented for instance for fixed FiP schemes in Germany) sets the volume to a benchmark level determined as the average from generators of the same technology. This gives each individual generator the incentive to "beat the benchmark", injecting electricity with a different – and more valuable – time profile than other similar generators. This incentive is aligned with the system's welfare maximisation objective, because a more valuable time profile corresponds to increased injections in periods of higher demand.

In all the mechanisms described above, a central counterparty is established for the settlement towards (and from, in the case of two-ways CfDs) renewable generators. This central entity then markets the renewable production at the spot price, thus implementing the risk transfer from renewable generators to final consumers. All costs associated with support schemes are usually recovered in ad-hoc tariff components in the consumers' electricity bills.

Finally, we remark that in early implementations of the mechanisms described above, the FiT or FiP ultimately determining the remuneration was set administratively, based on estimations of the costs of each technology. Subsequently, auctions started to be used extensively across Europe to determine the remuneration level (either feed-in-tariff, feed-in-premium or the strike price in case of CfDs). Usually, auctions are differentiated by technology (e.g., solar, onshore wind, offshore wind) to ensure that investors in each technology can compete on a level playing field.

Figure 51 Countries that implemented auctions for renewable support schemes, with the year when the first auction was held. Source: DG ENER[62]

Contracts for differences as instruments to support the decarbonisation process

On 14th March 2023, the European Commission launches a proposal to reform the EU internal electricity market "to boost renewables, better protect consumers and enhance industrial competitiveness"[63]. The proposal foresees revisions to several parts of the legislation and design, as also discussed in section 2.

[62] Zabala, C., Diallo, A., (2022) Study on the performance of support for electricity from renewable sources granted by means of tendering procedures in the Union 2022, Publications Office of the European Union – https://op.europa.eu/en/publication-detail/-/publication/e04f3bb2-649f-11ed-92ed-01aa75ed71a1/language-en?WT_mc_id=Searchresult&WT_ria_c=37085&WT_ria_f=3608&WT_ria_ev=search&WT_URL=https%3A//energy.ec.europa.eu/

[63] The full proposal can be retrieved at: https://ec.europa.eu/commission/presscorner/detail/en/IP_23_1591

The proposed reform selects two-way CfD as the go-to support instrument (including for renewables). The EU Commission states that

> In order to provide power producers with revenue stability and to shield industry from price volatility, all public support for new investments in infra-marginal and must-run renewable and non-fossil electricity generation **will have to be in the form of two-way Contracts for Difference (CfDs)**, while Member States are obliged to channel excess revenues to consumers.

It is therefore worth discussing in more detail the implications of different implementation of two-way CfDs. These are contracts in which the generator and the central counterparty (i.e., consumers) agree to exchange payments based on the difference between the strike price and the market price, multiplied by a volume (in kWh).

While it is commonly accepted that the strike price is selected via an auction, and the market price is identified as the day-ahead hourly price, different implementations of the CfD model differ for the definition of the volume that defines the payment. Given the purpose of the scheme implemented, this can be alternatively defined as:

- The actual hourly production. This leads to the two-way CfD effectively implementing a FiT scheme (where the tariff is defined by the strike price). In fact, the generator known with certainty that the total remuneration (say, at the end of the year) will be equal to the total production in kWh (irrespective of the time of production) multiplied by the strike price
- A constant volume for all hours in the year. This leads to the one-way CfD model, formally equivalent to an option contract for the generator
- A standard hourly profile per technology and market zone. This leads to the model used in Germany and Spain in the early 2000s
- A production potential, as proposed by ENTSO-E in a recent paper[64]
- A reference production profile that defines the payment from the generator, in exchange for a fixed payment by the central entity – see the recent proposal by Schlect et al.[65]

As shown by these definitions, the CfD scheme can be extremely versatile and flexible. It is therefore essential for this instrument to be carefully designed to meet the targets set by the regulator. In particular, different definitions lead to different balancing responsibilities for the renewable generator; more 'market-based' implementations of the CfD shall require the generator to maintain balancing responsibility.

[64] ENTSO-E Position on the EC proposals on Market Design, 31st March 2023 - https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/Publications/Position%20papers%20and%20reports/2023/entso-e_EMDR_One-pagers_230331.pdf

[65] Schlecht, I., Hirth, L. Maurer, C. Financial Wind CfDs, Leibniz Information Centre for Economics, Kiel, Hamburg, 2022 - http://hdl.handle.net/10419/267597

ANNEX A COUNTRY SHEETS: ELECTRICITY

Fundamentals of the electricity sector

We present in this section the electricity sector fundamentals for the Adriatic-Ionian region. For each country we review the following quantities:

- Structure of the demand and supply
- Consumption per sector
- Electricity prices for final consumers

Italy (EUSAIR)

Demand and supply

Italy represents the largest market in the Adriatic-Ionian region, with a total consumption (from EUSAIR regions only) of 232.5 TWh in 2021[66]. In the following we shall refer to the Italian regions that are part of the Adriatic-Ionian region as Italy (EUSAIR).

The following **Figure 52** displays the electricity balance for Italy (EUSAIR) region for the period 2012-2022. Italy is historically a net importer, with national production meeting about 90% of total consumption in 2021.

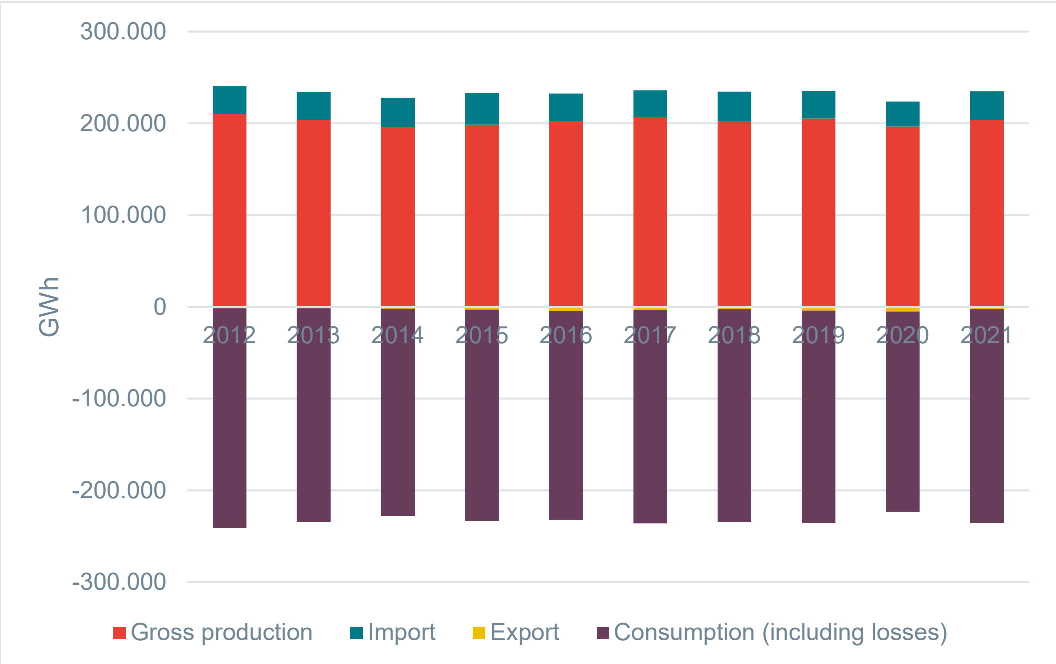


Figure 52 Electricity balance for Italy (EUSAIR) in the period 2012-2021. Source: Eurostat

Figure 53 below shows the breakdown of electricity production sources for Italy (EUSAIR) in 2021. Data for each Italian region is provided by the Italian TSO,

[66] This also includes San Marino. Data is available for the entire country, and estimated for the EUSAIR quota using a 70% share extrapolated from 2019 data

Terna. As the figure shows, gas-fired generation is very relevant in the Italian mix (47%), followed by renewable sources (hydro, solar, wind, geothermal and biomass make up 38% of the total supply). Other fossil-fuel sources include coal (7%) and oil (15%).

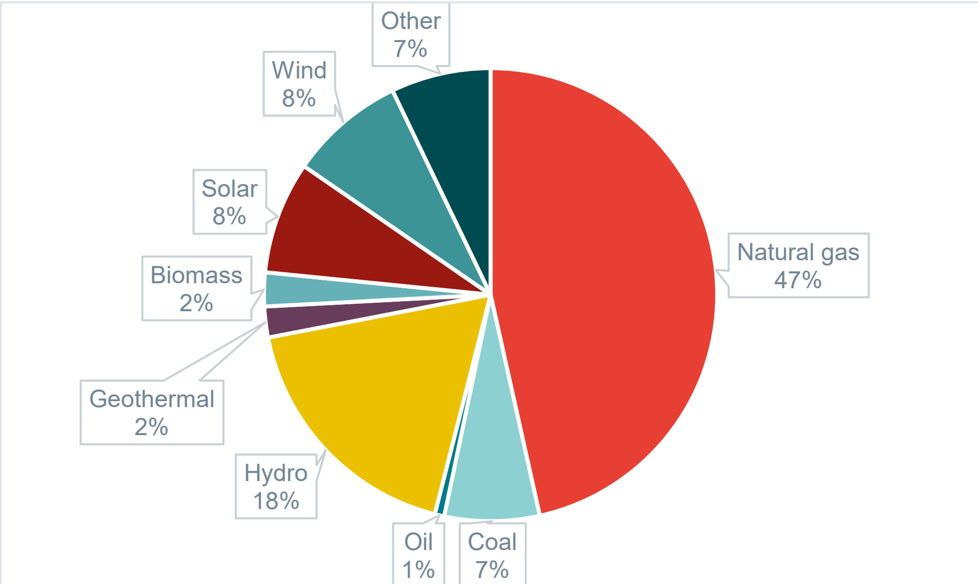


Figure 53 Electricity production by source in Italy (EUSAIR) for year 2021. Source: Eurostat and Terna

Electricity consumption per sector

Figure 54 displays the final energy consumption in Italy in 2021, with electricity highlighted in red. Electricity accounts for about a fifth of the total final consumption, equally split between industrial uses and other sectors (mostly, residential and businesses).

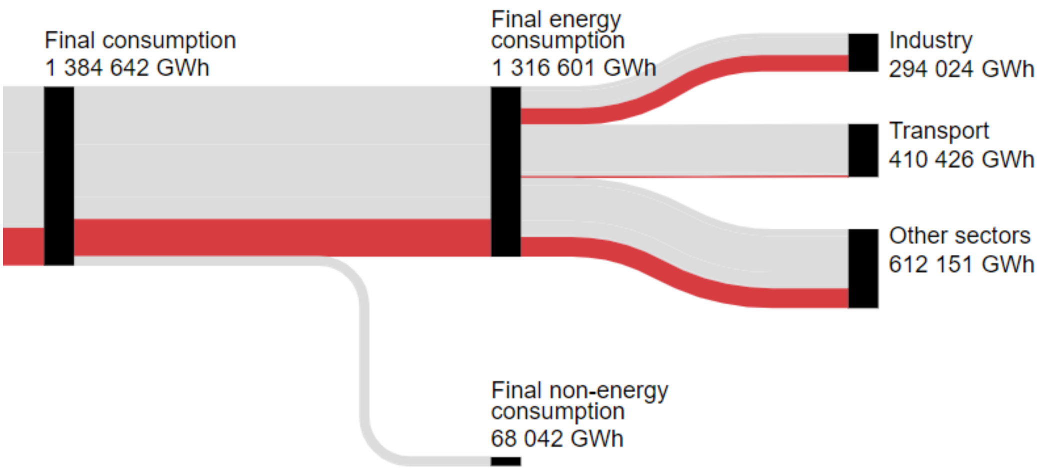


Figure 54 Energy consumption by sector in Italy in 2021, with electricity highlighted. Source: Eurostat

Electricity prices for final consumers

The following **Figure 55** shows the evolution of electricity prices for final consumers in the period 2012-2022. Non-household prices displayed a stable pattern about

20% higher than household prices. Prices for end-consumers increases materially in 2022, following the energy prices crisis in Europe. Overall, prices in Italy are on average higher than other countries in the Adriatic-Ionian region, and particula

Figure 55 Electricity prices for household and non-household final consumers in Italy in the period 2018-2021. Source: Eurostat

Slovenia

Demand and supply

The following **Figure 56** displays the electricity balance for Slovenia for the period 2012-2021. As of 2021, electricity consumption reached 15,614 GWh, while electricity generation was at 15,885 GWh – making Slovenia a net exporter.

Figure 56 Electricity balance for Slovenia in the period 2012-2021. Source: Eurostat

Figure 57 below shows the breakdown of electricity production sources for Slovenia in 2021, showing a dominance from hydro sources (33%) and coal-fired generation (24%)

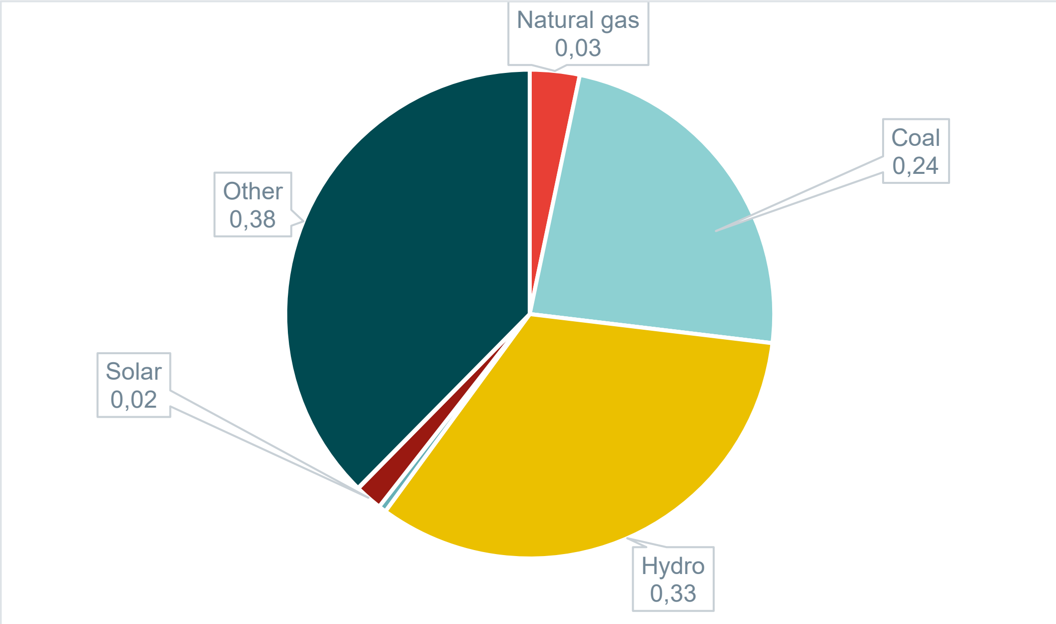


Figure 57 Electricity production by source in Slovenia for year 2021. Source: Eurostat

Electricity consumption per sector

Figure 58 below displays the final energy consumption in Slovenia in 2021, with electricity highlighted in red. As the figure displays the largest quota of electricity consumption is for other sectors (7.2 TWh), followed by direct consumption for energy uses for industry (6.1 TWh), and a marginal quota of consumption in the transportation sector.

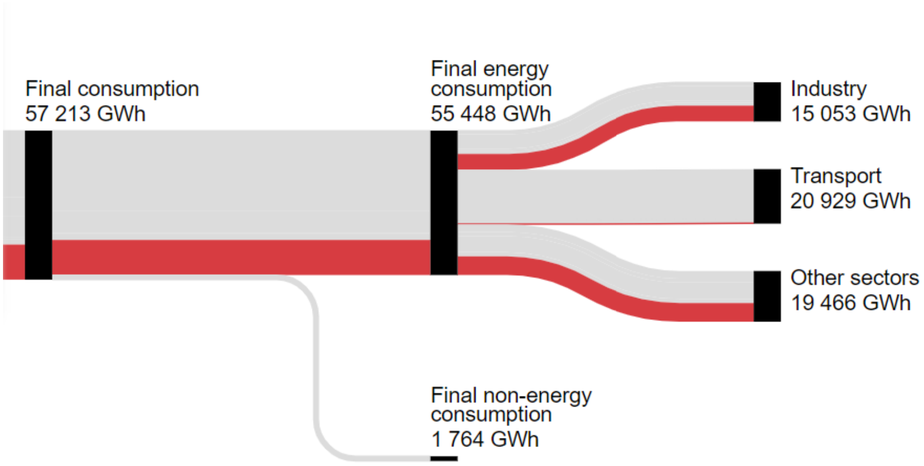


Figure 58 Energy consumption by sector in Slovenia in 2021, with electricity highlighted. Source: Eurostat

Electricity prices for final consumers

Household and non-household electricity prices in Slovenia are relatively aligned and settled around 10 c€/kWh, with an increase (particularly for the non-household segment, where prices reached the 20 c€/kWh level) in the second semester of 2022.

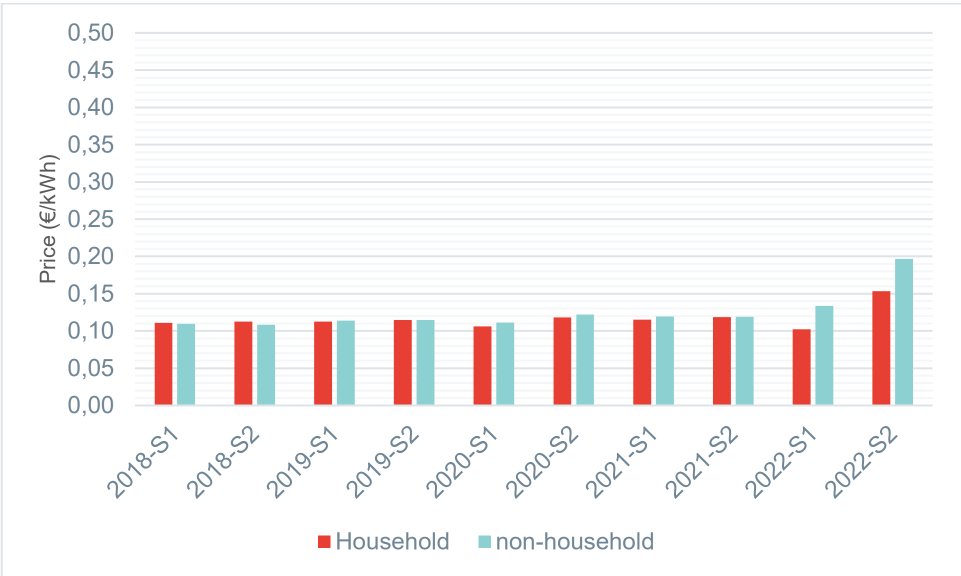


Figure 59 Household and non-household electricity prices in Slovenia. Source: Eurostat

Croatia

Demand and supply

The following **Figure 60** displays the electricity balance for Croatia for the period 2012-2022. As of 2021, Croatia consumed about 20,379 GWh of electricity and exported an additional 7,543. Supply was provided via imports (11,504 GWh) and national production (16,418 GWh).

Figure 60 Electricity balance for Croatia in the period 2012-2021. Source: Eurostat

Figure 61 below displays the breakdown of electricity production sources for Croatia in 2021, showing that Croatia features a hydro-dominated electricity mix (48%) with a material wind contribution to renewable penetration (15%); gas (19%) and coal (9%) are the main fossil-fuel sources in the country.

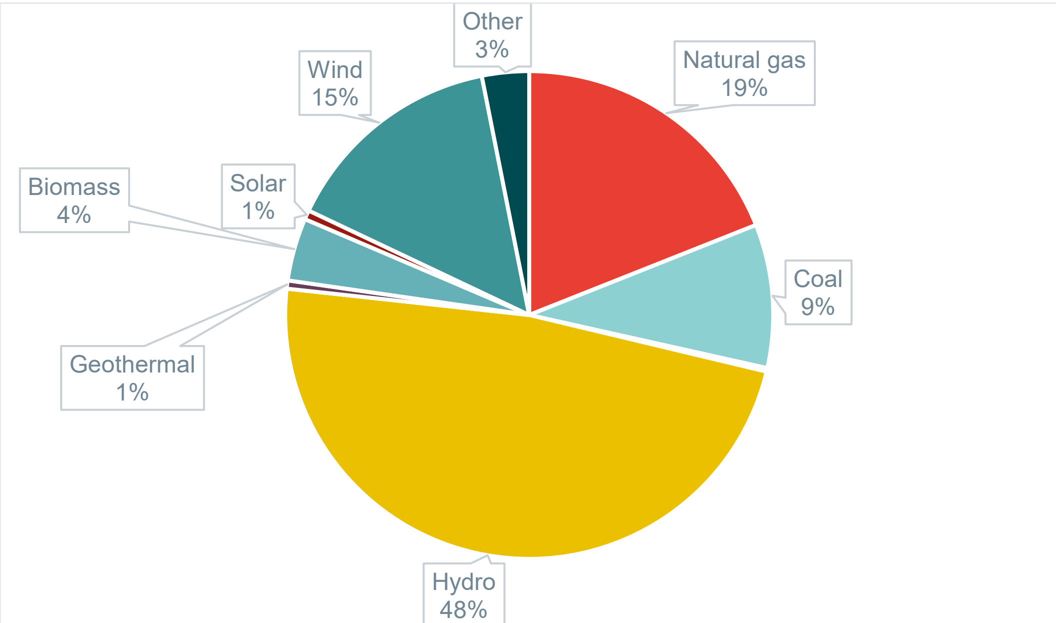


Figure 61 Electricity production by source in Croatia for year 2021. Source: Eurostat

Electricity consumption per sector

Figure 62 displays the total energy consumption in Croatia in 2021, with electricity highlighted in red. As the figure displays the largest quota of electricity consumption is for other sectors (12.4 TWh, 75.3% of total consumption), followed by electricity consumption in industry (3.8 TWh). A small quota is used by transportation (0.3 TWh).

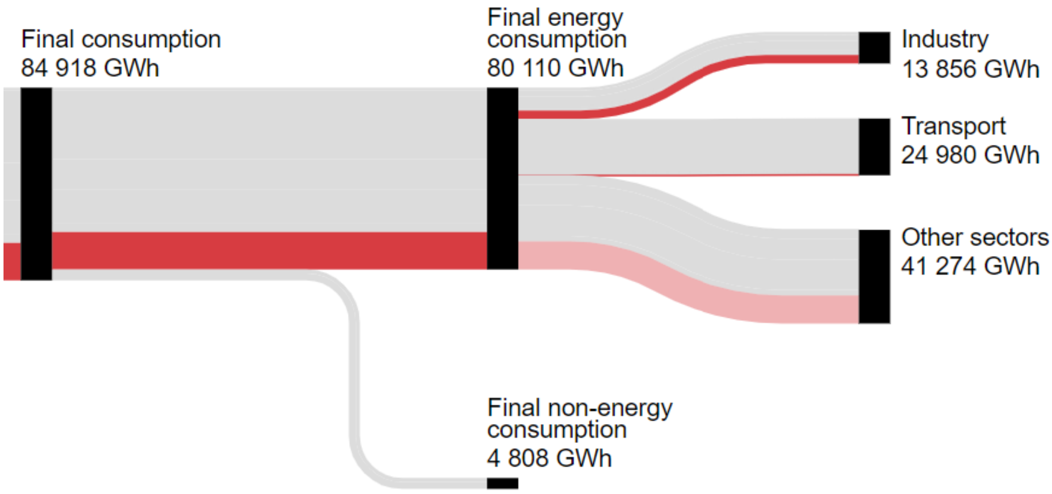


Figure 62 Energy consumption by sector in Croatia in 2021, with electricity highlighted. Source: Eurostat

Electricity prices for final consumers

Electricity prices in Croatia settled at around 10 c€/kWh and 12 c€/kWh for household and non-household consumers, respectively. Following the energy price crisis, prices for non-household consumers spiked up to 35 c€/kWh in the second semester of 2022, while prices were maintained below the 12 c€/kWh threshold for household consumers.

