National Report 2021

Regulation and performance of the electricity market and the natural gas market in Greece, in 2020.

Regulatory Authority for Energy (RAE)

Athens, June 2021.

REGULATORY AUTHORITY FOR ENERGY

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1. Foreword

Dear Readers,

Year 2020 was a milestone year for RAE's history, as a significant reform took place in the electricity market on 1 November 2020, with the implementation of the European Target Model in Greece. The role of the Regulatory Authority has been of considerable throughout the transition period from the model that was valid in the Greek electricity market energy since 2005. The Target Model includes the establishment of four separate electricity markets (Forward, Day-Ahead, Intraday and Balancing). The first electricity market started its operation in March 2020, while the remaining three started in November 2020.

Additionally, on 15 December 2020 the Greek and Italian Day-Ahead markets were coupled, offering the potential for bilateral contracts between producers and suppliers, the possibility of correcting their positions on Intraday basis, the introduction of risk management tools and the creation of reliable financial signals for necessary investments.

For 2021, certain milestones already exist including, among others, the coupling of the Greek Day-Ahead market with the Bulgarian one and its integration to the common European Intraday market (XBID). Furthermore, the integration to the MARI and PICASSO European balancing platforms is planned within 2022. The role of Energy Exchange (HEnEx S.A.) and the TSO (ADMIE S.A.) is crucial for the achievement of these goals.

Regarding the measures taken to digitalise some aspects of the national energy market, RAE created a Price Comparison Tool for electricity and natural gas consumers, in order to facilitate their active participation into energy markets and increase transparency.

Furthermore, a digital platform for the automatic issuance of RES Electricity Generation Certificates was developed within 2020. This platform will decrease the average time for the issuance of such certificates, bypassing the unnecessary bureaucracy.

A digital platform for the submission of complaints by consumers will be established in 2021. RAE will be able to forward a specific complaint to the relevant supplier or Operator or even the Consumer Protection authorities.

As regards the natural gas sector, the commercial operation of TAP pipeline started in 2020. RAE has been in close cooperation and coordination with the Regulatory Authorities of Albania (ERE) and Italy (ARERA) for the approval the necessary regulatory framework to ensure the smooth operation of TAP and the natural gas markets. The next goal for RAE is the development of a gas trading platform within 2021.

The President of RAE

Assoc. Prof. Athanasios Dagoumas

2. Main developments in the electricity and gas markets

2.1 Electricity

Developments in the Electricity Market

Wholesale Market

The reform in the wholesale electricity market, with the operation of new electricity markets provided by the European Target Model since November 1, 2020, was a key point for the development of the Greek energy market. More specifically, the forward market started operating in March 2020, while Day-Ahead, Intraday and Balancing markets began operating in November 2020 (RAE Decision 1298/2020). The System Operation and RES and Guarantees of Origin Codes were amended to include the relevant provisions of the new markets.

RAE, within the framework of its competences, approved the operation of HEnEx S.A. as the Greek Energy Exchange with the functions of managing and operating the Day-Ahead and Intraday markets with its Decision 36/2020. Following this development, RAE amended Day-Ahead and Intraday Operation Regulations and proceeded with the issuance of 16 Decisions which regulated the operation of the new markets. Furthermore, RAE published additional 21 Decisions regarding the operation of the Balancing market and amended the Balancing Code, as well as the participation of ADMIE S.A. and DAPEEP S.A. to the Intraday market. Regarding the European Regulations, RAE published specific Decisions in relation to Regulations 2015/1222, 2016/1719 and 2017/2195.

In 2020, RAE recorded a rise of prices in the balancing market and assessed all market components to avoid manipulation and abuse of the dominant position in the market. In general, within the first few months of the new markets' operation, a few weaknesses have appeared regarding the operation of the system. For that reason, RAE had already foreseen possible obstacles in Target Model's implementation and proposed the creation of a Market Monitoring and Surveillance Mechanism for electricity and natural gas. More specifically, a Market Monitoring Mechanism (MMM) and a Market Surveillance Mechanism (MSM) were created, along with a methodology regarding capacity availability (CHARYBDIS).

Another important milestone was achieved on 15 December 2020, when the coupled operation of the Day-ahead market at the Greek-Italian border commenced according to RAE's Decision 1574/2020. This was the first important step for the participation of the Greek market to the EU Target Model. The Day-Ahead market coupling with Bulgaria will take place within 2021, along with the Intraday market coupling with Italy.

Retail Market

In 2020, RAE intensified the regulatory control and the systematic monitoring of the financial transactions of the retail market participants by issuing seven regulatory Decisions calling electricity Suppliers for written hearings and three Decisions calling Operators for written hearings on the settlement of overdue regulated charges of electricity Suppliers. Furthermore, RAE, with its Decision

409/2020 (Gazette B' 1364/14.04.2020), published the Guidelines for the transparency and the verifiability of charges in the competitive part of the tariffs. RAE also submitted an Opinion to the Ministry regarding the amendment of the Electricity Supply Code.

Furthermore, RAE finalised the development of a Retail Monitoring Tool together with some Usage Manuals, which were submitted also to the Operators and the Suppliers of electricity and natural gas. In addition to that, RAE, based on the European Directives, created a Price Comparison Tool (PCT) for the electricity and natural gas, in order to help consumers find a contract which fits their needs. In 2020, the PCT included 387 energy products (275 for electricity and 112 for natural gas) and was made available for consumers on 9th December 2020.

The consumer's right to be protected from the accumulation of overdue debts has been systematically assessed and publicly consulted by RAE. In this regard, RAE will submit its proposal to the Ministry for the amendment of Article 42 of the Electricity Supply Code. Additionally, the status of Universal Service Provider was redefined, by submitting a relevant Opinion to the Ministry (Opinion 2/2020), according to which, the maximum period for offering Universal Services was set to 3 months, with special provisions for vulnerable consumers and which includes the criteria and the procedures for choosing Supplier of Universal Services. Since there were no applications submitted by the Suppliers to assume the role of the Universal Service Provider, the Ministry appointed the 5 Suppliers with the highest market shares as Universal Service Providers. At the same time, RAE, with its Decision 1352/2020, appointed ELPEDISON S.A. as the Supplier of Last Resort until 28.09.2022.

Electricity Network

RAE, with its Decision 1171/2020, amended the Electricity Transmission Code for the implementation of the new Transitory Flexibility Remuneration Mechanism, based on the Ministerial Decision (YPEN/DHE/66574/810/9/7/2020), ADMIE's proposal and the results of the relevant public consultation. Within the context of the reorganization of the Greek electricity marketσ and the implementation of the Target Model, RAE with its Decision 1412/2020 approved the reissuance of the Electricity Transmission Code.

In 2020, RAE approved the tariffs for non-competitive activities and more specifically the system usage charges, the non-readjustment of transmission system's Allowed Revenue for the 3rd year of the regulatory period 2018-2021, the Required Revenue for 2020 and the distribution network's Allowed Revenue for the same year. At the same time, RAE worked to adopt new methodologies for the calculation of distribution network's Required and Allowed Revenue (Decision 1431/2020).

RAE, with its Decision 1432/2020, approved a Regulation defining the details for a mechanism offering incentives to the Distribution Network Operator. The mechanism is designed to provide incentives to the DSO for continuous and sustainable reductions in network losses, throughout the regulatory period, while including provisions to protect its revenue and to limit the increase of usage charges, through limits set in the annual and total amount that may be included in the Required Revenue. The regulation directly distributes part of the benefit / loss from a reduction / increase of the losses, to the Network users.

RAE, after taking into consideration the developments in the energy markets, started to update the methodologies for the calculation of the System Usage Charges, with the goal to apply the optimal cost-orientation principle, provide more effective signals to the users and reduce peak loads, reducing consequently the need for strengthening the long-term cost of the System, for the benefit of all its users.

- **Target Model**: In 2020, RAE proceeded with the implementation of the EU “Target Model” in the Greek wholesale electricity market. Law 4425/2016 (Gazette A’ 185/30.09.2016) aimed to facilitate the transition of the Greek electricity market towards the single European electricity market. According to Law 4425/2016, electricity wholesale market for forward products, day-ahead market, intraday market and balancing market were created. Also, by virtue of Law 4512/2018 (Gazette A' 5/17-01-2018 and A' 8/23-01-2018) a Greek energy exchange (HENEX S.A.) was established through the split-off and the contribution of the relevant sector of LAGIE. S.A. which was renamed as DAPEEP S.A..
- **E-mobility**: RAE’s Opinion 7/2019 was incorporated in Law 4710/2020 "Promotion of electromobility and other provisions" (Gazette 142 A'/23.07.2020), including incentives for the development of e-mobility, data on the organization of the e-mobility market, regulations for the installation of charging infrastructure and organizational provisions for e-mobility implementation in the Greek territory. Furthermore, the Joint Ministerial Decision No. ΥΠΕΝ/ΔΜΕΑΑΠ/93764/396/2020 (Gazette B' 4380/05.10.2020) "Technical Instructions for the Electric Vehicles Charging Plans " was issued for the positioning of publicly accessible recharging points within the administrative boundaries of municipalities, as defined in article 17 of Law 4710/2020 (More details in section 3.2.2.1).
- **Market Monitoring**: RAE, in 2020, intensified its effort to monitor the financial transactions of retail market participants in order to secure the smooth execution of transactions between Operators, Producers, Suppliers and Traders, putting emphasis on those participants who are active in the electricity sector (as the natural gas market was liberalized in the beginning of 2018) and their due fulfillment of their obligation to attribute Regulated Tariffs towards Operators. RAE, called several suppliers to written hearings. This process was concluded in 2020 and RAE published (7) Decisions (1234/2020 & 1630/2020, 1233/2020 & 1631/2020, 1232/2020 & 1632/2020, 1230/2020 & 1633/2020, 1636/2020, 1635/2020, 1634/2020) (More details in section 3.2.2.3).
- **Non-Interconnected Islands Market**: After the opening of the retail market in Non-Interconnected Islands at the beginning of 2018, 21 suppliers were active in 2020, 5 of which are Providers of Universal Services (More details in section 3.4.1).

<u>Development of Electricity Networks</u>

- **Transmission System Development Plan**: RAE evaluated the Network Development Plan for the period 2021-2030, which was set to public consultation in November 2020, and its results have been published. In this Plan, several projects are included. RAE will proceed with the assessment of the project and will approve it within 2021. (More details in sections 3.1.2 and 3.3.2).
- **Cyclades Interconnection**: Phase I of Cyclades Interconnection was inaugurated in March 2018. Phase II, which was completed in September 2020, includes the interconnection of Paros, Naxos and Mykonos. (More details in sections 3.1.2, 3.3.2 and 3.4).

2.2 RES

- **New RES Licensing Regulation.** Law 4685/2020 (Gazette A’ 92/2020) introduced major changes to the environmental legislation and RES administrative licensing procedures. Specifically, the Electricity Generation License, as provided by Law 3468/2006 was replaced by an Electricity Generation Certificate (EGC). There are two types of EGCs: (a) Electricity Generation Certificates for RES and CHP power plants and (b) Electricity Generation Certificates for Special RES and CHP power plants. The competent certificate issuing authority is RAE until a relevant decision, which will determine the licensing authority, is issued by the Minister of the Environment and Energy. The certificate is issued upon the submission of a relevant application to RAE and its subsequent approval by the regulator. By virtue of article 18 of the Law 4685/2020, RAE drafted and proposed (RAE Opinion 11/2020) to the Ministry of Energy, a Regulation of Electricity Generation Certificates for RES, CHP and innovative projects. This Opinion was adopted by the Ministry without any further amendments. At the same time, an advanced IT system was developed that met specific requirements set by Law 4685/2020 as well as high interoperability standards with other financial and government platforms. The first implementation of the new system started during December’s application submission round for EGCs, when the largest number of submitted applications was recorded, both in terms of number of submissions but also in installed capacity throughout the 20-year history of RAE. In particular, 1,864 new applications for projects with a total capacity of 45.5 GW were submitted during the December’s application submission round (More details in section 3.5.6)

- **RES Auctions**: In the context of its responsibilities, and in accordance with the provisions of Law 4414/2016, RAE carried out the following auctions within 2020:
  1. Joint Auction for RES power plants, in accordance with the provisions of tender No. 1/2020 (RAE Decision 204/2020, Gazette B '352 / 07.02.2020).
  2. Two Auctions for RES power plants, in accordance with the provisions of tenders No. 2/2020 and No. 3/2020 (RAE Decision No. 834/2020, Gazette B '2108 / 02.06.2020).
  3. Joint Auction for RES power plants (which will be held in 2021), in accordance with the provisions of the tender No. 4/2020 (RAE Decision No. 1648/2020, Gazette B '5760 / 28.12.2020) (More details in section 3.5.4).

- **Licenses**: In 2020, RAE issued a great number of production licenses and EGCs including transfer, modification, time extension, renewal, revocation, and the simple certification of the licenses for which no modification was required, as per the Production License Code and RAE’s Evaluation Guide. In 2020, RAE issued a total of 1,656 administrative acts (More details in section 3.5.3).

- **Agios Efstratios RES pilot project**: RAE established a special regulatory framework, with its Decision 429/2020, for the operation of the innovative, hybrid RES project and the electrical system located at the island of Agios Efstratios. Furthermore, RAE gave its Opinion 15/2020 to the Minister of Energy on the tariff methodology for the innovative project and the district heating system on the island, in accordance with the provisions of law 4495/2017 (More details in section 3.4.3).

2.3 Natural Gas

The key drivers in the natural gas sector in 2020 were a) the intense activity of network users in the Transmission System, especially in the LNG terminal of Revithoussa, due to the very low LNG prices, and b) the growing interest for the development of new infrastructure.

- **Trans Adriatic Pipeline (TAP)**. At the end of December 2020, the TAP pipeline was put into commercial operation and was connected to the National Natural Gas System (NNGS) at the "Nea Mesimvria" Entry Point. The imported natural gas from the fields of Azerbaijan is transported through TAP, but also, using commercial reverse flow practices, from the Italian market (More details in section 4.1.4).
- **NNGS System Administration Code amendment.** In this context, in 2020, significant amendments were adopted to the NNGS Code. Decision 727/2020 introduced focused provisions in order to provide more flexibility to LNG Users given the intense competition among them for the booking of storage capacity, gasification capacity, transport capacity and unloading slots at the “Agia Triada” Entry Point. Decision 1035/2020 approved the 5th amendment of the NNGS Code, in order to address possible congestion issues in the NNGS and maximize the available capacity, with the introduction of three new transmission capacity products: Conditional, Coupled and Competing Transmission Capacity. Furthermore, upon the written Proposal received from DESFA, and in view of the start of the commercial operation of TAP, RAE: a) canceled the annual and quarterly capacity booking auctions at the “Kipi” Entry Point (Decision 919/2020), without any changes to the capacity that was already booked by the active users in that Entry Point, and b) approved the tenders for booking competing capacity between "Kipi" and "Nea Mesimvria" Entry Points (Decision 1399/2020). Within 2020 RAE also approved the 6th Revision of the NNGS Code with Decision 1433/2020, which fundamentally revised the LNG Cargoes Unloading Annual Planning process. The Annual Planning now becomes mandatory and the booking of slots for ships to unload LNG takes place through electronic auctions. The booking of a time slot also translates into booking of storage space in the Revithoussa LNG terminal, re-gasification capacity and transmission capacity at the Entry Point "Agia Triada" (More details in section 4.1.2).
- **TAP regulatory framework.** RAE completed the regulatory framework governing the operation of the TAP pipeline by issuing the following Decisions: a) Approval of the TAP Network Code (Decision 1036/2020), b) Approval of the Market Test framework for incremental capacity and in particular to increase the capacity of the pipeline from 10 to 20bcm, by collaborating with the TSOs of Greece and Italy, DESFA and SNAM, respectively, c) Approval of the Compliance Program and the appointment of a Regulatory Compliance Officer (Decisions 1331/2020 and 1332/2020), d) Approval of the process of competing capacity allocation between the NNGS Exit Points of Nea Mesimvria and Melendugno of the TAP pipeline, and e) Issuance of an Independent Natural Gas System Operation License (More details in section 4.1.4).
- **Alexandroupolis FSRU.** In March 2020, the second binding stage of the Market Test for the floating terminal LNG FSRU named "Alexandroupolis Independent Natural Gas System" was successfully carried out by Gastrade S.A.. Following this development, RAE proceeded to examine the company's Exemption Request from the third-party access rules and the tariff regulation, and issued the preliminary Exemption Decision in September 2020 (Decision 1333/2020), and the final Exemption Decision for the “Alexandroupolis Independent Natural Gas System” - following a relevant decision by the European Commission - in December 2020 (Decision 1580/2020). The decision grants the requested exemption for 25 years, under

specific terms and conditions, while setting out the basic regulatory principles that will be developed by RAE in the coming years (More details in section 4.1.4).

- **IGB pipeline**. The Exemption Decision of the IGB pipeline was amended and the deadline for the commercial pipeline operation was extended to 1 July 2021 (More details in section 4.1.4).
- **Network Development Plans and network tariffs**. In addition to the above, RAE exercised its mandate for the approval of the Network Development Plans of the network operators as well as their respective network usage tariffs. In particular, the following Decisions were adopted regarding the **National Natural Gas Transmission System (NNGTS)**: a) Approval of the TYNDP 2020-2029 (Decision 755/2020), with emphasis on the reinforcement of the Transmission System and its interconnections with neighboring systems. The Plan also includes the development of small-scale LNG services and a LNG truck loading station at Revithoussa LNG terminal, b) Approval of the TYNDP 2021-2030 (the final decision was issued in January 2021, Decision 116/2021), with important new pipeline projects which are mainly located in the regions of Patras and West Macedonia, c) Revision of network tariffs for the year 2021, due to the creation of a new Entry Point after the commercial operation of TAP, and a large (more than 10%) recoverable difference. In addition, the following Decisions were taken regarding the natural gas **Distribution System Operators**: a) Approval of the Network Development Plans of the DSOs of EDA Attica, EDA Thessaloniki-Thessaly and DEDA for the period 2020-2024, b) Approval of the Network Development Plans of the DSOs of EDA Attica, EDA Thessaloniki-Thessaly and DEDA for the period 2021-2025, c) Approval of the Required Revenue and the network usage tariffs for the regulatory period 2019-2022. With these Decisions, additional **incentives** were approved for the DSOs by increasing the Weighted Average Capital Cost (WACC) of specific investments and based on achieving specific milestones for the years 2020 to 2022, which concern the further expansion of the existing networks, as well as their expansion to new areas in accordance with the approved Development Programs. The above WACC incentive is granted from the year of achievement of the investment milestone and for the next three years, providing strong incentives to the DSOs for the timely implementation of the approved Development Programs and d) Approval of the Natural Gas distribution license application submitted by the company HENGAS for the development of distribution networks in the Municipalities of Paionia, Polygyros, Edessa, Deskati, Megalopolis, Tripoli and Corinth (More details in section 4.1.3).
- **Security of Supply**. Regarding the competence of RAE as the Competent Authority for the security of the country's natural gas supply, the 4th updated version of the National Risk Assessment Study for the years 2020-2022 was completed in 2020. The Study includes an assessment of all relevant risks that may affect the energy market and the security of gas supply, taking into account significant changes that took place in December 2019, both at international and national level. Furthermore, based on the results of the National Risk Assessment Study, RAE prepared a Preventive Action Plan, which is expected to be communicated to the European Commission at the beginning of 2021, after the end of the relevant public consultation. The Plan presents appropriate measures (actions) to reduce or eliminate the risks that may affect the security of the country's gas supply. In addition, RAE has undertaken a coordinating role for the elaboration of the Common Risk Assessment (CRA) within the framework of the Trans-Balkan risk group. The completion of the CRA and its communication to the European Commission took place at the beginning of 2020. Finally, at regional level, RAE, prepared and put up for a public consultation a Draft Plan for the implementation of the Solidarity Mechanism, which includes internal market measures that

will enter into force when a neighboring Member State is unable to supply gas to solidarity-protected consumers situated in its territory (More details in section 4.4).

2.4 Consumer Protection

The unprecedented conditions that occurred in Greece in 2020 due to the COVID-19 pandemic, directly affected the energy markets and the consumers. In 2020, 6,453 complaints were submitted to the Authority, recording an increase of 20% compared to 2019 (5,392) and reaching the highest level of the last decade (More details in section 3.6.6).

Protection of vulnerable consumers and energy poverty. RAE, in the framework of its mandate for consumer protection, undertook a series of regulatory initiatives. In particular, for the protection of Vulnerable Consumers: (a) RAE gave its Opinion to the Ministry of Energy to strengthen the vulnerable consumer protection framework and develop a special regulatory provision to protect vulnerable consumers in mechanical support against disconnections; and (b) provided regulatory guidelines to suppliers on vulnerable consumers' debt settlement programs. In addition, RAE took initiatives to tackle energy poverty. In particular, the Authority actively participated in a series of actions of the Pan-European Research Program "STEP-IN: Using Living Labs to roll out sustainable strategies for energy poor individuals", in close cooperation with the National Technical University of Athens (More details in section 3.6.5).

Social Tariffs. After a relevant public consultation, RAE Issued Decision 759/2020 on the new methodology for the calculation of annual fee to cover the cost of the Social Tariffs service, which is provided to vulnerable consumers. The above methodology ensures the transparency of the capital received by electricity Suppliers to cover their costs for the provision of Social Tariffs, without affecting the competition in the electricity market (More details in section 3.6.8).

3. Regulation and Performance of the Electricity Market

3.1 Network Regulation

3.1.1. Unbundling

The EU's third legislative package in 2009 introduced Ownership Unbundling (together with the ITO and ISO models) for transmission system operators (TSOs – owners of high-voltage networks), whereas for distribution system operators (DSOs – owners of low-voltage or "last mile" networks) it maintained the requirements for "legal and functional unbundling".

3.1.1.1. Certified Transmission System Operator - ADMIE S.A.

In 2017 ADMIE S.A.(ADMIE) changed from the ITO model to the OU model as a consequence of its changed ownership structure from 100% Public Power Corporation S.A. (PPS) to 51% ADMIE SYMMETOCHON S.A. (Energiaki Holding), 25% DES ADMIE S.A. and 24% STATE GRID EUROPE LIMITED (SGID).

The new certification procedure under Article 11 of the Electricity Directive (certification of TSOs in relation to 3rd countries) started by the notification from the company to RAE of its change of ownership structure on March 1, 2017.

On June 9, 2017 RAE issued its final certification decision 475/2017 after having taken due account of the Opinion of the European Commission of 24 May 2017 on the draft certification decision 267/2017 of RAE. Certain conditions in the form of a sophisticated monitoring process were nevertheless imposed to ADMIE including the obligation that any future development (ex. regarding the activities of SGID, its mother company and in general China in Greece and Europe, or any change in control over ADMIE etc.) would need to be notified to RAE underpinned also by adequate reasoning for continuous compliance with the unbundling requirements (e.g. security of supply criteria).

RAE continued monitoring the correct application by ADMIE of the aforementioned conditions throughout 2019 with ADMIE submitting an annual report concerning its compliance with the Electricity Directive.

3.1.1.2. Distribution System Operator - DEDDIE S.A.

The Hellenic Electricity Distribution Network Operator (HEDNO S.A. or DEDDIE S.A.), is a 100% subsidiary of PPC S.A. and is responsible for the development, operation and maintenance of the Hellenic Electricity Distribution Network (HEDN). PPC S.A. remains the owner of the Distribution Network assets. HEDNO is also the Power System and Market Operator for the Non-Interconnected Islands of the country. There was no change in the status of the DSO during 2020.

3.1.1.3. Accounting unbundling

Pursuant to the relevant provisions of the Energy Law 4001/2011 and the European Directive 2009/72, vertical integrated utilities are obliged to keep separate accounts and report unbundled financial statements (Balance Sheet and Profit & Loss Account) for each activity. RAE approves the accounting unbundling rules, based on the company's proposal. RAE published its decision 121/2017 issuing the Principles and Rules for the Allocation of Assets - Liabilities and Expenses – Revenues for the preparation of its unbundled financial statements of "DEDDIE S.A.".

3.1.2. Technical functioning and network development

Technical functioning

Law 4001/2011 identifies ADMIE as the owner of the national electricity transmission system. The national electricity transmission system includes: a) High Voltage Lines, b) Cross-Border Interconnection Lines, and c) the facilities and equipment necessary for the uninterruptible flows of electricity into High Voltage lines of 150kV to 400kV in Greece. In addition, the national electricity transmission grid includes projects of interconnection of the islands to the interconnected (mainland) system (i.e. subsea interconnections HVAC and/or HVDC). The total length of the national transmission system is 17,586 km (2020).

According to Law 4001/2011, the owner of the national electricity distribution system is PPC SA. The distribution system includes: a) the entire Medium and Low Voltage networks, as well as certain High voltage infrastructure (overhead lines, underground cables), namely in the national capital area and the non-interconnected islands and b) the facilities and equipment necessary to safely operate the network and ensure security of supply . The total length of the distribution system (low, medium and high voltage) is 242,562 Km (2020).

Ten-Year Network Development Plan (TYNDP)

RAE evaluated the Network Development Plan for the period 2021-2030, which was set to public consultation in November 2020, and its results have been published. In this Plan, several projects are included. However, the most significant are the interconnection of Dodecanese and the islands of Northern Aegean Sea with the national transmission system. RAE will proceed with the assessment of the project and will approve it within 2021.

Five-Year Network Development Plan (Distribution)

Investment in developing the distribution network amounted to 174 million Euro in 2020, out of a planned annual investment of 270 million, according to the 2019-2023 Distribution Network Development Plan. The gap was mainly due to delays in a number of major projects.

There was no need to update the 2019-2023 network development plan in 2020.

3.1.3. Security and reliability standards, quality of service and supply

Regarding Network Performance and Quality of Service, in December of 2010 RAE published an integrated set of Regulatory Guidelines for the reporting of the Transmission System performance. Following these guidelines, the TSO publishes annual reports on the performance of the Transmission System. These reports provide availability indices for overhead lines, underground cables, autotransformers, as well as indices for the impact of the system unavailability to customers (energy not served) [1].

The Distribution Network Code, in force since January 2017, includes provisions for a penalty/reward scheme for QoS regulation. In this new framework, whichis planned to come in effect from the 2nd regulatory period (2025-2028), to allow for necessary preparatory work to be completed first, the role of the Regulator will include the following:

- Setting, per regulatory review period, the regulated service quality dimensions, the corresponding overall and individual minimum quality standards, as well as the respective penalties/rewards, in conjunction with the allowed revenue for the distribution activity.
- Approval of rules, procedures, and methodologies for monitoring, assessing and reporting service quality levels.
- Validation of data completeness and accuracy.

Minimum levels of quality as regards commercial services of the DSO are set in the form of Guaranteed Standards for a number of transactions, such as maximum time for new connections or reconnections after a debt settlement, through the "Guaranteed Services" Programme of DEDDIE. Upon RAE's initiative, this Programme has been updated twice: in 2014 and 2020. Improvements introduced via these updates include, among others, automatic compensation payments, compensation scaling and differentiation between customer classes, refined rules & definitions, and specification of detailed reporting requirements to enable effective regulatory monitoring and validation. For more information on the Guaranteed Services, refer to section 3.6.4.

Incentives' regulation for distribution network losses

RAE, with its Decision 1432/2020, approved a Regulation specifying the details of the incentive mechanism to the distribution network operator for the reduction of network losses, as part of the methodology for calculating the Required Revenue of HEDNO and in accordance with the provisions of the Electricity Distribution Code.

The purpose of the mechanism is to provide incentives to the DSO to reduce energy losses to cost-effective levels and to maintain them at these levels, with the aim of long-term benefit to Network users. For this purpose, part of the costs incurred in the market due to network losses can be internalized through the mechanism. Increasing network losses to a higher level than a predetermined

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[1] Additionally, RAE participates in the annual CEER Benchmarking report on the quality of electricity and gas supply. These reports evaluate, in a comparative analysis, the technical functioning of the national electricity grids and of the natural gas transmission and distribution networks. See: "The 6th CEER Benchmarking Report on the quality of electricity and gas supply, in 2016", CEER Publication, as also updated by CEER's Benchmarking Report 6.1 on the Continuity of Electricity and Gas Supply (July 2018).

reporting level leads to a reduction in Required Revenue and Network Usage Charges. Accordingly, reducing network losses leads to additional revenue for the DSO. In this way, the DSO has in principle an incentive to take into account the cost of energy losses in his network and to make an effort to reduce the losses, as far as this is justified in financial terms.

For the 1st Regulatory Period of 2021-2024, the mechanism is planned to be implemented in the Interconnected Network, due to the unavailability of the necessary data for the NIIs. The values of the parameters for the application of the incentive will be determined by the Distribution Regulation Decision for this period. From the 2nd regulatory period, the penalty/reward scheme will be replaced by explicitly including the cost of losses that the Regulator deems reasonable, in the Allowed Revenue of the DSO. In this way, incentives are still provided to the DSO to reduce losses, while ensuring that associated benefits are passed directly to network users through Network Use Charges.

3.1.4. Network Tariffs for connection and access

Since 2011 (Law 4001/2011, article 140), RAE has been approving the tariffs for access to the national electricity networks (Transmission System and Distribution Network), one month before their entry into force, based on the proposals submitted to the Regulator by the Electricity Transmission Network and Distribution System Operators (ADMIE and DEDDIE respectively).

3.1.5. Transmission Network operation

Required Revenue and user tariffs:

RAE, with its Decision 1650/2020, sets the TSO’s Required Revenue (RR) for 2020 at 198.5 million euros. The most important financial values of ADMIE in the last 5 years (2016-2020), according to its annual financial statements and RAE Decisions for the approval of the Required and Allowed Revenue are the following:

In million €	2016	2017	2018	2019	2020
Revenues from System Use Charging	225.5	236.9	194.9	229.1	273.6
Net Revenues before tax	54.1	82.9	108.9	134.8	122.1
Approved Allowed Revenue of Transmission System	250.2	260.9	233.9	252.4[2]	281
Approved Required Revenue of Transmission System	203.4	202.6	197.5	198.9	198.5

[2] The approved Allowed Revenue, based on Decision 235/2018 was 252.4 million euros, but it was readjusted in real terms with Decision 100/2019 το 253.9 million euros.

The methodology for the calculation of TSO's Allowed Revenue and Required Revenue dates back to 2014 (Decision 340/2014). The most critical changes, in comparison to the previous applied methodology (a cost-plus methodology), were:

- A multi-year regulatory period: the Regulator sets the Allowed Revenue for 4 years
- Calculation of TSO's Allowed Revenue based on real terms.
- A detailed methodology for the calculation of Return on Capital Employed, based on real pre-tax Weighted Average Cost of Capital (WACC).
- Calculation of assets' depreciation using economic instead of accounting assets' life.
- Smoothing the volatility of revenues within and between regulatory periods, to minimize the impact of such volatility to consumers' prices.
- Additional incentives for the investment in projects of major importance, particularly those which offer a significant benefit to consumers. Further details on the methodology can be found on RAE's webpage.

In approving the Allowed Revenue, RAE validates TSO's proposal against historic performance and future trends. No formal methodology or benchmarking has been used in the cost assessment. The total Required Revenue (Allowed Revenue and all the adjustments according to 340/2014 Decision) is then allocated to the different consumer categories.

According to Decision 340/2014, RAE processed the relevant data submitted by ADMIE for the determination of the Allowed Revenue of the next Regulatory Period 2018-2021. Based upon the above-mentioned methodology, RAE's Decision 235/2018 approved the following Allowed Revenues for 2018-2021 and Required Revenue for 2019 as shown in Table 1 and Table 2 below. Furthermore, Table 3 presents the regulated tariffs applied for the use of the transmission system in 2019.

	2018	**2019**	**2020**	**2021**
OPEX	77,269,000	77,862,000	78,461,000	79,066,000
Annual Depreciation	55,203,000	58,335,000	76,370,000	77,063,000
Total OPEX	132,472,000	136,197,000	154,831,000	156,129,000
Regulatory Asset Base (RAB)	1,449,808,000	1,684,495,000	1,941,335,000	2,059,771,000
WACC	7.0%	6.9%	6.5%	6.3%
Allowed Return	**101,487,000**	**116,230,000**	**126,187,000**	**129,766,000**
Allowed Revenue (AR)	**233,959,000**	**252,427,000**[2]	**281,018,000**	**285,895,000**

Table 1: Allowed Revenue of Transmission System for the regulatory period 2018 -2021 based on RAE Decision 235/2018 (amounts in €)

(AR) Allowed Revenue of Transmission System	281,018.000
Cost of investments financed by third parties	-10,000,000
Under/Over Recovery	2,518,896
Adjustments due to over/under investment (depreciation and allowed return) of previous years	779,358
Revenues from Interconnection Capacity Rights	-68,082,483
Inter-Transmission System Operator Compensation mechanism (ITC)	237,666
Revenues from Non-Regulatory Activities	-11,501,000
OPEX (ARIADNE Interconnection & RSC)	3,498,533
(RR) Required Revenue of Transmission System 2020	198,468,970

Table 2: Required Revenue of National Transmission System 2020 in real terms based on RAE Decision 1650/2020 (amounts in €)

With RAE's Decision 1650/2020, the approved Required Revenue for was set to 198.47 million €.

After taking into account the conditions in the energy market and the developments taking place in the last years (RES integration and change of System's capacity curve), RAE deemed necessary to update the methodologies which determine the Transmission Use of System tariffs. This change will help towards the better implementation of the cost-reflectivity principle and will provide more efficient signals for the consumers, to help limit the peak load and thus reduce the need for reinforcing the System and its long-term cost. However, the procedure for amending and updating the methodologies was not completed in 2020, therefore tariffs were based on the same methodology that applied also in previous years. According to this methodology:

• Transmission system cost is allocated between HV, MV and LV connected customers based on the contribution of each users/customers' category to the transmission system summer and winter peak demand.

• Tariffs for HV-connected customers follow a €/MW structure, charged on the customer's average hourly demand during the following three hours: system summer peak, system winter peak and the maximum of the two.

• For the purposes of the transmission system use charging (TUoS), the following four (4) customer categories are classified: 1. Medium Voltage (MV) customer, 2. Residential customer, 3. Residential customer with Residential Social Tariff (KOT), 4. Other Low Voltage (LV) and Public Lighting Use LV, excluding Agricultural MV and Agricultural LV that have zero charges.

- For MV customers, there is only a capacity-based charge (no energy charge for TUoS) which is based on the monthly maximum metered demand (MW) during peak hours (11am-2pm).

- The Residential customers with Social Tariff (KOT) are charged a simple €/MWh energy charge (no capacity-based charge for TUoS). For Residential customers (except for Residential customers with Social Tariff), 10% of the allocated cost is recovered through capacity-based charges, which are charged based on the connection capacity (kVA), given the lack of metered demand (MW), whereas the remaining is recovered through a simple €/MWh energy charge.

- For other LV customers, 20% of the allocated cost is recovered through capacity charges, which are charged based on the connection capacity (kVA) given the lack of metering (MW), whereas the remaining amount of the total cost is recovered through a simple €/MWh energy charge.

In the following table, the Transmission System user tariffs based on the Required Revenue of 2019 (RAE Decision 100/2019) are shown, based on ADMIE's proposal. Those charges are applied since 1st April 2020 based on Decision 3/2020.

Consumers Category	Capacity charge	Energy charge (cents €/ kWh)
Large Consumers HV	24,062 €/MW /per year	-
Consumers MV	1,197 €/MW Peak time/ month	-
Households LV,	0.13 €/kVA per year	0.542
LV – Vulnerable customers	-	0.602
LV others*	0.52 €/kVA per year	0.488
*This category includes street and square lighting		

Table 3: Regulated Tariffs applied for the use of the transmission system in 2020

Operation for Southeastern Europe (SEE) RSC in Thessaloniki

Regional Security Coordinators (RSCs) are companies established and owned by Transmission System Operators (TSOs), with the purpose of maintaining the operational security of electricity system at European level, according to Regulation (EU) 2017/1485. The TSOs receive from the RSCs specialized services, such as advanced calculations of complex components of the electricity transmission system at regional level, from computer models that are created exclusively to meet the needs of their region. For this reason, the establishment of RSCs is one of the most important steps towards the integration of Europe's energy zones.

In this context, four European Transmission System Operators, IPTO (Greece), ESO-EAD (Bulgaria), TERNA SpA (Italy) and Transelectrica (Romania), established on 22 May 2020, a RSC under the name

SEleNe CC (Southeast Electricity Network Coordination Center), the headquarters of which is located in Thessaloniki. SEleNe CC operates as the energy center of Southeastern Europe and the Greek-Italian border. ACER Decision 10/2020 defines the System Operation Region of Southeast Europe (SEE SOR), in line with article 35 (1) of Regulation (EU) 2019/943. The RCC includes the Transmission System Operators of Greece (IPTO) and Bulgaria (ESO EAD), while the TSOs of Italy (TERNA) and Romania (TRANSELECTRICA) will have contractual agreements with the RCC of Thessaloniki, as they operate in bidding zones and in border bidding zones neighboring with SEE SOR.

In July 2020, IPTO submitted RAE - as well as to the Bulgarian Regulatory Authority - a proposal for the establishment of a Regional Coordination Center (RCC) for the SEE SOR, which will replace the existing RSC SEIeNeCC, according to Article 35 of Regulation (EU) 2019/943. The approval of the TSO's request, will be approved in 2021.

Guarantee Manual of the Electricity Transmission Network Code:

RAE Decision 1426/2020 (Government Gazette B '4659 / 22.10.2020) approved the Guarantee Manual of the Transmission Network Code according to subsection 11.3 of the new Electricity Transmission Network Code. These new texts significantly modify the transaction clearing process of the Hellenic Electricity Transmission System Operator concerning System Usage Charges as well as other services provided outside the Balancing Market.

Specifically: a) The in-advance fee payment for the System Usage Charges (and charges for the Transitional Flexibility Mechanism) for the immediately preceding month was introduced, so that the credit margin for these charges is limited to one month with a corresponding reduction on the amount of the guarantee fee. b) The amount of the guarantee is based on the Maximum Monthly Charge, which is defined as the maximum price between the sums of the monthly debits calculated in the context of the settlements concerning the accounts covered by the guarantee (based on the most recent 12-month accounts for which the transaction clearances are available). c) An adjustment mechanism for the amount of the guarantee is introduced and is activated within the year of the guarantee application if the current transactions exceed by at least 20% the amount of the guarantee as defined by the accounting data. d) The "Participant's Financial Risk Ratio" factor for calculating the amount of guarantee fee to the transmission network operator has been abolished. This factor took into account the market size of the participant and the duration of his reliable activity in the market. e) Introduction of Non-Compliance Charges for the failure of submission of the guarantees in due time to the TSO.

3.1.6. Distribution Network operation

Required Revenue and user tariffs:

In 2020, RAE, with its Decision 1431/2020, approved the Methodology for calculating the Allowed Revenue and Required Revenue of HEDNO. In this Methodology incentive mechanisms were introduced to improve the efficiency of the DSO. In particular, an incentive mechanism for controllable operational expenditure (opex efficiency incentive mechanism) is introduced, commencing from the 1st Regulatory Period, that aims to gradually reduce the operating costs for HEDN users between Regulatory Periods, as well as sharing the relevant benefit from the expenditure saving between the Operator and HEDN users within the Regulatory Period in which the saving occurs. Also, the parameters affecting the outcome of the incentive mechanisms foreseen in the HEDNOC for the reduction of Network energy losses and the improvement of Distribution service quality were considered. Another significant methodological matter that was considered in the Methodology is the characterization of projects of

Major Importance (PMI), that is based on a fully justified proposal (cost-benefit analysis) and the provision of an incentive in the form of a return premium, which may range from 0.5% to 2% for a period of 4 to 7 years.

Taking into consideration that the Required Revenue methodology for the Regulatory Period 2021-2024, established with RAE's Decision 1431/2020, is applied on a transitional basis, the previous methodology, prescribed in RAE's Decision 840/2012, remains in force.

RAE, with its Decision 1515/2020, approved the Allowed and the Required Revenue of the Distribution Network Operator for 2020 setting the Allowed Revenue at 758 million € (2019: 753.4 million €) and the Required Revenue at 751.4 million € (2019: 728.6 million €).

The most important financial values of DEDDIE in the last 5 years (2016-2020), according to its financial statements and RAE Decisions for the approval of the Required and the Allowed Revenue are the following:

In million €	2016	2017	2018	2019	2020
Revenues from Network Use Charging	717.1	740.9	711.1	727.8	710.8
Net Revenues before tax	13.8	36.7	-17.83[4]	99.4	26.03
Approved Allowed Revenue of Distribution System	757.8	753.7	743.6	753.4	758
Approved Required Revenue of Distribution System	747.5	741.7	752.8	743.6	751.4

Regarding the relevant regulatory framework, the Distribution Network Code includes provisions for a 3-5-year regulatory period. This is subject to a methodology being in place for setting Allowed and Required Revenue. Until this methodology is developed in order for the new framework to become effective, distribution Allowed Revenue continues to be set on an annual basis, examining operator CAPEX & OPEX proposals considering historic performance and any changes in current conditions or requirements and applying a predominantly cost-plus approach, with ex-post adjustments for realized CAPEX & OPEX (beyond a 3% null zone).

[4] Financial Statements DEDDIE 2018. The significant decrease of net revenues before tax compared to 2017 is attributed to provision of 58.1 million euros for compensation of departing staff (Law 4533/2018).

Distribution network Required Revenue is allocated between MV and LV connected customers based on the contribution of each class to the distribution network summer and winter peak demand.

For calculating charges on consumers using the Distribution System (DUoS), consumers are classified based on their connection voltage and metering capabilities. More specifically, consumers were classified into five categories: MV consumers, LV consumers with subscribed demand >25 kVA (with and without reactive power metering), LV residential consumers, and other non-residential LV consumers.

For MV consumers, 50% of the cost is recovered through a capacity charge and 50% through an energy charge. For residential consumers (households), 10% of the cost is recovered through a capacity charge and 90% through an energy charge. These percentages for the Other LV customers are 20% and 80%, respectively.

RAE's Decision 2/2020 approved the tariffs of Distribution Network to be applied on 1st April 2020 (see Table 4):

Consumers Category	**Capacity Charge**	**Energy charge (cents €/kWh)**
Consumers MV	1,097 €/MW Peak Demand /month	0.28
Consumers LV (over 25 kVA), based on the calculation of the maximum supply and taking into consideration the non-used power	3.98€/kVA subscribed capacity, charged per year	1.73
Consumers LV (over 25 kVA), based on the calculation of the maximum supply and non-taking into consideration the non-used power	2.72€/kVA subscribed capacity, charged per year	1.9
Consumers LV	0.52 €/kVA subscribed capacity, charged per year	2.13
Consumers (vulnerable customers)	-	2.37
Others LV (maximum 25 kVA)	1.46 €/kVA subscribed capacity, charged per year	1.9

Table 4: Regulated tariffs applied for the use of the distribution system in 2020 (from 1st April 2020)

3.1.7. Transmission network connection tariffs

Only shallow connection costs are charged to network users, i.e. costs for necessary network expansion from users' site to the appropriate connection point of the Transmission System. The charges are applied by the TSO, for specific tasks carried out by the Operator that are related to the connection works performed by the generators themselves (e.g. review of connection works studies, acceptance tests for built connection networks, etc.). Such charges have not yet been formally approved by the

Regulator. Per the provisions of Law 4001/2011, a detailed price list is to be submitted by the TSO to RAE for final approval.

3.1.8. Distribution network connection tariffs

A detailed methodology for setting connection tariffs has not yet been approved by the Regulator. Basic principles included in the Distribution Network Code provide for a hybrid connection cost model for load (coinciding with the model applied historically) and a deep connection cost model for generation.

3.1.9. Cross-border issues

The synchronously interconnected neighboring control area includes Albania, Bulgaria, Italy, North Macedonia and Turkey. The connection with Italy is DC and links to the southern zone of Italy. Table 5 shows the interconnection figures updated at the end of 2020.

Import trading schedules in 2020 decreased considerably by 22% compared to 2019, amounting to 10,695 GWh. After calculating the amount of electricity imported, we observe a decrease in the imported electricity from all countries compared to the respective values of 2019. More specifically, the decrease per country is recorded as follows: Albania (-26%), Bulgaria (-16%), Italy (-30%), North Macedonia (-18%) Turkey (-14%).

With regards to electricity exports, they were also reduced in 2020 compared to the respective values of 2019 and amounted to 1,834 GWh. More specifically the decrease per country was recorded as follows: Albania (-50%), North Macedonia (-45%) Bulgaria (-14%) and Italy (-47%). The only country which received a greater amount of electricity in comparison to 2019 is Turkey, which increased its imports from Greece by +263%.

Countries	**Imports (MWh)**			**Exports (MWh)**		
	2019	**2020**	**Change (%)**	**2019**	**2020**	**Change (%)**
Albania	1.903.382	1.412.242	-26%	677.257	339.467	-50%
Bulgaria	4.083.933	3.423.960	-16%	347.974	300.339	-14%
North Macedonia	2.946.962	2.415.995	-18%	807.720	442.052	-45%
Italy	4.078.673	2.852.757	-30%	1.030.858	544.547	-47%
Turkey	690.381	590.571	-14%	57.252	207.728	263%
TOTAL	**13.703.331**	**10.695.525**	**-22%**	**2.921.061**	**1.834.133**	**-37%**

Table 5: Scheduled trade by country in 2020

Table 6 presents the total electricity imports made through interconnection points, per month, for the years 2018 to 2020, and presents the import share of cross - border allocation of the interconnection trading in 2020 and its performance compared to 2019.

	2018	2019	2020
January	1,030,381	956,376	1,029,529
February	834,638	1,184,268	1,091,038
March	818,854	1,263,866	1,185,451
April	975,046	1,162,579	768,489
May	829,034	1,220,985	813,487
June	886,421	910,936	935,263
July	1,264,253	1,117,685	1,012,724
August	932,106	964,605	1,038,632
September	843,305	913,656	722,199
October	803,520	876,339	834,128
November	894,569	960,742	560,821
December	1,111,534	2,171,294	738,963
Total	**11,223,661**	**13,703,331**	**10,730,724**

Table 6: Total import interconnection trading (MWh), 2018 - 2020

	2018	2019	2020
January	227,453	660,968	128,874
February	267,891	391,373	44,707
March	413,479	260,334	57,258
April	287,184	225,471	123,504
May	259,722	210,418	81,582
June	314,872	47,522	147,707
July	390,833	119,993	135,801
August	523,430	202,193	57,127
September	496,642	213,578	277,321
October	600,405	284,093	123,087
November	565,234	131,809	205,945
December	635,458	173,309	475,164
Total	**4,982,603**	**2,921,061**	**1,858,077**

Table 7: Total export interconnection trading (MWh), 2018 – 2019 – 2020

The electricity trading balance at interconnection points (Figure 1) in 2020 showed a particularly slight decrease of 10.66% compared to 2019 and the balance was set at 8.88 TWh in 2020 compared to 9.94 TWh in 2019. The variability of the interconnection balance was significant, with the lowest flow of 258 GWh recorded in December 2020 and the highest flow of 1,126 GWh recorded in 2020.

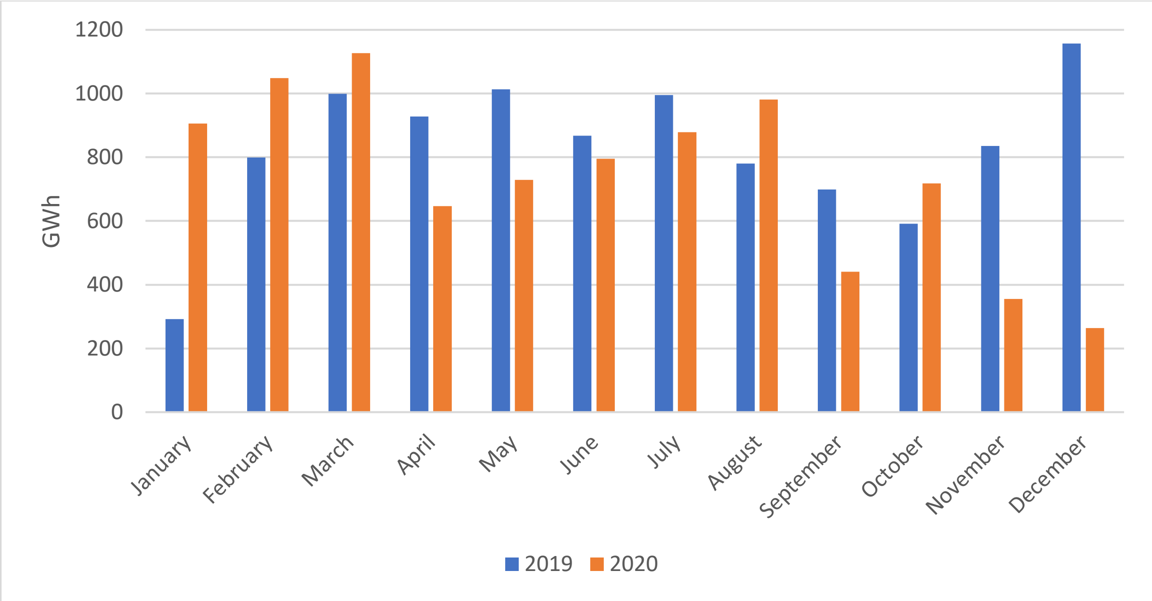

Figure 1: Evolution of Electricity Trading Balance at interconnection points during 2019 and 2020 (GWh)

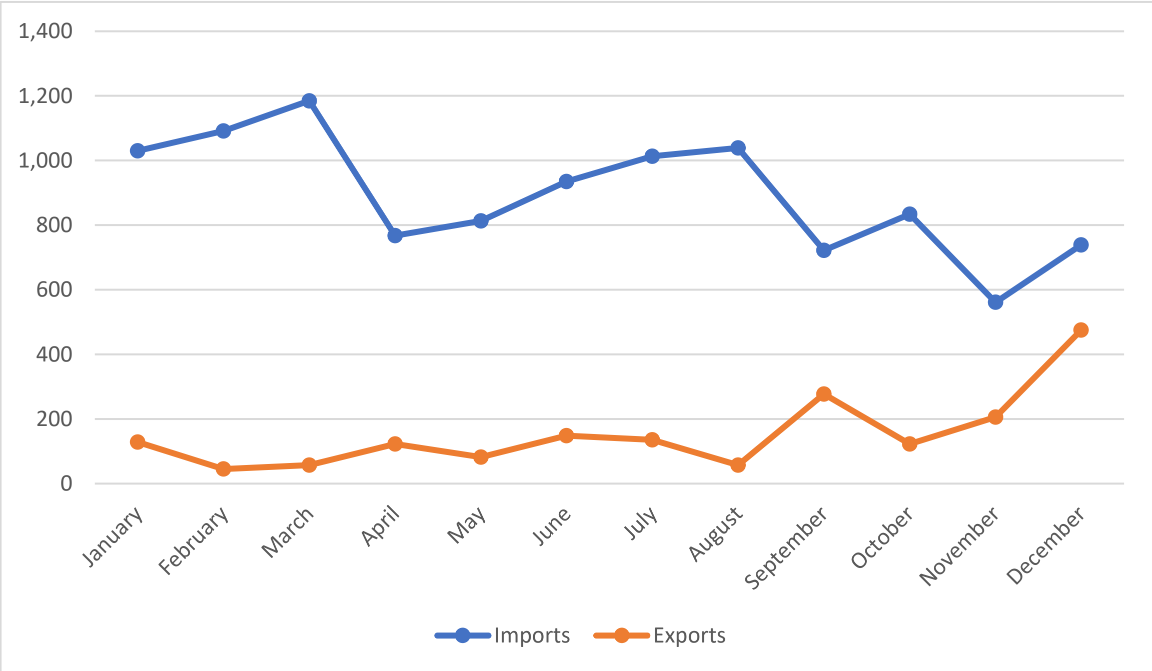

Figure 2: Electricity Imports and Exports (GWh) 2020

3.1.9.1 Interconnection auction rules and access rights

RAE adopted in 2020 the following Decisions related to auctions for the contracting of access rights to the interconnections of the Greek transmission system with the neighboring countries for cross-border electricity trading:

1. Decision No. 1512/2020 concerning the approval of the auction rules for the allocation of access rights to the northern interconnections of the Hellenic Electricity Transmission System with Albania, North Macedonia and Turkey, of the Coordinate Allocation Office (CAO) of the region of Southeast Europe (SEE) for 2020.

2. Decision No. 1546/2020 ADMIE, submitted to RAE a proposal regarding the auction rules for offering transmission capacity rights for electricity imports and exports through the Greek – Bulgarian interconnection of the two transmission systems for 2021. In case of a market coupling of the Bulgarian and Greek electricity day-ahead and intra-day markets, the competent TSOs must suggest a modification or the abolition of the above mentioned auction rules.

3.1.9.2 Implementation of European Network Codes and Guidelines

(A) In 2020, RAE, within the framework of Regulation (EU) 2015/1222 concerning the capacity allocation guidelines and congestion management (CACM), published the following Decisions:

1. Decision No. 728/2020 on submitting a request to ACER on the common SEE CCR TSOs proposal amendment for the redispatching and countertrading cost sharing methodology, according to Article 74 of Regulation (EU) 2015/1222 of the Commission of 24 July 2015, concerning the guidelines setting for capacity allocation and congestion management (Gazette B’ 1620/2020).

