ΡΥΘΜΙΣΤΙΚΗ ΑΡΧΗ ΕΝΕΡΓΕΙΑΣ
REGULATORY AUTHORITY FOR ENERGY

National Report 2020

Regulation and performance of the electricity market and the natural gas market in Greece, in 2019.

Regulatory Authority for Energy (RAE)

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1. Foreword

Dear Readers,

In 2019, in view of its institutional role and its statutory competences, RAE remained firmly committed to its core values and actively pursued its mission towards the creation of a secure, competitive and sustainable energy market at national, regional and EU level.

Throughout the year, RAE paid particular attention to the timely execution of the operators' network plans and the development of strategic infrastructures and interconnections, the establishment of the new electricity market design as per the EU Target Model and the market coupling process, the successful implementation of the RES auctions, the effective monitoring of the energy markets and the empowerment of the final consumers.

Ahead of the transformative energy transition process in the EU and worldwide, by implementing these reforms, Greece ensures its adequate participation in the integrated European energy market in a gradual, organized and efficient way, while safeguarding the country's security of energy supply, and securing the lowest prices for both households and businesses that is a key driver of growth for the national economy.

In this framework, and in compliance with the responsibilities assigned to it by the Greek legislation (in particular Energy Law 4001/2011), RAE proceeded in 2019 with the adoption of a set of key regulatory decisions, opinions, and recommendations, the most significant of which are summarized below and analyzed further in detail in this 2020 National Report.

The President of RAE

Dr. Nikolaos Boulaxis

2. Main developments in the electricity and gas markets

2.1 Electricity

<u>Developments in the Electricity Market</u>

- **Target Model**: In 2019, 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..
- **HENEX S.A. as a NEMO**: RAE, with Decision 1124/2019, appointed HENEX S.A. as Nominated Energy Market Operator (NEMO) for a period of 5 years according to Law 4425/2016 article 8 par.2. With this Decision, RAE certified that HENEX S.A. fulfills all necessary preconditions as provided by Laws 4001/2011 and 4425/2016 and the respective secondary legislation in order to meet the requirements of Article 6 of Regulation (EU) 2015/1222 for the fulfillment of NEMO's obligations (More details in section 3.2.1.1).
- **EnExClear S.A.**: RAE, with Decision 1125/2019, approved the operation of EnExClear S.A. which is a 100% subsidiary company of HENEX S.A. as a Payment Clearing Entity for the Day Ahead and Intraday Markets according to Law 4425/2016, article 12, par. 4. RAE's Decision 1125A/2019 (Gazette B' 428/12.02.20) also approved the Regulation for the clearing of Day Ahead and Intraday Market payments (More details in section 3.2.1.1).
- **Energy Markets Operation**: In 2019, based on the operation timelines submitted by HENEX S.A., ADMIE S.A. and the Ministry of Energy for the new energy markets, the start date of Day Ahead and Intraday Markets operation in decoupling mode («Go-Live date of Local DA & ID Markets) and the start date for the operation of the Balancing Market diverged from the previously agreed timeline. RAE, after taking into consideration the delayed completion of all necessary actions by HENEX S.A. and ADMIE S.A. for the operation of energy markets and the consequences this may entail for the achievement of the national goals related to the Target Model, published Decisions 664/2019 and 665/2019 with which RAE called HENEX S.A. and ADMIE S.A. respectively to implement their obligations for the start of the energy markets operation according to Law 4425/2016 (More details in section 3.2.1.1).
- **Capacity Allocation and Congestion Management Guidelines**: RAE, within the framework of the transition to an integrated electricity market and the implementation of Regulation 2015/1222 concerning capacity allocation and congestion management on interconnections, and Regulation 2016/1719 concerning future capacity allocation, approved a set of rules and methodologies for the Greek market. These rules and methodologies ensure a clear legal framework for an efficient capacity allocation and congestion management system that will facilitate electricity trade at EU level, and guarantee the more efficient use of the network and the enhancement of competition. (More details in section 3.1.9)

- **NOME auctions**: RAE, in the framework of the auctioning system of forward lignite and hydroelectric products (NOME), which served as a means to open the retail electricity market in favor of the national economy and final consumers, fulfilled its obligations in accordance with the legislation in place at the time for the proper execution of the auctions for 2019. However, during 2019, pursuant to article 1 of the Act of Legislative content of 30.09.2019 (Gazette A' 145/30.09.2019) which was ratified by Law 4638/2019 (Gazette A' 181/18.11.2019), NOME auctions were terminated (More details in section 3.2.1).
- **E-mobility**: The development of charging stations for electric vehicles is a key element for the expansion of the electric vehicles market. RAE, in 2019, published Opinion 7/27.2.2019 on the subject. RAE's Opinion includes the main aspects of the proposed development model of public charging infrastructure. To this end, an inter-ministerial Committee was established for the implementation of the "Promotion of e-mobility in Greece" in 21.10.2019 (YPEN/DAPEEK/95823/3190), aiming at devising a national business plan for the development of e-mobility in Greece until 30.06.2020 (More details in section 3.2.2.1).
- **Market Monitoring**: RAE, in 2019, 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 oral hearings. This process was concluded in 2019 and RAE published (7) Decisions (292/2019 to 297/2019 and 662/2019) (More details in section 3.2.2.3).
- **Automated Data Collection and Assessment of Retail Market**: RAE continued the periodical collection and assessment of distribution and supply market data for electricity and natural gas, submitted by active suppliers and the relevant Operators. The constant increase of the number of Suppliers made evident that a flexible data collection and assessment framework for the better monitoring of retail market participants and the registration of their billing policies related to Annex II of Supply Code was necessary. In this regard, RAE, proceeded with automated procedures for collecting and assessing data provided by Suppliers through the implementation of a financial tool which was completed at the end of 2019 (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, 19 suppliers were active in 2019 (More details in section 3.4.1).

Development of Electricity Networks

- **Distribution Network Development Plan**: RAE, in 2019, assessed the proposal of DEDDIE S.A. for the Development Plan of the distribution network and requested the submission of additional information requesting a more meticulous presentation of projects feasibility, cost, funding and implementation planning. After the submission of those clarifications by the distribution network Operator, RAE approved the Development Plan for the period 2019-2023 (More details in section 3.1.2).
- **Regulated Revenues and Usage Tariffs**: RAE adjusted the Regulated Revenue (RR) of 2019 for both the Transmission System and the Distribution Network and based on those, it approved the Usage Tariffs (More details in sections 3.1.1.1 and 3.1.1.2).
- **Transmission System Development Plan**: The timely implementation of ADMIE's TYNDP Projects and especially those concerning the interconnection of the Greek islands constitutes a top priority for RAE. To this end, RAE adopted Decision 1097/2019, with which it approved under certain conditions the terms of the TYNDP for the period 2019-2028 (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 is currently ongoing, includes the interconnection of Paros, Naxos and Mykonos and it is expected to be completed in 2020. The necessary steps for the implementation of Phases III and IV of Cyclades Interconnection are carried out without any delay. RAE, with Decision 785/2019, approved the implementation of HV and MV interconnection of Southern and Western Cyclades, Dodecanese and the islands of Northeastern Aegean which operate now as autonomous systems heavily relying on oil-based power generation units. This Decision is based on the conclusions of the Experts Committee established by RAE for assessing the most cost-efficient method to secure power supply of NIIs and the relevant proposals of Operators according to article 108A par.2 of Law 4001/2011 (More details in sections 3.1.2, 3.3.2 and 3.4).
- **Islands' Energy Efficiency and Security of Supply**: According to the National Energy and Climate Plan, the Islands' interconnection with the mainland system becomes more important, and its implementation is viewed as urgent both in terms of cost efficiency, as it helps considerably to reduce the Public Service Obligations, and for security of supply reasons for the next years. EU rules which impose caps on CO2 emissions on oil-based power generation units (2010/75/EU, 2015/2193/EU), underline the importance of adoption of national measures to reduce emissions as soon as possible, leaving big islands like Crete with capacity constraints starting from 2020. The same challenge is also evident for small islands as they will have to phase out their thermal units at the end of the next decade. Within this framework, RAE has cooperated with the competent Operators to ensure capacity adequacy of the NIIs (More details in section 3.4).
- **Crete-Attica Interconnection**: As for the electricity supply of Crete, in particular, RAE has coordinated all involved parties on three levels: (a) to ensure security of supply until Phase II of Crete-Attica Interconnection is operational, (b) to cover emergency incidents of summer 2020 and (c) to search measures for market operation of Crete between Phase I and II of the Crete-Attica Interconnection (More details in section 3.4.4).
- **ARIADNE INTERCONNECTION S.A.**: In 2019, the Greek state decided that the Crete-Attica Interconnection will be implemented as a national project by ARIADNE INTERCONNECTION S.A., effectively removing it from the PCI list. Moreover, RAE with its Decision 150/2019 affirmed that ADMIE S.A. can dispose a share up to 49% of ARIADNE INTERCONNECTION S.A. to a third party under the terms and conditions imposed by RAE's Decisions 838/2018 and 1190/2018. The concession of up to 49% of the shares may be attributed to interested third parties, to which certified Transmission System Operators of the European Union shall have a priority (More details in section 3.1.9).

2.2 RES

- RAE, in 2019, undertook the following actions in relation to the **application of the provisions of Law 4414/2016** in the Greek energy market:
  - Submitted an Opinion to the Minister of Energy (n. 12A/2019) regarding small hydroelectric stations with a capacity up to 15MW, and more specifically about the calculation of their reference price, whether they should participate in the competitive tender procedures, and the preconditions for their participation.
  - Adopted Decision 663/2019 with which RAE has set new limits to the absorption of RES electricity by the saturated electricity network of the Peloponnese, as well as the conditions for the allocation of this capacity.

- Carried out a public consultation with market participants and other interested parties concerning the main features of a new regulatory framework for the installation, operation and pricing of electricity storage units (More details in section 3.5.7).

- **RES Auctions**: In the context of its responsibilities, and in accordance with the provisions of Law 4414/2016, RAE carried out the following auctions in 2019:
  1. Joint Auction for RES power plants, in accordance with the provisions of tender No. 1/2019 (RAE Decision 230/2019, Gazette B '656 / 28.02.2019).
  2. Two Auctions for RES power plants, in accordance with the provisions of tenders No. 2/2019 and No. 3/2019 (RAE Decision No. 441/2019, Gazette B '1558 / 08.05.2019).
  3. Two Auctions for RES power plants, in accordance with the provisions of the tenders No. 4/2019 and No. 5/2019 (RAE Decision No. 828/2019, Gazette B '3578 / 26.09.2019) (More details in section 3.5.4).

- **Licenses**: In 2019, RAE issued a great number of production licenses, including their transfer, modification, time extension, renewal, revocation, and the simple certification of the licenses for which no modification is required, as per the Production License Code and RAE's Evaluation Guide. In 2019, RAE issued a total of 642 administrative acts (More details in section 3.5.3).

2.3 Natural Gas

- **Natural gas balancing**: In the context of the provisions of Regulation (EU) 312/2014, RAE with Decision 274/2015 (Gazette B΄1916 / 08.09.2015) approved a Report on the Provisional Measures submitted by DESFA S.A. to improve the liquidity conditions of the gas market. The implementation period of the provisional measures initially was 5 years and expired on 15 April 2019. According to the relevant regulatory framework, the provisional measure concerning the balancing platform may be maintained for a further period, not exceeding fire years, after the approval of the competent NRA. In this context, the Operator submitted a proposal to RAE for the approval of the 2nd Report of Provisional Measures taking into account the comments of the public consultation carried out from 17.12.2018 to 18.01.2019. EWRC gave its positive opinion, and RAE approved the proposal of DESFA with Decision 774/2019 (More details in section 4.1.2).
- **Creation of an organized wholesale gas market**: RAE assigned to HENEX S.A. the elaboration of a feasibility study as well as the creation of a cooperation group with representatives of all interested parties, which would continuously monitor the individual stages for the design and implementation of the new gas market. Throughout 2019, RAE actively participated in the work for the design and implementation of the new gas markets and monitored the progress of the study prepared by HENEX S.A., which was completed at the end of 2019. According to this study, there is great interest in the creation of a natural gas trading system in Greece by the already active participants in the natural gas market but also by potential newcomers taking into account the positive prospects for the development of the natural gas market. Based on the above, in 2020 the work between HENEX and RAE is expected to be intensified for the organization of the gas market with the aim of starting the operation of trading platform at the beginning of 2021 (More details in section 4.1.2).

- 2019 was the second year after the full liberalization of the **retail natural gas market**. More specifically, from 01.01.2018 (pursuant to Law 4336/2015), the monopoly of gas supply companies in Attica and Thessaloniki/Thessaly was abolished and, thereafter, gas supply companies have been active in the Greek market, supplying natural gas or bundled electricity and gas packages without geographical restriction, as long as there is an active network in the area. At the same time, with the establishment of the gas distribution companies (EDA), which operate the relevant networks, the separation of the distribution activity from that of the natural gas supply (unbundling) was realized. At the end of 2019 and, despite the short period of operation of the liberalized market, a total of 25 Suppliers were active in the retail gas market (More details in section 4.2.3).

- **Amendment of the gas transmission tariff regulation – Regulation (EU) 2017/460**. RAE, with Decision 539/2019, approved the 4[rth] Amendment of the Tariff Code of the National Natural Gas System (Gazette B '2601 / 28.06.2019). The amended Code will apply to the tariffs starting in 2020. The most important points of the new methodology are summarized as follows: (a) The Capacity Weighted Distance (CWD) methodology to calculate the transmission tariffs is adopted. The Allowed Revenue is mainly recovered through capacity-based transmission tariffs and only the amount of Old Recoverable Difference is retrieved by a commodity-based transmission tariff which is only applicable to the Exit Points of the natural gas transmission system; (b) the capacity charges in the Entry Points at Sidirokastro and Kipi are the same since both of those Entry Points now lead to the same cluster; (c) two Exit Point clusters are created, the "North Zone" and the "South Zone"; (d) for reasons related to the contribution of the LNG facility in Revithoussa to the balancing of the natural gas, the security of supply and the facilitation of the natural gas market accessibility by new suppliers, 50% of the Required Revenue of the LNG service is recovered through a separate "Spreading LNG tariff" charged at the Exit Points of the transmission system; (e) a 30% discount is applied to the capacity charge at the Agia Triada Entry point, pursuant to Article 9 (2) of Regulation (EU) 2017/460, as it is an entrance to an infrastructure system specifically developed for the purpose of ending the energy isolation of Greece and it operates towards the enhancement of the security of supply of the country (More details in section 4.1.3).