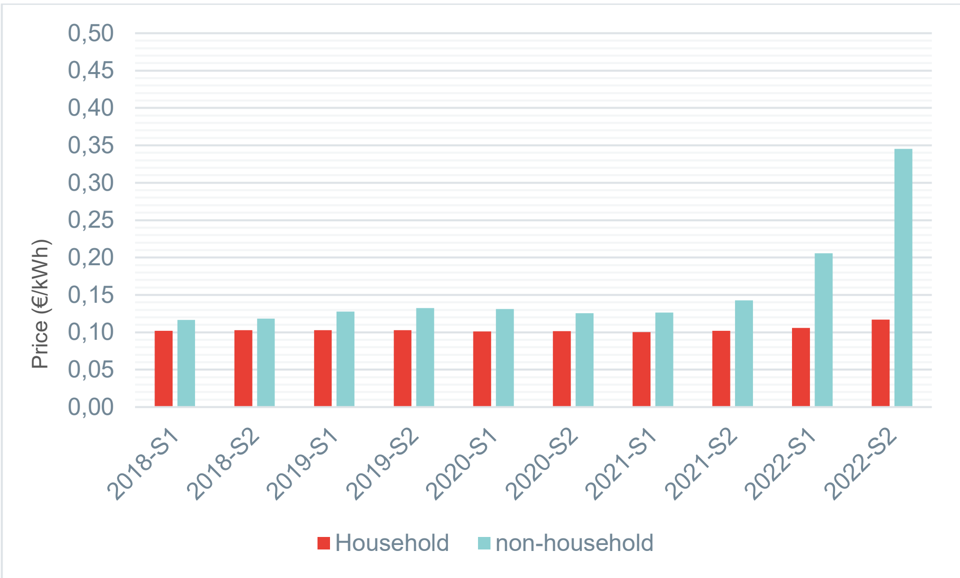


Figure 63 Household and non-household electricity prices in Croatia. Source: Eurostat

Bosnia and Herzegovina

Demand and supply

The following **Figure 64** displays the Electricity balance for Bosnia and Herzegovina for the period 2014-2021. As of 2021, Bosnia and Herzegovina was responsible for a consumption of 13,959 GWh and contributed with 8,014 GWh of experts towards neighbouring countries. Generation amounted to 18,714 GWh and imports contributed for 3,259 – making Bosnia and Herzegovina a net electricity exporter.

Figure 64 Electricity balance for Bosnia and Herzegovina in the period 2014-2021. Source: Eurostat data

Figure 65 below displays the breakdown of electricity production sources for Bosnia and Herzegovina in 2021, showing that (as for other Western Balkan countries) hydroelectric generation brings a relevant contribution to the mix (35%), followed by biomass (35%) and natural gas (27%).

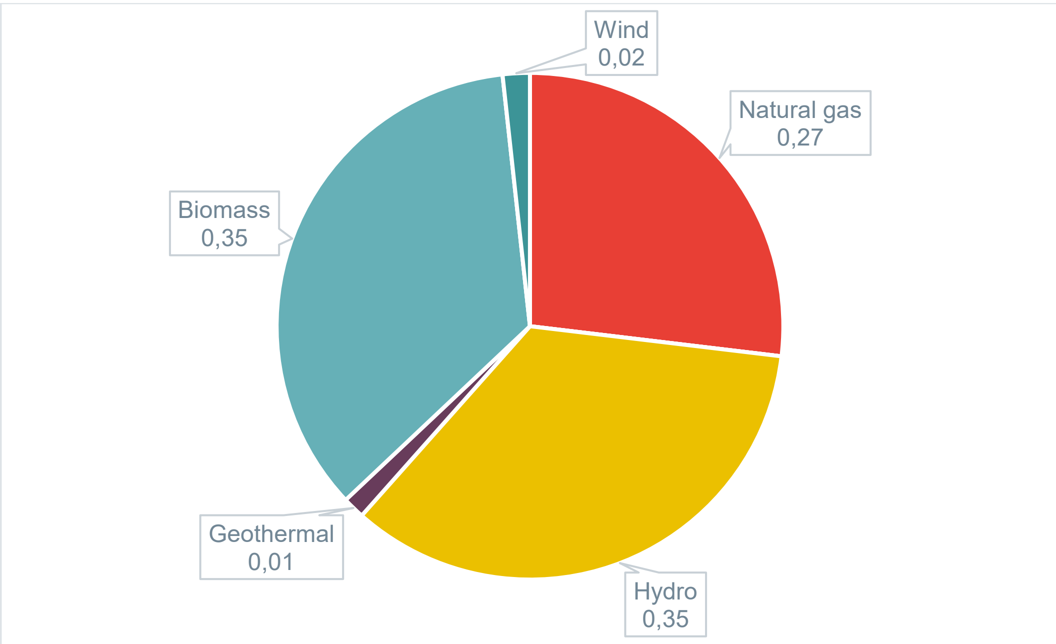


Figure 65 Electricity production by source in Bosnia and Herzegovina for year 2021. Source: Eurostat

Electricity consumption per sector

Figure displays the final energy consumption in Bosnia and Herzegovina in 2021, with electricity highlighted in red. As the figure displays the largest quota of electricity consumption is for other sectors (7.3 TWh, 73.2% of total consumption), followed by consumption in industrial uses (2.6 TWh). A small quota is used by transport (0.06 TWh).

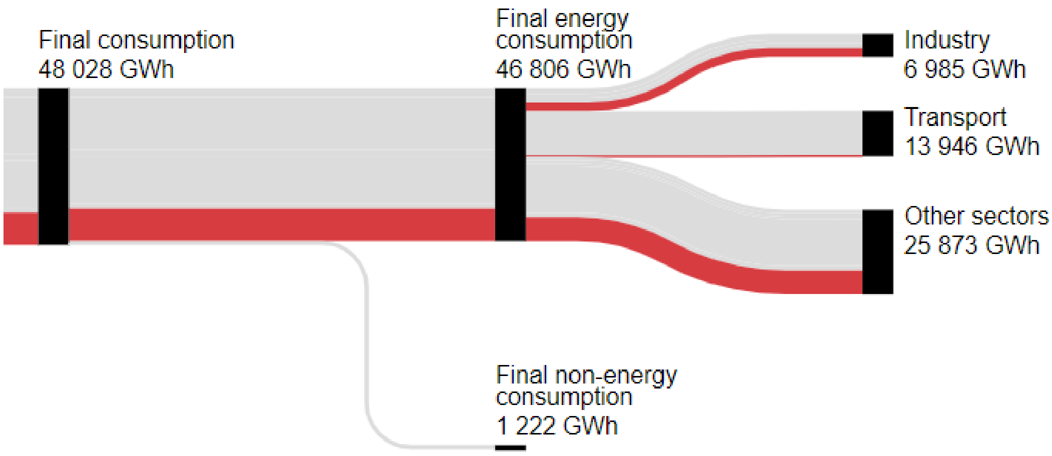


Figure 66 Energy consumption by sector in Bosnia and Herzegovina in 2021, with natural gas highlighted. Source: Eurostat

Electricity prices for final consumers

The following Figure 67 displays the household and non-household electricity prices in Bosnia and Herzegovina. Prices observed are lower than for other Adriatic-Ionian countries, settling at around 10 c€/kWh for non-household consumers and below the 8 c€/kWh level for household consumers. Following the energy price crisis, apparently consumers have been protected via policy tools – only non-household prices increased by about 25%, materially less than in other countries.

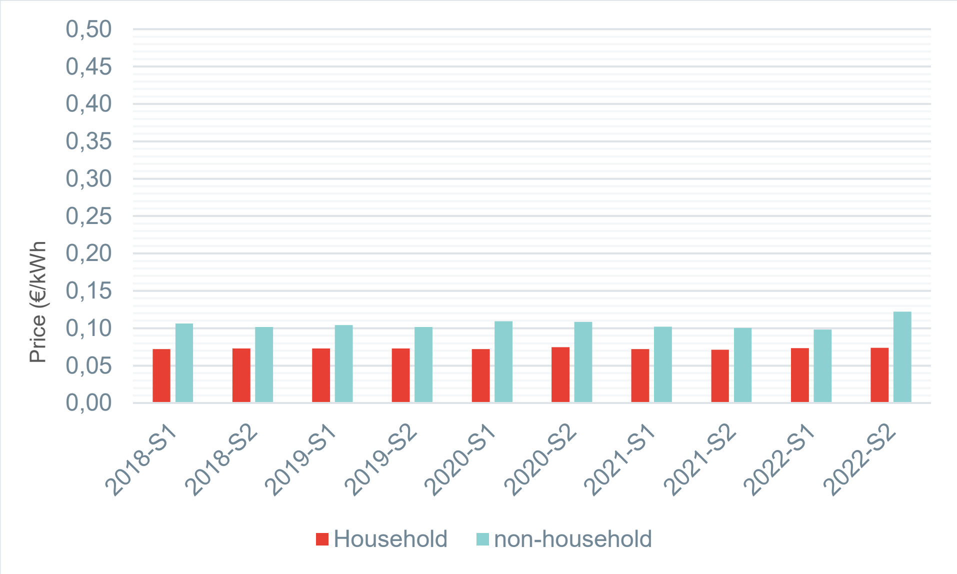


Figure 67 Household and non-household electricity prices in Bosnia and Herzegovina. Source: Eurostat

Republic of Serbia

Demand and supply

The following **Figure 68** displays the Electricity balance for Republic of Serbia for the period 2012-2021. Serbia imports and exports roughly the same amount of electricity over the year; as of 2021, 40,485 GWh of electricity were met by local generation for a 98.3% share (generation: 39,833 GWh).

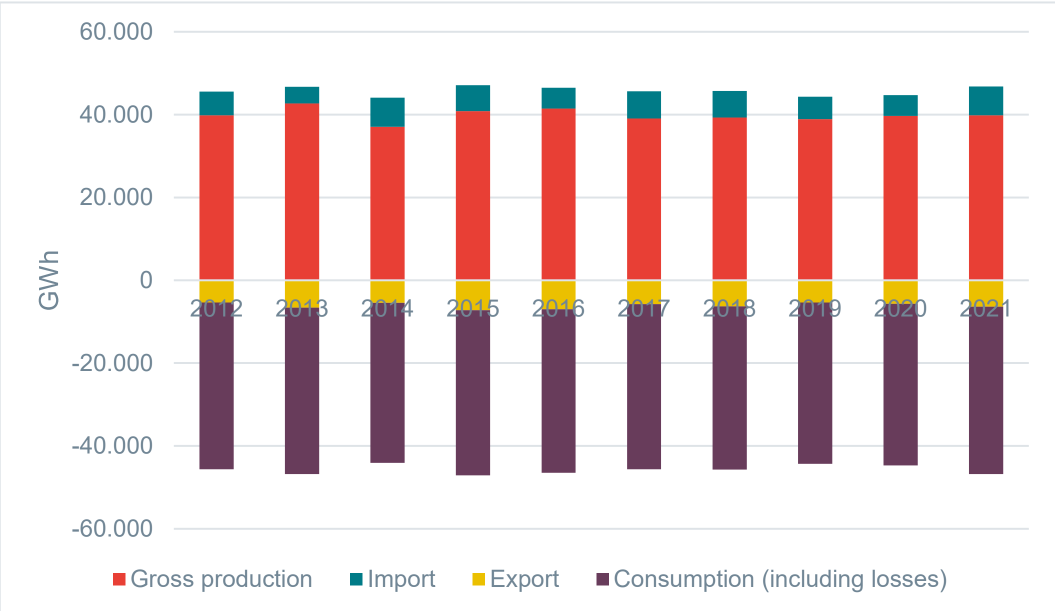


Figure 68 Electricity balance for Republic of Serbia in the period 2012-2021. Source: Eurostat

Two sources dominate the Serbian electricity mix: coal (62%) and hydro (34%), as displayed by the following **Figure 69**.

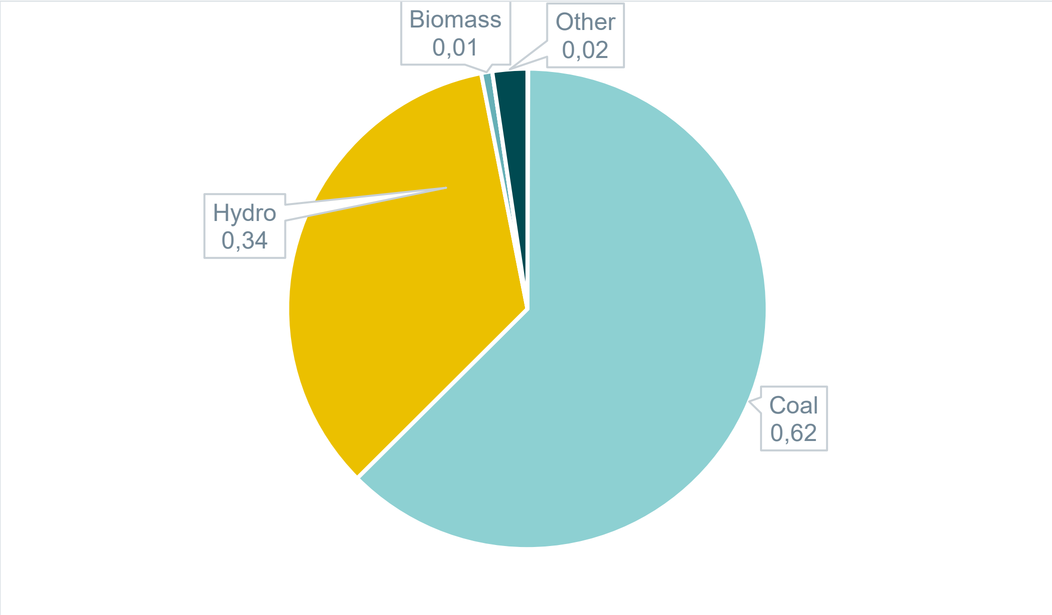


Figure 69 Electricity production by source in Serbia for year 2021. Source: Eurostat

Electricity consumption per sector

Figure 70 displays the final energy consumption in Republic of Serbia in 2021, with electricity highlighted in red. As the figure displays the largest quota of electricity consumption is for other sectors (18.9 TWh, 67.8% of total consumption), followed by electricity consumption for industry (8.6 TWh). A small quota is used in the transportation sector (0.3 TWh).

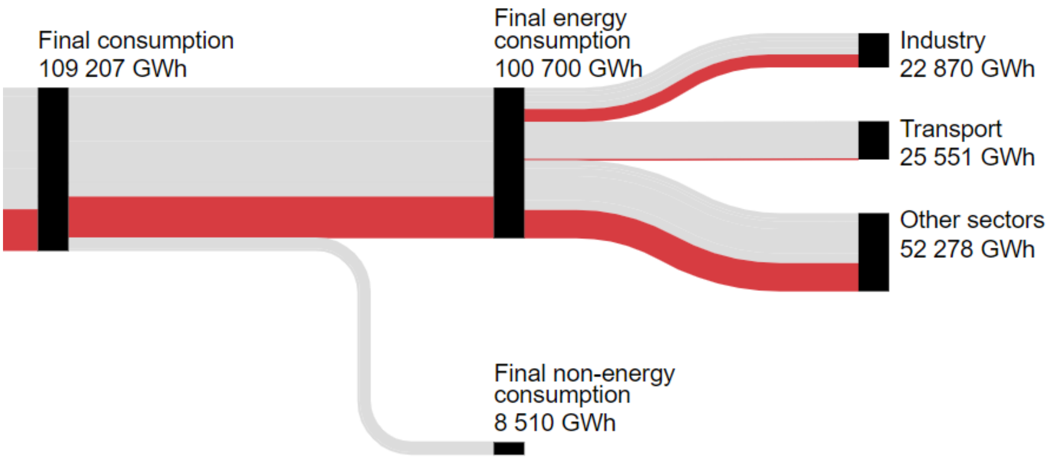


Figure 70 Energy consumption by sector in Republic of Serbia in 2021, with electricity highlighted. Source: Eurostat

Electricity prices for final consumers

The following **Figure 71** displays the household and non-household electricity prices in the Republic of Serbia. Prices observed are relatively lower than for other Adriatic-Ionian countries, settling below the 10 c€/kWh level for both household and non-household consumers in the past four years.

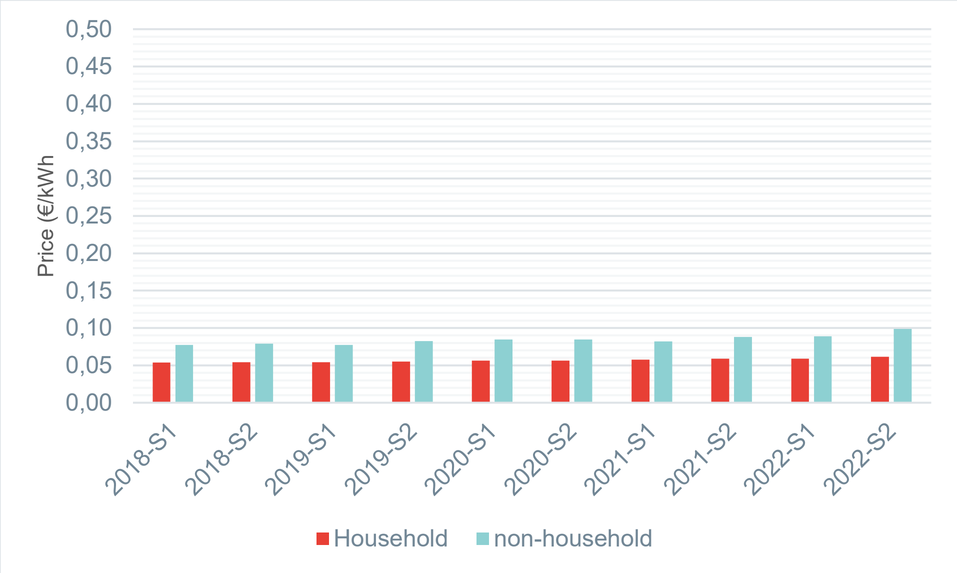


Figure 71 Household and non-household electricity prices in Serbia. Source: Eurostat

Montenegro

Demand and supply

The following **Figure 72** displays the electricity balance for Montenegro for the period 2012-2022. While consumption is relatively stable through the years (2021 value: 3,985 GWh), imports and exports increased in 2020; Montenegro is currently a net exporter (2021 exports: 5,489 GWh, 2021 imports:4,156 GWh), with national production contributing for 5,318 GWh in 2021.

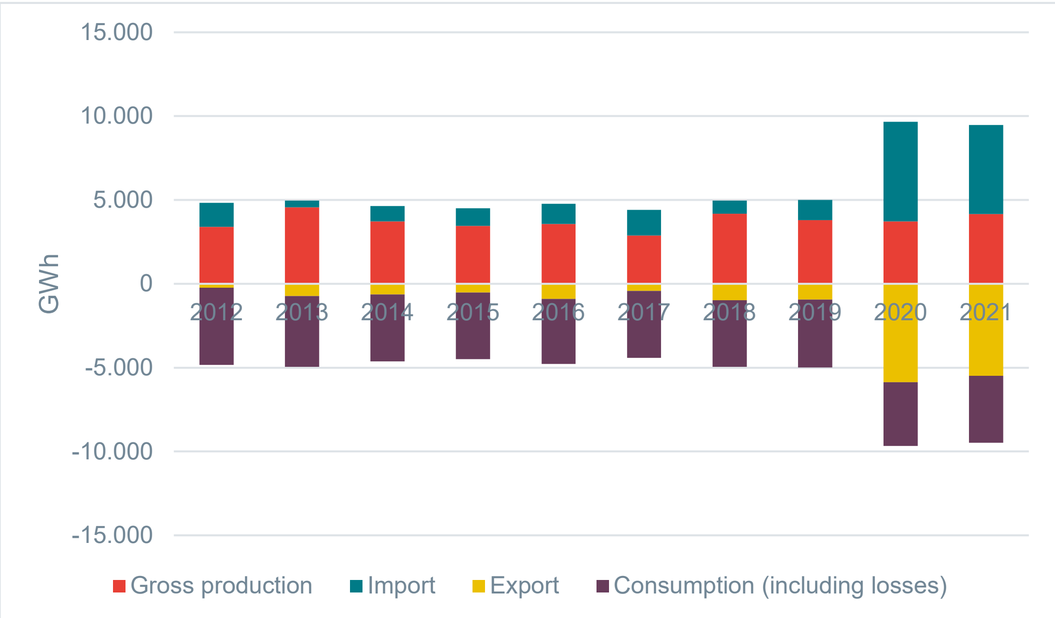


Figure 72 Electricity balance for Montenegro in the period 2012-2021. Source: Eurostat

Looking at the generation mix in Montenegro, hydroelectric generation contributes for 53%, followed by coal (38%) and wind generation (9%).

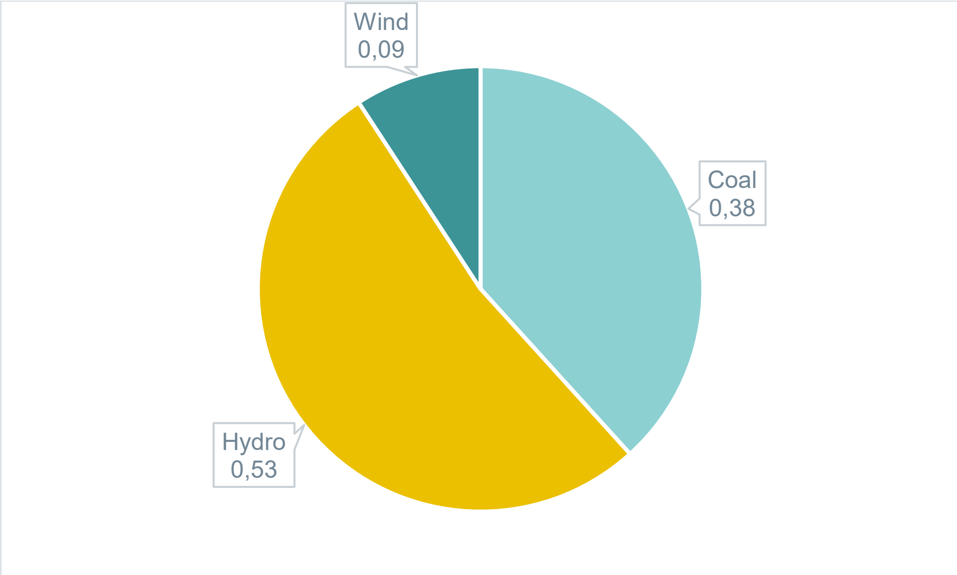


Figure 73 Electricity production by source in Montenegro in 2021. Source: Eurostat

Electricity consumption per sector

Figure 74 displays the total energy consumption in Montenegro in 2021, with electricity highlighted in red. As the figure displays the largest quota of electricity consumption is for other sectors (2.1 TWh, 75% of total consumption), followed by electricity consumption for industrial uses (0.7 TWh). A marginal share of electricity consumption is dedicated to the transportation sector.

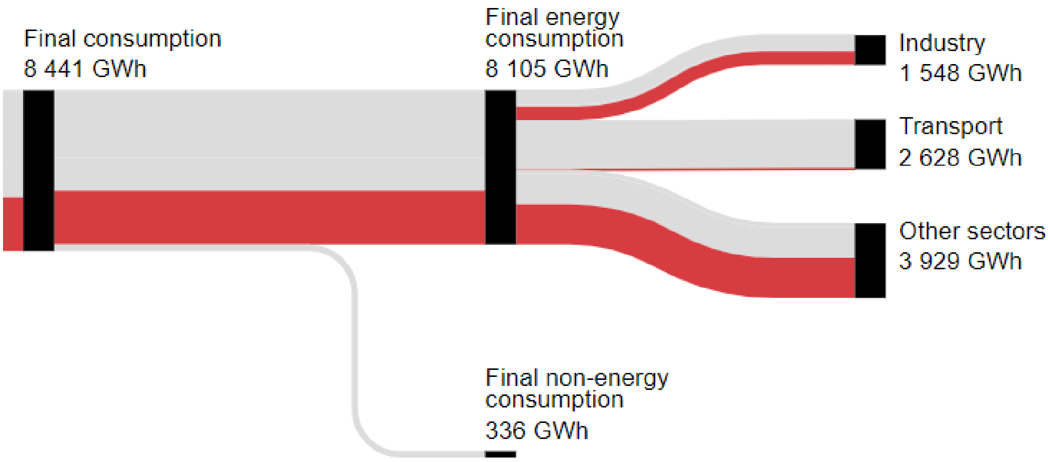


Figure 74 Energy consumption by sector in Montenegro in 2021, with electricity highlighted. Source: Eurostat

Electricity prices for final consumers

As in Bosnia and Herzegovina and Serbia, household and non-household electricity prices in Montenegro were stable and below the 10 c€/kWh – even through 2022.

Figure 75 Household and non-household electricity prices in Montenegro. Source: Eurostat

Albania

Demand and supply

While relatively volatile, Albania's electricity consumption has shown an increasing trend from 2012 (8,375 GWh) to 2021 (9,745 GWh). Despite its ample hydroelectric potential, export capacity is currently limited – so that Albania is, in most years, a net importer (2021 being the exception with around 550 GWh of electricity exported to neighbouring countries).

Figure 76 Electricity balance for Albania in the period 2012-2021. Source: Eurostat

Albania disposes of ample hydroelectric capacity; as of 2021, this covered 96% of the consumption with the remaining 4% met via oil-fired generation.