2. Decision No. 1379/2020 on the shipping arrangement for the exchange of energy and financial transactions within the framework of the Single Intraday coupling in all European bidding zones, according to Article 68 (6) of Regulation (EU) 2015/1222 of the Commission of 24 July 2015, concerning the guidelines setting for capacity allocation and congestion management (Gazette B’ 4480/2020).

3. Decision No. 1573/2020 concerning the determination of fallback procedures for GRIT CCR, according to Article 44 of Regulation (EU) 2015/1222 of the Commission of 24 July 2015, concerning the guidelines setting for capacity allocation and congestion management (Gazette B’ 5522/2020).

(B) In 2020, RAE, within the framework of Regulation (EU) 2016/1719 establishing a guideline on forward capacity allocation (FCA), published the following Decisions:

1. Decision No. 210/2020 concerning the approval of GRIT CCR TSOs’ common proposal for the Capacity Calculation Methodology according to Article 10 of Regulation (EU) 2016/1719 of the Commission of 26 September 2016 concerning the guidelines setting for future capacity allocation (Gazette B’ 763/2020).

2. Decision No. 211/2020 concerning the approval of GRIT CCR TSOs’ common proposal on the methodology for splitting long-term cross-zonal capacity according to Article 16 of Regulation (EU) 2016/1719 of the Commission of 26 September 2016 concerning the guidelines setting for future capacity allocation (Gazette B’ 694/2020).

3. Decision No. 799/2020 concerning the amendment of SEE CCR TSOs’ common proposal for the Capacity Calculation Methodology according to Article 10 of Regulation (EU) 2016/1719 of the Commission of 26 September 2016 concerning the guidelines setting for future capacity allocation (Gazette B’ 2061/2020).

4. Decision No. 933/2020 concerning the submission of request to ACER to issue a Decision on SEE CCR TSOs’ common proposal on the methodology for splitting long-term cross-zonal capacity according to Article 16 of Regulation (EU) 2016/1719 of the Commission of 26 September 2016 concerning the guidelines setting for future capacity allocation (Gazette B’ 4023/2020).

5. Decision No. 1460/2020 concerning the approval of SEE CCR TSOs’ common proposal for the Capacity Calculation Methodology according to Article 10 of Regulation (EU) 2016/1719 of the Commission of

26 September 2016 concerning the guidelines setting for future capacity allocation (Gazette B’ 4876/2020).

(C) In 2020, RAE, within the framework of Regulation (EU) 2017/2195 concerning the establishing of a guideline on electricity balancing (EB), published the following Decisions:

1. Decision No. 122/2020 on the amendment of the Continental Europe TSOs proposal on common settlement rules applicable to intended exchanges of energy as a result of the frequency containment process and the ramping period, pursuant to Article 50 par. 3 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing (Gazette B’ 811/2020).

2. Decision No. 132/2020 on the amendment of the Continental Europe TSOs proposal for common settlement rules applicable to all unintended exchanges of energy, pursuant to Article 51 par. 1 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing (Gazette B’ 812/2020).

3. Decision No. 935/2020 on the approval of the Continental Europe TSOs proposal on common settlement rules applicable to intended exchanges of energy as a result of the frequency containment process and the ramping period, pursuant to Article 50 par. 3 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing (Gazette B’ 3656/2020).

4. Decision No. 936/2020 on the approval of the Continental Europe TSOs proposal for common settlement rules applicable to all unintended exchanges of energy, pursuant to Article 51 par. 1 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing (Gazette B’ 3738/2020).

5. Decision No. 1089/2020 on the amendment of the GRIT CCR TSOs joint proposal for a methodology on a market-based allocation process of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves, pursuant to Article 41 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing (Gazette B’ 3687/2020).

6. Decision No. 1090/2020 on the amendment of the GRIT CCR TSOs joint proposal for a methodology for the allocation of cross-zonal capacity based on an economic efficiency analysis, pursuant to Article 42 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing (Gazette B’ 3795/2020).

7. Decision No. 1555/2020 on the amendment of the GRIT CCR TSOs joint proposal for a methodology on a market-based allocation process of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves, pursuant to Article 41 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing (Gazette B’ 505/2021).

8. Decision No. 1556/2020 on the amendment of the GRIT CCR TSOs joint proposal for a methodology for the allocation of cross-zonal capacity based on an economic efficiency analysis, pursuant to Article 42 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing (Gazette B’ 733/2021).

3.1.9.3 Monitoring of electricity PCIs

Euroasia Interconnector: In the context of the high-level meeting, on the final selection of projects to be included in the 4th PCI list, between the European Commission and the Member States on 4th October 2019, the Hellenic Ministry of Environment and Energy informed the European Energy Commissioner Mr. Miguel Arias Cañete that the electricity interconnection of Crete-Attica will be implemented as a national project by the company "Ariadne Interconnection S.P.L.C., a subsidiary of ADMIE. According to the official announcement of the Ministry, since the negotiations between all the parties involved in the last period, in order to find a consensual solution for the implementation of the project as a PCI, were not successful. This position of the Ministry was dictated by the need for the rapid implementation of the project which is of high national importance. At the same time, the Greek government provides strong political support at EU level for the Crete-Cyprus and Cyprus-Israel interconnections in the revised PCI list.

The 4th revised PCI list was published on 11.03.2020 (Regulation 2020/389), in which the Euroasia Interconnector project was no longer officially part of the original PCI lists, which now consists of the other two sections, the Crete-Cyprus section and the Cyprus-Israel section.

Furthermore, within 2020, the project promoter, Euroasia Interconnector Ltd informed the Greek authorities of its difficulty to meet the interoperability standards of the Crete – Cyprus interconnection with the Attica - Crete interconnection and that it would be its final choice to proceed with the selection of submarine cable of different voltage. This development will result in the construction of a second substation in Crete. Furthermore, the project promoter declared that the additional costs incurred by this technical differentiation will be covered entirely by Euroasia Interconnector Ltd.

Maritsa-Nea Santa interconnection line: The construction of the project started in March 2020 in Bulgarian territory, while in Greece it is expected to start within the first half of 2021. Given the high rate of progress of the construction works in Bulgaria, the overall project is expected to be completed within the first half of 2022, even earlier than the foreseen binding timetable of Decision 681/2018.

3.2 Promoting Competition

3.2.1. Wholesale market

3.2.1.1. Description of the wholesale market

A historical reform took place in the electricity market in Greece starting the 1st of November 2020, according to the provisions of RAE's Decision 1298/2020[6] (Government Gazette B'4415/07.10.2020). A new wholesale electricity market design, in line with the European Target Model, replaced the day-ahead mandatory pool system, which was in operation since 2005 (see previous reports for detailed description).

Following proposals made by RAE and the competent Operators, in cooperation with the Ministry of Energy, Law 4425/2016, as amended by Law 4512/2018, came into force, according to which the

[6] See http://www.rae.gr/site/categories_new/about_rae/factsheets/2020/gen/1109.csp.

following four separate markets have been established: A) Energy Derivatives Market, B) Day-Ahead Market, C) Intra-Day Market, and D) Reserves and Energy Balancing Markets.

The Energy Derivatives Market started operation in March 2020 and the remaining three spot electricity markets started operation in November 1, 2020. The first three markets are operated by the Hellenic Energy Exchange (HENEX SA), whereas the Balancing Market is the exclusive responsibility of IPTO. The Hellenic Energy Exchange has been designated as the Nominated Electricity Market Operator (NEMO) for the coupling of the day ahead market and the coupling of the single intraday electricity market (RAE Decision 1124/2019).

A) Energy Derivatives Market: The Energy Derivatives Market's organization and support of its transactions is carried out by HENEX SA, while the settlement of transactions, having the role of the central counterparty (CCP), is carried out by ATHEXClear, one of the member companies of the Hellenic Exchanges S.A. The futures contracts are traded within the framework of the Energy Derivatives Market, which relate to the exchange of electricity by determining the time, quantity and price of the transaction with physical delivery obligation as an option and can be concluded either bilaterally (OTC) or through an organized Energy Exchange (Forward Market). The futures market is a useful tool for participants in order to mitigate their exposure to price volatility in energy markets where there is a physical delivery obligation.
B) Day-Ahead Market (DAM): The DAM is an hourly spot market balancing demand and supply via electricity prices, reflecting the highest generation bid needed to meet the lowest willingness to pay of load representatives. Participants submit electricity transaction (buy/ sell) orders (per unit in the case of conventional producers, per portfolio in the case of RES producers or aggregators and per Bidding Zone or Border in the case of other Market Participants) with the obligation of physical delivery on the next day. Participants declare the energy quantities to be delivered physically corresponding to forward-market product transactions. Producers are obliged to submit orders for capacity that has not been allocated via the forward contracts with physical delivery nominations. The outcome of the DAM is a market schedule submitted to the system operator for physical implementation the next day either at a unit/ entity level (for conventional thermal, hydro units and interconnections) or portfolio (for suppliers and aggregators).
C) Intraday market (IDM): This market allows participants (same participants as in the DAM and for traders under the existence of relevant explicit Physical Transmission Rights) to place transaction orders for physical delivery in order to modify their position in the generation schedule, load declarations, etc., close to the time of the physical delivery, taking into consideration the energy quantities committed through forward electricity products, the DAM schedule as well as any events and deviations and limitations emerging from the balancing market, in an aim to reduce their exposure to imbalances costs. The transactions in the IDM concern upward and downward changes, and their financial settlement is based on market equilibrium prices that are common for upward and downward changes. The IDM launched in 2020 included three local intra-day auctions (LIDAs) per day and participation is voluntary.
D) Balancing Market (BM): The Balancing Market includes the Balancing Capacity Market (BCM) to ensure that sufficient reserves are available, the Balancing Energy Market (BEM) to activate energy in real time to ensure that the system is in balance while meeting demand for energy and reserves and respects all technical plant operation constraints, and the Imbalance Settlement (IS) to allocate the costs of the Balancing Market to market participants. Generators are required to submit bids with a physical delivery obligation for their total available capacity, both in the Balancing Energy

market and the Balancing Capacity Market. The following table presents an overview of the design of the balancing markets, which comprises three steps running sequentially.

Name of the procedure	Integrated Scheduling Process (ISP algorithm)	Balancing Energy Market (RTBM algorithm)	Settlement of Balancing Energy & Capacity, and Imbalances
Time resolution	30 minutes	15 minutes	15 minutes
Objective	Balancing capacity procurement	Balancing energy procurement	Metering and Settlement
Ancillary services	FCR, aFRR, mFRR	aFRR, mFRR	
Remuneration rule	Capacity remunerated pay-as-bid	aFRR remunerated pay-as-bid mFRR remunerated at market clearing prices	Single Imbalance price Volumes, prices and settlement amounts calculated
Real time operation	Unit Commitment Schedule (from the ISP)		

Table 8: Overview of the design of the balancing markets in Greece

Participation and bids in the BCM take place day-ahead. The TSO defines the volume of reserve requirements for each balancing capacity (reserve) product, namely for FCR (Frequency Containment Reserve), up and down, aFRR (automatic Frequency Restoration Reserve), up and down, mFRR (manual Frequency Restoration Reserve), up and down, except for RR (Replacement Reserve) which does not yet apply in Greece. The participants submit their offers for balancing capacities in the ISP. The ISP procedure operates at least three times daily, namely once after clearing the DAM and after the first LIDA, and twice after the other two LIDAs. For balancing capacity awarded to them, the bidders receive as compensation an amount calculated using their offer price; i.e. a pay-as-bid auction applies. Upon selection, they have an obligation to commit to the respective capacity as a reserve. Otherwise, they are not compensated for the awarded capacities resulting from the ISP results since the remuneration considers the real-time availability as indicated from the real-time operation (SCADA system).

The result of the ISP procedure is a commitment schedule of the power plants, the awarded capacities and an indicative generation schedule. The ISP algorithm applies a central scheduling – central dispatch design. It takes as given the generation schedule of the DAM as modified by the IDM, considers in detail the technical plant operation constraints, the reserve requirements, the network constraints and the load and RES forecasts, and produces a commitment schedule that meets the calculated imbalances (also for RES and load forecasts that differ from RES and load amounts included in the DAM and the intra-day trading) and the reserve requirements at a minimum total cost, based on the participants' bids.

Close to real-time, the IPTO estimates the need for upward or downward balancing energy to activate, depending on events that drive a frequency restoration process. Activation for both the automatic and manual frequency restoration reserves are based on the balancing energy merit order, i.e. ascending (descending) prices corresponding to upward (downward) balancing energy bids. Thus, the activation of balancing energy combined with system operation constraints implies changes in electricity generation (re-dispatching), upwards and downwards, for which generators receive remuneration, defined at a market-clearing marginal price for the activated balancing energy needed to meet mFRR, and according to a pay-as-bid rule for the aFRR. More specifically, the higher (lower) accepted bid in the mFRR procedure sets the marginal price for the upward (downward) mFRR balancing energy. Regarding the aFRR, the BSPs receive at least the price of the mFRR balancing energy (of the same direction) or the price of the offer of the last accepted bid step if higher.

The Imbalance Settlement is an ex-post market procedure, which determines the revenues or payments of balancing demanders (Balancing Responsible Parties - BRPs) and the revenues or payments of balancing suppliers (Balancing Service Providers - BSPs). The imbalance settlement period has already been set to 15 minutes since 1st November 2020. The imbalance price is the weighted average price of activated balancing energy in the relevant direction (upward or downward) for manual and automatic frequency restoration reserve. The Imbalance Price per Imbalance Settlement Period is calculated as the weighted average price of the activated Balancing Energy for manual and automatic FRR for that Imbalance Settlement Period in the predominant direction (upward or downward). If there has been no activation of balancing energy, the imbalance price reflects the value of avoiding balancing energy activation. Bids accepted for non-energy balancing purposes (e.g. re-dispatching or for voltage control) are not taken into account in the imbalance price calculation and are paid-as-bid. Any additional cost (difference of bid price and imbalance price) is recovered through an uplift account that ensures financial neutrality of the TSO.

RAE issued over sixty decisions which all together comprise the secondary framework for the operation of the three spot markets (DAM, IDM and BM). In an excellent cooperation with the Hellenic Capital Market Commission (HCMC), RAE issued opinions to HCMC on issues related to the Energy Derivatives Market.

3.2.1.2. Installed Capacity and Generation

In 2020, the installed capacity in the interconnected system of Greece was increased (19,407 MW) compared to 2019 (18,330 MW), due to the increase of RES units' installed capacity from 6,355 MW in 2019 to 7,120 MW in 2020 and the increase of natural gas units' installed capacity from 4900 MW in 2019 to 5211 MW in 2020[11]. In terms of installed capacity (excluding RES), PPC S.A. held a market share of 72.49% compared to 71.8% in 2019, whereas the market share of PPC's conventional units including RES amounted to 45.9% compared to 46.9% in 2019.

The information presented below is based on the Monthly Energy Balance Reports available at TSO's site (https://www.admie.gr/en/market/reports/monthly-energy-balance) and the TSO's TYNDP.

[11] According to the provisions of paragraph 1 of article 104 of Law 4685/2020 (GG A'20), the Megalopoli 5 Unit can operate at 811 MW, and not only at 500 MW, as was provided in paragraph 10 of article 3 of Law 4533/2018 (GG A'75).

Installed capacity and production by fuel, in 2020	Installed capacity (MW)	Total annual production (TWh)	Share in produced volume, including RES (%)
Lignite	3,904	5.72	14%
Large Hydro (P > 15 MW)	3,171	2.9	7%
Natural gas	5,212	17.81	43%
Total Thermal + Large Hydro (1)	12,287	26.43	64%
Total RES (Grid + Network) (2)	7,120	14.77	36%
Total (1+2)	19,407	41.21	100%

Table 9: Installed Capacity and Production by fuel, including RES, in the Interconnected System in 2020

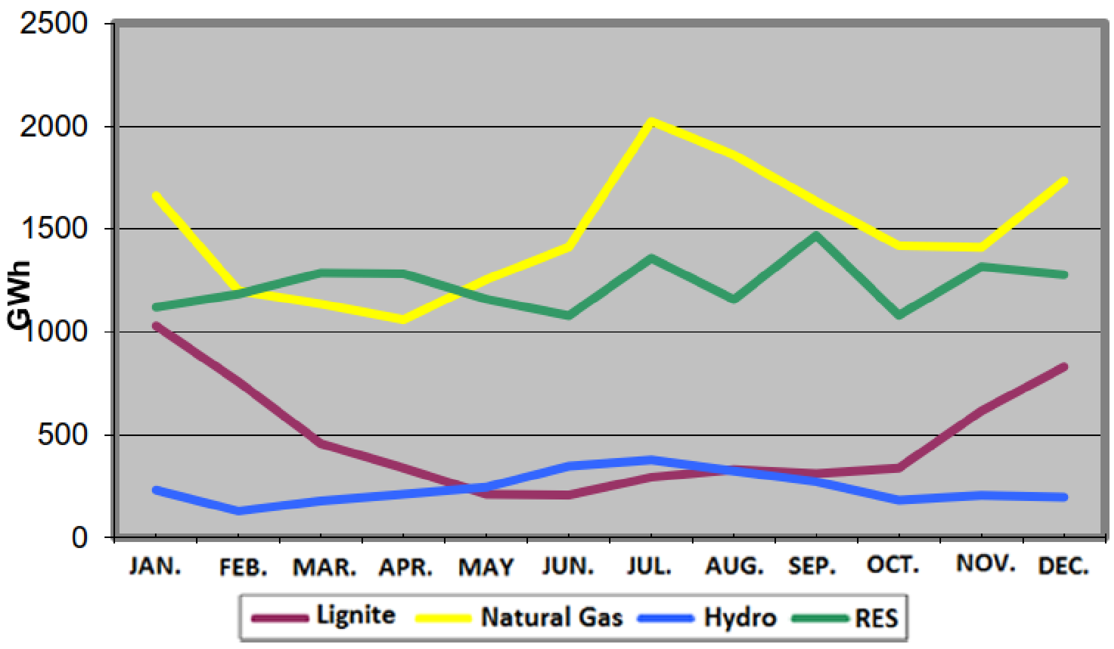

Figure 3: Monthly Production by Generation Fuel in 2020

In terms of the generation mix, in 2020 the lignite production showed another significant decrease of 45.06% (4,694 GWh) compared to 2019. More specifically, in 2020 lignite production amounted to a total of 5.72 TWh (10.42 TWh in 2019). Regarding other technologies, the electricity generation from natural gas increased to 17.81 TWh (an increase of 9.74% compared to 2019, 16.23 TWh), while hydroelectric production dropped by 13.8%, amounting to 2.9 TWh in 2020 (from 3.36 TWh in 2019). Finally, RES and CHP generation continued the upward course of the previous year and reached 14.77 TWh, recording an increase of 20.9% compared to 2019 (12.22 TWh). Overall, domestic production showed a decrease of 2.41% reaching 41.21 TWh compared to 42.23 TWh in 2019.

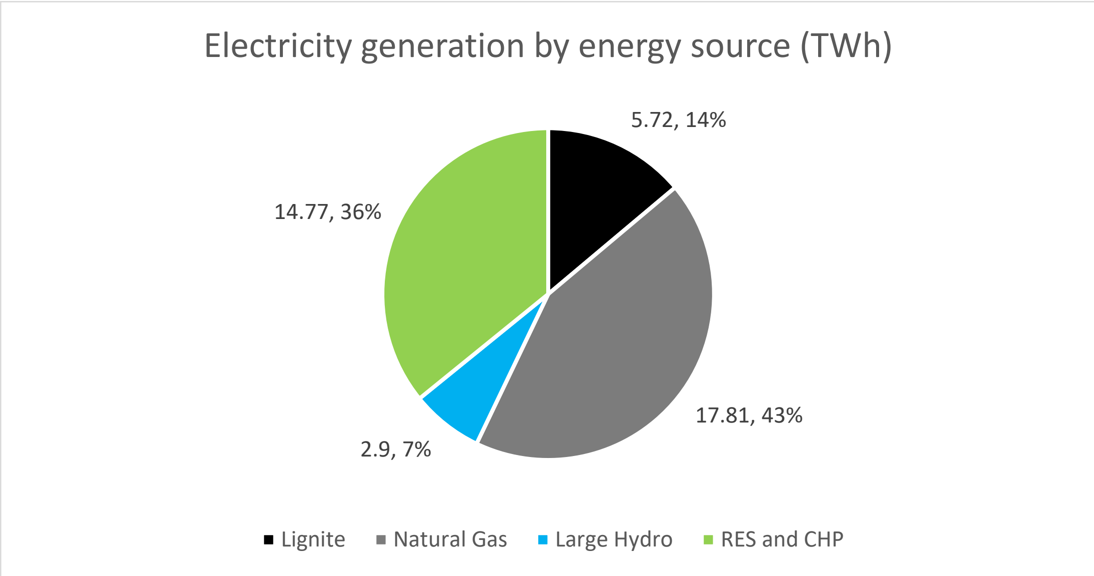

Figure 4: Electricity generation by energy source in 2020

On a monthly basis, generation from lignite showed a sharp fluctuation between 207 GWh and 1,030 GWh. June was the month with the lowest demand for lignite-based power while January was the month with the highest demand in 2020. Electricity generation from natural gas showed a sharp fluctuation between 1,060 GWh (April) and 2,024 (July) GWh, however that fluctuation was lower than the one recorded in 2019. Hydroelectric generation varied between 129 GWh in February and 377 GWh in July. RES generation also showed greater fluctuations compared to 2019 (between 1,079 GWh in June and 1,470 GWh in September 2020). The balance of interconnections in 2020 decreased by 10.88% compared to 2019 and amounted to 8.86 TWh in 2020 compared to 9.94 TWh in 2019. The fluctuations of electricity imports and exports through interconnections (Figures 1 & 2) were significant over 2020, with the lowest value being recorded in December 2020 (258.05 GWh) and the highest value in March 2020 (1,126.46 GWh).

3.2.1.3. Auxiliary and Generation capacity reserves mechanisms (market)

In 2018, the European Commission approved the new Transitory electricity Flexibility Remuneration

Mechanism[12] (4947 final/30.7.2018 in State aid case “SA 50152” for Greece) with a maximum implementation period until December 2019, or until the implementation of the Long-Term Capacity Remuneration Mechanism, if the latter occurs earlier.

Considering the forthcoming Target Model, the implementation period of the above mechanism was divided in two periods, with at least two separate auctions. The first implementation phase covered the period starting from 3 August 2018 until 31 March 2019, and the second, which would run in parallel with the Target Model, should have covered the period from April 2019 to December 2019. However, the mechanism wasn’t implemented for the second period. Currently there are ongoing discussions with the European Commission for the extension of the TFRM.

By virtue of Article 129 of Law 4685/2020, the Minister of Energy implemented the new TFRM with Ministerial Decision ΥΠΕΝ/ΔΗΕ/66754/810/9.7.2020. The new TFRM is practically the 2nd extension of the previous TFRM, the implementation of which expired in 2017. The 1st extension of the Mechanism ended prematurely in March 2019, as the introduction of the balancing market and the electricity Target Model were set as prerequisites by the EU for the approval of the second auction of the TFRM.

Ministerial Decision ΥΠΕΝ/ΔΗΕ/66754/810/9.7.2020 defined the details of the new TFRM, including its duration, the criteria for determining the eligible service providers, the details of their financial compensation and their obligations as well as the amount of the auctioned capacity.

RAE, after taking into account the positive opinion of DG COMP, set in public consultation the Recommendation of the TSO IPTO regarding the implementation of the new TFRM with the aim of integrating the relevant provisions into the revised Electricity Transmission Network Code. Subsequently, after considering the feedback received during the public consultation, RAE issued Decision 1171/2020 on the amendment of the Electricity Transmission Network Code for the implementation of the new Transitional Flexibility Compensation Mechanism.

This Mechanism, given its transitional nature, is similar to the previous TFRM. The maximum implementation period of the new TFRM was set until 31.03.2021, or until the implementation of the Long-Term Capacity Remuneration Mechanism, if the latter occurs earlier. The Mechanism foresees the holding of two main auctions, with the first having a delivery period between the date of application of the Mechanism and until the end of the month following the start of the balancing market (or no later than 31 December 2020, whichever occurs first). The second auction may take place after the operation of the new balancing market, with a delivery period from the end of the month following the operation of the balancing market until March 31, 2021. The compensation of the award winners in the tender procedure is determined based on pay-as-bid pricing. The auctioned capacity for the first auction was set at 4,500 MW and the maximum bid cap at € 39,000 / MW per year. The maximum cost of the mechanism for a yearly implementation period amounts to approximately € 175.5 million (or € 14.6 million per month corresponding to the maximum bid price on the auctioned capacity). This cost is the same as the budget cost of the previous mechanism, which expired in March 2019, with the payments received by all eligible units amounting to € 77.04 million after transaction settlements. It should be noted, that the actual cost of this new TFRM will depend on the results of the auctions, combined with a "claw-back" mechanism, the implementation of which will concern the delivery period of the second

[12] The New Transitory Electricity Flexibility Remuneration Mechanism (TFRM) was transposed into the Greek legislation with law 4559/2018.

auction to avoid any unfair market practices during the operation of the new balancing market.

The European Commission approved the extension of the Flexibility Mechanism with its Decision C (2020) 6659 SA.56102 (2020 /N),[13] to ensure sufficient power generation capacity, considering that this Mechanism of its nature is a transitional measure that seeks to ensure a smooth transition to the new electricity markets and is compatible with the Union State aid scheme. The first auction for the new Mechanism took place on August 14, 2020.

3.2.1.4. Market Size

The assessment of electricity demand dynamics is a multidimensional issue and thus requires the assessment of many different factors. According to ADMIE's data, based on the metered consumption level at the interconnection point between the transmission and the distribution systems, demand decreased in 2020 by 4.16% compared to 2019, and more precisely it reached 49.93 TWh compared to 52.1 TWh in 2019 (and 51,46 TWh in 2018). The consumption at HV decreased by 7.68% compared to 2019, ending in this way the uprising trend of the previous years.

Moreover, the consumption at the distribution network decreased by 3.4% compared to 2019, while in 2019 an increase of 2.8% had occurred compared to 2018.

The demand in the distribution network in June 2020 showed a significant decrease (by 13.1%) compared to June 2019 when the demand was increased by 6% compared to June 2018. More specifically, according to data recorded by HEnEx S.A., demand in the LV network decreased by 18.45% while demand in the MV network decreased by 22.08%. The decrease in electricity demand in June 2020 is mainly due to the decrease of economic activity (suspension of tourism activities and other businesses). The demand in the distribution network during the months of March, September and November 2020 (0.3%, 1.2% and 2.7% respectively) marked a positive sign compared to the respective months of the previous year.

Peak demand occurred in July 2020 (overall demand, i.e. after taking into account the pumping and the estimated demand in the distribution network that was covered by the production therein), and more specifically, it was recorded on 31.07.2019, at the 15th hour of allocation, reaching 9,547 MW (compared to 9,634 MW in July 2019, at the 15th hour of allocation).

Figure 5 displays the aggregated demand fluctuations on a monthly basis, including the grid metering and the RES connected to the distribution network (real demand level).

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[13] SA.56102 (2020/N) Second prolongation of the Transitory Flexibility Remuneration Mechanism (TFRM). Available online at: https://ec.europa.eu/competition/elojade/isef/case_details.cfm?proc_code=3_SA_56102

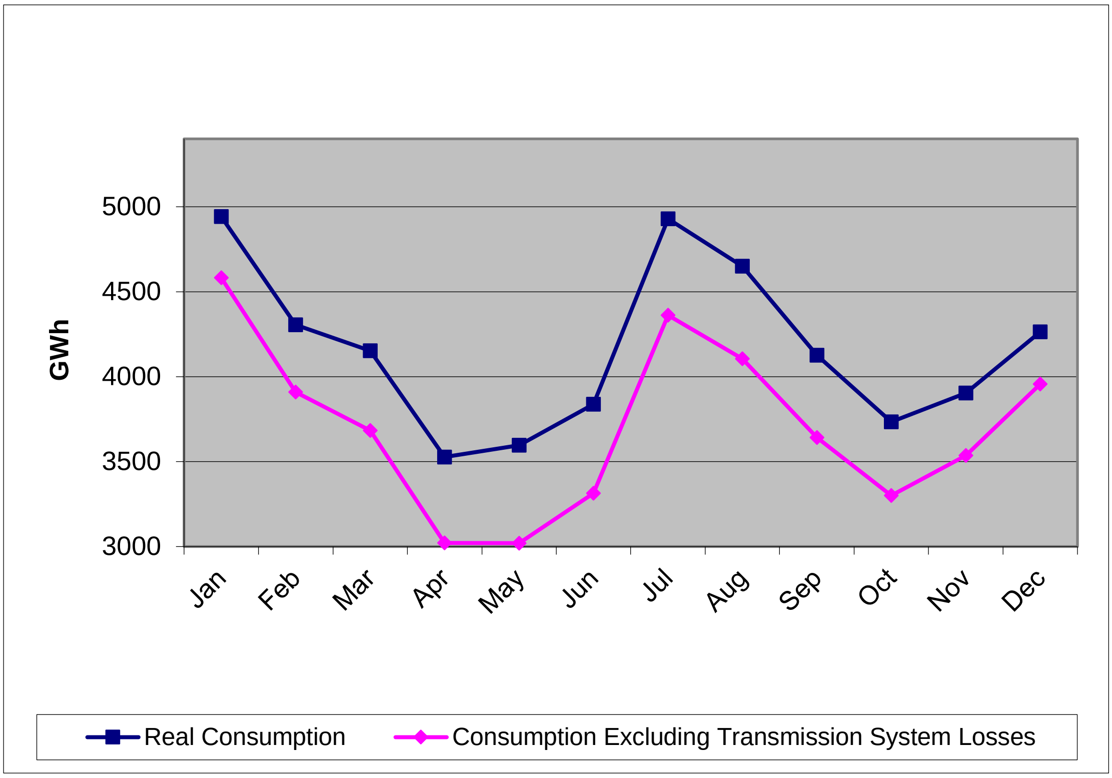


Figure 5: Monthly Electricity Demand in 2020

In Table 10, the monthly imbalances of demand are portrayed.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Real Consumption (GWh), in 2019	5,089	4,346	4,242	3,911	3,862	4,437	4,980	5,005	4,129	3,805	3,792	4,503	52,101
Consumption at the Grid level (GWh), in 2020	4,805	3,990	3,751	3,456	3,368	3,942	4,486	4,480	3,693	3,422	3,502	4,210	47,105
Real Consumption in 2020 (GWh)	4,942	4,306	4,152	3,527	3,596	3,838	4,930	4,650	4,127	3,733	3,904	4,263	49,968
Difference between real consumption in (2020-2019) (GWh)	-147	-40	-90	-384	-266	-599	-50	-355	-2	-72	112	-240	-2,133
% change in real consumption (2019-2018)	-2.97%	-0.93%	-2.17%	-10.89%	-7.40%	-15.61%	-1.01%	-7.63%	-0.05%	-1.93%	2.87%	-5.63%	-4.27%
Source: December 2020 Monthly Report TSO ADMIE													

Table 10: Monthly Electricity Demand in the Interconnected System (2019-2020)

3.2.1.5. Monitoring market shares

The installed capacity during 2020 was divided per technology and production companies as shown in the figures below:

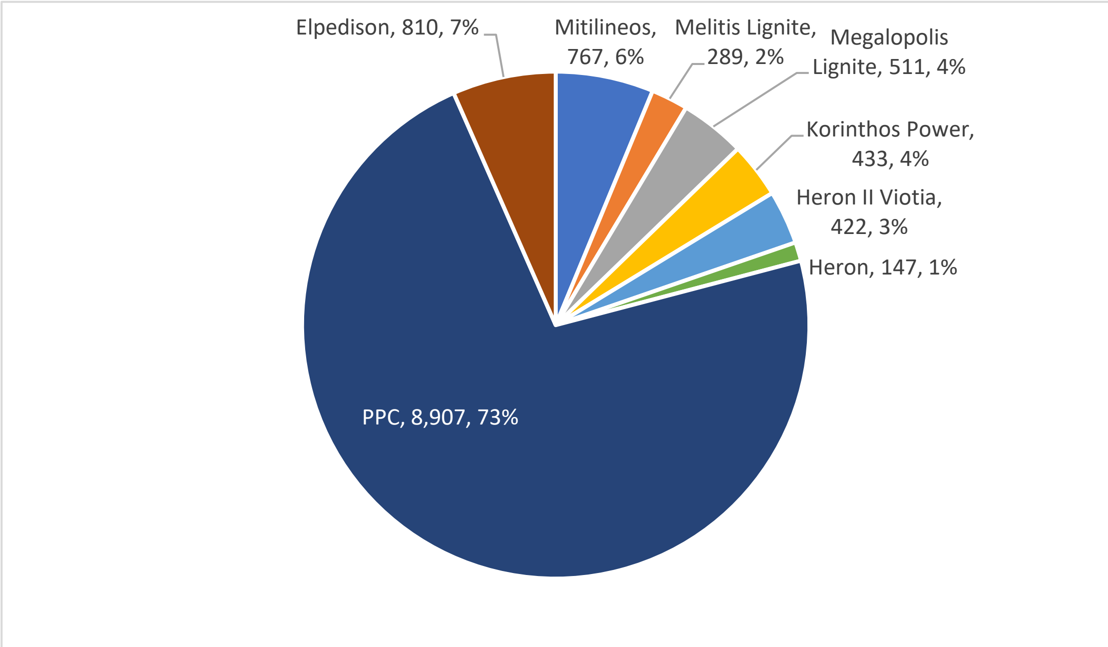


Figure 6: Installed (net) capacity (MW) and as a percentage of total capacity per producer in 2020, excluding RES

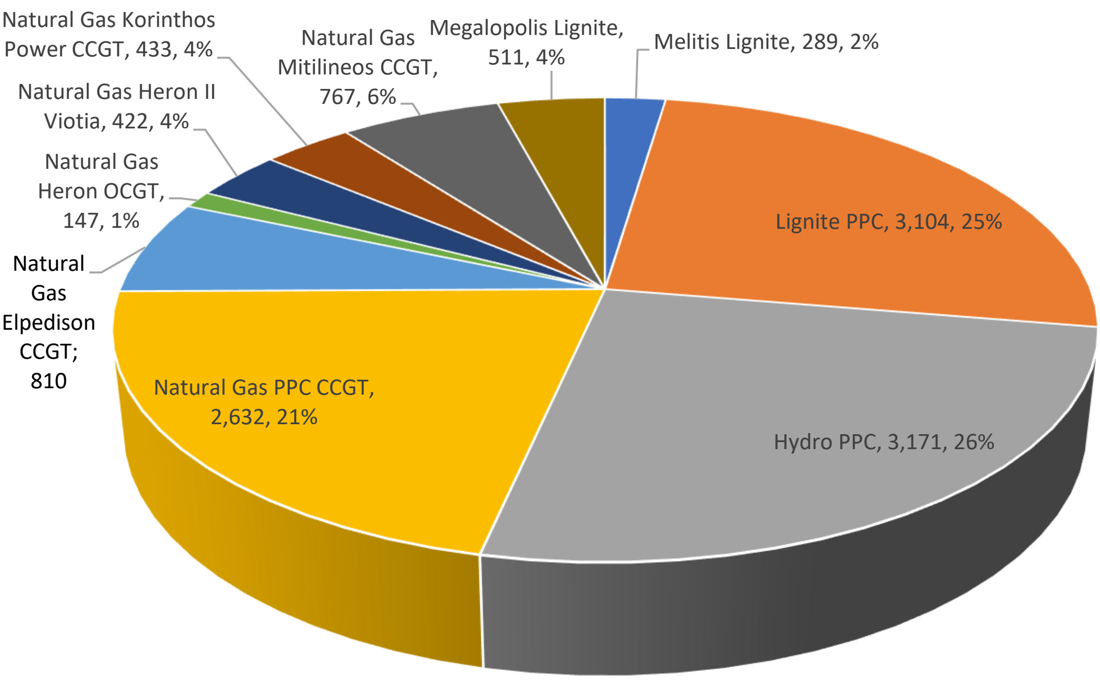


Figure 7: Installed (net) Capacity (MW) per producer and generation technology (%) in 2020 excluding RES

In terms of annual electricity generation, the total generation (GWh) and market shares (%) of the biggest generation companies were as follows:

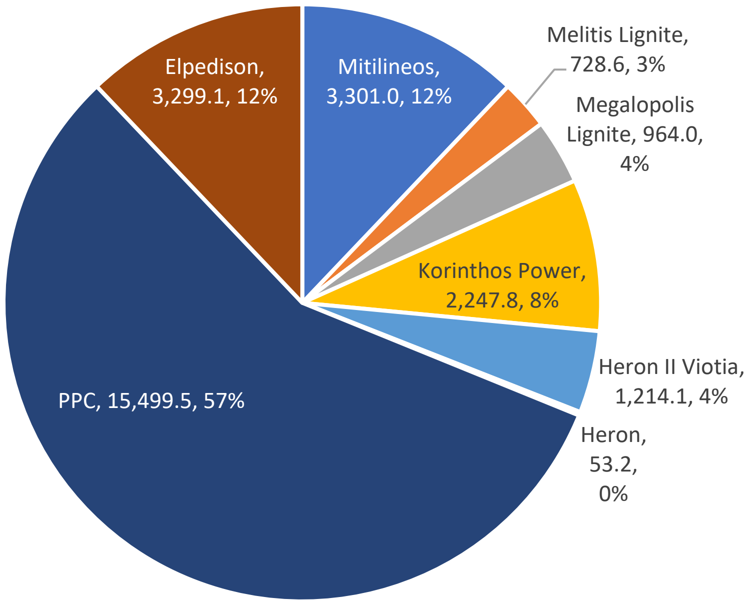


Figure 8: Share in Electricity Generation in 2020 per producer and technology (excluding RES)

The HHI (Herfindahl index)[14], when calculated in terms of the shares of energy produced by the electricity generation companies (excluding RES), increased in 2020 (4,343) compared to 2019 (3,550) but it was still lower compared to 2018 (4,359). If the same index is calculated in terms of capacity shares, then it amounts to 6,350 in 2020 compared to 5,290 in 2019.

Regarding PPC's share in terms of capacity, on conventional technologies (excluding RES) was decreased from 71.8% in 2019 to 62.96% in 2020, whereas if we include RES it was decreased from 46.9% in 2019 to 45.9% in 2020.

Year	HHI index (generation)
2020	**4,343**
2019	3,550
2018	4,359
2017	5,982
2016	5,999
2015	7,820

Table 11: Share in electricity generation per company (%) & HHI Index in 2020

[14] The HHI index for 2020 was calculated by assuming that Melitis Lignite and Megalopolis Lignite were part of the PPC as the public tender for the privatization of these companies was unsuccessful.

Year	HHI index installed capacity
2020	**6,350**
2019	5,290
2018	5,627
2017	6,357
2016	6,423
2015	6,804

Table 12: PPCs' Market Share Installed Capacity & HHI Index in 2020

3.2.1.6. Price Monitoring

This section presents the evolution of the prices of the wholesale markets separately during the period 1.1.2020 to 31.10.2020, as formed by the Day-Ahead Scheduling (DAS) of the Mandatory Pool Model and during the period 1.11.2020 to 31.12.2020, as formed in the context of the new markets of the Target Model. This is because the basis for determining these prices is different and not directly comparable.

Mandatory Pool - Day-Ahead Scheduling (1.1.2020 to 31.10.2020)

The System Marginal Price (SMP) is the price at which the electricity market is cleared (i.e. the price that all those who inject energy into System are paid) and is paid by all those who absorb energy from the System. In particular, the Marginal Price of the System is shaped by the combination of price offers and submitted quantities each day by the available units of electricity generation, and the hourly demand for electricity, formed on a daily basis by consumers.

The average system marginal price (SMP) in 2020 amounted to 42.94 €/MWh, a decrease of 34.04% compared to the average SMP of the same time period of the previous year (01.01.2019-31.10.2019).

Concerning monthly variations of the SMP, we observe that the SMP fluctuated between 28.51€/MWh (in April) to 58.38 €/MWh (in January). The variation of the monthly SMP compared to 2019 levels is about -47.5% in April and -22.46 in January.

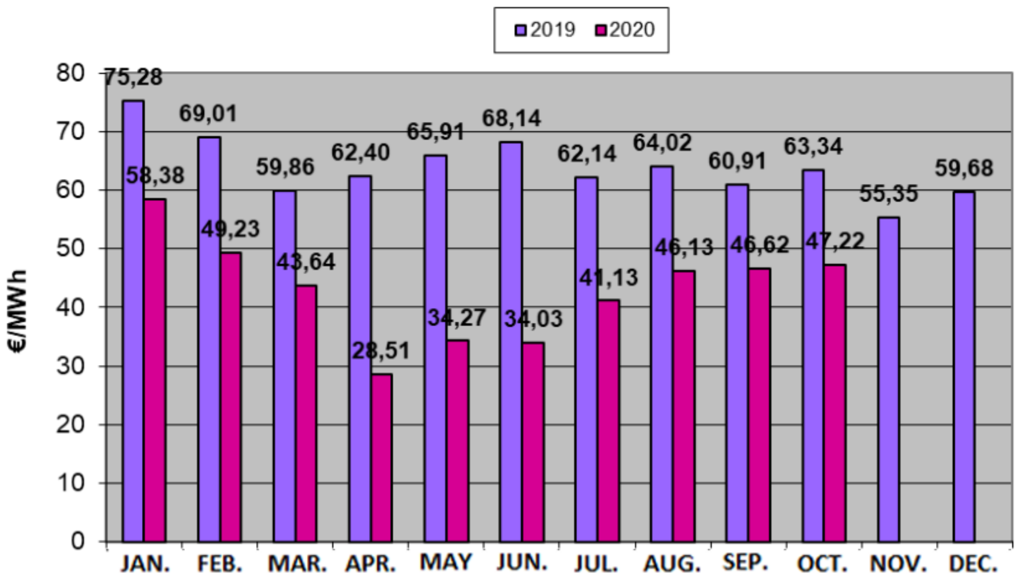


Figure 9: Monthly System's Marginal Price (2019-2020)

The SMP remained below € 75/MWh for 97% of hours and below € 55/MWh for 82% of hours, compared to 87% and 10% respectively for 2019. Regarding significant price spikes, the maximum SMP was recorded at 1st hour of 3 July 2020 and was equal to 150.05 €/MWh. The number of hours that the SMP recorded zero values increased to 18 compared to 9 during the corresponding period of 2019.

The SMP was determined mostly by natural gas units (53.6% compared to 58.5% in 2019), followed by imports (24.9% compared to 12.1% in 2019), then from exports (16%, compared to 4.8% in 2019), lignite power plants (4.1%, compared to 18.9% in 2019) and hydro plants (1.4%, compared to 5.2% in 2019).

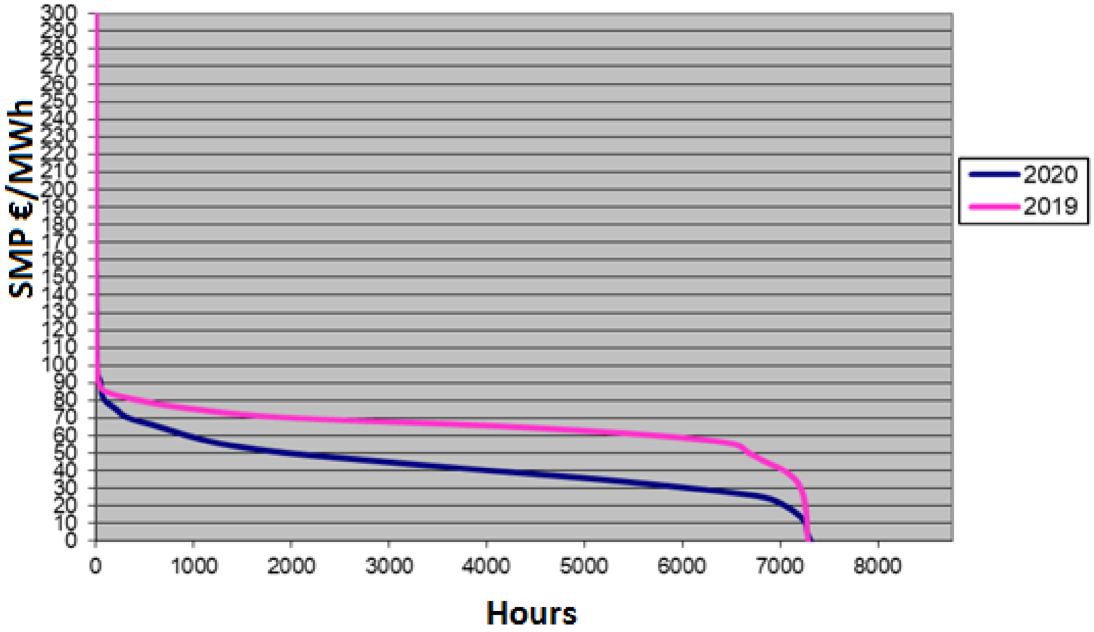


Figure 10: SMP Duration Curve (January-October 2020)

Regarding the difference between the average SMP and the average imbalance price, on an hourly basis, this amounted to 6.07 €/MWh in 2020 compared to 3.86 €/MWh in 2019.[17] The variation of the difference between the average monthly SMP and the average imbalance price is ranged between 2.33 €/MWh in September 2020 and 11.57 €/MWh in March 2020.

The Figure 11 below depicts the monthly variations between the average SMP and the average imbalance price.

[17] January to October 2020 compared to the same period of 2019.

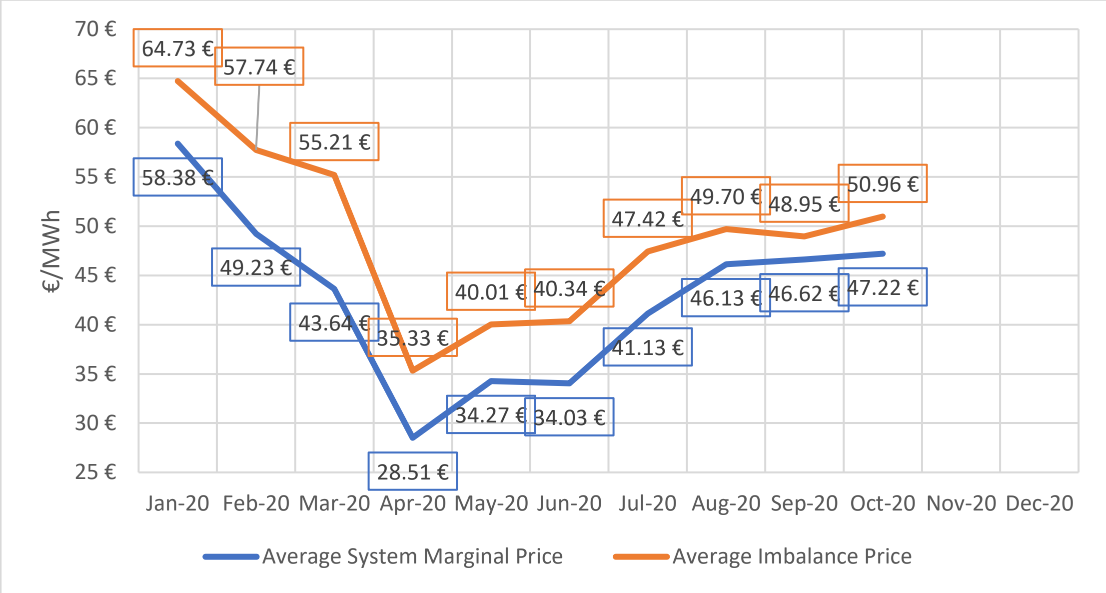


Figure 11: Imbalance Prices IMP (OTA) and SMP (ΟΤΣ) Variation

In terms of cash-flow, the revenues of conventional technology producers (excluding RES) resulting from the resolution of the DAS between January and October 2020 amounted to € 1 billion, showing a significant decrease compared to 2019, during which the equivalent revenues were € 1.76 billion. Specifically, in 2020, the revenues resulting from the resolution of the DAS significantly decreased for PPC (€573 million compared to €1.19 billion in 2019), while for the Independent Producers revenues were €429 million (compared to €577 million in 2019).[18]

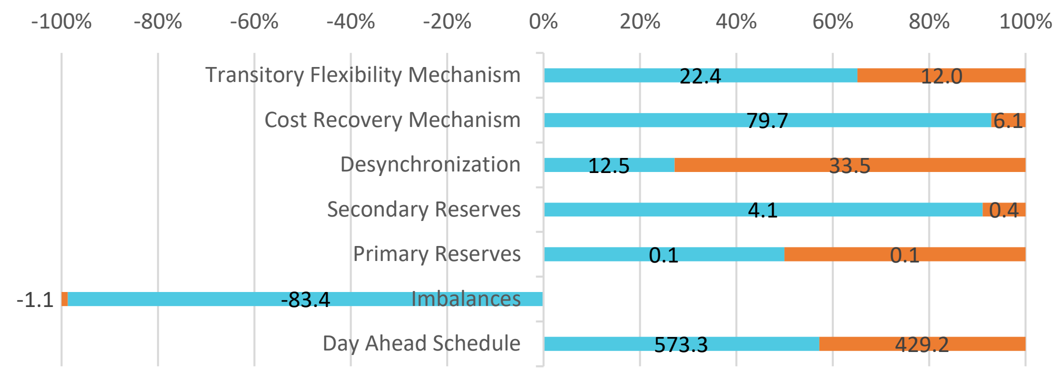
The ex-post clearances carried out by the TSO (ADMIE) amounted to € 86 million compared to € 141 million in 2019.[18]

The revenues from the mechanism for the recuperation of marginal cost amounted to € 86 million for all producers in 2020, compared to € 69 million in 2019.[18] One additional revenue source for August, September and October of 2020 for the producers was the transitory flexibility mechanism, the revenues of which amounted to € 34 million for producers, compared to € 41 million in 2019.

Therefore, the DAS represents 92% of the total revenues of the electricity broken down to 94% for PPC and 89% for the independent producers.[20]

[18] All these figures concern the period from January to October 2020 compared to the same period of 2019.

[20] In 2018 the new Transitional Flexible Remuneration Mechanism became operational. The European Commission, after taking into consideration the constant need for flexible capacity in the System and the situation of the Greek Electricity Wholesale Market, approved the implementation of the new Mechanism founded under Law 4559/2018 (Gazette A΄ 142/03.08.2018) which became operational for the period from 03.08.2018 to 31.12.2019. RAE proceeded, upon a proposal by ADMIE, to the amendment of System's Network Code. The main difference between the two mechanisms is the introduction of bidding procedure for the setting of units' remuneration.



	Day Ahead Schedule	Imbalances	Primary Reserves	Secondary Reserves	Desynchronization	Cost Recovery Mechanism	Transitory Flexibility Mechanism
PPC	573.3	-83.4	0.1	4.1	12.5	79.7	22.4
IPPs	429.2	-1.1	0.1	0.4	33.5	6.1	12.0

PPC IPPs

Figure 12: Generators' Revenue by Source for the year 2020 under the Mandatory Pool – DAS model (in mil. and in %, January – October 2020)

Target Model (1.11.2020 to 31.12.2021)

During November and December, the sources of the cash-flows for the producers were different from those under the Mandatory Pool – DAS model, as from 1 November 2020 the operation of the electricity market is governed by the principles of the Target Model. The cash-flows of Cost Recovery Mechanism and Desynchronization ceased with the operation of the Target Model.

In November, the average MCPs in the successive clearing of the relevant markets were € 52.66 / MWh, € 53.21 / MWh, € 51.84 / MWh and € 56.03 / MWh for the Day-Ahead Market and three local intraday auctions (LIDAs)respectively. The average MCP at the second LIDA decreased by -3% compared to the average MCP at the first LIDA and finally, the average MCP at the third LIDA is increased by 8% compared to the average MCP of the second LIDA.

In December, the average Market Clearing Prices (MCPs) in the successive clearing of the relevant markets amounted to € 58.93 / MWh, € 60.26 / MWh, € 59.09 / MWh and € 54.98 / MWh for the Day-ahead Market (DAM) and the three Local Intra Day Auctions (LIDAs) respectively. The average MCP in the second LIDA is reduced by -2% compared to the average MCP in the first LIDA and finally, the average MCP in the third LIDA is reduced by 7% compared to the second LIDA.

Figures 13 to 17 below present the MCPs for DAM and LIDAs and their respective duration curves.