- **Natural Gas distribution licenses, distribution network operation licenses and Network Development Plans**. According to Article 58 of the Distribution Network Operation Code, each Operator prepares and submits to RAE an updated network development program each year. In this context, EDA Attica and EDA Thessalonikis submitted to RAE an updated network development program for the period 2019-2023. These updated network development programs, after a public consultation, were approved respectively with RAE Decisions 1096/2019 (Gazette B 4831 / 24.12.2019) and 860/2019 (Gazette B 4642 / 17.12.2019). For the third gas DSO in the country, DEDA, an updated network development program was not approved and therefore the previous development program approved with RAE Decisions 1318/2018 (Gazette B'5905 / 31.12) and 1319/2018 (Gazette B'5903 / 31.12.2018) is still valid. Also**,** a new natural gas distribution company, EDIL, submitted its application for a license to distribute natural gas in the areas of Deskati, Polykastro, Edessa and Polygyros. RAE after evaluating the proposed network development programs, granted distribution licenses to EDIL in the above areas with Decisions 799/2019 (Gazette B'3874 / 22.10.2019), 800/2019 (Gazette B '3844 / 17.10.2019) and 1099/2019 (Gazette B '5096 / 31.12.2019), 1099A/2019 (Gazette B' 5212 / 31.12.2019) Decisions respectively. (More details in section 4.1.2)

- RAE approved with Decision 235/2019 (Gazette B '4818 / 24.12.2019) a **single Metering Regulation** for all the natural gas distribution networks. The Metering Regulation specifies the methodology for measuring the amount of natural gas delivered to and exported from the Distribution Network and exported from it, the accuracy of the meters, the dispute resolution process, the data sharing procedures, so that accuracy, transparency and the right to access the data by all parties that have a legitimate interest (More details in section 4.4.3).

- **DESFA Certification**: At the beginning of 2019, DESFA S.A. submitted to RAE an administrative appeal against RAE's Decision 1220/2018, with which DESDA was certified under the Ownership Unbundling model. RAE assessed in detail the reasoning of the administrative appeal on the merits and issued Decision 460/2019 (Gazette B'3853 / 17.10.2019) with which it partially amended the conditions set out in the original certification Decision 1220/2018. Moreover, in August 2019, DESFA SA notified RAE of a change in its shareholding structure, as the company "Damco Energy S.A." intended to enter as a passive shareholder/investor in the company "Senflouga S.A." (which is the majority shareholder of DESFA SA) acquiring shares equal to 10% of Senflouga's issued share capital, without any voting rights. RAE, after examining the above request and with the consent of the European Commission, approved the acquisition of 10% of the share capital of "Senflouga S.A." by "Damco Energy S.A." (More details in section 4.1.1).
- **Trans-Adriatic Pipeline (TAP)**. During 2019, RAE, in cooperation with the NRAs of Italy and Albania (ARERA and ERE), provided guidance for the finalization of the TAP Network Code. At the same time, in 2019 the three Regulatory Authorities established the regulatory framework under which a "Market Test" was conducted to increase the capacity of the TAP pipeline from 10 up to 20 bcma m3 / year. The first, non-binding, stage of the "Market Test" took place in July 2019, and thereafter the project proposal plan was put to a public consultation jointly by the three TSOs (More details in section 4.1.4).

- Regarding the **Interconnector Greece-Bulgaria (IGB),** the NRAs of Greece and Bulgaria cooperated throughout 2019 for the approval of the regulatory texts deriving from the Joint Exemption Decision which govern the access rules of third parties and the operation of the pipeline (the operation code, the tariff regulation and the standard transportation contract) (More details in section4.1.4).

- Moreover, in 2019, RAE approved the Guidelines and the Notice for the submission of bids in the framework of the Market Test of Gastrade S.A. for the **FSRU of Alexandroupolis**, which is expected to be completed within the first quarter of 2020 (More details in section 4.1.4).

- **Security of Supply**: In the framework of Regulation (EU) 2017/1938 on the measures to ensure the security of gas supply, RAE, as the competent authority, updated the National Risk Assessment Study. For the elaboration of the Study, RAE cooperated with DESFA S.A., ADMIE S.A. and the Ministry of Energy. The Regulation also puts emphasis on the Regional Dimension. To this end, RAE participated in three risk groups and prepared 3 Common Risk Assessments (CRAs). In particular, RAE took on the role of the coordinator for the preparation of the Joint Risk Assessment Study in the Trans-Balkan Risk Group, with the assistance of the two Greek TSOs, DESFA and ADMIE, the JRC and the two competent authorities of the other states that are part of the Risk Group (Bulgaria and Romania). The study is expected to be completed and communicated to the European Commission in early 2020. RAE was also a member of the Algeria and Ukraine Risk Groups for Common Risk Assessment Studies for natural gas supply from North Africa and from the eastern countries. The first study was completed in late 2018 and the second was completed in February 2019.

  In addition, RAE, after a relevant public consultation as provided in Article 29 of Law 4001/2011 and a consultation of the competent NRAs of Bulgaria and Romania, approved the updated Emergency Plan in 2019 (Decision No. 567/2019) which was concluded by DESFA in accordance with Regulation (EU) 2017/1938 and in particular with the Articles 8 and 10, in conjunction with the provisions of article 12 and 73 of Law 4001/2011 and Chapter 10 of the National Natural Gas System Administration Code.

Regarding the obligations set out in Article 13 of the Regulation (EU) 2017/1938 on the implementation of the Solidarity Mechanism, RAE launched a public consultation in April 2019 on the necessary measures and the determination of a reasonable compensation in case those measures are implemented for a neighboring EU member state. Within the first half of 2020, RAE will make a proposal on the required arrangements (technical, legal and financial) agreed between the neighboring EU member state for the implementation of the Solidarity Mechanism (More details in section 4.5).

2.4 Consumer Protection

- **Regulatory initiatives for the protection of vulnerable consumers**. In 2019, RAE received a significant number of complaints from vulnerable consumers who were unable to pay their electricity bills. To this end, RAE proceeded with a series of interventions, in favor of the vulnerable consumers, both in order to strengthen their position in the electricity, and for reasons of transparency of charges applied to a significant portion of the vulnerable consumers. In particular, RAE (a) strengthened the relevant regulatory framework to ensure, on the one hand, sustainable settlement conditions and, on the other hand, uninterrupted electricity supply to people who need mechanical support or have serious health problems, and (b) amended the methodology for the calculation of the revenue to Suppliers who provide PSOs to beneficiaries in the form of a social tariff (ie amendment of RAE Decision No. 1525/2011, Gazette B΄ 2991 / 28.12.2011), following the Decision 892/152 of the Minister of Energy regarding the "Application of Social Housing Tariff" (B΄ 1403) as in force (Gazette B΄ 242 / 01.02.2018). The above Ministerial Decision amended radically the structure, the criteria and the way Social Tariff is provided to vulnerable consumers, without restricting free competition in the market (More details in section 3.6.8).

- **Energy Poverty**: Energy poverty has been one of the most serious socio-economic problems in Europe in the recent years. Greece is at the top of the list of the countries affected, amid a severe economic downturn in recent years. Given the emergence of the problem of energy poverty as one of the most critical European issues in the recent years, but also its integration into the new European Clean Energy Package, RAE has taken initiatives to integrate energy poverty into the agenda of regulatory interventions. RAE also actively participated throughout 2019 in the HORIZON 2020 European Research Program "STEP-IN:" Using Living Labs to roll out Sustainable Strategies for Energy Poor Individuals "on the fight against energy poverty, in close cooperation with the National Technical University of Athens. At the same time, issues of Energy Poverty were presented to the Georgian Regulatory Authority in the context of the ongoing twinning program "Twinning Project for Service Quality and Smart Metering in Georgia" (More details in sections 3.6.5 and 5).

- **Regulatory initiatives to protect consumer interests**. To strengthen the implementation of the basic principles of transparency, verifiability and comparability, as well as compliance with the relevant provisions of the national and EU framework, in 2019 RAE undertook the following 4 important initiatives:
  - It evaluated the components of the competitive charges of the electricity bills, with the ultimate goal of issuing “Guidelines for transparency, verifiability and comparability of charges in the competitive part of the LV bills”, mainly for the protection of the LV consumers who do not wish to take risks.

- It assessed the tariff structure of all suppliers, aiming at issuing a decision on the uniform application of the category “Other Charges” on the bills.
- Evaluated the content of the advertisements and marketing strategies of all Suppliers, aiming at providing instructions regarding their clarity so that the consumers can make the necessary comparisons before selecting the most advantageous offer for them.
- Finally, RAE, investigated the compliance with the provisions of the Electricity Supply Code (see Gazette B 832 / 9.4.2013), especially with regard to the configuration of tariffs in accordance with the basic principles of electricity pricing laid down on Annex II of the Supply Code. This investigation mainly concerned the protection of the interests of consumers in relation to prices, the transparency of tariffs and charges, and the special terms of energy supply (Article 3 par. 4 of Law 4001/2011), as well as the compliance of Electricity Suppliers with the provisions of the Electricity Supply Code that concern the principle of “cost-reflectivity”, as specified in Article 11 (2) and Annex II of the relevant Electricity Supply Code (More details in section 3.6.8).

- **Price Comparison Tool (PCT)**: RAE pursuant to the provisions of article 22-24, 27 and 49 of Law 4001/2011 and Article 7 of the Supply Codes (for natural gas, Gazette B΄1969 / 2018 and for electricity, Gazette B΄ 832/2013) and, after having taken into account the provisions of Directives 2009/72 and 2019/944, decided to apply the CEER Guidelines for the development of a PCT in Greece. The main objectives pursued by the tool shall be the following: (a) to have a single website where the consumer may have direct access to all the offers of all active suppliers, (b) to be an objective and easy-to-use user tool by all the consumers, regardless of their level of familiarity with the technology, for comparing the pricing data that is updated in real time and (c) the data provided by the tool should always be up to date based on the latest changes in the suppliers’ invoices. In 2019, RAE issued the Price Comparison Tool Operating Regulation (Gazette B '1254 / 12.04.2019), in order to describe the operating procedures and to capture the roles of the parties involved, as well as their obligations and rights. The existence of such Regulation is deemed necessary to properly prescribe the parties’ obligations and rights, and in the end to ensure that the information included therein is objective, transparent and impartial. In 2019, the first phase of implementation of the PCT by RAE was completed, as well as the completion of its first pilot operation. The PTC is expected to be released for use by the general public in 2020 (More details in section 3.6.3).

2.5 Other important actions of RAE

- **Long-term energy planning**. In addition, in the framework of elaboration of the NECP and support of achieving the objectives of the National Energy Planning and other than participating in several working groups set up for that purpose by the Ministry of Energy, RAE deemed appropriate to assign a consultant (Decision 897/2019) for the elaboration of a specialized study that focuses on economic, regulatory and infrastructure development measures that aim to promote e-mobility and the usage of biofuels in the transport sector in Greece for the decade 2020-2030. In the same context, RAE commissioned a consultant (Decision 1002/2019) for the elaboration of a study that focuses on examining the feasibility of installing large-scale storage systems in the Greek interconnected system for operation under high RES penetration conditions prescribed in the NECP. Both studies were completed in December 2019 (More details in sections 3.2.2.1 and 3.5.7).

- In 2019, RAE took several important decisions regarding the **Public Service Obligations** (PSO), including the adjustment of the annual charge limit for electricity consumers pursuant to article 16 of law 4635/2019 (More details in section 3.6.8).

- The participation of RAE for the third consecutive year in the **Thessaloniki International Fair** (TIF) was an important outreach action for RAE. With the active involvement of RAE experts and guidance from the Board of the Authority, six energy workshops took place during the Fair. With the moto “We regulate energy markets for the benefit of consumers and the national economy”, RAE was able to present its vision, showcase its main activities and discuss with the general public and all industry stakeholders the current challenges in the energy market (companies, technical and scientific chambers, professional organizations, development agencies, SMEs, participants in the electricity and natural gas markets and other stakeholders).

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 2019.

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 17,330 km (2019).

According to the Law 4001/2011, the owner of the national electricity distribution system is PPC SA. The distribution system includes: a) the Medium and Low Voltage and few High voltage lines which are part of the distribution system, b) the total facilities and equipment necessary for the uninterruptible flows of electricity and the security of supply into Medium and Low Voltage lines in Greece and c) the lines of the non - interconnected system in the islands. The total length of the distribution system is 239,236 Km (low and medium voltage).

Ten-Year Network Development Plan (TYNDP)

In 2019, RAE with Decision 785/2019 pursuant to the procedure of Art. 108A of Law 4001/2011 approved the implementation of HV and MV Interconnections in the Southern and Western Cyclades, the Dodecanese and the North Eastern Islands of the Aegean Sea, which are included in Phase 3 and 4 of islands' interconnection.

Following a public consultation held in January 2019, the requests for additional information by RAE, and the corresponding submissions of the relevant data by ADMIE, RAE finally approved, under certain conditions, the TYNDP of ADMIE for the period 2019-2028 in November 2019 with Decision 1097/2019. Specifically, RAE imposed on ADMIE S.A. the following conditions:

1. The Phase I of the interconnection of Crete (with the Peloponnese) to be implemented as proposed by ADMIE SA in the submitted TYNDP. In this context, the TSO must take all necessary measures to expedite its construction, as the timeline for the completion of the project is set for the second half of 2020.
2. The Phase II of the interconnection of Crete (with Attica), which is approved with a capacity of 1000 MW, to be implemented in accordance with the relevant decisions of RAE. This project should be implemented with the appropriate specifications in order to ensure interoperability of the Attica-Crete interconnection with the interconnections of Cyprus and Israel, which are part of the "EuroAsia Interconnector" PCI. In any case, the timeline for the completion of the project remains binding for Q4 of 2022.
3. A binding schedule is set for the Cyclades interconnection project with the completion of Phase II in the first half of 2020 and Phase III in the second half of 2020. It is noted that the Phase I of Cyclades interconnection has been in operation since 2018.
4. Based on the conclusions of the study on the interconnection of the electrical systems of the NII of Cyclades (Phase IV), which was submitted to the competent operators by the expert committee established on the basis of RAE Decision 469/2015, RAE accepts the incorporation of the project in

the TYNDP (2019-2028). In particular, the amended plan proposed by ADMIE S.A. in the context of the submitted TYNDP is approved, with the request of further investigation and documentation of the required cold reserve (capacity and spatial planning) that will be required for the total of the 4 phases in a 25 year horizon. For the Phase IV, a binding timetable is set for the second half of 2023. This project is of major significance due to its benefit to the final consumer through the reduction of services of general interest charges and the strengthening of the security of supply of the Cyclades.