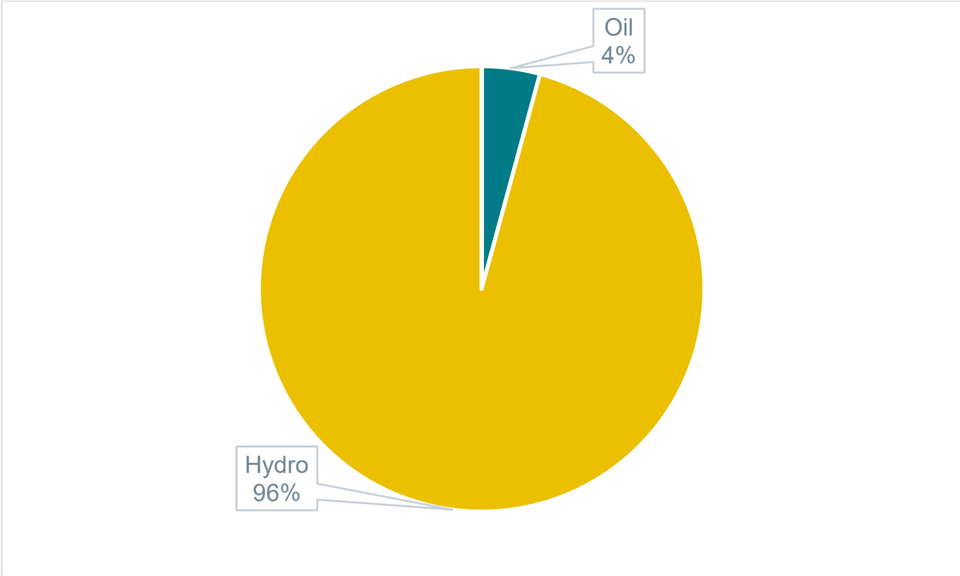


Figure 77 Electricity production by source in Albania in 2021. Source: Eurostat

Electricity consumption per sector

Figure displays the total energy consumption in Albania in 2021, with electricity highlighted in red. As the figure displays the largest quota of energy consumption is for other sectors (4.9 TWh, 78.4% of total consumption), followed by consumption in the industry (1.4 TWh) and a marginal quota (0.1 TWh) in the transportation sector.

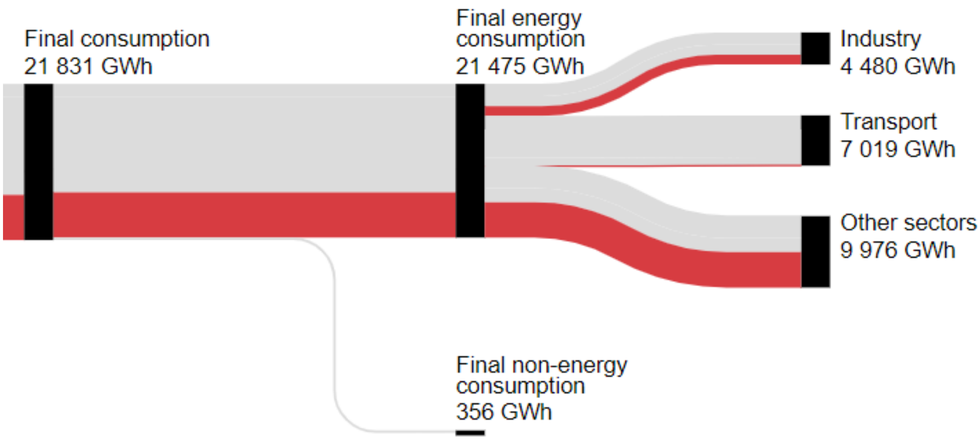


Figure 78 Energy consumption by sector in Albania in 2021, with electricity highlighted. Source: Eurostat

Electricity prices for final consumers

The following **Figure 79** displays the electricity prices in Albania, showing that both household and non-household consumers enjoyed relatively low prices over the years (up to around 10 c€/kWh, even throughout the energy price crisis).

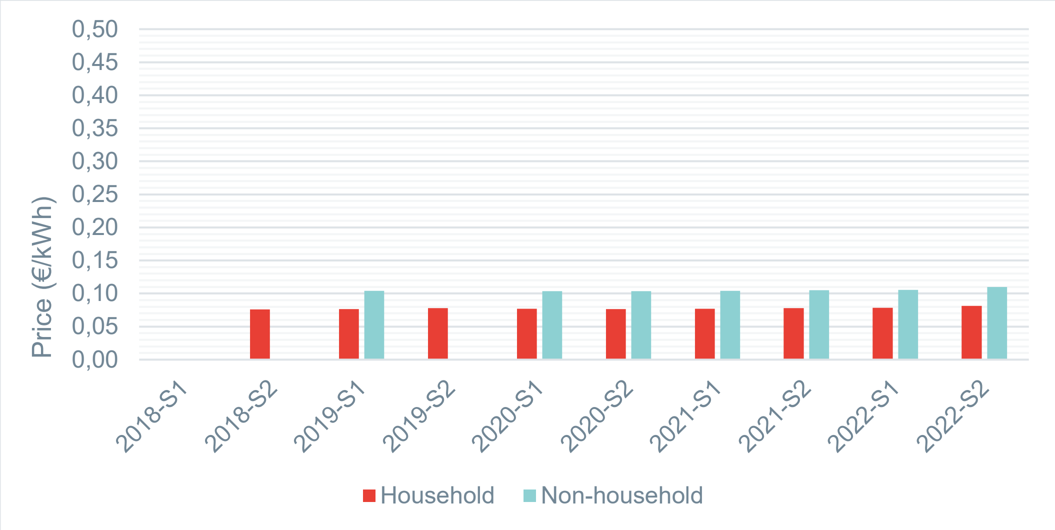


Figure 79 Household and non-household electricity prices in Albania. Source: Eurostat

Greece

Demand and supply

Greece is one of the largest electricity markets in the Adriatic-Ionian region, with around 62,352 GWh of consumption in 2021, met at 94% (58,668 GWh) by local production and by 6% (3,684 GWh) by net imports into the country.

The following **Figure 80** displays the electricity balance for Greece for the period 2012-2021.

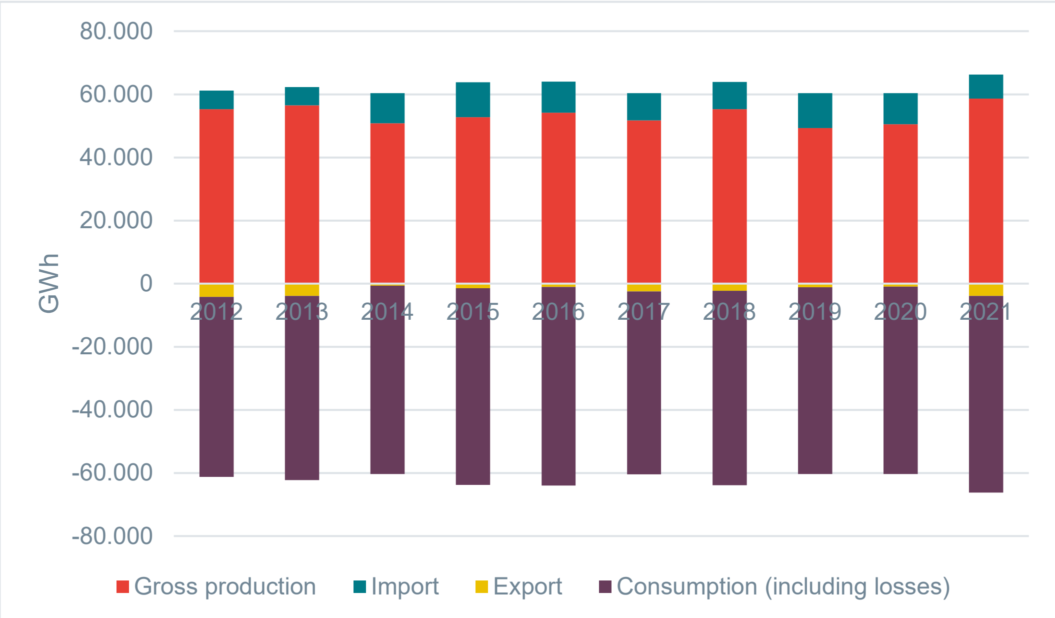


Figure 80 Electricity balance for Greece in the period 2012-2021. Source: Eurostat

As of 2021, fossil fuels accounted for 60% of electricity generation (48% gas, 12% coal). Renewable energy sources include wind (20%), solar (10%) and hydro (11%) production.

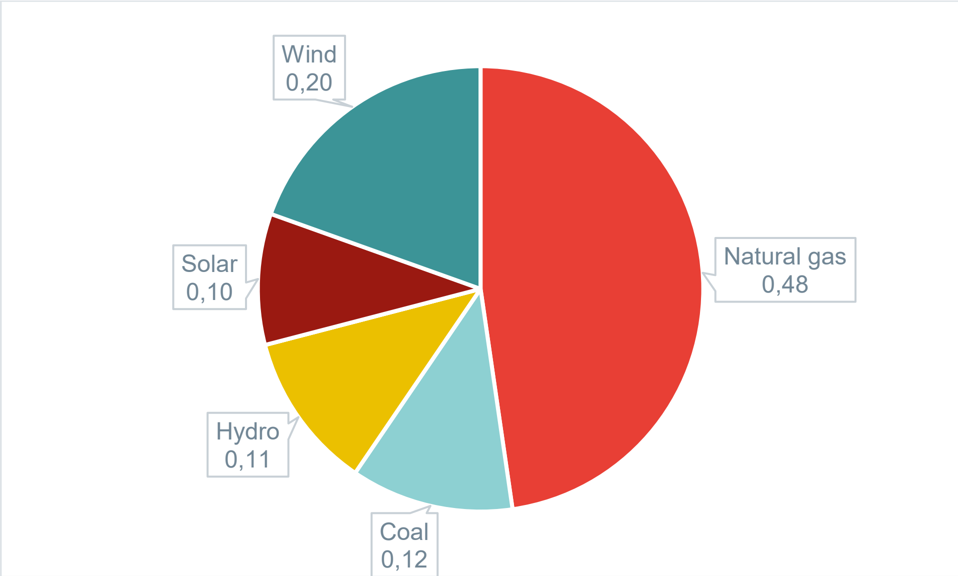


Figure 81 Electricity production by source in Croatia for year 2021. Source: Eurostat

Electricity consumption per sector

Figure displays the total energy consumption in Greece in 2021, with electricity highlighted in red. As the figure displays the largest quota of electricity consumption is for other sectors (36.9 TWh, 74.9% of total consumption), followed by electricity consumption in the industrial sector (12.2 TWh). A small quota is used by transport (0.2 TWh).

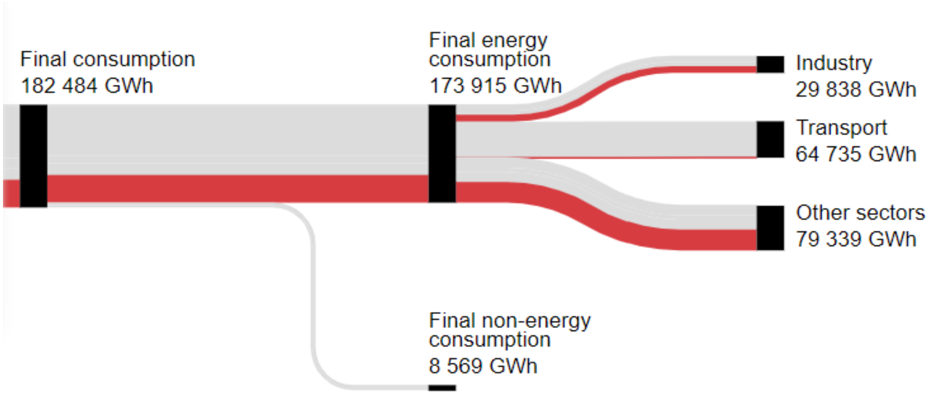


Figure 82 Energy consumption by sector in Greece in 2021, with natural gas highlighted. Source: Eurostat

Electricity prices for final consumers

Greece features the highest electricity prices in the Adriatic-Ionian region; while they were (similarly to the rest of the region) in the range 10-15 c€/kWh until 2021, the spiked up to 50 c€/kWh for non-household consumers in the second semester of 2022.

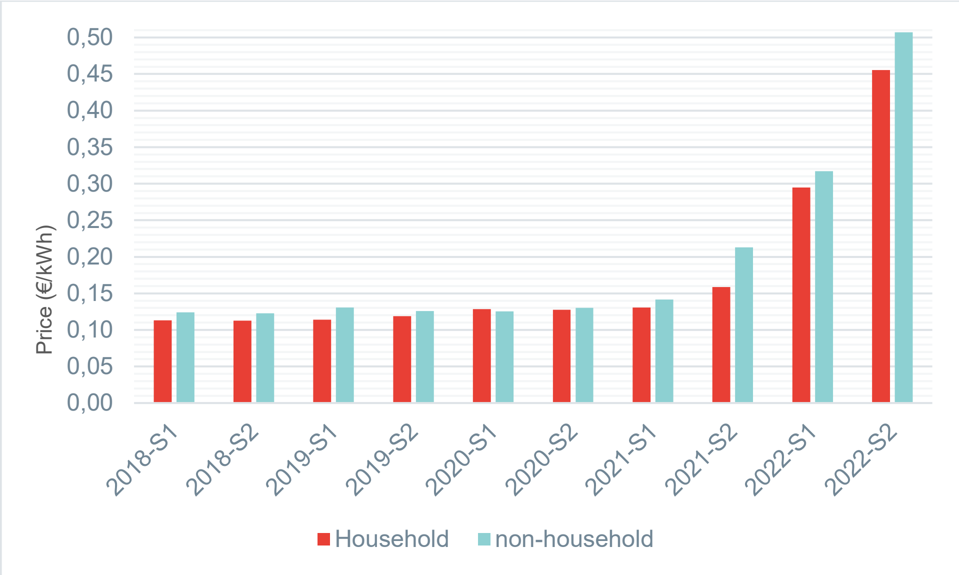


Figure 83 Household and household electricity prices in Greece. Source: Eurostat

North Macedonia

Demand and supply

North Macedonia had a total consumption of 8,717 GWh in 2021, with an additional 4,929 GWh exported to neighbouring countries. Imports accounted for 7,407 GWh, making the country a net importer – 6,240 GWh of local electricity generation complete the electricity balance as displayed in **Figure 84** for the period 2012-2021.

Figure 84 electricity balance for North Macedonia in the period 2012-2021. Source: Eurostat

Coal-fired generation and hydroelectric generation dominate the electricity mix with a 52% and 47% share, respectively – the remaining generation being provided by wind sources.

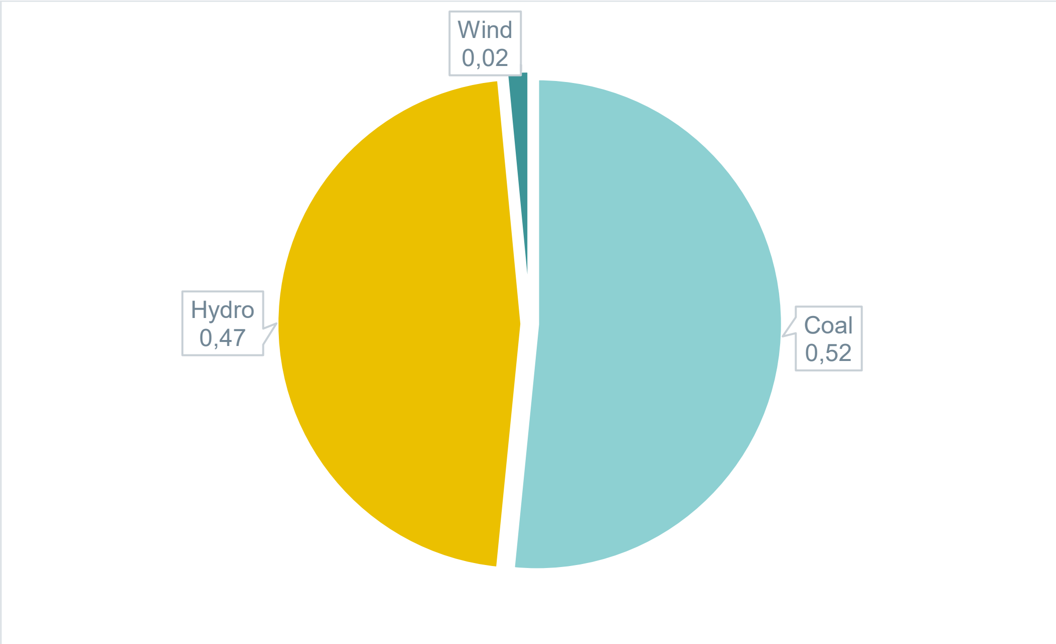


Figure 85 Electricity production by source in North Macedonia in 2021. Source: Eurostat

Electricity consumption per sector

Figure 86 displays the total energy consumption in North Macedonia in 2021, with electricity highlighted in red. As the figure displays the largest quota of electricity consumption is for other sectors (4.5 TWh, 73.5% of total consumption), followed by consumption for industrial uses (1.6 TWh).

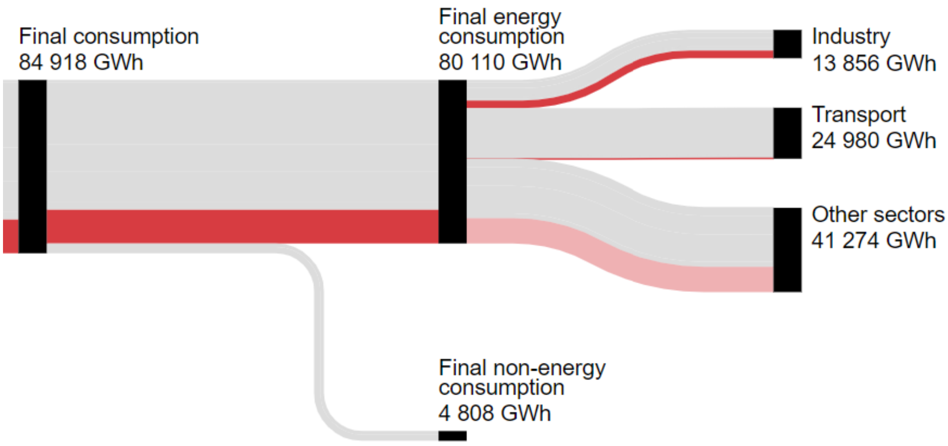


Figure 86 Energy consumption by sector in North Macedonia in 2021, with natural gas highlighted. Source: Eurostat

Electricity prices for final consumers

Prices for household consumers in North Macedonia are among the lowest in the region, including following the energy prices crisis period (2021 onwards) when household prices remained below 10 c€/kWh. Non-household prices are materially higher (roughly twice the prices for household consumers, or even more in the second semester of 2022).

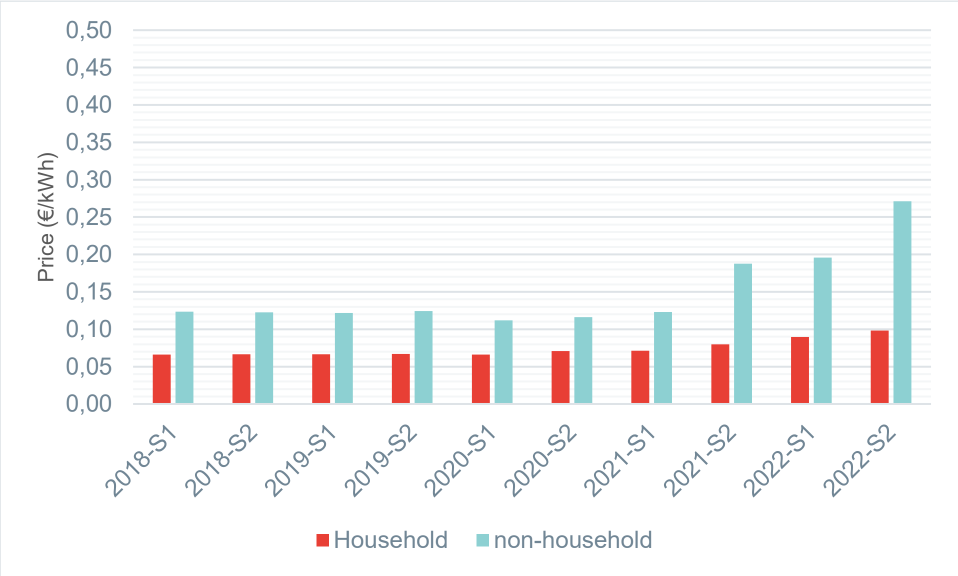


Figure 87 Household and non-household electricity prices in North Macedonia. Source: Eurostat

Organisation of the electricity sector

Italy

Unbundling

The Italian transmission system operator, Terna, is certified under ownership unbundling provisions. The major shareholder of Terna is CDP Reti, a subsidiary of CDP S.p.A. – a joint-stock company under public control. CDP majority shareholder is the Italian Ministry of Economy and Finance (82.77% of shares). Distribution system operators are also fully unbundled from other activities and licensed to operate in their geographical areas of competence; regulated-price supply to end-consumers (so-called *Servizio di Maggior Tutela*) is provided by distributors in each area.

System access

The tariff methodology is in place, allowing for transparent, non-discriminatory access to the gas network. Terna publishes conditions for the access to the grid in its Grid Code, reviewed and approved by the regulator. The regulator is responsible for tariff setting.

Wholesale market

The Gestore Mercati Energetici (GME) manages the day-ahead and intraday market in Italy. GME is qualified as NEMO and Italy participates in both SDAC and SIDC. The ancillary services and balancing market is operated by Terna, that also participates in the TERRE and Imbalance Netting platforms. Terna is also planning to join the other balancing EU paltforms (MARI and PICASSO).

Italy is divided into seven market zones, with capacity between the zones being allocated implicitly. A specific feature of the Italian day-ahead market is that while generators are remunerated at the marginal price for each zone, consumers pay a uniform price (*Prezzo Unico Nazionale*, PUN). This feature is expected to be removed in the future, as it creates scalability issues in the SDAC mechanism.

Forward trading takes place mostly via future contracts on EEX.

The REMIT Regulation is adopted and fully implemented.

Retail market

The retail market is fully liberalised, with a coexistence of regulated prices (but for large industrial consumers, *Servizio di Maggior Tutela*) and free market offers from hundreds of retailers. Italy has undertaken a unique path to end the regulated price regime, by assigning through auctions all consumers that did not opt of the regulated-price regime (small and medium enterprises first, and then domestic consumers in separate auctions).

Vulnerable consumers are identified by the legislation, and protected via regulated-price schemes.

Regional integration

Italy has cross-border interconnections to seven countries, with Switzerland, France, Austria, Slovenia, and Greece, Malta, and Montenegro. Cross-border interconnection capacity accounts for an equivalent of about 10% of total installed generation capacity.

Italy fully implements the integration model provided for by the European framework, by implementing the TEN-E regulation and participating in the SDAC, SIDC mechanisms as well as the EU balancing platforms.

Long-term cross-border capacity rights are allocated via JAO, but for the Italy-Montenegro border which is allocated via SEECAO. Financial transmission rights between Italian market zones are allocated via auctions by Terna.

Security of supply

The details of Italy’s electricity emergency response procedures, and the requirements placed on the TSO and DSOs, are outlined in Chapter 10 of the Italian Grid Code, known as the Defence Plan. In accordance with the Defence Plan, the TSO can implement a variety of response measures after activating a state of ‘alert’, ‘alarm’ or ‘emergency’ in the electricity system.

Terna has a dedicated unit, Computer Emergency Readiness Team (TERNA-CERT), to respond to cybersecurity threats. TERNA-CERT would coordinate with Italy’s national cybersecurity agency, CSIRT Italia, in the event of a cyber-attack on the electricity system. However, while procedures have been established to respond to potential cyber-attacks, a comprehensive risk assessment on the vulnerability of the electricity system to cyber-attacks has not been carried out.

Slovenia

Unbundling

Electricity infrastructure is managed by one TSO (ELES) and one DSO (SODO), which are both state-owned. Pursuant to the Third Energy Package, the regional distribution companies were obliged to unbundle their distribution and supply activities; SODO has contracts to operate the distribution network with the entities owning the assets.

System access

Access to the transmission network is regulated by the *Regulation on the Method for Implementing the Public Service Obligation*. In accordance with its public service obligations and the principle of regulated third-party access, ELES grants third parties non-discriminatory access to the transmission grid in a transparent manner, at cost-based tariffs.

Wholesale market

BSP SouthPool provides market participants with day-ahead, intraday and balancing and long-term auction trading for physical products on the Slovenian market. While BSP is qualified as NEMO, the market-clearing algorithm is run by GME, the Italian power exchange. This is implemented as follows: BSP collects the bids and the offers from participants, send them in anonymised form to GME, receives the set of accepted offers and prices, and performs the settlement.