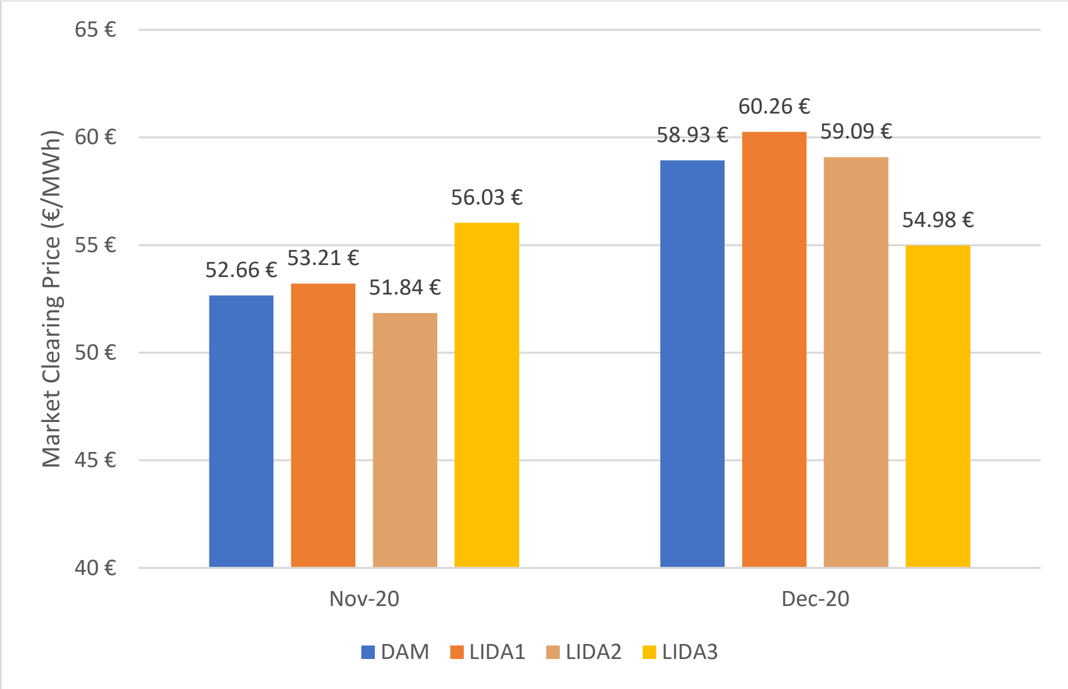


Figure 13: Day-ahead and Intraday Markey Clearing Prices for November and December 2020

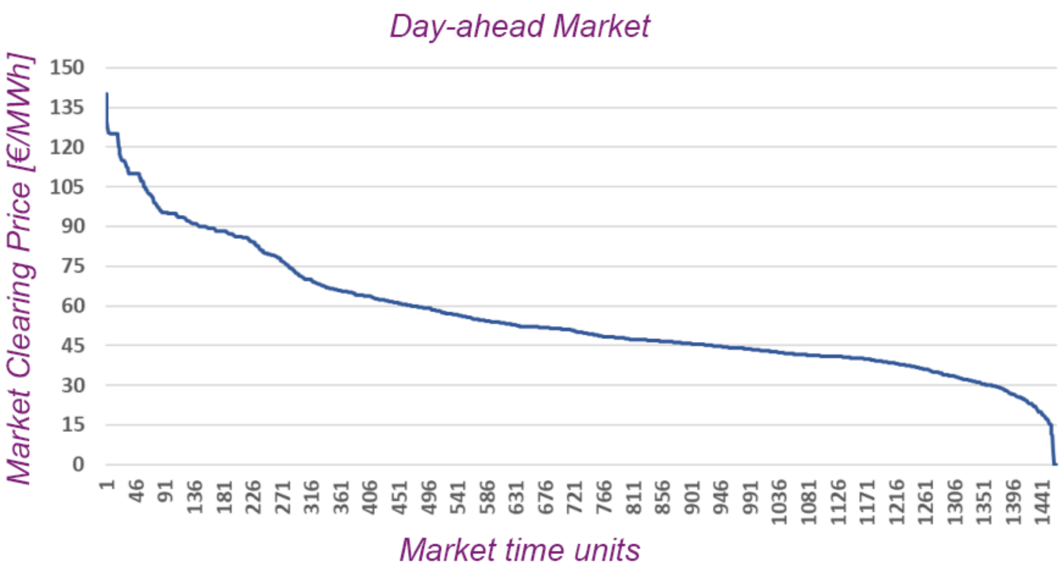


Figure 14: DAM Duration Curve (November-December 2020)

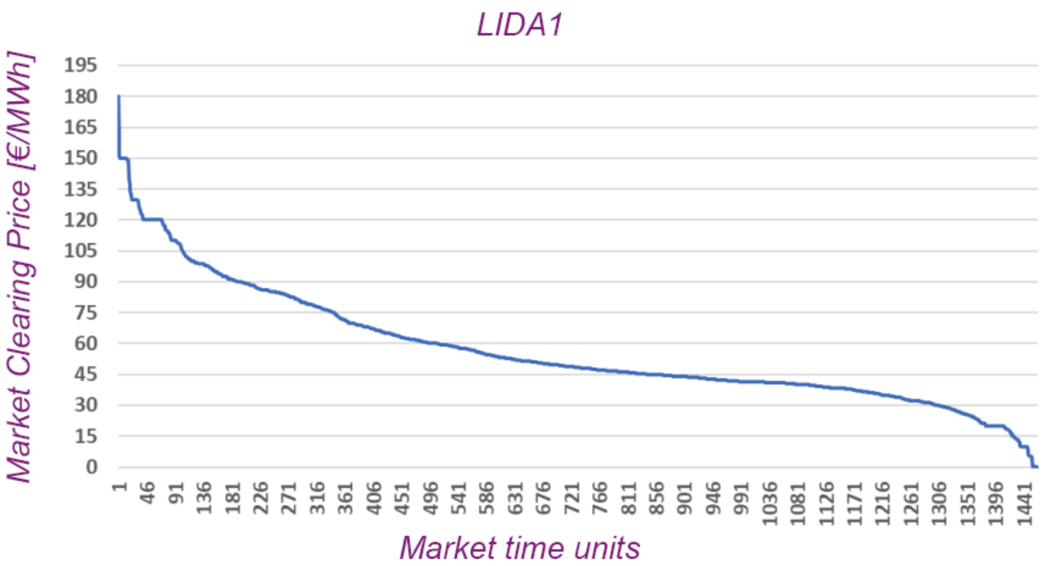


Figure 15: LIDA1 Duration Curve (November-December 2020)

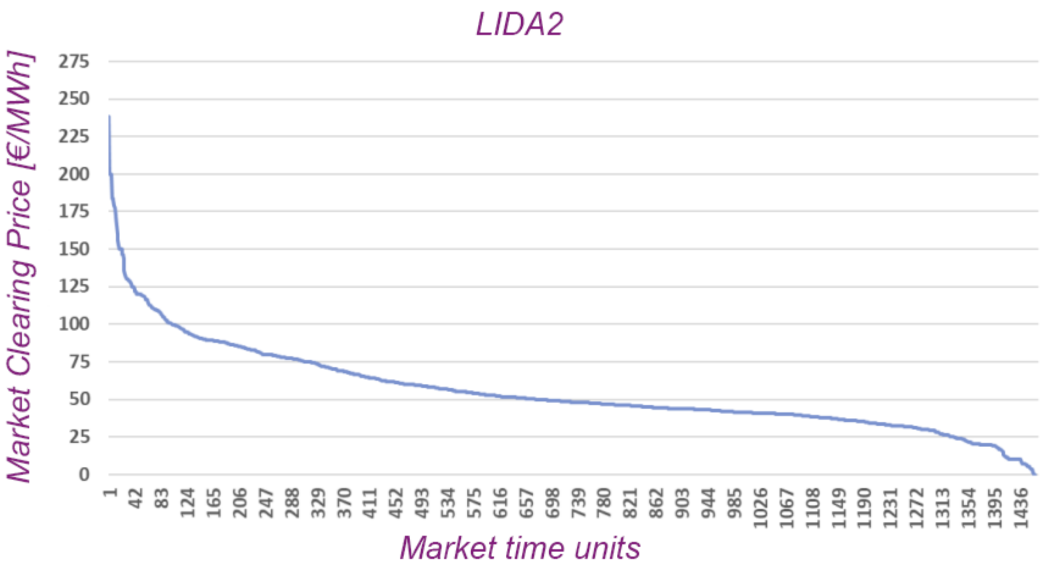


Figure 16: LIDA2 Duration Curve (November-December 2020)

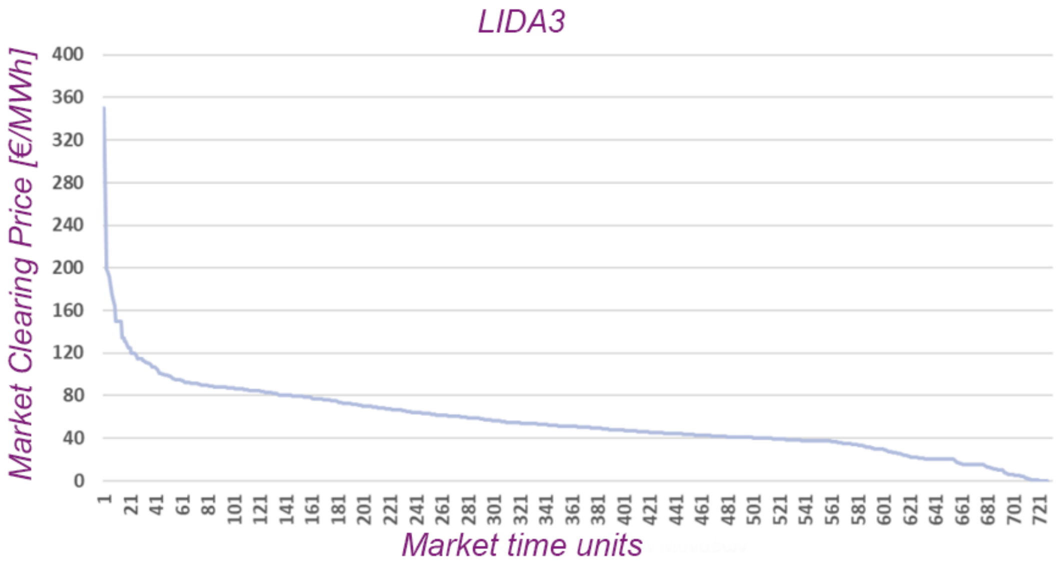
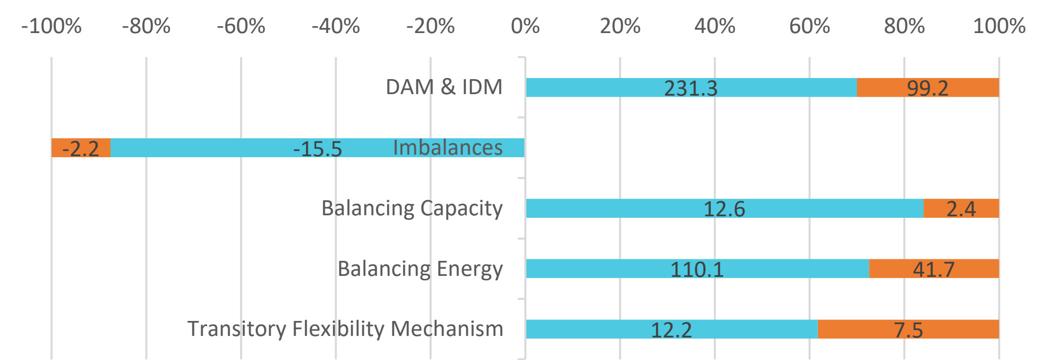


Figure 17: LIDA3 Duration Curve (November-December 2020)

Revenues from Day-ahead and Intraday Markets accounted for 66% of the total revenues of all producers (66% for PPC and 67% for the other independent producers). Revenues from the Balancing market accounted for 30% of revenues for all producers (31% for PPC and 28% for the other independent producers). An additional source of income for producers during November and December was the Transitory Flexibility Mechanism. The revenues from the mechanism are estimated at € 19.69 million for all producers, of which € 12.16 million correspond to PPC and € 7.53 million to independent producers.



	Transitory Flexibility Mechanism	Balancing Energy	Balancing Capacity	Imbalances	DAM & IDM
PPC	12.2	110.1	12.6	-15.5	231.3
IPPs	7.5	41.7	2.4	-2.2	99.2

PPC IPPs

Figure 18: Generators' Revenue by Source for the year 2020 under the Target Model (in mil. and in %, November – December 2020)

3.2.1.7. Monitoring of transparency

Following the transparency requirements prescribed in the Rulebooks and Network Codes governing the operation of the new electricity markets, the Hellenic Energy Exchange and the TSO publish daily detailed market data related to the day-ahead, intraday markets, market coupling results and the balancing markets respectively. The published data are not confined to hourly levels of prices and key fundamentals. Both HENEX and ADMIE upload Excel files with clear quantitative market inputs (except strictly confidential data), as well as all outputs relevant to the cost-minimization algorithms that each operator solves.

In this context, ADMIE publishes daily forecasts for various market inputs, including demand and renewable production (across technology categories), plant availability declarations, mandatory water declarations submitted by PPC on a weekly basis (forecasts or metered data), reserve requirements, long-term interconnection capacity rights and NTC values. Apart from market inputs, the TSO also publishes the real-time plant schedule (DS), solved with the TSO's demand forecast and with network constraints more explicitly incorporated. This schedule is obtained initially on a day-ahead basis and, subsequently, gets updated within the day. In addition, ADMIE publishes the outcomes of the ex-post market clearing obtained with metered data (instead of predicted values) for the various inputs.

After the implementation of Target Model HENEX publishes the daily, weekly and monthly quantitative data related to day-ahead, intraday and derivative markets. Monthly energy reports focusing on production allocation, fuel market shares and demand segmentation, but not on prices, are also published on the TSO's website.

At the beginning of the fourth quarter of 2020, RAE put into public consultation the framework regarding the general principles, methodologies and indicators that will govern the Mechanism for Monitoring and Surveillance of the competition in the Greek electricity and gas markets. Taking into account the points raised by the consultant, who was awarded a relevant contract by RAE[22] as well as the urgent need for effective monitoring of the competition conditions and the behaviors of energy companies, RAE formulated the proposed mechanism, which is based on two pillars, the Market Monitoring Mechanism (MMM) and the Market Surveillance Mechanism (MSM), as well as a distinct component, related to the applied Methodology for the available capacity (CHARYBDIS).

In particular, the text of the public consultation explained that the MMM seeks, through structural indicators and conduct/performance indicators, to assess its level of concentration and the market power of each participant, while the MSM focuses on identifying and then preventing anti-competitive strategies implemented by participants due to their specific power in the relevant market. Furthermore, RAE presented the framework of the "CHARYBDIS" Methodology, which, taking into account the Available Capacity (and not the offered or generated electricity) as well as data from the Integrated Scheduling Process (ISP), will calculate a series of concentration indicators, which will focus

22 In 2019, RAE announced a tender for the provision of consulting services for the identification, development and implementation of the appropriate methods, rules and monitoring tools of the Electricity Wholesale Market under the Target Model.

-at the time- on the Day-ahead Market of the Wholesale Electricity Market and on long-term / medium-term gas supply contracts at the NNGS Entry Points.

The above methodology seeks to capture on the one hand the level of market concentration and on the other hand, the market power of each participant, in a coherent and uniform way, through the application of four thresholds. It is pointed out that the application of the Methodology aims at capturing the market power/influence of each Participant not only ex post but, gradually, and ex ante, taking into account the provisions of article 125 of Law 4549/2018, as well as those provided in sub-paragraph B2, of article 2 of Part B of Law 4336/2015.

Following the above developments, RAE issued Decision 1451/2020 on the monitoring and supervision of Electricity Markets. This decision specifies the data of the Monitoring and Supervision Mechanism of the Day-ahead market, the Intraday Market and the Balancing Market that the Authority will receive from the network operators and restores the application of the methodology used to calculate the variable cost of Hydroelectric Power Plants. It is worth noting that already from the beginning of the Target Model in Greece, RAE is conducting its own assessments which are related to the above decision, based on data provided by HENEX and IPTO.

3.2.1.8. REMIT (EU Regulation 1227/2011)

Furthermore, as the Greek NRA is responsible for the application of REMIT Regulation in the energy wholesale markets in the country, RAE has collaborated with the Agency for the Cooperation of Energy Regulators (ACER) and with other European NRAs towards a common understanding on the administration and methodology to be followed regarding the identification, investigation and sanctioning of REMIT breaches. In parallel, RAE has worked on capacity building among its staff, especially about market participants' registration process and data collection.

More specifically, under the EU regulation 1227/2011 on wholesale markets integrity and transparency, market participants entering transactions, which are required to be reported to the Agency shall register with the relevant National Regulatory Authority (NRA). The requirement to register applies to any person, legal or natural.[23]

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[23] Pursuant to the provisions of implementing Regulation 1348/2014, NRAs shall establish national registers of market participants. This means that each NRA had to establish a registration system no later than three months after the adoption of the European Commission's implementing acts, i.e. counting from 17 December 2014, to enable market participants to provide their registration information to that NRA. NRAs can, if they wish, open the registration process to market participants also earlier. NRAs are free to use whatever system they consider most appropriate for their market.
The Agency developed the Centralized European Register for Wholesale Energy Market participants (CEREMP) to establish the European register of market participants in natural gas and electricity markets. This system is also available to NRAs as a means for registering market participants in their own Member State. RAE has chosen the option to use CEREMP platform and not to develop its own registration system for cost limitation reasons. Accordingly, RAE signed a Service Legal Agreement, SLA with ACER to use CEREMP platform, in 2014. Additionally, RAE signed with ACER a Memorandum of Understanding on the sharing of information under REMIT. Finally, RAE successfully completed the registration of all market participants in electricity and natural gas markets, in September 2015, and all the requirements for the reporting of market participants' standard contracts transactions, on 7th October 2015.

The reporting of market participants' transactions take place through the Registered Reporting Mechanisms (RRM) which have been certified by RAE.

3.2.1.9. Monitoring the effectiveness of market opening and competition

Methods, rules and monitoring tools of the Electricity Wholesale Market under the Target Model

Ahead of the full implementation of the EU Target Model, it was deemed appropriate to review and repeal national regulatory rules that might cause distortions in pricing under the new operating framework of the domestic wholesale electricity market. In this context, it was decided to abolish the ex-ante regulatory tools to reduce the market power and prevent the possible abuse of the dominant position, such as the rule of Minimum Variable Cost of Thermal Power Plants or the limit of the transaction orders of Thermal Power Plants.

Given the abolition of the existing ex-ante regulatory tools, there is an urgent need to develop and implement effective processes to monitor the operation of the wholesale electricity market at the ex-post level, by establishing new mechanisms in the market segments (future, day-ahead, intra-day, balancing), and data recording mechanisms in pre-determined time periods. Similarly to the power generators, the same need arises for the effective supervision of all the market participants (suppliers, traders, aggregators etc.), as their wider potential to participate in distinct markets and different time periods, in addition to their ability to practice a variety of strategies when submitting bids, also makes it easier for them to manipulate the market outcomes.

In the light of the above, a new monitoring mechanism was deemed necessary to ensure a competitive and health market. This project will aim to record and analyze the structure of the new Greek electricity market under the Target Model, and to identify and develop the appropriate tools, methods and indicators, which would allow RAE, to identify abusive practices prone to market manipulation (through systematic selling below cost, resulting in false and misleading signals about the supply, demand or the price of energy products). The above tools, methods and indicators should be based on the data that HENEX and ADMIE share with RAE, and will enable the regulator to evaluate the commercial strategy of each Participant, after taking into account the laters' degree of vertical integration, the need to offset the risks and the willingness to exercise arbitrage between the four different markets.

In this regard, RAE announced a tender for the provision of consulting services for the identification, development and implementation of the appropriate methods, rules and monitoring tools of the Electricity Wholesale Market under the Target Model within 2019. The results of this action would be used to develop the appropriate conditions in order to ensure transparency and liquidity in the market. These conditions are crucial in ensuring that the market operates efficiently and produces the necessary prices to provide the right signals for investment. In this way, the market is protected from possible distortions, due to stakeholders' behaviour, and becomes more effective. Guaranteeing the maintenance of compensation mechanisms and market liquidity is crucial to attract small market participants.

At the beginning of Q4 of 2020, RAE set the issue of general rules, methodologies and indicators of the Market Monitoring Mechanism for competition in electricity and natural gas markets. After taking into consideration the need for efficient market monitoring, the regulator formed the proposed mechanism which includes a Market Monitoring Mechanism and a Market Surveillance Mechanism. In addition to these, there is a distinct component, concerning an applied methodology for capacity availability

(CHARYBDIS). This methodology tries to depict both market concentration and the capacity of each participant, in order to identify the influence of participants within the market.

RAE, with its Decision 1451/2020 regarding the monitoring of electricity market, specified the data to be collected from the network operators concerning the DAM, IDM and Balancing Market. From its side, RAE conducts analyses based on the data provided by HENEX and IPTO.

Market coupling

Day-Ahead market coupling between Greece and Italy was successfully implemented on 16 December 2020 (Decision 1574/2020 – Gazette B' 5505/2020).[24] Regarding the Day-Ahead market coupling between Greece and Bulgaria, the starting date is scheduled for May 2021. Intraday Market coupling includes Complementary Regional Intra-Day Auctions (CRIDA) and Continuous Trading.

HEnEx, declared that the Greek borders will be integrated to XBID within the "4th wave", which will take place in Q4 of 2021. However, HEnEx mentioned that it will take part in the 3rd wave connection testing, in order to proceed with the necessary amendments, based on the architecture and the rules of the members who have already implemented Day-Ahead market coupling.

For that reason, RAE is working along with ADMIE and HEnEx, to guarantee the participation of Greece to CRIDA, as it will result in a more efficient capacity distribution between Greece and Italy through the HVDC interconnection and it will enhance Intraday market liquidity.

3.2.1.10. Provisional measures for the proper functioning of the Electricity Balancing Market

Following the start of operation of the electricity Target Model, RAE, within the framework of its responsibilities, is monitoring on a continuous basis the operation of the three new spot markets, i.e. DAM, IDM and BAM. In this regard, RAE noticed within the first weeks of operation of the new markets a significant increase in the balancing market costs and in particular in the Financial Neutrality Uplift Account (UA-3) [25].

In particular, the costs of the Balancing Market, during the week 30.11.2020 to 06.12.2020, amounted to unforeseen levels, and in particular they amounted to 36 €/MWh, when during the first four weeks of operation of the Balancing Market the costs of UA-3 were approximately at 5, 12, 16 and 17 €/MWh respectively.

In order to investigate, on the one hand the conditions under which the above, constantly increasing, prices were formulated and on the other hand to prevent possible market manipulation, influence or abuse of dominant position of the electricity generating companies, RAE had taken all necessary steps to thoroughly examine all the parameters and identify the root causes of this market situation, taking

[24] Physical flow delivery date.

[25]The UA-3 Financial Neutrality Uplift Account is used to allocate to Balance Responsible Parties any remaining balance after the calculation of the debits and credits calculated by IPTO for the activated Balancing Energy for manual FRR, the activated Balancing Energy for automatic FRR, the energy activated for purposes other than balancing and Imbalance Settlement.

into account letters, complaints, and requests from participants to the energy regulator for interim measures in the Balancing Market.

In the context of examining the parameters that contributed to the manifested price increase, RAE identified as early as 2021 issues in the following areas:

a) Regarding the bids of the Market Participants and restrictions due to the congested network of Peloponnese

After the implementation of the Target Model, ADMIE S.A. informed RAE of an issue arising from the implementation of the system constraints of the Peloponnese on a systematic basis and requested the completion of the regulatory framework governing the operation of the Balancing Market in order to address these system constraint issues in a uniform manner, reducing the possibility of possible market abuse due to the special geographical location of the electricity generation units.

More specifically, ADMIE S.A. pointed out that the network in the Peloponnese region is congested.[26] For this reason, to ensure the safe operation of the System, energy constraints are applied to these production units. According to the rules of the Target Model, these restrictions are not taken into account in the energy markets of the Energy Exchange (Day-ahead Market and Intraday Market) except in the Balancing Market during its various stages of resolution. The most common limitation is the maximum amount of energy injected by these units per Dispatch Period.

To meet the above constraints, in the Balancing Market the units are redispatched during the stage of the Integrated Scheduling Process (ISP). In this regard, it was not possible to distinguish between the energy activated for balancing purposes and the one activated for other purposes (redispatching for congestions), resulting in the possibility for the electricity generating units in the specific geographical location to take advantage of the constraints of the System to make an arbitrarily high, or correspondingly low bid value (in the case of the downward balancing energy).

According to ADMIE S.A., the constraint due to congestion in the Peloponnese System is expected to be lifted with the completion of construction and commissioning of the 400 kV Megalopolis – System electricity line. The TSO proposed a series of measures to mitigate the market impact until the above line is commissioned. Following a request from the RAE, ADMIE proposed the necessary amendments to the Electricity Balancing Code and, in particular, the addition of a new article to the transitional provisions of the Code which establishes special regulations for the BSPs located within the Peloponnese system. RAE set the above proposal in a public consultation from 11.12.2020 until 16.12.2020.

RAE, in search of a uniform and permanent way of dealing with the issues of system constraints and by taking into account the fact that the redispatching carried out by ADMIE in the Peloponnese region falls within the scope of Article 13 of Regulation (EU) 2019/943 and is subject to the provisions of that article regarding the remuneration mechanism for the redispatch units, requested the TSO to give its Opinion on the effective integration and application of these provisions in the Balancing Code and any relevant regulatory and technical decisions required. In this regard, ADMIE submitted his Opinion and a Proposal

[26] The congested network, due to insufficient transmission capacity 150 kV, is situated South of the Extra High Voltage Centre (EHVC) of Koumoundouros and it includes the electricity generating units Megalopolis 3, Megalopolis 4, Megalopolis 5, Korinthos Power and Ladonas as well as a high number of renewable energy units.

to solve the above issue, which is already being further elaborated by the company in order to formulate a permanent solution to the problem.

b) Regarding the upward and downward bids for volumes of balancing energy

Based on the published records of the requirements of the ISP, RAE observed, starting from the Dispatch Day of 23.10.2020, an increase in the zonal and systemic needs of the Transmission System in Balancing Power in both directions, in relation to the volumes of the required reserves (aFRR, mFRR) that had been announced during the previous period, in the context of the Balancing Market dry run tests. The above needs were required to be met by the BSPs and for this purpose were included as a given in the ISP, according to Articles 41 and 58 of the Balancing Code.

To investigate the above issue, RAE requested ADMIE SA to justify the updated values of the quantities of reserves (aFRR, mFRR) required during the ISP in a clear and reproducible way and to compare the quantities of reserves required during the ISP from the start of operation of the Balancing Market to the real-time system operation as well as calculate usage percentage of the required reserves in real-time. ADMIE SA provided the required justification and benchmarking, accompanied by indicative calculations of the reserve requirements, in order to demonstrate the results of the application of the approved methodology.

At the same time, RAE, recognizing that the provision of the necessary balancing reserves for the continuous restoration of the production-demand balance is crucial for the achievement of smooth system operation and that this process must be achieved with the least possible cost, considered it appropriate to investigate the use of methodologies and dynamic models, in relation to the already approved methodology. In this regard, RAE assigned the elaboration of a study to an external consultant on the use of possible methods for the dynamic reserve sizing and their potential application in the Greek Balancing Market. A second study that will provide an overview of modern Capacity Remuneration Mechanisms and their basic design principles will be also carried out by the consultant.[27]

Regarding the large volumes of simultaneous activation of upward and downward balancing energy, mainly from the thermal production units, although the electricity imbalances of the system may be much smaller (either positive or negative), RAE considered it practical for ADMIE S.A. to conduct a review of the Methodology and the Optimization Algorithm of the ISP. In particular, the TSO was invited to consider the effect of introduction of additional terms/parameters in the ISP function on the simultaneous activation of upward and downward balancing energy that will "penalize" the significant differences between the Market Schedules and the ISPs, and consequently to examine the necessity of redefining the Methodology and the Optimization Algorithm of the ISP.

In addition, RAE, in order to address the rising costs of the Balancing Market and to examine all possible causes, considered it appropriate to simultaneously explore ways to reduce the volume of simultaneous activations of upward and downward balancing energy. To this end, with its Decision 1601/2020, RAE awarded a contract to an external consultant to investigate the aforementioned issue.

According to ADMIE SA, the issue of counter balancing activations is a result of the way the Market Participants submit their bids and not a matter of the ISP algorithm, as the observed counter activation emerges as the most economical based on the offers. Although this phenomenon, according to ADMIE SA, is not caused by a technical problem of the ISP algorithm, two alternative approaches have been

[27] Both reports are available online at https://www.rae.gr/

put into investigation in the framework of the market test platform, and the results of the investigation will be brought to the attention of RAE and if it will be deemed that this implementation will improve the results of the ISP, ADMIE will submit a relevant proposal for the amendment of the Balancing Code, as well as the ISP process.

c) Regarding the submission of a single step bid for the Technically Minimum Production in balancing energy and the Interruptibility Service

RAE brought to the attention of ADMIE two additional and important issues. The first concerned the provision of the technical minimum of the generation units for a downward balancing bid in a single step since the existence of thermal unit charge steps between the technically minimum and zero is technically impossible. Based on the data for the period 01.11.2020-29.11.2020 which was analyzed by RAE and it was concluded that for more than 90 cases, the method of submission of bid offers in more than one step affects the allocation so that the respective BSPs determine the marginal prices of the downward mFRR. ADMIE, due to the need for immediate introduction of special regulation to resolve this issue, submitted a relevant proposal to amend the Balancing Code and the technical decision of the ISP mechanism in the beginning of 2021.

Furthermore, in accordance with Commission Decision C (2020) 6658 final / 29.09.2020, the industrial consumers benefiting from the interruptibility scheme are obliged to participate in the balancing market (par. 28), while the above mentioned decision also recognized the need for flexibility provided by this service to the network operator (“Therefore, the only possible way for the TSO to make use of the flexibility that energy consumers have to offer - the necessity of which has been established in Section 3.2.2 of this decision - is by way of a scheme outside the market, that will operate for a limited period, as a “bridge mechanism” [see recital (19)] until demand response is able to participate in the balancing market . », Par. 73). RAE considered it necessary, especially in the present circumstances, for the TSO to examine thoroughly the possible activation of the above mentioned interruptibility service. In this regard, article 5 par. 1 of the Ministerial Decision on the interruptible Load Service (ILS) provides that “1. The TSO may issue ILS Orders when one or more of the following cases occur: […] v. There is a sharp change in the generation or demand of electricity in the Interconnected System. ". The TSO has submitted its views regarding the activation of the Type 2 of the ILS and although he does not consider, due to technical constraints, that it is possible to integrate the Type 2 of the ILS directly into the Balancing Market, the TSO will examine the possibility for its integration in a mechanism related to the redispatched energy.

d) Regarding the appropriateness of setting caps on bids for upward and downward balancing energy and balancing capacity

RAE, in parallel with the investigation of all issues related to the operation of the Balancing Market, within the framework of its competences, also investigated the need to take interim measures, which will focus on maintaining liquidity and competition in the markets. These measures will be implemented temporarily, in order for RAE to complete the investigation of the multidimensional issue of the operation of the Balancing Market, in connection with the examination of the operation of the Day-ahead Market and the Intraday Market, in order to proceed with the necessary actions, ie in the exercise of its regulatory and / or sanctioning responsibilities.

In this regard, RAE conducted a Public Consultation from 17.12.2020 to 22.12.2020 regarding the feasibility of setting caps on the submitted bids for upward and downward balancing energy and balancing capacity, for a transitional period of three (3) months. Within the framework of the public consultation, RAE received comments from twelve participants.

Taking into account the above developments, RAE with its Decision 54/2021 amended the Balancing Code and introduced the following changes: a) the submission of bids with negative prices for balancing energy was suspended until the resolution of the congestion issue of the Peloponnese network and b) the introduction of a requirement that the quantity of the first step of the balancing energy upward bid offer (or the quantity of the last step of the downward bid, respectively) should coincide with the Technical Minimum generation in MW.

3.2.2. Retail market

The description of the retail electricity market is executed separately per Interconnected and Non-Interconnected System, taking into consideration that since 01.01.2018 and according to RAE's Decision 908/2017 (Gazette 4461 B'/19.12.2017), the full liberalization of electricity supply was institutionalized in Non-Interconnected Islands (NIIs).

3.2.2.1. Description of the retail market

Electricity consumption for 2020 sharply decreased (-4.4%) compared to 2019 levels in the Interconnected System (44,906 GWh, compared to 46,969 GWh), which is attributed to the effects of COVID-19 pandemic and the imposition of a "lockdown" at national level for long periods of time. This unprecedented situation resulted in a small increase in consumption in the household sector during the months of the lockdown, but this change is not reflected in the year-on-year consumption of household customers (increase by 1% compared to 2019 levels). At the same time, there was a significant decrease in the consumption of all other categories of customers, such as Low (LV) and Medium Voltage (MV) commercial and industrial customers (-7%), other LV and MV customers (-3%) and High Voltage (HV) customers (-8%). Table 13 illustrates the evolution of electricity consumption in the Interconnected System during the last 8 years (2013-2020), according to the information published by the relevant Operators (DEDDIE S.A. and ADMIE S.A.).

	Year	Domestic customers	Small Industrial & Commercial customers	Other (e.g. agriculture, public, traction)	Large Industrial Customers	TOTAL
LV	2013	15,973	9,560	3,640	-	**29,173**
	2014	15,569	9,523	3,735	-	**28,827**
	2015	15,817	9,245	3,277	-	**28,339**
	2016	15,048	9,192	3,385	-	**27,625**
	2017	15,651	9,344	3,285	-	**28,280**
	2018	14,767	9,324	2,983	-	**27,074**
	2019	15,633	9,735	3,108	-	**28,476**
	2020	15,724	8,806	3,033	-	**27,563**
MV	2013	-	8,904	1,487	-	**10,391**
	2014	-	8,179	1,477	-	**9,656**
	2015	-	8,351	1,473	-	**9,824**

	2016	-	8,643	1,478	-	**10,121**
	2017	-	8,764	1,536	-	**10,300**
	2018	-	9,049	1,486	-	**10,535**
	2019	-	9,040	1,546	-	**10,587**
	2020	-	8,565	1,487	-	**10,052**
HV	2013	-	-	1,168	6,599	**7,767**
	2014	-	-	1,314	6,702	**8,016**
	2015	-	-	1,150	6,805	**7,955**
	2016	-	-	1,115	7,062	**8,177**
	2017	-	-	1,028	7,268	**8,296**
	2018	-	-	937	7,351	**8,288**
	2019	-	-	903	7,003	**7,906**
	2020	-	-	826	6,465	**7,291**
Total	**2013**	**15,973**	**18,464**	**6,295**	**6,599**	**47,331**
	2014	**15,569**	**17,702**	**6,526**	**6,702**	**46,499**
	2015	**15,817**	**17,596**	**5,900**	**6,805**	**46,118**
	2016	**15,048**	**17,835**	**5,978**	**7,062**	**45,923**
	2017	**15,651**	**18,108**	**5,849**	**7,268**	**46,876**
	2018	**14,767**	**18,374**	**5,407**	**7,351**	**45,898**
	2019	**15,633**	**18,775**	**5,557**	**7,003**	**46,969**
	2020	15,724	17,371	5,346	6,465	44,906

Table 13: Evolution of electricity consumption in the Interconnected System in GWh (2013-2020)

Source: DEDDIE’s data and ADMIE’s monthly energy reports

Regarding the activity in the supply market of the Interconnected System in 2020, the competition remained at the same level as in 2019, without significant problems affecting the smooth supply of electricity customers. Within 2020, there were no new entrants in the supply sector while, on the contrary, three (3) companies ceased their supply activity: ECONOMIC GROWTH, INTERBETON and NOVAERA.

Also, regarding the Last Resort and Universal services, in 2020 and specifically from 31.12.2019, the Last Resort service was activated, following the cease of supply activity of "GREEK ENVIRONMENTAL & ENERGY NETWORK S.A." commonly known as "GREEN S.A." and consequently its removal from the Load Representatives Registry of NIIs.[30] In addition, from 23.06.2020 the provision of Universal Service was modified, with the appointment of five (5) Universal Service Providers[31] against one (1) during 2019.

Therefore, during 2020, a total of 31 Suppliers were active in the retail electricity market of the Interconnected System, including the five (5) Universal Service Providers and the Supplier of Last Resort:

	Electricity Suppling Company
1.	VIENER
2.	VIOLAR
3.	PPC
4.	ECONOMIC GROWTH[32]
5.	ELINOIL
6.	ELTA
7.	ELPEDISON
8.	ENEL GREEN POWER
9.	ZENITH
10.	WE ENERGY
11.	NATURAL GAS
12.	GREEN
13.	HERON
14.	TH. SOUMPASIS
15.	INTERBETON
16.	KEN
17.	K. V. MARKOU
18.	PROTERGIA
19.	NOVAERA
20.	NRG
21.	OTE ESTATE

[30] GREEN S.A was supplying electricity to the costumers of Crete, Rhodes, Kos-Kalymnos, Lesvos and Samos.
[31] According to Ministerial Decision YPEN/GDE/57469/2612/2020 (Gazette 2400/B/17-6-2020)
[32] The company "ECONOMIC GROWTH S.A." remained an active Supplier until 30.04.2020.

22.	PETROGAZ
23.	Universal Service Provider (PPC S.A.)
24.	Universal Service Provider (MYTILINEOS S.A.)
25.	Universal Service Provider (ELPEDISON S.A.)
26.	Universal Service Provider (HERON S.A.)
27.	Universal Service Provider (NRG S.A.)
28.	Supplier of Last Resort (SLR)
29.	VOLTERRA
30.	VOLTON
31.	WATT & VOLT

Table 14: Companies active in the electricity supply market (2020)

In December 2019, forty-three (49) supply licenses and fifty-six (61) electricity trading licenses were valid.

Throughout 2020, RAE assessed:

• (3) requests for supply licenses, (10) requests for amendments of electricity supply licenses, (7) requests for electricity trading licenses, (5) requests for amendments of trading licenses and (1) request for amendment of an electricity generation license of a natural gas CCGT unit. After assessing these requests, RAE issued (2) decisions to grant a supply license, (4) decisions to grant an electricity trading license, (3) decisions amending supply licenses, (1) decision amending a trading license, and (1) decision amending an electricity generation license of a natural gas CCGT unit.

• (1) request for a supply license, (7) requests for amendment of electricity supply license, (3) requests for trading licenses and (4) requests for amendment of trading licenses are still pending for a final decision.

• (1) request for amendment of an electricity supply license is still pending from previous years.

Electromobility and biofuels in Greece

The regulatory framework for the establishment of Electrical Charging infrastructure, both in terms of quantity of charging points as well as their density in terms of spatial location, remains a challenge for the development of a national electric vehicle market.

Since 2014, the institutional framework for recharging infrastructure has significantly evolved in both Europe and Greece. Regarding the main legal framework, the EU Directive 2014/94/EU on the deployment of alternative fuels infrastructure (AFID) foresees the establishment of a common framework for the development of alternative fuels infrastructure in the EU in order to minimize the dependence on oil and to limit the environmental consequences in the transportation sector.

In addition to that, AFID Directive underlines that (a) Operators of recharging points accessible to the public are free to purchase electricity from any supplier, (b) Operators of publicly accessible recharging points can provide recharging services to customers on a contractual basis, on behalf of other service providers, and (c) Smart metering systems are used, if it is technically feasible and economically reasonable, for recharging in publicly accessible recharging points. During the past few years, a number of legislative provisions were incorporated in the Greek legal system, starting with Law 4277/2014 (amendment of Law 4001/2011 which prescribes the definition of Charging Point Operator. This Law foresees the adoption of a Joint Ministerial Decision following an opinion of the RAE on the role and obligations of operators of recharging points.

Law 4439/2016 incorporated the European Directive (EU Directive 2014/94/EU) and Law 4513/2018 allowed the installation of EV charging points in public areas. On 31 October 2017, by Joint Ministerial Decision 77226/1, the National Policy Framework for the Development of Alternative Fuels Infrastructure Market in the transportation sector was established as required by Article 3 of Directive 2014/94/EU.

In addition, to further strengthen the electromobility sector, RAE submitted a recommendation to the Minister Energy to clarify in Law 4001/2011 that no supply license or trading license should be required for the operators of electric vehicle recharging points to conduct their operations.

In 2018, RAE raised several key issues in a public consultation to clarify and delineate the institutional and operational framework for the integration of electric vehicle recharging infrastructure in Greece. Fifteen (15) participants submitted comments to RAE on the above public consultation.

RAE, after processing the comments submitted in the public consultation and considering the provisions of par. 2, Article 134 of Law 4001/2011, as amended by Article 53, par. 3 of Law 4277/2014, as well as provisions of Law 4493/2016, issued its Opinion 7/27.02.2019 on the operation of electric vehicles' Charging Stations (definitions on operation, market structure, interoperability, creation of infrastructure register, tariffs, metering, etc.). After RAE's Opinion, a ministerial special committee was created aiming at promoting e-mobility in Greece in October 2019.

Finally, RAE's Opinion 7/2019 was incorporated in Law 4710/2020 "Promotion of electromobility and other provisions" (Gazette 142 A'/23.07.2020), which includes incentives for the development of e-mobility, data on the organization of the e-mobility market, spatial, urban and other regulations for the installation of charging infrastructure and, finally, organizational and other provisions for e-mobility implementation in the Greek territory. Furthermore, the Joint Ministerial Decision No. ΥΠΕΝ/ΔΜΕΑΑΠ/93764/396/2020 (Gazette B' 4380/05.10.2020) "Technical Instructions for the Electric Vehicles Charging Plans " was issued for the positioning of publicly accessible recharging points within the administrative boundaries of municipalities, as defined in article 17 of Law 4710/2020.

Also, in the context of the elaboration of the National Energy and Climate Plan (NECP), it was deemed appropriate to prepare a specialized technical study focused on the economic, regulatory and infrastructure development measures to promote e-mobility, and the use of biofuels in the transport sector in Greece during the decade 2020-2030. RAE, within the framework of its responsibilities, deriving from law 4001/2011, and from its obligations imposed by EU law, with Decision 897/2019, assigned the elaboration of the "E-mobility and transportation using RES energy development plan" study to an external consultant. The study was completed in December 2019. The economic measures to promote e-mobility included subsidies for the purchase of small electric cars, increase of road tax for conventional diesel and gasoline cars, increase of the excise tax on conventional fuels, as well as financial incentives for the penetration of e-mobility in the private sector. The regulatory measures in the field of e-mobility included, inter alia, measures to ban the circulation of old vehicle technologies in city centers, to exclude electric vehicles from the "Athens ring" and to provide special parking spaces for electric vehicles. The infrastructure development measures concern the creation of charging points in various parts of the urban centers. The economic measures to promote biofuels in the transport energy mix concerned boasting investments for domestic production of advanced biofuels, as well as the financing of research programs for supply planning and sustainable production of advanced biofuels. Regulatory measures in this regard included the establishment of minimum limits for mixing advanced biofuels with the corresponding petroleum products, the adoption of regulations on the maximum mixing rate of the 1st generation biofuels in accordance with the revised Renewable Energy Directive (EU) 2018/2001, the determination of land lots suitable for the cultivation of lignocellulosic raw materials and special regulations regarding the pricing of advanced biofuels, and contracts to ensure the absorption of agricultural production of biomass raw materials. Finally, the measures included proposals aiming at the development of relevant infrastructure to produce advanced biofuels, appropriate planning in the supply chains, as well as special tenders to subsidize similar infrastructure projects.

Throughout 2020, RAE cooperated with DEDDIE, the Ministry of Energy and other stakeholders in matters within its competence for the required amendments to the regulatory framework, with a view to promoting e-mobility in Greece.

The main entities involved in the e-mobility market in Greece as well as their definitions are summarized in Table 15. Furthermore, Figures 19 and 20 provide a description of the e-mobility model of Greece for EV users that have not signed a contract with an Electromobility Service Provider and for users with such contracts respectively.

Term	Definition
Charging Point Operator	The natural or legal person that is active in the of operation of charging infrastructure for which electricity is supplied in order to provide EV charging services.
Electromobility Service Provider	A sole proprietorship or a legal entity that is registered in the General Commercial Registry in order to provide e-mobility services to contracted parties.
Owner of the EV charging infrastructure	A natural or legal person who owns a EV charging point.
Processor of electromobility transactions	A sole proprietorship or legal entity registered in the General Commercial Registry, with the aim to develop and operate information systems to facilitate data exchange and the processing of financial transaction between the Charging Point Operators and the Electromobility service providers in order to achieve the interoperability of the charging infrastructure.
Electromobility load aggregator	A legal entity which undertakes the aggregation of the load of the electric vehicles, which are connected to the electricity network and thus participate in the electricity market, and provides services to the DSO.
Electricity supplier	The natural or legal person that undertakes the activity of electricity supply (including supply of electricity to the EV charging points).
Regulatory Authority for Energy	The energy regulator is responsible for the development of the regulatory framework of electromobility. Cooperation between the Ministry and the NRA is foreseen for issues that fall under its competence and relate to the energy market. To this end, RAE provides its Opinion on various electromobility issues to the Ministry of Energy.

Local authorities (Municipalities)	Local authorities are responsible to prepare an Electric Vehicle Charging Plans, which will include possible locations for the development of sufficient number of publicly accessible EV charging points and public parking spaces for EVs. In addition, they are responsible to hold an open tender for the development of the EV recharging infrastructure. Any party that is interested in participating in the market can participate these tenders except the DSOs.

Table 15: Entities involved in the e-mobility market of Greece and their definitions

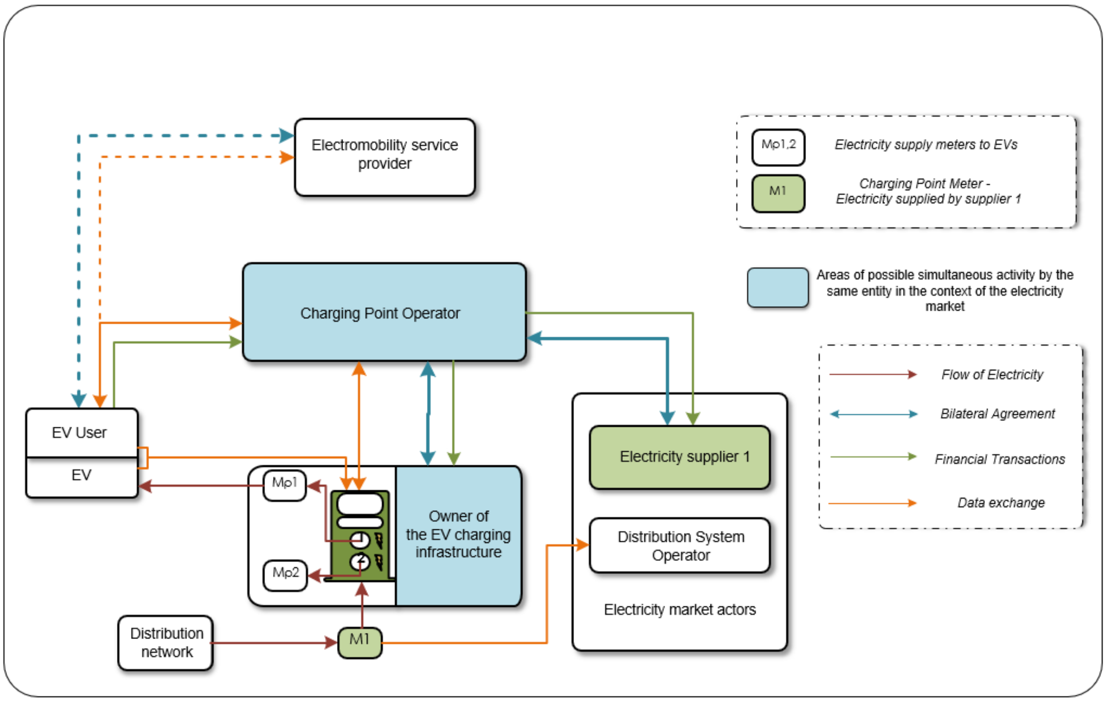

Figure 19: Description of the e-mobility market model in Greece

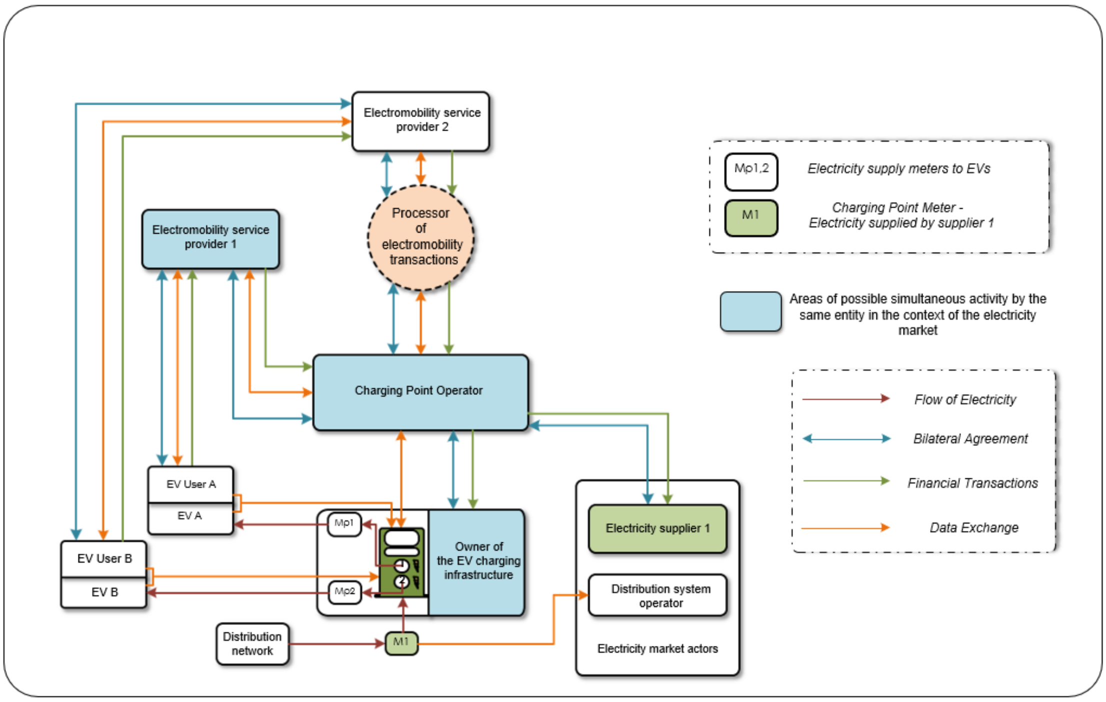

Figure 20: Description of the e-mobility market model in Greece for EV users that have a signed contract with an Electromobility Service Provider

Support of Suppliers and Consumers due to COVID-19

RAE, within the framework of its responsibilities, sent a series of letters providing recommendations to the energy companies to proceed with all necessary measures to avoid physical contact with consumers and to implement measures of remote services provision, such as contract conclusion, providing clarifications on the bills, drawing up settlements and other functions, mass turn of consumers towards electronic transactions (electronic payment of bills). Furthermore, RAE recommended the implementation of incentives to strengthen the timely payment of bills by consumers. The Authority also requested that the Suppliers share their cash flows on a weekly basis to better monitor the energy markets during the pandemic.

Finally, RAE's Opinion 07/2020 regarding the adoption of a legislative act, to facilitate electricity Suppliers concerning the payment of regulated tariffs on their part towards the relevant operators due to the pandemic crisis (Legislative Act A 84/13.04.2020). At the end of 2020, RAE gave its Opinion to the Ministry of Energy (Opinion 14/2020) concerning the implementation of interim measures for the deferral of payments of regulated tariffs towards the relevant operators by the Suppliers due to the pandemic crisis until March 2021.

3.2.2.2. Competition and market shares

PPC remained the main supplier in the retail electricity market in 2020, representing 77.8% of the total number of Low and Medium Voltage connections in the Interconnected System at the end of 2020, and (63.2% of the total consumption).