5. In the framework of the submission of the next TYNDP, DEDDIE S.A. must closely cooperate with ADMIE S.A. in the field of NII, by presenting a solid interconnection plan for additional islands in the Cyclades by using submarine cables of MV, taking into account the conclusions of the study of the above expert committee (Phase IV) and RAE Decision 785/2019. This interconnection plan must also be included in the next network development plan of 2020-2024.
6. Regarding the interconnection project of Crete and the Cyclades, ADMIE S.A. should submit every two months a detailed report of the actions taken to achieve those projects as well as their results. The report must also include any possible problems faced and the methodology chosen to solve them, as well as the planning of the next actions, aiming at the timely implementation of these projects.
7. RAE, demands the inclusion of the interconnection of Dodecanese and the islands of North Aegean in the next TYNDP in accordance with the provisions of RAE Decision 785/2019.
8. The operator is called upon to take all possible action for the timely implementation of the interconnection of the High Voltage Centre (HVC) of Megalopolis with the HVC of Distomo and the HVC of Acheloos with a 400 kV line, within the second semester of 2019. In this context, ADMIE is requested to intensify its efforts to expedite the implementation plan of the 400 kV line between the HVC of Corinth and Koumoundouros, with a target to complete it before 2024. Finally, ADMIE S.A. must include in the next TYNDP the new RES safe load absorption limits in the Peloponnese network, based on RAE Decision 663/2019.
9. Following the coordination of the actions of ADMIE S.A. and DEDDIE S.A. through the submission of a joint proposal and with a view to a unified approach to the issue of strengthening the security of supply in the Sporades, the project of Skiathos and Mantoudi substations was approved in the TYNDP of the period of 2019-2028. The operator is called to complete the project in the first half of 2021.
10. In the future, the TYNDPs submitted for approval by RAE should include a distinct analytical table, which records the margin of penetration of RES units that is expected with the completion of every new interconnection project, especially for the most important projects of Cyclades and Crete. Furthermore, a corresponding table should be included for the existing critical elements of the network, such as the HVC and the most important substations in terms of load management.
11. Regarding the project of Nea Santa – Maritsa East, in addition to the obligation to submit the semi-annual progress reports in the framework of the cross-border cost allocation agreement, the operator must, in the context of the next TYNDP, summarize the progress of the above project until the date of the final submission of the TYNDP. It should be noted that the two operators of Greece and Bulgaria have jointly made a timely submission of the six-month progress report of the project. Furthermore, in view of RAE's constant concern for the lowest possible burden on Greek consumers, ADMIE is obligated to re-apply in the next call for proposals by the CEF mechanism, as in a previous call for proposals of the mechanism in 2018 only the Bulgarian TSO received a funding of 28.64 million €.
12. Regarding the projects of "Third Parties", the operator must report within the national TYNDP the above projects included in the TYNDP of ENTSO-E. In this regard, it is necessary to inform RAE in

relation to the position of ADMIE regarding the planning and the benefits of these projects, which have been included in the Regional List and consequently in the TYNDP of ENTSO-E.

13. The operator is called upon to implement the provisions of RAE's Decision 256/2018 and to incorporate hereafter in the TYNDPs a progress of the projects in a separate section where any deviations from the implementation schedule will be reported and documented with conclusive data. The operator must also describe therein his actions to eliminate any delay and his actions for the timely implementation of the projects.
14. RAE demands from ADMIE S.A. to review the implementation plans of projects of major importance in the NII and justify any occurred deviations.

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 that will become effective in the 2nd regulatory period following Distribution Code approval, 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.

Until now, the minimum levels of quality are set for specific support reasons such as maximum time for new connections or reconnections after a debt settlement agreement through the "Guaranteed Services" Programme of DEDDIE. Upon RAE's initiative, this Programme was updated twice: in 2014 for Phase I and in 2016 for Phase II. Phase I was completed in 2019 although the final Decision is expected to be issued in the first semester of 2020, and for the implementation of Phase II in the second semester of 2020.

Moreover, RAE, acknowledging the need for a total re-evaluation of the regulatory framework about network theft, prepared in 2018 a system that would provide incentives to the Network Operator to decrease the non-technical power losses by associating a part of its regulated revenue with the observed level of power losses. This issue will be assessed in 2020 as there was no decision taken in 2019. However,

[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).

during the above process, RAE requested from DEDDIE the following information concerning power theft in 2019:

1. Data related to debt settlement and the number of monthly instalments paid by consumers found liable of electricity theft.
2. Information about any judicial decisions power theft including the DSO as a litigant.

On this subject, moreover, the new Code sets forth a more refined general framework to effectively address this growing problem, while ensuring transparency and fairness for final consumers. In this direction, operator and network users' rights and obligations are better defined as well as the basic principles and rules which govern, inter alia, the procedures for investigation and detection of theft, the communication with network users involved to ensure objectivity and equal treatment, the estimation and valuation of non-metered consumption due to theft collection and disposal of energy-theft related income etc. Until the full application of the above rules, which is pending due to the necessary adaptations to operator processes and systems, the relevant regulatory framework is provisionally set by RAE decisions 236/2017 (Gov. Gazette B' 1881/30.05.2017) and 237/2017 (Gazette B' 1946/07.06.2017), as amended by RAE Decisions 1019/2017 and 1020/2017 respectively (Gazette B' 4496/20.12.2017). RAE, during the years 2017-2018, received a significant number of reports on requests to increase the number of installments of debt settlement from the established power thefts. In addition, a high number of reports challenged the actions of the Administrator and invoked judiciary decisions in favor of consumers.

Moreover, distribution loss factors for 2019, as set out in RAE's Decision no.1242/2018, were slightly lower, compared to those of 2018. More specifically, the rates were set at 1.0360 for the MV customers and at 1.1274 for LV customers. As noted in previous annual reports of RAE, the total amount of lost energy in the Distribution Network is on a constant rise since 2012. In fact, the total power losses in the Network are calculated by DEDDIE in relevant studies and show a constant rise in the last years (2017: 9.3%, 2016: 9.7%, 2014-2015: 8.5%, 2012-2013: 6.5%). The main reason for this, is power theft.

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:

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 System's user tariffs. On the one hand, this change will help towards the better implementation of the cost-reflectivity principle and the creation of more efficient signals for the consumers. On the other hand, this will limit the peak load and thus reduce the need for reinforcing the System and its long-term cost. The procedure for amending and updating the methodologies will be completed in 2020.

In 2019, Decision 100/2019 set the TSO's' Allowed Revenue (AR) and the TSO's Required Revenue (RR) for 2019. Required Revenue for 2019 was set at 198.9 million euros. The most important financial values of

ADMIE in the last 5 years (2015-2019), according to its annual financial statements and RAE Decisions for the approval of the Required and Allowed Revenue are the following:

In million €	**2015**	**2016**	**2017**	**2018**	**2019**
Revenues from System Use Charging	239.7	225.5	236.9	194.9	229.1
Net Revenues before tax	61.9	54.1	82.9	108.9	134.8
Approved Allowed Revenue of Transmission System	254.7	250.2	260.9	233.9	252.4[2]
Approved Required Revenue of Transmission System	215.1	203.4	202.6	197.5	198.9

The methodology for setting the TSO's Allowed 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.

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.

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

[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.

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.

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	253.941.562[2]
Cost of investments financed by third parties	7.163.738
Under/Over Recovery	2.023.506
Adjustments due to over/under investment (depreciation and allowed return) of previous years	-17.317.832
Revenues from Interconnection Capacity Rights	-37.909.930
Inter-Transmission System Operator Compensation mechanism (ITC)	454.070
Revenues from Non-Regulatory Activities	-9.366.000
(RR) Required Revenue of Transmission System 2019	198.989.114

Table 2: Required Revenue of National Transmission System 2019 in real terms based on RAE Decision 100/2019 (amounts in €)

In December 2019, ADMIE submitted all necessary data for the evaluation and approval of 2020 Required Revenue. RAE will publish in 2020 the relevant Decision re-adjusting the approved Required Revenue in actual terms taking into account the values of all other parameters.

With RAE's Decision 100/2019, the approved Required Revenue for 2019 (252.4 million €) was adjusted to actual terms and was set to 253,9 million €. Based on that and on other parameters included into the calculation methodology for Transmission System's Required Revenue, the RR was set to 198,9 million €.

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 will be applied on 1st April 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

Table 3: Regulated Tariffs applied for the use of the transmission system in 2019

3.1.6. Distribution Network operation

Required Revenue and user tariffs:

Regarding the Required Revenue for the Distribution Network, until the methodology of Required Revenue that is mentioned in the Distribution Network Code is fully applicable, the previous methodology, prescribed in RAE's Decision 840/2012, remains in force.

RAE, with its Decision 572/2019, approved the Allowed and the Required Revenue of the Distribution Network Operator for 2019 setting the Allowed Revenue at 753. 4 million € (2018: 743.6 million €) and the Required Revenue at 728.6 million € (2018: 752.8 million €). The Required Revenue is lower than the Allowed Revenue of the same year due to the clearance of OPEX / CAPEX which are higher than in previous years.

However, RAE, with Decision 1248/2019, and after the regulatory appeal against RAE Decision 572/2019 by PPC, re-adjusted the Required Revenue for 2019 raising the necessary amount to cover previous under-recoveries by 15 million €, and hence setting the Required Revenue of 2019 at 743.6 million € in the end.

The most important financial values of DEDDIE in the last 5 years (2015-2019), according to its financial statements and RAE Decisions for the approval of the Required and the Allowed Revenue are the following:

In million €	**2015**	**2016**	**2017**	**2018**	**2019**
Revenues from Network Use Charging	715.6	717.1	740.9	711.1	727.8
Net Revenues before tax	39.4	13.8	36.7	-17.83[4]	99.4
Approved Allowed Revenue of Distribution System	774.2	757.8	753.7	743.6	753.4
Approved Required Revenue of Distribution System	765.8	747.5	741.7	752.8	743.6

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).

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

[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).

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.

For the full implementation of Distribution Network Operation Code, the publication of several Manuals is required. This procedure should be completed within an 18 months period. In 2018, RAE received the first Manuals. In 2019 the review was completed for the already submitted Manuals and some comments by RAE were communicated to the competent parties. Until all Manuals are approved, the DSO applies the regulations, practices and rules in accordance with the general principles of the Distribution Network Code. RAE can, within its competences, indicate to the DSO how to comply with the rules.

RAE's Decision Ref no 1248/2019 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 2019

3.1.7. Transmission network connection tariffs

Only shallow connection costs, i.e. connection costs from the production plant site to the appropriate connection point of the Transmission System, are charged to producers. 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

In 2019, import trading schedules increased considerably (+22.09%) reaching a total of 13,703 GWh. After calculating the amount of electricity imported, we observe a small decrease in the imported electricity from Albania, North Macedonia and Turkey (-4.18%, -1.03%, -6.04% respectively) and a significant increase of electricity imported from Bulgaria (+29.8%), while the imports from Italy surged by 151%. Italy's share constitutes 29,76% of the total Greece's power imports.

Electricity exports dropped in general and more specifically the decrease per country was shaped as follows: Albania (-32.87%), North Macedonia (-49.28%) and (-32.87%), North Macedonia (-49.28%) and Italy (-51.71%), which absorb 23.19%, 27.65% and 35.29% of power exported by Greece respectively. On the other hand, Bulgaria absorbed 11.91% of total exported electricity (increase by 54.75%) while exports to Turkey increased by 163% which represent 1.96% of total exported electricity).

Interconnections	Transmission lines power (KV)	Transmission Power Capacity (MW)	Transmission Trading Capacity (real) MW*.
Greece - Bulgaria	1 line 400 KV	500 - 600MW	500MW
Greece – North Macedonia	2 lines 400Kv	2X (500-600MW)	0-250MW
Greece - Albania	1 Line 400 KV	500- 800MW	0-100MW
	1 Line 150KV	100MW	0MW
Greece - Italy	1 Line 400KV (HVDC)	500MW	500MW
Greece - Turkey	1 Line 400KV (HVDC)	500-600MW	130MW
Note: Trading available transmission capacity is lower than the nominal transmission capacity due to technical and legal barriers			
*Transmission trading capacity are defined by the TSOs based on real flows (indicated year 2012)			

Table 5: Greece's cross border interconnections transmission capacity in 2019

Description	Turkey	Albania	North Macedonia	Bulgaria	Italy	Total
Interconnections Voltage (kV)	1 line 400kV	1 line 400kV, 1 line 150kV	2lines 400kV each	1 line 400kV	1 line 400kV (HVDC)	
Exported Energy (GWh)	57,252	677,257	807,720	347,974	1,030,858	2,921,061
Imported Energy (GWh)	690,381	1,903,382	2,946,962	4,083,933	4,078,673	13,703,331

Table 6: Interconnection power capacity and scheduled trade in 2019

Table 7 presents the total electricity imports made through interconnection points, per month, for the years 2019, 2018, and 2017, and Table 8 presents the import share of cross - border allocation of the interconnection trading in 2019 and its performance compared to 2018.

	2017	2018	2019
January	348,376	1,030,381	956,376
February	625,873	834,638	1,184,268
March	1,040,800	818,854	1,263,866
April	1,001,664	975,046	1,162,579
May	830,233	829,034	1,220,985
June	750,881	886,421	910,936
July	941,112	1,264,253	1,117,685
August	761,562	932,106	964,605
September	909,413	843,305	913,656
October	540,553	803,520	876,339
November	509,023	894,569	960,742
December	821,315	1,111,534	2,171,294
Total	**9,080,805**	**11,223,661**	**13,703,331**

Table 7: Total import interconnection trading (MWh), 2017 - 2019

Import share									
Turkey		**Albania**		**North Macedonia**		**Bulgaria**		**Italy**	
2018	**2019**	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
6,55%	5.04%	17,70%	13.89%	26,53%	21.51%	34,72%	29.8%	14,51%	29.76%

Table 8: Cross border allocation of interconnection trading (2018-2019)

	2017	2018	2019
January	281.129	227,453	660,968
February	263.471	267,891	391,373
March	120.310	413,479	260,334
April	157.805	287,184	225,471
May	179.804	259,722	210,418
June	176.935	314,872	47,522
July	249.908	390,833	119,993
August	376.668	523,430	202,193
September	253.092	496,642	213,578
October	285.488	600,405	284,093
November	217.167	565,234	131,809
December	289.771	635,458	173,309
Total	**2.851.548**	**4,982,603**	**2,921,061**

Table 9: Total export interconnection trading (MWh), 2017 – 2018 – 2019

Turkey		Albania		North Macedonia		Bulgaria		Italy	
2018	**2019**	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
0,44%	1.96%	20,25%	23.19%	31,96%	27.65%	4,51%	11.91%	42,84%	35.29%

Table 10: Energy Export share per country (2018-2019)

The electricity trading balance at interconnection points (Figure 1) in 2019 showed a particularly strong increase of 58.28% compared to 2018 and the balance was set at 9.94 TWh in 2019 compared to 6.28 TWh in 2018. The variability of the interconnection balance was significant, with the lowest flow of 292.2 GWh recorded in January 2019 and the highest flow of 1,156.7 GWh recorded in December 2019.