Market coupling is fully operative, as Slovenia is part of the SDAC and SIDC mechanisms.

The Remit Regulation is fully implemented.

Retail market

As of 2018, 23 operators competed in the electricity retail market– with the incumbent holding a 47.8% share and the top 5 holding a 67.2% share.

Electricity retail prices are not regulated in Slovenia. The regulatory environment of entering energy markets requires no license for energy-related activities. Registration of market participants takes place according to REMIT. Slovenian utility bills must specify cost components related to: electricity, network access, contributions for energy efficiency, contributions for RES and CHP, excise duty, VAT.

Regional integration

Slovenia fully implements the integration model provided for by the European framework, by implementing the TEN-E regulation and participating in the SDAC, SIDC mechanisms. Long-term cross-border capacity rights are allocated via JAO at all Slovenian borders (Austria, Italy, Hungary, Croatia).

Security of supply

Emergency measures related to electricity security of supply are in place. In September 2022, a package of three laws designed to ensure a stable supply of electricity was passed by the Slovenian parliament. The package provides for measures to control crises in energy supply which will allow the government to order state-owned companies to secure a reliable energy supply. In the worst-case scenario, the management and coordination of individual parts of the system would be entrusted to the national grid operator, ELES.

SI-CERT (Slovenian Computer Emergency Response Team) is a designated national computer security incident response team (CSIRT) that operates within the framework of the ARNES (Academic and Research Network of Slovenia) public institute. According to tasks and responsibilities identified by NIS Directive it monitors incidents at a national level, provides early warning, alerts, announcements and dissemination of information to relevant stakeholders about risks and incidents, responds to incidents and provides risk and incident analysis and situational awareness.

Croatia

Unbundling

The transmission system operator (HOPS) acts as the sole electricity transmission system operator in the Republic of Croatia, and the owner of the entire Croatian transmission network (400 kV, 220kV and 110kV included voltage levels), and has a license to carry out the energy activity of electricity transmission as a regulated public service.

HOPS operates as an independent transmission system operator, which implies functional independence from the parent company, Hrvatska elektroprivreda d.d., and its affiliated companies, and non-discriminatory behaviour towards all transmission system users.

The national distribution company is HEP-Distribution System Operator (HEP ODS), a company within the HEP Group legally and functionally unbundled from other activities. HEP ODS has 21 distribution areas in Croatia.

System access

The connection to the transmission network is regulated by secondary legislation. The respective connection fees are set by the TSO in accordance with the Croatian Energy Regulatory Agency's (HERA) methodology for the calculation of the connection fees and approvals. These competences are granted to HERA by the Energy Act and the Act on Regulation of Energy Activities.

In accordance with the Electricity Market Act the TSO must connect all entities, including generators, to the transmission network on a non-discriminatory basis.

Wholesale market

Croatia's electricity market is managed by HROTE, a company indirectly controlled by the government. HROTE collects bilateral trades as well as bids and offers by participants, and solves the market according to the SDAC and SIDC mechanisms.

Croatia has not joined the European balancing platforms as of yet, but this is provided for by the MARI and PICASSI implementation roadmap.

The REMIT Regulation is fully implemented.

Regional integration

Slovenia fully implements the integration model provided for by the European framework, by implementing the TEN-E regulation and participating in the SDAC and SIDC mechanisms.

Long-term cross-border capacity rights are allocated via JAO at the Slovenian, Hungarian and Serbian borders.

Security of supply

Regulation (EU) 2019/941 on risk-preparedness in the electricity sector is applied by the national regulator (HERA) and implemented.

Bosnia and Herzegovina

Unbundling

The transmission network operator and the system operator are organised within two entities. Legal requirements for unbundling are not transposed and the transmission system operator is not unbundled.

Three power utilities, Elektroprivreda Bosne i Hercegovina (EPBIH), Elektroprivreda Hrvatske zajednice Herceg-Bosne (EPHZHB) and Elektroprivreda Republike Srpske (ERS) are vertically integrated with generation, distribution and supply activities. JP Komunalno Brčko is exempted from unbundling requirements, performing distribution and supply to less than 100.000 customers in the Brčko District.

Five distribution companies owned by Elektroprivreda Republike Srpske are legally and accounting unbundled from generation and supply activities. Functional unbundling and full management independence are not confirmed yet. Compliance officers are appointed, but compliance programmes are yet to be approved and implemented.

Distribution activities in the other two power utilities are operated within a single vertically integrated company, in breach of Energy Community law. The unbundling provisions are expected to be introduced by the new Electricity Law which is still pending approval by the entity government of Federation of Bosnia and Herzegovina.

System access

Network tariffs are published and implemented in a non-discriminatory manner. The State Electricity Regulatory Commission (SERC) reviewed the application of the transmission company (Elektroprijenos BiH) and decided to keep the transmission network tariffs unchanged for 2022 but increased the tariffs for the operation of the independent system operator (NOS BiH). Distribution network tariffs and public supply tariffs were increased in Brčko District only. The entity regulator in Republika Srpska reviewed tariff applications for distribution and public supply. Its decision is pending.

Connection Network Codes for transmission were transposed in 2019 through the corresponding rules, and implemented through the amended grid code and the decisions on derogation adopted by the SERC.

Wholesale market

The wholesale market is dominated by the three state-owned incumbent suppliers, trading through bilateral contracts. ERS trades also directly in foreign spot markets, whereas EPBIH and EPHZHB employ an agent to trade on their behalf.

The current Law on Electricity Transmission, Regulation and System Operation of Bosnia and Herzegovina of 2002, as amended, does not define the functioning of an organized spot market. The Ministry of Foreign Trade and Economic Relations, in coordination with entities' ministries, regulatory authorities and key energy undertakings, established a working group to define a pathway for setting up an organized market, following the Secretariat's proposal for amending the Law. The working group has made no progress.

The competitive market for balancing energy and ancillary services is in place since 2016. SERC set the regulated price of electricity for losses in the transmission network, with limited scope and duration, for the periods in the course of 2022 when it cannot be purchased from public auctions, empowering the independent system operator (NOS BiH) to determine the volumes and the entities obliged to supply the missing volumes.

The Regulation on Integrity and Transparency of the Wholesale Energy Market (REMIT) is transposed and implemented in the electricity sector.

Retail market

Supply takes place predominately by the three incumbent utilities, even more so following the price surge in 2021. Regulated prices are available for customers entitled to universal service, namely households and small customers. In the Federation, two power utilities are responsible for providing universal service in their respective areas, at the prices calculated in accordance with the methodology defined by the entity regulator FERC. In Republika Srpska, prices for universal service are determined by the entity regulator RERS, based on the cost of production in the incumbent power utility ERS. Brčko District consumes around 2% of the country's electricity consumption, with prices for universal service determined by SERC.

In the competitive segment of the retail market, prices were freely negotiated until the price surge in the second semester of 2021. As the prices in bilateral supply contracts began to reflect European and regional spot market prices, the Chamber of Commerce in Republika Srpska assisted in striking a general deal with the dominant supplier ERS for supply of eligible customers.

In the Federation, an amendment to the Electricity Law, adopted in December 2021, introduced a provision limiting the price increase for eligible customers to a maximum 20% per annum. As a consequence, concentration in the retail market increased.

The concept of vulnerable customers is defined in the primary legislation of Republika Srpska, however, the exact criteria for obtaining the status of a vulnerable customer are still to be developed and implemented. In Federation of Bosnia and Herzegovina, the concept of vulnerable customers is not explicitly provided in the legislation, nevertheless, there is a programme for subsidizing the below-average consumption implemented by EPBIH and EPHZHB. The Electricity Law of Brčko District includes the definition of a vulnerable customer. A programme for subsidizing vulnerable customers of electricity is being implemented.

Regional Integration

As Bosnia and Herzegovina has still not transposed the TEN-E Regulation, it does not rectify the infringement established by Ministerial Council Decision 2018/8/MC-EnC. The realisation of the part of the Transbalkan corridor, a PECI project, that goes through Bosnia and Herzegovina (OHL 400 kV Visegrad – Bajina Basta) hinges on the completion of the necessary work in Serbia (OHL 2x400 kV Obrenovac - Bajina Basta). Interconnection capacity on the borders with Montenegro and Croatia is allocated annually, monthly and daily through regionally coordinated auctions at SEE CAO. The allocation of capacity for all timeframes on the border with Serbia and the intraday capacity auctions on all borders is bilaterally coordinated between the respective system operators.

Cross-border balancing is implemented within the SHB control block shared with Slovenia and Croatia. The market rules were changed with the aim to implement system operation and electricity balancing guidelines. Bilateral exchanges of balancing energy with the operators of Serbia and Montenegro are applied.

Security of supply

Directive 2005/89/EC is only partially transposed through the laws governing electricity sector on entity level. There is no state-level legal framework on cybersecurity and the Law of Republika Srpska on Information Security does not transpose NIS Directive (EU) 2016/1148.

Republic of Serbia

Unbundling

The transmission system operator EMS is legally and functionally unbundled from other electricity activities and certified by the regulator.

The distribution system operator, Elektrodistribucija Srbije, is fully unbundled from other activities. The Government is the sole shareholder of the company. After the transfer of the ownership rights from the vertically integrated undertaking EPS, the independence of the distribution system operator from other activities was strengthened. A new compliance programme was adopted in January 2022 and approved by the regulator, and the conditions for the appointment of the compliance officer were adopted in June 2022.

System access

Access to the system is based on transparent rules for connection and use of the system. Transmission and distribution tariffs are regulated in accordance with the published methodology, amended in 2021.

Following an infringement procedure opened by the Secretariat, the Ministry adopted three decrees transposing the Network Codes, on connection to the network of production units, connection to the network of the customer's facilities and the connection to the network of DC high voltage systems in September 2022. Within one year of the decrees’ entry into force, system operators are obliged to align their rules governing connection and obtain approval of the regulator.

Wholesale market

The wholesale market operates through bilateral transactions and transactions on the organized day-ahead market operated by the power exchange SEEPEX. Incumbent producer and supplier PE EPS is still a dominant player in the market, withholding approximately half of total consumption and acting as provider of universal service supply.

Traded volumes in the day-ahead market reached 10,8% of final electricity consumption in 2021. By adoption of the Decree on Day-ahead and Intraday Market Coupling in January 2022 and appointment of SEEPEX as NEMO in June 2022, Serbia advanced in transposing and implementing CACM, paving the way towards market coupling. An intraday market is not yet in place.

The balancing market is functioning in accordance with the market rules amended in December 2021. Prices for ancillary services and balancing reserves are regulated and adjusted annually.

The REMIT Regulation is transposed and implemented by the regulator.

Retail market

All customers are free to choose their supplier, but only 3,8% of final customers were supplied from the competitive market in 2021. These were primarily big industrial customers which do not have access to guaranteed supply. The volume of electricity sold on the competitive retail market amounted to 51% of total final consumption, including supply of last resort to the customers which used the right to guaranteed supply.

Retail market concentration in 2021 was high with EPS holding 97% of total final consumption. As in other Contracting Parties, the increase of spot market prices in the EU spilled over to Serbia causing retail prices in the competitive market to rise. As a response, the Government issued a recommendation to EPS' supply branch on maximum retail prices. This brought the final customers back to EPS supply which is now practically supplying 100% of the market.

The regulator's report for 2021 repeatedly concluded that deregulation of prices for universal service would be premature. Consequently, the appointment of a universal supplier in a market- based procedure is further postponed. End-user prices for guaranteed supply were adjusted in September 2022, to better reflect the costs of electricity.

The Decree on Energy Vulnerable Customer, adopted in 2015 and amended in 2018, provides safeguards to protect vulnerable customers in Serbia. The definition of vulnerable customers is provided in the Energy Law.

Regional integration

Amendments to the Law on Energy from April 2021 stipulate that the Government prescribes the conditions and manner of promoting strategic energy projects. Certain provisions of the TEN-E Regulation were to be defined within six months from the entry into force of the Law. However, that has not happened yet. There are currently three electricity PECI projects in Serbia, all grouped into the Trans-Balkan corridor project. Section 2 of this project, OHL 400 kV Kragujevac 2 – Kraljevo 3, has been recently finished, while section 3, OHL 2x400 kV Obrenovac-Bajina Basta, is in a final preparatory phase. Section 4, OHL 2x400 kV Bajina Basta - Visegrad/Pljevlja, is pending further developments on the extension of the HVDC link between Montenegro and Italy, on which it relies.

No progress has been made towards extension of cross-border capacity allocation through the Joint Auction Office, which is for now allocating capacities on the interconnections with Croatia and Bulgaria only. On other interconnectors, joint auctions still apply.

Cross-border exchange of balancing energy is performed bilaterally with neighbouring transmission system operators and imbalance netting with Montenegrin transmission system operator within the control block with operators of Montenegro and North Macedonia. As of October 2022, the transmission system operator of Serbia became an operational member of the European platform for imbalance netting (IGCC).

Security of supply

Directive 2005/89/EC is transposed and implemented and the security of supply statement is regularly submitted. A cybersecurity strategy for 2021 - 2026 was adopted and the cybersecurity acquis is transposed in national law. The energy sector critical information infrastructure is defined and designated at national level.

Montenegro

Unbundling

With the state as the major shareholder and Italian Terna, Serbian transmission system operator EMS and several minor shareholders, the transmission system operator CGES is unbundled from other energy activities and certified in accordance with the acquis.

The distribution system operator, CEDIS, owned by the dominant supplier Elektroprivreda Crne Gore (EPCG), is legally and functionally unbundled from supply and generation activities. A new compliance programme was approved in 2021. The compliance officer’s report for 2021 is not published yet.

Regulatory supervision revealed that the mother company EPCG interfered in the operation of CEDIS, instructing CEDIS to bear the costs of a discount granted to end-customers by the supplier. Both companies complied with the regulator’s instruction to amend the respective statutes and EPCG annulled its decision from 2021, by which the independence of CEDIS, as distribution system operator, was preserved.

System access

Access to and use of the system are based on transparent grid codes under regulated terms and conditions. A capacity charge for producers connected to the distribution network also applies. Electricity prices on the wholesale market increased the operating costs of CGES and CEDIS in 2021 due to their obligation to procure electricity for losses in a competitive market. CEDIS incurred an operating loss in 2021.

Transmission and distribution tariffs increased from January 2022. New tariff methodologies for the market operator, distribution system operator and transmission system operator applicable from 2023 were adopted in June 2022. Network operators submitted applications for the regular tariff review for the three-year period 2023 - 2025. The decision is expected in December 2022.

The Connection Codes were transposed in 2020 by corresponding Government decrees. To reflect the requirements of the Connection Codes, amendments to the transmission grid code of CGES were drafted in 2021. CEDIS adopted a new distribution grid code in June 2022 but the requirements of the Connection Codes were not integrated therein.

Wholesale market

Montenegro's wholesale bilateral market is small and highly concentrated with one dominant producer and trader, whereas the day-ahead market is not yet operational. It is pending the operationalisation of a day-ahead trading, clearing and settlement platform, which is currently being established by the power exchange company MEPX, and the adoption of day-ahead market rules. The designation of a nominated electricity market operator is still to be completed in line with the Energy Law. Currently, MEPX serves only as an auction platform for procurement of electricity for covering losses by the two network operators.

The balancing market functions, whereas the price of the balancing reserve is regulated pursuant to the methodology adopted by the regulator.

The adoption of amendments to the VAT Law, necessary to harmonize taxation regimes on cross-border transactions, is still pending.

The REMIT Regulation was transposed by the Law on Monitoring the Wholesale Market in Electricity and Natural Gas, adopted in December 2021, and implemented.

Retail market

Although there are five licensed suppliers in Montenegro, the retail market is entirely served by EPCG. In a transparent procedure, EPCG was selected to perform the public service obligation of supplier of last resort and supplier of vulnerable customers.

Households supplied by EPCG are since 2019 offered the possibility to select among four models and switch between them in order to optimize costs. For households and small customers, EPCG is obliged to respect restrictions imposed by the Energy Law and the 2019 regulator's decision that capped annual price increases at 6% until the end of 2022.

The Energy Law defines the concept of vulnerable customer. The relevant subsidies are provided through the Ordinance on Supplying Electricity to Vulnerable Consumers and the Electricity Bill Subsidization Programme.

Regional integration

The adoption of the new Law on Cross-Border Energy Infrastructure Projects, which seeks to transpose TEN-E Regulation (EU) 347/2013, initially scheduled for 2019, has not happened to date.

The 400 kV overhead line Lastva - Čevo - Pljevlja, previously holding the PECI status, has not been completed yet. A new 400 kV line Pljevlja (ME) - Bajina Basta (RS), the actual PECI project related to section 4 of the Trans-Balkan corridor, awaits the necessary preconditions to be realised, namely the construction of the 2x400 kV line Obrenovac - Bajina Basta in Serbia.

Cross-border capacities are allocated in a coordinated manner through SEE CAO for all interconnections except with Serbia where bilateral auctions still apply.

The cross-border exchange of balancing energy is applied bilaterally with neighbouring transmission system operators and the imbalance netting with Serbia within the control block with North Macedonia and Serbia.

Market coupling projects are pending the establishment of the day-ahead market in Montenegro.

Security of Supply

The Energy Law together with the transmission and distribution grid codes provides a framework governing security of supply in line with Directive 2005/89/EC.

The Law on Information Security partially transposes the NIS Directive, and cybersecurity is supported by CIRT-ME.

Albania

Unbundling

The transmission system operator is unbundled and certified. Legal unbundling of the distribution system operator from the supply branch was completed by the restructuring of the former integrated utility OSHEE into a holding of three subsidiaries, licensed respectively as a universal service provider (FSHU), electricity supplier (FTL) and distribution system operator (OSSH).

Functional unbundling is still to be completed by the appointment of the compliance officer and completion of rebranding, which are still pending.

System access

Access and use of the system, including for cross-border exchanges, is implemented in accordance with the Third Energy Package. Tariffs for the use of the transmission network are reviewed every three years, whereas tariffs for the use of the distribution network are reviewed on an annual basis.

The Connection Codes are transposed but their implementation is still pending.

Wholesale market

KESH has a public service obligation to provide electricity for universal service and, as of July 2022, losses in the transmission network for the duration of the emergency situation. Electricity supplier FTL has an obligation to sell electricity for covering distribution losses to OSHH. This is not in compliance with Energy Community law and limits the potential for competition significantly.

The power exchange ALPEX was established by the transmission system operators of Albania OST and Kosovo KOSTT to become the day-ahead and intraday market operator for Albania and Kosovo. The establishment of electronic platforms for trading, clearing and settlement is ongoing and a training for the participants will commence in December 2022. The day-ahead market was launched in April 2023.

The competitive balancing and ancillary services market is established, but still operates with limited liquidity.

REMIT Regulation (EU) 1227/2011 is transposed and implemented.

Retail market

The universal service provider FSHU holds the major share of retail supply, either as a universal service supplier to 0,4 kV customers or as a supplier of last resort, selected via tender procedure in March 2022, to customers connected at 20 kV, 10 kV and 6 kV voltage level. Customers connected to 35 kV and the high voltage level are obliged to be supplied at the free market.

Primary legislation defines vulnerable customers. Currently, financial support to vulnerable customers is provided through two Government decisions on compensations for electricity consumption.

Regional integration

The Decision on the Approval of Practices for the Promotion of Joint, Regional Investment in Energy Infrastructure transposed TEN-E Regulation (EU) 347/2013. However, the bulk of its provisions has not been implemented.

The PECI project, 400 kV overhead line between Albania (Elbasan) and North Macedonia (Ohrid - Bitola), is under construction, to be completed by 2023.

All cross-border capacities are allocated through SEE CAO, except split auctions on the interconnection with Serbia. The Albania-Kosovo (AK) control block cooperates on cross-border balancing. Market coupling between Albania and Kosovo is envisaged to take place in parallel with the launch of the day-ahead market in Kosovo.

Greece

Unbundling

Law 4001/2011, as in force, adopted the unbundling model of independent transmission operator for the electricity sector. Following a full ownership unbundling, the former vertically integrated monopolist (PPC) has fully divested its interest in the independent power transmission operator (IPTO), which was initially a PPC wholly owned subsidiary, following a divestment plan driven by both the Third EU Energy Package and the provisions of the restructuring and privatisations plan. IPTO is currently owned partly (51%) by the Greek state (directly and through DES ADMIE SA), and partly by private investors (49%).

With regard to the distribution network, it is currently operated by the Hellenic electricity distribution network operator (HEDNO), pursuant to RAE Decision No. 83/2014. HEDNO was established in 2012 following the spin-off of the distribution segment from PPC to a wholly owned subsidiary, as a means to achieve the legal and functional unbundling of the electricity distribution network operation activities from the other activities of PPC's vertically integrated undertaking. PPC commenced the sale process of 49 per cent of its shares in HEDNO in December 2020. PPC initially retained ownership of the distribution network, but this was transferred to HEDNO in 2021.

System access

Greek law ensures full access on a non-discriminatory basis to the transmission and distribution systems in the electricity sector. Transparent Network Codes regulate the access conditions and are published by IPTO and HEDNO.

The electricity system of a significant number of Hellenic islands is still not connected to the interconnected system and comprise a separate network called the ‘non-interconnected islands’ network. HEDNO owns, controls and managed the ‘non-interconnected islands’ network.

Wholesale market

On 1 November 2020, following Greece's transition to the European Target Model for the operation of its wholesale electricity market (with the derivatives energy market already launched in March 2020), the day-ahead, intraday and balancing markets were launched. Day-ahead and intraday markets are operated by HEnEx and cleared by HenExClear. HenEx is also a NEMO, with the Greek market being part of the SDAC and SIDC mechanisms.

Regional integration

Market coupling is fully operative in Greece (SDAC and SIDC). The Greek TSO, ADMIE, is also part of the implementation roadmap for the EU balancing platforms (MARI and PICASSO),

Long-term transmission rights at the borders with Italy and Bulgaria are allocated via JAO. Other borders (Albania, North Macedonia, Turkey) are allocated on the SEE CAO platform,

Security of supply

Law 4577/2018, which transposed Directive 2016/1148/EU into Greek law, imposes important obligations for system and network security on businesses operating in, among others, the fields of energy, water and digital infrastructure (Cybersecurity Law). The framework was further supplemented by the Ministerial Decision 1027/2019, specifying the implementation of procedures stipulated in the Cybersecurity Law. A new Cybersecurity Authority has been established, which is vested with, mainly supervisory, powers, responsibility for assessing businesses' compliance with the Cybersecurity Law and, to the extent required, imposing sanctions.

North Macedonia

Unbundling

The state-owned transmission system operator, MEPSO, is unbundled from other energy activities. It is certified in accordance with the acquis. Compliance is monitored by the compliance officer and the regulatory authority.

The distribution system operator, Elektrdistribucija dooel, is legally and functionally unbundled from supply and generation activities in the vertically integrated EVN. The compliance programme is adopted and monitored by the compliance officer.

System access

Access to the system is governed by transparent rules for connection and use of the system based on regulated network tariffs.

The increase of market prices and corresponding costs of network losses seriously endangered the operation and financial viability of both network operators, as the actual costs of losses in 2021 were several times higher than those approved. In June 2022, the regulator approved a tariff increase for network operators to at least partly recover the costs.

The Energy Law prescribes direct applicability of the Network Codes, however, none have been translated and published as a legislative act in the official gazette thus far. The transmission grid code was amended accordingly in December 2021 to implement the Network Codes. The distribution grid code of 2019 was amended in 2022, however, it did not implement all required provisions of the Network Codes and is yet to be upgraded to reflect all required parameters of the Connection Codes.

The Transparency Regulation is transposed and largely implemented.

Wholesale market

The wholesale market is fully open to competition since July 2019 when the regulator terminated the regulation of the generation price for ESM, the dominant producer in North Macedonia.

The national electricity market operator of North Macedonia, MEMO, was established as a legal entity spun off from MEPSO. In line with the Government's Decree on Designation of a Nominated Electricity Market Operator, MEMO was appointed to establish the day-ahead electricity market in the bidding zone of

North Macedonia and to conduct market coupling. It obtained the license for the operation of the day-ahead market from the regulator in October 2022. MEMO is currently in the process of establishing a day-ahead trading, clearing and settlement platform. Day-ahead market rules are still to be adopted following the amendments to the Energy Law which transposed provisions of CACM Regulation enabling market coupling.

The balancing market is functional. The balancing reserve and balancing energy are procured on a competitive platform managed by MEPSO.

With rising regional and European wholesale prices and reduced production from indigenous sources, the average wholesale price in 2021 increased by 73% from 2020. The Government provided financial aid to ESM so that it could honor its contractual obligations towards the universal supplier and the supplier of last resort. In October 2022 the Government limited the trading margin to 10% for all retail market participants.

Amendments to the Energy Law aimed at the general transposition of the REMIT Regulation are adopted. Regulatory rules to complete full transposition still have to be adopted.