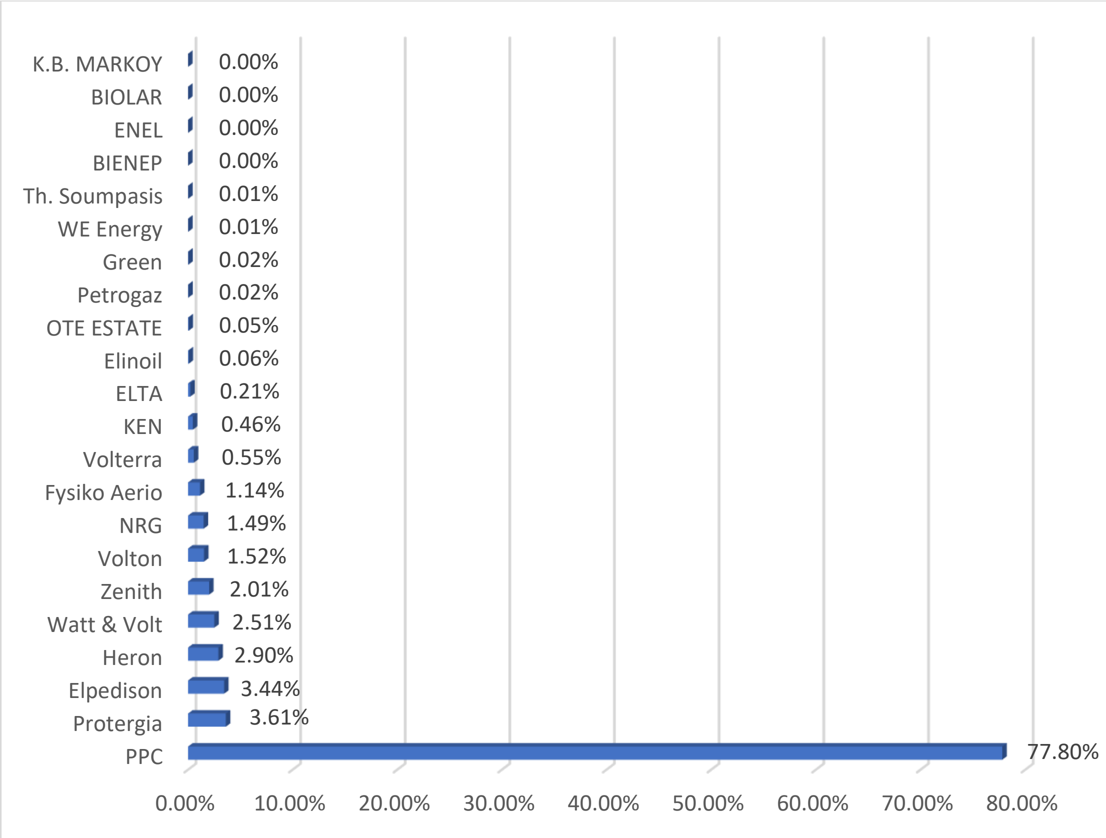

Figure 21: Market shares in Retail Electricity Market based on suppliers' total meter connections in the Interconnected System (2020)

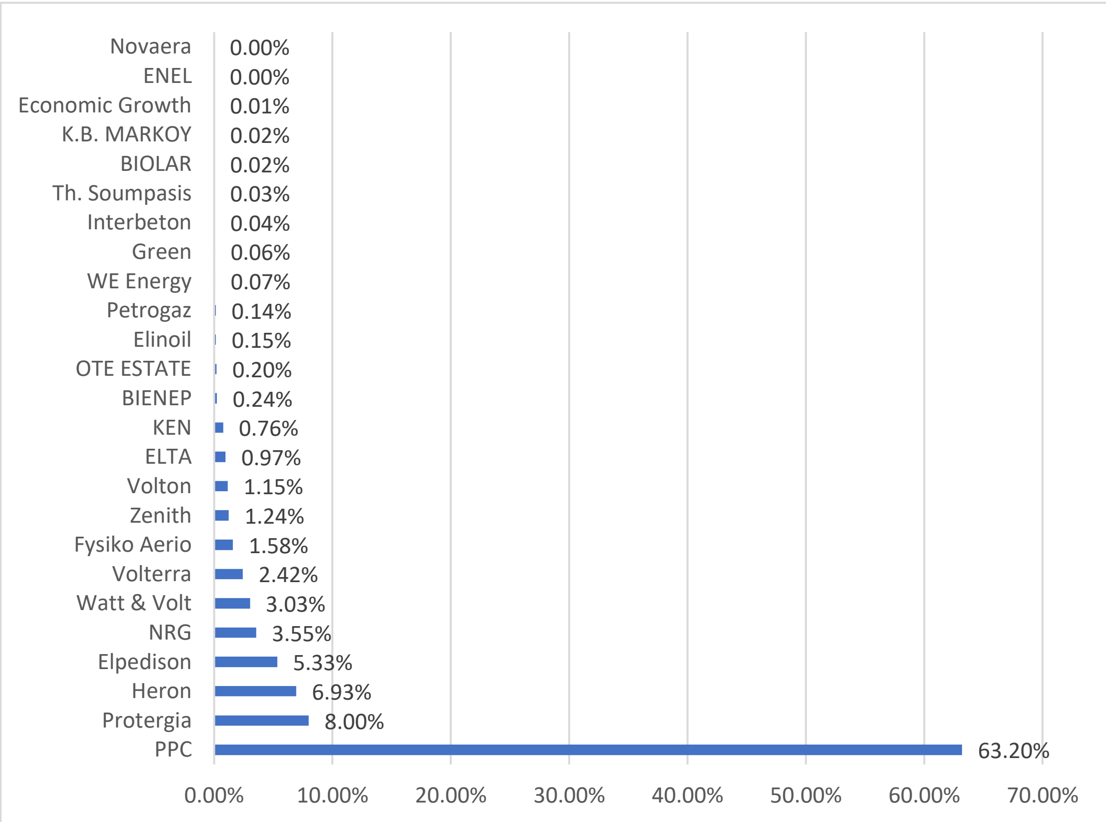

Figure 22: Market shares in Retail Electricity Market based on consumption volume (LV and MV) in the Interconnected System (2020)

The Herfindahl-Hirschman Index (HHI), at the end of 2020 amounted to 4,171 in the interconnected system per volume, surpassing considerably the 2.000 level (of a high concentrated market). However, the HHI is significantly lower than in 2019 (5,167). Regardless of the increasing number of the alternative suppliers over the past years in Greece, the supply market in 2020 remains highly concentrated.

Regarding supplier switching rates, according to HEDNO's data, 7.8% of LV and MV customers in the Interconnected System switched their supplier in 2020 (8.1% of total consumption in the LV and MV market). The same level of supplier switching is observed at both household customers and LV-MV commercial and industrial customers in terms of number of connections. On the other hand, in terms of volume, commercial and industrial customers showed the greatest switching trend. In general, compared to 2019, the switching trend shows a stagnation or slight decrease in terms of number of connections while in terms of volume, the switching trend was excessively upward due to the increase of switching rate for all categories of customers but mainly the LV and MV commercial and industrial customers.

The following table includes data regarding customer switching (LV and MV) in the Interconnected system for 2020 (data by HEDNO):

Customer Category	Number of Customers in the Interconnected System in 31.12.2020	Number of customers that switched supplier in 2020	Switching rates (% in number of customers)	Total Consumption in 2020 (MWh)	Consumption of customers that switched supplier in 2020 (MWh)	Switching rates (% of consumption volume)
Household customers (not including Social Tariff)	4,871,122	423,141	8.69%	13,857,593	495,719	3.58%
Household Customers under Social Tariff	437,137	31	0.01%	1,866,835	27,568	1.48%
Small industrial and commercial customers	1,170,250	103,382	8.83%	8,806,167	925,283	10.51%
Oher LV customers	306,055	2,665	0.87%	3,032,509	23,694	0.78%
Total LV customers	**6,784,564**	**529,219**	**7.80%**	**27,563,105**	**1,472,264**	**5.34%**
Commercial and Industrial customers	9,757	820	8.40%	8,565,062	1,520,466	17.75%
Oher MV customers	1,713	25	1.46%	1,487,193	62,881	4.23%
Total MV customers	11,470	845	7.37%	10,052,255	1,583,346	15.75%
Total number of LV and MV customers	**6,796,034**	**530,064**	**7.80%**	**37,615,360**	**3,055,610**	**8.12%**

Table 16: Number of metering points, consumption volume and switching rates per consumer category in the

interconnected system's electricity retail market (2020)

3.2.2.3. Price Monitoring

Prices for all electricity consumers have been fully liberalized since 01.07.2013. The only regulated tariffs are those under Public Service Obligations, i.e. the Social Tariffs and the prices offered under the Supplier of Last Resort and by the Universal Service Supplier.

Under Law 4001/2011 (Art. 140, par. 6), RAE monitors deregulated retail prices and may intervene ex-post, if an abusive behavior is identified (prices are too high, therefore abusive towards consumers, or too low, therefore abusive towards competitors).

With Decision 692/2011 (and, subsequently, in the new Electricity Supply Code), RAE determined the general principles for tariff setting in the competitive market. Per these principles, tariffs should be simple, transparent, cost-reflective and avoid cross-subsidies; they must take account of consumer category characteristics, offer real choices to the consumers and, where possible, provide incentives for the efficient use of electricity. Special guidelines were provided for large consumers, where it is possible to tailor-make price offers and not to have a general published tariff, by considering the specific characteristics of each customer.

All alternative suppliers publish their tariffs on their websites, while RAE regularly publishes comparative estimates of the 4-monthly bill for residential and small commercial customers under the various tariffs on offer (both from PPC and from the alternative suppliers). RAE continuously monitors suppliers' pricing information to ensure availability and clarity of information, to the benefit of final consumers, while the retail domestic market evolves and matures further.

RAE, in the context of its responsibilities for monitoring and supervision of energy market (Article 22 of Law 4001/2011) and in particular in the context of monitoring the conduction of activities and the compliance with suppliers licenses' obligations (Article 13 of Law 4001/2011, Codes of Electricity and Natural Gas Supply to Customers), as well as given that from 1st January 2018 both electricity retail market in the Non-Interconnected Islands and natural gas retail market have been fully liberated, has further strengthened its monitoring of energy markets, by collecting and processing data of supply and distribution activities of electricity and gas retail energy markets. RAE collects periodically data by active Electricity and Gas Suppliers and Operators on:

- Supply activity of active suppliers of electricity and natural gas
- Distribution activity of operators of electricity and natural gas
- Sustainability financial data of supply and production activities (for enterprises that are active both in production and supply activity)
- Information on complaints and consumer requests

In this context, RAE, at the end of 2018 the developed a financial-methodological tool/application (retail monitoring tool) in order to automate the process of collecting and processing data from suppliers and operators. The tool was completed in the end of 2019 accompanied by the relevant letters and usage manuals which were shared to the Suppliers and electricity and natural gas Operators in 2020. This Tool collects:

1) The supply of electricity and natural gas in the retail market, including detailed information on the bill charges, overdue debts, switching and disconnection applications.

2) Financial viability (total revenues and costs) from the supply and production of electricity, aiming at controlling the profitability of the participants in the relevant retail market.
3) Electricity and natural gas distribution data from the DSOs (number of metering points, consumption per supplier, switching and disconnection applications and order execution for the DSO given by the Suppliers).
4) Data on consumers’ complaints and management of requests

The main objective of the retail monitoring tool is to validate that the Suppliers' tariffs reflect the real cost of supply plus a reasonable profit, to identify any cross-subsidies between tariffs of different customer categories, to avoid discrimination between customers of the same category in order to avoid competition distortion and ensure healthy growth in the energy retail markets. The first implementation of the Tool took place in 2020 when its interoperability was checked and its main strengths and weaknesses were designated. In the last quarter of 2020, the Tool’s required updating procedures were initiated which will be concluded in 2021 when its second edition will be shared to the relevant bodies (electricity and natural gas Suppliers and Operators) with the updated usage manuals.

Tariff deficit

RAE through 2018 and 2019 intensified its effort to monitor also the financial transactions of Retail Market Participants emphasizing on electricity supply (considering that natural gas market was liberalized in the beginning of 2018), and more specifically the implementation of obligations of Suppliers for regulated fees attribution to the relevant Operators. Such tariffs include the RES Levy, the Public Service Obligations (PSO) and of course the Distribution and Transmission Network Tariffs.

In this context, in 2018, RAE examined overdue payments of Retail Market Participants towards Market Operators. Those companies and the three Market Operators (IPTO, HEDNO and DAPEEP) were summoned for a written hearing. RAE published (7) regulatory Decisions inviting electricity suppliers and another (3) Decisions towards the three Market Operators to manage their overdue payments concerning regulated tariffs.[34]

Regarding the RES levy, the levels applied in the past were not enough to cover the total cost of the mechanism for supporting renewable generation (i.e. the feed-in tariff system). A deficit was created, which peaked at around €550m in 2013. The deficit decreased significantly since then until the early months of 2020. The COVID-19 pandemic and the subsequent low energy prices resulted in great revenue losses that fund the RES Special Account. This development resulted in extraordinary measures taken by the Ministry of Energy to deal with the deficit of the account with the least possible impact for the final consumers.[35]

Separate Financial Accounts of Supply Activity of Horizontally Integrated Enterprises

RAE, in the context of its monitoring and supervision responsibilities of the energy market (Article 22 of Law 4001/2011) and, in order to avoid discrimination, cross-subsidies and distortions of competition in retail markets of electricity and natural gas, defined the ‘Guidelines on the Standard Rules of

[34] RAE Decisions towards Suppliers: 1234/2020 & 1630/2020, 1233/2020 & 1631/2020, 1232/2020 & 1632/2020, 1230/2020 & 1633/2020, 1636/2020, 1635/2020, 1634/2020
RAE Decisions towards Market Operators: 1637/2020 (IPTO), 1638/2020 (DAPEEP) and 1629/2020 (HEDNO)
[35] For more information see Section 3.5.5.

Distribution of Assets and Liabilities, as well as Expenditures and Revenues, for the Preparation of Separate Accounts of Supply Activity in Electrical Energy and Natural Gas of Horizontal Integrated Enterprises, according to provisions of Law. 4001/2011' (RAE Decision 541/2019, amending Decision 162/2019, Gazette B' 2155/07.06.2019). More precisely, a Horizontally Integrated Enterprise active in both the supply activity of gas and electricity, is subject to the obligation of maintaining separate financial statements for the performance of these two business segments, being also subject to the rules established by RAE, while having the possibility to maintain consolidated accounts for activities other than the supply of electricity and gas. This division should reflect the asset structure, the demands and the duties of supplying electricity and natural gas as if they were two different enterprises.

Decision 541/2019 was implemented for the first time by all companies during the financial year 2020. Therefore, the result of the implementation of this Decision will be identified in the financial statements to be issued in 2021.

3.3 Security of supply

Pursuant to article 12 of Law 4001/2011, RAE shall monitor the security of energy supply, especially with regard to the balance between supply and demand in the Greek energy market, projected future demand, transmission and distribution projects, the level of maintenance and reliability of transmission and distribution systems, the application of measures to cover peak demand and conditions of the energy market in terms of the facility to develop new power generation potential.

3.3.1. Monitoring the balance of supply and demand – interconnected system

Electricity demand and electricity demand peak

Table 17 represents the evolution of annual electricity consumption and peak load demand in the interconnected system between 2011 and 2020, as reported by the TSO, ADMIE S.A.. In 2020, electricity consumption was around 49,93 TWh.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total electricity consumption excluding pump storage (GWh)	52,915	52,611	50,664	50,228	51,355	51,212	51,932	51,462	52,174	49,968
Peak load (MW)	10,105	10,438	9,161	9,263	9,813	9,207	9,674	9,062	9,634	9,547

Table 17: Energy and peak electricity demand in the interconnected system (2011-2020)

Table 18 presents a forecast of the evolution of annual electricity consumption and peak demand in the interconnected system for the period 2020 - 2030, according to the Adequacy Study of ADMIE S.A. It is noted that the values include also the demand of the islands that will be interconnected with the mainland grid during this decade. In particular, from 2021 the demand of Crete is included which will be served through the AC submarine interconnection, while after 2023 the overall demand of the island is included (with the completion of the DC link). After 2025, the estimated demand of the Western Cyclades is included (4th Phase of Cyclades interconnection), while from 2028 and 2029 the estimated demand of the interconnected Dodecanese islands and the islands of the North Aegean Sea is included respectively.

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total electricity consumption – NECPs (GWh)*	53.200	54.320	54.100	55.830	56.200	57.000	57.150	57.280	58.940	60.080	60.730
Total electricity consumption – Increased demand Scenario (GWh)**	53.870	56.310	56.900	59.300	59.900	60.850	61.460	61.980	64.510	65.540	66.160
Peak load - NECPs (MW)*	9.960	10.050	10.000	10.520	10.590	10.740	10.770	10.790	11.100	11.320	11.450
Peak load - Increased demand Scenario (MW)**	10.080	10.420	10.530	11.170	11.280	11.460	11.575	11.675	12.160	12.350	12.470

* According to the National Energy and Climate Plan (NECP) and the key national targets for 2030

** Scenario estimated by ADMIE taking into account the electricity demand data of 2019 while for the evolution of GDP a scenario based on the recently published forecasts of the European Commission and the IMF has been taken into account.

Table 18: Electricity consumption and peak load demand forecast in the interconnected system, for the period 2020-2030

3.3.2. Monitoring investment in generation capacities

According to article 94 /Law 4001, the Greek electricity transmission system operator shall operate, exploit, maintain and develop the Greek electricity transmission system, so as to safeguard security of supply in Greece in an adequate, secure, efficient and reliable manner.

In this respect, according to the provisions of article 95, ADMIE shall execute generating capacity contracts in the interests of security of supply. The overall capacity of the contracts shall be set following a special study of capacity adequacy and reserve margin adequacy prepared by the Greek electricity transmission system operator, taking account of the ten-year Greek electricity transmission system development program approved by RAE.

According to the latest TYNDP for the period 2019-2028 approved by RAE with Decision 1097/2019, the completion of the following investments in thermal power capacity has been considered:

- The combined cycle power plant of PPC in Megalopoli (Megalopoli V), of 811 MW.
- The lignite power station of PPC in Ptolemaida of 660 MW.

Except of projects related to international interconnections, the following crucial projects related to the security of supply in the electricity system, are included in the TYNDP (2019-2028):

- Expansion of 400 kV system towards Thrace.
- Expansion of 400 kV system towards Peloponnese.

- The completion of the construction of High Voltage Centers that will allow safer and more reliable supply of consumers in the wider areas.
- Reinforcement of power supply system to the islands of North Sporades and East Magnesia.
- An additional Phase, which is called the 4th Phase of Cyclades Interconnection, except the three (3) Cyclades interconnection phases (A, B, C), which have also been included in the previous, approved, TYNDPs 2014-2023, 2017-2026 and 2018-2027. The 4th Phase includes the interconnection of the islands of the Southern and Western Cyclades to the mainland grid, with completion horizon within the 2nd half of 2024. The interconnection to the mainland grid is considered to be the economically optimal solution for the electrification of these islands (against the continuation of their autonomous operation) in the relevant Proposal submitted in 2016 to the competent network operators and RAE (IPTO, HEDNO) by the "Committee for the alternative ways of electricity supply to the non-interconnected islands" consisting of members of all relevant Operators (ADMIE, DEDDIE and DESFA). Based on the results of this Study, RAE, in 2019, issued the Decision 785/2019, with which, among other things, determines the most economically efficient way of electrification of the non-interconnected islands of the Southern and Western Cyclades and also sets a timetable for its completion.

Crete island interconnection with the mainland electricity system which has also been included in the previous, approved, TYNDPs 2014-2023, 2017-2026 and 2018-2027.

3.3.3. Measures to cover peak demand or shortfalls of suppliers

Regarding interruptible load services (ILS) the Law 4342/2015 (Gazette FEK A' 143/09.11.2015) integrated EU Energy Efficiency Directive 2012/27 (henceforth EED), which requires among others, a) member states to adopt demand response measures, b) legal and personal entities to provide balancing and/or ancillary services and c) the regulator to expand its monitoring role for the successful implementation of the energy efficiency directive in the market.

By the virtue of article 6 of the Ministerial Decision ΥΠΕΝ/ΔΗΕ/66759/811/9.7.2020, based on the "Warning time", the "Maximum time of order" and the "Maximum time per year", a distinction is made between two types of ILS. The ILS are auctioned by the TSO IPTO. The Ministerial Decision defines the categories of Consumers who are entitled to contract ILS, the conditions for drawing up the ILS Contracts, the reasons for activating the ILS as well as the manner, time and financial compensation of the Services of the contracted consumers, the recovery by IPTO of the amounts paid as financial compensation and the text of a Standard ILS Agreement and the minimum content of the ILS Contracts concluded by the TSO in accordance with Article 14 of Law 4001/2011. In addition, the Differentiation Factors are determined per category of Generation Units, according to article 143B of law 4001/2011.

In exchange for being available to be disconnected, the beneficiaries are remunerated with a fixed payment which is determined by means of three-monthly auctions. Beneficiaries can bid to provide two different services, summarized in Table below. To be eligible for participation in the auction for the interruptibility scheme, the minimum threshold is a capacity of 3 MW. The installations must moreover be connected to the transmission grid or the medium voltage network.

Following the relevant notification of a plan for the 2nd extension and the implementation of the interruptibility scheme by the Ministry of Energy, DG COMP, with the decision No. SA (56) (C / 2020) 6658 N[36] approved the extension of the measure.

Types of Interruptible load services (ILS)	**Warning time**	**Maximum time of order**	**Maximum time per year**
Type 1*	5 minutes	48 hours	288 hours
Type 2**	5 minutes	1 hour	24 hours

*Minimum time between two successive orders for the type 1 interruptible load services (ILS) is 1 day. Maximum no of orders of type 1 ILS is 3orders/month.

**Minimum time between two successive orders for the type 2 ILS is 5 days. And the maximum no of orders of the type 2 ILS, is 4 orders/month.

Table 19: Interruptible load services (ILS)

In 2020 the Greek TSO (ADMIE) organized two (2) pairs of auctions (one auction for each type of ILS). The results of the auctions are summarized in the tables below.

Period of Auctions	Marginal price (€/MW-year)	Number of participants succeeded in auction	Maximum Load Capacity Offered (MW)	Total Interruptible Load capacity asked (MW) by the TSO	Difference between the Load Capacity offered and Load Capacity asked (MW)
01.08.2020 - 30.09.2020	63,800	27	400	400	0
01.10.2020 - 31.12.2020	63,850	20	400	400	0

Table 20: Type 1 of Interruptible load capacity services (ILS 1 services) Auctions in 2020

[36] SA.56103 (2020/N) Second prolongation of the interruptibility scheme. Available online at: https://ec.europa.eu/competition/elojade/isef/case_details.cfm?proc_code=3_SA_56103

Period of Auctions	Marginal price (€/MW-year)	Number of participants succeeded in auction	Maximum Load Capacity Offered (MW)	Total Interruptible Load capacity asked (MW) by the TSO	Difference between the Load Capacity offered and Load Capacity asked (MW)
01.08.2020 - 30.09.2020	44,750	19	400	400	0
01.10.2020 - 31.12.2020	44,850	16	400	400	0

Table 21: Type 2 of Interruptible load capacity services (ILS 2 services) Auctions in 2020

3.4. The Non-Interconnected islands system (NIIs)

The completion of Phase 1 of Cyclades interconnection (Syros, Mykonos, Paros) with the interconnected system in 2018 was a turning point for the Greek electricity system. Nevertheless, a great number of islands are still electrified from local production units of PPC which operate on oil products[37].

However, the contribution of RES (wind turbines and PVs) which operate on those islands is also important. RES share in the non-interconnected systems amounted to 16.77% of total power consumption in 2019. In Crete, this percentage touched 20.92% of total power consumption. However, until power stocking through hybrid units reaches a level where they can guarantee energy autonomy for those islands, the non-interconnected systems will still rely mainly on oil thermal units.

For the completion of the TYNDP's reviewing process (2019-2028), RAE requested in July 2019 the submission of a Cost-Benefit Analysis Study for Phase IV of Cyclades Interconnection and further the cooperation between the TSO and DSO for the reinforcement of Sporades supply taking in to account the TYNDP in comparison to the Network Development Plan (2019-2023).

ADMIE, submitted in August 2019 the requested Cost-Benefit Analysis Study for Cyclades Interconnection, while in October he informed RAE about the results of the TSO-DSO coordination for Sporades reinforcement of supply attaching the letter submitted to it by DEDDIE.

With Decision 1097/2019, RAE approved the TYNDP (2019-2028) and asked from ADMIE to set a bidding deadline for Phase II & III of Cyclades Interconnection. More specifically, Phase II should be completed within the first semester of 2020 while Phase III should be completed within the second semester of 2020.

As for Phase IV of Cyclades Interconnection, RAE approved the inclusion of the Project in the TYNDP (2019-2028) after taking into consideration the requests by the Operators. The binding deadline for Phase IV is the second semester of 2023. Phase IV is characterized as a Project of Major Importance according to Transmission System Operation Code. The social benefit of this Project is great as final consumers will observe a reduction of PSO tariff and the interconnection will guarantee secure supply

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[37] In February 2014, RAE adopted the Operation Code for Non-Interconnected Islands (NII Code, Decision 39/2014, National Gazette B '304 / 02.11.2014), which largely completed the secondary legislation that regulates the operation and the transactions at the NII electrical systems, as provided for by Law 4001 / 2011. Therefore, with the NII Code in effect, the NII markets may be open to competition, for both the production and the supply activities. In addition, on August 14, 2014, the European Commission granted to Greece (Decision 2014/536/EC) derogation from the provisions of Chapters III and VIII of Directive 2009/72/EC for the NIIs. This derogation is valid until 1 January 2021. This Decision followed the relevant applications of the Greek State in December of 2003, based on article 26 of Directive 2004/54/EC, and then in January of 2012, based on article 44 of Directive 2009/72/EC. Per the Commission's above Decision: (1) All NIIs except Crete are recognized as micro isolated systems per art. 2 par. 27 of the Directive 2009/72/EC, while Crete is characterized as a small isolated system per art. 2 par. 26 of the same Directive.

and credibility to the System. For that reason, the collaboration between ADMIE and DEDDIE is considered necessary for the completion of the Project.

The Phase II of Cyclades interconnection was completed in September 2020 while the Phase III was completed in October 2020.

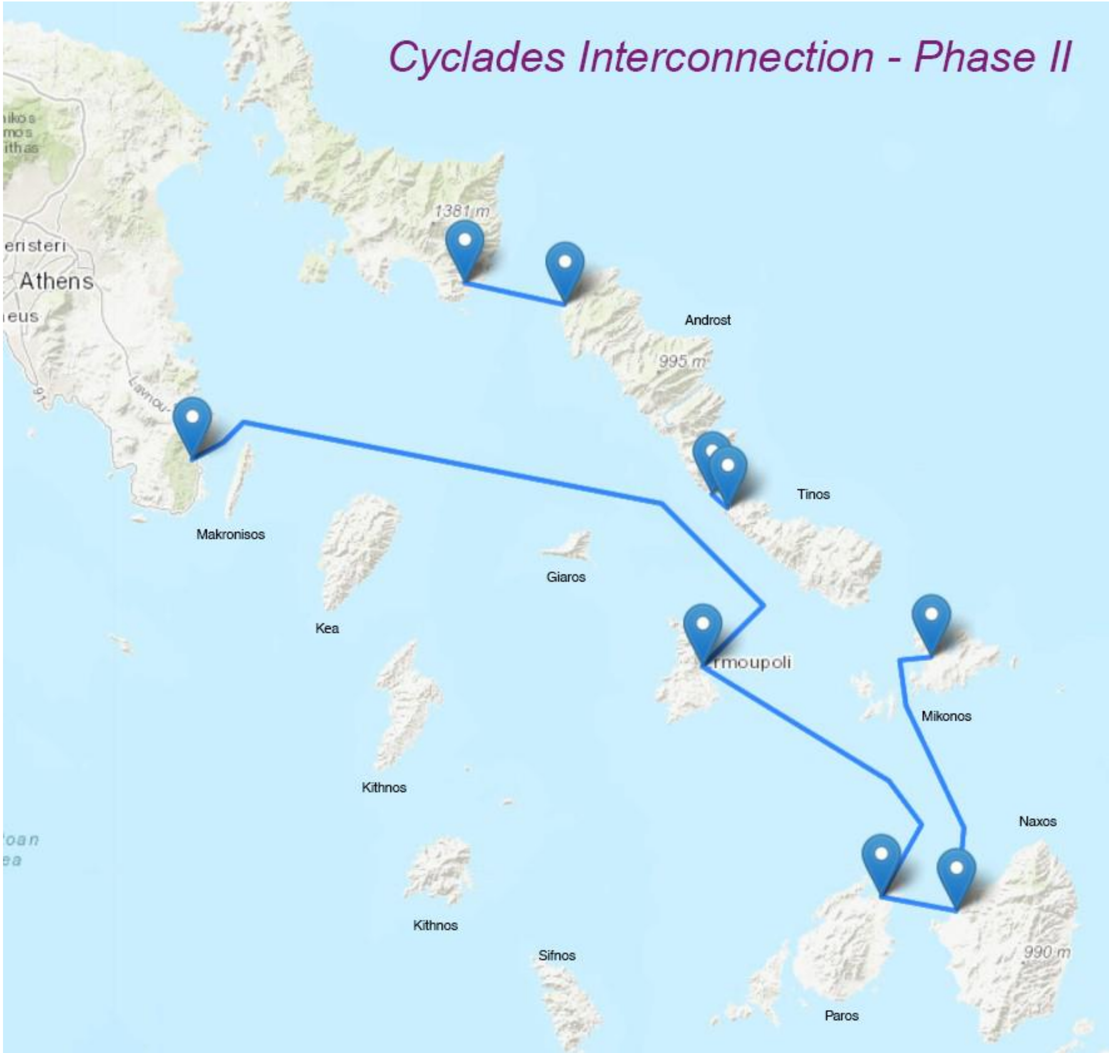

Figure 23: Cyclades Interconnection – Phase II

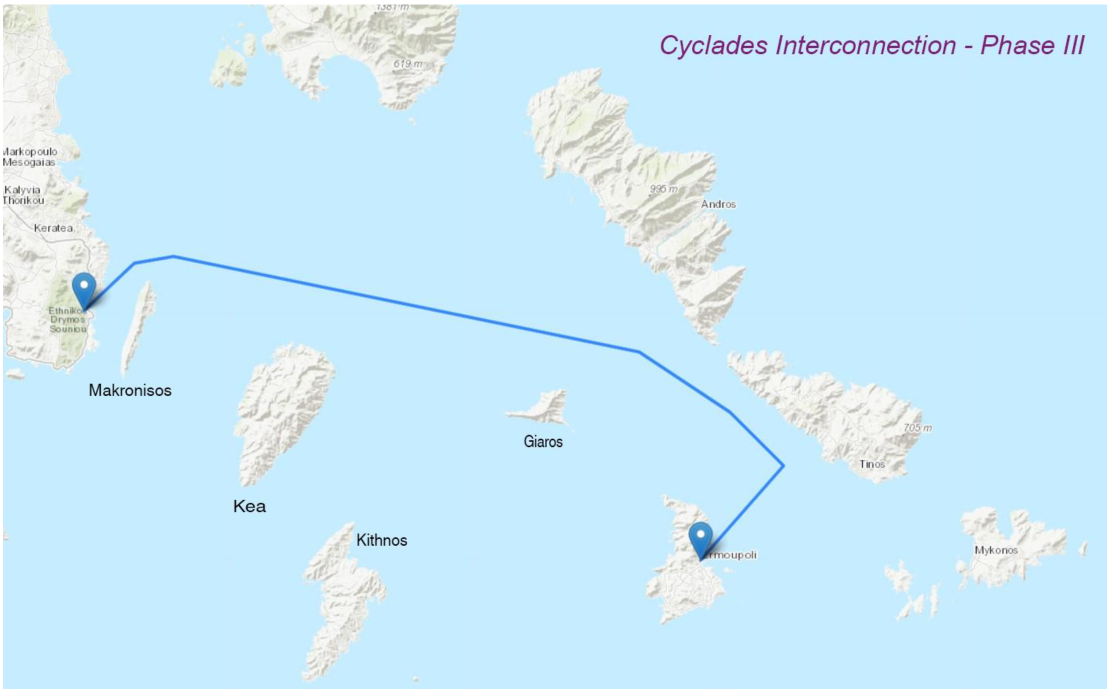

Figure 24: Cyclades Interconnection – Phase III

All remaining Greek Non-Interconnected Islands (NNIs) are electrified by autonomous electrical units. Renewable energy sources (wind parks and small photovoltaic stations), most of which are owned by independent producers (other than PPC S.A.), contribute with a significant percentage in the total NII electricity production per year (not exceeding 15-20% for each NII).

3.4.1. Electricity Supply Structure

In Non – Interconnected Islands, the autonomous power systems currently operate without any wholesale electricity market (i.e. forward electricity market, day-ahead electricity market, intraday electricity market, balancing market etc.)

In all systems, currently neither the producers nor the suppliers submit daily offers for their production or for their customers' loads. The dispatching of the units is done to achieve the lowest cost, maximizing at the same time the contribution of RES production while also considering the security of supply. The network operator in the non-interconnected islands is DEDDIE S.A..

Thus, in those systems there is no system marginal price but an estimated clearance price of energy. The estimation is done monthly, based on the variable costs of the conventional power units for each of all these autonomous power systems, pursuant to Law 4001/2011 and the Code of operation of the Non - Interconnected Islands. All suppliers that are active in NII can buy the produced electricity.

The inability of existing RES plants to provide guaranteed power to the local island systems inevitably leads to continued strengthening of the conventional power resources of each island, with new thermal units designed to meet both peak demand and the necessary reserve capacity. It is noted that to ensure sufficient resources and minimize the risks to security of supply, especially in the event of power loss, in each autonomous island system, and in addition to the required power to meet the maximum demand (peak), reserve conventional capacity is also installed and kept at standby status, to cover the possibility of loss of the largest power unit in each autonomous system.

In 2020, the company “GREEK ENVIRONMENTAL & ENERGY NETWORK S.A.” withdrew from the supply of electricity in the NII market while the company “WE ENERGY S.A.” begun its supply activity in the NII market. By the end of the year, 23 suppliers (including the five (5) Universal Service Providers and the Supplier of Last Resort were active in the Non-Interconnected Islands:[38]

	Supplier Name:
1.	PPC
2.	ECONOMIC GROWTH
3.	ELINOIL
4.	ELTA
5.	ELPEDISON
6.	ZENITH
7.	HERON
8.	KEN
9.	PROTERGIA
10.	NRG
11.	OTE ESTATE
12.	PETROGAZ
13.	UNIVERSAL SERVICE PROVIDER (PPC S.A.)
14.	UNIVERSAL SERVICE PROVIDER (MYTILINEOS S.A.)
15.	UNIVERSAL SERVICE PROVIDER (ELPEDISON S.A.)
16.	UNIVERSAL SERVICE PROVIDER (HERON S.A.)
17.	UNIVERSAL SERVICE PROVIDER (NRG S.A.)
18.	SUPPLIER OF LAST RESORT
19.	NATURAL GAS
20.	VOLTERRA
21.	VOLTON
22.	WATT & VOLT
23.	WE ENERGY

Table 22: Companies active in the electricity supply market of Non-Interconnected Islands (2020)

PPC remained the dominant supplier in the non-interconnected system representing at the end of 2020 82.6% of total number of connections of LV and MV customers and 73.9% in terms of consumption volumes, this is a decrease of PPC’s share by 5% and 6% respectively compared to 2019 (88.24% and 79.58% accordingly). Figure 25 shows the shares of all suppliers in the non-interconnected system in terms of number of connections according to HEDNO’s data for 2020.

[38] As of 01.01.2018 and according to RAE Decision No. 908/2017 (Gazette 4461 B '/ 19.12.2017), the full liberalization of electricity supply in the Non-Interconnected Islands was enacted.

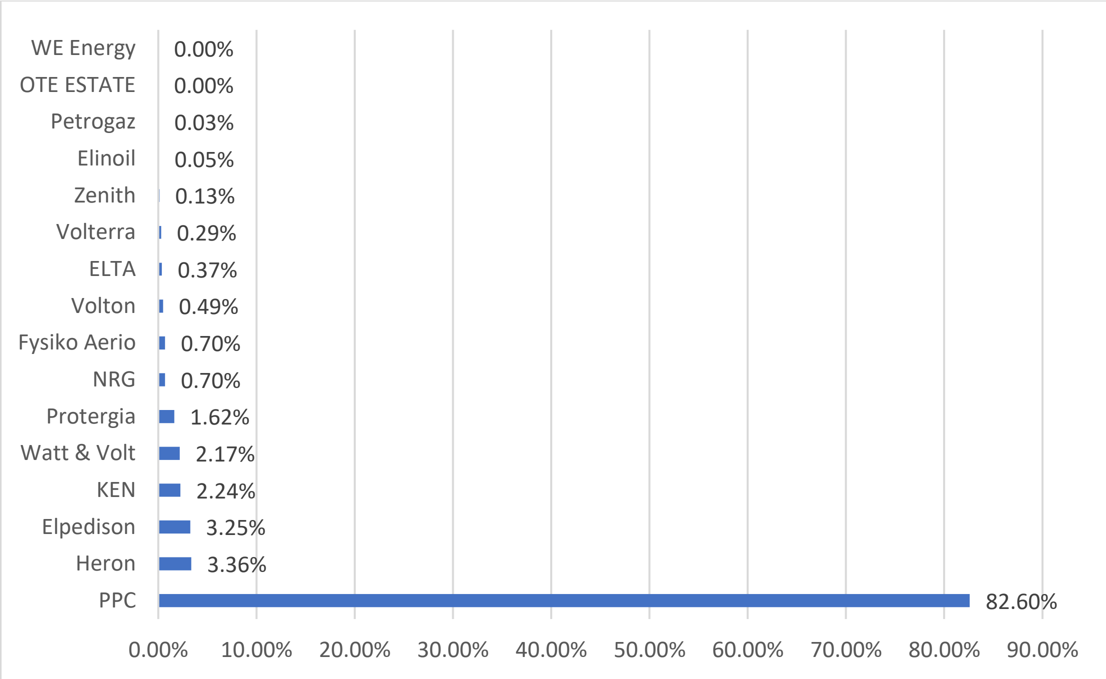

Figure 25 Market shares in Retail Electricity Market based on suppliers' total meter connections in the Non-Interconnected Autonomous Systems (2020)

Figure 26 presents the market shares in the non-interconnected system per volume rates in the low and medium voltage according to DEDDIE's data for 2020.

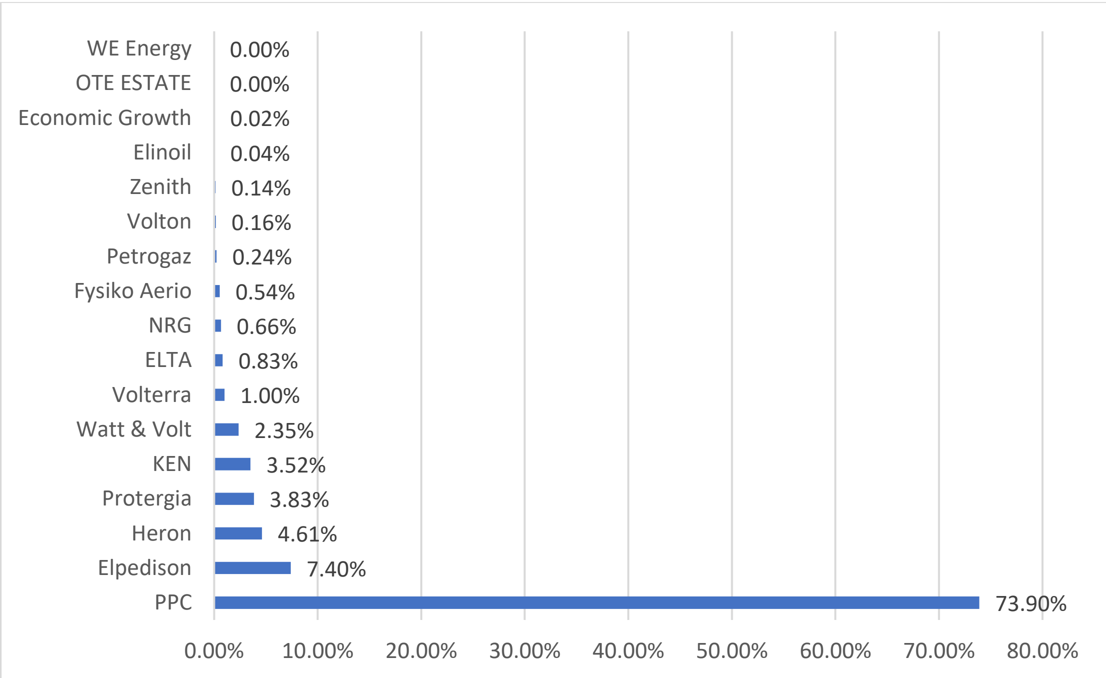

Figure 26: Market shares in Retail Electricity Market based on based on consumption volumes (LV and MV) in the

Non-Interconnected System (2020)

The Herfindahl-Hirschman Index (HHI), measuring market concentration, amounted to 5,565 for the NIIs (measured by volume). This figure exceeds by far the limit of 2,000 (limit for highly concentrated markets). The decrease may not be sufficient, but it is significantly lower than that of 2019, when market concentration reached 6,146. All in all, the retail electricity market of the NIIs is rightly characterized as still very concentrated and significantly more concentrated related to the Interconnected System.

Regarding supplier switching in the NNIs, according to DEDDIE’s data 7% of LV and MV customers switched their supplier in 2020 (8.6% of total consumption in the LV and MV market). The highest level of supplier switching is observed at MV (commercial and industrial) customers in terms of both number of customers and consumption volume followed by commercial and industrial customers at LV and household customers. The switching rates are showing a noticeable increase in terms of consumption volume compared to 2019 (2.3% at LV and MV) which means an increase of 273% within a year due to the high switching rate in all categories of customers and mainly the commercial and industrial customers at LV and MV.

The following table portrays data of customer switching (LV and MV) in the NIIs in 2020 (data of DEDDIE):

Customer Category	Number of Customers in the Non-Interconnected System in 31.12.2020	Number of customers that switched supplier in 2020	Switching rates (% in number of customers)	Total Consumption in 2020 (MWh)	Consumption of customers that switched supplier in 2020 (MWh)	Switching rates (% of consumption volume)
Household customers (not including Social Tariff)	571,583	41,947	7.34%	1,556,130	57,235	3.68%
Household (including Social Tariff)	27,724	4	0.01%	126,679	2,076	1.64%
Small industrial and LV Customers	153,877	13,589	8.83%	1,382,815	126,716	9.16%
Oher LV customers	42,997	189	0.44%	404,403	1,552	0.38%
Total LV customers	796,181	55,729	7.00%	3,470,027	187,579	5.41%
Commercial and Industrial MV customers	1,005	168	16.72%	721,693	183,208	25.39%
Oher MV customers	191	3	1.57%	174,507	4,330	2.48%
Total MV customers	1,196	171	14.30%	896,200	187,538	20.93%
Total LV and MV customers	797,377	55,900	7.01%	4,366,226	375,118	8.59%

Table 23: Consumer Switching (LV and MV) in NIIs (2020)

3.4.2. Electricity Generation Capacity and Electricity Demand

The share of RES' generation in the total electricity generation of the 29-autonomous power system was 19.76% in 2020. In Crete, the largest island of the non- interconnected system, the share of RES in total generation was 23.38%. The level of demand of the 29 autonomous non-interconnected islands varies significantly:

- 20 out of 29 have a peak demand level less than 10 MW.
- 7 out of 29 have a peak demand level from 10 MW up to 100 MW.
- And only 2 autonomous non-interconnected islands have a peak demand level over 100 MW (Crete, Rhodes).

The annual electricity demand among the autonomous non-interconnected systems varies too, from few hundreds of MWh up to few TWh (Table 25).

	Non-interconnected autonomous power systems (islands)	Electricity Production from Conventional Plants (MWh)	Electricity Produced from RES (MWh)	% Production from RES	Demand (MWh)	Peak demand (MW)
1	St Eustratios	1,104	0	0%	1,104	0.306
2	Agathonisi	828	0	0%	828	0.220
3	Amorgos	9,351	455	4.64%	9,806	2.710
4	Anafi	1,208	0	0%	1,208	0.552
5	Antikythera	308	0	0%	308	0.085
6	Arkie	399	0	0%	399	0.139
7	Astepalaia	6,184	552	8.20%	6,736	2.060
8	Gavdos	486	0	0%	486	0.136
9	Donoussa	954	0	0%	954	0.416
10	Erikoussa	817	0	0%	817	0.412
11	Thira	146,046	413	0.28%	146,459	38.250
12	Ikaria	20,999	6,228	22.87%	27,227	6.839
13	Karpathos	27,228	4,865	15.16%	32,093	7.510
14	Crete	2,134,453	651,259	23.38%	2,785,712	605,100
15	Kythnos	9,657	402	4.00%	10,059	3.460
16	Kos-Kalymnos	265,036	50,041	15.88%	315,078	74.000
17	Lesbos	238,094	51,868	17.89%	289,962	63.190
18	Lemnos	49,744	8,817	15.06%	58,560	12.900
19	Megisti	3,582	0	0%	3,582	0.935
20	Melos	39,562	7,384	15.73%	46,946	11.770
21	Othonei	578	0	0%	578	0.250
22	Patmos	14,916	2,839	15.99%	17,755	4.600
23	Rhodes	537,093	100,473	15.76%	637,567	148,300
24	Samos	97,160	29,661	23.39%	126,821	27.800
25	Serifos	8,375	165	1.93%	8,540	3.520
26	Sifnos	14,960	2,489	14.26%	17,449	5.650
27	Skeros	14,862	467	3.05%	15,329	3.910
28	Semi	11,951	254	2.08%	12,205	3.910
29	Chios	175,856	25,066	12.48%	200,921	43.000
	TOTAL	3,831,791	943,698	19.76%	4,775,489	

Table 24: Electricity Generation in Non-Interconnected Islands (NII) for 2020

Non-interconnected islands	2012	2013	2014	2015	2016	2017	2018	2019	2020
St Eustrations	1,102	1,075	1,115	1,118	1,096	1,095	1,124	1,123	1,104
Agathonisi	599	642	650	702	749	727	718	765	828
Amorgos	9,354	9,129	9,334	9,865	10,069	10,710	11,188	11,282	9,806
Anafe	1,199	1,179	1,223	1,259	1,277	1,298	1,371	1,358	1,208
Antikythera	216	241	243	261	255	276	274	300	399
Astepalaia	7,089	6,670	6,599	6,772	6,856	7,008	7,064	7,268	6,736
Donoussa	667	690	721	810	841	1,016	1,118	1,125	954
Hereikousa	746	746	697	795	832	879	895	820	817
Thera	120,817	120,199	135,772	152,375	164,060	181,674	199,744	217,105	146,459
Ikaria	28,977	27,613	27,423	28,658	27,129	28,047	27,878	28,528	27,227
Karpathos	38,988	36,931	36,928	37,966	37,799	37,319	38,455	39,805	32,093
Kythnos	8,672	7,991	8,240	8,607	9,005	9,586	9,578	10,000	10,059
Kos-Kalemnos	361,681	352,984	351,942	367,337	368,521	382,075	392,964	405,385	315,078
Lesvos	300,822	288,230	285,542	296,582	297,670	299,860	299,177	299,923	289,962
Lemnos	61,743	59,672	58,486	60,244	59,831	60,411	60,378	60,724	58,560
Megisti	3,126	3,005	3,152	3,207	3,479	3,549	3,762	3,866	3,582
Melos	49,952	45,402	47,885	49,834	47,642	49,181	50,573	52,479	46,946
Othonoi	688	632	634	634	601	645	640	629	578
Patmos	17,475	17,020	17,019	17,788	17,477	18,438	18,894	19,570	17,755
Samos	146,503	137,315	136,178	138,186	138,050	140,447	140,252	140,629	126,821
Serifos	8,153	7,654	8,178	8,358	8,202	8,680	8,701	9,183	8,540
Sifnos	17,364	16,521	17,047	17,617	17,984	18,633	19,069	19,344	17,449
Skeros	15,549	14,782	15,073	15,955	15,663	16,266	15,666	16,126	15,329
Semei	15,275	14,662	14,132	14,649	15,175	14,285	14,673	14,900	12,205
Chios	212,476	200,042	196,993	202,519	205,833	210,435	204,987	206,908	200,921
Rhodos	790,593	760,658	760,187	791,768	814,488	836,397	864,624	867,271	637,567
Crete	2,944,351	2,825,132	2,866,699	2,898,169	2,975,755	3,027,253	3,055,605	3,083,427	2,785,712
Note: Most of the 29 autonomous power systems include more than one island (micro islands)									

Table 25: Annual Electricity Consumption (Demand) in NII, 2012 – 2020 (MWh)

3.4.3. Other regulatory developments in NIIs

Special Pilot Projects in NIIs

According to Article 151 of Law 4495/2017 (Gazette A' 167) which was amended by Article 60 of Law 4546/2018 (Gazette B' 101), RES integration is foreseen for NIIs together with meeting of their demand in an efficient way. Three (3) pilot projects can be implemented in three electricity systems which will be under the Operating Aid regime. Those projects are special because they combine electricity generation by RES units with storage facilities to cover the electricity demand of the system.

In accordance with the provisions of the above article for the implementation of the pilot projects and by taking into account DEDDIE's proposal as well as the results of the relevant Public Consultation held in January 2020, RAE issued Decision 429/2020 which formulated the special framework of operation of the Ag. Efstratios pilot hybrid power plant, in derogation of the NII Code.

In addition, RAE, in 2020, issued an opinion to the Minister of Energy (RAE Opinion 15/2020) on the determination of the tariff framework of the pilot Ag. Efstratios project, in accordance with the provisions of article 152 of Law 4495/2017 and the Ministerial Decision ΥΠΕΝ/ΔΑΠΕΕΚ/51966/2203/2020.

Meeting electricity demand for the summertime period of 2020 in Crete

Following relevant Recommendations by the competent network operator of NII (HEDNO), RAE examined and evaluated technical and financial alternative scenarios for the timely coverage of the forecasted electricity demand shortage of 93.5 MW in Crete with the criterion of the best economic and technical solution. The results combined the leasing of an electricity generating set of at least 58 MW installed capacity, and its installation in the Atherinolakkos thermal power plant, while the rest of the demand would be covered by: a) additional leasing of an electricity generating set of 25 MW installed capacity at the Atherinolakkos thermal power plant, b) leasing of a 25 MW generator at the Chania thermal power plant, and c) leasing of a floating power plant of at least 25 MW at the Atherinolakkos thermal power plant.

3.5. RES

3.5.1. RES Installed capacity and generation

The installed capacity of RES units at the end of 2020 amounted to 7,700 MW, showing an increase of approximately 14.38% compared to the one recorded at the end of 2019 (6,732 MW), this significant increase in the country's progress towards achieving national climate and environmental goals is mainly due to the installation of new wind turbines with a total capacity of 512 MW and PV power plants with a total capacity of 442 MW as shown by the capacity distribution per technology presented in Table 26. This increase was the result of the implementation of projects that had secured fixed tariff under the previous guaranteed price regime (Feed-in-Tariff) and the first projects completed under the new support scheme of law 4414/2016 (sliding Feed-in-Premium).

This increase in installed capacity as is considered to be particularly significant, as there is a steadily increased investment activity in the RES sector over the past three years and mainly in the field of solar PVs and onshore wind parks. Furthermore, this trend is expected to be strengthened over the next years due to the provision of operating aid to new power plants which were successful in the competitive tender procedures held by RAE since 2018, but also due to the improved economic and investment climate in the country.

RES Technology	Installed Capacity in 2017 (MW)	Installed Capacity in 2018 (MW)	Installed Capacity in 2019 (MW)	Installed Capacity in 2020 (MW)	% change 2019-2020
Wind	2,624.60	2,860.49	3,607.40	4,119.25	14.19%
PV	2,229.90	2,269.60	2,417.77	2,860.00	18.29%
PV on roof (P < 10 kW)	374.80	375.04	375.21	375.34	0.03%
Hydro Small (P < 15 MW)	230.60	239.77	240.56	245.55	2.07%
Biomass - Biogas	61.50	83.15	87.89	97.41	10.83%
Hybrid RES	0.00	0.40	2.95	2.95	0.00%
CHP	228.10	228.67	233.37	235.45	0.89%
Total RES	5,521.40	5,828.05	6,728.83	7,700.5	14.39%
Total RES, Hybrid RES & CHP	5,749.50	6,057.12	6,965.15	7,935.95	13.94%

Table 26: Total RES installed capacity and percentage change (2017-2020)

In 2020, RES production in Greece amounted to 14.7 TWh in total, which was increased compared to 12.3 TWh in 2019 and represented a share of 34.9% of the total electricity consumption in the country.

	2017	**2018**	**2019**	**2020**
Biomass	280	298	367	429
Small Hydro (< 15 MW)	586	718	688	541
PV on roofs (< 10 kW)	511	489	494	494
PV	3,480	3,304	3,468	3,898
Wind	5,515	6,300	7,278	9,323
Total RES*	**10,374**	**11,110**	**12,297**	**14,687**
Hybrid RES	0	0,37	1.7	3.27
CHP	1,178	1,107	1,062	1,102
Total RES, Hybrid RES & CHP	**11,552**	**12,217**	**13,359**	**15,789**
*Excluding large hydroelectric power plants (>15 MW)				

Table 27: RES Generation in GWh for 2017-2020

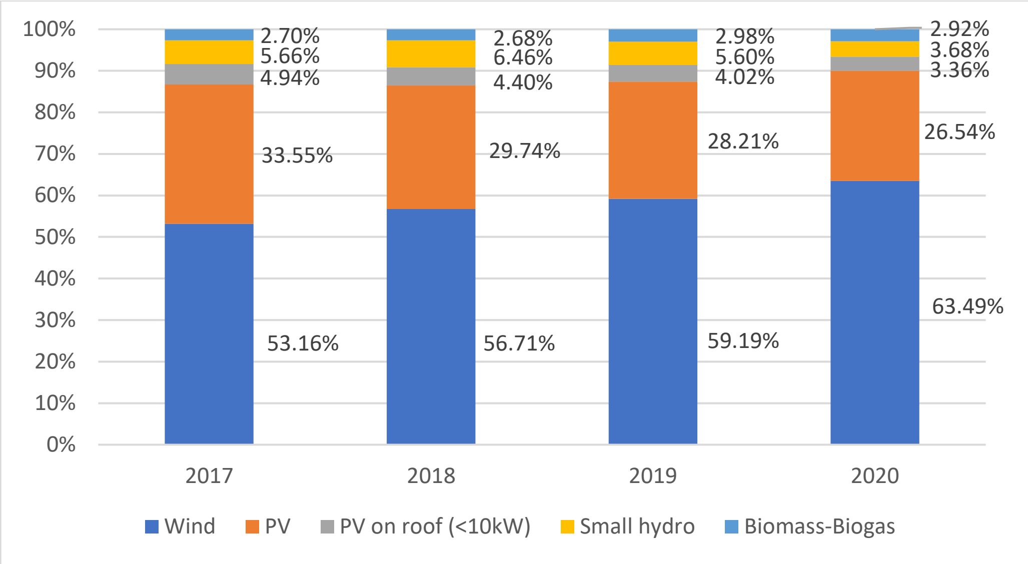

Figure 27: RES Generation percentage excluding large hydroelectric plants per technology (2017-2020)

3.5.2. RES and the electricity Market

In 2020, RAE hired a private consultant to elaborate a specialized technical study on the analysis of the margins for the development of RES power stations in the island of Crete, after its interconnection with the mainland electricity system.