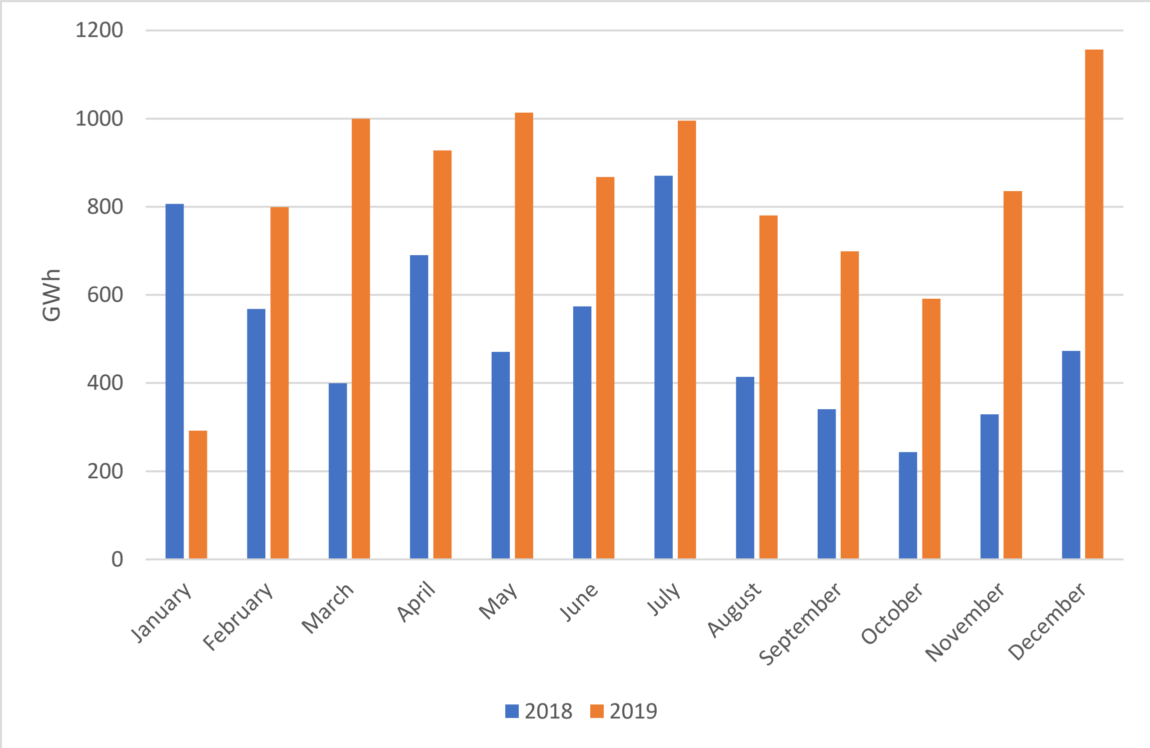


Figure 1: Balance of Electricity trading at interconnection points (GWh)

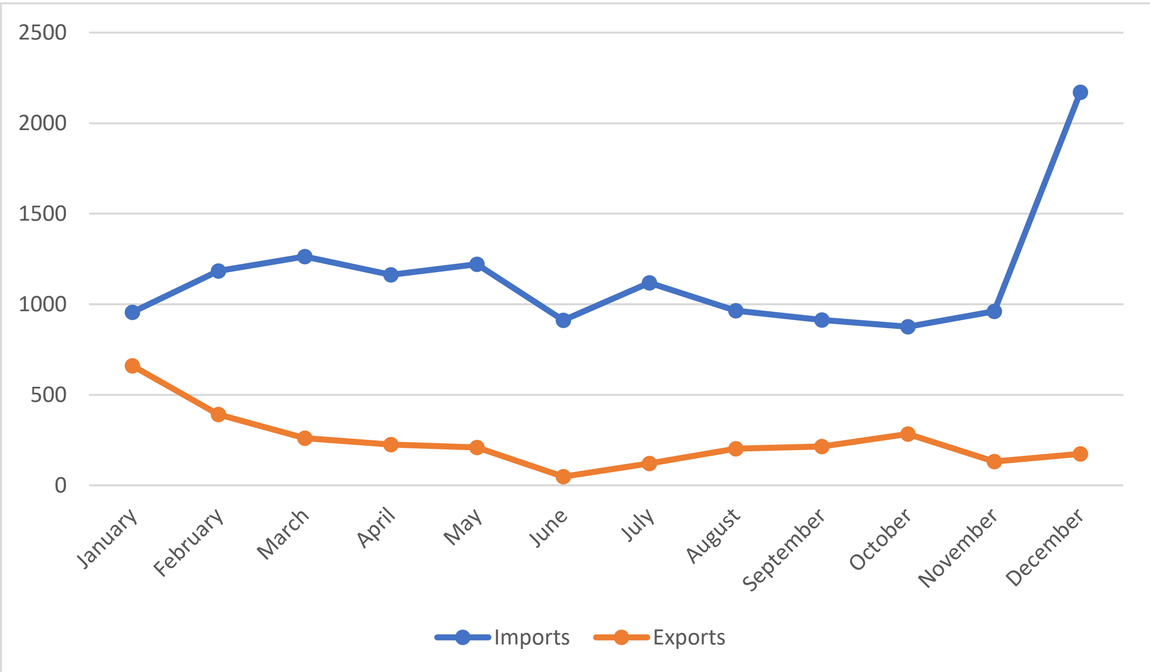


Figure 2: Electricity Imports and Exports 2019

The physical flows for the year 2019 amounted to:

- Greece imported from Albania 1,903 GWh while exported 677 GWh to Albania.
- Greece imported from Bulgaria 4,084 GWh while exported 348 GWh to Bulgaria.
- Greece imported from Italy 4,079 GWh while exported 1,031 GWh to Italy.
- Greece imported from North Macedonia 2,947 GWh while exported 808 GWh to North Macedonia.
- Greece imported from Turkey 690 GWh while exported 57 GWh to Turkey.

3.1.9.1 Interconnection auction rules and access rights

RAE adopted in 2019 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. 1243/2019 concerning the approval of the Joint Allocation Office (JAO) auction rules for the allocation of daily capacity in the interconnection of Greece and Bulgaria for the year 2020.

In case of a market coupling of the Bulgarian and Greek electricity day-ahead and intra-day markets, the competent Operators must suggest a modification or the abolition of the above auction rules.

2. Decision No. 1244/2019 concerning the approval of the Joint Allocation Office (JAO) Auctions' Code for the allocation of daily capacity in the interconnection of Greece and Italy for the year 2020.

It should be noted that when Italian and Greek day-ahead and intra-day markets will be coupled, the allocation of daily capacity will be done implicitly within the framework of Regulation (EU) 2015/1222 of the Commission.

3. Decision No. 1245/2019 concerning the approval of the auction rules for the assignment of access rights to the northern interconnections of the Greek Electricity Transmission System with Albania, Northern Macedonia and Turkey, of the Coordinate Allocation Office (CAO) of the region of Southeast Europe (SEE) for 2020.

ADMIE, in accordance with the provisions of Article 280 (3) of the Network Code and the provisions of Regulation EC/714/2019, submitted a proposal on the rules for conducting auctions for long-term and short-term Physical Transmission Rights (PTRs) for the imports and exports through the interconnection lines of the Greek Transmission System with the transmission systems of Albania, Northern Macedonia and Turkey for 2020 and onwards. It is noted that the rules concern auctions, which will be carried out by the SEE CAO on behalf of the Operators of the transmission systems of the SEE region who participate in the project. RAE with Decision 1245/2019 ruled for the extension of the auction rules, given the needs and conditions regarding the allocation of transfer capacity in the interconnections remained the same and no other event had taken place during their implementation period.

3.1.9.2 Implementation of European Network Codes and Guidelines

(A) In 2019, 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. 56/2019 concerning the approval of the common CCR GRIT TSOs proposal for coordinated redistribution and counterbalancing transaction methodology, according to Article 35 of Regulation (EU) 2015/1222 of the Commission of 24 July 2015, concerning the guidelines setting for capacity allocation and congestion management (Gazette B' 793/2019).

2. Decision No. 206/2019 on submitting a request to ACER to publish a Decision on the common SEE CCR TSOs proposal for coordinated redistribution and counterbalancing transaction methodology, according to Article 35 of Regulation (EU) 2015/1222 of the Commission of 24 July 2015, concerning the guidelines setting for capacity allocation and congestion management (Gazette B' 892/2019).

3. Decision No. 208/2019 concerning the approval of the common TSOs proposal on the methodology for calculating scheduled exchanges resulting from single day-ahead coupling, according to Article 43 of Regulation (EU) 2015/1222 of the Commission of 24 July 2015, concerning the guidelines setting for capacity allocation and congestion management (Gazette B' 747/2019).

4. Decision No. 209/2019 on submitting a request to ACER, according to Article 8 par. 1 of Regulation (EC) 713/2009 of European Parliament and Council of 13 July 2009 for the extension of the deadline to make a decision by competent NRAs on the proposal of TSOs on the methodology for calculating scheduled exchanges resulting from single intraday coupling, according to Article 56 of Regulation (EU) 2015/1222 of the Commission of 24 July 2015, concerning the guidelines setting for capacity allocation and congestion management (Gazette B' 643/2019).

5. Decision No. 254/2019 on submitting a request to ACER to update the designation of CCR GRIT area within the framework of a Decision publication on the common TSOs proposal on Capacity Calculation Regions (CCRs), according to Article 9 (par. 5,6 and 12) of Regulation (EU) 2015/1222 of the Commission of 24 July 2015, concerning the guidelines setting for capacity allocation and congestion management (Gazette B' 1310/2019).

6. Decision No. 208/2019 concerning the approval of the common TSOs proposal on the methodology for calculating scheduled exchanges resulting from single intraday coupling, according to Article 56 of Regulation (EU) 2015/1222 of the Commission of 24 July 2015, concerning the guidelines setting for capacity allocation and congestion management (Gazette B' 1134/2019).

7. Decision No. 357/2019 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' 1252/2019).

8. Decision No. 374/2019 concerning the approval of SEE CCR TSOs proposal on the coordinated capacity calculation methodology, according to Articles 20 and 21 of Regulation (EU) 2015/1222 of the Commission

of 24 July 2015, concerning the guidelines setting for capacity allocation and congestion management (Gazette B’ 1252/2019).

9. Decision No. 440/2019 concerning the approval of CCR GRIT NEMOs’ and TSOs’ proposal for the designation and implementation of complementary intraday regional auctions, according to Article 63 of Regulation (EU) 2015/1222 of the Commission of 24 July 2015, concerning the guidelines setting for capacity allocation and congestion management (Gazette B’ 1651/2019).

10. RAE Decision No.312/2019 concerning the approval of the Joint TSOs proposal on the methodology for calculating scheduled exchanges resulting from single intraday coupling, in accordance with Article 56 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management

(B) In 2019, RAE, within the framework of Regulation (EU) 2016/1719 concerning the establishing a guideline on forward capacity allocation (FCA), published the following Decisions:

1. Decision No. 510/2019 concerning the amendment of TSOs’ common proposal for the SEE CCR on regional requisitions of Harmonized Allocation Rules according to Article 52 par. 3 and 51 of Regulation (EU) 2016/1719 of the Commission of 26 September 2016 concerning the guidelines setting for future capacity allocation (Gazette B’ 2360/2019).

2. Decision No. 597/2019 concerning the approval of the common TSOs’ proposal for the Congestion Income Distribution Methodology (CIDM) according to Article 57 of Regulation (EU) 2016/1719 of the Commission of 26 September 2016 concerning the guidelines setting for future capacity allocation (Gazette B’ 2596/2019).

3. Decision No. 784/2019 concerning amendment of SEE CCR common TSOs’ proposal on regional requisitions of Harmonized Allocation Rules according to Article 52 par. 3 and 51 of Regulation (EU) 2016/1719 of the Commission of 26 September 2016 concerning the guidelines setting for future capacity allocation (Gazette B’ 3394/2019).

4. Decision No. 786/2019 concerning the amendment of CCR GRIT 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’ 3393/2019).

5. Decision No. 787/2019 concerning the amendment of CCR GRIT 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’ 3273/2019).

6. Decision No. 1151/2019 concerning the approval of CCR GRIT TSOs’ common proposal for on regional requisitions of Harmonized Allocation Rules according to Article 52 par. 3 and 51 of Regulation (EU) 2016/1719 of the Commission of 26 September 2016 concerning the guidelines setting for future capacity allocation (Gazette B’ 5023/2019).

(C) In 2019, 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. 688/2019 on submitting a request to ACER, according to Article 8 par. 1 of Regulation (EC) 713/2009 of European Parliament and Council of 13 July 2009 for the deadline extension for decision making

by NRAs on the TSOs' proposal for the implementation framework of the European platform for imbalance netting process, according to Article 22 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing (Gazette B' 2996/2019).

2. Decision No. 688/2019 on the amendment of TSOs' proposal for the implementation framework of the European Platform for imbalances calculation, according to Article 22 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing (Gazette B' 3507/2019).

3. Decision No. 792/2019 on submitting a request to ACER for the publication of a Decision concerning an implementation framework for the exchange of balancing energy from frequency restoration reserves with manual activation, according to Article 20 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing (Gazette B' 3518/2019).

4. Decision No. 793/2019 on submitting a request to ACER for the publication of a Decision concerning an implementation framework for the exchange of balancing energy from frequency restoration reserves with automatic activation, according to Article 21 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing (Gazette B' 3518/2019).

5. Decision No. 794/2019 on amending the TSOs proposal on the methodology on activation of balancing energy bids from common merit order list, according to Article 29 par. 3 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing (Gazette B' 3561/2019).

6. Decision No. 795/2019 on submitting a request to ACER for the publication of a Decision on the pricing for balancing energy and cross-zonal capacity used for exchange of balancing energy or for operating the imbalance netting process, according to Article 30 par. 1 and 3 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing (Gazette B' 3506/2019).

7. Decision No. 796/2019 on the amendment of the TSOs proposal on common settlement rules for all cases of: power exchange as a result of reserve replacement procedure, frequency restoration process with manual and automatic activation and imbalance netting process, according to Article 50 par. 1 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing (Gazette B' 3517/2019).

8. Decision No. 797/2019 on amending TSOs proposal for the further clarification and harmonization of imbalance settlement, according to Article 52 par. 2 of Regulation (EU) 2017/2195 of the Commission of 23 November 2017 concerning the guidelines setting for power balancing (Gazette B' 3532/2019).

(D) In 2019, RAE, within the framework of Regulation (EU) 2017/1485 concerning the transmission system operation guidelines of Member States (SOGL), published the following Decisions:

1. Decision No. 56/2019 concerning the approval of updated proposal of TSOs for basic organizational requirements, duties and competences related to data exchange according to Article 40 paragraph 6 of Regulation (EU) 2017/1485 of the Commission.

2. Decision No. 231/2019 on submitting a request to ACER for the publication of a Decision on the common proposal of TSOs on the methodology for assessing the relevance of assets for outage coordination

according to Article 84 and on the methodology for coordinating operational security analysis according to Article 75 of Regulation (EU) 2017/1485 of the Commission.

3. Decision No. 387/2019 on the approval of continental Europe and Scandinavian TSOs' updated proposal for CBA methodology according to Article 156 paragraph 11 of Regulation (EU) 2017/1485 of the Commission.

4. Decision No. 388/2019 on the approval of continental Europe TSOs' proposal on rules of Frequency Containment Reserves' (FCR) dimensioning according to Article 153 paragraph 2 of Regulation (EU) 2017/1485 of the Commission.

5. Decision No. 389/2019 on the approval of continental Europe TSOs' proposal concerning the limits of quantity exchanged or frequency restoration reserves allocated between synchronous areas according to Article 176 paragraph 1 and Article 177 paragraph 1 of Regulation (EU) 2017/1485 of the Commission.