Retail market

The open retail market in North Macedonia, with more than 50% of final consumption in 2021 purchased in the competitive market, faced a downturn with the rise in wholesale prices in 2022. Those retail suppliers that were left exposed to the market without proper hedging were forced to cancel existing contracts with end-customers. Consequently, customers turned to regulated supply, pushing the incumbent generator to provide sufficient energy to meet the increasing demand for universal service by the regulated supplier EVN Home and emergency supply of customers without a contract.

In order to incentivize energy savings, the regulator redesigned the tariff system for customers entitled to universal service by introducing four-block tariffs for households based on the coefficient of the average price of electricity from 1 July 2022, starting with the lowest thresholds of 210 kWh/month and the highest threshold for monthly consumption exceeding 1050 kWh.

Vulnerable customers in North Macedonia are protected through annual programmes adopted by the Government. The system for protection of vulnerable customers is further improved with the amendments of the Energy Law in 2022.

In October 2022 the Government adopted a set of decision aimed at ensuring affordable electricity prices for activities of public interest, obliging ESM Trade to supply them at the price determined by the Government. This measure is financed from the State budget.

Regional integration

Amendments to the Energy Law which transpose the TEN-E Regulation were adopted and recently published in the Official Journal.

Interconnection capacities with Greece and Kosovo are allocated by the common coordination platform SEE CAO. The yearly and monthly allocation of cross zonal capacities with Serbian EMS is performed by MEPSO, daily and intraday auctions by EMS. On the Bulgarian border, annual allocation is performed by MEPSO and daily by the Bulgarian transmission system operator, ESO.

Cross-border exchange of balancing energy is applied within the control block with Montenegro and Serbia. Despite that the transmission system operator MEPSO signed an agreement on grid control cooperation with other transmission system operators in the control block, MEPSO is not yet participating in the imbalance netting with Montenegrin and Serbian transmission system operators.

Security of supply

The Energy Law transposes Directive 2005/89/EC. A framework for security of supply is further detailed by the Governmental Regulation on the Criteria and Conditions for Announcement of Crisis in the Electricity Supply, Transmission and the Distribution Grid Codes.

ANNEX B COUNTRY SHEETS: NATURAL GAS

Fundamentals of the gas sector

We present in this section the gas sector fundamentals for the Adriatic-Ionian region. For each country we review the following quantities:

- Gas supply and demand in each country
- Infrastructures and gas flows (pipeline, LNG, storage)
- Gas prices for final consumers

Italy (EUSAIR)

Demand and supply

Italy represents the largest gas market in the Adriatic-Ionian region, with a total consumption (from EUSAIR regions only) of 53.86 bcm/year in 2021[67]. In the following we shall refer to the Italian regions that are part of the Adriatic-Ionian region as Italy (EUSAIR).

Based on import data from the entire country, it can be estimated that Italy (EUSAIR) imported:

- 44.17 bcm via pipeline, through the entry points at Tarvisio, Griespass, Melendugno, Gela and Mazara del Vallo
- 7.29 bcm via LNG, though the three terminals of Rovigo, OLT Offshore and Panigaglia

Further, we estimate that 2.24 bcm and 1.12 bcm contributed to the balance of the Italy (EUSAIR) region from national production and storage withdrawals, respectively.

The following **Figure 88** displays the natural gas balance for Italy (EUSAIR) region for the period 2012-2021.

[67] This also includes San Marino. Data is available for the entire country, and estimated for the EUSAIR quota using a 70% share extrapolated from 2019 data

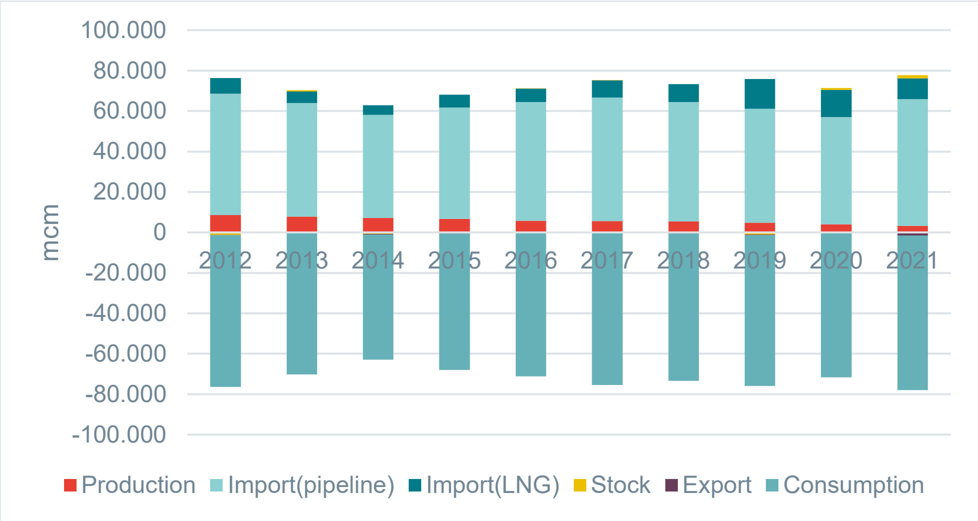


Figure 88 Natural gas balance for Italy (EUSAIR) in the period 2012-2021. Source: Eurostat

The following **Figure 89** provides additional details on the natural gas supply structure to Italy: as of 2021, pipeline gas has been imported via Russia (46%), Algeria (35%), Azerbaijan (11%), Libya (5%) and Norway (3%). Looking at LNG import, Qatar has been the largest exported with 81%, followed by US (13%) and Nigeria (3%).

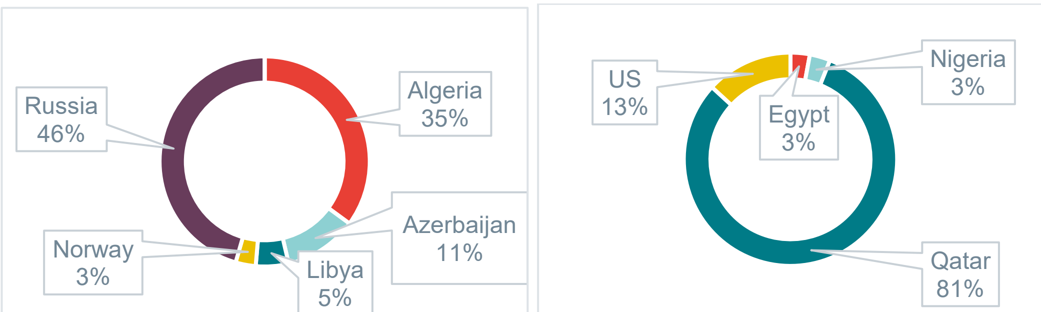


Figure 89 Natural gas supply per source country (pipeline, left, and LNG, right). Source: Eurostat

Natural gas consumption per sector

Figure 90 displays the total energy consumption in Italy in 2021, with natural gas highlighted in orange. As the figure displays the largest quota of energy consumption is for other sectors (281 TWh, 68.6% of gas final energy consumption consumption), followed by direct consumption for energy uses for industry (104 TWh), and transport (16.6 TWh). A small quota (1.9%) of natural gas is used for non-energy purposes.

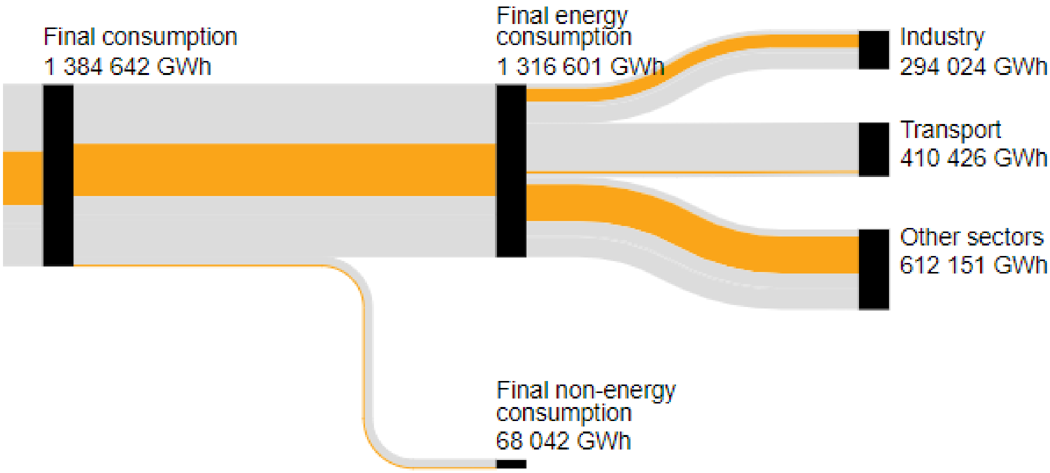


Figure 90 Energy consumption by sector in Italy in 2021, with natural gas highlighted. Source: Eurostat

Gas infrastructures

Table 6 lists the entry points into the Italian natural gas network, including regassification facilities. These infrastructures combined, and accounting for a network constraint that confines entry capacity in Mazara and Gela at 1,583 GWh/d, add up to a total 3,863 GWh/day of import capacity.

Additionally, three storage operators are active in Italy for a total storage capacity of about 196 TWh.

Category	Entry point	Capacity (GWh/d)	Avg Flow (GWh/d)	Utilization rate 2021
Pipelines	Mazara del Vallo	1,583	612.99	44.6%
	Gela		93.58	
	Tarvisio	1200.36	817.14	68.1%
	Passo Gries	693.56	60.08	8.7%
	Gorizia	38.99	1.12	2.86%
	Melendugno	214.12	207.93	97.11%
LNG	OLT Offshore LNG Toscana (IT)	155.00	41.4	26.7%
	GNL Italia (IT)	119.50	31.2	26.1%
	Adriatic LNG (IT)	270.70	210.8	77.9%

Table 6 Natural gas infrastructures in Italy. Source: ENTSOG

Looking at physical flows and infrastructure utilisation, **Figure 91** shows the capacity and utilisation rate of the LNG terminals in Italy in 2021. As the graph shows, regassification facilities are utilised to an average send-out rate of 90.8% of the nominal capacity (for a total 487 GWh/d in the course of 2021).

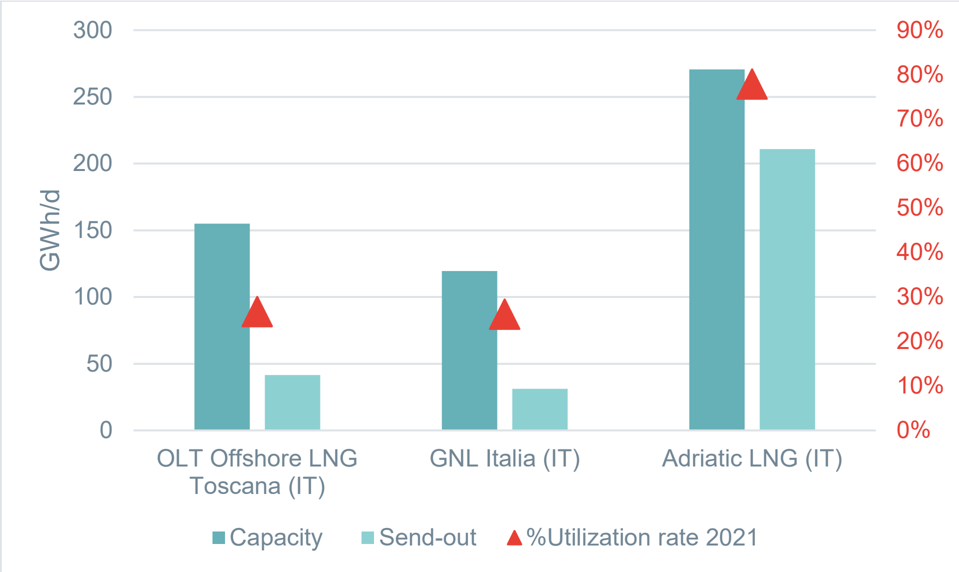


Figure 91 LNG import capacity and send-out in 2022. Source: GIE AGSI Transparency Platform.

Turning our attention to pipeline imports, Italy utilised on average 48% of its pipeline import capacity, with 1,937 GWh/d (or 70.7 bcm/year) being available for import.

Finally, given its ample size storage capacity (196 TWh, equal to about 25% of the Italian consumption in 2021) plays a crucial role in the Italian gas sector. **Figure 92** displays the injection-withdrawal pattern (left panel) in the period October 2019-March 2023 and the corresponding filling level (right panel), showing the seasonality of the storage utilisation (injection in the summer months, followed by withdrawals in the winter period).

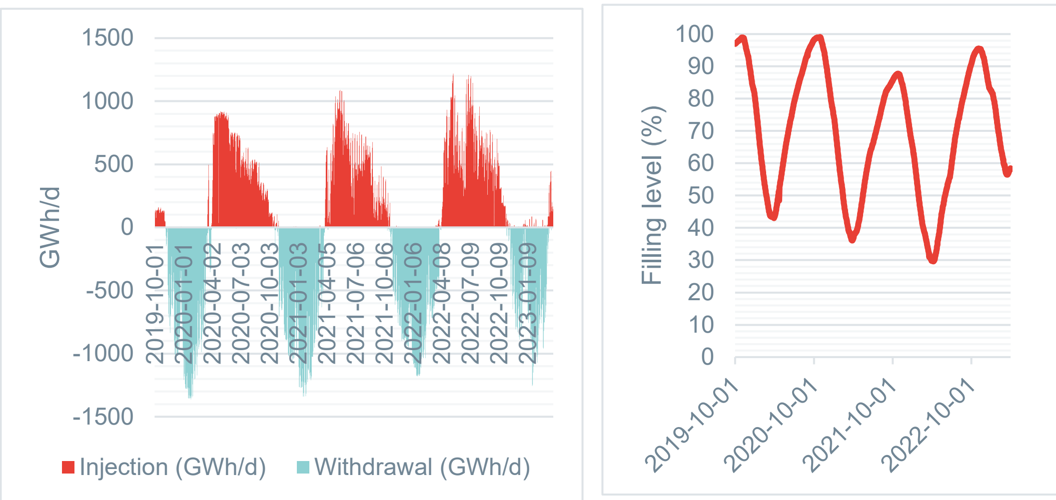


Figure 92 Injection and withdrawal pattern in the Italian storage. Source: GIE AGSI Transparency Platform

Gas prices for final consumers

The following **Figure 93** displays the final gas prices for households and non-households consumers in Italy, in the period 2018-2021. Prices for non-household consumers are materially lower than for household consumers, although both remained relatively stable throughout the years.

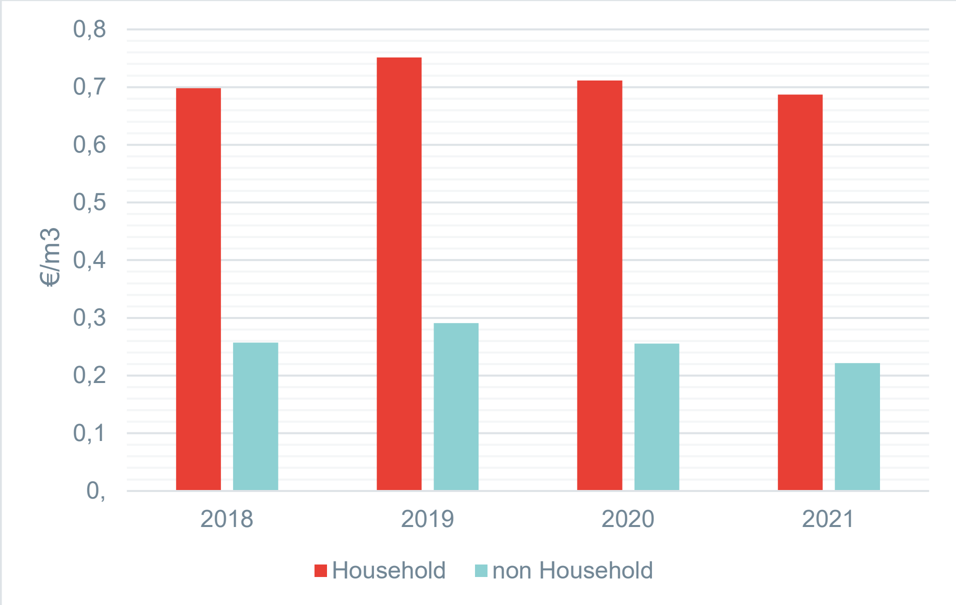


Figure 93 Natural gas prices for household and non-household final consumers in Italy in the period 2018-2021. Source: Eurostat

Slovenia

Demand and supply

Slovenia features a total gas consumption of 952 mcm in 2021. In 2021, Slovenia imported 99.47% of its gas consumption through the entry points at Cersak, Rogatec and Sempeter. In addition, 5.07 mcm were supplied by national production.

The following **Figure 94** displays the energy balance for Slovenia for the period 2012-2021.

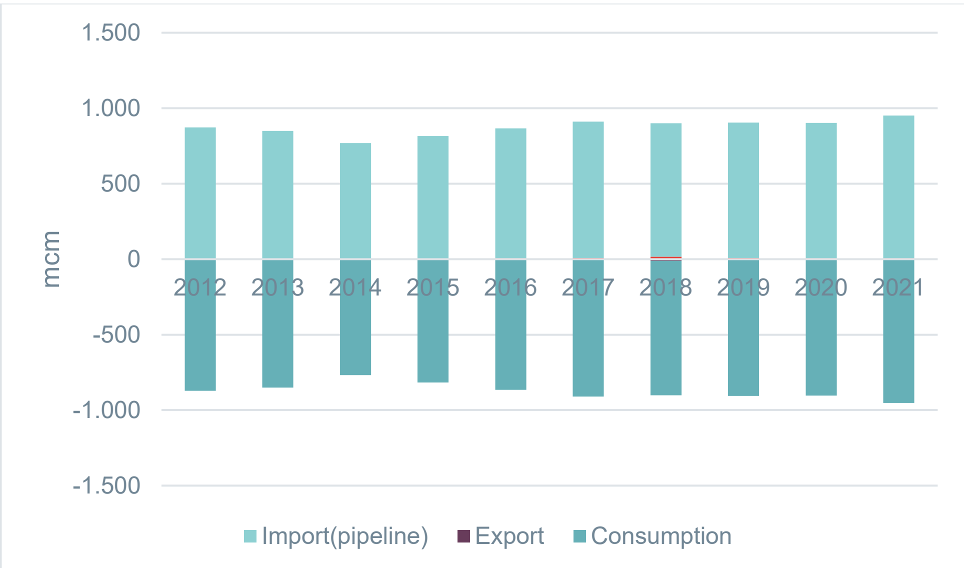


Figure 94 Energy balance for Slovenia in the period 2012-2021. Source: DFC analysis on Eurostat data

The following **Figure 95** provides additional details on the natural gas supply structure to Slovenia: as of 2021, pipeline gas has been imported via Russia (93%), and from Algeria via Italy (7%).

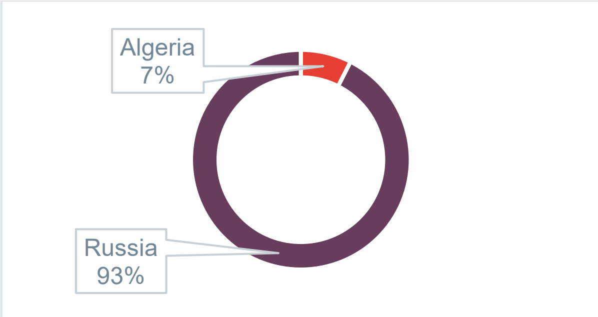


Figure 95 Natural gas supply per source country (pipeline). Source: Eurostat

Consumption per sector

The figure below displays the energy consumption per sector, with natural gas highlighted in orange. The largest quota of gas consumption is for industrial uses (5.6 TWh, 76.7% of total consumption), followed by consumption for other sectors (1.6TWh). A small quota of natural gas is used for non-energy purposes (0.9%) and transport (0.7%).

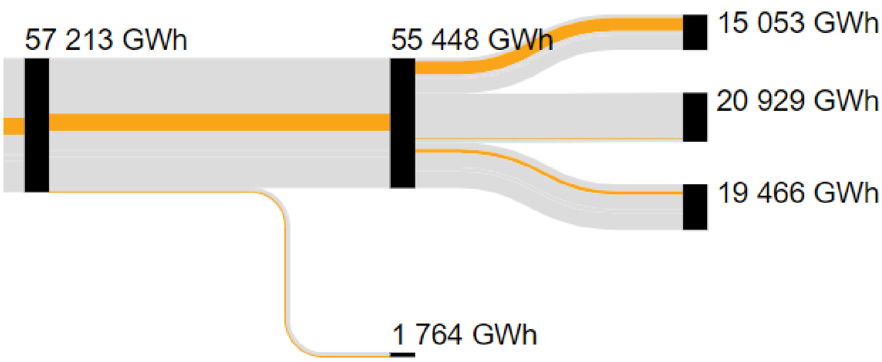


Figure 96 Energy consumption by sector in Slovenia in 2021, with natural gas highlighted. Source: Eurostat

Gas infrastructures

Table 7 lists the entry points into the Slovenian natural gas network. These infrastructures combined add up to a total 187.42 GWh/day of import capacity. Slovenia utilised on average 17% of its import capacity, with about 162 GWh/d (or 5.9 bcm/year) being available for import.

Entry point	Category	Capacity (GWh/d)	Flow	Utilization rate 2022
Cersak (AT)	Pipeline	139.87	32.59	23.30%
Rogatec (HR)		7.70	0.26	3.42%
Sempeter (IT)		47.55	0.13	0.26%

Table 7 Gas infrastructures in Slovenia and utilisation rates in 2022. Source: ENTSOG

Gas prices for final consumers

The following **Figure 97** displays the gas prices for households and non-households consumers in Slovenia, in the period 2018-2021.

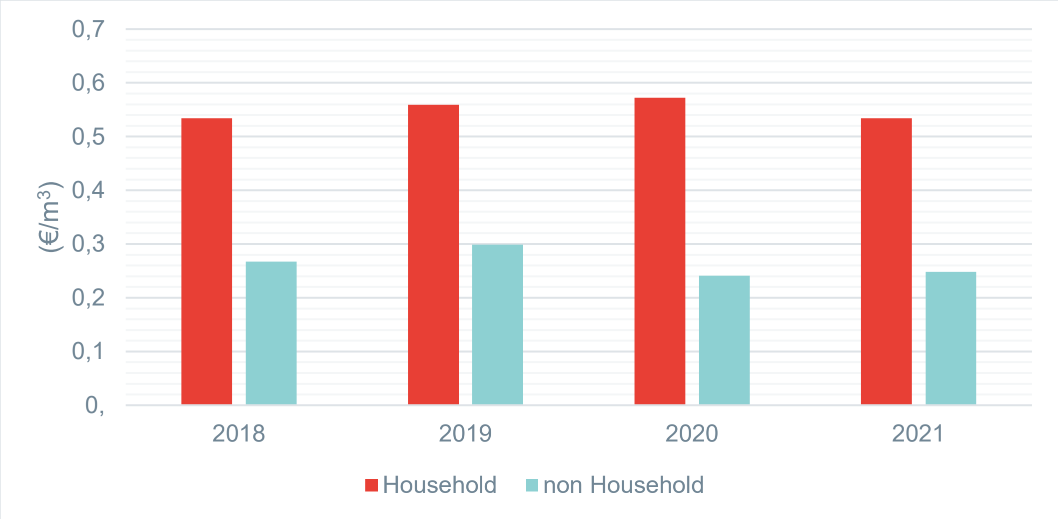


Figure 97 Prices for household and non-household final consumers in Slovenia in the period 2018-2021. Source: Eurostat

Croatia

Demand and supply

Croatia featured a total consumption of 2,905 mcm in 2021, with additional exports for 126 mcm, supplied as follows:

- 545.83 mcm via pipeline, through the entry points at Dravaszerdahely (Hungary) and Rogatec (Slovenia)
- 1,744.77 mcm via LNG, through the KrK terminal
- 745.9 mcm via national production
- Storage accounted for 4.40 mcm of net storage injection.

The following **Figure 98** displays the natural gas balance for Croatia for the period 2012-2021.