3.5.3. RES projects' licensing

Major changes were introduced in 2020 to reduce the time and to simplify the administrative RES licensing procedures.[41] RAE issued a total of 1,656 administrative acts and sent 223 letters for supplementary data as part of the evaluation process. The total number of licenses and the number of RAE decisions per category in 2020 is presented in the tables below.

[41] For a more detailed overview of the changes introduced to the licensing procedures please refer to section 3.5.6.

Type of Decision	Number
Decisions on Generation License granting (accepted)	955
Decisions on Generation License granting (denied)	21
Decisions on Generation License modification / transfer	119
Decisions on Generation License extension	38
Administrative acts on Generation License infringements	1
Decisions on Generation License revocations	62
Decisions on modification of Generation License Information (before Law 4685/2020 was enacted)	202
Generation Certificates granted	258
Decisions on modification requests	0
Total	1,656

Table 28: RAE's licensing activity in 2020

Technology	No of Granted Licenses	Installed Capacity (MW)
Wind	1,406	24,460.1
PV	1083	12,275.3
Hydro (small)	383	845.6
Geothermal	1	8
Biogas	44	143.1
Biomass	34	181.7
CSP	46	273.3
Hybrid	157	938.7
Total	3,154	39,125.8

Table 29: Projects with a license/permission of generation (operational & non-operational) approved by RAE, December 2020

Technology	2020	
	Decisions/ Permissions approved by RAE	
	No	Installed Capacity (MW)
Wind	284	3,241.19
P/V	484	6,688.98
Hydro small	46	78.64
Biomass	2	7
Hybrid	137	509.86
Biogas	2	5
Total	955	10,530.67

Table 30: RES licenses issued per technology[42] (2020)

Technology	No of Revoked Licenses	Installed Capacity (MW)
Wind	22	697
PV	6	17.46
Hydro (small)	14	28.11
Geothermal	0	0
Biomass	4	19.66
Biomass - Teleheating	1	14.1
CSP	15	93.5
Hybrid	0	0
Co-generation (electricity & heat)	0	0
Total	62	869.84

Table 31: Revoked RES licenses per technology (2020)

3.5.4. RES Financial Support Scheme

The current financial support scheme was approved by the European Commission, in November 2016. The main objective of this RES support mechanism is to achieve an efficient integration of renewables' generation into the electricity market. The main change in the RES support financial scheme was the abolition of the Feed-in-Tariff financial support mechanism for new RES projects, and specifically for wind parks larger than 3 MW and other RES projects larger than 0.5 MW, which will now receive operating aid based on the new mechanism of sliding Feed in Premium[43]. Currently, only RES units with installed capacity of 400 kW or less as well as innovative projects can be remunerated under the FiT scheme.

[42] Table 30 does not include data on the RES projects that were granted a Generation Certificate.
[43] Energy Communities are exempted from that rule. Specifically, wind farms up to 6 MW and PVs up to 1 MW, that are operated by Energy Communities, may still receive operating aid based on feed-in-tariffs.

Renewable technologies and project categories	**RT (€/MWh)**	**Project IRR**
Onshore wind parks in the Interconnected System	98	9%
Onshore wind parks in the Non-Interconnected Islands[44]	98	9%
Small hydropower P ≤ 3MW	100	9%
Small hydropower 3MW < P ≤ 15 MW	97	9%
Solar PV < 0.5MW [*Roof-top solar PV installations are regulated by special legislation and hence excluded from the present briefing.*]	1,1 * wholesale electricity market price of the previous calendar year	-
Solar PV ≥ 0.5MW	Competitive bidding	-
Biomass (or bioliquids) from thermal processing P ≤ 1MW (excluding the biodegradable fraction of urban waste)	184	9%
Biomass (or bioliquids) through gasification P ≤ 1MW (excluding the biodegradable fraction of urban waste)	193	9%
Biomass (or bioliquids) from thermal processing (including gasification) 1MW< P ≤ 5MW (excluding the biodegradable fraction of urban waste)	162	9%
Biomass (or bioliquids) from thermal processing (including gasification) P < 5 MW (excluding the biodegradable fraction of urban waste)	140	9%
Landfill gas and biogas from anaerobic digestion of the biodegradable fraction of urban waste P ≤ 2MW	129	9%
Landfill gas and biogas from anaerobic digestion of the biodegradable fraction of urban waste P > 2MW	106	9%
Biogas released from anaerobic digestion of biomass (energy crops, rural waste and residues, etc.) P ≤ 3MW	225	10%
Biogas released from anaerobic digestion of biomass (energy crops, rural waste and residues, etc.) P > 3MW	204	9%
Solar thermal without storage system (unless bioliquids are used, in which case see above)	257	9%
Solar thermal with storage system (minimum two hours) (unless bioliquids are used, in which case see above)	278	9%
Geothermal power P ≤ 5MW	139	10%
Geothermal power P > 5MW	108	10%
Other renewable energy technologies	90	10%
Solar energy that is utilized by photovoltaic power stations with installed capacity <500kW	Weighted R.T. that is determined by the previous three before the last, competitive bidding procedures for the same technology increased by 5%	-
Solar energy that is utilized by photovoltaic power stations that belong to Energy	Weighted R.T. that is	-

Renewable technologies and project categories	RT (€/MWh)	Project IRR
Communities with installed capacity of ≤1MW or to farmers with installed capacity of <500kW	determined by the previous three before the last, competitive bidding procedures for that technology, or if there weren't any procedures for that technology yet, for the same technology increased by 10%	

Table 32: Reference Tariffs of Law 4412/2016, Table 1 of Article 4.1(b)

In essence, this scheme is designed to support revenue based on cost reflective, market-based Operating Aid, which ensures that both phenomena of *over-compensation* and *under-compensation* of power production from RES and HECHP are minimized. A technology-specific **Sliding Scale Feed in Premium** (FiP) is added as a premium, to the revenues received by the RES producers, through their participation in the wholesale electricity market, for the relevant Operating Aid to reach an acceptable level of support, measured against a Reference Tariff (RT) per renewable energy technology. The RTs initially are administratively determined for all technologies, and from 2017 would be set through competitive bidding for most producers, on a project-by-project basis.

As from 1 January 2016, all RES and HECHP power plants that commence (commissioning or commercial) operation in the interconnected system, participate in the electricity market and are included in a support mechanism in the form of *Operating Aid* based on a *Differential Compensation Price* (*Sliding Premium*), for the power they generate and inject into the interconnected system. The *Sliding Premium* is expressed in a monetary value per measurement unit of the generated power that is injected, and which is cleared, billed and its transactions are settled monthly, in accordance with Article 5 of the Law 4414/2016.

The *Sliding Premium* shall be calculated monthly, as the difference between on the one hand, the **RT** applicable for the *"Contracts of Difference"* (Feed in Premium Contracts, FiPC), and on the other hand, the **Special Market Price for Renewables (SMPRES)** for the specific RES or HECHP technology: **FiP = RT – SMPRES**. The FiPCs are signed between the producer and DAPEEP, for the power generated from RES and HECHP plants under Article 10 of the Law, and which is defined per RES and HECHP power plant technology and category, or per RES or HECHP power plant, in case this results from a competitive processes, in Euro per megawatt hour (€/MWh). The SMPRES will be calculated differently for *intermittent* (i.e. wind power, solar PV and small hydro power plants) and *non-intermittent* (i.e. biomass, biogas, geothermal, solar thermal including storage facilities, and highly efficient co-generation of heat and power plants) renewable energy projects. The type and contents of the FiPC, as well as the conclusion procedure, was set out in a Ministerial Decision based on a proposal of DAPEEP and the opinion of the RAE. The duration of the Operating Aid is 20 years for all RES and HECHP technologies, apart from small rooftop PV installations up to 10 kW and CSP installations for which the duration is set to 25 years.

[44] Those installations are compensated with operating aid based on a fixed tariff since they cannot participate in the electricity market until the interconnection of the island

The auctioning procedure, which includes an electronic submission of applications and their evaluation by RAE followed by an electronic auction, is innovative, transparent, simplified, valid and reliable, and regarded as best practice by many European stakeholders. The innovative electronic auction procedure is based on a Yankee Reverse auction type, and is conducted in two phases: (1) online submission of the applications' supporting documents, and (2) conduction of the auctions on the same custom made platform for all the relevant categories of projects.

Based on RAE Opinion 4/2019 the Ministerial decision ΥΠΕΝ / ΔΑΠΕΕΚ / 34495/1107 (Gazette B '1341 / 12.04.2019) was issued. The Decision set the maximum auctioned capacity per RES and HECHP technology, the minimum number of RES competitive procedures per year, the maximum bidding prices per auction, and the relevant fees for the participation in the auctions until 2020. More specifically, it was determined therein that in the first half of 2020 at least one common competitive procedure (PV & Wind) will be held. In addition, one competitive procedure will be held for PV technology, one for the wind technology and one for PV and Wind projects in a specific area until the end of 2020. Furthermore, within 2020, based on RAE Opinion 10/2020 the Ministerial decision ΥΠΕΝ / ΔΑΠΕΕΚ / 119064/4379 (Gazette B '5523 / 17.12.2020) was issued. RAE's Opinion stressed the need for the conduction of a common competitive process for "small RES projects" (i.e. PV with $P_{pv} \leq 20$ MW & wind farms with $P_{wind} \leq 50$ MW). This auction will be held in May 2021.

YEAR	TECHNOLOGY	**Maximum Auctioned Capacity (MW)**
2019	PV	430 MW
	WIND	400 MW
	COMMON COMPETITIVE PROCEDURES (AREA SPECIFIC)	The capacity that will become available in the special interconnection project "Connection of N. Makri – Polypotamos and HV Network of S. Evia" after the expiry/revocation of the production licenses of the wind farms operating in that area
2020	PV	Remaining capacity of PV technology of 2019 plus 300 MW
	WIND	Remaining capacity of Wind technology of 2019 plus 300 MW for projects with 3 MW < $P_{wind} \leq 50$ MW of installed capacity and 20 MW for projects with $P_{wind} \leq 60$ kW
	COMMON COMPETITIVE PROCEDURES	500 MW
Total Maximum Capacity to be auctioned between 2019 - 2020		At least 1,950 MW

2021	COMMON COMPETITIVE PROCEDURES	350 MW

Table 33: Maximum auctioned capacity per RES technology

In 2020, three (3) RES auctions were held in Greece, the results of which are summarized in Table 34:

1st Cycle Auction, Technology Neutral – Common Competitive Auction, April 2020 - Results													
Categories	Auctioned Capacity (max) (MW)	Final Auctioned Capacity (MW)	Project Applications (No/MW)						Auction				
			Applied		Approved		Granted		Bids	Celling price (€/MWh)	Highest Bid (/€MWh)	Lowest Bid (€/MWh)	Weighted average price (€/MWh)
PV stations with 500 kW ≤ P_{pv} ≤ 20 MW & Wind farms with 3 MW < P_{wind} ≤ 50 MW	600	508.35	9	712	9	712	5	502.9	44	61.32	54.82	49.11	51.59
2nd Cycle Auction, Technology Specific, July 2020 - Results													
Categories	Auctioned Capacity (max) (MW)	Final Auctioned Capacity (MW)	Project Applications (No/MW)						Auction				
			Applied		Approved		Granted		Bids	Celling price (€/MWh)	Highest Bid (€/MWh)	Lowest Bid (€/MWh)	Weighted average price (€/MWh)
PV stations with P_{pv} ≤ 20 MW	482.03	142.45	52	199	52	199	39	142	532	63	62.45	45.84	49.81
Wind farms with 3 MW < P_{wind} ≤ 50 MW	481.45	481.45	25	748	25	748	15	472	118	62.99	57.7	53.86	55.67

Table 34: Detailed results for all RES auctions held in 2020

3.5.5. RES Financing

Several instruments have been in place to support the financing of RES, including: (a) a revenue from the operation of the day ahead and intraday markets, (b) a revenue from the imbalances settlement procedures of the balancing market, (c) a revenue equal to the average variable cost of conventional Generation units (this is important especially for NIIS), (d) a revenue from the RES power plants that participate in the electricity wholesale market through the Aggregator of the Last Resort (e) a revenue from the Temporary Mechanism of Optimal Forecast Accuracy, (f) a revenue from the RES levy paid by the consumers and (g) a revenue for CO2 emission rights.

Ministerial Decision ΥΠΕΝ/ΓΔΕ/76979/4917 (Gazette 3373 / B / 31-8-2019) sets forth the appropriate regulatory framework in order to put into effect the new scheme of reduced charges of the so-called "RES Fee" ("ETMEAP") from 1 January 2019, as required by the European Commission Communication on State Aid Guidelines for the Environment and Energy 2014 to 2020 (EEAG) (Official Journal of the European Union, 2014 / C200 / 01). DAPEEP S.A. is defined as the responsible body for the implementation and operation of the information system for ETMEAP. The details of transaction management procedures of ETMEAR from 1.4.2019 are determined in the DAPEEP Code. In addition, in accordance with the provisions set in article 143 of Law 4001/2011, RAE determines the ETMEAR unit charges imposed on consumers of each category. These responsibilities were taken away from RAE for the years 2019 and 2020, while from the year 2021, RAE will determine again those unit charges. In this context, in 2019, the ETMEAR unit charges set by RAE Decision 1101/2017 continued to apply until the publication of Ministerial Decision ΥΠΕΝ/ΓΔΕ/76979/4917 (Gazette 3373 / B / 31-08-2019) in August, which set thereafter the ETMEAR unit charges for all the categories of the consumers. Furthermore, the Ministry of Energy issued Decision ΥΠΕΝ/ΔΗΕ/108553/2053 (Gazette 4295 / B / 27-11-2019) which determined the procedure for the retroactive reimbursement of ETMEAR charges to the final consumers for 2019. RAE, taking into account the relevant data received by DAPEEP S.A., the body responsible for the management of the RES financing account, with its Decision 1654/2020 (Gazette B' 5928) maintained the ETMEAR unit charge at 17 €/MWh for 2021. The RES unit charges are available in the table below:[45]

[45] All consumer categories except those that use electricity for agriculture must pay the full base charge of 17€/MWh for the first 250 MWh consumed annually.

Customers Classification	Unit Charges (€/MWh)
Households (LV)	17.00 €
Other uses (LV)	17.00 €
Other consumers	17.00 €
Business organizations with activities in a sector which is included in Annex 3 of the EEAG, with electro-intensity < 10%	2.55 €
Business organizations with activities in a sector which is included in Annex 3 of the EEAG, with electro-intensity ≥ 10% and electro-intensity < 20%	2.55 €
Business organizations with activities in a sector which is included in Annex 3 of the EEAG, with electro-intensity ≥ 20%	2.55 €
Business organizations with activities in a sector which is included in Annex 5 of the EEAG, with electro-intensity ≥ 20%	2.55 €
Business organizations with activities in a sector which is included in Annex 5 of the EEAG, with electro-intensity ≥ 10% and electro-intensity < 20%	3.40 €
Business organizations with activities in a sector which is NOT included in Annexes 3 & 5 of the EEAG, with electro-intensity ≥ 20%	3.40 €
Lignite mines and pumping stations with HV connections and rail transit with MV or HV connections	3.40 €
Agricultural use of electricity (LV or MV)	9.01 €

Table 35: New RES Levy Unit Charges (2019-2021)

At the end of 2020, the RES financing account recorded a deficit of €263.76 million, mainly due to a drop in electricity demand and in the wholesale electricity prices as a result of the COVID-19 pandemic (see Figure 28). Specifically, it must be pointed out that (a) over 60% of the total RES account revenues originate from the sales of electricity of RE producers in the wholesale electricity market and the RES Levy (ETMEAR) imposed to the electricity consumers for each kWh consumed, (b) the consumption of electricity, according to the operator of the transmission system recorded a decrease of 6% during the first half of 2020 compared to the corresponding period of the previous year. Specifically, during the second quarter (during which a strict lockdown was imposed), the decrease was greater than 10% compared to the corresponding quarter of 2019 and (c) the System Marginal Price (SMP) from January to June 2020 recorded a sharp decrease, which ranged from -22% to -54%. Specifically, the SMP in April 2020 was reduced by 54% compared to April 2019, while the corresponding numbers for May and June 2020 were 48% and 50% respectively.

In this regard, the Greek State adopted Law 4759/2020 (Gazette A' 245) which introduced a package of financial and structural measures to address the existing deficit, provide financial support and ensure the sustainability of the RES financing account to achieve the desired targets of RES penetration in the country's energy mix. Briefly, the following measures were imposed: (a) a one-time special contribution amounted to 6% of the total electricity sales that were made by RES and CHP generators that started operating before 31st of December 2015, (b) an additional charge of 2 €/MWh for the electricity supplied by the Suppliers to their customers or generated by self-consumers for 2021 and (c) a "green levy” of 30 €/kl on diesel fuel, with the exemption of the diesel which is used for heating purposes. Part of the above diesel revenues would be used to finance the RES account after a relevant Ministerial Decision is issued.

		2019[46]	2020
Aggregator of the last resort account	DAM and IDM revenues for units represented by the aggregator of the last resort	6.925	12.500
	Settlement of units represented by the aggregator of the last resort	-8.114	-10.918
	Aggregator of the last resort account balance	**-1.189**	**1.583**
Subaccount for the electricity market (ΛΓ1)	DAM and IDM revenues for units operating under PPAs, FiTs and the terms of the Special PV rooftop programme	84.013	463.253
	Imbalance settlement of units operating under PPAs, FiTs and the terms of the Special PV rooftop programme	2.231	-5.525
	Imbalance settlement of units that are either represented by an aggregator or participate directly in the electricity market	-0.061	-5.600
	Imbalance settlement of units represented by the aggregator of the last resort	1.388	-1.943
	Temporary Mechanism of Optimal Forecast Accuracy (ΜΜΒΑΠ)	0.011	0.075
	Variable cost of conventional Generation units (ΜΜΚΘΣΣ)	18.641	150.012
	Disincentive for units represented by the aggregator of the last resort	0	0.132
	Imbalance cost	0	0.142
	Total revenues	**106.222**	**600.546**
	Aggregator of the last resort account balance	-1.189	1.583
	Subaccount for the electricity market (ΛΓ1) balance	**105.033**	**547.528**
Subaccount for RES support (ΛΓ2)	Res levy (ΕΤΜΕΑΡ)	-7,270	551.284
	CO_2 emission rights	125.775	409.703
	Total revenues	118.505	975.450
	Remuneration of units operating under FiPs	-9.989	-149.139
	“Readiness” Support payments (ΠΑΕΣΑ)	-0.029	-0.981
	Total expenses	**-10.018**	**-150.120**
	Non-interconnected islands’ account balance	-1.068	64.869
	Subaccount for RES support (ΛΓ2) balance	107.419	935.368
Main RES financing account	Subaccount for the electricity market (ΛΓ1) balance	105.03	547.53
	Subaccount for RES support (ΛΓ2) balance	107.42	935.37
	Total revenues	212.45	1,482.90
	Remuneration of units operating under PPAs & FiTs	-210.79	-1,645.94
	Remuneration of roof PV units	-33.66	-193.92
	Total expenses	-244.45	-1,839.85
	Main RES financing account balance	-32.00	-356.96
	Main RES financing aggregated account	83.99	-263.76

Table 36: RES’ Financing Account statistics in million EUR (2019-2020)

[46] The RES Special Account was restructured for the proper operation of the Target Model from November 2019. Therefore, this column only covers data for November & December of 2019 only.

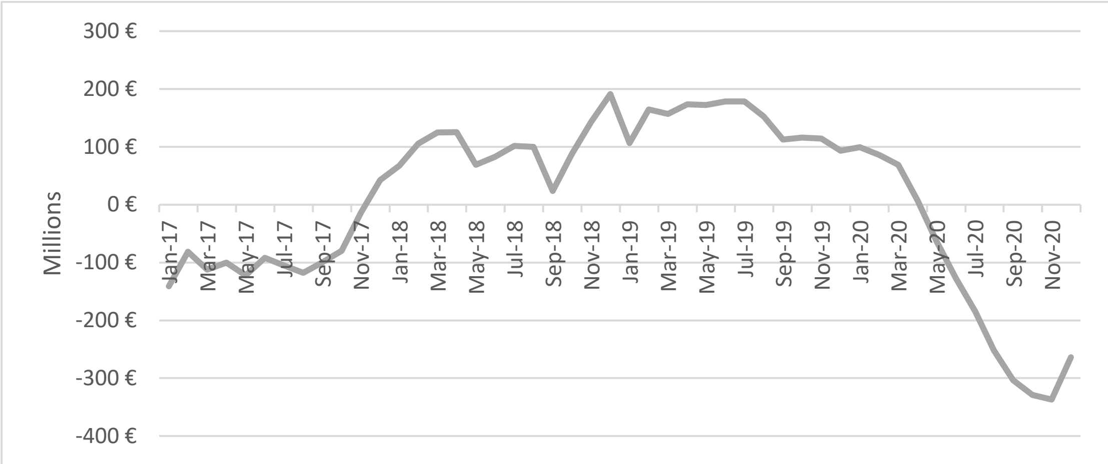

Figure 28: Special Account's Progress

3.5.6. New RES Legislation and Regulatory Development

Ministerial Decisions

- The Ministry of Energy published Decision **ΥΠΕΝ/ΔΑΠΕΕΚ/114746/4230 (Gazette B' 5291/01.12.2020)** under which the new regulation on the Electricity Generation Certificates (EGCs) entered into force. The new regulation specifies and further clarifies issues of the RES licensing process while it also introduces new licensing elements. There are not any substantial changes in the content of the application file submitted to RAE and the applicant for Electricity Generation Certificate for Special RES and CHP power plants must still submit an economic and technical report that will prove the project's viability. On the other hand, for planned projects in Non-Interconnected islands, the regulation contains more detailed provisions regarding the additional information that the licensing authority is entitled to request from the applicant to verify the compatibility of the power plant with any of the autonomous systems of the Non-Interconnected Islands.

  In addition, regarding the applications for modification of an EGC or a Generation License, the new regulation sets certain conditions under which applications for projects that have participated in the competitive procedures of article 7 of Law 4414/2016 are given priority over other applications. In particular, the requested modification to the EGC or Generation License (a) should not cause an increase of more than 10% to the installed capacity of the power plant, (b) should not extend the boundaries of the installation unless it is required by an opinion under the environmental regulation and (c) there is no power plant location overlapping with an already submitted or approved application for an EGC or a Generation License issued for another power plant.

  In case of location overlap disputes, the new regulation gives 30 days to the parties so they can settle their relevant disputes amicably while also specifying the order in which the licensing body conducts the evaluation of projects with location overlap. Under the new framework power plants that hold *"EGC for Special RES and CHP power plants"* gain priority over normal projects in cases of location overlapping disputes.

At the same time, the new regulation specifies the procedure and conditions to extend the EGCs' validity period. The power plant owner must prove that it is operational at an availability rate of more than 70% or that the average annual energy produced by the station has not decreased by more than 30% of the average annual energy produced in the last five calendar years from the year when the EGC renewal request was submitted.

The new legislative framework also regulates to some extent the right of the landowner to challenge the legal right of the EGC owner to install photovoltaic power plants in his land. In addition, the new photovoltaic, wind turbines and small hydro power plants must comply with the new location rules until 31 December 2021. The licensing body will proceed with the revocation of the relevant EGC or Generation Licenses of the power plants if the above deadline is not met.

RAE's Opinions

- **RAE Opinion 11/2020**. Pursuant to the provisions of article 18 of Law 4685/2020, some provisions of the Law are implemented through the appropriate secondary regulatory framework, namely the Regulation of Electricity Generation Certificates for RES, CHP and innovative projects (EGC Regulation). This Regulation is issued by a decision of the Minister of Energy following RAE's Opinion. In particular, the regulation specifies: a) The criteria for the evaluation of license applications, b) the procedure for the electronic submission of applications for the issuance of EGCs, as well as the procedure for the examination of these applications and the procedure for electronic submissions of objections against submitted applications, c) the technical details for the structure and content of the Electronic Register, the user categories, the way of access, the credentials and special issues related to registration and user authentication, the system security policy, the interoperability with the systems of network operators and licensing bodies, d) the procedure for amending and transferring the EGCs and the existing Generation Licenses, as well as the procedure for registering the new information in cases where an EGC amendment is required, e) The specific obligations of the EGC or Generation License holder, the procedure of monitoring the fulfillment of the milestones of Article 12 and any related obligations, as well as the procedure for automatic termination and the revocation of the EGCs, f) the benchmarking criteria in cases where there is an inability to settle of land differences, the projects' energy efficiency or when the maximum capacity for installation of RES power plants is reached in the municipality, g) network congestion issues, including the initiation of the license application submission procedure as well as the allocation of existing capacity to RES categories, in accordance with the provisions of Article 13 (1), h) Any other specific issue.
  In this context, RAE developed a Regulation that covers the above issues. The proposal included 12 Annexes' which are the main tool for any licensing action taken by the RES project promoters in relation to the issuance, amendment or transfer of the EGC through the electronic system. These Annexes include the application forms that must be submitted for

the issuance, amendment or transfer of the EGC, the type and content of the progress reports submitted in order to monitor the implementation process of the projects, as well as the general and special conditions that apply for each EGC and which govern the relevant activity for which it is issued. Furthermore, Annex 12 is a special annex that has been introduced for the examination of the criterion of legal area possession in which the RES power plant will be constructed. This annex specifies the relevant supporting documents that have to be submitted to RAE for the evaluation of the above criterion.
Prior to submitting its Opinion to the Minister, RAE launched a public consultation on the draft of the above regulation. After taking into account the proposals and comments made, RAE issued the Opinion 11/2020 on 5 November 2020.

Primary Legislation

Law 4685/2020 (Gazette A' 92) introduced major changes to the environmental legislation and RES administrative licensing procedures. The goal of the first chapters of the law is to simplify and reduce the timeframe for both environmental and initial RES administrative licensing procedures, contributing in this way to the general national objectives, the public interest and a more efficient exploitation of natural resources for economic growth. Specifically, the Electricity Generation License, as provided by Law 3468/2006 is replaced by an Electricity Generation Certificate (EGC). There are two types of EGCs: (a) Electricity Generation Certificates for RES and CHP power plants and (b) Electricity Generation Certificates for Special RES and CHP power plants. The competent certificate issuing authority is RAE until a relevant decision, which will determine the licensing authority, is issued by the Minister of the Environment and Energy. The certificate is issued upon submission of a relevant application to RAE by its president's approval. The above application can be submitted by any interested party using its TAXISnet credentials at the portal rae.marketsite.gr in 3 cycles (1st to 10th of February, June and October). All cycle applications must be examined before a new cycle of applications can be initiated.

The EGC is issued for a period of up to 25 years with the possibility of renewal for 25 more years. In order to promote the implementation of the projects, the certificate loses its validity automatically if (a) the holder of the certificate does not submit an application for the "Approval of the Environmental Conditions" within 6 months from the certificate's issuance date (this deadline is extended by 12 months for projects located in NATURA areas, (b) the holder of the certificate does not accept the "Final Connection Offer" made by the network operator or/and does not submit the relevant letter of guarantee and (c) the holder of the certificate does not submit an application for a Final Connection Offer to the network operator accompanied by a "Decision on the Approval of the Environmental Conditions" within 30 months from the certificate's issuance date in case the project is planned to be connected to a saturated electricity network.

The law foresees a reduction of the application fee submitted in favor of RAE, which is now calculated with a base value of 60€/MW, while its maximum value cannot be greater than 12,000 €. In addition, for the issuance of the EGC, the applicant must submit a onetime fee in favour of the RES Special Account for the Interconnected Network and System. The amount of the fee is defined per unit of the project's installed capacity as presented in Table 37. The maximum limit of the one-time fee for issuing an EGC corresponds to a power plant of 250 MW of installed capacity. The process of project licensing begins with the EGC. The EGC issuance process does not depend on a thorough and exhaustive evaluation of the viability and feasibility of the projects. In this scope, the Law 4685/2020 abolished certain criteria such as: the maturity of the project, the scientific and technical adequacy of the applicant, the provision of PSOs, the compatibility of the proposed project with the NECP, the criterion that ensures the safe facility and network operation for PVs and Wind parks, as these issues are thoroughly examined by the competent network operators at a later stage, except in cases where the power plant is planned to be constructed in a saturated network in any of the Greek islands. In any case, the evaluation of more specific criteria (such as economic feasibility and energy efficiency) is still in place for innovative projects due to the complexity of the technology used and the special conditions for their network integration.

The new law combines the simplification of the licensing process with the setting of specific time limits for the implementation of the RES projects. The automatic termination of the EGC in cases where some reasonable time milestones are not met by the project promoters, is a measure that would free up more space for other new projects to be constructed and connected to the network.

In conclusion, the introduction of the new licensing scheme with the replacement of the Generation Licenses with EGCs, with the substantial cut in red-tape and the automation of procedure present the key pillars of simplification and acceleration of the first stage of the RES licensing process. Accordingly, the amendments to the environmental regulation are aimed at speeding up and simplifying the relevant procedures to create an investment friendly environment, introducing a faster, safer and more efficient regulatory framework.

Project's Installed Capacity (MW)	Fee (€/MW)
Installed capacity ≤ 1 MW	3,000 € / MW
1 MW < Installed Capacity ≤ 10 MW	2,500 € / MW
10 MW < Installed Capacity ≤ 50 MW	2,000 € / MW
50 MW < Installed Capacity ≤ 100 MW	1,500 € / MW
100 MW < Installed Capacity ≤ 1,000 MW	1,000 € / MW

Table 37 Fee submitted by the applicant in favour of the RES Special Account for the issuance of an Electricity Generation Certificate

3.5.7. Other developments in the RES sector

Development of an IT system for RES power plants applications for EGCs

According to the provisions of Article 3 of the EGC Regulation:

The applications for the issuance of an EGC, as well as any other application referred to in the EGC Regulation, are submitted through the Electronic Register of Electricity Generation from RES and CHP power plants (hereinafter

"Electronic Register") which is specially developed for this purpose.

The Electronic Register should include at least the following:
Full authentication and certification of Legal and Natural Persons through its interoperability with TAXISnet systems and their login into the Electronic Register's platform.

- Structured recording, sending and retrieval of the necessary supporting information and supporting documents that must be submitted by the applicant.
- Data storage in a secure and reliable manner in electronic means.
- Development of interoperability software for the interconnection of the Electronic Register with other electronic systems. Specifically:
- Interconnection with RAE's GIS spatial control system.
- Interconnection with the electronic system of DAPEEP S.A..
- Interconnection with the systems of network operators ADMIE S.A. and DEDDIE S.A..
- Classification of the users' accounts into three levels: simple users, administrators and superuser accounts.

Based on the above provisions, RAE proceeded to the development of an IT system that meets these specifications set by the EGC Regulation. The interoperability of the system is presented in Figure 29, while Figure 30 shows the process that the license applicants go through starting from the registration of the user in the IT system to the issuance of the EGC, if the application is approved.

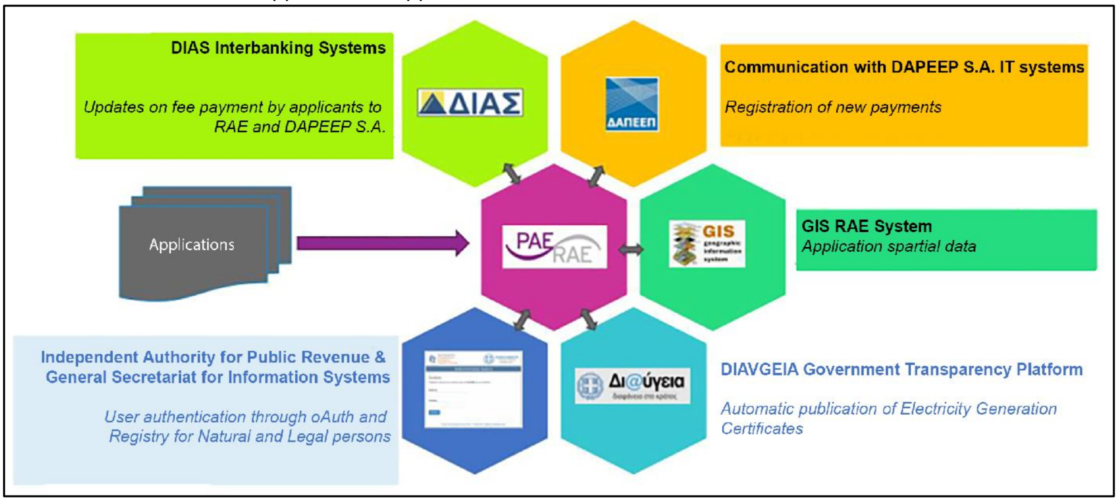

Figure 29: Interoperability of RAE's IT RES application system for EGCs

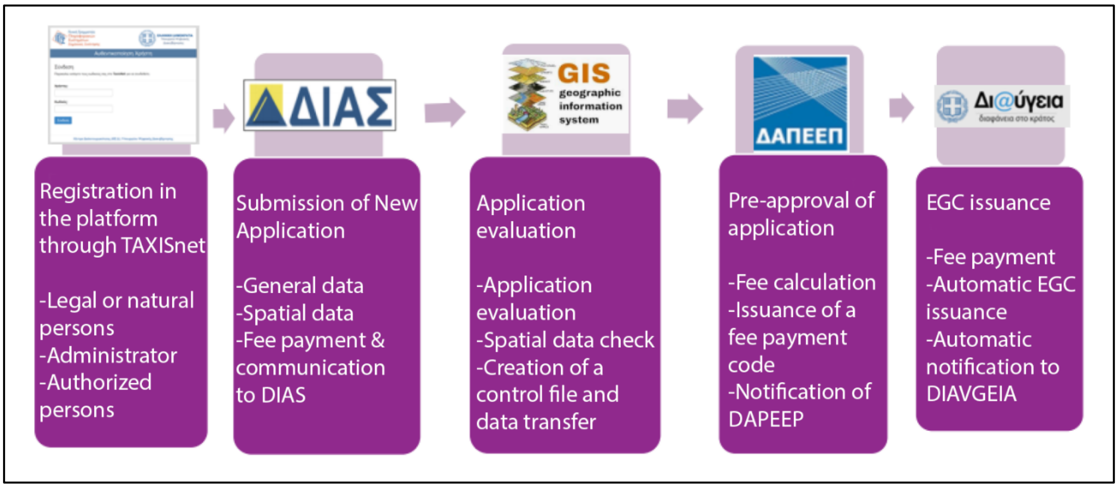

Figure 30: Process for the issuance of RES EGCs in the new RAE IT system

Framework for the penetration of electricity storage facilities.

Greece has set a very ambitious goal of 35% of the participation of RES in its gross final energy consumption according to its National Energy and Climate Plan (NECP). In order to achieve this high penetration target, it was deemed necessary to establish a regulatory framework to promote and support investments in storage facilities.

The importance of defining a framework to support investments in storage facilities is also emphasized by the European Commission in the Clean Energy for all Europeans Package. According to the Commission, the viability of these investments should be based primarily on revenue acquired from the participation of these storage facilities in the markets by offering their services and not based on subsidies or other state aid.

Storage stations can support the increase of intermittent RES, which are known to represent the largest percentage of the NECP projects for 2030 (Wind parks and PVs), storing any surplus of the energy produced during hours of low demand or during technical network problems that result in inability to absorb the electricity produced, while utilizing the energy when it becomes possible and necessary. In addition, storage facilities are, due to their technical characteristics, flexible units that can provide ancillary services to DSOs and TSOs.

RAE, in order to support the elaboration of an integrated framework proposal of the storage units, elaborated a relevant study which was completed within 2020, on the subject of "Formulation of a legislative framework for the storage of electricity", as well as consultations with European bodies and energy market actors which will be finalized within 2021, on best practices for the penetration of these units in principle, and possible addition mechanism to support the relevant investments.

Taking into account the objectives set in the National Energy and Climate Plan (NECP) and, in particular, the increased RES penetration in the electricity generation, RAE developed a specialized technical study on the analysis of the operation of the interconnected system in its future development with RES, as defined in the NECP, the assessment of the contribution of storage in the management of RES generation and the system in general, and the quantification of the appropriate size of storage units in the interconnected system for the support of the above objectives during the reference year of the NECP (2030).

3.6. Consumer Protection

The strengthening of competition in the energy retail markets and the relevant developments of the last three years had a direct impact on final consumers. In addition, the unprecedented conditions that prevailed in the country in 2020 due to the COVID-19 pandemic, directly affected both energy markets and consumers.

RAE, in the context of its responsibilities for consumer protection, deals with the issues of energy consumers protection in accordance with its responsibilities as defined by the Energy Law 4001/2011 and that are further specialized in the secondary legislation.

3.6.1. Compliance with Annex 1 of Directive 2009/72/EC

Articles 37, paragraph 1, point n), and article 41, paragraph 1, point o), of Directives 2009/72/EC require that the regulator, if necessary, in collaboration with other Authorities, guarantee that their consumer protection measures, including those in Annex 1, are effective and applied. Table 38 illustrates the implementation status in Greece of the measures set out in Annex 1.

PARAGRAPH 1	LETT.	IMPLEMENTATION STATUS
Customers have a right to a contract with their electricity supplier that specifies a series of aspects.	a)	This obligation is covered by the Electricity Supply Code, which sets out the information that must be provided before the conclusion of a contract and the main clauses that must be included in a contract. The same Code also requires that the customer must be provided with the contract in a durable medium. With regards to the services and the service quality levels offered, they must be available to consumers through the Services Leaflet which is published on the Supplier's site. Currently compensation schemes which apply if contracted service quality levels are not met, are not offered by Suppliers.
Customers are given adequate notice of any intention to modify contractual conditions and they are informed about their right of withdrawal when the notice is given	b)	The Electricity Supply Code requires that customers must receive 60 days of notice prior to the application of the modifications to contractual terms, except for price modifications where customers can be informed with the next bill after the price change. In any case, customers have the right to withdraw from the contract at no cost if they do not agree with the new terms.
Customers must receive transparent information on applicable prices and tariffs and on standard terms and conditions in respect of access to and use of electricity services.	c)	The Electricity Supply Code stipulates that contracts must contain a section which clearly summarizes the costs borne by customers for the supply of electricity.
Customers are offered a wide choice of payment methods.	d)	This obligation is derived from the Electricity Supply Code with the additional term that at least one payment method offered by each Supplier must be cost free

General terms and conditions shall be fair and transparent, and given in clear, comprehensible language. Customers shall be protected against unfair or misleading selling methods	d)	The Electricity Supply Code contains the minimum "Principles of information and contact with clients" that cover all the required obligations. Suppliers are obliged to introduce a Code of Contact based on at least the above referred principles.
Customers are not charged for changing supplier.	e)	Supplier switching is free of charge according to the Electricity Supply Code.
Consumers benefit from transparent, simple and inexpensive procedures for dealing with their complaints.	f)	The Electricity Supply Code stipulates that Suppliers must operate a Consumer service department that handles customer complaints according to at least the minimum "Standards of complaints handling" included as a separate section of the Code. Written complaints / enquires must receive a first or final response within 10 working days.
Consumers benefit from information about their rights regarding universal service (electricity customers) of their right to be supplied at reasonable prices	g)	The relevant information for consumers can be found on the Authority's website (www.rae.gr)
Consumers can have at their disposal their consumption data and shall be able to allow any registered supply undertaking to access, by explicit agreement and free of charge, their metering data	h)	Consumers are adequately informed about their actual consumption, quarterly or every four months through their bills. In addition, an application form is available at their Supplier's site and/or customer service centers, to request historical consumption data.
Consumers receive a final closure account following any change	j)	Energy Suppliers are obliged to issue a final closure account, within 6 weeks after the contract termination/change of supplier.

of supplier, no later than six months after the change of supplier has taken place.		
PARAGRAPH 2		
Member States shall ensure the implementation of intelligent metering systems that shall assist the active participation of consumers in the electricity and natural gas supply markets		In the electricity sector, the timeframe for the roll-out of smart meters is set by Law no. 4001/2011 for the replacement of at least 80% of old meters by 2020.

Table 38: State of implementation of measures set out in Annex 1 (Directive 2009/72/EC)

3.6.2. Ensuring access to consumption data

Ministerial Decision published in GOV Gazette B' 82/27.1.2006 ("Guide for management and periodic settlement of DSO measurements") requires that the DSO, gather actual consumption measurements at least every 6 months. In practice, the frequency of recording consumption data is every four months. Consequently, small consumers are informed about their actual consumption at least every four months through their Suppliers bill.[48] Furthermore, consumers can have access to historical consumption data through a simple application registered to their Supplier.

3.6.3. Consumer empowerment - The Price Comparison Tool (PCT)

RAE in the context of its competences, under the provisions of articles 22-24, 27 and 49 of law 4001/2011 and article 7 of the Supply Codes (for gas Gazette B ' 1969/2018, and for electricity, Gazette B΄ 832/2013 respectively) and, with due of the provisions of Directive 2009/72 and the guidelines, focused on the creation of a fully functionable Price Comparison Tool for electricity and gas, starting in Q4 of 2018.

This tool is designed to reflect and compare as fully as possible, on the basis of the principles of transparency, accessibility, completeness of information and independence, the overall estimated cost of the Competitive part of the offers, while also calculating the corresponding cost of the regulated part. This Price Comparison Tool is targeted to the electricity low-voltage customers, and domestic and commercial customers of natural gas as defined in article 3 of the respective supply codes.

In order for all the participants in the PCT to have clear obligations and rights, which will ensure that the information that reaches the end consumer is reliable, transparent and impartial, the Authority has adopted a relevant Operation Manual for the PCT. The purpose of this Regulation is to describe the operating procedures of the "Price Comparison Tool for retail electricity and gas", to outline the roles of the parties involved, as well as their obligations and rights. The Regulation was based on RAE's Decision 313/2019 and was issued in Gazette B '1254/12.04.2019.

In addition, in 2019, the first phase of the implementation of the tool was completed as well as its first pilot operation. More specifically, the tool was designed to capture and compare as fully as possible, on the basis of the principles of transparency, accessibility, availability of information and independence, the total estimated cost of the competitive part of the consumers' offers, while at the same time calculating the respective costs of the regulated charges and the Social Tariff for vulnerable consumers.

With regard to making the Tool available for public use, the Authority initially presented it to Social Partners (consumer organizations) as a pilot project. In 9 December 2020 the PCT was made available to consumers and any other relevant party through the website https://www.energycost.gr/en.

[48] The consumers have to option to submit their meter readings by themselves to the DSO, in which case they get billed their actual consumption.

This Tool is designed to reflect and compare in the most inclusive way possible, based on the principles of transparency, accessibility, completeness and independence of information, the total estimated cost of the competitive part of the offered tariffs, while calculating the corresponding cost of the regulated part, related to consumption and use of energy. In addition, emphasizing on the support and protection of low-income consumers, the Tool is designed with the option to include the discounts offered to Social Tariff beneficiaries. The Tool was created aiming to be applied on LV customers as well as the household and commercial final customers in the natural gas segment, as defined in Article 3 of the respective Electricity and Gas Supply Codes.

3.6.4. Quality of DSO Services

The Distribution Network Code provides for a comprehensive regulatory framework for the service quality provided by the electricity DSO. This framework consists of a financial incentive mechanism to promote optimal overall and minimum quality levels for the provision of electricity distribution services. These mechanisms are implemented after the introduction of the service quality manuals of the Distribution Network Code, in combination with the introduction of a regulatory period of 3 to 5 years.

Code provides for a comprehensive regulatory framework for the service quality provided by the electricity DSO. This framework consists of a financial incentive mechanism to ensure a satisfactory instrument and a minimum level of quality for the provision of electricity distribution services. These mechanisms are implemented after the introduction of the service quality manuals of the Distribution Network Code, in combination with the introduction of a regulatory period of 3 to 5 years.

Currently, minimum quality levels are set for certain commercial services (maximum execution time for new connections, maximum time for reconnection after debt settlement, maximum time for responding to complaints, etc.) through the “Guaranteed Services” DSO program[50]. Through RAE’s initiative, this program was modernized in 2014 and further improved in 2020. The main points of improvement were the automation of the payment procedure foreseen in cases where the deadlines for the provision of Guaranteed Services were not met by DEDDIE, the better organization and documentation of the implementation of the program through IT systems and the addition of new services (guaranteed maximum interruption in power supply caused by network issues for MV consumers).

The implementation of the first improvement phase was extended until the end of 2016, when DEDDIE submitted the necessary proposals on the improvements for the second phase. The evaluation of those proposals by RAE was postponed in 2017 and was completed within 2019, with the launch of a public consultation by RAE. The final RAE Decision 1151 A/2019 was issued during the first half of 2020 and was enacted from 1 July 2020. The main improvements of the “Guaranteed Services” program under this decision are the following:

- Increase of the compensation paid by the network operator to LV consumers to 20€ and MV consumers to 40€, from the amount of 15€ that was previously foreseen.
- Scaling of the amount of consumer compensation paid by the network operator (up to 4 times the basic compensation) in cases of significant breach of guaranteed standards for connection

[50] You may find more information on the “Guaranteed Services” project on HEDNO website: https://www.deddie.gr/en/eggyimenes-ypirisies-katanaloton/

to the network, maximum duration of a single unplanned or planned long interruption, investigation of reports related to voltage quality, supply restoration following failure of customer fuse and reconnection to the network following debt payment or upon consumer request.

- New guaranteed services related to the establishment of new connections that require major network extension, the replacement of a simple meter with a daytime and nighttime meter and keeping the agreed schedule for the visits on consumer properties.

- Defining specific reporting requirements to enable effective regulatory monitoring and validation of program execution.

Regarding the monitoring of the quality of services through overall performance indicators, RAE's Decision 1151 A/2019 foresaw specific indicators related to customer call centres, metering, connection of producers to the network and supplier switching, with the aim to assess the current situation and explore potential future regulatory interventions to improve the quality of services by setting overall performance standards.

Finally, regarding the procedure for consumer compensation by DEDDIE whose applications have been damaged due to an accidental interruption of supply through the neutral conductor, the above RAE's Decision increased both the time available for the consumer to submit a claim and the maximum amount of compensation to 600€ regardless of the type of the connection (three-phase/single-phase).

3.6.5. Vulnerable customers and Energy poverty

According to Article 52 of Law 4001/2011, vulnerable customers are defined as: (a) The financially weak customers suffering from energy poverty[51]; (b) Customers who themselves or their family rely heavily on continuous and uninterrupted power supply, due to mechanical support; (c) Elderly who are over seventy years old, provided they do not live together with another person who is younger than the above age limit; (d) Customers with serious health problems, especially those with severe physical or mental disability with intellectual disabilities, severe audiovisual or locomotor problems, or with multiple disabilities or chronic illness who cannot manage their contractual relationship with their Supplier; (e) Customers in remote areas, especially those living at the Non-Interconnected Islands.

RAE, within the framework of its competences, collects and processes data related to settlements between consumers and suppliers, it controls and monitors the implementation of the obligations that are particularly provided for vulnerable customers and has the right, as prescribed by law 4001/2011, to impose penalties in cases where those obligations are breached to protect the vulnerable customers.

According to the data collected within 2020, the average number of electricity consumers who were included in the vulnerable customers' category was amounted to 558,714, which translates into a percentage of 9.4% of the total household consumers in the electricity retail market. Furthermore, the total number of debt settlements made by vulnerable customers was amounted to 67,015. It should be

[51] Energy Poverty as defined in Article 2 of Law 4001/2011 is *"a situation in which consumers are in a difficult position to cover their expenses for their supply of electricity or natural gas, due to their low income as proved by their income declarations in combination with their professional status, family status and special health conditions, as these expenses constitute a significant percentage of their disposable income."*

noted that completed debt settlements are amounted to only 6.91% (4,634) of the total settlements made. This low percentage can be explained by both the high number of settlements that were not completed but also due to the fact that in many cases, the time period given to consumers to repay their debts was longer than one year.[52]

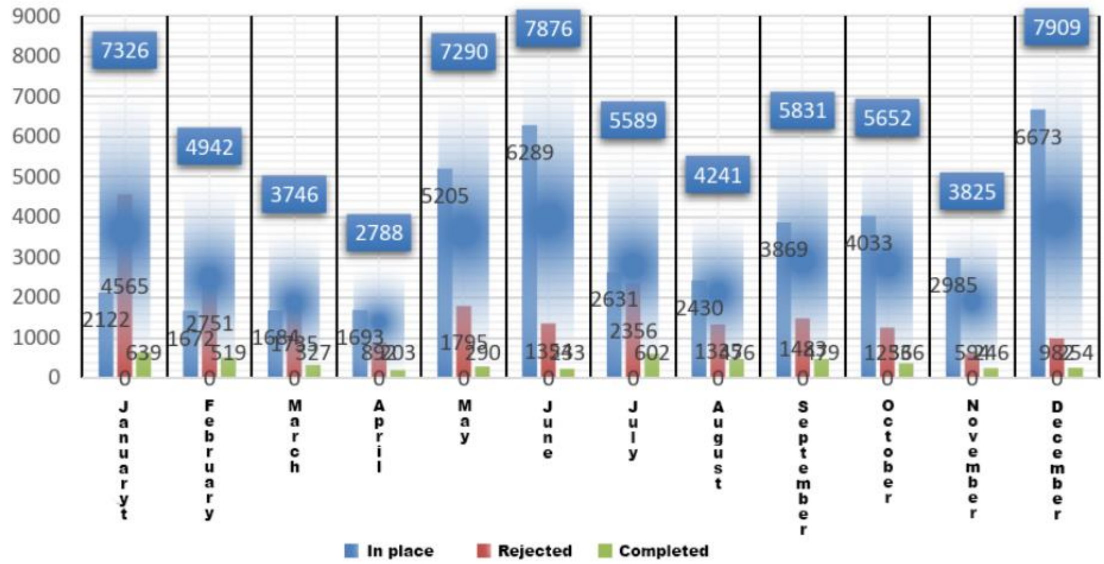

Figure 31: Situation of debt settlements of vulnerable consumers within 2020

In 2020, RAE focused on the protection of vulnerable customers specifically looking into issues such as the transparency of utility bills, charges and terms of supply. In addition, a great number of complaints that RAE received in the past two years was related to the difficulty to understand the competitive charges of the electricity bill. Most of the customers complained that they cannot verify the relevant methodology.

[52] Based on the information made available to RAE, there isn't a significant number of vulnerable consumers in the natural gas market who have drawn up a debt settlement agreement with a gas supplier in 2020.

	Residential Social Tariff 2011 - 2020	
Year	Number of customers	Total Energy (TWh)
2011	247,666	548
2012	250,568	404
2013	412,883	1.582
2014	522,760	1.251
2015	656,834	1.315
2016	578,311	1.549
2017	693,487	1.651
2018	471,706	0.999
2019	483,710	1.801
2020	437,137	1.867

Table 39: Number of customers and total consumption - Residential Social tariff 2011 – 2020

RAE, aiming at tackling energy poverty, actively participated together with the National Technical University of Athens in the pan-European Research Program «STEP-IN: Using Living Labs to roll out Sustainable Strategies for Energy Poor Individuals», which falls under the umbrella of Horizon 2020. On 29 January 2021, the project was successfully concluded.[53]

In addition, RAE participates in the "Twinning Project for Service Quality and Smart Metering in Georgia - Development of Incentive Based Regulation for Service Quality and Regulatory Strategy to Support Roll-out of Smart Metering", analyzing energy poverty and consumer protection in Georgia.

3.6.6. Handling of consumer complaints

RAE, according to article 24 of Law 4001/2011, has the competence for the protection of consumers and handles their complaints, if these concern issues of regulatory nature. Issues of civil or commercial nature are not examined by RAE. Nevertheless, the Authority receives numerous requests, notifications, reports and complaints from the consumers and other public bodies (e.g. the Greek Consumer Ombudsman, General Secretariat of Commerce and Consumer Protection) which handle consumer complaints of civil nature and non-regulatory issues for the distribution networks. Issues such as debt settlement, bill verification, interbank payments, application of discounts as well as nuisances and disturbances caused by network infrastructure do not belong to the competences of the Authority. The consumer behaviour highlights the need for a systematic and well-structured cooperation between agencies, in order to reduce the phenomenon of submitting the same requests to different consumer protection bodies.

Furthermore, starting from 2018, RAE systematically processes the data collected by the electricity and gas suppliers, in accordance with the relevant provisions of the natural gas and electricity supply codes. In this scope, 2020 was the first year of implementation of the "Financial tool for monitoring the retail

[53] For more information and access to project deliverables visit https://www.step-in-project.eu/.

market participants". This tool provides a standard way to record and classify complaints, requests and consumer communications made between consumers and the energy suppliers.