6. Decision No. 390/2019 on the continental Europe TSOs' proposal on the limits of quantity exchanged or replacement reserves allocated between synchronous areas according to Article 178 paragraph 1 and Article 179 paragraph 1 of Regulation (EU) 2017/1485 of the Commission.

The following Decisions belong to the section of Synchronous Area Operational Agreements (SAOA) of the Regulation titled "Load-Frequency Control and Reserves" and aim at guaranteeing a secure operation of Interconnected System, operational security, frequency quality and efficient use of Interconnected System's resources:

7. Decision No. 689/2019 on continental Europe TSOs' proposal on parameters-goals concerning frequency restoration control error for each load frequency control (LFC) block according to Article 118 paragraph 1 point (d) and Article 128 of Regulation (EU) 2017/1485 of the Commission.

8. Decision No. 690/2019 on the methodology to assess the risk and the evolution of the risk of exhaustion of FCR of the synchronous area according to Article 118 paragraph 1 point (e) and Article 131 paragraph 2 of Regulation (EU) 2017/1485 of the Commission.9. Decision No. 691/2019 concerning the designation of a monitoring director of the synchronous area according to Article 118 paragraph 1 point (f) and Article 133 of Regulation (EU) 2017/1485 of the Commission.

10. Decision No. 692/2019 on the calculation of the control program from the netted area AC position with a common ramping period for ACE calculation for a synchronous area with more than one LFC area according to Article 118 paragraph 1 point (g) and Article 136 of Regulation (EU) 2017/1485 of the Commission.

11. Decision No. 693/2019 concerning the LFC structure methodology according to Article 118 paragraph 1 point (i) and Article 139 of Regulation (EU) 2017/1485 of the Commission.

12. Decision No. 694/2019 on the methodology to reduce the electrical time deviation methodology according to Article 118 paragraph 1 point (j) and Article 181 of Regulation (EU) 2017/1485 of the Commission.

13. Decision No. 695/2019 concerning the decision-making on the specific allocation of responsibilities between TSOs whenever the synchronous area is operated by more than one TSOs according to Article 118 paragraph 1 point (k) and Article 141 of Regulation (EU) 2017/1485 of the Commission.

14. Decision No. 696/2019 on the reduction of the system frequency deviation according to Article 118 paragraph 1 point (n) and Article 152 paragraph 10 of Regulation (EU) 2017/1485 of the Commission.

15. Decision No. 697/2019 concerning the decision-making on the roles and responsibilities of the TSOs implementing an imbalance netting process, a cross-border FRR activation process or a cross-border RR activation process according to Article 118 paragraph 1 point (o) and Article 149 paragraph 2 of Regulation (EU) 2017/1485 of the Commission.

16. Decision No. 698/2019 concerning the requirements on availability, reliability and redundancy of the technical infrastructure according to Article 118 paragraph 1 point (p) and Article 151 paragraph 2 of Regulation (EU) 2017/1485 of the Commission.

17. Decision No. 699/2019 concerning the common rules for the operation in normal state and alert state according to Article 118 paragraph 1 point (q) and Article 152 paragraph 6 of Regulation (EU) 2017/1485 of the Commission.

18. Decision No. 700/2019 concerning the roles and responsibilities of the reserve connecting TSO, the reserve receiving TSO and the affected TSO as regards the exchange of FRR and RR according to Article 118 paragraph 1 point (u) and Article 165 paragraph 1 of Regulation (EU) 2017/1485 of the Commission.

19. Decision No. 1124/2018 concerning the roles and responsibilities of the control capability providing TSO, the control capability receiving TSO and the affected TSO for the sharing of FRR and RR according to Article 118 paragraph 1 point (v) and Article 166 paragraph 1 of Regulation (EU) 2017/1485 of the Commission.

20. Decision No. 1179/2018 concerning the roles and responsibilities of the reserve connecting TSO, the reserve receiving TSO and the affected TSO for the exchange of reserves between synchronous areas, and of the control capability providing TSO, the control capability receiving TSO and the affected TSO for the sharing of reserves between synchronous areas according to Article 118 paragraph 1 point (w) and Article 171 paragraph 2 of Regulation (EU) 2017/1485 of the Commission.

21. Decision No. 704/2019 on the technical design of the frequency coupling process according to Article 172 paragraph 2 of Regulation (EU) 2017/1485 of the Commission.

22. Decision No. 703/2019 on the methodology to determine limits on the amount of sharing of FCR between synchronous areas according to Article 118 paragraph 1 point (x) and Article 174 paragraph 2 of Regulation (EU) 2017/1485 of the Commission

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.

RAE, with Decision 150/2019, decided that ADMIE can dispose 49% of “ARIADNI INTERCONNECTION S.A.” shares to third parties under the terms set by RAE in Decision 838/2018 and 1190/2018. The disposition of shares will be organized by ADMIE S.A. There will be a priority procedure for certified TSOs of the European Union through a tender on specific terms that will be approved by RAE.

Maritsa-Nea Santa interconnection line: In February and in July 2019, the two regulatory authorities of Greece and Bulgaria, received the first two progress reports, as dictated by the provisions of the Cross-Border Cost Allocation decision(CBCA)[5] for Biannual Progress Reports. In the beginning of 2020, the two sponsors sent the third progress report of the Project which concluded that the project is considered mature and can be completed. All the necessary licenses have been issued for both construction and environmental protection.

3.2 Promoting Competition

3.2.1. Wholesale market

3.2.1.1. Description of the wholesale market

Pursuant to article 8 par.2 of Law 4425/2016, RAE published Decision 1124/2019 appointing HENEX S.A. as the Nominated Energy Market Operator (NEMO) for a period of 5 years. RAE also confirmed that HENEX S.A. fulfills all necessary preconditions as provided by Laws 4001/2011 and 4425/2016 in order to perform all NEMO services.

Moreover, RAE, with Decision 1125/2019, approved the operation of EnExClear S.A. which is a 100% subsidiary company of HENEX S.A. as a Payment Clearing Entity for the Day Ahead and Intraday Markets according to Law 4425/2016 article 12, par. 4, and RAE Decision 1125A/2019 (Gazette B' 428/12.02.20), concerning the Regulation for the clearing of Day Ahead and Intraday Market payments. According to Decision 1125A/2019, EnExClear S.A. should submit the following Executive Decisions to RAE for approval, which will be set for public consultation at the beginning of 2020. Those Executive Decisions concern:

- The investment policy of EnExClear S.A.
- Risk management procedures in the clearing system
- Measures imposition methodology towards clearing members
- EnExClear S.A. charges and fees for the clearing of Day-Ahead and Intraday transactions

Moreover, in 2019, HENEX S.A. and ADMIE S.A. submitted to RAE the operation timelines for the new energy markets (Day Ahead and Intraday), the commencement of their operation in decoupling mode («Go-Live

[5] RAE reviewed the submitted investment plan in order to publish a Cost Allocation Report in collaboration with the Regulatory Authority of Bulgaria (EWRC). The two Authorities approved the investment request in 8th August 2018 through an agreement («Cross- Border Cost Allocation Agreement between the Regulatory Authority for Energy (RAE) and the Energy and Water Regulatory Commission (EWRC)»). RAE approved that Agreement through its Decision 681/2018 (Gazette B’ 5732/19.12.2018). The total cost of the Project is estimated at 79.1 million € from which 9,74 million € (12% of total cost) belong to Greece and 69,36 million € (88% of total cost) to Bulgaria. The Bulgarian part of the Project will begin to be constructed in March 2020, while the Greek part will begin in 2021 aiming at finishing before the end of 2022. The deadline is common for both countries according to Decision 681/2018. This project is indivisible part of the wider PCI (cluster) 3.7 which includes another 3 HV lines inside the Bulgarian territory. The proposed project (3.7.1) would constitute the second Greece-Bulgaria interconnection after the interconnection of Thessaloniki with Blagoevgrad.

date of Local DA & ID Markets) and the start date for the operation of Balancing Market which diverged from the previously agreed timeline. RAE, after taking into consideration the fact that the implementation of all necessary actions for the operation of electricity markets by HENEX S.A. and ADMIE S.A. was delayed, published Decisions 664/2019 and 665/2019 with which it called ADMIE S.A. and HENEX S.A. to implement their obligations for the start of energy markets operation according to Law 4425/2016.

According to the institutional set-up selected, in the Day-Ahead Market, transaction orders for supply and demand will be submitted per unit in the case of Producers and per Bidding Zone or Border in the case of other Market Participants. The transaction orders for RES injection and for the aggregators can be submitted per portfolio of every technology and category of RES unit and per load zone. Aggregators submit different orders for supply and demand. Producers are obliged to submit orders for supply for the total amount of their units capacity which has not been bound through Financial Energy Markets or bilaterally out of this Market with a commitment of physical delivery.

For the participation in the Intraday Market, the Participants submit their transaction orders per unit and other Market Participants submit their orders per Bidding Zone or Border. The transaction orders for RES injection and for the aggregators can be submitted per portfolio of every technology and category of RES unit and per load zone. The aggregators submit different orders for supply and demand.

The Balancing Market is based on the principle of the central scheduling and allocation (central allocation), where scheduling is happening, and the Allocation Orders are published per unit (unit based central dispatching model). Within that framework, Integrated Scheduling Process is realized which constitutes a balancing energy and a balancing capacity, according to Article 5 of Law 4425/2016[6].

Until the full implementation of the above system, the Greek wholesale electricity market will continue to be based on a pure day-ahead mandatory pool mechanism. Day-ahead scheduling model is the current model for the organization and operation of the national wholesale market through which the total amount of electricity generated and consumed the next day is traded. Generators, auto-producers and importers must declare an offer price for each hour of the following day (D) for their available capacity to supply electricity to the system. Currently a cap of EUR 300/MWh applies to all generators' offers. At the same time, all buyers of electricity, retailers, exporter, pumped storage hydro and self- supplied consumers must submit demand declarations for each hour of the following day (D) while not submitting price-based offers. The day-ahead market clears on an hourly basis according to a system marginal price (SMP), corresponding to the economic offer of the block lastly accepted in the economic merit order to meet demand.

The TSO runs the system using an algorithm which co-optimizes energy, ramping and ancillary services and runs in real time. To address the load fluctuations (a rapid increase in net demand) the algorithm suggests calling upon fast ramping generation. These plants are obliged to operate to provide flexibility services to the TSO, remaining on a stand-by at their minimum stable level, rapidly increasing or decreasing generation,

[6] RAE in 2018 adopted the following regulatory Decisions pertaining to necessary technical arrangements for the proper functioning of the electricity wholesale market: Decision 508/2018 (Gazette B΄ 2310/18.06.2018), Decision 509/2018 (Gazette B΄ 2307/18.06.2018), Decision 511/2018 (Gazette B΄ 2309/18.06.2018), Decision 780/2018 (Gazette B'3974/13.09.2018), Decision 1299/2018 (Gazette B'164/30.01.2019) , Decision 1322/2018 (Gazette B' 6185/31.12.2018), Decision 294/2018 (Gazette B΄1474/27.04.2018), Decision 405/2018 (Gazette B'4547/18.10.2018), Decision 931/2018 (Gazette B' 5794/21.12.2018), Decision 1003/2018 (Gazette B'6066/31.12.2018), Decision 1041/2018 (Gazette B'5094/15.11.2018), Decision 1231/2018 (Gazette B'5918/31.12.2018), RAE's Decision 1249/2018 (Gazette B'5958/31.12.2018), Decision 1322/2018 (Gazette B'6185/31.12.2018)

and are therefore called to operate as "must run" plants. As lignite generation has not sufficient ramping up capability, the system must be based on natural gas fired generation (in the older times in oil fired generation) and hydroelectric generation.

The Greek wholesale electricity market continues to operate as a day-ahead mandatory pool mechanism since its inception in 2005, to allow competition to emerge in a context with a severe constraint up to now. Regardless of the NOME mechanism and the turn of ADMIE to the OU model, the incumbent (PPC) remains the prevailing actor in both the generation and retail sectors, retaining exclusive access to cheap lignite and hydro resources, while retail prices, despite the gradual removal of cross-subsidies up to 2013, were not linked to wholesale costs, but rather regulated at PPC's average cost, to transfer the benefit of the generator surplus to consumers. This combination of market features posed severe obstacles to new entry in the early years of market liberalization, giving a strong signal for upcoming capacity shortages in the following years.

In other words, the current market design (the mandatory pool) incorporates two distinct "settlement processes":

- The day-ahead market, in which generators' payments (suppliers' charges) are calculated, based on the System Marginal Prices (SMP) and the plant schedules derived from the day-ahead dispatch (load declarations submitted with a gate closure one day ahead of real time).

- "The settlement of imbalances", in which deviations from day-ahead schedules are charged or compensated, based on the Marginal Imbalance Price (IMP/OTA), depending on whether they reflect the TSO dispatch orders (the real operated time) or plant-specific reasons. The marginal Imbalance Price (IMP) which is the Diverted marginal price distinguished by the System Marginal Price of the day ahead market, it can also be called as the operating marginal price of the system[7].

3.2.1.2. Installed Capacity and Generation

In 2019, the installed capacity in the interconnected system of Greece was increased (18,330 MW) compared to 2018 (17,443 MW), notwithstanding the increase of RES units' installed capacity which was 5,468 MW in 2018 and amounted to 6,355 MW in 2019. In terms of capacity share (excluding RES), PPC S.A. holds 71.8% compared to 74.2% in 2018, whereas the market share of PPC's conventional units including RES amounts to 46.9% compared to 50.9% in 2018.

[7] There is also a provision for imbalance penalties, if certain limits are violated, regarding the magnitude and the frequency of the deviations. It should be noted that the System Marginal Prices (SMP), computed by LAGIE (and now HENEX), and the imbalance prices, computed by ADMIE, are derived by solving the same cost-minimization algorithm with respect to the same technical and network constraints, based on the offers and bids submitted by generators and suppliers. In the former case, the values inserted for the various stochastic inputs (demand, plant availabilities and renewables output) are declared (day-ahead expected) values, while in the latter case, they are actual, metered, values. In the day-ahead market, uniform pricing still applies, reflecting the offer of the most expensive unit dispatched to provide energy (and not reserves), so that predicted demand is satisfied along with plant technical constraints and reserve requirements. Zonal pricing, intended to reveal congestion problems and signal the location for new capacity, has not been activated yet, although two zonal prices (for northern and southern Greece), applicable to generators, are explicitly derived, currently only as an indication. Participants may enter bilateral financial contracts (CfDs), but physical delivery transactions are constrained within the pool and related contracts do not exist. At the same time, the lowest offer accepted on all generators (lower) offers to the mandatory pool (the day-ahead market) equals to the defined variable cost of every generation unit of the generator.