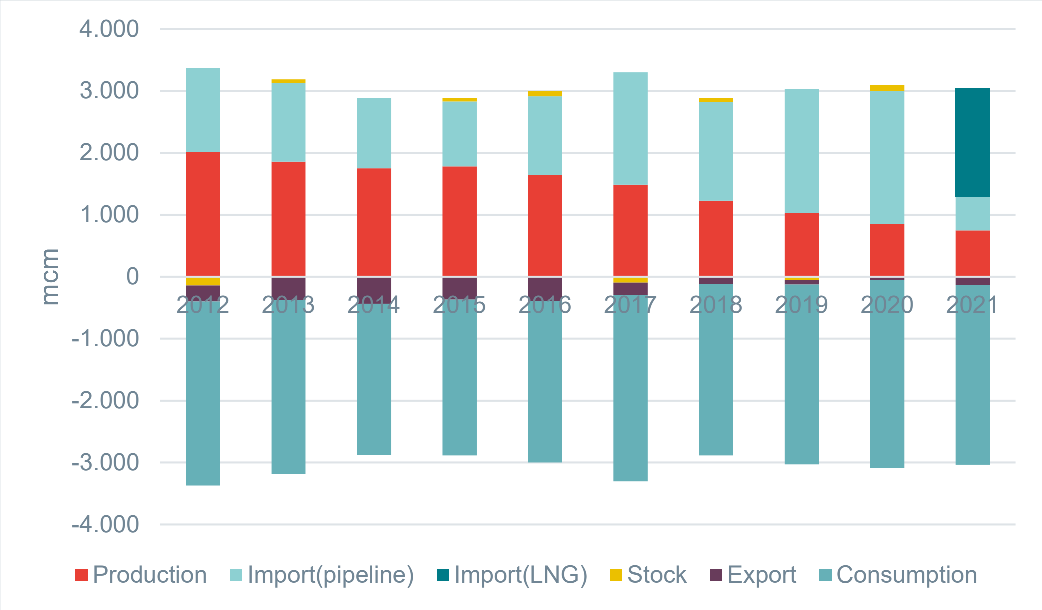


Figure 98 Energy balance for Croatia in the period 2012-2021. Source: DFC analysis on Eurostat data

The following **Figure 99** provides additional details on the LNG supply structure to Croatia: as of 2021, LNG has been imported via US (68%), Nigeria (13%), Qatar (12%) and Egypt (7%).

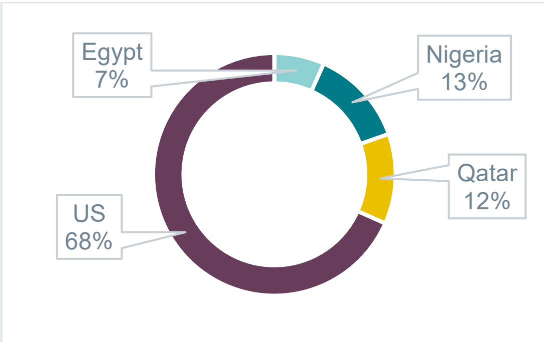


Figure 99 Natural gas supply per source country in 2021 (LNG). Source: Eurostat

Consumption per sector

The following **Figure 100** displays the energy consumption per sector in Croatia in 2021. As the figure displays the largest quota of gas consumption is for other sector (mostly heating, 9.2 TWh or 55.2% of total consumption), followed by consumption in the industrial sector (4.3TWh), and consumption for non-energy purposes (3.2TWh). A small quota of natural gas (1.72%) is used for transport.

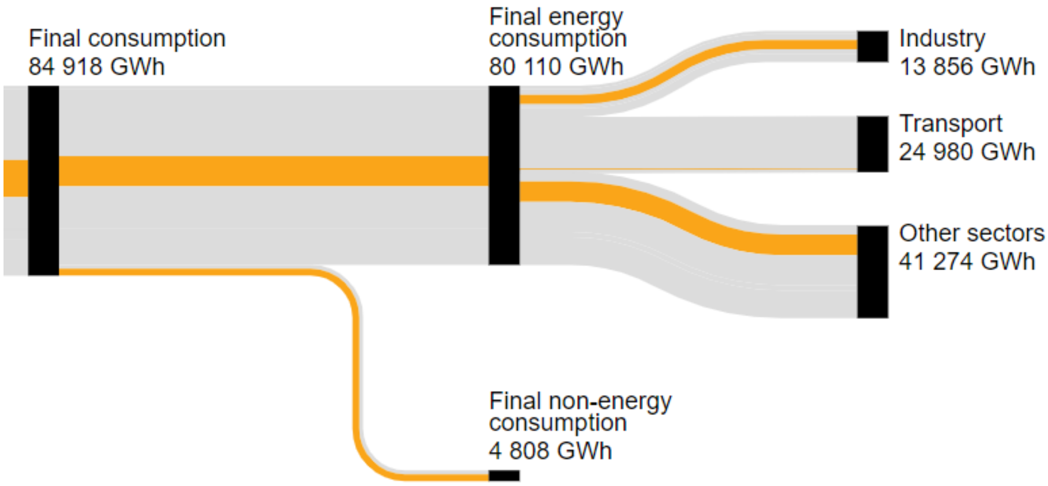


Figure 100 Energy consumption per sector in Croatia, with natural gas highlighted. Source: Eurostat

Gas infrastructures

Table 8 lists the entry points into the Croatian natural gas network. These infrastructures combined add up to a total 190.61 GWh/day of import capacity.

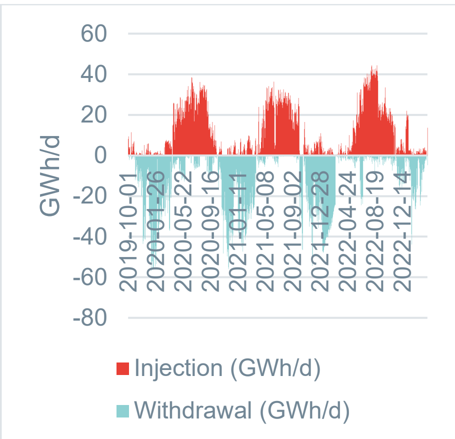
Croatia is the only country, together with Italy, that disposes of storage capacity in the Adriatic-Ionian (UGS Okoli facility, 55.60 TWh of capacity).

Entry point	Category	Capacity (GWh/d)	Flow (GWh/d)	Utilization rate 2022
Dravaszerdahely (HU)	Pipeline	51.74	1.46	2.82%
Rogatec (SI)		5.37	4.02	74.84%
Krk	LNG	85.50	79.32	92.77%

Table 8 Gas infrastructures in Croatia. Source: ENTSOG and GIE

With respect to pipeline imports, as of 2022 Croatia utilised on average 44% of its import capacity, with 105.81 GWh/d (or 3.8 bcm/year) being available for import.

The following figures display the injection-withdrawal patterns and the filling level dynamics for the UGS Okoli underground storage facility.



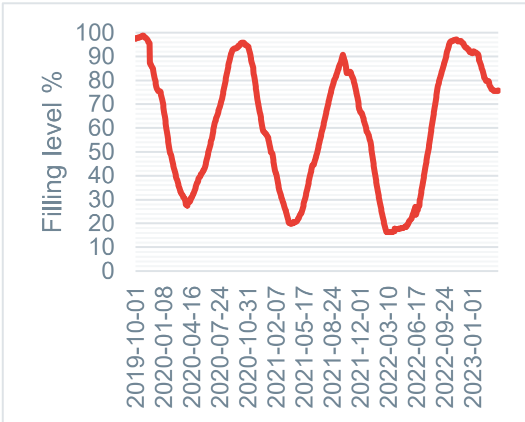


Figure 101 Injection-withdrawal pattern and filling level at the UGS Okoli storage facility. Source: GIE AGSI Transparency Platform

Gas prices

The following **Figure 102** displays the final gas prices for households and non-household consumers in Croatia, in the period 2018-2021.

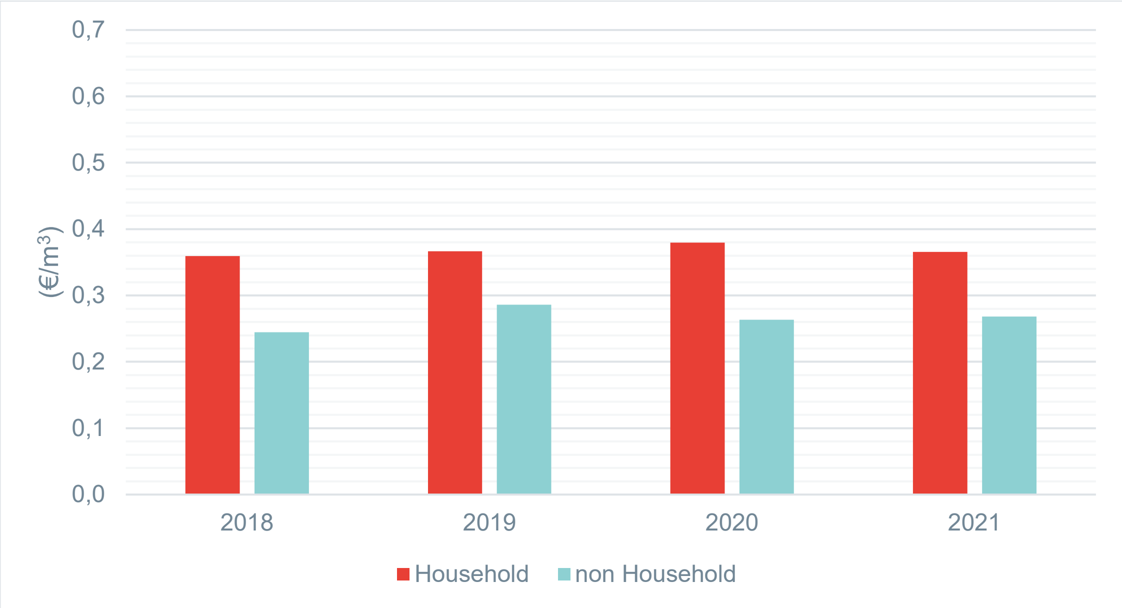


Figure 102 Prices for household and non-household consumers in Croatia in the period 2018-2021. Source: Eurostat

Bosnia and Herzegovina

Demand and supply

Bosnia and Herzegovina featured a total consumption of 253.91 mcm/year in 2021; 100% of gas has been imported via pipeline at the Zvornik interconnection point.

The following **Figure 103** displays the natural gas balance in Bosnia and Herzegovina for the period 2014-2021.

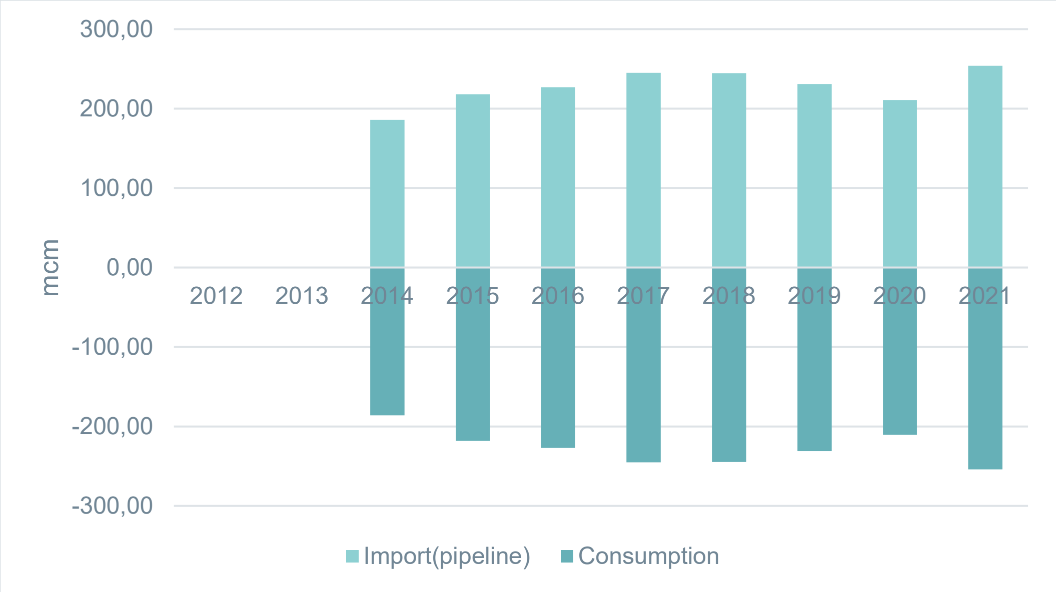


Figure 103 Natural gas balance for Bosnia and Herzegovina in the period 2012-2021. Source: Eurostat

Consumption per sector

Figure 104 displays the energy consumption per sector in Bosnia and Herzegovina in 2020[68], with natural gas highlighted. As the figure displays the largest quota of gas consumption is for industry (1.3 TWh, 43.6% of total consumption), followed by other sectors (heating, 0.7 TWh). Small volumes of natural gas are used for non-energy purposes (2.5%), and transport (1.36%).

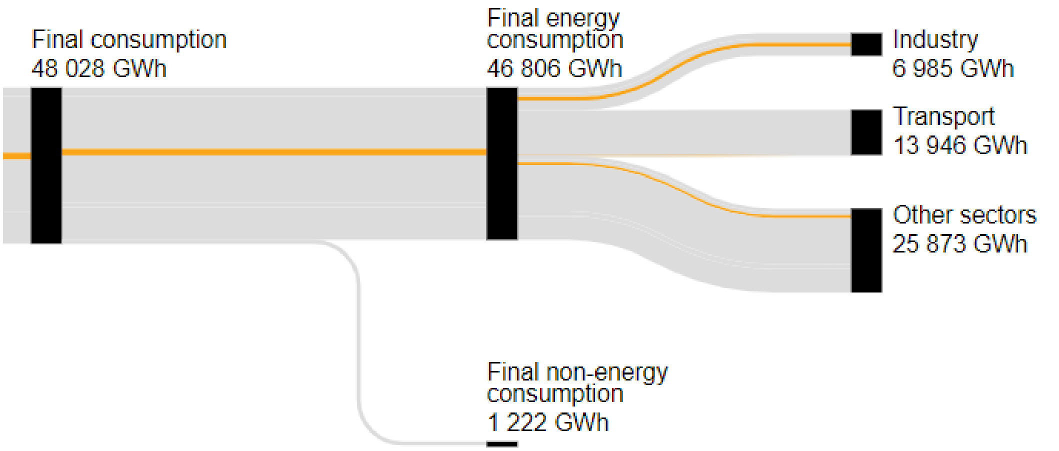


Figure 104 Energy consumption per sector in Bosnia and Herzegovina, with natural gas highlighted. Source: Eurostat

Gas infrastructures

Bosnia and Herzegovina is connected the European gas network only via Serbia (Zvornik interconnection point), and has been historically fully dependent on Russia for its gas supply.

[68] 2021 data from Eurostat are not available at the time of writing

Entry point	Category	Capacity (GWh/d)	Flow (GWh/d)	Utilization rate 2022
Zvornik	Pipeline	19.54	6.79	34.7%

Table 9 Entry point into the Bosnia and Herzegovina gas network. Source: Energy Community Secretariat

Gas prices

The following **Figure 105** displays the gas prices for household and non-household consumers in Bosnia and Herzegovina, in the period 2018-2021

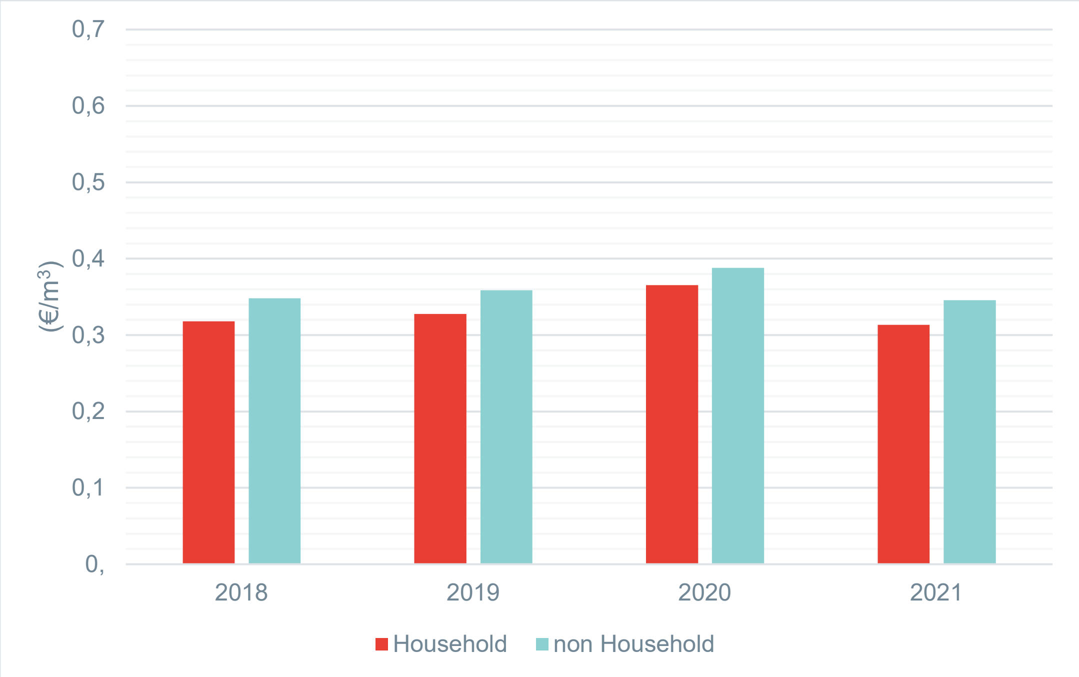


Figure 105 Prices for household and non-household final consumers in Bosnia and Herzegovina in the period 2018-2021. Source: Eurostat

Republic of Serbia

Demand and supply

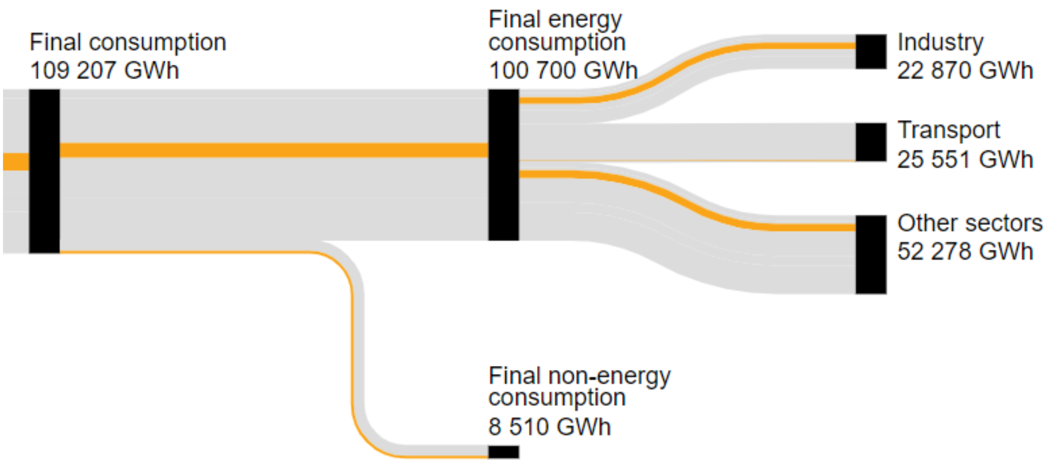
Serbia is the largest market in the Western-Balkan region, featuring a natural gas consumption of 3.01 bcm/year in 2021. In 2021, Serbia imported 78.65% of its gas consumption via pipeline through the entry points at Zaychar (Bulgaria) and Horgos (Hungary). Further, 0.36 bcm were supplied by national production, and 0.28 bcm were withdrawn from stock.

The following **Figure 106** displays the natural gas balance for Serbia for the period 2012-2021.

Figure 106 Natural gas balance for Serbia in the period 2012-2021. Source: Eurostat

Consumption per sector

Figure displays the natural gas consumption in Serbia in the period 2019-2022. As the figure displays the largest quota of gas consumption is for other sectors (5.2 TWh, 44.5% of total consumption), followed by direct consumption for industrial use (4.5 TWh) and non-energy consumption (1.7TWh). A small quota of natural gas (3.1%) is used for transport.



Gas infrastructures

Serbia has historically been fully dependent on Russia for its gas supply. In 2022, Serbia signed a three-year intergovernmental agreement on gas supply with Russia in 2022, aimed at satisfying at least 75% of its current demand[69]. **Table 10**

[69] Source: Energy Community Annual Implementation Report 2022

lists the entry points into the Serbian natural gas network. These infrastructures combined add up to a total 421.77 GWh/day of import capacity.

Entry point	Category	Capacity (GWh/d)	Flow (GWh/d)	Utilization rate 2022
Zvornik (BA)	Pipeline	20.07	-	-
Zaychar (BG)		401.70	64.8	16.1%

Table 10 Gas infrastructures and utilisation rate in 2021. Source: ENTSOG and Energy Community Secretariat

Gas prices

The following **Figure 107** displays the gas prices for household and non-household consumers in Serbia, in the period 2018-2021.

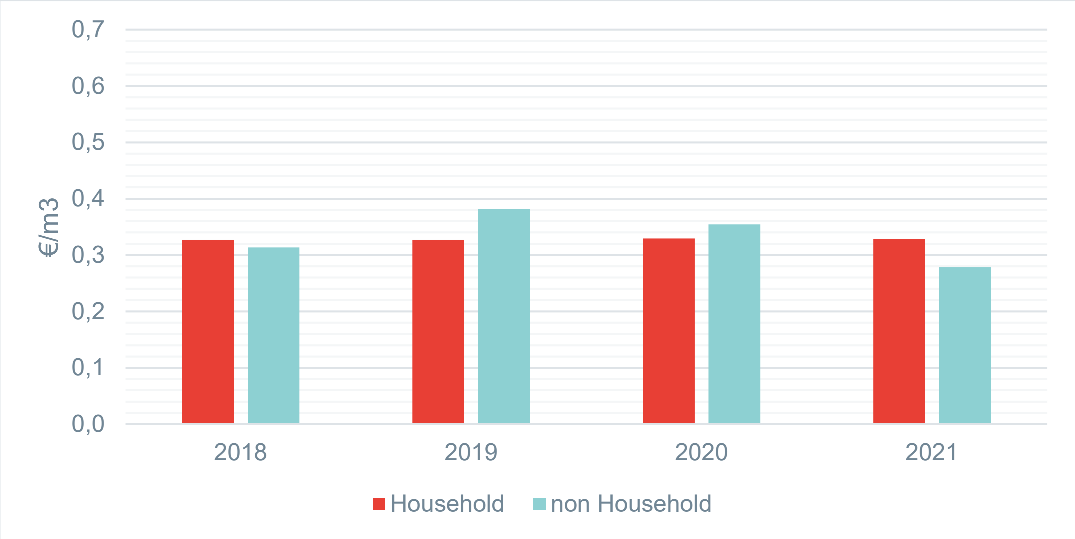


Figure 107 Prices for household and non-household final consumers in Serbia in the period 2018-2021. Source: Eurostat

Montenegro

Montenegro does not currently feature a gas sector.

Albania

Demand and supply

Albania features a low gas consumption (57.21 mcm/year in 2021), fully supplied by national production. Albania does not dispose of an internal gas network.

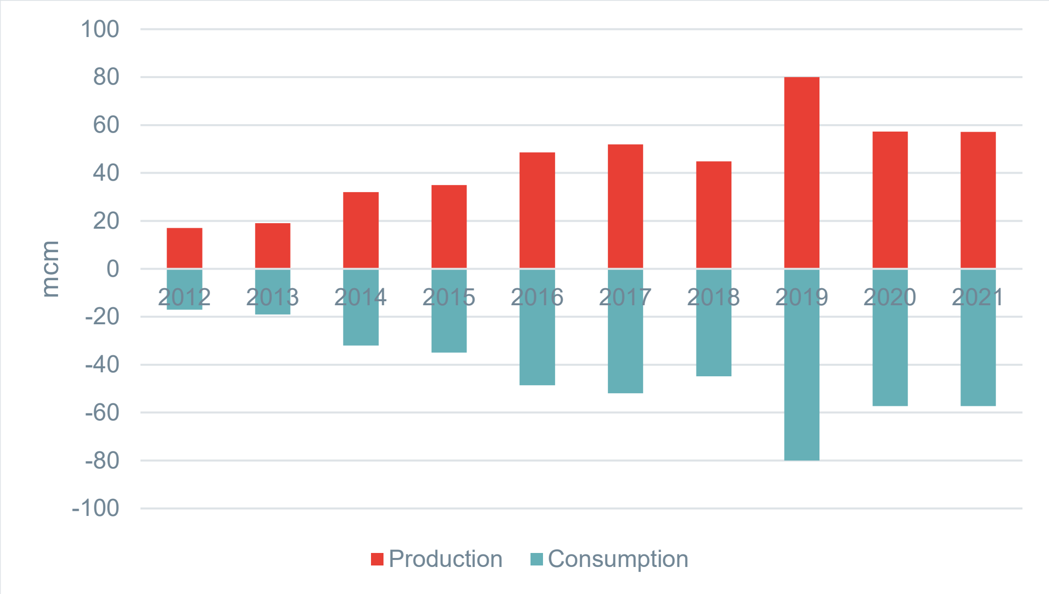


Figure 108 Natural gas balance for Albania in the period 2012-2021. Source: DFC

Gas infrastructures

Albania acts as a transit country for the Trans-Anatolian Pipeline (TAP), connecting Azerbaijan to Italy via Turkey and Greece. The Albanian gas TSO, Albgaz, is acting as a company engaged in the maintenance of TAP under a separate contract.