In general, consumers can submit enquiries and complaints to RAE in writing through a personal visit to RAE office, by email to info@rae.gr, or by mail post. They can also contact the central telephone of RAE for simple information enquiries. Particularly complex enquiries should be sent in written form. RAE also has on its website an online form for consumer complaints and enquires.

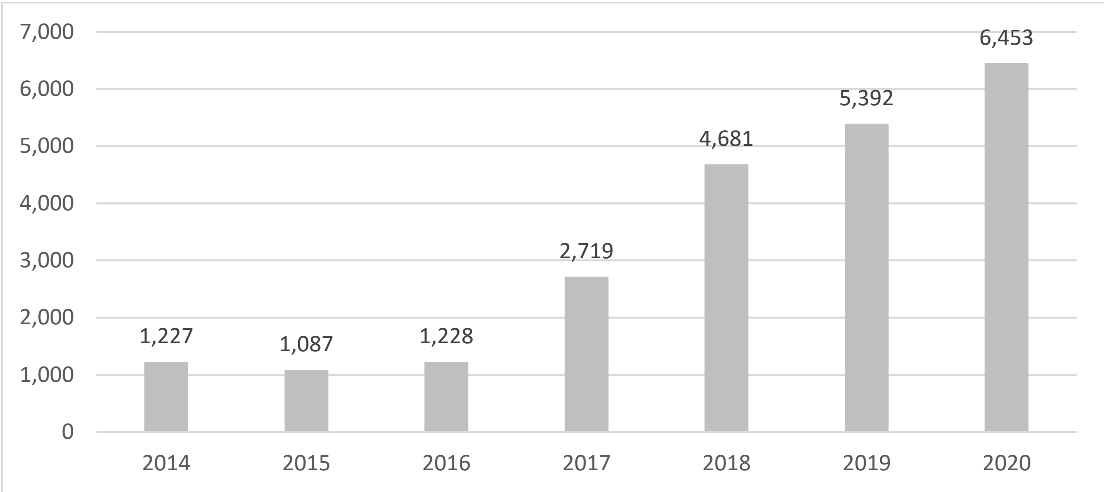

Figure 32: Consumer Complaints submitted to RAE (2014-2020)

The total number of consumer complaints submitted to RAE in 2020 amounted to 6,453, and hence it was significantly increased (by approximately 19.68%) compared to 2019 (5,392 reports), reaching the highest level of the last decade.

In 2020, a significant proportion of complaints submitted to the Authority by consumers regarding the difficulty in understanding electricity non-regulated tariffs in the bills, their inability to verify the relevant methodology used for these tariffs and, in some cases, the vague and confusing terms of the actual cost of energy consumption in relation to their contractual agreement with the Supplier. Furthermore, there were also complaints about content ambiguity and misleading messages in the advertising and promotional activities of Suppliers, which makes it difficult for the average consumer to make the necessary comparisons and choose the most beneficial offer.

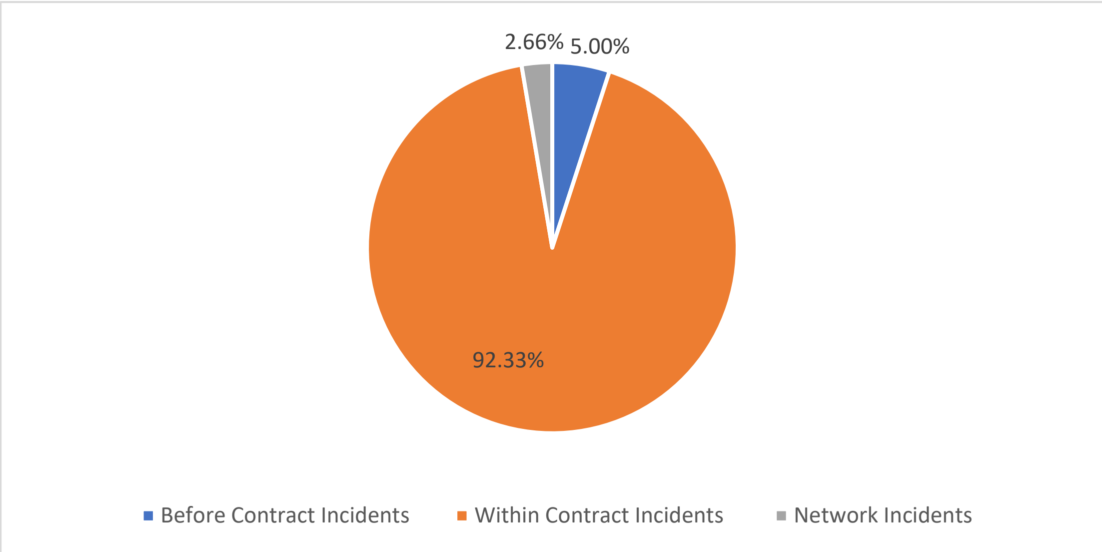

Figure 33: Percentage of total electricity and gas complains per category of complaints

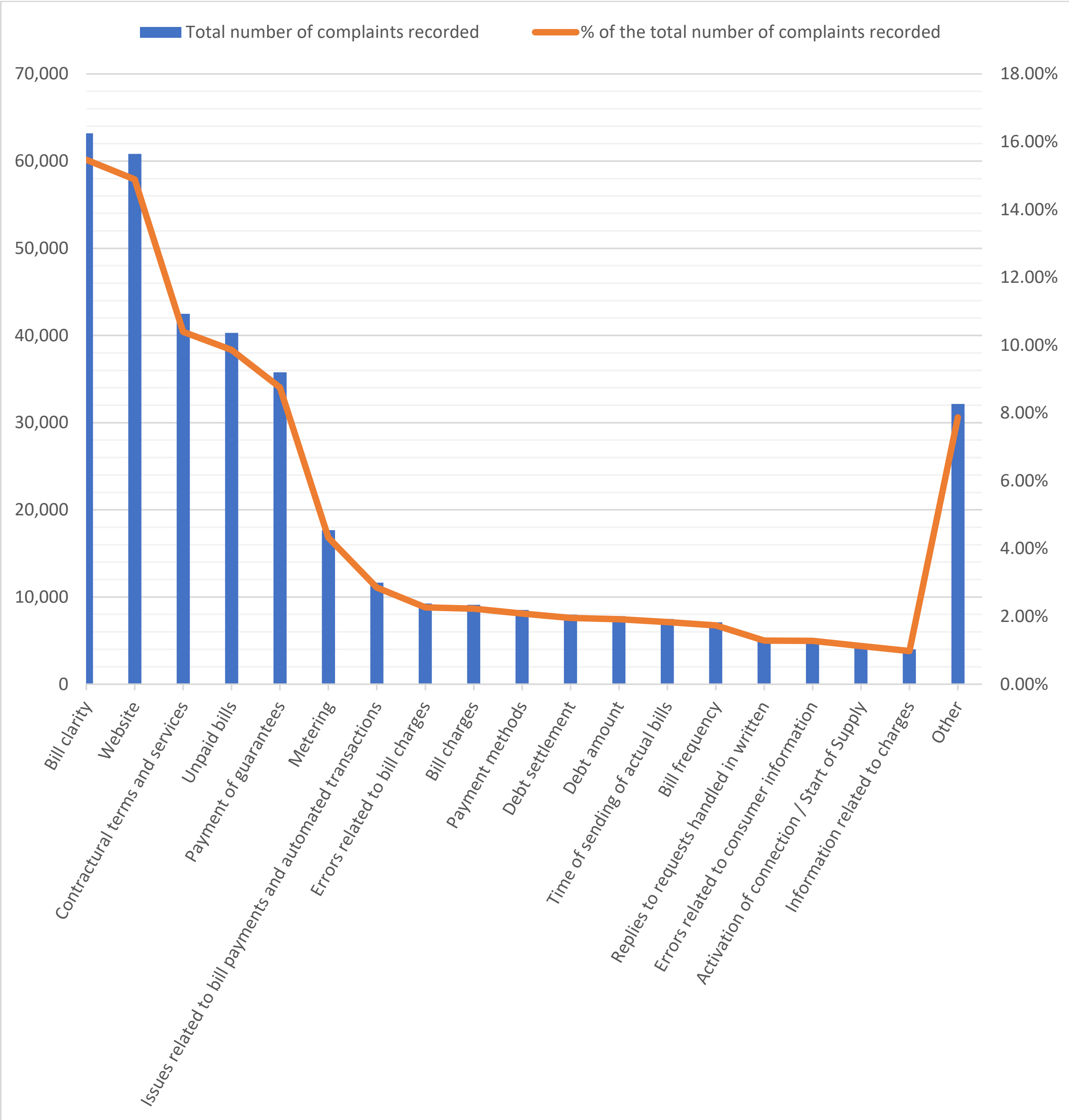

Figure 34: Total Number of consumers' queries per category submitted to electricity suppliers (2020)

In 2020, the majority of complaints concerned disputes and clarifications over electricity tariffs for the conventional period. The dominant supplier had most of the complaints (58.59%). On the contrary, the market share of alternative suppliers is not proportional to the amount of complaints received (80.01% of complaints concerning the conventional period). Due to the COVID-19 crisis, the consumers submitted a significantly large number of complaints concerning Suppliers' websites and applications as electronic payments increased in 2020.

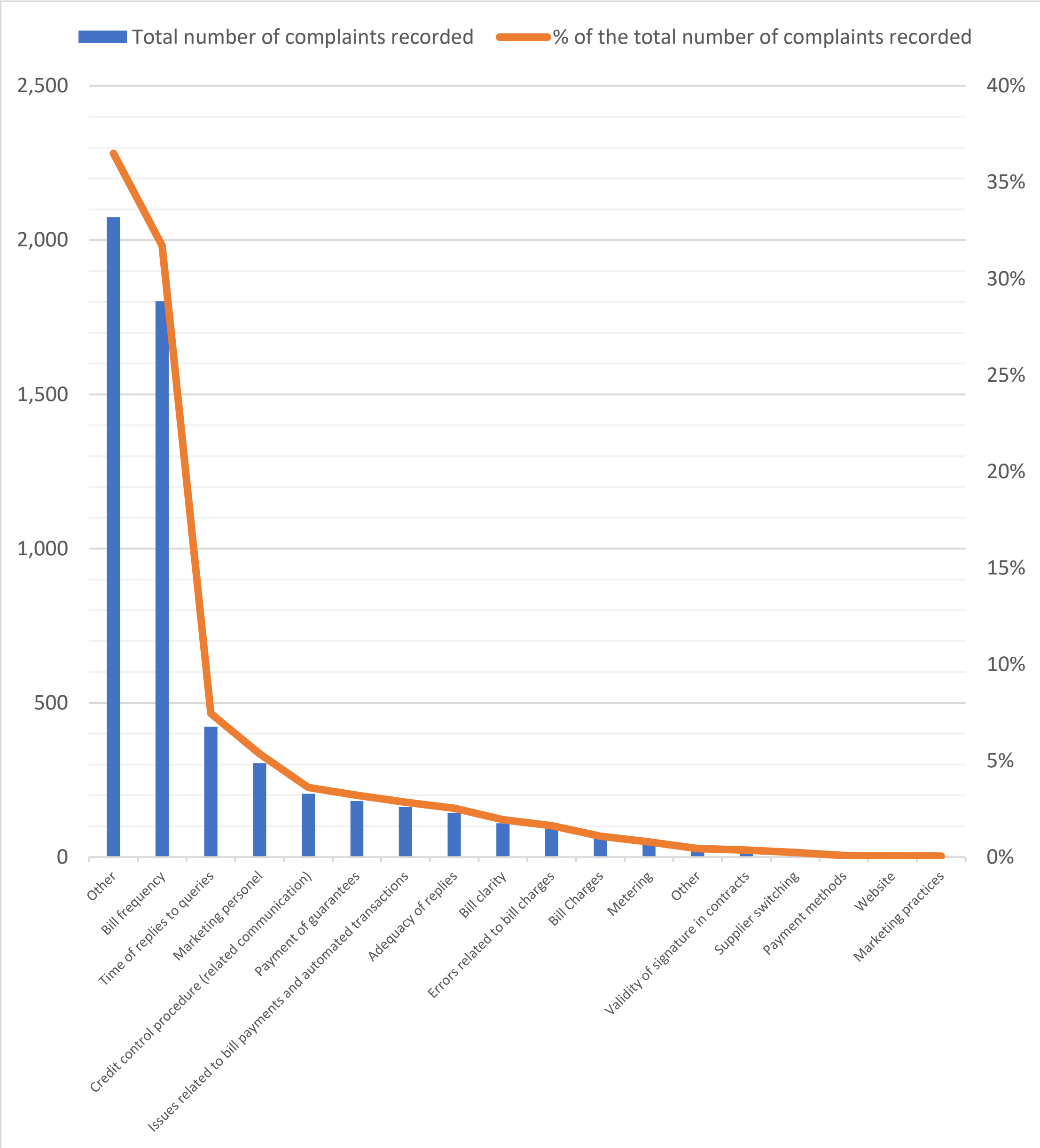

Figure 35: Total Number of consumers' queries per category submitted to gas suppliers (2020)

Regarding the natural gas sector, the majority of complaints concerned the conventional period but for other Suppliers' services excluding clarifications over tariffs as well as the frequency of bill issuance. Most of the customers' complaints (88.4%) concern the conventional period.

In this context, in 2018, RAE introduced for the first time a weighted index for the number of consumer complaints per supplier, based on the market share of each supply company and the number of complaints received by the company and in total. Figure 36 represents the results of the Weighted Complaint Index (WCI) per Supplier for 2020.

Calculation methodology: WCI = $\dfrac{\dfrac{Number\ of\ complaints\ received\ by\ the\ supplier}{Total\ Number\ of\ complaints\ received\ by\ all\ suppliers}}{\dfrac{Number\ of\ supplier's\ customers}{Total\ number\ of\ consumers\ active\ in\ the\ market}}$

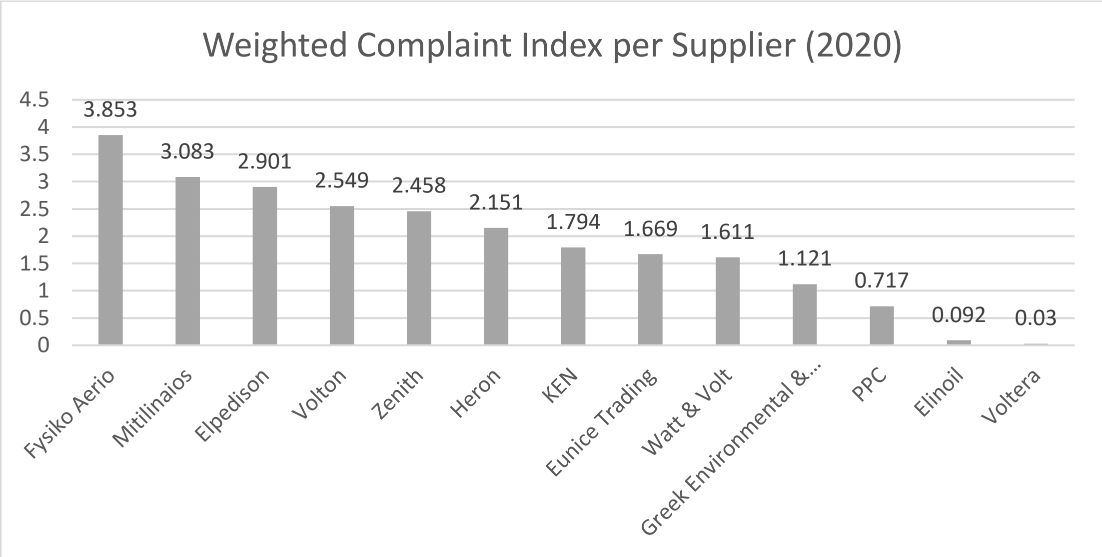

Figure 36: Weighted Complaint Index per Supplier (2020)

3.6.7. Dispute Settlement

The Greek Consumers Ombudsman is the legally responsible authority for dispute settlement between consumers and companies including energy service providers.

As a mediator, the Greek Consumers Ombudsman draws conclusions, makes recommendations and/or proposals to the companies after following a hearing process, but is not authorized to impose sanctions. However, if any of the involved parties does not accept the authority's recommendation, the Consumers Ombudsman may disclose the case to the public.

RAE receives a great number of requests and complaints from both customers and other Authorities like the Greek Consumers Ombudsman concerning debt settlement disputes, difference between contract tariffs and actual tariffs, discounts, and regulatory issues of the Distribution Network.

In addition, RAE handles all complaints addressed in written to the Authority, investigates the cases and tries to settle the disputes, to make recommendations to the companies, to take regulatory measures and/or imposes sanctions to the companies if a violation of the regulatory framework is proved.

3.6.8. Regulatory Decisions and Opinions of RAE

- **Regulatory interventions concerning the Supplier of Last Resort and the Universal Service Provider**

The Universal Service is provided to the consumers, in accordance with the provisions of Article 58 of Law 4001/2011 and Article 44 of the Electricity Supply Code, without any time restrictions. RAE, in the context of dealing with abusive consumers' behaviors and the abuse of the Universal Service Regulations and with the data provided by PPC as the Universal Service Provider, considered it necessary issue an Opinion to the Minister of Energy to modify the relevant legislative framework. The recommendation concerned an amendment of Article 52 of Law 4001/2011 that introduced a maximum limitation of three months stay on this Service for the consumers in order to give them appropriate time to negotiate a new contract with the Supplier of their choice but also to tackle any abusive consumer behavior during the utilization of the Universal Service.

Furthermore, considering that the retail gas market differs from the electricity market, as the activity of the Gas Suppliers is linked to both geographical data and consumption characteristics (commercial, industrial and household consumers), it was considered that the provisions governing the "Electricity Supplier of Last Resort" do not meet the specifics of the natural gas market. Therefore, in the light of the conclusions reached, RAE pinpointed the importance of drafting the relevant legislative framework for the natural gas market to the Minister of Energy.

In the electricity sector, with Decisions 594/2019 (Gazette B΄ 2770/04.07.2019) and 595/2019 (Gazette B΄ 2964/19.07.2019), RAE proceeded with the assignment of Universal Services and Supplier of Last Resort to PPC S.A. under the terms included in those two Decisions. No other body expressed interest to provide those two Services. It concerns a 1-year period (23.06.2019 until 22.06.2020) for Universal Service and a 3-months period (29.03.2019 until 28.06.2019) for Supplier of Last Resort. In July 2019, the process determined in Articles 57 and 58 of Law 4001/2011 for the assignment of Universal Services Provider to the supplier with the greatest market share per customer category for both Services was activated for a period of 1 year (23.06.2019 until 22.06.2020 and 29.06.2019 until 28.06.2020, accordingly). This clause was indeed activated in 31.12.2019 when Green S.A. terminated its activities in NIIs.

According to Law 464/2019 (Gazette B' 193/03.12.2019), the first 5 suppliers (in terms of volume in the Interconnected System) will offer Universal Services for a period of 2 years. This change in the legal network was considered as necessary because the number of consumers entering that category was increasing from year to year and there was no provision for how long one consumer can be under that status.

RAE submitted an Opinion to the Ministry of Energy (Opinion 2/2020) which provides: (a) a maximum period for providing Universal services which equals to three (3) months including special provisions for vulnerable customers and (b) criteria selecting the Universal Service Provider (assessment based on turnover beyond market share) and offered tariff (provision for a fixed and simple tariff without price adjustment mechanisms).

With RAE Decision 407/27.02.2020 (Gazette B' 1397/2020) a public tender was announced for the selection of candidates that will provide the universal service for a period of two years beginning from

23.06.2020” in the electricity sector. This tender was declared unsuccessful with RAE’s Decision 886/2020 as no bids were submitted during the competitive procedure.

Finally, according to Ministerial Decision ΥΠΕΝ/ΓΔΕ/57469/2612/2020 (Gazette B’ 2400/2020), the five (5) Suppliers with the greatest market share in the Interconnected System (PPC, Mytilineos, Heron, ELPEDISON and NRG) will undertake the responsibility to offer Universal Services for a period of 2 years based on their share of connections.

Regarding the Supplier of Last Resort, according to RAE’s Decision 1043/2020, PPC S.A. was nominated to undertake the responsibility to offer relevant services for a transitional period of 3 months (29.06.2020- 28.09.2020) after an unfruitful tender which was organized within the framework of RAE’s Decision 408/2020 (Gazette B' 1314/2020).

Finally, with RAE’s Decision 1055/2020, a second tender was announced “Call for expression of interest for candidate electricity Supplier of Last Resort for a period of two years beginning from 29.09.2020”, Subsequently, RAE published Decision 1352/2020 (Gazette B’ 4311/2020) appointing ELPEDISON S.A. as the electricity Supplier of Last Resort (29.09.2020 – 28.09.2022).

- **Amendments in the “PSO” due to changes in the “Social Tariff” structure.**

In view of the substantial changes made in the context of the provision of the Social Tariff in 2018, with regard to both the eligibility criteria and the content of the scheme, it was necessary to review and reformulate the relevant methodology for the calculation of the input flows to the “PSO”, in force since 2011, in order for it to be compatible with the new framework and to allow for easy and transparent application. In this regard, in order to develop a new methodology, RAE cooperated with DEDDIE, who is the operator of the special “PSO”. The main changes that were introduced in 2018 concerned the structure, the way the Social Tariff is provided and the criteria for the consumers to be included in Social Tariff. The new structure significantly facilitates the determination of the Social Tariff which is closely related to the supplier’s discount on the “Supply Charge”. For this reason, in the context of simplifying the procedure, RAE recommended the creation of provisional invoices based on certified measurements which will be made available for the reference month that the Social Tariff is calculated. The final regulatory decision on the new methodology is expected to be adopted in 2020, following the completion of the required public consultation.

After organizing a public consultation (19 February 2020 - 04 March 2020) and while collaborating with DEDDIE S.A. which is the operator of the special “PSO”, RAE published Decision 759/2020 “New Methodology for the Calculation of Annual Fee for covering the Cost of Social Tariff Provision as a Public Service Obligation implementing Ministerial Decision ΥΠΕΝ/ΥΠΡΓ/892/152 (Gazette B’ 242/01.02.2018)”. This methodology ensures the transparency of the fees received by electricity Suppliers for the provision of Social Tariffs, without affecting competition, since the Social Tariff is not fixed by the State but is offered in the form of a discount (in €/MWh) to the vulnerable customers on the Supplier’s invoice. For this reason, the new Social Tariff structure significantly facilitates the determination of the Annual Fee for covering the Cost of Social Tariff. In order to achieve further simplification of the procedure and to avoid significant account clearances, it was proposed by RAE that monthly provisional calculations are carried out, based on certified metering measurements which are available during the reference month.

- **Empowerment of the Framework for Consumer Protection**

In the context of protecting the interests of consumers in relation to the transparency of charges and having taken into account the relevant consumer complaints submitted to RAE, the Authority evaluated the structure of tariffs and issued a relevant Decision regarding the structure of the category of “Other Charges” on the consumers’ bills which must be followed by all suppliers so that the latter can publish electricity supply tariffs in the most uniform way possible to facilitate the consumer. Following the above Decision, RAE proceeded to further investigate the legality of the revenues received by the suppliers under the category of “Other Charges”. The investigation will be completed in 2020 and a relevant Decision will be issued.

- **RAE COVID-19 Guidelines for all entities active in the retail energy market**

In view of the COVID-19 pandemic and in the scope of protecting public health, the Authority, amid a period of imposed restrictive measures, requested that the participants of the retail energy markets receive all necessary measures to reduce the risk of spreading the coronavirus. RAE recommended that the participants should take all necessary measures to avoid physical contact with consumers, to promote the remote provision of services to the consumers and the provision of incentives to increase the timely payment of energy bills by consumers. It was also requested that Suppliers’ cash flow data be sent on a weekly basis to identify the impact of the pandemic to their cashflows.

- **RAE Guidelines for suppliers on debt settlement plans**

In 2019, RAE received a significant number of complaints and requests from vulnerable consumers, in particular on the difficulty they face in settling their accounts with the suppliers under the existing trading framework of electricity and gas as well as the difficulty they face in understanding the settlement plans offered. In this context, RAE approved the provision of guidelines to suppliers on the “Dept Settlement Schemes for Vulnerable Consumers – Enhancing Transparency in Information”. RAE also issued a related Opinion to the Minister of Energy and Environment, proposing modifications to the electricity codes and favorable arrangements in facilitation of the debt repayment of vulnerable consumers. More specifically, based on the aforementioned Guidelines, electricity suppliers are obligated to post at least on an easily accessible point on their website, the application criteria as well as the content of the offered tariff plans available to consumers under the debt settlement process which depends on the company policy. In addition, RAE requested relevant debt settlement data from the suppliers in order to examine the distribution of vulnerable consumers to each supplier, the debt agreements drawn up and the debts likely to occur due to a failure in meeting their obligations.

- **RAE Guidelines for suppliers on content promotion strategies**

In 2019, RAE received a significant number of reports from the consumers which revealed that most of the advertising messages and promotional packages of the suppliers are characterized by intense ambiguity. There has been a fragmented listing of pricing data and unfair comparisons with corresponding services of other suppliers that ultimately prevent the consumer from selecting the most advantageous offer. For these reasons, RAE decided to provide specific guidelines for the Electricity and Gas suppliers (RAE letters O-80342/24.12.2019 and O-81677/03.04.2020) regarding the advertisements and promotional messages of their services/products in order to contribute to the comprehensibility of the information by the consumers and their protection from vague and misleading promotional messages and ensure healthy competition between the retail suppliers.

- **Publication of the suppliers' market share data by the DSOs**

In June 2020, RAE, acting within the framework of its competences for monitoring the electricity and natural gas markets and with the aim to enhance transparency, requested from all network operators to publish, on a quarterly basis, the active energy suppliers and their respective market shares on their websites.

- **Amendment of the Meter Representation and Periodic Clearing Manual**

RAE, following a significant number of complaints submitted by consumers and suppliers regarding incorrect and irregular meter representations, as well as incorrect indications of new meter representations, considered it appropriate to amend the Meter Representation Agreement, but also the necessary supporting documents required in cases of a new connection and in cases of consumer succession, according to the provisions of the Distribution Network Code. A public consultation on these issues was held from 21 February 2020 to 9 March 2020. The feedback received from the stakeholders during the public consultation was taken into account in the final RAE Decision 1443/2020 (Gazette B '4737 / 26.10.2020) on the "Establishment of a Meter Representation and Periodic Clearing Manual".

Furthermore, within the framework of its competences on electricity market monitoring and on the implementation of the regulatory framework for supplier switching, and especially of Article 42 paragraph 1 of Electricity Supply Code, RAE collects the necessary data in order to enforce the relevant rules.

In this context, and after observing the situation of supplier switching in the electricity market, RAE identified that the current regulatory framework is intentionally circumvented by some customers to avoid paying their debts towards their suppliers. For that reason, RAE started considering a plan for enhancing the framework to deter those abusive behaviours by incorporating the same provision for the natural gas market too. The provision permits the DSO to monitor the legality of the switching process. RAE's proposals will be finalized in 2020.

During the above public consultation, it was proposed to include a provision on the implementation of a system that would monitor overdue consumer debts before the final approval of switching requests. In this framework, RAE requested from DEDDIE, the electricity DSO, to develop an IT system that would facilitate communications between the network operator and the old supplier, in order to investigate if there are any consumer debts towards the previous electricity supplier. However, certain issues with the process were identified during the pilot application of the system and further assessment of cases where abusive consumer behaviour was detected. Therefore, in October 2020, RAE considered it reasonable to suspend the implementation of the system by the network operator and to evaluate the issues occurred during the pilot implementation of the system that concern supplier switching requests made by consumers who have overdue debts.

- **Improving consumer compensation framework for damage caused to appliances due to "accidental loss of the neutral wire"**

Since 2011, RAE requested PCC S.A. to draft a proposal on a procedure for consumer compensation due to damage caused to electrical appliances, due to accidental interruption/loss/brake of the neutral wire of the overhead or underground power lines. The compensation was set at 300 € for a single-phase and 400 € for three-phase electricity supply, while there was a provision that demanded consumers to submit the relevant application within 4 working days.

RAE, following a significant number of consumer complaints, acknowledged the need to review the consumer compensation process by the network operator in cases of appliance failures caused due to accidental loss of the neutral wire. Considering that four days are usually not sufficient for the identification of the problem, the repair or/and the assessment of the financial damaged caused, and that the compensation provided in identified cases is usually not enough to cover the damage caused to modern equipment, RAE decided to extent the time period for the submission of the relevant application to 10 working days and the maximum compensation amount to 600 €, taking into account the Proposal 15800/27.05.2016 of the Greek Consumer Ombudsman. This change was incorporated in the revised “Guaranteed Services” Program implemented by DEDDIE with RAE Decision 726/2020 (Gazette B’ 1876/18.05.2020).

- CO_2 adjustment clause in PPC’s electricity offers

In 2019, RAE called the incumbent company to include detailed data and methodology for the calculation of the “CO_2 adjustment clause”, which became part of PPCs pricing policy for LV consumers starting from 1.11.2019, in its offers and/or its online website. PPC SA responded by providing detailed data on the EUA futures per day and month, the company’s emissions for the electricity generating installations of the interconnected network and the creation of a special website with detailed information for the calculation of the above charge.[54] PPC complied with RAE’s request and currently all the required information related to the “CO2 adjustment clause”, is available in its website.

- Active participation in the "Single Digital Portal" of the Ministry of Digital Governance, to ensure adequate and transparent information of Consumers

RAE emphasizes on the adequate and transparent information of both the consumers and the participants in the energy market, regarding the issues of its competence. For this reason, in addition to direct regulatory interventions such as the development of a Price Comparison Tool, providing guidance to Suppliers on the content of advertising messages, etc., the Authority has ensured (a) the improved content of information published on its new website, which is in the final stage of implementation, but also (b) its active participation in the initiative of the Ministry of Digital Governance for the creation of the "Single Digital Gateway".

According to the Ministry’s initiative, the content of consumer information issues on RAE’s website, must have a specific structure and quality criteria, in order to be part of this European portal. Thus, after the preparation of the necessary texts according to the required specifications, RAE, with a letter sent on 08.07.2020 requested the translation of these texts and their integration into both the Single Digital Gateway, and the new website of the Authority in 2021.

[54]https://www.dei.gr/el/oikiakoi-pelates/xrisimes-plirofories-gia-to-logariasmo-sas/logariasmos-kai-xrewseis/poia-dedomena-xrisimopoiounte-gia-ti-rirta-co2

4. Regulation and Performance of the Natural Gas Market

4.1. Network Regulation

4.1.1 Unbundling

A) TSO Unbundling

DESFA S.A. is the Transmission System Operator of the Greek National Natural Gas System (NNGS) and is certified under ownership unbundling according to RAE's Decision 1220/2018 (Government Gazette B '5740 / 19.12.2018) as amended with Decision 460/2019 (Government Gazette B '3853/17.10.2019).

In 2018, Senfluga S.A., a joint venture of Snam S.p.A, Enagas Internacional S.L.U. και Fluxys S.A., acquired 66% of DESFA's share capital, while the remaining 34% is owned by the Greek State. After RAE's Decision 1100/2019 (Government Gazette B '958/21.3.2020) based on which Damco S.A. entered as a passive shareholder in Senfluga, Senfluga's shareholder's structure is formed as Snam with 54%, Enagas and Fluxys with 18% each and Damco with 10%.

There were no changes related to the unbundling of DESFA S.A. within 2020.

B) DSO Unbundling

In March 2019, the Greek government adopted, by Article 53 of Law 4602/2019, the Ownership Unbundling Model for the distribution networks (excluding the already established DSOs) in order to ensure the complete independence of the DSOs,[55] to avoid exchanges of confidential information, and to ensure competition at the supply market.

Also, RAE was designated as the body responsible for the certification of the DSOs. The certification process begins after all the necessary documents have been submitted by the DSO, and it is completed within a specific timeframe. Within its competences RAE may issue instructions and guidance on matters related to the certification process

[55] The three (3) EPAs, EPA Attikis, ie. EPA Thessalonikis and EPA Thessalias had been operating under a regime of exclusive rights for both the activities of distribution and the supply of gas in their areas. DEPA, the main gas supplier in Greece, is the owner and operator of three (3) distribution networks in three (3) areas known as new-EPA areas. DEPA also owns a small distribution system in Corinth (with only one industrial client).
Law 4336/2015 introduced the obligation for the unbundling of the distribution activities from the supply activities by January 1st, 2017. As part of the reform, RAE acquired a decisive role in matters relating to the functioning of the EPAs and DEPA and their switching to legally separated companies, where the DSO (renamed as EDAs) would be responsible for the distribution system and the EPAS and DEPA would be gas suppliers.
According to the provisions of Article 8 of Chapter III of the Law 4336/2015, the old Licenses for Supply & Distribution which were granted to EPAs would be abolished in the end of 2017.

RAE had already issued Decision 1412/2011 on the specificities for the certification of TSOs and DSOs for electricity networks however it was recognized that a new decision for the natural gas networks should be issued following the same principles. For this reason, RAE with Decision 835/2019 found it appropriate to apply Decision 1412/2011 by analogy with regard to the Certification of Natural Gas DSOs in accordance with Article 80 of Law 4001/2011.

There were no changes related to DSO unbundling within 2020.

4.1.2 Technical functioning

National Natural Gas System (NNGS) transports Natural Gas to consumers connected to the NNGS in the Greek mainland from the upstream Interconnected NNGS of Bulgaria and Turkey at the Greek-Bulgarian and Greek-Turkish borders, Trans Adriatic Pipeline (TAP) and the Liquified Natural Gas (LNG) terminal, installed at Revithoussa island at Megara (Athens/Attica region).

In Table 45, key elements for the four entry points of the Greek NNGS are presented.

Interconnection Point	Imports (MWh)	Exports (MWh)	Active Users	Technical Capacity (MWh/day)
Sidirokastro (Greece Bulgaria border)	31,877,674	7,369,577	16	117,804 (physical flow) 64,826 (reverse flow)
Kipi (Greece - Turkey border)	6,143,695	0	2	48,592
Agia Triada (Greece - Revithoussa LNG)	32,432,358	0	6	204,482
Nea Mesimvria (TAP)	648	0	2	53,368
Total	**70,454,375**	**7,369,577**	**26**	**424,246 (physical flow)** **64,826 (reverse flow)**

Table 40: Natural gas deliveries, Active Users and Technical Capacity per Entry Point in 2020 (source: https://www.desfa.gr/userfiles/pdflist/DERY/TT/Et.Stoix.ESFA_2020.pdf)

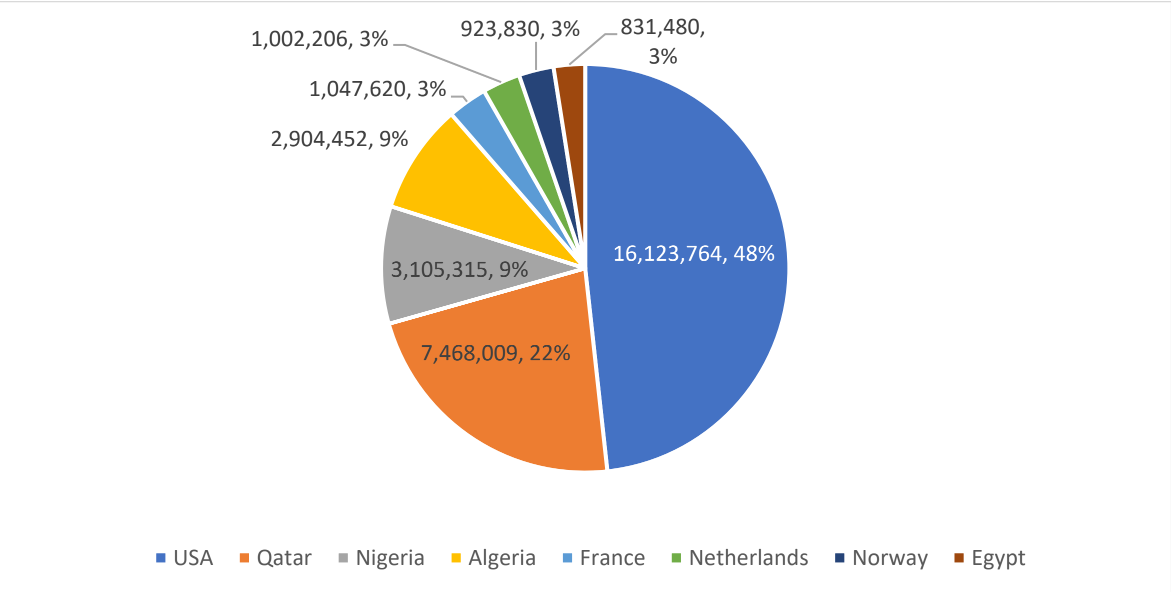

Figure 37: LNG imports at Revithoussa LNG terminal in MWh (2020)

According to the regulatory framework, every year the TSO submits to RAE for approval an annual planning for balancing gas. The plan includes TSO's estimated natural gas needs for network balancing, as well as an evaluation of possible balancing gas supply sources for the next year. The plan also includes DESFA's proposal regarding the characteristics of the framework contract for purchasing balancing gas for the next year. DESFA can either buy or sell balancing gas throughout balancing platform, procure balancing gas under the contracts signed with suppliers as a result of an international tender procedure or directly from DEPA's long-term LNG contract in line with the provisions of the Greek Energy Law (last two options are addressed as balancing services).

RAE approved the annual balancing plan submitted by DESFA for the year 2021 with Decision 941/2020 (Gon. Gazette B' 2990/20.07.2020). TSO's estimation on balancing gas needs was 1.3% of the total estimated gas demand (805,846 MWh) for purchasing gas and 0.7% (413,881 MWh) for selling. It is estimated that 41% of the total required balancing gas will be purchased through balancing services. Within 2020, the quantity of balancing gas auctioned by DESFA (buy & sell) amounted to 3.8 TWh (6% of the total quantities injected into the NNGTS), while contracted quantities amounted to approximately 1.02 TWh. Fourteen (14) Users participated in the auctions in total.

RAE is also responsible for approving the parameters involved in the calculation of balancing cost and the methodology for allocating these costs to the Transmission System users. With Decision 1197/2020 (Gon. Gazette B' 5082/18.11.2020), RAE approved the balancing cost allocation scheme and the relevant shippers' charges, for 2020. All balancing charges and the methodology for their calculation, as well as the Daily Balancing Gas Price, are published on DESFA's website, in both Greek and English.

According to the provisions of EU Regulation 312/2014 (BAL NC), transmission users are responsible for balancing their inputs and outputs using balancing rules designed to promote a short- term wholesale gas market and participating in trading platforms established to better facilitate gas trade between network users and the transmission system operator. The TSOs carry out any residual balancing of the transmission networks that might be necessary. Throughout 2020, RAE participated actively in the establishment of the regulatory framework for the operation of a trading platform by Hellenic Energy Exchange (HeNeX) according to the provisions of BAL NC and the Greek Law 4425/2016. For the purpose of procurement of short term standardized products, DESFA shall trade on this trading platform and will terminate the operation of the existing Balancing Platform.

In order to enable network users to balance their balancing portfolios, BAL NC sets out minimum requirements for information provisions. The information flows aim to support the daily balancing regime and seek to be a set of information to support the network user in managing its risks and opportunities in a cost efficient way. Especially for Users supplying non-hourly metered customers, information is limited as it is not based on real measurements but on estimates. BAL NC, taking into account the differences among the European natural gas markets, provides three alternative information models and the responsible NRA decides on the model which suits better the balancing zone. RAE with it's Decision 780/2020 (Gazette B' 1949/21.05.2020) chose the model based on which the information on the non-daily metered off-takes consists of forecasts of the same day or the day before, as the model that will be implemented in the NNGS. In addition, the NRA must designate the Forecasting Party that will be responsible for the forecasting of the non-daily metered Users' off-takes. RAE has already consulted with the Operator of the NNGS and the DSOs, as provided in the BAL NC, and will issue a Decision to appoint a Forecasting Party at the beginning of 2021.

Operational Gas Offsetting

Pursuant to the provisions of Article 69 (2) of law 4001/2011, the NNGS Network Code regulates, inter alia, issues related to the process of offsetting the technical losses and self-consumption of the NNGS. The methodology and the parameters that are included in the calculation of the cost of compensation of technical losses and self-consumption of the NNGS, are approved by RAE. In this context, RAE, in 2020, issued Decision 1383/2020 for the periods from 01.01.2019 07:00 to 01.01.2020 07:00 and from 01.01.2020 07:00 to 01.01.2022 07:00 (Gazette B '4766 / 29.10.2020).

Regulatory Framework for Natural Gas (Network Code, Tariff Code, Standard Framework Agreement)

5th Amendment

The 5th Amendment of the NNGS Network Code focuses on establishing congestion management mechanisms for overcoming, temporary, lucks of capacity until the actual upgrade of the transportation system by DESFA in 2023. DESFA initial proposal for the 5th revision of the Code was submitted in October 2019 and was put up for public consultation between December 2019 and February 2020. Following comments submitted during the public consultation, as well as remarks done by RAE, DESFA submitted a revised proposal in May 2020. The revised proposal was put into an additional public consultation and was finally approved by RAE with Decision 1035/2020 (Gazette B' 2840/13.07.2020). The fifth revision introduces three new capacity products:

- **Competing capacity**: The existing technical constraints of the System allow a maximum quantity of natural gas to flow from the north to the southern part of Greece through the compression station at Nea Mesimvria. To avoid any discrimination between the NNGS entry points, instead of setting the maximum capacity available through each of the entry points, total available maximum capacity is offered though auctions simultaneously at the entry points which are competing each other. This provides access to the entry points, with an expressed interest, rather than an ex ante identification of the interest.
- **Coupled Capacity**. This provision covers the case of a Transmission User who wishes to move a quantity of natural gas between specifi Entry Points and Exit Points. Although, according to the European Regulations, the capacity booking must be made separately at the point of entry and exit (entry-exit systems), and the User does not have to declare the "flow" of the gas inside the System, in order to have the possibility of anonymous transactions anywhere. However, in cases of congestion, if a User intends to commit that gas entering at an Entry Point situated at the north will be also exported / consumed in the north, and therefore will not contribute to congestion in the Nea Mesimvria compressor station, it is proposed to be able to do so through Coupled Capacity. Because this service limits the user's ability for free movement of gas its offered at a discount.
- **Conditional Capacity** is defined as the Transmission Capacity for Delivery at an Entry Point offered by the TSO on a Firm Basis, which is available for booking by the Users. During the NNGTS Daily Operation Planning, the usage of the total or part of the Conditional Transmission Capacity for Delivery, Reception, results from the satisfaction of the Capacity Usage Condition for the said Point. Capacity Usage Condition at an Entry Point, at a Reverse Flow Exit Point, is defined as the sum of the physical and technical terms and conditions, under which the delivery or reception of the Natural Gas total is possible, through the Conditional Transmission Capacity for Delivery or Reception correspondingly. During the NNGTS daily operation

planning, TSO can restrict the use of the Conditional Transmission Capacity for Delivery/Reception down to zero in case the Capacity Usage Condition is not met. With this scheme, an attempt is made to offer additional capacity, without disturbing the operation of the system and also avoid making unnecessary investments in infrastructure. User has full access to the VTP for these quantities. This service is offered at a discounted rate because there is a possibility of interruption of the gas declaration. The discount rate is proposed by the TSO and approved by RAE on a case-by-case basis, based on the interruption probability, but it cannot be less than 10%.

The 5th Revision of the Code introduced the basic principles of the above schemes. However, in order these products to be offered TSO submits to RAE for approval proposal with the relevant details for the product offering.

RAE, with its Decision 919/2020 (Gon. Gazette B '2463 /22.06.2020), canceled the annual and quarterly auctions for the gas year 1.10.2020-30.09.2021 at Kipoi Entry Point, in order allow competing auctions between “Kipoi” and “Nea Mesimvria”, Interconnection Point between NNGS and TAP. In order not to affect the rights of Users who were to participate in the canceled auctions, the starting price for the monthly capacity products, until the announcement of the operation of the new entry point "Nea Mesimvria", was calculated as if it were a service of more than or equal to one year.

In August 2020, DESFA submitted a proposal to RAE for offering Competing and Conditional Capacity products. This proposal was approved by RAE Decision 1399/2020 (Gazette B’ 4622/21.10.2020), after a public consultation was held. Specifically, the tenders for Competing Capacity at the Entry Points of “Kipi” and “Nea Mesimvria” was approved, with a specific schedule and conditions, depending on the final start date of the commercial operation of TAP. Furthermore, to maximize the booking capacity that can be offered at the northern entrances of the country, it was decided to offer additional capacity equal to 40,000,000kWh / Day in the form of a service of Conditional Capacity at the Entry Point of “Nea Mesimvria”, with the following Capacity Use Condition: The total amount of natural gas that enters to the NNGTS from the northern Entry Points of NNGTS (Sidirokastro, Kipi and Nea Mesimvria) is less than or equal to the total technical capacity of the northern Entry Points of the NNGTS (171,172,292 kWh/Day). Based on historical data, the probability of not using the full capacity was estimated at 3.5% and this service was offered at a 10% discount.

Amendment of Network Code provisions related to the use of LNG facility at Revitoussa

Moreover, in early October 2019, DESFA proposed an amendment of the National Natural Gas System Network Code to Article 83 (8), expressing its concern at a possible congestion at the LNG Facility under the Annual LNG Unloading Program for 2020. This concern stemmed from the fact that LNG Users submitted statements during the Monthly LNG Planning Process for November 2019, whereby estimated unloads of LNG for the following two months (December 2019 and January 2020) were declared. Specifically, 10 unloads of LNG cargoes were declared for January 2020 totaling 6,834 TWh, corresponding to 91% of natural gas demand in January 2019 (7.4 TWh).

RAE initiated a public consultation on the TSO proposal, the results of which showed that the proposal was treated positively by the market players, in order to prevent the over-declaration of LNG cargoes and the appearance of a contractual congestion at Revithoussa’s LNG terminal. In addition, participants’ comments highlighted the need for a comprehensive review and significant interventions in the management of the LNG facility.

Considering: a) the high interest for LNG imports at Revithoussa LNG Terminal, b) that there is no organized gas market in Greece yet while the electricity's market is still in transition, RAE issued Decision 1005/2019 in October for specifi changes in the LNG Cargoes Unloading Annual Plan, requesting DESFA to submit a proposal for radical changes in the LNG Annual Planning mechanism.

At the beginning of 2020 amendments to the NNGS Network Code were deemed necessary to give more flexibility to LNG Users taking into account the intense competition between them to book unloading, storage, regasification and transmission capacity at Ag. Triada NNGTS entry point. This need for flexibility was particularly increased while taking into consideration that Greece lacks an organized secondary natural gas market and that its electricity market is in a transitional phase. Main changes introduced with RAE Decision 727/2020 (Gazette B' 1684) can be summarized as follows:

- multiple LNG cargoes declaration,
- Ability to book intraday regasification capacity,
- Introduction of caps for the Additional Storage Space,
- Establishment of a Minimum Unit Price to book Additional Storage Space,
- provisions allowing release storage when not needed,
- TSO stops accepting non-binding nominations for LNG Cargoes for months M+1 and M+2 during the Monthly Planning and
- Shortening deadlines (e.g., transaction agreements between Network Users, LNG application).

6th Amendment of the Natural Gas System Administration Code

RAE launched a public consultation on DESFA's proposal for the total revision of the annual LNG planning at Revithoussa's LNG terminal, according to RAE's Decision 1005/2019. In June, DESFA considering the feedback gained during the public consultation, presented his revised proposal for the LNG Cargoes Unloading Annual Plan to RAE and to the market participants. Under the new scheme, standard LNG slots will be offered for auction by DESFA for a period of five consecutive years with specific characteristics related to the size of the LNG cargo, the period of temporary LNG storage, the necessary capacity bookings and the injection timeframe.

To ensure the smooth and successful implementation of the new procedure, it was deemed necessary to adopt transitional provisions and ensure the availability of the maximum booking capacity in the LNG terminal for the LNG Cargoes Unloading Annual Plan as well as avoid the amendment of any parameters taken into account to offer the standard LNG offers from the time of their finalization and their communication to the market until the end of the auction procedures for the benefit of all LNG terminal Users. RAE with Decision 1400/2020 (Gazette B' 4585) approved the amendment of the National Natural Gas System Administration Code and the transitional provisions for the implementation of the new scheme for the LNG Cargoes Unloading Annual Plan ensuring LNG Planning for 2020 and the established Users' rights will not be affected.

The final proposal of DESFA for the revision of LNG Cargoes Unloading Annual Plan preparation was put in public consultation by RAE in the summer of 2020 (31.07.2020 – 11.09.2020). RAE deemed that the proposed scheme significantly improves the Annual Planning process by satisfying the basic Users' requests as reflected in the relevant public consultations, enhancing healthy competition and preventing anti-competitive and predatory behaviour.

The main points of the new Annual Planning process, as they were established with RAE Decision 1433/2020 (Gazette B' 4799 and Gazette B' 5078), are the following:

- The elaboration of the annual planning is carried out for each year for the next five years. During the first implementation of the new scheme, the Annual Planning process will be developed only for 2021 and subsequently will be evaluated by RAE and DESFA. Should any shortcomings arise during the evaluation, necessary actions will be taken to address any occurred issues.
- Auctions will be distinct for each year of the Annual Planning comprising of two phases. During the first phase the Standard LNG Slots are auctioned, while in the second one LNG Complementary Capacity is auctioned, the later is obligatorily integrated with sections of LNG bundled capacity of the first phase in Continuous Capacity for each LNG User, per year.
- LNG Users who are also Transmission Users have the right to participate in the auctions under the condition that they have submitted the relevant guarantees under their Transport Contract and the LNG Contract that they have concluded with DESFA.
- LNG Users that were successful during the first phase of the LNG auctions are granted Standard LNG Slots, LNG Bundled Capacity which is specific to their Standard LNG Slots and are included in the LNG Annual Planning process.
- During the first phase of LNG auctions slots are awarded to the highest bidder and if two Users offer the same price, the earliest one is appointed with the slot.
- After the end of the first phase, the TSO calculates the maximum limit of Continuous Capacity limit for each successful bidder during the first phase, as the difference between the Bundled LNG Capacity awarded to the User and the sum of the Bundled LNG Capacity for each of the LNG Users who are also successful bidders, as derived from the Standard LNG Slots at which these LNG Users have successfully bided in the first phase of the Auction (excluding the bidding User), for each Day of the Year that the auction concerns.
- An Ascending Clock Procedure with multiple bidding rounds is applied for the allocation of LNG Complementary Capacity during the second bidding phase to satisfy all the bids of the participating LNG Users. The award criterion is the highest unit price.
- The Annual LNG Unloading Plan is binding for Users that were allocated Standard LNG Slots, while there are provisions for monetary penalties in case a scheduled LNG cargo is not unloaded and the corresponding LNG slot was not made available in the secondary market by the LNG User that was successful in the auctions.
- TSO submitts LNG auction reports and LNG system reports to the regulator. In this regard, RAE monitors the natural gas market to promote healthy competition and its efficient operation.

Amendment of the NNGS Tariff Regulation

In October 2020, due to the implementation of the new Annual LNG Planning process, an amendment of the Tariff Regulation was deemed necessary to: a) set the auction reserve price, as the sum of the tariff for LNG Regasification Capacity and the tariff for the Transmission Capacity for Delivery at the LNG entry point, b) the award price, as the price submitted by the highest bidder-User equal to the sum of the Marginal Price and the possible increase that resulted from the auction, c) the methodology for distributing any additional charges between the Transmission and LNG Activities.

The 5th Amendment of the Tariff Regulation was approved with the Decision 1434/2020 (Gazette B'4801 / 30.10.2020) and did not affect the existing NNGS Tariffs.

Auction LNG Manual

LNG auctions are performed according to the provisions of the Auction LNG Manual approved by RAE with its Decision 1436/2020 (Gazette B'4803 / 30.10.2020). Key parameters of LNG auctions are:

- LNG auction dates.
- Duration of the Planning Periods.
- List with the offered Standard LNG Slots, including the Unloading Date for each slot.
- Reserve Price for each phase of the LNG auction.
- The major and minor step in the price increase in the various rounds of the procedure.
- The maximum length of the procedure for the increasing price of bids of the Phase B through which the Network Users can submit bids to book Complementary LNG Capacity.

According DESFA's proposal, put out for a short public consultation, 46 Standard LNG Slots, allocated into 5 planning periods will be auctioned for the year 2021. Taking into account the technical details of the LNG facility and the LNG cargoes that have been historically unloaded, the volume of the LNG per Standard LNG Slot was set at 1 TWh and 0.5 TWh of natural gas, while the time for its injection was set for 36 and 18 hours respectively. The time for the temporary storage of natural gas was set at 13 days for the winter months (January, February and December) and at 18 days for the remaining 9 months considering that this would be more beneficial in strengthening the security of supply of the country. The proposal was approved by RAE Decision 1513/2020 (Gon. Gazette B' 5094).