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

Installed capacity and production by fuel, in 2019	**Installed capacity (MW)**	**Total annual production (TWh)**	**Share in produced volume, including RES (%)**
Lignite	3,904	10.42	25%
Large Hydro (P > 15 MW)	3,171	3.36	8%
Natural gas	4,900	16.23	38%
Total Thermal + Large Hydro (1)	11,975	30.01	71%
Total RES (Grid + Network) (2)	6,355	12.22	29%
Total (1+2)	18,330	42.23	100%

Table 11: Installed Capacity and Production by fuel, including RES, in the Interconnected System in 2019

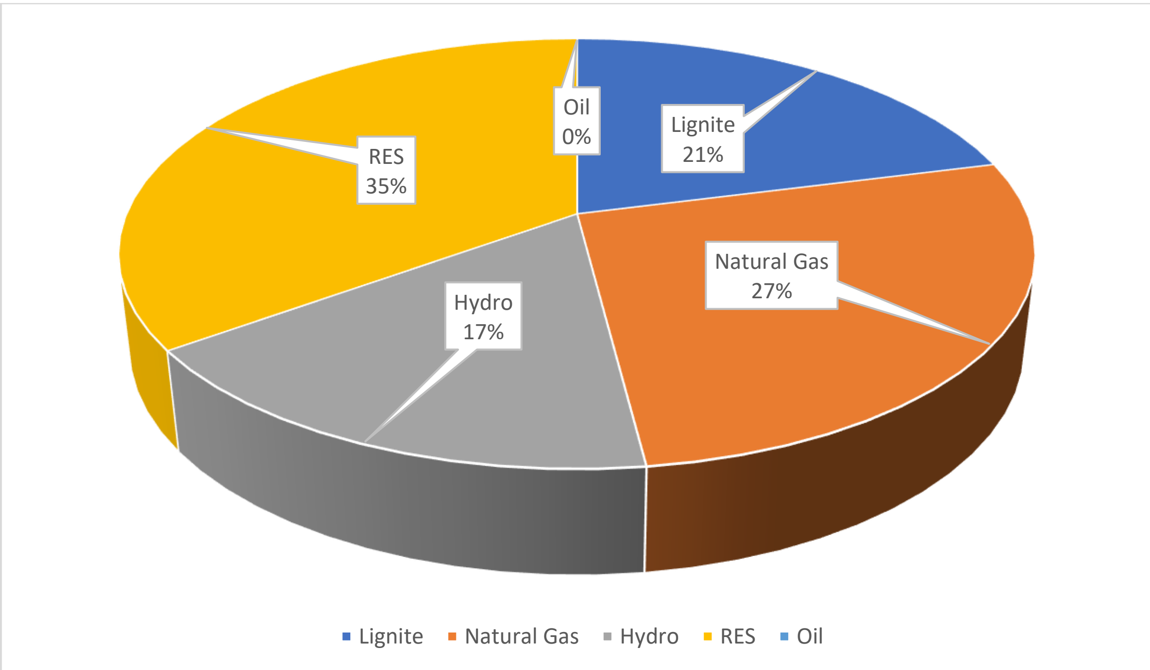


Figure 3: Installed (net) capacity (as a percentage of total capacity) per technology in 2019

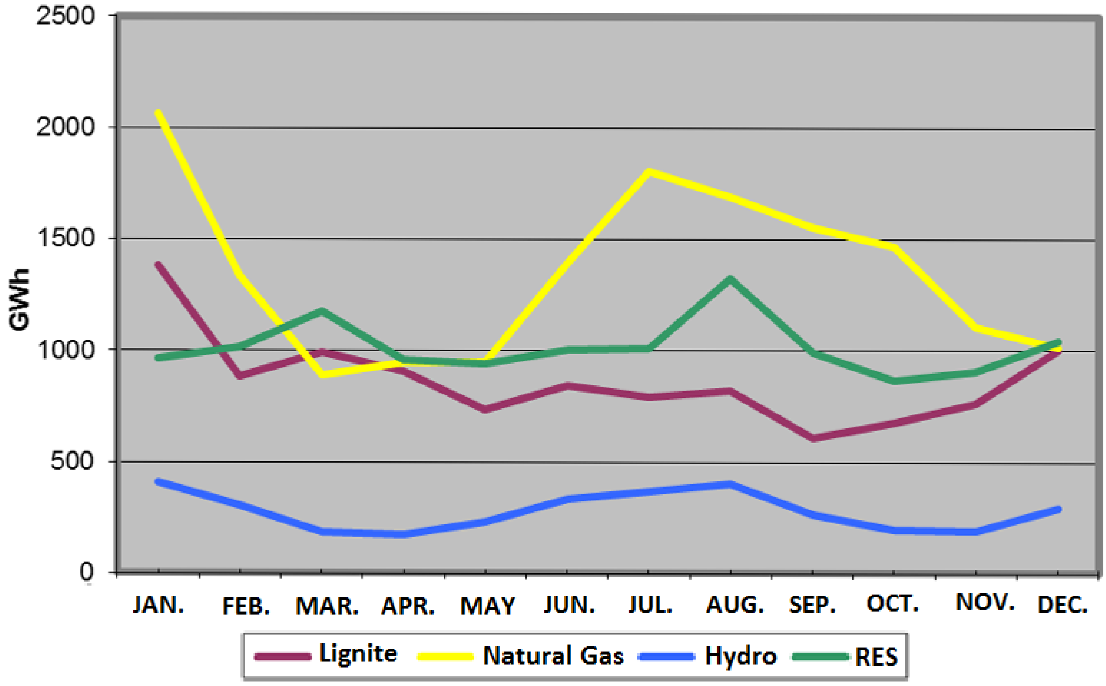


Figure 4: Monthly Production by Generation Fuel in 2019

In terms of the generation mix, in 2019 the lignite production showed a significant decrease of 30.12% (4,489 GWh) compared to 2018. It should be noted that electricity production from lignite units had also been decreased in the period 2017-2018 by 9.03%. Specifically, in 2019 it amounted to a total of 10.41 TWh (14.91 TWh in 2018). The natural gas production experienced an upward trend (14.79%) and increased to 16.23 TWh (compared to 14.14 TWh in 2018). The hydroelectric production dropped by 33.43%, amounting to 3.36 TWh in 2019 (from 5.05 TWh in 2018), and reaching 2017 levels. RES production and CHP continued the upward course of the previous year and reached 12.22 TWh, recording an increase of 9.99% compared to 2018 (11.11 TWh). Production by other fuels in the Interconnected System was at zero level for a fifth consecutive year. Overall, domestic production showed a decrease of 6.59% reaching 42.23 TWh compared to 45.21 TWh in 2018.

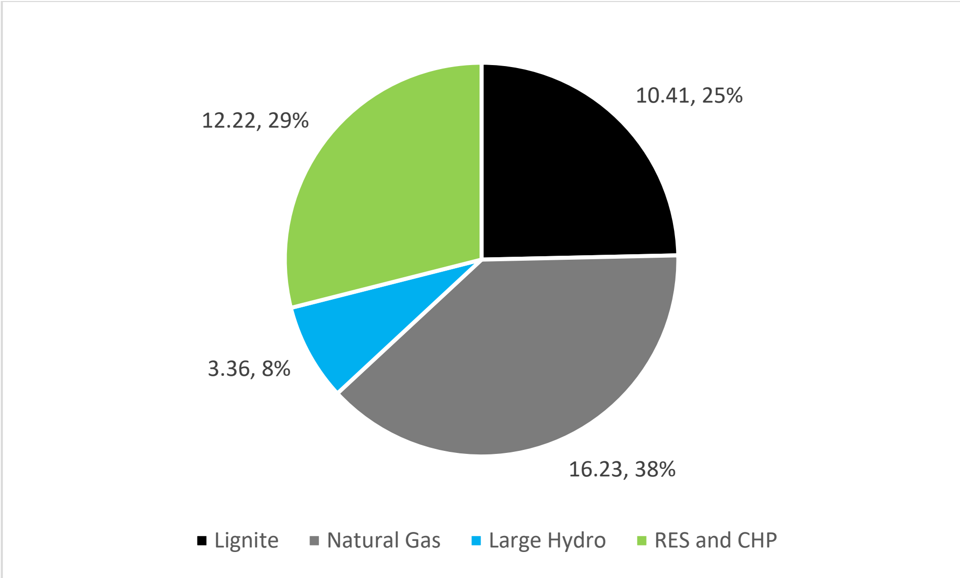


Figure 5: Electricity generation by energy source in 2019

On a monthly basis, generation from lignite showed a sharp fluctuation between 610 and 1,382 GWh. September was the month with the lowest demand for lignite-based power while January was the month with the highest demand in 2019. Electricity generation from natural gas showed a sharp fluctuation between 890 (March) and 2,062 (January) GWh as well. Hydroelectric generation varied between 176 GWh in April and 407 GWh in January, and with having lower fluctuation levels compared to the previous year.

3.2.1.3. Auxiliary and Generation capacity reserves mechanisms (market)

In 2018, the European Commission approved the new Transitory electricity Flexibility Remuneration Mechanism[8] (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

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

the European Commission for the extension of the TFRM.

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 increased in 2019 by 1.24% compared to 2018, and more precisely it reached 52.1 TWh compared to 51.46 TWh in 2018 (and 51,93 TWh in 2017). The consumption at HV decreased by 4.73% compared to 2018, ending in this way the uprising trend of the previous years.

Moreover, the consumption at the distribution network increased by 2.8% compared to 2018, while in 2018 a reduction of 1.6% had occurred compared to 2017. More precisely, the demand in the distribution network in January, April and August increased significantly (+10.2%, +8.1% and +10% respectively, compared to the corresponding months of the previous year.

The real consumption was significantly increased especially in January, April, and August 2019, compared to January 2018 (+7.8%), April 2018 (+7%) and August 2018 (+6.7%). On the contrary, in November and December 2019, the real consumption was significantly decreased (-7.5% and -5.9% respectively).

Peak demand occurred in July 2019 (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 09.07.2019, at the 14th hour of allocation, reaching 9,634 MW, compared to 9,062 MW in July 2018. However, it is worth noting that high demand was recorded also in January 2019 at 9,495 MW, in June at 9,541 MW, and in August at 9,308 MW.

Figure 6 displays the aggregated demand fluctuations on a monthly basis, including the grid metering and the RES connected to the distribution network (real demand level).

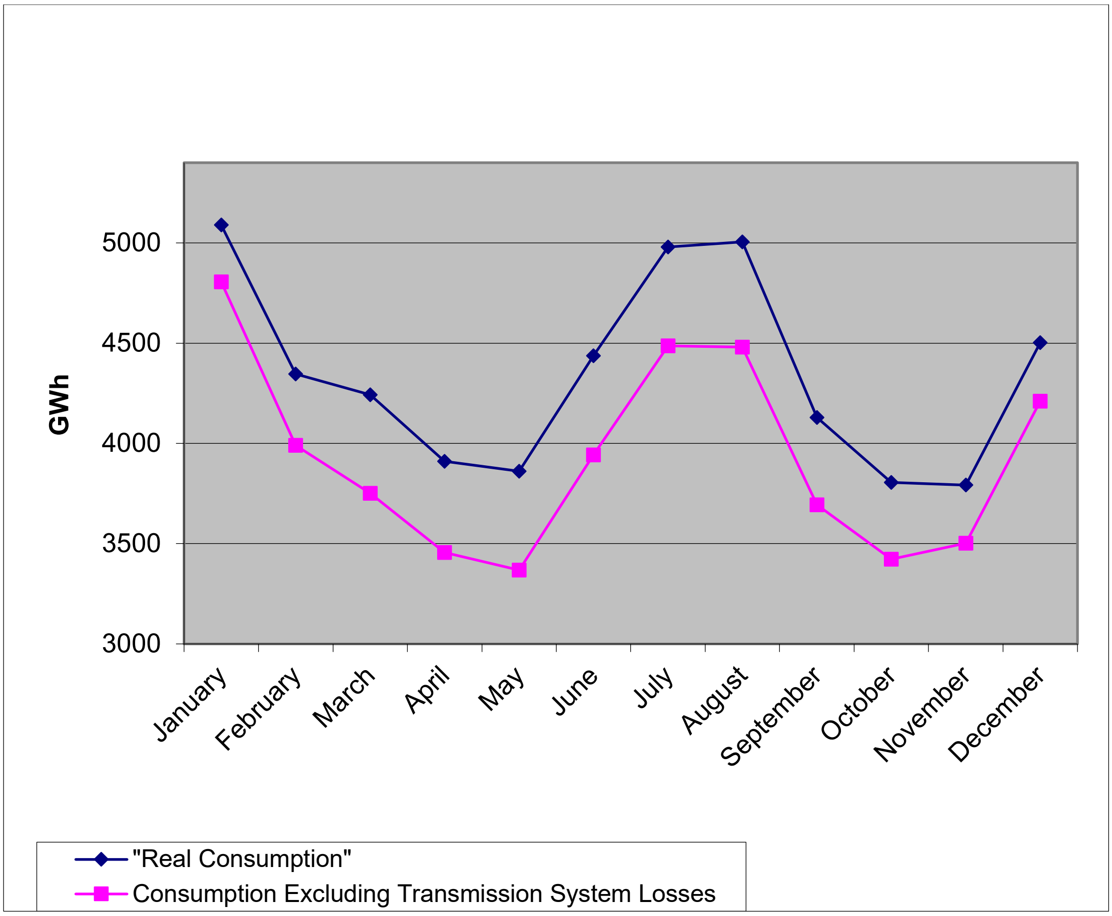


Figure 6: Monthly Electricity Demand in 2019

In Table 12, 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 2019	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 2018 (GWh)	4,722	4,167	4,203	3,657	3,894	4,257	4,951	4,690	4,164	3,874	4,099	4,784	51,462
Difference between real consumption in (2019-2018) (GWh)	367	179	39	254	-32	180	29	315	-35	-69	-307	-281	639
% change in real consumption (2019-2018)	7.77%	4.30%	0.93%	6.95%	-0.82%	4.23%	0.59%	6.72%	-0.84%	-1.78%	-7.49%	-5.87%	1.24%
Source: December 2019 Monthly Report TSO / ADMIE													

Table 12: Monthly Electricity Demand in the Interconnected System (2018-2019)

3.2.1.5. Monitoring market shares

The installed capacity during 2019 was divided per technology and production companies as shown in the figures below:

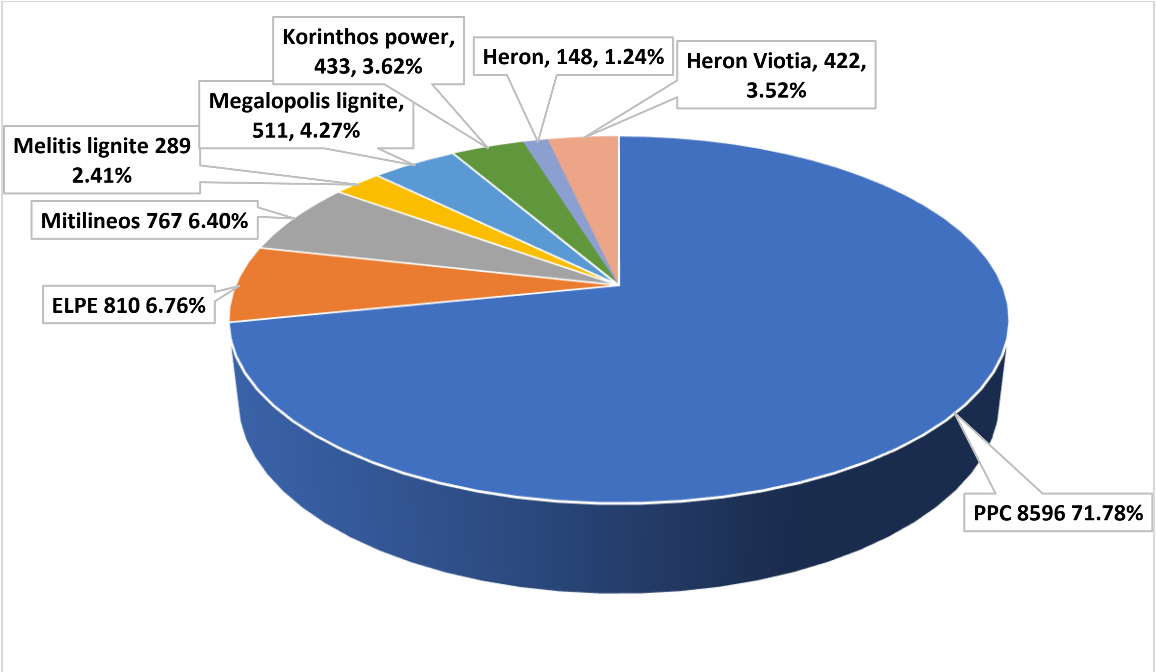


Figure 7: Installed (net) capacity (MW) and as a percentage of total capacity per producer in 2019, excluding RES

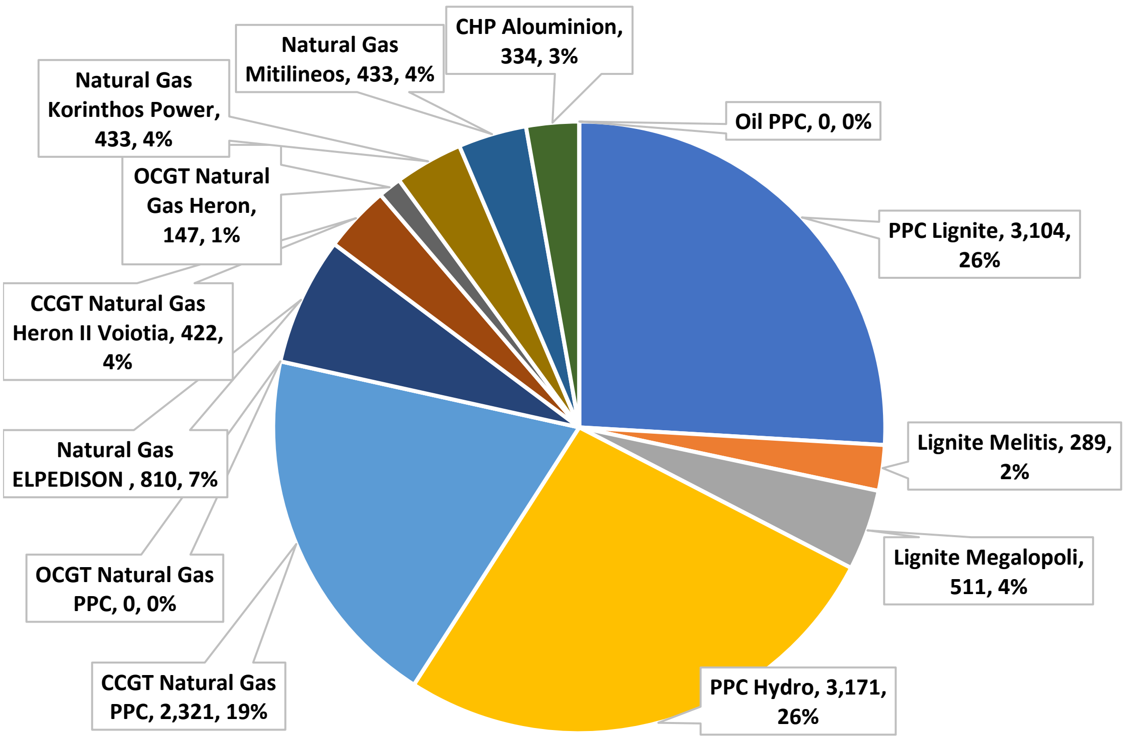


Figure 8: Installed (net) Capacity (MW) per producer and generation technology (%) in 2019 excluding RES

In terms of annual electricity generation, the market shares of the biggest generation companies were as follows:

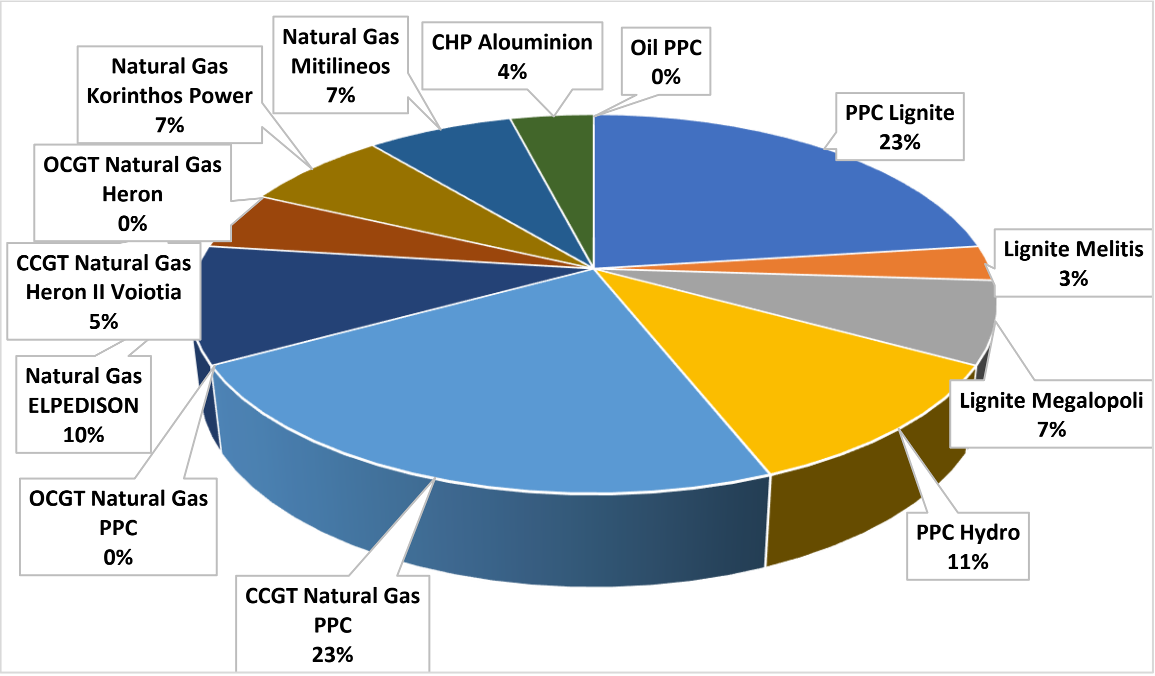


Figure 9: Share in Electricity Generation in 2019 per producer and technology (excluding RES)

The HHI (Herfindahl index), which sums up the squared number of shares of the biggest companies in the market of electricity generation, continued to decrease in 2019 (3,550) compared to 2018 and 2017 (4,359 and 5,982 respectively). The lower level of concentration in the relevant market shows the important steps made in order to integrate more independent producers. If the same index is calculated in terms of capacity shares then the numbers amount to 5,290, 5,627 and 6,357 for the years 2019, 2018, and 2017 respectively.

Regarding PPC's share in terms of capacity, on conventional technologies (excluding RES) this was dropped from 74.2% in 2018 to 71.8% in 2019, whereas if we include RES it was decreased from 50.9% in 2018 to 46.9% in 2019.

PPC+Melitis+Megalopolis	67%
Elpedison	10%
prot+aloum+kp	18%
Heron	5%
Note: * Electricity generation from RES is not included	
Year	**HHI index (generation)**
2019	**3,550**
2018	4,359
2017	5,982
2016	5,999
2015	7,820

Table 13: Share in electricity generation per company (%) & HHI Index in 2019

PPC[9]	71.8%
Melitis Lignite	4.3%
Megalopolis Lignite	2.4%
Heron Viotia	3.5%
Heron	1.2%
Korinthos Power	3.6%
Mitilineos	6.4%
ELPE	6.8%

Table 14: Share in installed capacity (MW) by company (%) in 2019

2019	PPC
PPC's Share in installed capacity (excl. RES)	71.8%
PPC's Share in installed capacity (incl.RES)	46.9%
Year	**HHI index installed capacity**
2019	**5,290**
2018	5,627
2017	6,357
2016	6,423
2015	6,804

Table 15: PPCs' Market Share Installed Capacity & HHI Index in 2019

3.2.1.6. Price Monitoring

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, 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 2019 amounted to 64.28 €/MWh, continuing its rising trend of the previous years (60.68 €/MWh in 2018, 54.68 €/MWh in 2017 and 42.85 €/MWh in 2016). This constitutes an increase of 5.9% compared to 2018.

Concerning monthly variations of the SMP, we observe that the SMP fluctuated between 55.90€/MWh (in November) to 75.86 €/MWh (in January). More specifically, the variation on a monthly basis was between -20% and +41%. In 2019, the average SMP showed a downward trend from January to March and then a steady upward trend from April to the end of the year (with the exception of July, September and November, where although the reduction was significant it did not affect to a large extent the increasing trend of the average SMP).

[9] Melitis Lignite and Megalopolis Lignite are subsidiary companies of PPC. Including those companies, PPC has a share of 78% (9,396 MW) in total installed capacity of electricity generation units.

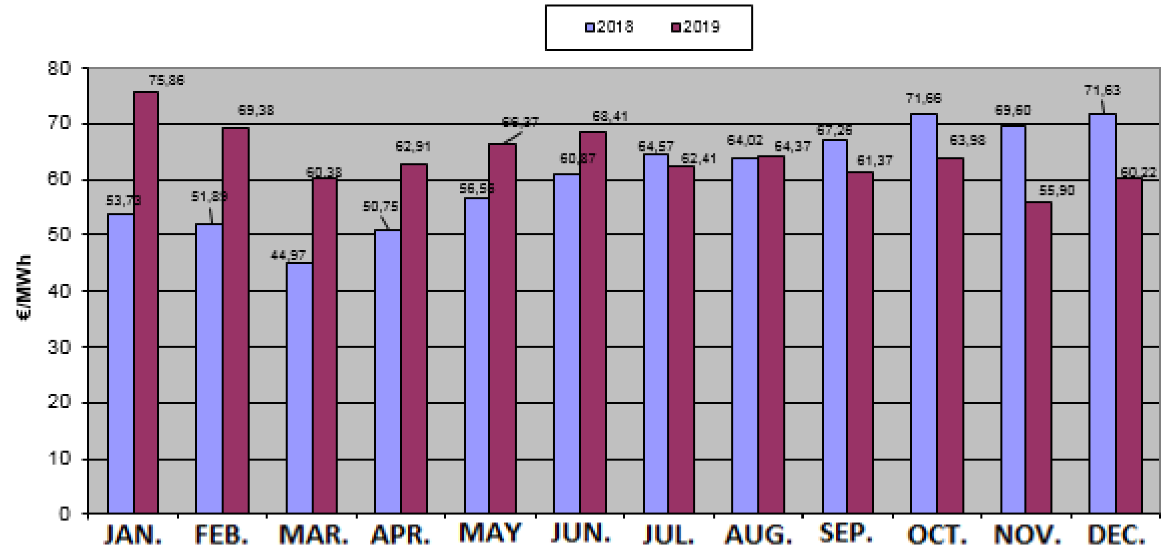


Figure 10: Monthly System's Marginal Price (2018-2019)

The percentage of hours during which the SMP surpassed the value of 80 €/MWh was also sharply increased (5.06% of hours compared to 1.9% in 2018).

The SMP was determined mostly by natural gas units (57% compared to 44% in 2018), followed by lignite power plants (19% compared to 37% in 2018), then from imports (13%, compared to 11% in 2018), exports (7%, compared to 8% in 2018) and hydro plants (5%, compared to 3% in 2018).

The hourly variation of SMP was significantly increased to an average daily price of 8.10 €/MWh compared to 4.64 €/MWh in 2018, 7.83 €/MWh in 2017 and 4.63 €/MWh in 2016.

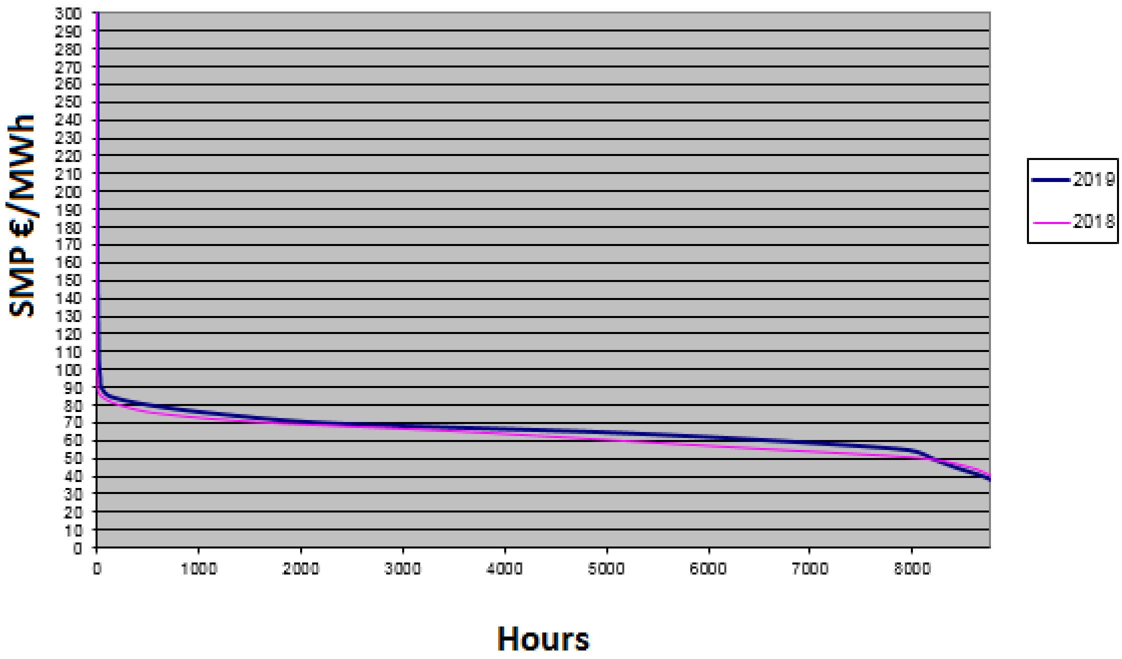


Figure 11: SMP Duration Curve (2019)

Regarding the difference between the average SMP and the average imbalance price, on an hourly basis, this amounted to 3.97 €/MWh in 2019 compared to 1,58 €/MWh in 2018, 3,57 €/MWh in 2017 and 2,78 €/MWh in 2016.