Gas prices

The following **Figure 109** displays the final gas prices (excluding taxes and levies) for households and non-households consumers in Albania, in the period 2018-2021.

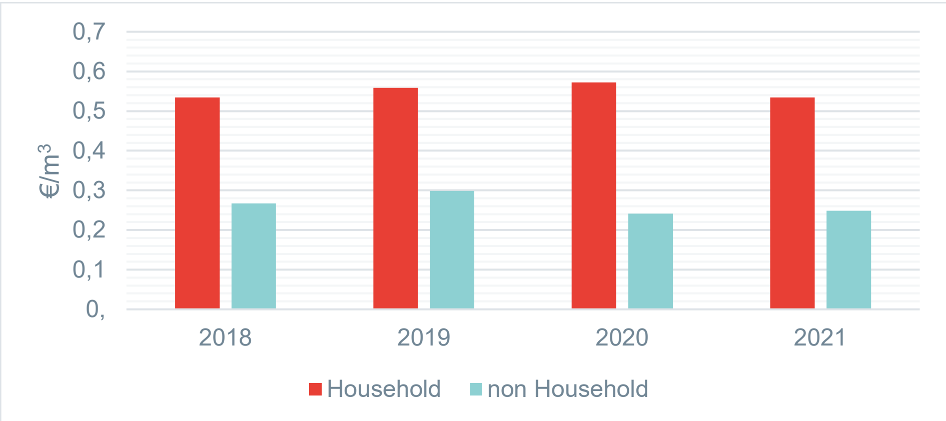


Figure 109 Gas prices for household and non-household consumers in Albania in the period 2018-2021. Source: Eurostat

Greece

Demand and supply

Greece gas sector is growing, and the country featured a gas consumption of 6.45 bcm/year in 2021 (a 50% increase with respect to 2012). Greece fully relies on imports (via pipeline and LNG) for its supply, as the country does not dispose of natural production or storage.

Figure 110 Natural gas balance for Greece in the period 2012-2021. Source: Eurostat

The following **Figure 111** provides additional details on the natural gas supply structure to Greece.

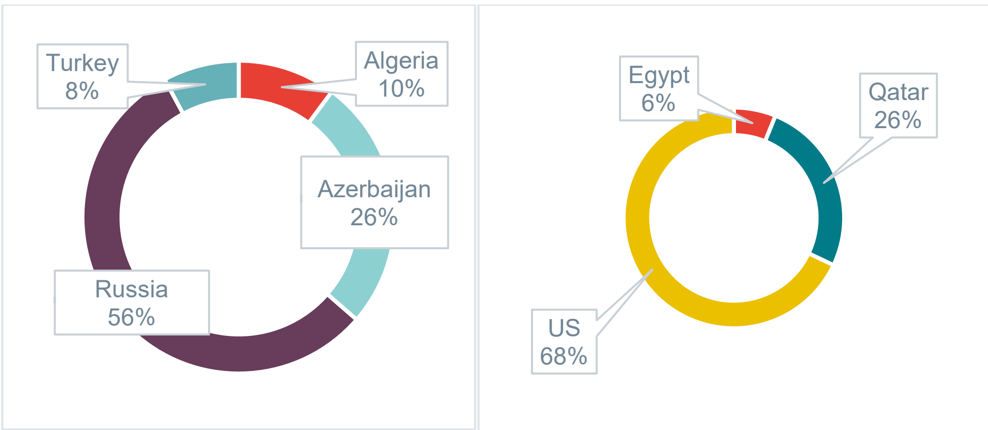


Figure 111 Natural gas supply per source country in 2021 (pipeline, left, and LNG, right). Source: Eurostat

Consumption per sector

Figure 112 below displays the energy consumption per sector in Greece in 2021, with natural gas highlighted in orange. As the figure displays the largest quota of gas consumption is for other sectors (mostly heating, equal to 7.5 TWh or 43.8% of total consumption), followed by consumption for industrial uses (5.9 TWh) and non-energy uses (3.5 TWh). A small quota of natural gas (1.1%) is used in the transportation sector.

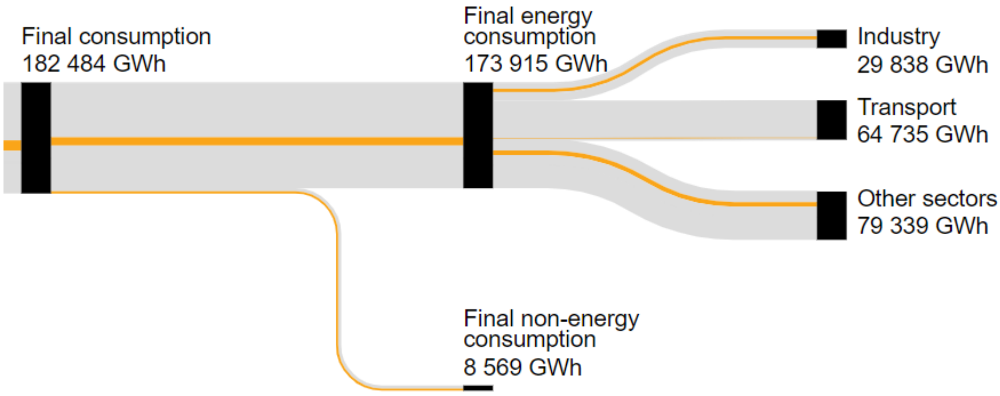


Figure 112 Energy consumption per sector in Greece in 2021, with natural gas highlighted. Source: Eurostat

Gas infrastructures

Table 11 lists the entry points into the Greek natural gas network. These infrastructures combined add up to a total 440.76 GWh/day of import capacity.

Entry point	Category	Capacity (GWh/d)	Flow (GWh/d)	Utilization rate 2022
Nea Mesimvria	Pipeline	53.37	24.6	46.0%
Sidirokastron		117.49	50.3	42.8%
Revythoussa	LNG	269.90	101.7	37.7%

Table 11 Natural gas infrastructures in Greece and utilisation rate in 2021. Source: ENTSOG and GIE

Greece utilised on average 40% of its import capacity (pipeline and LNG), with 264 GWh/d (or 9.8 bcm/year) being available for import.

Gas prices

The following **Figure 113** displays the natural gas prices for household and non-household consumers in Greece, in the period 2018-2021.

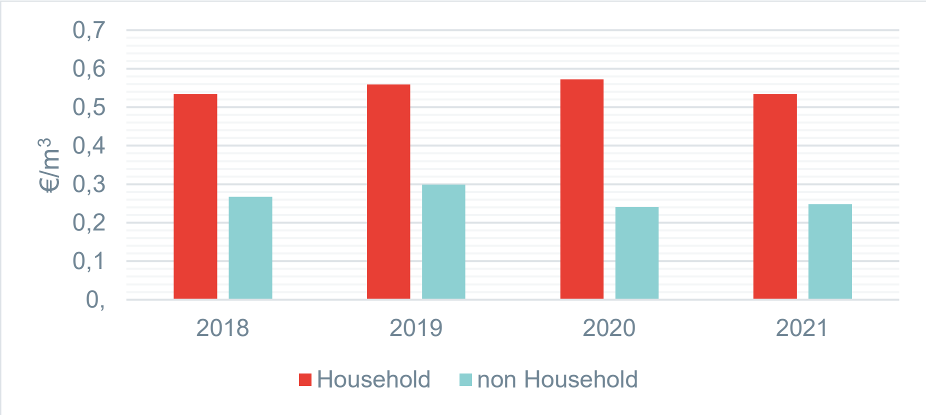


Figure 113 Prices for household and non-household final consumers in Greece in the period 2018-2021

North Macedonia

Demand and supply

North Macedonia's gas sector has been growing steadily, featuring 423.51 mcm/year of consumption in 2021 (a 66% from 2012). North Macedonia is fully reliant on pipeline imports for its supply (at the Zidilovo entry point).

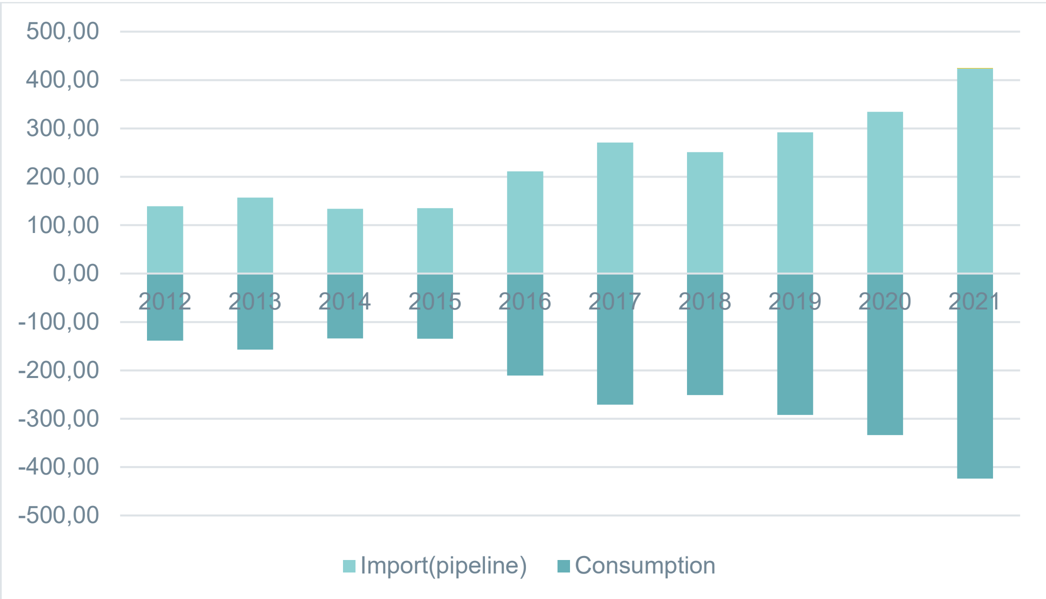
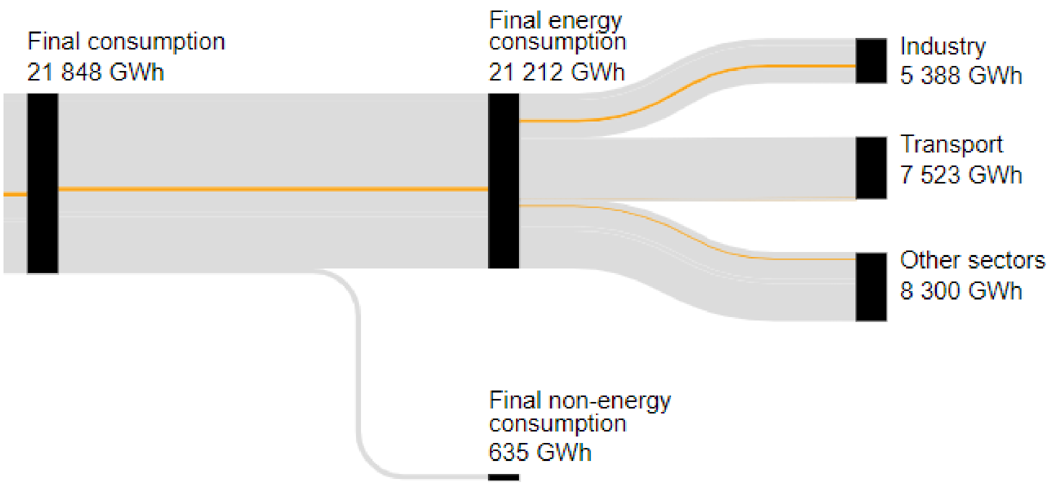


Figure 114 Natural gas balance for North Macedonia in the period 2012-2021. Source: Eurostat

Consumption per sector

Figure displays the natural gas consumption in North Macedonia in the period 2019-2022. As the figure displays the largest quota of gas consumption is for industrial use (415 GWh, 81% of total consumption), followed by consumption for other sectors (72GWh) and transport (24GWh).



Gas infrastructures

Together with Bosnia and Herzegovina and Serbia, North Macedonia has historically been fully dependent on Russia for its gas supply. The only entry point is at the Zidilovo interconnection point with the Bulgarian gas network.

Entry point	Category	Capacity (GWh/d)	Flow (GWh/d)	Utilization rate 2022
Zidilovo (BG)	Pipeline	44.3	11.3	25.5%

Gas prices

The following **Figure 115** displays the gas prices for household and non-household consumers in North Macedonia, in the period 2018-2021.

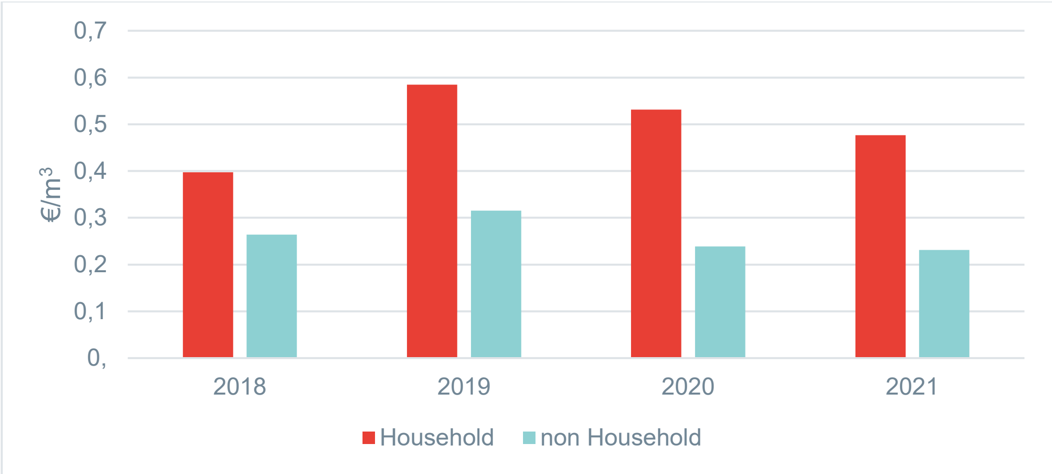


Figure 115 Gas prices for household and non-household consumers in North Macedonia in the period 2018-2021. Source: Eurostat

Organisation of the gas sector

Italy

Unbundling

Ownership unbundling provisions are fully implemented for both the transmission system operator (Snam) and natural gas distributors. DSOs that serve less than 100,000 customers are not subject to unbundling provisions.

System access

The Italian regulator, through Resolution No. 137/02 and subsequent amendments, set out the rules for free access to the transportation system, as well as guidelines for the implementation of the grid codes. On the basis of the principles contained in such Resolution, Snam has drafted its own grid code, which sets out transparent and non-discriminatory rules regulating access to and use of the transport service on its gas pipeline grid.

Wholesale market

A wholesale market for delivery at the Italian VTP (*Punto di Scambio Virtuale*, PSV) has been operational since 2010. Snam operates on the market as balancing operator. The market operator GME also manages a forward market that is relatively illiquid; most forward trading takes place via financial futures on EEX.

The REMIT Regulation is fully implemented.

Retail market

The retail market is fully deregulated and all consumers can access free-market conditions.

Vulnerable consumers are identified and protected according to Energy Law; vulnerable consumers can access natural gas at regulated prices. All retailers are obliged to supply vulnerable consumers.

Regional integration

Italy is connected to Northern Europe via TAG (Austria) and TENP (Swizerland), as well as to Northern Africa via the Transmed and TTPC infrastructures. Within the Adriatic-Ionian region, TAP interconnects Italy with Albania; an interconnection point (Sempeter) also connects Italy to Slovenia.

Further, Italy disposes of three regassification infrastructures.

Cross-border transmission capacity is offered via PRISMA, fully implementing the CAM principles. Regassification capacity is offered through competitive and open tenders as approved by the regulator; anti-hoarding procedures are in place.

Security of supply

Italy fully implements Regulation 2017/1938 on security of supply, as well as Regulation 2022/1032 regarding storage filling obligations.

Slovenia

Unbundling

The gas TSO Plinovodi is responsible for natural gas infrastructure, together with 13 DSOs in more than 70 local communities. Most DSOs service less than 100,000 customers in total, and therefore no legal unbundling is required. Plinovodi was certified as an independent transmission system operator (ITO) in 2012.

System access

Third party access is granted under regulated, cost-based tariffs for the gas network in Slovenia, and implemented via the Network Codes.

Wholesale market

As of 2015 Plinovodi, in accordance with the adopted System operating instructions for the natural gas transmission network (Official Gazette of the RS, No. 55/2015) and the Energy Act established a Virtual Trading Point for natural gas on the transmission system.

Plinovodi provides the following services in the Virtual Trading Point:

- Performing transactions with natural gas,
- Bulletin board for trading with natural gas.

Currently there are 20 operators registered at the VTP. REMIT Regulation is fully implemented.

Regional integration

Transmission capacity at all entry-exit points (with Italy, Austria and Croatia) fully implements the European CAM regulation, providing for transparent, open and competitive allocation procedures.

Security of supply

Slovenia fully implements Regulation 2017/1938 on security of supply.

Croatia

Unbundling

Unbundling and certification of the gas transmission system operator (Plinacro) is determined by the Law on Gas Market (adopted on February 22, 2018). About 38 certified distribution system operators are active in the country.

System access

Third party access is granted under regulated, cost-based tariffs for the gas network in Slovenia, and implemented via transparent Network Codes.

Wholesale market

The Croatian gas market is organized pursuant to the Energy Act, the Regulation of Energy Activities, the Gas Market Act, and secondary legislation arising from the Gas Market Act.

A trading platform is established to provide trading and balancing with conditions of the Commission Regulation (EU) No 312/2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Networks.

The market is operated by HROTE; 31 operators are currently registered on the market.

Regional integration

Croatia is interconnected to the European network via Slovenia (Rogatec IP) and Hungary (Drava Szerdahely IP). Further, Croatia imports LNG at the Krk terminal.

Cross-border transmission capacity and regassification are offered via transparent and open procedures implementing the CAM principles. Regassification capacity is offered through competitive and open tenders as approved by the regulator; anti-hoarding procedures are in place.

Security of supply

As of 31 October 2022, Croatia adopted and implemented Regulation (EU) 2017/1938 on gas security of supply via the Government *Decision 127/2022 adopting the Intervention Plan concerning measures to safeguard the security of gas supply of the Republic of Croatia.*

Regulation (EU) 2022/1032 defining the storage filling target obligations entered into force from 1 July 2022.

Bosnia and Herzegovina

Unbundling

Gas Promet Pale, one of two operators in Republika Srpska, is certified under the ownership unbundling model by the entity’s regulator. The second one, which performs transport, distribution, system operation and supply, is still not unbundled. In Federation of Bosnia and Herzegovina, one company operates the transmission network, as an exclusive and sole task in line with the Decree on Organization and Regulation of the Gas Sector, but there is no legal basis for unbundling under the Third Energy Package.

Distribution of gas in both entities is bundled with the supply and trade of natural gas as allowed by the Directive's de minimis clause.

System access

Third party access is granted under regulated tariffs for the gas network in Republika Srpska, while access is negotiated in the Federation. Tariffs are determined by the entity governments as part of the gas price at the distribution level. Third party access is not established under the Network Codes provisions in both entities.

Wholesale market

Bosnia and Herzegovina has a foreclosed gas market, organised in two parallel entity gas markets. Republika Srpska's wholesale market prices are not regulated, however, there is only one dominant gas importer. This is also the case for Federation of Bosnia and Herzegovina, where wholesale prices are determined by the entity government. All transactions are based on bilateral contracts. A virtual trading point for Republika Srpska is not functional and it does not exist in the Federation.

The REMIT Regulation was not transposed.

Retail market

In Republika Srpska, all retail market customers are supplied under non-regulated prices and switching rules are in place. The public supplier for households has not been appointed yet. The dominant supplier, the public company GAS RES, serves circa 85% of the retail market in Republika Srpska. Customers in Federation of Bosnia and Herzegovina are still captive and supplied under regulated prices.

Regional integration

For the single interconnection point between Serbia and Bosnia and Herzegovina, there is an interconnection agreement signed between the adjacent operators.

There is no gas PECI project on the territory of Bosnia and Herzegovina, but two PMI projects: Interconnector Bosnia and Herzegovina - Croatia North and Interconnector Bosnia and Herzegovina - Croatia South. The former one, on the territory of Republika Srpska, is in the feasibility stage albeit it has not matured further during recent years.

The interconnector Bosnia and Herzegovina - Croatia South is in the design and permitting phase. The project would enable Bosnia and Herzegovina, and particularly the Federation, to access alternative sources of gas, contribute significantly to its security of supply and enable access to competitive gas markets of the European Union via Croatia, thus bringing in price competition. The project would introduce natural gas in new territories of the Federation.

Security of Supply

Bosnia and Herzegovina has not yet started with the transposition of Regulation (EU) 2017/1938.

Republic of Serbia

Unbundling

Neither gas transmission system operator in Serbia was certified or in line with the gas acquis. The unbundling plans for Srbijagas and Yugorosgaz, adopted by the Government in 2021, are not progressing. Srbijagas' spin-off company, Transportgas Srbija, is not unbundled and certified, nor is Yugorosgaz Transport.

Transportgas Srbija is owned by the Republic of Serbia, but the separation of the public bodies who control the state-owned supplier and trader, Srbijagas and Transportgas Srbija, was not accomplished. Transportgas Srbija aims to be unbundled under the independent system operator model. For Yugorosgaz Transport, no progress with respect to unbundling was made.

Gastrans, exempted and certified by the regulator, was licensed under the independent transmission operator model. Banatski Dvor storage needs to undergo certification according to the new Gas Storage Regulation.

System access

The Network Codes were transposed by the Government in October 2022. However, in practice, there is no capacity allocation at the interconnection points and the capacity at the interconnection point Horgos, with Hungary, is still hoarded

by the incumbent shippers. Srbijagas thus effectively prevents new entrants to the Serbian market from more liquid central European hubs.

The entry-exit transmission tariff methodology is in place, but harmonised tariffs are yet to be transposed. Gastrans was exempt from third party access.

Wholesale market

The wholesale market in Serbia is monopolised by Gazprom and Srbijagas. It is illiquid with no exchanges nor the possibility to purchase gas elsewhere. Serbia signed a three-year intergovernmental agreement on gas supply with Russia in 2022, aimed at satisfying at least 75% of its current demand.

REMIT Regulation

(EU) 1227/2011 is transposed by the regulator.

Retail market

In retail gas supply, Srbijagas is the dominant market player.

Protection of customers is well established. Supplier switching occurs but to a very limited extent. Updated supply rules, adopted by the Government, enabled that measurement of natural gas was switched to energy units.

Regional integration

The interconnector Bulgaria - Serbia is also a PCI priority project. It is currently under construction in the Serbian territory and is scheduled to be commissioned in 2023. The project will diversify the available gas sources.

In order to exploit its full potential for regional integration, third party access on the Horgos interconnector should be in place so that the pipeline can link Southeast and Central markets. Transportgas Srbija has interconnection agreements with the adjacent transmission system operators.

The interconnectors Bulgaria - Serbia and Serbia - North Macedonia are PECI projects.

Security of supply

The national security of supply rules such as Preventive and Emergency Plans are in place but the framework needs to be aligned with Regulation (EU) 2017/1938 and the storage amendments.

Montenegro

Unbundling

The future transmission system operator, Montenegro Bonus, designated by the Government, is not yet unbundled under the ownership unbundling model, as defined by the Energy Law.

System access

No gas network exists in Montenegro. The regulator REGAGEN continues to proceed with the drafting and adoption of secondary acts. The Energy Law and the Law on Cross Border Exchange of Electricity and Natural Gas transposed the relevant articles to ensure third party access, but the Network Codes transposition is still pending.

The energy regulator REGAGEN adopted methodologies for maximum revenues for a storage operator. The transmission methodology is not aligned with the Tariffs Network Code.

Wholesale market

Montenegro does not have a gas market. REMIT Regulation (EU) 1227/2011 is in place. REGAGEN adopted methodologies for maximum revenues for a market operator.

Retail market

Supply rules for natural gas are in place. The Energy Law set the legal basis for protection of customers.

Market integration

The Ionian Adriatic Pipeline (IAP) is a PMI, crossing Montenegro. The project, which is in the planning and design phase, could introduce natural gas into the energy mix of Montenegro from the south, e.g., via the TAP pipeline, or from the north by accessing LNG sources from Croatia.

Security of supply

The Law on Cross Border Exchange transposed elements of the security of supply acquis; nevertheless, Montenegro is exempt from the implementation of Regulation (EU) 2017/1938 until gas is supplied to the country.