Amendment of the mechanism for offsetting LNG losses

With the 6th amendment of the NNGS Administration Code, the mechanism for offsetting LNG losses was also revised. According to the new provisions, some LNG is kept as stock for the operational needs of the LNG facility. Those operational needs are defined as the sum of the LNG self consumption, the LNG losses, the Balance of Natural Gas Quantities of the LNG Facility and the maintenance of LNG reserve to cover the operational needs of the LNG facility. The Operator shall annually submit to RAE for approval a study for Offsetting the Operational Needs of LNG Terminal, which will include the following:

- Operational Expenses assessment methodology,
- A forecast regarding the necessary quantities of LNG that will be required to cover the operational needs of the LNG facility for the year to come,
- The determination of the contract specifications that will be concluded with the Operator under Article 91 of Law 4001/2011.

In this context, RAE Decision 1610/2020 (Gazette B' 5814) approved the Offsetting Operational planning of the LNG Terminal for the Year 2021, according to which TSO will sign a contract to purchase gas for covering lng operational needs for 2021 following a tender procedure. This new scheme is expected to lead to optimization of gas supply conditions, possible entry of new players in the gas market and contribution to the cost-reflectiveness of this service, benefiting both LNG Users and the end-consumers.

Amendment of Standard Contracts for the transmission of natural gas and the usage of the Revithoussa LNG facility

In order to harmonize the regulatory framework of the Standard Contracts concluded for the transmission of natural gas and the usage of the LNG facility with the Regulation (EU) 2016/679 of the European Parliament and of the Council of 27 April 2016 on the protection of natural persons with regard to the processing of personal data and on the free movement of such data, and repealing Directive 95/46/EC (General Data Protection Regulation), RAE after receiving a proposal from DESFA, issued Decision 821/2020 that amended the Standard Contracts to be in line with GDPR Regulation. The same Decision amended the procedure for updating the required legal documents that have to be submitted for the conclusion of the contracts.

In addition, RAE with its Decision 1435/2020 (Gazette B'4802 / 30.10.2020) approved the necessary amendments to the Standard Contract for the Transmission of Natural Gas and to the Standard Contract for the Use of the LNG Installation, so that network users could participate in LNG auctions for the year 2021 onwards.

National Natural Gas System Registry

At the end of 2020, nighty-five (95) System Users are registered and can transfer gas in the NNGS:

	User’s Name	Status/Classification
1	ALUMINIUM S.A.	Eligible Customer
2	MOTOR OIL(HELLAS) KORINTH REFINERIES S.A.	Eligible Customer
3	PUBLIC POWER CORPORATION S.A. (DEI)	Eligible Customer
4	EDISON S.p.A.	Third Party
5	PUBLIC GAS CORPORATION S.A. (DEPA)	Natural Gas Supplier
6	ELPEDISON POWER S.A.	Eligible Customer
7	ELFE S.A.	Eligible Customer
8	PROMETHEUS GAS S.A.	Third Party
9	HERON THERMOELECTRIC S.A.	Eligible Customer
10	HERON THERMOELECTRIC STATION OF VIOTIA S.A.	Eligible Customer
11	M AND M GAS CO	Natural Gas Supplier
12	KORINTHOS POWER S.A.	Eligible Customer
13	E.ON RUHRGAS AG	Third Party
14	STATOIL ASA	Third Party
15	EDISON HELLAS S.A.	Natural Gas Supplier
16	TRANS ADRIATIC PIPELINE A.G.	Third Party
17	GASTRADE S.A.	Third Party
18	LARCO S.A.	Third Party
19	ELPE S.A.	Third Party
20	TERNA S.A.	Natural Gas Supplier
21	SOVEL S.A.	Eligible Customer
22	SIDENOR S.A.	Eligible Customer
23	FULGOR S.A.	Eligible Customer
24	HELLENIC HALYVOURGIA S.A.	Eligible Customer
25	PROTERGIA S.A.	Eligible Customer
26	GREEK ENVIRONMENTAL & ENERGY NETWORK A.E.	Natural Gas Supplier
27	BA GLASS GREECE S.A.	Eligible Customer
28	ANOXAL S.A.	Eligible Customer
29	ERLIKON WIRE PROCESSING SA	Eligible Customer
30	FITCO METAL WORKS SA	Eligible Customer
31	HALCOR METAL WORKS SA	Eligible Customer
32	ALUMAN S.A.	Eligible Customer
33	PAPYROS PAPER MILL S.A.	Eligible Customer
34	GREENSTEEL - CEDALION COMMODITIES SA	Natural Gas Supplier
35	SONOCO PAPER MILL AND IPD HELLAS SA	Eligible Customer
36	EP-AL-ME S.A.	Eligible Customer
37	DAIRY INDUSTRY OF XANTHI SOCIETE ANONYME "RODOPI"	Eligible Customer
38	INOTEX PRIVATE COMPANY	Third Party
39	DIAXON PLASTIC PACKING MATERIAL ABEE	Eligible Customer
40	ENGIE S.A.	Third Party
41	HALYVOURGIKI INC	Eligible Customer
42	DUFENERGY GLOBAL COMMODITIES S.A.	Natural Gas Supplier
43	EPA ATTIKIS S.A.	Natural Gas Supplier
44	EPA THESSALONIKIS THESSALIAS S.A.	Third Party
45	HELLAGROLIP S.A.	Third Party
46	ELBAL S.A.	Eligible Customer
47	LPC S.A.	Natural Gas Supplier
48	NRG TRADING HOUSE S.A.	Natural Gas Supplier
49	CORAL S.A.	Natural Gas Supplier
50	VIENER S.A.	Natural Gas Supplier
51	PROTOS ENERGY	Third Party
52	TRAFIGURA NAT GAS LIMITED	Third party
53	MYTILINAIOS S.A.	Third party
54	Q CAPITAL INTERNATIONAL PARTENS LTD	Natural Gas Supplier
55	EDIL S.A.	Natural Gas Supplier
56	DANSKE COMMODITIES A/S	Third party

57	WATT & VOLT S.A.	Natural Gas Supplier
58	SD PROJECT EAD	Third party
59	GUNVOR INTERNATIONAL B.V.	Natural Gas Supplier
60	VOLTERRA S.A.	Natural Gas Supplier
61	SINTEZ GREEN ENERGY CYPRUS LTD	Natural Gas Supplier
62	ELINOIL Hellenic Petroleum Company S.A.	Natural Gas Supplier
63	EFA Energy S.A.	Natural Gas Supplier
64	KEN S.A.	Natural Gas Supplier
65	Kavala Oil S.A.	Eligible Customer
66	MET ENERGY TRADING BULGARIA EAD	Eligible Customer
67	ENERGIKO EOOD	Eligible Customer
68	Petrogaz S.A.	Natural Gas Supplier
69	SYMETAL S.A.	Eligible Customer
70	OMV PETROM GAS SRL	Eligible Customer
71	GS GAS AEBEY	Natural Gas Supplier
72	Chipita S.A.	Third Party
73	Sentrade S.A.	Third Party
74	WIEE ROMANIA SRL	Third Party
75	Dioriga Gas S.A.	Third Party
76	Vitol Gas & Power BV	Eligible Customer
77	KOLMAR NL BV	Third Party
78	GASELA Gmbh	Third Party
79	RWE Trading GMBH	Third Party
80	Blue Grid Gas & Power S.A.	Third Party
81	BULGARGAZ EAD	Third Party
82	AIK ENERGY AUSTRIA GMBH	Third Party
83	AIK ENERGY ROMANIA S.R.L.	Third Party
84	Tekal S.A.	Natural Gas Supplier
85	DANSKE COMMODITIES A/S	Third Party
86	AXPO BULGARIA EAD	Third Party
87	ALPIQ ENERGY S.E.	Third Party
88	OMV PETROM S.A.	Third Party
89	PROTERGIA S.A.	Natural Gas Supplier
90	Eni Trading and Shipping S.p.A.	Third Party
91	Eni S.p.A.	Third Party
92	FREEPOINT COMMODITIES B.V.	Third Party
93	AIK ENERGY LTD	Third Party
94	GEN – I. ATHENS SMLLC	Third Party
95	TIBIEL EOOD	Third Party

Table 41: NNGS Users registry, 31.12.2020

DESFA's TYNDP

DESFA submitted RAE its proposal for the TYNDP 2020-2029 in October 2019, pursuant to the provisions of Article 92 of the NNGS administration code. In the context of the evaluation of the submitted draft TYNDP and taking into account the TSO's investment needs, RAE requested that DESFA makes targeted changes to the draft TYNDP. Taking into consideration the proposed amendments, DESFA resubmitted a revised TYNDP (2020-2029) in December 2019. RAE, acting in accordance with Law 4001/2011, held a public consultation on the revised TYNDP 2020-2019 starting from 09 December 2019. The consultation ended on 17 January 2020, with 9 participants submitting comments on the Plan. The final TYNDP 2020-2029 was approved by RAE with Decision 755/2020 (Gazette B' 1746 07.05.2020) and it included projects that will reinforce the network, development projects and interconnections with other natural gas systems.

In August 2020, DESFA submitted to RAE for approval a draft TYNDP for the period 2021-2030. DESFA, after taking into account the comments that were submitted during a public consultation that was held, submitted a final draft of the Plan on 22 December 2020. The most important new projects that were included in the TYNDP 2021-2030 are two high pressure natural gas pipelines that will be built towards Patras and West Macedonia. RAE, following the guidelines of the NECP that promotes natural gas as a transition fuel to green growth, has expressed the view that it is appropriate for the NNGTS to be extended during the next few years so there would be enough time for depreciation and to support the transmission of biofuels and hydrogen, while also considering the principle of economic efficiency. In this regard, RAE asked DESFA to investigate the economic aspects of the network extension to Epirus (Ioannina), Overall, the proposed TYNDP 2021-2030 contributes a) to the promotion of gas penetration in new areas, for the benefit of regional development, b) to the strengthening of the System and to the increase of capacity and security of supply, c) to the implementation necessary projects for the smooth, economical and uninterrupted operation of the NNGS and (d) in achieving an increased level of environmental protection, in particular in regions in transition. The approval of TYNDP, with specific interventions made by RAE, took place in January 2021. At the same time, the Authority having identified in time the need to reinforce the NNGS to avoid congestion that may arise due to its connection with the TAP pipeline and on the other hand, in view of the connection of new infrastructures (Alexandroupolis FSRU, Dioriga Gas FSRU, Kavala UGS), requested from DESFA to develop a relevant cost-benefit study, the results of which will be used to formulate DESFA's proposal for the next TYNDP.

Distribution network development

RAE monitors the development of natural gas distribution networks with the aim to increase their coverage and the rate of penetration of the natural gas in an efficient and cost-effective manner in the Greek energy market, based on the criterion described in Article 12 of the Distribution Network Tariff Regulation.[57] The DSOs must construct the distribution network in accordance with the approved development plan and the relevant time schedule included in their Distribution Licenses. The Operators shall inform RAE at the end of each calendar semester on the construction progress of each distribution network in their licensing area. In particular, Article 58 of the Distribution Network Operation Manual provides that each Operator shall submit to RAE an updated distribution network development plan. In this context, RAE with its Decisions 673/2020 (Gazette B' 1715/06.05.2020), 677/2020 (Gazette B' 2981/20.07.2020) and 853/2020 (Gazette B' 2836/13.07.2020) approved the development plans of EDA Attikis, EDA Thesalonikis and DEDA. The proposals of the DSOs were approved by RAE except of DEDA's proposal regarding network development in the municipalities of Tripoli, Corinth, Argos-Mycenae, Nafplio, Kalamata and Sparti which were rejected due to delays in their implementation by the company based on the provisions of Article 80Γ (3) of Law 4001/2011.

The distribution network of the country, depending on their operating pressure, is divided into two categories: (a) Medium pressure network (19.0 bar) and (b) Low pressure network (0.025-4.0 bar).

The following table shows the total length of medium and low-pressure distribution network in Greece in 2020, as well as the percentage change compared to 2019:

	2019	2020	%	2019	2020	%

[57] Gazette B' 3067/26.09.2016

	Medium Pressure (km)	Medium Pressure (km)	Percentage change (%)	Low Pressure (km)	Low Pressure (km)	Percentage change (%)
Attica	333.2	333.7	0.45%	3,272.0	3,419.0	4.49%
Thessaloniki	137.2	152.5	11.18%	1,241.5	1,319.6	6.29%
Thessaly	106.0	108.9	2.74%	941.1	1,005.1	6.80%
DEDA (rest of Greece)	334.85	334.85	0.00%	175.24	175.24	0.00%
Total	**910.2**	**930.0**	**2.17%**	**5.629.9**	**5,918.9**	**5.13%**

Table 42: Distribution Network Development per category/region (2019-2020)

In the following Table the distribution network length of the rest of Greece operated by DEDA is presented:

Distribution Network	**Low pressure (Km)**	**Medium Pressure (Km)**
Central Greece	83.33	126.67
Central Macedonia	62.29	83.88
Eastern Macedonia and Thrace	29.61	117.43
Peloponnese	0.00	6.87
Total:	**175.24**	**334.85**

Table 43: Distribution Network Development per category/region operated by DEDA (2018-2019-2020)

Furthermore, in October 2020, according to the provisions of Article 58 of the Distribution Code, EDA Attica, EDA THESS and DEDA submitted to RAE for approval the Network Development Plans for the period 2021-2025. The plans were put to public consultation and RAE approved them with Decisions 1581/2020 (Gazette B' 5754/28.12.2020), 1582/2020 (Gazette B' 5999/31.12.2020) and 1615/2020 (Gazette B' 844/4.03.2021) were approved, respectively. According to the approved network development plans, investments totaling 560 million euros will be made in the next five years 2021-2025 and 2,724 kilometers of pipelines will be developed and 254,791 new consumers will be connected to the gas distribution networks. The estimated increase of natural gas consumption for the next five years will be over 6 million MWh.

Distribution Network	**Investments (€)**	**Network length increase (km)**	**Estimated new connections**	**Estimated increase of consumption (MWh)**
Thessaloniki	96,820,000	238	60,100	814,701
Thessalia	61,450,000	199	30,250	648,558
Attica	129,220,000	560	96,076	2,857,465
Central Greece	47,417,680	320	17,255	357,892
Central Macedonia	43,658,699	327	12,463	404,748

Eastern Macedonia-Thrace	62,077,073	485	18,211	550,452
West Greece	39,005,942	208	10,909	274,990
West Macedonia	57,129,554	238	5,312	216,610
Epirus	23,252,152	149	4,215	200,735
Total	**560,031,101**	**2,724**	**254,791**	**6,326,150**

Table 44: Distribution Network Development for the period 2021-2025

Furthermore, by the virtue of Law 4001/2011 and the provisions of the Natural Gas Licensing Regulation (Gazette B' 3430/17.08.2018), the company EDIL S.A. was granted Distribution Licenses in the Municipalities of Deskati, Paionia, Edessa, Polygyros, Tripoli and Corinth.

Following the above developments and in the context of unbundling its distribution from its other activities, the company EDIL applied to RAE for the transfer of its Distribution Licenses to its subsidiary company "HENGAS S.A.". The submitted applications of these transfers for the Municipalities of Paionia, Polygyros, Edessa and Deskati, were approved by RAE with Decisions 1437/2020 (Gazette B '5363 / 07.12.2020), 1438/2020 (Gazette B' 5370 / 07.12 .2020), 1439/2020 (Gazette B '5411 / 09.12.2020) and 1376/2020 (Gazette B' 4770) respectively. The company HENGAS was also granted, with the RAE Decision 1478/2020 (Gazette B' 5253 / 27.11.2020), a Distribution License for the Municipality of Megalopolis. HENGAS is currently in the process of being certified as the DSO of these distribution networks.

4.1.3 Network and LNG Tariffs for Connection and Access

A. Transmission System and LNG terminal access tariffs

The Decision for transmission tariffs according to the new tariff regulation (Decision 1038/2020) will be in force from 1.1.2021.

Transmission System for each Entry and Exit	SDMi (€/kWh GCV /Hour/Year)	SEM (€/kWh GCV)	SDDY (€/kWh GCV /Hour/Year)
Entry Sidirokastro	5.0971411	-	-
Entry Ag. Triada	1.6924135	-	-
Exit Sidirokastro*	5.0971411		
Exit North Zone	3.5412506	0.0001959	1.4024558
Exit South Zone	3.7677268	0.0001959	1.4024558
LNG Tariffs	SDY (€/kWh GCV /Hour/Year)	-	-
LNG Facility	3.5584231	-	-
*The use of an Exit Point as an Entry Point that is also an Interconnection Point and vice versa, is charged with the tariffs of the respective Entry Point, based on article 9 (6) of the tariff regulation.			

Table 45: Natural Gas Transmission Tariffs coefficients for 2021

In June 2020, RAE adopted Decision 1038/2020 which set the Required Revenue for the Transmission System and LNG Facility in Revithoussa for the regulatory period 2019-2022. The following table contains the Required Revenue per basic NNGS service.

Year	Basic Transmission Service[59]	Basic LNG storage service	Total Sum
2019	101,807,713	42,509,863	144,317,576
2020	101,098,410	41,112,281	142,210,691
2021	99,084,171	40,508,395	139,592,566

Table 46: Required Revenue per basic NNGS service (€/year)

Decision 1038/2020 also set the Allowed Revenue for the Transmission System and LNG Facility in Revithoussa for 2021. In addition, with the same Decision, RAE approved the following table containing the Allowed Revenue per basic NNGS service.

Basic Transmission Service (Entry)	Basic Transmission Service (Exit)	Dispersion of LNG Activity	LNG Activities	Recovery of Old Recoverable Difference	Total Sum
49,542,085.50	49,542,085.50	20,254,197.50	20,254,197.50	11,560,521	151,153,087

Table 47: Allowed Revenue per basic NNGS service for the year 2021 (€)

B. Distribution System access tariffs

In November 2020, RAE issued Decisions 1428/2020, 1429/2020 and 1430/2020 that approved the Required Revenue and the distribution tariffs for the DSOs of Attica, Thessaloniki-Thessaly and DEDA respectively for the Regulatory Period 2019-2022. These decisions were issued based on the gas distribution tariff regulation (RAE's Decision 328/2016) which provided the methodology for calculating gas distribution tariffs for the distribution system operators that was developed in 2016. The calculation of the regulated tariff is based on the methodology of the Allowed Revenue [Allowed Revenue =

[59] The Required Revenue for the basic transmission service is allocated by 50% to the Entry Points and 50% to the Exit Points of the Transmission System.

Allowed Return on the Regulated Asset Base + Annual Depreciation of Assets + Operating Costs – Other Revenue + Any Under / Over Recovery].

Furthermore, the above three Decisions approved the provision of incentives for certain investments by increasing the WACC by 1.5% based on achieving specific milestones for the years 2020 to 2022. The above increase is granted from the year of achievement of the milestone and for the next three years onwards, giving a strong incentive to the DSO for the timely implementation of the approved network development plan.

	2019	2020	2021	2022
Risk-free rate	0.35%	0.35%	0.35%	0.35%
Market Risk Premium	5.30%	5.30%	5.30%	5.30%
Beta	0.80%	0.80%	0.80%	0.80%
Gearing (loan)	16%	18%	20%	20%
Country Risk Premium	2.00%	1.80%	1.50%	1.50%
Cost of equity (post-tax)	6.59%	6.39%	6.09%	6.09%
Tax rate	28%	24%	24%	24%
Cost of equity (pre-tax)	9.15%	8.41%	8.01%	8.01%
Debt rate	3.08%	3.08%	3.08%	3.08%
Total WACC (nominal, pre-tax)	8.18%	7.45%	7.03%	7.03%

Table 48: Main parameters of WACC- Gas Distribution 2019-2022 (Decisions 1428/2020, 1429/2020 and 1430/2020)

	2019	**2020**	**2021**	**2022**
Attica Distribution Network				
Return on RAB	22,012,344	21,465,064	21,377,544	22,405,195
Depreciation	15,062,659	15,544,034	15,630,624	15,692,478
OPEX	18,876,289	22,480,076	24,795,117	25,127,239
Other Revenues	697,228	471,550	195,000	200,850
Old Recoverable Difference	4,048,890	4,056,988	4,065,102	4,073,232
Total	59,302,955	63,074,612	65,673,387	67,097,295
Thessaloniki Distribution Network				
Return on RAB	15,355,185	15,043,076	14,802,418	14,650,812
Depreciation	8,832,137	9,223,480	10,291,278	10,832,711
OPEX	9,962,846	11,235,846	12,314,312	12,833,926
Other Revenues	436,005	666,066	657,436	690,983
Old Recoverable Difference	-607,659	-608,874	-610,092	-611,312
Total	33,106,504	34,227,462	36,122,480	37,015,154
Thessalia Distribution Network				
Return on RAB	7,041,442	7,184,932	7,227,278	7,211,101
Depreciation	4,148,949	4,467,287	5,073,365	5,377,563

OPEX	6,604,361	7,472,225	8,697,673	8,254,239
Other Revenues	396,552	515,103	562,703	574,380
Old Recoverable Difference	-1,205,075	-1,207,485	-1,209,900	-1,212,320
Total	16,193,125	17,401,857	19,225,713	19,056,204
Central Greece Distribution Network				
Return on RAB	2,903,532	2,640,835	3,442,295	3,983,493
Depreciation	1,000,284	1,175,423	1,684,587	2,009,280
OPEX	2,687,321	3,843,617	4,746,442	4,713,229
Other Revenues	0	0	0	0
Old Recoverable Difference	465,166	466,096	467,028	467,962
Total	7,056,302	8,125,970	10,340,352	11,173,964
Central Macedonia Distribution Network				
Return on RAB	1,535,872	1,417,680	2,045,862	2,324,340
Depreciation	570,310	667,981	1,032,822	1,200,998
OPEX	1,377,465	2,909,717	4,244,014	4,221,454
Other Revenues	0	0	0	0
Old Recoverable Difference	273,584	274,131	274,680	275,229
Total	3,757,231	5,269,510	7,597,377	8,022,022
Eastern Macedonia-Thrace Distribution Network				
Return on RAB	1,796,234	1,652,491	2,541,660	3,163,465
Depreciation	665,229	785,765	1,281,503	1,609,570
OPEX	1,636,331	3,046,816	4,616,752	4,891,352
Other Revenues	0	0	0	0
Old Recoverable Difference	294,018	294,606	295,195	295,785
Total	4,391,812	5,779,678	8,735,111	9,960,173
Corfu - Peloponnese Distribution Network				
Return on RAB	105,282	94,053	85,675	83,080
Depreciation	39,801	44,639	45,015	45,887
OPEX	97,534	74,186	57,135	45,206
Other Revenues	0	0	0	0
Old Recoverable Difference	12,397	12,422	12,447	12,472
Total	255,013	225,300	200,272	186,645
Western Greece Distribution Network				
Return on RAB	0	0	152,694	751,410
Depreciation	0	0	50,374	404,212
OPEX	0	0	1,650,459	2,549,222
Other Revenues	0	0	0	0
Old Recoverable Difference	0	0	0	0
Total	0	0	1,853,527	3,704,844
Western Macedonia Distribution Network				
Return on RAB	0	0	80,771	890,133
Depreciation	0	0	26,194	382,033
OPEX	0	0	1,427,568	2,942,799

Other Revenues	0	0	0	0
Old Recoverable Difference	0	0	0	0
Total	0	0	1,534,533	4,214,964
Epirus Distribution Network				
Return on RAB	0	0	0	247,424
Depreciation	0	0	0	67,205
OPEX	0	0	0	1,170,517
Other Revenues	0	0	0	0
Old Recoverable Difference	0	0	0	0
Total	0	0	0	1,485,146

Table 49: Basic activity required revenue per distribution network (2019-2022)

In 2020, the distribution tariffs were adjusted based on the annual Consumer Price Index of 2019, as per the Distribution Code provisions. Therefore, the regulated distribution tariffs of 2020 were the following:

	Attica	Thessaloniki	Thessaly	Central Greece	Corfu - Peloponnese	Central Makedonia	Eastern Macedonia-Thrace	Western Macedonia	Western Greece	Epirus
	Capacity charges €/MW/h (2020)									
Households	1,064.7909	376.6857	434.4835	857.6128	0	693.6328	525.4540	1,165.8319	725.5651	670.6274
Commercial	1,064.7909	376.6857	434.4835	891.3389	0	703.9744	577.1375	1,162.6907	746.2438	694.6120
Industrial	4,282.9732	1,507.1268	1,737.4318	6,961.2356	10,830.0086	4,487.3640	6,465.1574	6,205.9740	3,215.4172	3,636.8682
A/C, Cogeneration	1,064.2062	0	0	0	0	0	0	0	0	0
CNG	0	0	0	0	0	0	0	0	0	0
	Energy charges €/MWh (2020)									
Households	14.2939	10.4287	10.6298	20.4328	0	17.6882	15.4905	21.0167	17.6983	13.8471
Commercial	14.2939	10.4287	10.6298	9.3006	0	7.2126	8.49	16.7844	11.5208	9.7429
Industrial	0.4878	0.1601	0.1546	0.5629	0.7309	0.5078	0.6450	0.6873	0.5270	0.3947
A/C, Cogeneration	2.6349	0	0	0	0	0	0	0	0	0
CNG	0	0.9410	0.7471	0	0	0	0	0	0	0

Table 50: Capacity and energy charges per distribution network per pricing category

4.1.4 Cross-border issues

Until the end of 2020, Natural gas in Greece was imported through three Entry Points of the NNGTS: Sidirokastro (Greek-Bulgarian borders), Kipi (Greek-Turkish borders) and Agia Triada (Revithoussa LNG Entry Point). A new entry point was created in 2020 called Nea Mesimvria which connects the NNGTS with the TAP pipeline.[60] Downstream, natural gas is received by the NNGS users at 43 Exit Points. In 2020, gas imports from the 4 entry points amounted to 63.53 TWh, which is an increase of 10% compared to 2019 (57.7 TWh).

Figure 38 presents natural gas import for each Entry Point for the time period 2010-2020 and Figure 39 the share of each supply source for 2020.

[60] The commercial operation of the Nea Mesimvria entry point started at 31 December 2020.

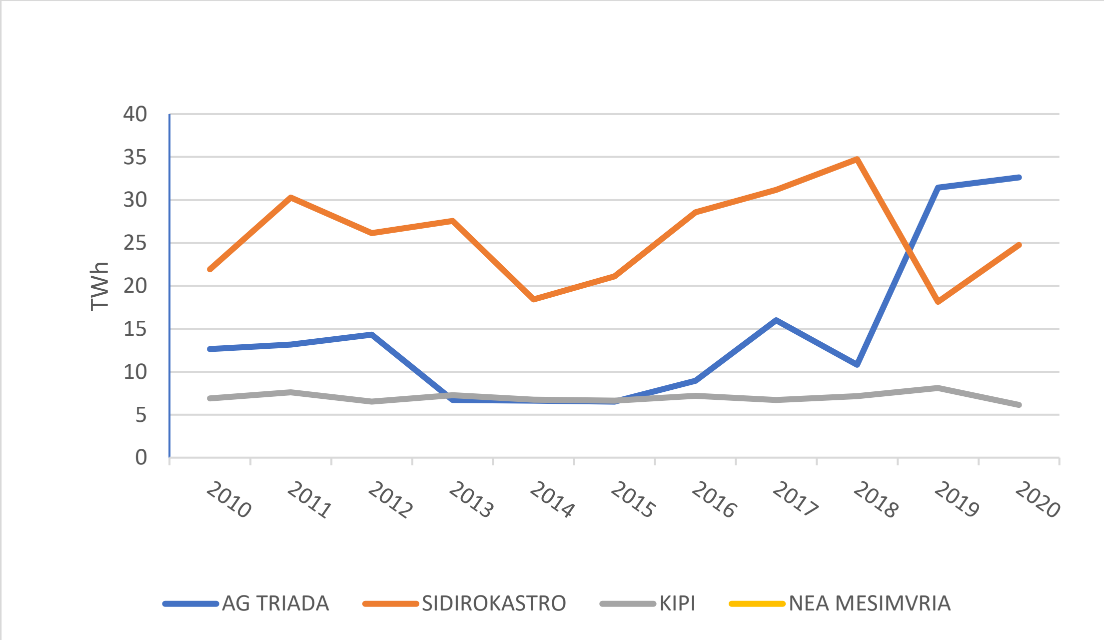

Figure 38: Imports of Natural Gas per Entry Point (2010-2020)

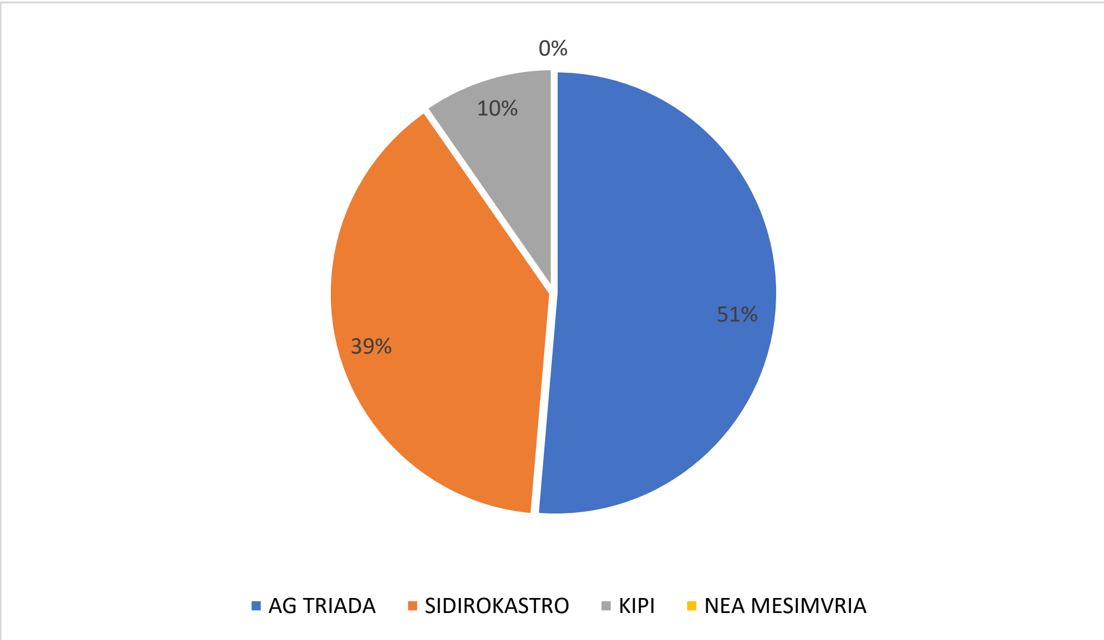

Figure 39: Percentages for imports of natural gas per Entry Point for 2020

“Kipi” Interconnection Point

As mentioned above, with the 5th Amendment of the National Natural Gas System Network Code (RAE Decision 1035/2020) competing Capacity products were introduced to the Greek market. According to RAE Decision 1399/2020, the available capacity at the “Kipi” IP depends on the respective available capacity at the new “Nea Mesimvria” IP. For this reason, RAE with Decision 919/2020, approved the cancelation of the annual capacity auction for the Year 2020/2021 and the auction of quarterly capacity products of the Year 2020/2021 to carry out competing auctions simultaneously between IPs “Kipi” and “Nea Mesimvria”.

The conclusion of an Interconnection Agreement between DESFA and BOTAS is still ongoing. The Agreement will include conditions for the transportation of natural gas quantities, for the resolution of technical and operational issues as well as procedures for the exchange of information during normal and emergency situations.

“Agia Triada” Interconnection Point (Revithoussa LNG Terminal)

The use of the Revithoussa LNG terminal has been increased significantly resulting in intense competition between the terminal Users. The LNG Cargoes Unloading Annual Plan for 2021 took place in November 2020 through competitive auctions, , under the provisions of the 6th amendment of the Network Code, in which 7 companies booked 35 out of the total 46 standard LNG slots offered by DESFA.

IGB pipeline

In June 2019, ICGB AD requested the postponement of the deadline for the commercial launch of the operations of the IGB pipeline until January 2021 instead of July 2020 as it was provided in the Exemption Decision. According to the company, the delay in the commencement of the commercial operation of the pipeline was due to the delay in the construction work because of objections and litigation in the contract award procedures. This request constituted an amendment to the Exemption Decision and could only be made following a new Joint Decision by the NRAs. The Directorate-General for Energy of the European Commission confirmed that it didn’t need to take any action on amending the Exemption Decision as long as the deadline of Article 36 (9) of the 2019/73/EC Directive is complied with. Although the reasons for the delay cited by the company appeared to be objective and beyond its control, RAE and EWRC sought the consent of users who had entered into Advanced Reservation Capacity Agreements (ARCAs) with the company, so that the modification of the Exemption Decision would not affect their business plans. RAE and EWRC jointly approved the requested amendment of the Exemption Decision (Decision 568/10.03.2020), according to which, the starting data of the commercial operation of the pipeline would be 1 July 2021. However, the ongoing pandemic may lead to further delays in the start of the commercial operation of the pipeline, in which case, the company will have to submit another request for amendment within the first half of 2021 to amend the Exemption Decision again.

In June 2019 RAE issued an Independent Natural Gas System License to the IGB pipeline for the section of the pipeline that is located on Greek territory. In December 2020, ICGB AD submitted an application for an Independent Natural Gas System Operation License according to the natural gas licensing regulatory framework. This application will be examined by RAE within the first half of 2021.

Furthermore, the company must also submit an application for its certification under the ITO model as provided for in the Exemption Decision.

TAP pipeline

TAP's regulatory framework is described in the "Final Joint Opinion of the Energy Regulators on TAP A.G.'s Exemption Application: Autorita per l'energia elettrica e il gas (Italy), Enti Rregullator i Energjise (Albania), Ρυθμιστική Αρχή Ενέργειας (Greece)" (FJO). This FJO is a result of collaboration of the regulatory authorities of Italy, Albania and Greece, following decision C (2013)2949_final/16.05.2013 of the European Commission, constitutes the Exemption Decision under Article 36 of Directive 2009/73/EC and was approved by RAE with the Decision No. 269/2013. safeguarding competition.

On 15 November 2020, TAP AG officially announced the completion of the construction and test operation of the pipeline, four years after the start of its construction. This date is defined as the official Commercial Operation Date (COD) of the pipeline, as defined in the Exemption Decision issued by ARERA, ERE and RAE. The COD milestone marks the beginning of the 25-year exemption period from the unbundling rules, third-party access and tariff setting. Starting from this date, Users who have booked capacity in the pipeline are obligated to pay the corresponding tariffs as defined in the Tariff Regulation. From 15.11.2020, TAP started offering daily physical capacity through the PRISMA platform at the "Kipi" Entry Point and at the "Melendugno" Exit Point. In "Nea Mesimvria", the daily auctions began at the end of December 2020, when the metering station was put into operation.

In addition, as 31 December 2020 was the last possible date for the commencement of the commercial operation of the pipeline in accordance with the Exemption Decision, TAP AG requested in June 2020, the three regulatory authorities to amend their Decision and postpone the commercial operation of the pipeline by one year. ARERA, ERE and RAE cooperated during the examination of this request and approved TAP AG's request as the conditions of Article 36 (9) of Directive 2009/73/EC were deemed to be fulfilled and the postponement of the pipeline operation occurred for reasons beyond the control of the company (COVID-19 pandemic, licensing barriers and local protests during the construction of the pipeline in Italy). The joint decision of the three NRAs was approved with Decision 1037/19.06.2020 and was notified to the European Commission. However, the above request was withdrawn by the company as the commercial operation of the pipeline became possible within 2020.

During 2020, TAP AG continued to meet its obligations under both the FJO, the national and EU law that govern the project. In this context, RAE, in cooperation with the Regulatory Authorities of Italy and Albania, ARERA and ERE respectively, has worked on the following issues:

1. TAP network code

Following close collaboration with the three NRA's from 2018, TAP submitted its final proposal for the Network Code in December 2019. The three regulators approved the final draft of the network code (Decision 1036/17.06.2020). which covers all the basic issues of User access to the pipeline and is in accordance with: (a) the Joint Exemption Decision, the Regulation (EC) 715/2019, the Regulation (EU) 459/2017 (NC CAM) for the capacity for which no exception was given Regulation (EU) 312/2014 (NC BAL) and the Regulation (EU) 2015/703 (NC IO).

2. Auctions on Nea Mesimvria and Melendugno Interconnections Points

TAP has an obligation to allocate 5% of its capacity (10bcm) to short-term products through auctions. Given that the only physical flow entry is currently the "Kipi" Entry Point, short-term forward capacity products can be picked up at either the Nea Mesimvria IP or the Melendugno IP in Italy. As this capacity may not exceed 0.5 bcm in total, TAP proposed to the NRA's in November 2020 - that capacity products at these two points shall be offered as competing capacity, so that users can decide - on market terms - how to direct these quantities of gas between Greece and Italy. RAE and ARERA drafted a joint decision for the approval of a specific procedure for the auctioning of competing products proposed by TAP, which was approved by RAE with its Decision 1489/05.11.2020.

3. Market Test

In accordance with paragraph 4.1.7 of the FJO, TAP is required to conduct Market Tests to allocate any remaining pipeline capacity at least every 2 (two) years starting from the date of its commercial operation, with the approval of the relevant Guidelines set by the Regulators. These Market Tests concern the expansion capacity, ie increasing the technical capacity of the pipeline from the initial capacity of 10bcm / year to 20bcm / year by installing the necessary compressors along the pipeline. The expansion of the capacity will be conducted only if it is considered economically feasible.

The extra capacity has not been granted an exemption from third party access and will therefore operate in a fully regulated regime. In this regard, the CAM NC, which provides for a specific procedure for increasing the capacity of a regulated pipeline, should apply.

Following extensive discussions with the Regulatory Authorities, which took place during 2018, in autumn of the same year, TAP AG submitted a proposal for approval on how to conduct the Market Test as compatible as possible with the FJO and the CAM NC, in collaboration with the adjacent TSOs, DESFA and SNAM Rete Gas.

The proposal was approved by the three regulatory authorities in April 2019,[61] with TAP conducting the first phase of the Market Test in July 2019, in application of the CAM NC Auction Calendar. In the light of the approval, on July 2019, the three Operators initiated the procedure for the assessment of the incremental capacity. All non-binding demand indications were submitted by the interested parties to TAP within the 8-week timeframe set forth in Article 26 (6) of the CAM NC until 26 of August 2019. The non-binding requests submitted for the TAP-DESFA interconnection point in Nea Mesimvria are summarized in the table below:

Year	Main TAP direction flow (Kipi → Nea Mesimvria)	TAP commercial reverse flow (Melendugno → Nea Mesimvria)	Total flows – Nea Mesimvria Entry Point	Reverse flow in Nea Mesimvria IP (Nea Mesimvria → Melendugno)
2020/21	1,370,000	87,470,000	88,840,000	
2021/22	32,370,000	87,470,000	119,840,000	
2022/23	41,980,000	98,450,000	140,430,000	6,850,000
2023/24-2029/30	71,021,096	98,450,000	169,471,096	6,850,000
2030/31-2031	71,021,096	12,350,000	83,371,096	6,850,000
2032/33	65,541,096	5,500,000	71,041,096	

[61] RAE Decision 651/2019

2033/24-2040	36,500,000	5,500,000	42,000,000	
2041/42	5,500,000	5,500,000	11,000,000	

Table 51: Non-binding requests for forward firm long-term capacity in TAP-DESFA Interconnection Point in Nea Mesimvria (kWh/day)

Subsequently, TAP, SRG and DESFA prepared a joint Demand Assessment Report (DAR) which was published in October 2019. The report concluded that the demand trends received from the Operators were sufficient to initiate an incremental capacity project in accordance with Article 26 (2) of the CAM NC.

Specifically, the proposed incremental capacity project included the following:

- Incremental capacity that is jointly offered by TAP and SRG in Melendugno interconnection point, as bundled product.
- Incremental capacity that is jointly offered by TAP and DESFA in Nea Mesimvria interconnection point as a bundled product. Unbundled capacity can also be allocated at this point but only from DESFA's side.
- Incremental capacity offered by TAP at Kipi, Korçë and Fier interconnection points, in the form of unbundled capacity, on TAP's side since Turkey and Albania do not implement CAM NC.[62]

There is no consideration of incremental capacity in Komotini interconnection point between TAP and IGB, since the latter hasn't been constructed yet and its Exemption Decision provides for a Market Test for incremental capacity within three years of its commercial operation.

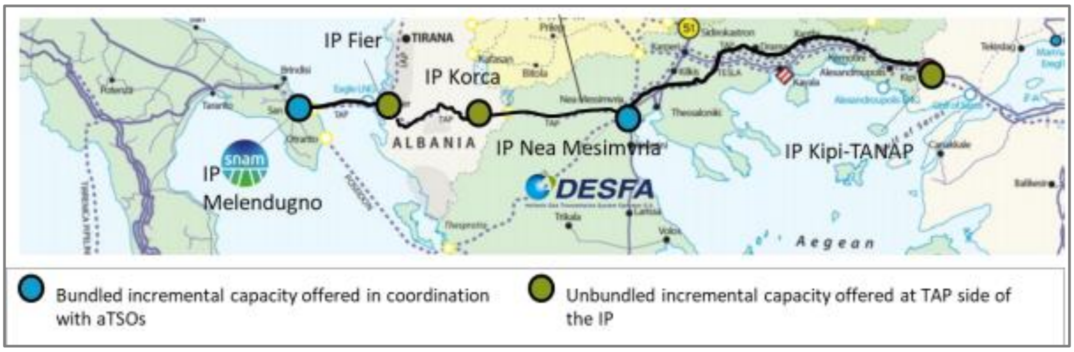

Figure 40: Interconnection points where incremental capacity is offered by the Operators TAP, DESFA and SRG

Furthermore, during the first phase of the market test, the five companies involved in the process submitted to the regulator the relevant data in order to verify the compatibility of their requests with respect to the capacity caps defined in the FJO. Based on the data submitted for 2017 and 2018 it was found that none of the five companies had a share of more than, or equal to, 40% in either gas (pipeline and LNG) imports or in the wholesale market or retail market. Market test participants were informed that they are compliant with the capacity limits set in the FJO following a decision of RAE.

[62] Albania as a Contracting Party of the EnC, applied the NC CAM Regulation from 28 February 2020, from this date the procedure for incremental capacity began.

The proposed incremental capacity project was put for a joint public consultation by the Operators starting from 20.01.20 to 21.02.2020. However, the three TSOs failed to submit the final plan for NRA approval by the end of 2020.

4. Obligations arising from the ITO Model

TAP AG has been certified by the Regulatory Authorities under the ITO model as it is defined in Directive 2009/73/EC (RAE Decision 45/2016, Gazette B '972 / 8.4.2016). Regulators have been monitoring the implementation of the company's obligations under the ITO model. During 2019, there were extensive discussions between TAP and the Regulators on issues related to the compliance program which has been submitted to the three NRAs for approval at the end of 2019.

RAE, in collaboration with the NRAs of Italy and Albania, issued Decision 1331/2020 that approved the compliance program submitted by TAP AG. In summary, the compliance program provides:

- The establishment of a Supervisory Body entrusted with the competences provided in Article 20 of Directive 2009/73/EC. For compliance reasons with the corporate governance rules of the place of establishment of the company TAP AG, the Supervisory Body and the Board of Directors of TAP AG consists of the same members that are appointed by the shareholders of the company. In view of the above situation, necessary steps have been taken, in particular regarding the unbundling provisions, in order to meet the requirements of the FJO Decision and of the Directive 2009/73/EC and ensure the independence of the network operator and the safeguarding of commercially sensitive information as well as avoiding risks such as conflict of interest with respect to the shareholders of the TAP AG. The compliance is monitored by a Regulatory Compliance Officer.
- Full implementation of the requirements that will ensure the independence of: a) the Managing Director, b) the members of the Leadership Team, c) the Regulatory Compliance Officer, d) members of the Supervisory Board (half of its members minus one according to Article 19 of the Directive/73/EC) and the employees of the company.
- The procedure for the appointment of the Regulatory Compliance Officer by the Supervisory Body and its tasks in accordance with the provisions of Article 21 if Directive 2009/73/EC, which include, inter alia, monitoring the implementation of the Compliance Program and monitoring compliance with the independence provisions by the above persons.
- The independence of the company in relation to its shareholders who are active in both production and supply of natural gas in terms of providing access to the transmission system in a transparent and non-discriminatory manner as well as the operation independence of the company in terms of maintaining the necessary human, material, technical and financial resources for the exercise of the gas transmission activity.
- The procedures for safeguarding sensitive commercial data.

At the same time, the three NRAs approved the appointment of the Regulatory Compliance Officer proposed by the Supervisory Body since the candidate had the necessary skills to perform the duties while also being independent of any external influence.

5. Independent Natural Gas System License and Independent Natural Gas System Operation License

Regarding the segment of the pipeline located in Greek territory, the Natural Gas Licensing Regulation provides for the issuance of an Independent Natural Gas System license and an Independent Natural Gas System Operation License. TAP received its Independent Natural Gas System license in 2014 (Decision 431 / 30.7.2014). In December 2018, this License was requested to be amended, due to changes in the TAP AG shareholder composition, as well as a redefinition of the timetable for the commercial operation of the pipeline. RAE with Decision 470/2019 approved the amendment of the license in April 2019.

In December 2018, TAP AG also filed an application for an Independent Natural Gas System Operation License. The above application was approved with Decision 752/2020 and the license will be valid for 50 years from the commercial operation of the pipeline.

Furthermore, RAE with its Decision 371/2020 approved the contract agreement between TAP AG and DESFA for the provision of consulting services of the later for the acquisition of an operating license by TAP AG. The contract describes in detail, the services provided by DESFA to TAP AG, the general terms and conditions, and the relevant costs.

The FSRU in Alexandroupolis

In June 2018, Gastrade submitted to RAE a request for the exemption of the planned FSRU from certain provisions of the Gas Directive, and subsequently also an amendment of its INGS license. Following the exemption request, the first phase of the market test took place between 30 October 2018 and 31 December 2018 following the approval by RAE of both the Guidelines (Decision 911/2018) and the Notice (Decision 1027/2018) addressed to interested parties. In 2019, RAE drafted specific Guidelines for the Binding Stage of the Market Test in collaboration with the company.[63] Subsequently, it issued a Notice to any interested parties to submit bidding offers.[64] The second phase of the Market Test will begin in 10.01.2020. Upon its completion, as set out in Directive 2009/73/EC, RAE will proceed with Gastrade's exemption request.

The second, binding stage of the Market Test took place between January 10 and March 24, 2020. The Market Test was completed with the signing of the Advanced Reservation Capacity Agreement (ARCA) between the contractor company and each of the companies to which capacity was allocated. The ARCA is the final statement, accompanied by a financial guarantee, of the participants that they will book capacity when/if the infrastructure is built, and of Gastrade SA. that will offer them this capacity on specific terms. On 5 May 2020, GASTRADE informed RAE of the signing of all ARCAs for the capacity booking and, consequently, the successful completion of the Market Test, and submitted a revised Exemption Request based on its results.

Following the above, RAE proceeded to examine Gastrade's Exemption Request and issued the preliminary Exemption Decision 1333/17.09.2020, which was communicated to DG ENER of the

[63] RAE Decision 596/2019

[64] RAE Decision 1145/2019

European Commission. On 25 November 2020, the Commission adopted its decision [C(2020) 8377 final] on the exemption of the Alexandroupolis Independent Natural Gas System from the requirements regarding third party access and tariff regulation. By its Decision the Commission requested RAE to make minor amendments, in accordance with Article 36(9) of Directive 2009/73/EC, its decision issued in accordance with Article 36(8) of the Directive.

With Decision 1580/10.12.2020, RAE amended the previous Preliminary Decision of 1333/2020 in order to fully comply with the decision of the European Commission. The final exemption decision was published in Government Gazette B '5941/31.12.2020.[65]

The main points of the Exemption Decision are the following:

- The exemption from Article 32 of the Third Party Access Directive is granted for 25 years to GASTRADE SA, only for the part of the infrastructure for which capacity has been reserved through the Market Test the following conditions: a) the company has to comply with the provisions of Regulation (EC) No 715/2009, and in particular Articles 15, 17, 19, 20 and 22 thereof, b) GASTRADE has to develop and submit to the RAE a Terminal Access Code at least 12 months before the start of the commercial operation of the infrastructure, with the minimum content that is specified in the Exemption Decision, c) the company has to publish all the necessary information that will ensure equal access of interested parties to the part of the infrastructure that has not been included in the Exemption Decision, d) GASTRADE shall offer on a regular basis the remaining available capacity through market-based arrangements, indicatively auctions or open seasons, and e) the company agrees not to interfere in any way in any way the operation of the NNGS nor to incur any costs to its users.
- In order to ensure the competitiveness of the tariff, as well as ensure transparency and predictability of the tariff for all users of the Alexandroupolis INGS, an exemption from the provisions of Article 41.6, 41.8, 41.10 was granted to GASTRADE SA for a period of 25 years starting from the beginning of the Commercial Operation Date for 100% of the Project's regasification capacity, under the following conditions: 1. At the latest 12 (twelve) months before the Commercial Operation Date, GASTRADE shall submit for the approval of RAE the final tariff methodology (Tariff Code) for the implementation of the Alexandroupolis Tariff. 2. The Tariff shall be stable over the whole duration of the exemption, shall reflect efficient costs, shall be transparent and non-discriminatory and shall follow the principles described in the present Joint Opinion. The same Tariff shall apply for the exempted and the nonexempted part of the capacity and b) any revenues from capacity bookings that increase IRR above a defined cap will be returned to the Terminal Users either through tariff reductions of following periods or by a profit-sharing mechanism in a non-discriminatory manner. The mandatory return of any profit beyond the set IRR cap to initial and future users of the Alexandroupoulis INGS will be subject to the terms of the forthcoming state aid decision.
- The dominant suppliers of the Greek and Bulgarian market (with a market share of over 40%) cannot reserve more than 25% of the regasification capacity of the Project.

[65] For more information see: https://rae.gr/wp-content/uploads/2020/12/%CE%91%CE%A0%CE%9F%CE%A6%CE%91%CE%A3%CE%97-1580-Final-exemption-decision_after-EC-decision-final-non-confidential.pdf

- The request for exemption from Article 9 of the Directive 2009/73/EC was not examined as non-relevant, as this article does not apply to LNG terminals.

Furthermore, in October 2020, GASTRADE SA submitted to RAE a request for a preliminary examination of a change in the shareholder composition of the company, as provided by article 18 (8) of the Natural Gas License Regulation. RAE Decision 1532/2020 approved the amendment of the shareholder composition and the transfer of the relevant shares to BULGARTRANSGAZ was completed in January 2021, following a decision of the competent Competition Authorities.

In addition, in December 2020, the company submitted to RAE a new request for a preliminary examination of a change in its shareholding structure, according to the provisions of article 18 (8) of the Natural Gas License Regulation. RAE is examining this request, both from the point of view of Gastrade's Independent Natural Gas System license and based on the terms of DESFA's certification. In accordance with the terms of the Exemption Decision, RAE reserves the right to examine whether the conditions under which the Exemption was granted continue to apply.

Finally, RAE is currently elaborating on the amendment of the Independent Natural Gas System license of the infrastructure, in order to include the terms of the Exemption Decision in GASTRADE's license, in accordance with the provisions of the Natural Gas License Regulation.

The company Gastrade SA is expected to make a Final Investment Decision (FID) within the first half of 2021.

DIORYGA GAS

The company DIORYGA GAS SA has received an Independent Natural Gas System License from RAE (Decision RAE 1321/2018) for a project related to:

- An Offshore Floating Terminal LNG which includes:
    - A Floating Storage and Regasification Unit.
    - A Multi-point floating anchorage / buoys for mooring the FSRU at the stern and bow.
- A Submarine and Land pipeline for the supply of natural gas to the NNGTS through a new Metering Station.

On June 20, 2019, the company DIORYGA GAS submitted DESFA an application for Advanced Reservation of Capacity for the connection of the planned FSRU with the NNGS.

In November 2020, DESFA submitted to RAE a Proposal for Capacity Expansion for the New Project "Creation of a New Entry Point of the NNGTS in the area of Agioi Theodoron, Corinth", in accordance with the provisions of article 95B of the NNGS Code, and included this project in its final Network Development Program of 2021-2030, which is expected to be approved by RAE within January 2021.

The project includes the construction of a metering & regulating station with a capacity of 490,000 Nm3 / h (or 11.76 million Nm3 / day). Upon completion of the project, a new Entry Point "DIORYGA GAS" will be created, which will satisfy the request of the applying company for a total delivery of natural gas of 11.76 million Nm3 / day, under the conditions set out in the proposal of DESFA.

Within the first half of 2021, DIORYGA GAS is expected to sign with DESFA an Advanced Reservation of Capacity Agreement (ARCA), as well as to launch a Market Test process to explore possible market interest in the new infrastructure.

4.2. Promoting Competition

4.2.1. Wholesale Markets

Greece has not developed an organized wholesale market in the natural gas sector, and all the transactions are based either (a) on bilateral contracts between the suppliers and the eligible consumers (over the counter contracts) with a pre-defined delivery point of the agreed traded quantity of natural gas either at the Virtual Trading Point of the National Natural Gas System or at a physical delivery point, (b) on DEPA's gas release mechanism or (c) on the balancing platform through which DESFA buys natural gas from network users to settle any imbalances caused in the NNGTS.