Albania

Unbundling

The Trans Adriatic Pipeline (TAP) is certified and unbundled in line with the exemption decision under the independent transmission operator model. The national transmission system operator Albgaz is certified under the ownership unbundling model.

However, all the conditions set in the certification decision are not yet met such as the complete transfer of competencies over investment decisions to the ministry exercising control over Albgaz.

System access

Network Codes are transposed and operationalised by TAP and Albgaz in separate codes. In practice, Albgaz is acting as a company engaged in the maintenance of TAP under a separate contract. Implementation of third party access is performed only by TAP, in line with the exemption conditions. The Energy Regulatory Entity (ERE) adopted the LNG and storage tariff methodologies and licensing rules for LNG.

Wholesale market

Albania has no national natural gas market. The REMIT Regulation was transposed by ERE. ERE has adopted all acts envisaged by the law save the market rules.

Retail market

Despite the lack of a national gas market, secondary legislation regulating supply to customers was adopted.

Regional integration

Following the operationalization of Trans Adriatic Pipeline (TAP), Albania is formally connected to gas markets. Albania has become a transit country, as TAP has commenced its commercial operation last year and is performing a market test for the expansion of its capacities.

As of late, Albania has been promoting an LNG-based source of supply to its long-abandoned project of converting the thermal power plant (TPP) Vlore to gas. At the same time, it looks at becoming also a transit route of LNG to Italy via TAP, as the construction of exit facilities of TAP towards a future Albanian network may need to revert its direction into an entry point to TAP. Nevertheless, no progress in terms of developing its own gas infrastructure took place.

The Albania - Kosovo Gas Pipeline (ALKOGAP) is a Project of Energy Community Interest (PECI). The Ionian Adriatic Pipeline (IAP) is a Project of Mutual Interest (PMI).

Security of supply

Gas emergency rules are in place. The Gas Law was amended in 2021 to transpose certain elements of Security of Gas Supply Regulation (EU) 2017/1938.

Greece

Unbundling

The transmission system operator Desfa was established in 2007 based on Law 3428/2005 for the liberalisation of the natural gas market, and has been certified under the provisions of Directive 2009/73/EC.

Today the shareholders of Desfa are the Greek State (34%) and the Senfluga Energy Holdings SA (66%), which is a consortium of the following companies: Snam (Italian TSO), Enagas (Spanish TSO), Fluxys (Belgian TSO) and Damco as a passive shareholder.

Distribution is subject to ownership unbundling provisions. Three distribution system operators are present in Greece:

- EDA Attica, owning and operating of the natural gas distribution network in the Attica region;
- EDA Thessaloniki-Thessaly, owning and operating the natural gas distribution network in the Thessaloniki and Thessaly regions; and
- DEDA, owning and operating the natural gas distribution networks of the rest of Greece.

System access

The entry-exit system of the Regulation (EU) 715/2009 and the provisions of the Regulation (EU) 2017/460 on the establishment of a network code on harmonised transmission tariff structures for gas are applied.

Third-party access is granted under open, transparent and non-discriminatory conditions. Desfa publishes the access conditions in a Network Code; tariffs are set by the national regulator.

Wholesale market

HenEX acts as market operator and manages the Natural Gas Trading Platform, a organized market operating in accordance with the Regulations EU BAL Network Code (Regulation (EU) 312/2014) and REMIT (Regulation (EU) 1227/2011). The Natural Gas Trading Platform was launched on the 21st March 2022.

Participants in the Natural Gas Trading Platform include Desfa, that participates by procuring balancing services at the Hellenic VTP. Dily products (up to the next three days) and intraday products are exchanged.

EnExClear, a subsidiary of HEnEx founded in November 2018, acts as a Clearing House for the gas wholesale market.

Regional integration

Greece is connected to the European network at the Kulata entry point with Bulgaria, as well as at the Nea Mesimvria IP (TAP entry). Further, Greece is interconnected with Turkey as the Kipi entry point.

Capacity allocation at all points is compliant with Regulation 459/2017 (CAM Network Code); capacity is allocated via the RBP platform for the Kulata entry point and via Prisma for the other points.

Furthermore, regassification capacity at the Revythoussa terminal (owned and operated by Desfa) is offered through competitive and transparent procedures. No separate LNG Access Code has been developed by Desfa; provisions related to the access to regassification capacity are published as part of the Network Code.

Security of supply

Gas emergency rules are in place. The Regulation (EU) 2017/1938 on gas security of supply is adopted and fully implemented.

North Macedonia

Unbundling

The gas transmission system operator in North Macedonia is neither unbundled nor certified in line with the Third Energy Package. The state took over the full ownership of GA-MA, a licensed gas transmission system operator, and decided to merge it with another state company, NER, responsible for gas transmission system development. The merging process is still ongoing.

Concrete actions to establish one national transmission system operator and certify it are still ongoing. All existing distribution companies have less than 100.000 customers and are exempt from the unbundling provisions.

System access

The tariff methodology is in place, allowing for transparent, non-discriminatory access to the gas network. The Energy Law stipulates the direct applicability of mandatory Network Codes.

However, the national transmission code has not been revised to that effect, and practices on balancing and capacity allocation are at a very basic level. Further, transparency is well below the level required by Annex I of Regulation (EC) 715/2009.

Wholesale market

There are only two active traders in the wholesale market, selling at market prices. All contracts are concluded bilaterally, on a monthly and yearly basis. However, the market remains illiquid, without a virtual trading point.

Amendments to the Energy Law aimed at general transposition of the REMIT Regulation are adopted. Regulatory rules to complete full transposition still have to be adopted.

Retail market

End-user gas prices are deregulated and all customers are formally eligible. Customer protection measures are defined in line with Annex I of Directive 73/2009/EC.

Regional integration

The gas network of North Macedonia is connected only to the Bulgarian gas system.

The exit from the Bulgarian system has been fully booked by Gazprom, and the lack of implementation of contractual congestion management procedures obstructs entrance for any new supplier to the North Macedonian gas market.

However, by the interconnection agreement in line with the Network Code on Interoperability and Data Exchange signed by the two adjacent operators, GA-MA and Bulgartransgaz, which will be fully implemented as of 1 January 2023, the unused capacity will be released and allocated in line with the Network Code on Capacity Allocation.

The North Macedonia - Kosovo Interconnector and the Serbia - North Macedonia Interconnector are PECI projects.

Security of supply

Security of supply provisions are in line with Directive 2004/67/EC, but do not transpose Regulation (EU) 2017/1938 and Regulation (EU) 2022/1032.

ANNEX C PLANNED INFRASTRUCTURES IN THE ADRIATIC-IONIAN REGION

Electricity

Transmission

The **Table 12** below reports the major planned electricity transmission infrastructures in the Adriatic-Ionian countries. The list is provided by ENTSO-E as part of its Ten Year Network Development Plan (TYNDP; list updated as of TYNDP 2022). Five projects have the status of Project of Common Interest (PCI); two projects are related to incremental capacity. Out of 19 total projects, 5 are interconnections within the Adriatic-Ionian region, and 14 connect the region to the wider European network.

Project Name	Description of the project	Promoters	Country	Status
Reschenpass Interconnector Project	New 220kV interconnector between the substations Nauders (AT) and Glorenza (IT), with a transmission capacity increase of 300 MW.	TERNA; APG	AT ;IT	Under construction
Italy-Montenegro	The project includes a new HVDC subsea cable between Villanova (Italy) and Lastva (Montenegro) and the DC converter stations. Transmission capacity increase of 600MW	Terna, CGES	IT ;ME	Under construction
Italy-Tunisia	New interconnection between Tunisia and Sicily to be realized through an HVDC submarine cable. Transmission capacity increase of 600MW	Terna, STEG	IT ;TN	In permitting
Central Northern Italy	The project consists in the strengthening of interconnection between the northern and the central part of Italy. It will involve the upgrading of existing 220 kV over-head line to 400 kV between Colunga and Calenzano substations as well as the removing of limitations on the existing 220 kV network in Central Italy	Terna SpA	IT	Under construction

Central Southern Italy	The project consists in the reinforcement of southern Italy 400 kV network through new 400 kV lines. The activities will involve the network portions between the substation of Villanova and Foggia, Deliceto and Bisaccia	Terna	IT	In permitting
CSE4	The project concerns the construction of a new AC 400kV interconnection between Bulgaria and Greece and new AC 400kV overhead lines at the south part of Bulgaria. This project will increase cross border transfer capacity between Bulgaria and Greece of respectively 930 MW and 600 MW	ESO, Admie	BG ;GR	Under construction
Mid Continental East corridor	The project consists of one double circuit 400 kV interconnection line between Serbia and Romania. The increased. The increased transmission capacity is 617MW and 335MW	EMS, Transelectrica	RO ;RS	In permitting
Greenconnector	HVDC interconnector project between Italy and Switzerland for power transport using DC cables rather than overhead lines. The route length is about 165 km. The design power is 1000 MW (1200 MW in overload condition), while the DC voltage is +/- 400 kV DC.	Worldenergy SA	CH ;IT	In permitting
Würmlach (AT) - Somplago (IT) interconnection	Somplago - Würmlach interconnection is a cross-border electrical line promoted by Alpe Adria Energia Srl. The project concerns a 220kV a.c. merchant line, about 300 MW thermal capacity from Somplago substation to new Würmlach substation, including Phase Shifter Transformer located in Austria.	Alpe Adria Energia Srl	AT ;IT	In permitting

EuroAsia Interconnector	The EuroAsia Interconnector is a multi-terminal VSC-HVDC scheme which will connect the transmission networks of Greece (Crete), Cyprus and Israel, and will comprise two converter stations with sea-electrodes, interconnected by HVDC cable systems. The initial development will allow the bidirectional transfer of 1000 MW. At full deployment, it will allow the transfer of 2000 MW.	EuroAsia Interconnector	CY ;GR ;IL	In permitting
Transbalkan Corridor	This project contains seven investments, with the new corridor spanning from Central and Western Serbia all the way to SS Visegrad in Bosnia and Herzegovina and SS Lastva in Montenegro.	EMS, NOS-BIH, CGES	BA ;IT ;ME ;RS	In permitting
Merchant line Castasegna (CH) - Mese (IT)	The planned Transmission project is a merchant line between Castasegna (CH) and Mese (IT). The planned Cable connection in 220 kV AC has a length of around 14 km, 13.5 of witch in Italy. The NTC increase is around 200-250 MW.	Repower, MERA SRL	CH ;IT	In permitting
SACOI3	New HVDC line between Italy mainland, Corsica and Sardinia replacing existing link SACOI2. The capacity increase will be 400MW	Terna, EDF	FR ;IT	In permitting
Dekani (SI) - Zaule (IT) interconnection	The project concerns an underground cable 110kV a.c. merchant line, 150 MW from Zaule (IT) substation to Dekani (SI) substation, including a 110/135 kV Phase Shifter Transformer.	HSE d.o.o. (Holding Slovenske Elektrarne) - E3 d.o.o. (ENERGETIKA, EKOLOGIJA, EKONOMIJA) - Adria Link Srl	IT ;SI	In permitting
Redipuglia (IT) - Vrtojba (SI) interconnection	A third party cross-border electrical line, the project concerns an underground cable 110kV a.c. merchant line, 150 MW from Redipuglia (IT) substation to Vrtojba (SI) substation, including a 110/135 kV Phase Shifter Transformer. Increased transmission capacity of 10MW	HSE d.o.o. (Holding Slovenske Elektrarne, d.o.o.) E3 d.o.o. (ENERGETIKA, EKOLOGIJA, EKONOMIJA, d.o.o) Adria Link Srl	IT ;SI	In permitting

Tyrrhenian link	Italian HVDC link between Campania, Sicily and Sardinia. Transmission capacity between 500MW and 1000MW	Terna	IT	In permitting
South Balkan Corridor	This project consists of two investments: 400 kV OHL Bitola(MK)- Elbasan(AL) and 400/110 kV SS Ohrid, Macedonia. The interconnection contributes to increasing the transmission capacity in the East-West direction. The increased transmission capacity will be of 500 MW	MEPSO	AL ;MK	Under construction
Interconnection of Crete to the Mainland System of Greece	The project aims to increase security of supply and improve stability issues of the island by its interconnection to the mainland system. In Phase I Crete will be connected to Peloponnese with a 150 kV AC double circuit submarine cable interconnector of 2x200 MVA nominal transfer capacity. In Phase II Crete will be connected to Attica with a bipolar submarine HVDC-VSC link of 2x500 MW capacity transfer. Increased transmission capacity of 800 MW.	Admie	GR	Under construction
Southern Italy	New 400 kV lines in Campania and in Calabria, affecting existing 400 kV substation. The link will remove grid constraints and congestions due to the new renewable installed capacity.	Terna	IT	In permitting

Table 12 Planned electricity infrastructures in the Adriatic-Ionian region. Source: ENTSO-E

Storage

The **Table 13** below reports the planned electricity storage infrastructures in the Adriatic-Ionian countries. The list is provided by ENTSO-E as part of its Ten Year Network Development Plan (list updated as of 2022). Currently one PCI-status storage project is part of the list, base don hydro pumped technology and located in Greece, promoted by Terna S.A.

Project Name	Project description	Technology

HPS AMFILOCHIA	The project consists of two independent hydro-pumped storage, with one upper reservoir each. Total net volume 7 million m^3. As lower reservoir of the complex, it is considered the existing, artificial reservoir of Kastraki (Owner Public Power Corporation). The electromechanical equipment will be installed in two independent power houses, on the right bank of the Kastraki reservoir. Total installed capacity is 680 MW for production and 730 MW for pumping.	Hydro Pumped Storage

Table 13 Planned electricity storage infrastructures in the Adriatic-Ionian region. Source: ENTSO-E

Natural gas

The planned infrastructures listed below are qualified either as FID (Final Investment Decision) or Advanced Phase in the context of the ENTSO-G Ten Year Network Development Plan 2022.

Pipelines

Name	Operator	Project description	Status
Interconnection Bulgaria - Serbia	Bulgartransgaz EAD	Interconnection Bulgaria-Serbia aims to connect the national gas transmission networks of Bulgaria and Serbia.	FID
Interconnector Greece-Bulgaria (IGB Project)	ICGB a.d.	Bi-directional gas interconnector between the high pressure natural gas systems of Greece and Bulgaria with a technical forward capacity of up to 3bcm/y, capable to be increased to up to 5 bcm/y with the installation of a Compressor Station.	FID
Larino - Chieti	SGI S.p.A:	Construction of 113 km 24" LARINO-CHIETI. The project forsee realisation of a Gas Tranportation system on Adriatic coast that will: - ensure the security of service on the current backbone over the coming decades - avoid congestion in this section and meet capacity increases in relation to changes in demand	FID

FSRU 1 Connection	Snam Rete Gas S.p.A.	The project concerns the connection between the new FSRU in Tuscany and Snam Rete Gas Grid. The project will envisage two pipiline with diameter equal to 26 inch	FID
Transmission Hybrid Compressor Stations	Snam Rete Gas S.p.A.	Installation of new electro compressors in partial replacement of the existing turbo compressors the italian compression plants in several compressor plants. The project makes possible the coupling of electricity and gas sectors by providing a demand flexibility source.	Advanced
Booster Compressor Station for TAP in Nea Messimvria	DESFA S.A.	The project consists of the implementation of a 5.5 MW booster station in order to enable flow from the Greek transmission system to TAP. This project is the second phase of development of project "TRA-N-941-Metering and Regulating station at Nea Messimvria" already in operation.	FID
Metering and Regulating Station at Alexandroupoli	DESFA S.A.	The project consists of the implementation of one Metering and Regulating Station at Alexandroupoli (Amphitriti) for the potential interconnection of the Greek transmission system with the LNG terminal in Northern Greece.	FID
Upgrade of Nea Mesimvria Compressor Station	DESFA S.A.	The addition of a third turbocompressor unit at the existing Comressor station of Nea Messimvria in order to increase the import capacity of the transmision system of DESFA to transport gas from north to south but also (in reverse flow) from south to north. This increase is needed in view of the operation of TAP that adds one additional Entry point (and future Exit point) to the system.	FID

Compressor station at Ambelia	DESFA S.A.	Installation of a new compressor station which will increase the capacity of the transmission system of DESFA to transport gas from north to south but also in reverse flow.	FID
Development for new import from the South (Adriatica Line)	Snam Rete Gas S.p.A.	The project consists in new on-shore pipeline and compressor station along the center-south of Italy that will allow the increase of transport capacity at new or existing Entry Points in south Italy.	Advanced
Poseidon Pipeline	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A	210 km of offshore from Greece crossing the Ionian Sea up to Otranto. In its first phase, Poseidon pipeline would transport an initial capacity of 12 Bcm/y allowing the flow of gas coming from Eastern Mediterranean region through EastMed pipeline, to which Poseidon pipeline will be connected in Thesprotia. The project will be able to transport up to 20 Bcm/y in a second phase.	Advanced
Melita TransGas Hydrogen Ready Pipeline	InterConnect Malta Ltd	Hydrogen ready gas pipeline between Malta and Italy with a capacity of 2 bcm/year, diameter of 22” (DN 560) and a length of 159 km (151 km offshore, 7 km onshore in Sicily and 1km onshore in Malta). The project will end Malta’s isolation by connecting the island to the trans-European gas network.	Advanced
Interconnection Croatia -Bosnia and Herzegovina (Slobodnica-Bosanski Brod)	Plinacro Ltd	The pipeline covers the countries Croatia and Bosnia and Herzegovina and it will be the part of Energy Community Ring. The pipeline goes from Slavonski Brod (Slobodnica) in Croatia, it will cross the Sava river to Bosanski Brod in Bosnia and Herzegovina with furter extension to Zenica.	Advanced

Ionian Adriatic Pipeline	Plinacro Ltd	The pipeline will cross the territory along the Adriatic coast from Fieri in Albania via Montenegro to Split in Croatia and will be linked to the existing Croatian gas transmission system (main direction Bosiljevo – Split). The Ionian-Adriatic Pipeline will have an influence on providing gas network for the entire region.	Advanced
Interconnection Croatia/Serbia (Slobodnica-Sotin-Bačko Novo Selo)	Plinacro Ltd	Implemetation of the project Slobodnica - Sotin (Croatia) - Bačko Novo Selo (Serbia) will enable connection of existing Croatian and Srbian gas transmission systems. First phase of the Project would be section Negoslavci-Sotin-Bačko Novo Selo together with the planned pipeline Osijek-Vukovar.	Advanced
LNG evacuation pipeline Zlobin-Bosiljevo-Sisak-Kozarac	Plinacro Ltd	LNG Main Evacuation Pipeline connecting LNG Krk with Central Eastern European countries. The pipeline is a continuation of the existing Hungary – Croatia interconnection.	Advanced
Interconnection Croatia/Slovenia (Lučko - Zabok - Jezerišće - Sotla)	Plinacro Ltd	New pipeline which will upgrade the existing interconnection Croatia/Slovenia. Considering almost all existing and new supply directions in the surrounding region and the Croatian storage potentials this opens significant transit potentials in both directions. Along this transit route, it is planned to upgrade the capacity to 5 bcm/y.	Advanced

Compressor Station Komotini (former Kipi)	DESFA S.A.	The project aims at increasing the pressure of the gas in the branch eastern of Komotini and is required in order to address the changing dynamics of the Greek market due to the forthcoming entry into operation of IGB and the new FSRU Terminal in Alexandroupolis. It will also enhance the flexibility of operation of the whole NNGTS and ensure the capacity of transportation of gas in the direction North to South. A regulating station is included in Komotini which is needed in order to protect the part of the DESFA network west of Komotini which has a lower operating pressure (66,4 barg) than the part from Kipi to Komotini (75 barg). The power of the compressor station is estimated at (2+1) units of 3.5 MW.	Advanced
Interconnection Croatia-Bosnia and Herzegovina (South)	Plinacro Ltd	South Interconnection of Croatia and B&H - the pipeline is a new supply route for Bosnia and Herzegovina that will enable the reliable and diversifed natural gas supply. The pipeline will enable the flow of IAPand Krk LNG to Bosnia and Herzegovina. The project will be H2 ready. For the implementatiion of the project, the first phase of the IAP project (Dugopolje -Zagvozd pipeline) has to be constructed.	Advanced
Stazione di Spinta "San Marco"	S.G.I. S.p.A.	Construction 3 MW compression station SAN MARCO The project forsees the realisation of a revers flow capacity on Gas Tranportation system of Adriatic coast	Advanced

Lucera - San Paolo	Società Gasdotti Italia spa	The pipeline has a diameter of 12" and develops for a total of about 69 km, exploiting the connection to the existing SGI pipelines.	Advanced
Southern Interconnection pipeline BiH/CRO	Gas Production and Transport Company BH-GAS Sarajevo	Southern Interconnection pipeline BIH/CRO (Posusje-N.Travnik with main branch to Mostar) will enable a new supply route for BiH providing a diversified and reliable natural gas supply such as LNG, Caspian, Middle East and other sources. Project will be bi-directional and together with planned gas pipeline Brod-Zenica (TRA-N-224) will create a part of EnC Gas Ring. The main purpose of Project is to establish a new, alternative supply route for existing and new consumers in BiH providing reliable and diversified natural gas supply increasing SoS for BiH (currently N-1=0). The importance of supply routes diversification is particularly reflected in the case of a possible interruption of gas supply and fulfilment of SoS standard. Project will contribute to diversification of entry/exit points and usability of Croatian gas transmission system. Project will enable meeting the set goals of decarbonization by gradualy replacing of coal with natural gas as a transition energy source.	Advanced

LNG Evacuation Pipeline Kozarac-Slobodnica	Plinacro Ltd	Gas pipeline Kozarac - Slobodnica jointly with gas pipeline sytem Zlobin - Bosiljevo - Sisak-Kozarac and with gas pipeline Omišalj-Zlobin makes LNG Main Evacuation Pipeline connecting LNG from the LNG solution on the island of Krk with Central Eastern European counties. The pipeline system is a continuation of the existing Hungary – Croatia interconnection (gas pipeline Varosföld-Dravaszerdahely-Donji Miholjac-Slobodnica) will be connected to the future Ionian Adriatic Pipeline (IAP) will be connected to Krk LNG. It will be the "backbone" of the Croatian gas system. The project will be H2 ready.	Advanced
Romania-Serbia Interconnection	SNTGN Tranzgaz SA	The project consists in the following: • Construction of an approximately 97 km long pipeline to interconnect the national gas transmission system in Serbia, in the Recas - Diameter of the interconnection pipeline: Dn 600; - Transmission capacity: max. 1.6 bScm/a (183,000 Scm/h), both in the Romania - Serbia direction and in the Serbia - Romania direction. • Construction of a gas metering station (located on the Romanian territory).	Advanced

Table 14 Planned natural gas pipeline infrastructures in the Adriatic-Ionian region. Source: ENTSO-G

Liquified Natural Gas

ENTSO-G TYNDP currently features 4 LNG projects in the Adriatic-Ionian region with FID or Advanced status: two in Greece and two in Italy.

Name	Operator	Projects description	Status
FSRU 1 - SNAM	Snam Rete Gas S.p.A.	Installation of a new FSRU in Tuscany to help satisfy the security of supply and the diversification of sources in Italy	FID
LNG terminal in northern Greece / Alexandroupolis - LNG Section	Gastrade S.A.	The LNG part of the prject consists of an offshore Floating Storage Regasification Unit, a Mooring a Pipeline system (24km Subsea and 4km Onshore) The floating unit will have up to 153,500m3 LNG storage capacity and a peak technical regasification capacity of 944,000 m3/h corresponding to 8.3 bcm/y.	Advanced
Italy-Sardinia Virtual Pipeline	Snam Rete Gas S.p.A.	Creation of a virtual connection between Sardinia and Italy through two LNG carrier (vessel capacity = 30.000 and 7.500 liquid cm) and the upgrade of the Panigaglia LNG Regasification plant with reloading facilities.	Advanced

Thrace LNG Terminal	GASTRADE SA	Offshore Floating LNG Storage & Regasification Unit. The pipeline will be connected to the existing downstream transmission systems of the region. The FSRU will have an LNG storage capacity of 170,000-185,000 m3 and a maximum regasification rate of 650,000 Nm3 / h which corresponds to approximately 6 bcma.	Advanced

Table 15 Planned LNG infrastructures in the Adriatic-Ionian region. Source: ENTSO-G

Storage

The only storage project currently featuring the TYNDP is the development of new gas storages in depleted fields in Italy by Stogit.

Name	Type	Operator	Project description	Status
System Enhancements - Stogit - on-shore gas fields	Depleted Field	Stogit S.p.A.	The project envisages the development of the following depleted on-shore gas fields: Fiume Treste - Minerbio - Ripalta - Cortemaggiore - Sabbioncello - Sergnano	FID

Table 16 Planned natural gas storage infrastructures in the Adriatic-Ionian region. Source: ENTSO-G