Total Trades & Volume		Average		NNGTS Physical Entries	
Total Trades Executed	Total Volume Traded	Trades per day	Volume Traded per day	Volume	VTP Trades / Entries
12,000	41.97 TWh	32.19	114.68 TWh	70.45 TWh	60%

Table 52: Transactions in the Virtual Trading Point (VTP) in 2020

Compared to 2019, the transactions in the VTP in 2020 were increased by 12.6% in terms of natural gas volume.

To boost competition and liquidity in the Greek gas market, the Hellenic Competition Commission (HCC), in November 2012, following a referral from RAE, adopted a gas release mechanism as a commitment in an alleged abuse of dominance case against DEPA SA. Suppliers and eligible customers entitled to participate in the auctions.

The original planned duration of the gas release mechanism was 10 years, until 2022. However, there was a provision under which DEPA's commitment would be reviewed, in cooperation with RAE after a relevant request of DEPA, if the latter market share falls below 60%. DEPA commercial S.A. submitted a request to review its above commitment in summer 2020. On 21.12.2020, the HCC announced its decision through a press release, following a positive opinion by RAE, to accept DEPA's request and exempt it from the obligation to implement the program of distribution of natural gas quantities through electronic auctions as it was recognised that there has been a substantial change in the facts on which HCC Decision No. 551/VII/2012 was based. Undoubtedly, the gas release mechanism was an important policy measure for the liberalisation of the domestic natural gas market, as it reinforced its competition and increased its gas liquidity.

The quantities of the natural gas put up for auction under the gas release mechanism for 2020 corresponded to a percentage of 20% on DEPA's natural gas sales in 2019. Regarding RAE's competences in calculating the starting price of the auctions, it should be noted that DEPA submitted accurately and by the end of the deadline the relevant data for the annual auction and the four quarterly auctions to RAE. In addition, after DEPA's suggestion and a relevant public consultation, RAE issued Decision 800/2020 (Gazette B΄1951) which amended its Decision 423/2016 on the methodology for calculating the starting price due to change in the calculation of the long-term contract price in DEPA's contract with BOTAS and more specifically by indexing the natural gas price to the European index.[66]

[66] In the past the natural gas price was indexed to the oil price.

After two years of the balancing platform's operation, some changes were deemed necessary in the calculation methodology of the marginal prices and the ceiling prices of the bids. Thus, in 2020, RAE Decision 1035/2020 (Gazette B' 2840) amended the Natural Gas Balancing Manual with the following changes:

- Amendment of the calculation methodology of Balancing Gas Marginal Buy Price and of Balancing Gas Marginal Sell Price in cases where no auctions were held for one day or were held but no bids were awarded to any User (either because there were no bids or the submitted bids were not accepted by the TSO) to better reflect the conditions in the balancing market.
- Amendment of the methodology for determining the Upper Unit Price bid limit, taking into account the historical data of the balancing platform.

The auctioned natural gas amount by the TSO (natural gas buying and selling balancing auctions) for 2020 corresponded to 3.8 TWh which is the 6% of the total quantities injected into the NNGTS. The contracted volume of natural gas amounted to 1.02 TWh approximately. Fourteen Users (14) have participated in the auctions.[67]

Table 53 represents the number of transactions between DESFA and the Users of the Balancing Platform in 2020, including their balancing natural gas selling and buying transactions.

Total Trades & Volume				Average			
Balancing Gas Purchases		Balancing Gas Sales		Balancing Gas Purchases		Balancing Gas Sales	
297 Trades	439.47 GWh	593 Trades	580.63 GWh	0.81 Trades/Day	1.20 GWh/Day	1.62 Trades/Day	1.59 GWh/Day

Table 53: Transactions in the Balancing Platform for the year 2020

Moreover, RAE, within the framework of its competences regarding monitoring of the Greek energy market, published for the first time in 2011, data on the calculated Weighted-Average Import Price (WAIP) of natural gas in the NNGS, monthly. The publication of data on WAIP, in combination with the publication of data on Balancing Gas Reference Price, Balancing Gas Marginal Sell and Balancing Gas Marginal Buy Prices on the TSO's (DESFA) internet site, allows current and potential market participants to gain a better understanding of the price conditions prevailing in the Greek market, and, therefore, to exploit business opportunities and enhance competition, to the final benefit of consumers.

[67] The Balancing Platform was used by 9 Users In 2018 and by 14 Users in 2019.

Furthermore, the publication of wholesale prices constitutes a necessity for the organization of a wholesale gas market where the prices will be determined real-time by supply and demand on a trading platform. Figure 41 presents the monthly WAIP as well as the prices for the balancing gas for the same month, as announced on the internet site of DESFA, from January 2020 to December 2020.

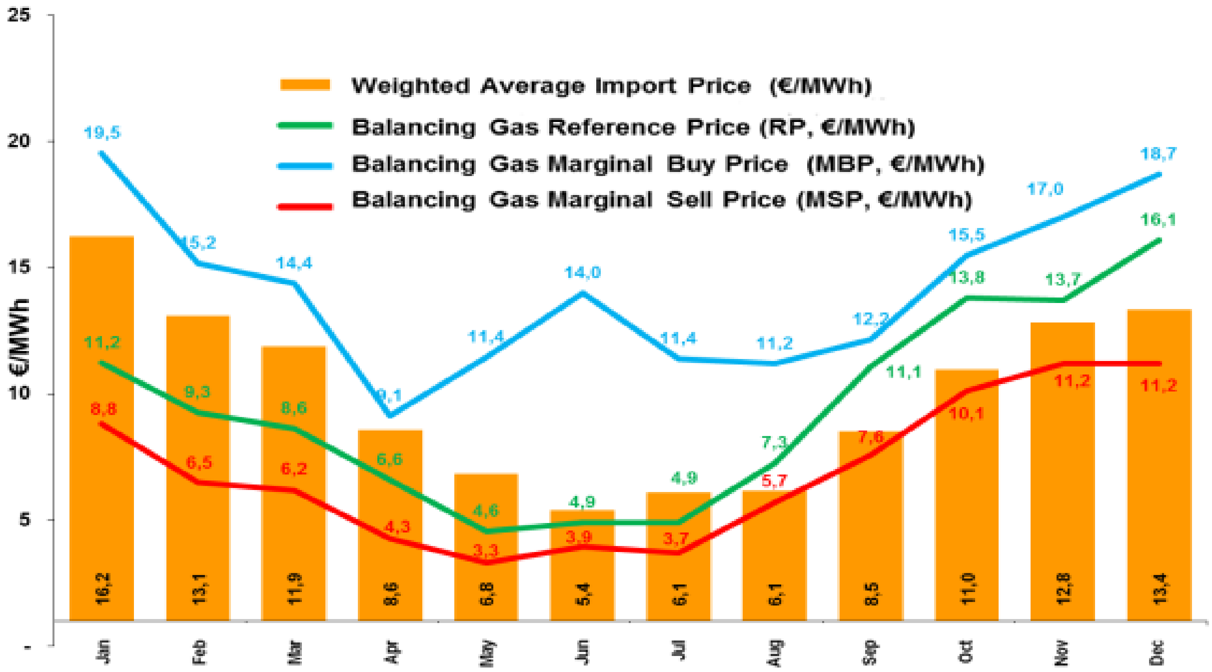

Figure 41: Price Monitoring in the Wholesale Natural Gas Market for the year 2020

4.2.2. Monitoring the level of transparency

Market Opening and Competition

In the end of 2020, a new entry point started its commercial operation at Nea Mesimvria, where NNGTS connects with TAP. There were no LNG or storage facilities, commissioned in 2020 except TAP. As explained in previous National Reports, there is no indigenous gas production in Greece. Furthermore, there are no storage facilities and the LNG terminal is used exclusively for temporary LNG storage. Therefore, as has been noted in the past, the Revithoussa LNG terminal remains the main road for new entrants in the Greek gas market. This remains valid although, as already explained above, in 2020 16 companies imported natural gas from the IP Kulata – Sidirokastro.

After the full liberalization of the natural gas market in early 2018 (opening up of the retail market), the publication of the weighted average import price, in combination with the balancing gas reference prices, as well as the balancing gas marginal buying and selling prices, but also the DEPA auctions prices[68], provide useful information on the price conditions in the Greek natural gas market which

[68] DEPA auction scheme ended in December 2020 with HCC Decision 723/2020. See: https://www.epant.gr/apofaseis-gnomodotiseis/item/1296-apofasi-723-2020.html

enables interested parties to pursue further business opportunities and the development of competition for the benefit of gas consumers.

4.2.3. Description of the Gas retail market

Radical changes were made in the retail market of natural gas starting from 2018, with the full liberalization of the gas market. In more detail, from 01.01.2018 (law 4336/2015), the monopoly of the gas supply companies in Attica and Thessaloniki/Thessaly was abolished, and thereafter the gas supply companies may operate on the market, without any geographical restriction, provided that there is an active network of gas. At the same time, with the establishment of the gas distribution companies, the separation of the distribution activity from that of the supply of gas was implemented.

At the end of 2020, a total of 24 suppliers were active in the retail market of natural gas:

	Supplier Name:
1.	ANOXAL
2.	BA GLASS
3.	PPC
4.	DEPA
5.	ELVALCHALCOR
6.	ELINOIL
7.	ELPEDISON
8.	ZENITH
9.	EFA ENERGY
10.	FULGOR
11.	NATURAL GAS ATTICA
12.	GREENSTEEL
13.	HERON
14.	KEN
15.	MNG TRADING
16.	MOTOR OIL
17.	MYTILINEOS
18.	NRG
19.	PETROGAZ
20.	PROMETHEUS
21.	SIDENOR
22.	SOVEL
23.	VOLTERRA
24.	WATT & VOLT

Table 54: Suppliers active in the retail market of natural gas (2020)

The Herfindahl-Hirschman Index (HHI) at the end of the year is estimated at 2,147, (calculated by consumption volumes). To a certain extent similar to the electricity market, the gas market is considered to be marginally concentrated.

The tables below represent the connections (55) and consumption (Table 56) per category of consumers per supplier including the suppliers market shares.[69]

Company	**Number of connections**				**Market share**
	Residential	**Commercial**	**Industrial**	**Total**	
ZENITH	308,120	8,396	75	316,591	60.38%
EPA ATTIKIS (FYSIKO AERIO)	128,820	6,465	70	135,355	25.82%
MYTILINEOS	19,506	479	22	20,007	3.82%
ELPEDISON	15,704	377	7	16,088	3.07%
NRG	9,494	432	1	9,927	1.89%
HERON	8,909	391	49	9,349	1.78%
WATT & VOLT	6,171	255	0	6,426	1.23%
EFA ENERGY	5,680	205	6	5,891	1.12%
PPC	2,192	33	0	2,225	0.42%
VOLTERRA	1,112	129	0	1,241	0.24%
KEN	769	38	0	807	0.15%
ELINOIL	159	6	1	166	0.03%
PETROGAZ	93	3	0	96	0.02%
DEPA	17	16	42	75	0.01%
MNG Trading	0	1	33	34	0.01%
HELLENIC HALYVOURGIA	0	2	9	11	0.00%
GREENSTEEL	0	0	2	2	0.00%
MOTOROIL	0	0	2	2	0.00%
PROMETHEUS GAS	0	0	1	1	0.00%
ANOXAL	0	0	1	1	0.00%
FULGOR	0	0	1	1	0.00%
SIDENOR	0	0	1	1	0.00%
SOVEL	0	0	1	1	0.00%
BA GLASS	0	0	1	1	0.00%
TOTAL	506,746	17,228	325	524,299	100.00%

Table 55: Natural gas connections per category of consumers and suppliers’ market share, 2020 (Source: Natural gas DSOs’)

[69] Please note that the tables do not take into account the consumption and connection data of consumers that are directly connected to the high-pressure transmission network.

Company	Consumption (MWh)				Market share
	Residential	Commercial	Industrial	Total	
ZENITH	2,895,572	526,228	538,742	3,960,542	33.71%
EPA ATTIKIS (FYSIKO AERIO)	1,999,486	927,617	484,737	3,411,840	29.04%
MITILINEOS	191,263	48,210	627,853	867,326	7.38%
HERON	63,363	34,853	607,352	705,568	6.01%
HELLENIC HALYVOURGIA	0	478	661,641	662,119	5.64%
MNG Trading	0	180	548,452	548,632	4.67%
DEPA	203	68,678	318,425	387,306	3.30%
GREENSTEEL	0	0	217,815	217,815	1.85%
ELPEDISON	132,077	21,659	40,303	194,039	1.65%
BA GLASS	0	0	171,097	171,097	1.46%
EFA ENERGY	47,695	21,874	63,458	133,027	1.13%
NRG	82,150	30,935	3,163	116,248	0.99%
MOTOROIL	0	0	62,384	62,384	0.53%
WATT & VOLT	48,002	13,518	0	61,520	0.52%
SOVEL	0	0	51,294	51,294	0.44%
SIDENOR	0	0	46,279	46,279	0.39%
FULGOR	0	0	43,588	43,588	0.37%
ANOXAL	0	0	42,046	42,046	0.36%
VOLTERRA	9,791	22,515	0	32,306	0.27%
PPC	12,528	1,271	0	13,799	0.12%
PROMETHEUS GAS	0	0	7,777	7,777	0.07%
KEN	5,130	1,022	0	6,152	0.05%
ELINOIL	1,551	698	1,850	4,099	0.03%
PETROGAZ	725	151	0	876	0.01%
TOTAL	5,489,536	1,719,887	4,538,256	11,747,679	100.00%

Table 56: Natural gas consumption (MWh) per category of consumers and suppliers' market share, 2020 (Source: Natural gas DSOs')

The total consumption of natural gas in 2020, as it is determined by the deliveries to the NNGTS, amounted to 63,5 TWh, an increase of about 10% compared to the consumption of natural gas in 2019 which amounted to 57,6 TWh. The consumption of natural gas in 2020 marked the highest gas demand level ever recorded in the country.

The highest percentage of natural gas consumption in Greece is absorbed for electricity production and, consequently, any variation in the demand of the electricity strongly affects the total gas consumption. Consumption in the electricity sector amounted to 41 TWh in 2020, an increase of 9.5% compared to 2019 (37.5 TWh). At the same time, consumption for other uses greatly increased by 11% and amounted to 22.4 TWh in 2020, compared to 20.1 TWh in 2019.

Based on DESFA's forecasts for the total natural gas demand for the next decade, as they are included in the TYNDP for the NNGS for the period 2020-2029, the natural gas demand according to the basic scenario, is expected to range from 62.5 TWh in 2021 to 69.2 TWh in 2030.

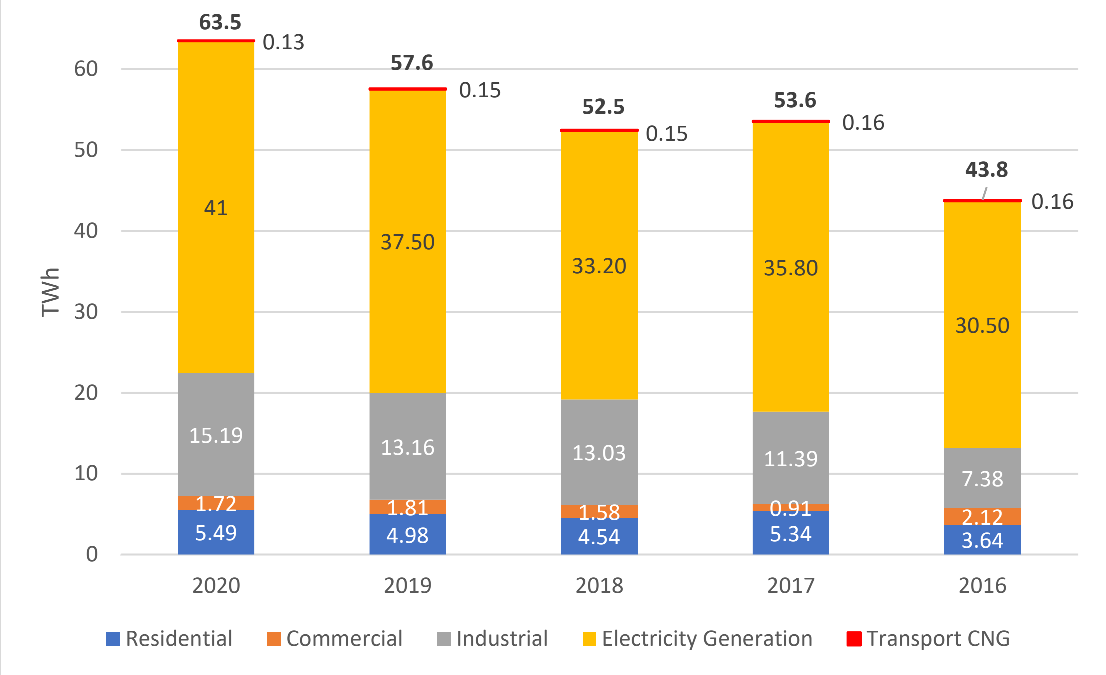

Figure 42: Natural Gas Consumption in Greece (2020)

The total volume of gas consumption in the distribution networks in 2020 slightly increased for all categories of consumers compared to 2019. The consumption of natural gas was at 11,75 TWh (compared to 11.16 TWh of 2019), showing an increase of 5.29%.

Table 57 portrays the number of customers who switched supplier in 2020, as well as their corresponding consumption. As it turns out, the highest switching rate was recorded at the category of commercial customers, followed by industrial and household customers.

Overall, customer switching rate in 2020 slightly decreased compared to 2019 in terms of connections (due to reduced mobility of household and commercial customers), while there was a slight increase in terms of consumption (mainly due to the increased mobility of commercial and industrial customers).

Customer Category	Total number of customers	Number of customers switching Supplier	Percentage of switching (Number of customers) (%)	Customers' total consumption (MWh)	Customers' consumption switching Supplier (MWh)	Percentage of switching (in volume) (%)
Household	506,746	17,610	3.48%	5,489,536	164,291	2.99%
Commercial	17,228	817	4.74%	1,719,887	131,867	7.67%
Industrial	324	14	4.32%	4,538,255	91,662	2.02%
Total number	524,298	18,441	3.52%	11,747,678	387,820	3.30%

Table 57: Customers switching their natural gas supplier per consumer category, 2020 (Source: Natural gas DSOs' data)

The companies "Zenith SA" and "Fysiko Aerio – Hellenic Energy Company" were the prevailing natural gas suppliers in the retail gas market (residential, commercial and industrial consumers), representing 60.38% and 25.82%, respectively, of the total number of connections at the end of 2020 and the 33.71% and 29.04% of the total natural gas volume consumed.

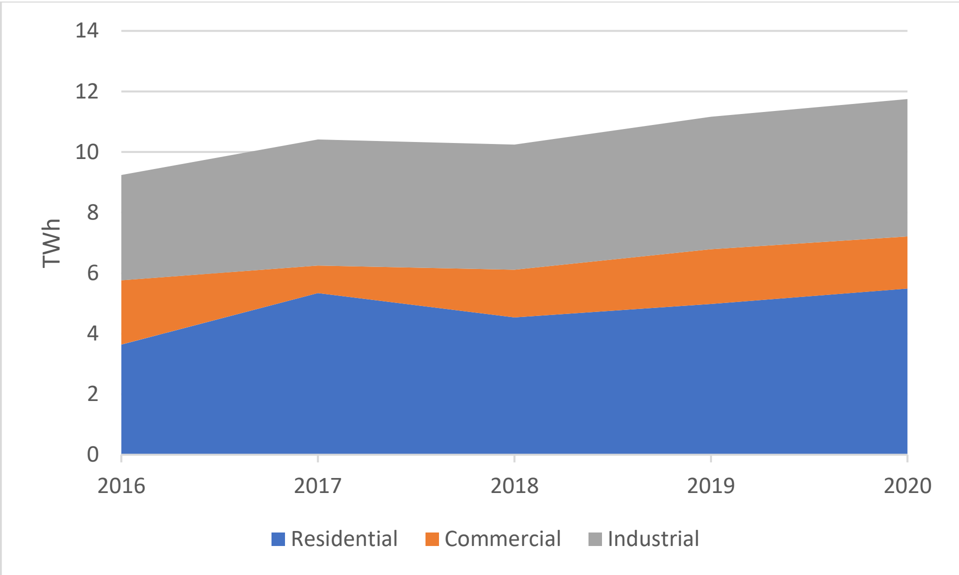

Figure 43: Natural Gas Consumption per customers' category in the distribution networks (2016-2020)

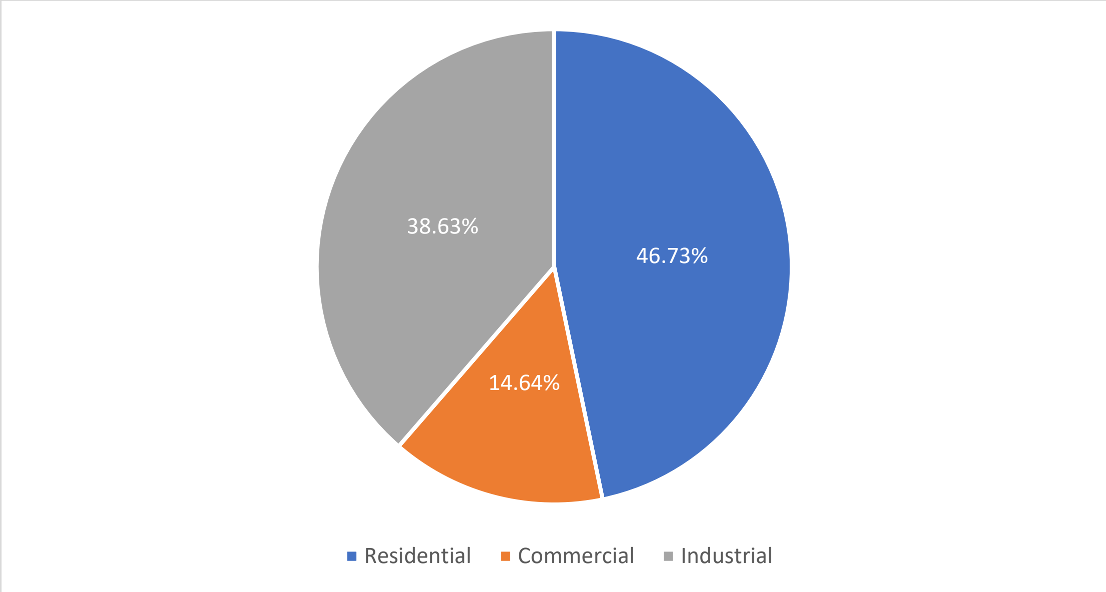

Figure 44: Natural Gas Consumption percentage per consumer category in the distribution networks (2020)

Households' share reached 46.73%, industrial users share amounted to 38.63% and commercial users to 14.64% in the gas Distribution Networks of the country. More specifically, in 2020 household consumption increased by 4.7%, from 4.98 TWh to 5.49TWh, while the industrial sector decreased by 1.43% from 4.37 TWh to 4.54 TWh. The commercial sector decreased its consumption by 9.46%, from 1.80 TWh to 1.72 TWh.

In general terms, after a long period of stagnation, the penetration of natural gas is showing a strong positive trend in the Greek territory. The natural gas market was liberalized 3 years ago, therefore, it is reasonably expected to mature even further soon.

Natural Gas Distribution Company	Category	Number of contracts	Number of orders executed	Number of overdue orders executed
EDA Attica S.A.	Households	21,248	18,139	5,471
	Commercial	402	390	130
	Industrial	0	0	0
EDA Thessaloniki – Thessaly S.A	Households	22,304	13,255	1,132
	Commercial	587	315	41
	Industrial	13	2	2
DEDA S. A.	Households	274	0	0
	Commercial	1	0	0
	Industrial	6	0	0
Source: Natural Gas Distribution Companies				

Table 58: Statistical data of new natural gas connections (2020)

It is noted that the large number of overdue reconnection orders is related to the fact that the reconnection date depends on the availability of the final customer and the time he wishes to reconnect. Similarly, the large number of overdue new connection orders is associated with a variety of reasons, such as the agreement with the contractor to complete the connection at a different time, the construction of a network connection, technical difficulties that required rescheduling and other difficulties in accessing final user facility due to the restrictive measures of COVID-19 during 2020.

4.3. Consumer Protection

4.3.1. Compliance with Annex 1 of EU Directive 2009/73/EC

Consumer protection provisions, as described in Annex 1, par. 1 of Directive 2009/73/EC, have been incorporated in the Gas Supply Code. Suppliers shall provide on their websites all necessary information regarding offered services and end-user prices per customer category. Moreover, they shall provide telephone lines through which customers may obtain information regarding prices, connection fees, connection details, etc. They are also obliged to handle customer complaints and to respond to them within a set deadline, as well as to offer a wide choice of payment methods to their customers.

4.3.2. Definition of Vulnerable Customers

Law 4001/2011 defines the following categories of Customers as Vulnerable Customers:

(a) Economically weak households affected by energy poverty.

(b) Customers, or persons who are lawfully under their care, who are heavily dependent on continuous and uninterrupted power supply. This category includes customers who require mechanical support and in particular, those who require continuous supply for the operation of vital support or monitoring devices, including respiratory or cardiac support devices and any similar physical device.

(c) Elderly customers who have reached the age of 70, provided that they do not stay with another person who has not reached the age limit.

(d) Clients with serious health problems, in particular people with severe physical or mental disabilities, as well as movement, hearing and visual problems which result in their disability to negotiate their contractual relationship with the supplier.

(e) Customers in remote areas, especially in the Non-Interconnected Islands who are entitled to the same services both in terms of price, quality, security of supply and transparency of contractual terms and other conditions as the other customers.

Depending on the difficulties encountered by each category, additional measures may be taken for their protection, in particular the provision of reduced bills or discounts, the installation of metering tools with the option of prepayment, or other favorable payment terms, alternative means of access to payment services and customer services as well as the prohibition of disconnection from the network of vulnerable consumers at critical times.

The criteria, the conditions and the procedure to include a customer in the category of vulnerable customers are determined by decisions of the Minister of Environment, Energy and Climate Change. Measures related to pricing and to invoice discounts, the protection measures for each category of vulnerable consumers, both in pre-contractual level and contractual level as well as contract termination with the Supplier are determined by the relevant provisions in the Supply Code.

The Natural Gas Supply Code lays down more provisions for vulnerable customers. For instance, vulnerable customers are granted 30 extra days to comply with the provisions set out in their Supply Contract before the Supplier can terminate their contract. Furthermore, the deadline to pay their bills cannot be less than 40 days. The Supplier is also obligated to provide the opportunity to vulnerable customers to pay their debts in installments without interest. Each installment may not be higher than the 50% of the monthly cost for the natural gas consumed by the vulnerable customer. However, the above option does not relieve the vulnerable customer of his/her responsibility for timely payments of his/her debts to the Supplier.

4.3.3. Other regulatory developments

Strengthening the legal framework concerning the provision of the “Gas Supplier of Last Resort" services

Due to the different characteristics of the electricity and natural gas markets, RAE proposed to the Ministry of Energy the need to supplement the relevant regulatory framework regarding the selection of a Gas Supplier of Last Resort.

The interested parties are invited to express their interest through an organized tender but in cases when no party expresses its interest for the position of the Supplier of Last Resort, RAE shall nominate as such one or more natural gas Suppliers based on their market share per geographical region and categories of customers. Furthermore, in cases when a Supplier ceases its operation in the natural gas supply market, the other Suppliers (who are not supplying only large customers) are obliged to offer uninterrupted supply services to the customers of the outgoing Supplier. This proposal by RAE was embodied to Article 107 of Law 4685/2019 (Gazette A’ 92/7.5.2020). Afterwards, RAE published its Decision 1364/2020 (Gazette B’ 4664/22.10.2020) “Selection procedure, terms and criteria with a call for expression of interest for candidate gas Supplier of Last Resort” which was terminated in 03.12.2020. The nomination of the gas SLR will take place in 2021.

Natural Gas Supplier switching procedure

During 2020, the retail natural gas market participants (Suppliers, Distribution Network Operators and Consumers) addressed RAE certain questions regarding the application of provisions of the Natural Gas Distribution Code in conjunction with the relevant provisions of the Natural Gas Supply Code.

In particular, the Authority was informed regarding problems observed during Supplier switching procedures due to the existence of overdue debts of a previous Customer, who was represented at the same Metering Point by another Supplier.

RAE found that there is no uniform solution to the aforementioned problem by the three DSOs and therefore proceeded to provide clarifications regarding the proper implementation of the regulatory framework. In particular, the Authority has delimited the actions that the DSOs should take in cases of supplier switching where the Metering Point that has different Customer details other than those registered in the Customer Register, in order not to interfere with the switching procedure. Furthermore, RAE, clearly defined the obligations of the DSOs following the receipt of a disconnection request submitted by an Old Supplier for a Metering Point, due to overdue debts of its Customer, in cases where a new customer has overtaken the specific Metering Point.

Approval of the Standard Contract for the establishment of connections to the distribution networks

RAE, following a public consultation as well as communication with the DSOs, approved the Standard Contract for the establishment of connection to the gas distribution networks with Decision 756/2020 (Gazette B’ 1788/11.05.2020), in accordance with the provisions of Article 80 (8ι) of Law 4001/2011 as well as Article 26 of the Distribution Code (Gazette B’ 487/20.02.2017). The approval of the Standard Contract for the establishment of connections to distribution networks is an important step towards the liberalisation of the natural gas market and the access of the final customers under the same terms and conditions to all distribution networks all over Greece.

Compensatory measures for natural gas network users that were burdened disproportionately by the provisional network tariffs set by RAE in 2016

According to Article 8 (2) of Law 4336/2015 (Gazette A’ 94/14.08.2015), the distribution tariff (basic activity) for all network users was set at 4 €/MWh for the period starting from the entry into force of the above law until the entry into force of the distribution tariffs approved by RAE (01.12.2016). The Association of Industrial Energy Consumers (EBIKEN) objected the above price, arguing that it does not reflect the true cost of the network operator for the distribution service provided and causes a disproportionate burden to certain categories of users of the distribution network because it does not take into account the profile of industrial consumers. EBIKEN, citing the provisions of Article 15 (4) of Law 4001/2011 and Article 41 (10) of the Directive 2009/73/EC, requested that RAE takes appropriate compensatory measures due to the large deviation of the temporary price of 4 €/MWh from the final distribution tariffs approved by RAE with Decisions 345/2016 (Gazette B '3490/31.10.2016) , 346/2016 (Gazette B '3490 / 31.10.2016), 347/2016 (Gazette B' 3537/03.11.2016) and 348/2016 (Gazette B '3537/03.11.2016).

Following the above developments, RAE sent an information note to the European Commission on the application of EU rules for compensatory measures in the event of temporary gas distribution tariffs deviating from the final ones, as well as its position on legal issues related to the starting point from which RAE has the power to set provisional distribution tariffs and decide on appropriate compensatory measures. The European Commission agreed with RAE's position on EBIKEN's request for compensatory measures. Regarding the determination of the period of the compensatory measures, the Commission stated that it should be connected with the date on which RAE took over the responsibilities under Article 41 (10) of Directive 2009/73/EC.

RAE Decision 1058/2020 (Gazette B' 3545/27.08.2020) approved compensatory measures for the period 14.08.2015 until 14.08.2015 for all Eligible Customers who were charged by EPA Attica, EPA Thessaloniki - Thessaly and DEPA, distribution tariffs of 4 €/MWh, based on the provisions of law 4336/2015, during that period.

The compensatory measures are calculated by the DSOs and are equal to the difference between the temporary distribution tariff of 4 €/MWh and distribution tariffs of the Table 59 based on the consumer consumption. RAE permitted the debit of the compensatory amounts to the consumers in installments for a period of up to five years (until 27 August 2025) to avoid liquidity issues. The DSOs requested the revision of Decision 1058/2020, but their requests were denied by the RAE Decisions 1457/2020, 1479/2020 and 1480/2020, while at the same time RAE set a specific action plan and monitoring tools for the effective implementation of Decision 1058/2020.

Distribution Network	**Capacity charges (€/MW/h)**		**Energy charges €/MWh**	
	2015	**2016**	**2015**	**2016**
Attica	4,753.1751	4,719.9028	0.8987	0.8924
Thessaloniki	1,796.6439	1,784.0674	0.3302	0.3279
Thessaly	2,061.0294	2,046.6022	0.3637	0.3612
Central Greece	8,461.6247	8,402.3933	0.648	0.6434
Central Makedonia	5,238.4277	5,201.7588	0.4877	0.4843
Eastern Macedonia-Thrace	6,681.2419	6,634.4732	0.5246	0.5209
Corfu	6,737.1235	6,689.9636	0.8182	0.8125

Table 59 Natural gas distribution tariffs for years 2015-2016 based on RAE Decision 1058/2020

4.4. Security of Supply

RAE is the designated Competent Authority for the implementation of the European Regulation 2017/1938 (EU) of the European Parliament and of the Council of 25th October 2017.

Implementation of Regulation (EU) 2017/1938

As the Competent Authority based on Article 12 of Law 4001/2011, RAE submitted to the European Commission the 3rd revision of the National Risk Assessment Study in July 2019. The study highlighted serious risks related to the expiration of the EU-Ukraine-Russia agreement for the transit of natural gas through Ukraine. However, significant changes at international and national level that took place in late 2019 and early 2020, and which are expected to affect the energy market and security of supply required another revision to the Study.

More specifically, RAE proceeded with the 4th revision of the National Risk Assessment Study for the period 2020-2022, by taking into account:

- The agreement reached between Russia, Ukraine and the EU on the transit of Russian gas through the Trans-balkan pipeline from 1 January 2020.
- The increase of uninterrupted capacity at the Interconnection Point Kulata (BG) - Sidirokastron (EL), in the direction from Greece to Bulgaria.
- The operation of a new Entry Point on the Bulgarian-Turkish border (connection with Turkish Stream – new Border Metering Station (BMS) at Malkoclar).
- The COVID-19 pandemic and the restrictive measures implemented.

For the elaboration of the Study, RAE collaborated with DESFA, IPTO, the natural gas DSOs, the Suppliers and Users of the NNGS as well the Ministry of Energy. RAE hired a specialized external consultant for the identification of the crisis scenarios and the development of the relevant risk assessment methodology.

The National Risk Assessment Study for the period 2020-2022, which was completed in May 2020, includes, among others:

- A review of historical data, qualitative demand elements and data related to the use of the NNGS.
- Identification of the crisis scenarios taking into account the latest gas demand estimates for the periods 2020-2021 and 2021-2022, the completion of the second upgrade phase of the Revithoussa LNG terminal and the start of the commercial operation of the Trans-Adriatic Gas Pipeline (TAP) in 2020.
- Quantification of the effects of the examined scnarios on the industrial consumers and on the production of electricity.
- Calculation of N-1 formula for the years 2020 and 2021 at national and regional level.

A total of 59 crisis scenarios have been examined and simulated, taking into account gas supply disruptions combined with specific demand profiles for each consumer category. It is noted that specifically for the demand of natural gas for electricity generation, it was considered that: (a) lignite power units will be withdrawn in the period 2020- 2021 and (b) that six lignite power units will be withdrawn in the period 2021-2022. In addition, it was considered that there would be no natural gas exports to Bulgaria. From the analysis of the above scenarios some of the main conclusions are listed below:

- In order for the Protected Consumers to receive uninterrupted supply, it is necessary to activate demand-side management measures such as the use of alternative fuel (diesel) in power plants that have this possibility, in accordance with the provisions of the Emergency Plan (Decision 567/201 Gazette B '2501/25.06.2019)
- Fourteen (14) scenarios were examined for electricity generation for each time period, which based on their results were categorized as (a) zero impact, (b) tolerable – low risk, (c) undesirable – medium risk and (d) intolerable – high risk.
- The supply of industrial customers is not expected to be interrupted in any of the crisis scenarios examined.
- A need to improve the demand estimation methodology for all categories of consumers was identified, which was also highlighted by a study conducted by the JRC. The rule N-1 is not satisfied with the existing infrastructure at national level. The Preventive Action Plan forecasts for the preparation of a Common Demand Estimation from the electricity and natural gas network operators contributed posively but highluighted the need for better demand assessments, especially in the distribution networks.
- The N-1 criterion is fulfiled at national level for the period 2020-2021, with the existing infrastructure, only if the demand-side management measures provided in the Preventive Action Plan are implemented and also by taking into account the updated assessment of the contribution of the alternative fuel. The results are further improved by the commissioning of of compressor stations in Ampelia and N. Msimvria (2023). While the N-1 criterion can be met at regional level in the Risk Groups of Algeria and Ukraine, it cannot be met in the Trans-Balkan Risk Group.

Furthermore, the National Risk Assesment Study 2020-2022 examined the effects of 28 additional crisis scenarios for Greek consumers, taking into account a fixed daily folume of exports to Bulgaria equal to the reverse flow technical capacity in the Interconnection Point of Sidirokastro. The results show a significant increase in the overall risk, potentially leading to gas interruptions for Protected Consumers.

Preventive Action Plan

RAE in 2020, proceeded to update the Preventive Action Plan that had been prepared in 2018, using the results of the National Risk Assessment Study for 2020-2022. For the development of the Plan, RAE collaborated with DESFA, IPTO and the Ministry of Energy as well as with an external consultant specializing in the development of risk management systems. The Preventive Action Plan 2020 aims to present appropriate measures to reduce or eliminate the risks that affect the security of the country's gas supply. At the same time, new precautionary actions are being considered related to the increased use of natural gas infrastructure, improving the availability of LNG in times of increased risk and increasing the degree of readiness of stakeholders to deal with disruptions in natural gas supply. The methodology followed for the identification and evaluation of new actions was based on the provisions of Regulation (EU) 2017/1938 and the JRC report on good practices for the development of Preventive Action Plans and Emergency Plans. The basic steps that were followed were the following:

- Identification of crisis scenarios based on the National Risk Assessment Study.
- Identification of feasible actions capable of supporting the objectives of the PAP. In particular, measures have beed designed to reduce the impact on the natural gas power units.
- Simulation of scenarios and evaluation of the effectiveness of actions based on risk reduction.
- Cost assessment of the actions and their potential impact on the environment, market functioning and the security of supply of another Member State
- Development and implementation of a multicriteria decision making analysis for the assessment of the actions as well as simulation of the actions' implementation (risk reduction loop) and assessment of the residual risk.

The actions that were considered in the context of the PAP were the improvement of the regulatory framework un order to increase the use of natural gas infrastructure by allocating additional capacity at the Entry Points by DESFA (Action Δ1) in combination with one of the alternative actions:

- Action Δ2: Improving the LNG Cargoes Unloading Annual Plan by implementing market-based mechanisms, according to the 6th Amendment of the NNGS Code, by providing Standard LNG Slots by DESFA where the temporary storage period is 18 months.
- Action Δ3: Similar to Action Δ2 with the only difference being the increase in the frequency of LNG cargo arrivals in the winter months (January, February and December) where the temporary storage period is limited to 13 days compared to 18 days during the other months.
- Actions Δ4: Use of Revitoussa LNG terminal to store seasonal LNG for the LNG electricity generators.

The above actions were evaluated in terms of: (a) their effectiveness in reducing risks, (b) the burden on the Security of Supply Levy (TAE), (c) the impact on the environment, (d) the impact on the functioning of the gas market and (e) the impact on the security of supply of neighboring Member States and (f) the uncertainty involved in their implementation. The evaluation of the actions showed that for both periods 2020 - 2021 and 2021 - 2022, the implementation of Action Δ1 in combination with Action Δ3 makes it possible to reduce the risk in the most efficient way.

In addition to the above, the PAP examined the ability to comply with the N-1 criterion, where it was found that with the existing infrastructure, the rule is not satisfied without the implementation of demand-side management measures. Finally, a set of ancillary measures and obligations were identified that strengthen the prevention and safe operation of the system.

RAE, in accordance with the provisions of Regulation (EU) 2017/1938 and Article 29 (1) of Law 4001/2011, held a public consultation between 10.11.2020 to 04.12.2020 for the PAP. Prior to the approval of this Plan, which will take place in early 2021, RAE will consult the neighboring Member States to check the consistency of the PAP with their own.

Regional Dimension

Regulation (EU) 2017/1938 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010 has introduced significant changes regarding the obligations of Competent Authorities and has enacted provisions for Regional Cooperation. Based on these provisions, RAE, being the Competent Authority, has participated in the development of three (3) Common Risk Assessments (CRAs) of all relevant risk factors which could lead to the materialization of the major transnational risk to the security of gas supply to the Ukrainian, the Algerian and the TransBalkan risk groups, as listed in Annex I of the Regulation. The CRA for the Algerian risk group has been completed in the end of 2018, while the CRA of the Ukrainian risk group was completed in the beginning of 2019.

Trans-Balkan risk group

RAE has undertaken the coordinating role for the elaboration of the CRA in the Inter-Balkan Risk Group in which Greece participates together with Bulgaria and Romania. The CRA was carried out with the collaboration of the network operators (DESFA, IPTO, Bulgartransgaz EAD and Transgaz S.A.), the Joint Research Center of the European Commission (JRC - EU Commission) and the Ministries of Energy of the countries that make up the Trans-Balkan Risk Group.

In the context of the CRA, RAE proposed a Cooperation Mechanism in order to ensure the smooth functioning of the Risk Group. The mechanism was accepted by the members of the Trans-Balkan Group and was notified to the European Commission. The members are committed mutual cooperation and exchange of data, with the aim of the successful elaboration of the CRA.

The CRA was communicated to the European Commission in February 2020 and it includes the assessment of six (6) key Scenarios with twenty eight (28) sub-cases in peak demand conditions (1-in-20) and a crisis duration of 7, 14 and 30 days. Especially for Greece, with the assistance of the JRC, an analysis and correlation of demand and temperature data was performed. Based on the results, the Scenarios with the greatest impact are those that take into account the complete interruption of Russian gas exports to EU countries, combined with a 50% reduction in available capacity in the Ag. Triada IP due to a technical problem or delay in the arrival of LNG cargo. For Bulgaria, the effects are described as "catastrophic" as they lead to power cuts for its Protected Consumers, something that does not apply to Greece and Romania. However, in Greece there are significant effects on industrial consumers and gas-fired power plants.

It is noteworthy to mention that it has been decided, with the consent of Bulgaria, Romania and the EU, to update the CRA in cooperation with the JRC and the RAE Risk Group Coordinator in order to take into account significant changes that have taken place in the end of 2019 and were identified in the PAP, which are expected to have a positive impact on the security of gas supply in the Trans-Balkan region.

Solidarity Mechanism

Within 2020, in collaboration with DESFA, IPTO, the Ministry of Energy and the Ministry of Foreign Affairs, RAE prepared a Draft Plan for the implementation of the Solidarity Mechanism in accordance with the provisions of Regulation 1938/2017 and Commission Recommendation (EU) 2018/177 of 2 February 2018. The Plan was put up for public consultation by RAE between 06.10.2020 and 02.11.2020, while its notification to the EU is expected in early 2021.

According to Regulation (EU) 2017/1938, EU Member States are required to take action in the event of an emergency where a Member State is unable to supply gas to its "solidarity-protected consumers", other Member States (directly connected or under conditions linked through a third country), are obliged to take measures to supply the quantities of gas necessary to meet the needs of those consumers in the country requesting solidarity. It is clarified that the measures to be taken by the member providing the solidarity include the restriction and/or the interruption of the supply of its non-solidarity protected consumers.

In this context, Member States should agree on the measures necessary to ensure the effective operation of the solidarity mechanism outlined in each country's Emergency Plans.

The solidarity mechanism is activated as a last resort, giving priority to market measures and voluntary demand-side management measures. It is particularly important to determine the compensation, which should cover the costs incurred by providing solidarity. According to the EU Recommendation, the determination of compensation must take into account a) the gas delivery price, on the basis of market or administrative pricing, b) the total transport costs, c) the cost of releasing any strategic reserves, d) losses due to cuts and (e) the cost of litigation in the State which provided solidarity.

In the light of the above, RAE incorporated in the Draft Plan the proposed methodologies for calculating compensation in case of imposed burden reduction to provide solidarity per consumer category, which were based on the ACER Study on the Cost of Disruption of the Gas supply in Europe -2018 "as well as in the comments of the participants in the public consultation held by RAE.

4.4.1. Monitoring Balance of Supply and Demand

4.4.1.1. Current demand

The following graph presents the gas volume consumption in Greece from 2016 to 2020, per category of consumers' consumption. As can be seen, the largest percentage of natural gas consumed during the previous years was used for electricity generation.

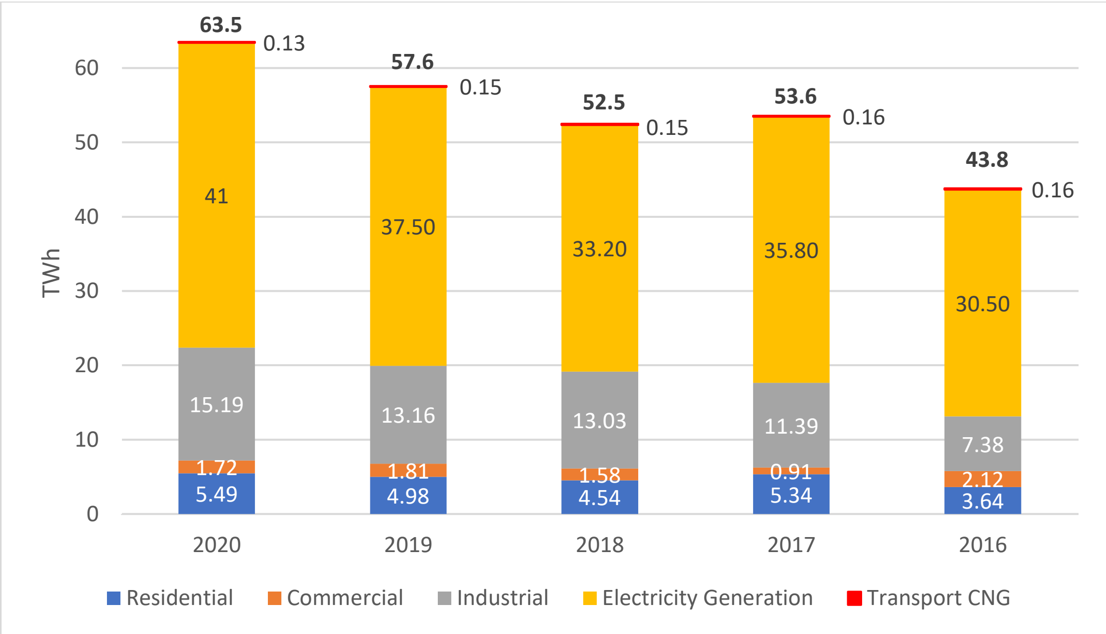

Figure 45: Natural Gas Consumption volume 2016-2020 (TWh)

The demand increase trend for natural gas continued in 2020. Specifically, the demand for natural gas in 2020 was increased compared to 2019 (by 10.2%) from 57.6 TWh to 63.5 TWh, out of which about sixty five percent (64.56%) was used for electricity generation, as shown in Figure 45.

Based on the forecasts for the total gas demand by DESFA for the next decade, as they are included in the TYNDP 2021-2030 which is annually updated, the gas demand according to the "basic scenario" is expected to range from 62.5 TWh (5.6 bcm) in 2021 to 69.2 TWh (6.2 bcm) in 2030. The "basic scenario" has been defined as the main demand scenario of the NECP for the electricity interconnected system in combination with a forecast of gas prices at 20.7 €/MWh in 2021 up to 21.5 €/MWh in 2030.

In Greece there is no indigenous gas production. The main sources of supply for the Greek gas market are Russia and Turkey for gas through pipelines, and the USA for the LNG. As shown in Figure 46, until 2018 the share of natural gas originating from Russia was at the level of 60% of the imported quantities. In 2019, a significant drop in market prices led to a radical change in the supply mix. In 2020, a balance was identified between the LNG imported quantities of natural gas and those imported from Russia.

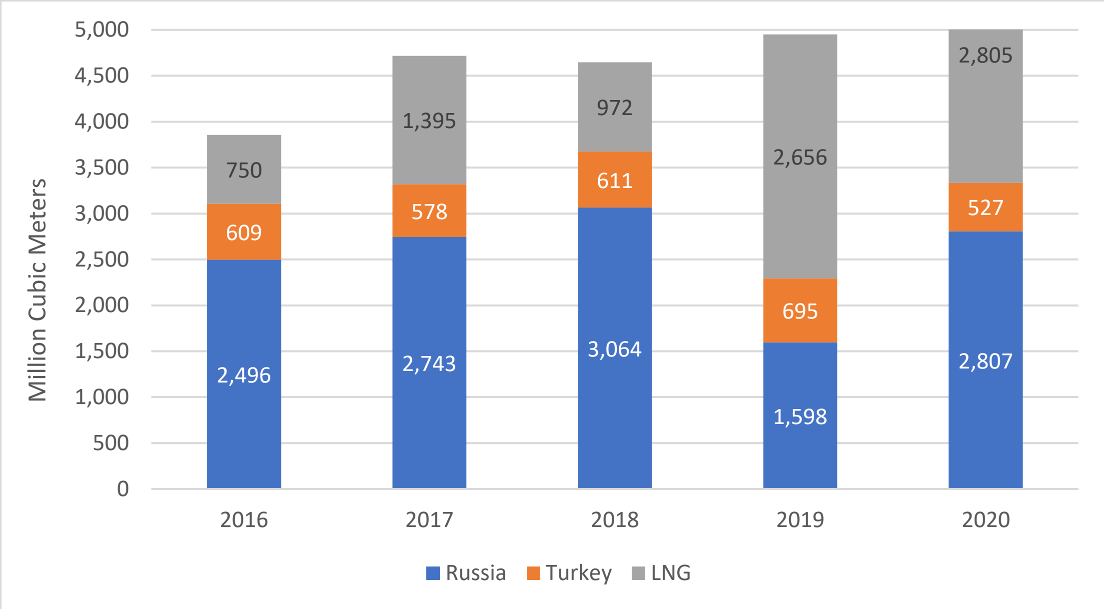

Figure 46: Evolution of natural gas imports per source of origin in Million Cubic Meters (2016-2020)

Figure 47 shows the main sources of LNG that have been imported in 2020. LNG quantities imported from Algeria, the traditional LNG source for Greece, were further decreased in 2020 to 9% from 20% in 2019. There was also a large increase in LNG quantities originating from the United States of America with the corresponding percentage increased from 8% in 2019 to 48% in 2020.

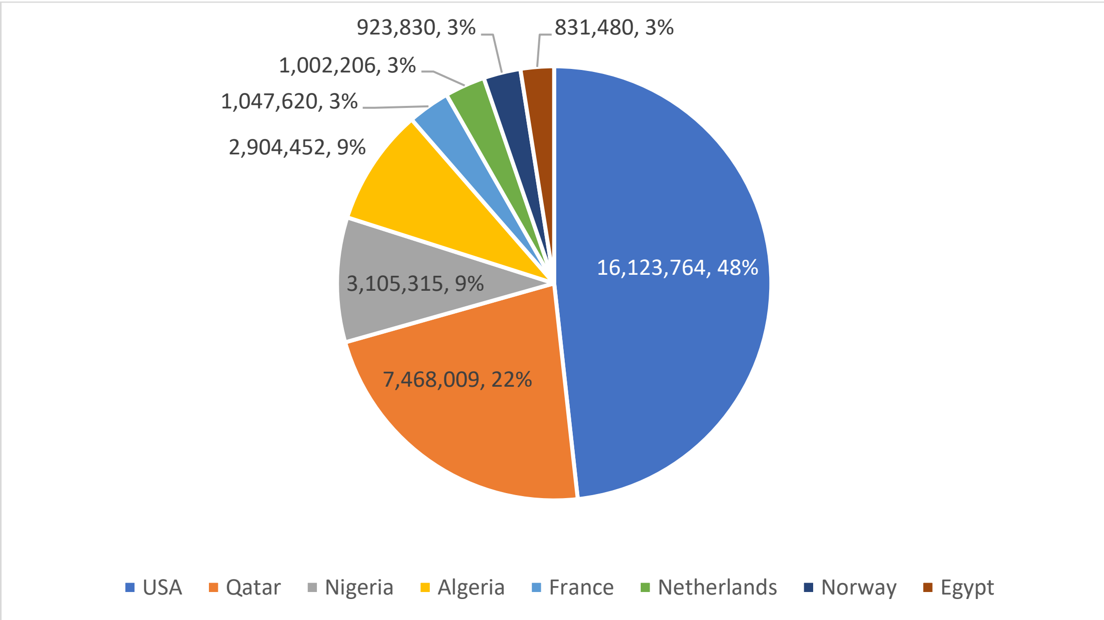

Figure 47: Share of LNG supply sources per country in MWh (2020)

4.4.1.2. Projected demand

DESFA’s projections (NNGS Development Study for the period 2021-2030, basic scenario) of natural gas demand for the next three years (2021 to 2023) are summarized in the table below.

	2021	2022	2023	2024	2025
Power generation	3,371	2,868	3,213	3,544	3,459
Consumers connected to High Pressure	816	817	874	878	924
Distribution Networks	1,065	1,132	1,169	1,298	1,334
Reverse flow / Exports	350	350	430	505	635
Total	5,602	5,167	5,687	6,225	6,352

Table 60: Future natural gas demand in mNm^3 (DESFA’s estimates)

4. Lists

4.1 List of figures

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