The Figure 12 below depicts the monthly variations between the average SMP and the average imbalance price.

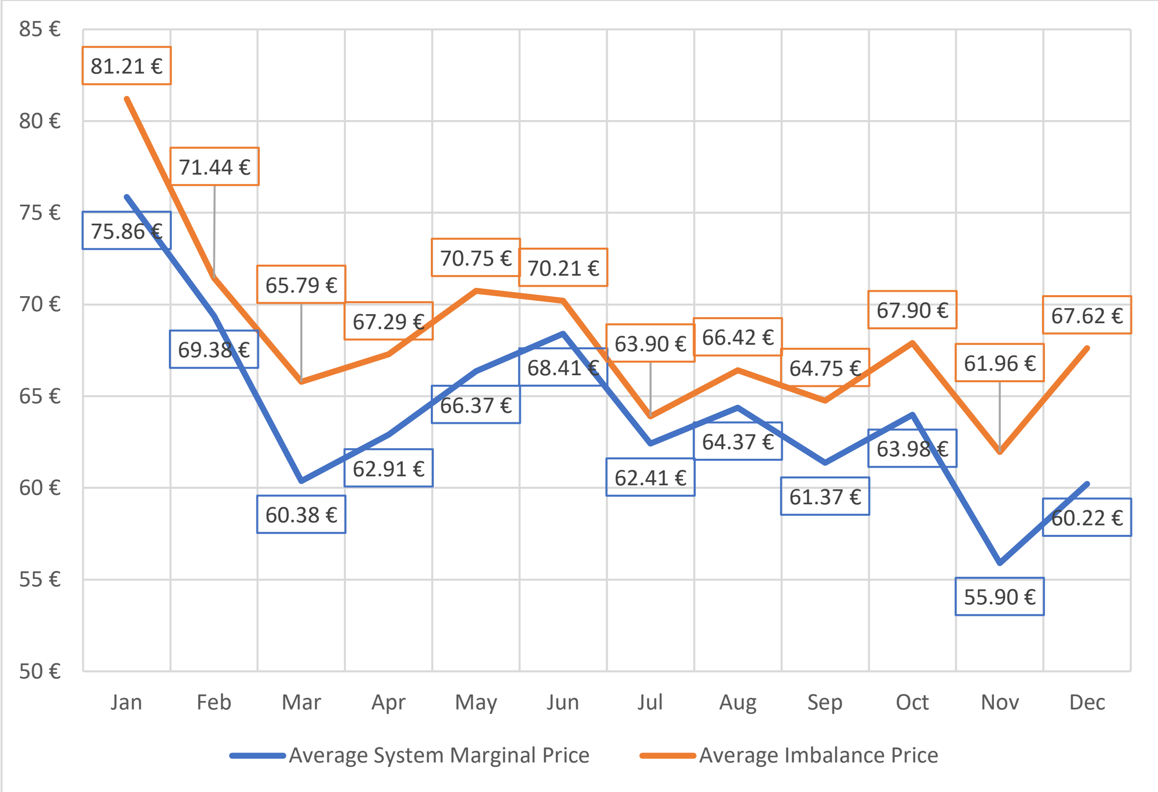


Figure 12: Imbalance Prices IMP (OTA) and SMP (OTΣ) Variation

In terms of cash-flow, the revenues of conventional technology producers (excluding RES) resulting from the resolution of the DAS, amounted to € 2.03 billion in 2019, showing a small decrease compared to 2018, during which the equivalent revenues were € 2.2 billion. Specifically, in 2019, the revenues resulting from the resolution of the DAS significantly decreased for PPC (€1.1 billion compared to €1.4 billion in 2018), while for the Independent Producers the trend was to the opposite direction (€910 million compared to €731 million in 2018).

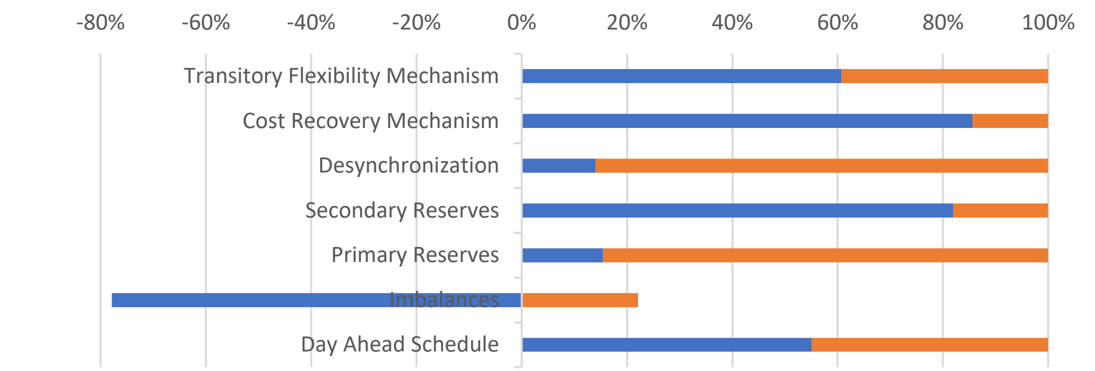
The ex-post clearances carried out by the TSO (ADMIE) amounted to € 0.15 billion compared to € 0.12 billion in 2018. In total, the value of the wholesale market amounted to € 2.2 billion in 2019 compared to € 2.3 billion in 2018.

The revenues from the mechanism for the recuperation of marginal cost amounted to € 87 million for all producers in 2019, compared to € 48 million in 2018. One additional revenue source for the first three months of 2019 for the producers was the transitory flexibility mechanism, the revenues of which amounted to € 41 million for producers. The Special Lignite Production Fee was abolished starting from 1st of January 2019[10].

Therefore, the DAS represents 90% of the total revenues of the electricity producers (compared to 93% in 2018 and 94% in 2017), broken down to 87% for PPC and 90% for the independent producers, as the

10 Law No. 4585/2018 (Gazette A'216/24/12/2018).

rest comes mainly from reserves, desynchronization (3%), the mechanism for the recuperation of marginal cost (4%) and the transitory flexibility mechanism (2%).[11]



	Day Ahead Schedule	Imbalances	Primary Reserves	Secondary Reserves	Desynchronization	Cost Recovery Mechanism	Transitory Flexibility Mechanism
PPC	1,116.58	-54.15	0.0021	2.46	8.78	74.14	24.77
IPPs	909.93	15.38	0.0115	0.54	53.95	12.47	16.00

PPC IPPs

Figure 13: Generators' Revenue by Source for the year 2019 (in mil. And in %)

3.2.1.7. Monitoring of transparency

Following the transparency requirements prescribed in the Network Codes, the TSO and the Market Operator publish daily detailed market data related to the day-ahead market and the imbalance settlement mechanism respectively. The published data are not confined to hourly levels of prices and key fundamentals. Both ADMIE and HENEX upload Excel files with clear quantitative market inputs (except generators' offers and suppliers' bids which constitute 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 (instead of load declarations) 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

[11] 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. In addition, the maximum approved cost of the Mechanism per year dropped to € 175.5 million compared to € 225 million in 2017. The revenues from the Transitional Flexible Remuneration Mechanism for 2019 are estimated at 41 million euros for all the producers.

publishes the outcomes of the ex-post market clearing obtained with metered data (instead of predicted values) for the various inputs.

HENEX publishes the values of inputs inserted to the DAS algorithm and all the resulting market outcomes, including prices and plant schedules for the day-ahead market, along with primary and secondary reserves (which are co-optimized), as well as tertiary reserve quantities. Monthly reports, which used to be issued in the past, continued to be published by ADMIE, focusing on production allocation, fuel market shares and demand segmentation, but not on prices.[12]

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.[13]

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

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[12] With the objective to increase transparency by further clarifying market parameters and market conduct, RAE requested from HENEX and ADMIE to develop monthly reports, displaying outcomes of the day-ahead market and ex-post settlements, respectively, to comply with the requirements of the new Codes. The structure of these reports was designed in collaboration with RAE. LAGIE issued its first market report for the month November 2012, which was subject to revisions and additions, before its standardized format was finally approved by RAE in February 2013. This report is uploaded on HENEX website, monthly, from November 2012 onwards. ADMIE has been drafting and publishing an energy report, which is focused on the dynamics and allocation of energy quantities. RAE has also requested the addition of references to the cash settlements in which the TSO is involved, so that transparency is enhanced further.

[13] 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.

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

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.

In particular, 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. This project is expected to be assigned and delivered within 2020.

Market coupling

On 30 October 2018, the go-live of the market coupling between Greece and Italy was approved by the Italian Borders Working Table Steering Committee (IBWT), and the finalization of the project is expected in Q4 of 2020.

Furthermore, in November 2018, the market operators and the TSOs of Greece and Bulgaria submitted a written request to their competent NRAs for the latter to agree to their initiative to add the market coupling between Greece and Bulgaria to the IBWT initiative. The NRAs approved this request in February 2019. In May 2019, the above market operators and the TSOs submitted a request to the NRAs of IBWT project to include the border of Greece-Bulgaria in the project, and the later gave equally a positive answer. Upon this development, the market operators and the TSOs of Greece and Bulgaria submitted their request to the IBWT Steering Committee, which was accepted in December 2019. The signing of an agreement for the inclusion of the Greek-Bulgarian border to the IBWT project is expected in 2020, to start thereafter the procedures for the preparation of the Greek-Bulgarian market coupling.

3.2.1.10.NOME Auctions (Nouvelle Organisation du Marché de l'Electricité)

Based on law 4336/2015 which detailed the Greek Government's responsibility to reduce PPC's market share by 25% and ultimately fall below 50% by 2020,[14] while system marginal prices would cover the cost of production, RAE submitted to the Ministry of Energy and to the Central Unit for State Aid, a proposal for the creation of a forward market based on NOME type auctions: an auction process with a regulatory-defined starting price that reflects the full cost of efficient lignite and hydro production. The auctions would be organized on an annual and quarterly basis for each year, for 4 years (2016-2020). The proposed auctions were transitional in nature, and designed so that by the time the EU Target Model was in place.

Following negotiations between the Greek authorities and the European Commission, an agreement was reached on the adoption of the NOME Auction System, which was introduced in the Greek legal order with Law 4389/2016 "Establishment of an electricity sale mechanism by PPC S.A., through auctions of forward electricity products with physical delivery - repeal of the provisions of Law 4273/2014 on the creation of a new vertically integrated electricity company - arrangements for full ownership unbundling of ADMIE from PPC S.A., pursuant to Directive 2009/72/EC, by maintaining public control - arrangements for introducing a transitional flexibility mechanism".

Pursuant to article 135 of Law 4389/2016 "*A mechanism is established for the sale of electricity by the public limited company PPC S.A., pursuant to natural gas forward products through natural gas Daily Energy Planning and with a regulated value starting point to Eligible Suppliers of Electricity. Purpose of the mechanism is the redistribution of shares in the retail electricity market in the interconnected system of PPC's shares and alternative suppliers, from the percentage held in August 2015 by PPC S.A., at less than 50%, up to the year 2019*".

Following the entry into force of Law 4389/2016, Decisions 35/2016 and 38/2016 of the Government's Economic Policy Council on the "Approval of auction application plan (NOME)" were adopted.

In this context, in 2019 RAE issued a series of regulatory decisions on the gradual development of the relevant mechanism, and its adaptation to requirements of the domestic electricity market:

- RAE published Decision 164/2019 (Gazette B' 260/06.02.2019) for the readjustment of annual electrical power quantity available through electricity forward auctions with physical delivery and quantity allocation in different forward products for the year 2018 according to Article 135 paragraph 4 and Article 138 paragraph 1 of Law 4389/2016.
- For the first scheduled auction for 2019, RAE issued Decision 165/2019 (Gazette B' 273/06.02.2019) on the approval of technical characteristics and the auctioning terms of the electricity forward product to be auctioned on 8 February 2019, according to paragraph 1 citation D' of Article 138 of Law 4389/2016 (Gazette A' 94/27.05.2016) and of Article 16 of Forward Electricity Product Auction Code (Gazette B΄3164/30.09.2016). The first auction took place on 8 February 2019.

[14] According to article 3 of Law 4336/2015, starting from 01.01.2020, no company can import or generate, directly or indirectly, more than 50% of the total electricity that is produced and imported in Greece.

- For the second scheduled auction for 2019, RAE issued Decision 360/2019 (Gazette B’ 1328/17.04.2019) on the approval of technical characteristics and the auctioning terms of the electricity forward product to be auctioned on 17 April 2019, according to paragraph 1 citation D’ of Article 138 of Law 4389/2016 (Gazette A’ 94/27.05.2016) and of Article 16 of Forward Electricity Product Auction Code (Gazette B΄3164/30.09.2016). The second auction took place on 17 April 2019.
- RAE published Decision 164/2019 (Gazette B’ 260/06.02.2019) on the readjustment of annual electrical power quantity available through electricity forward auctions with physical delivery and quantity allocation in different forward products for the year 2018 according to Article 135 paragraph 4 and Article 138 paragraph 1 of Law 4389/2016.
- RAE published Opinion 9/2019 on the minimum bidding price for electricity forward products according to the definition methodology of Article 139 paragraph 1 of Law 4389/2016 (Gazette A’ 94/27.05.2016).

According to the provisions of par. 2 of article 139 of law 4389/2016 the methodology to determine the minimum price is based on the variable costs of lignite and hydroelectric power plants of PPC S.A. and it determines the ratio of the mixture of lignite and hydroelectric production. RAE issued its Opinion 9/2019 based on the average minimum daily price of lignite and hydroelectric production for 2018, based on the annual accounting data of ADMIE S.A. and lignite production as follows:

Average Minimum Daily Lignite and Hydro Hourly Production	MW
P Min Lignite: Average Minimum Daily Lignite Hourly Production 2018	1,250.80
P Min Hydro: Average Minimum Daily Hydro Hourly Production 2018	156.04
Total Average Minimum Daily Hydro and Lignite Hourly Production 2018	1,406.84
Coefficient (α) = P min (Lignite) / (P min Lignite + P min Hydro)	88.91 %
Coefficient (β) = P min (Hydro) / (P min Lignite + P min Hydro)	11.09 %

Table 16 Average Minimum Daily Lignite and Hydro Hourly Production (2019)

On the variable cost of lignite and hydroelectric power plants of PPC S.A. RAE gave an Opinion based on the variable cost data provided by PPC S.A. as it was extracted from its financial statements:

Variable Costs of Lignite Production of PPC S.A.	**€/MWh**
Variable Mining Costs	18.13
Fuel Purchased by third party costs	1.98
Special Lignite Fee	2.00
Special Commencement Cost	2.68
Variable Operation and Maintenance Costs	3.18
CO2 rights purchase costs	37.13
Total	**65.10**

Variable Costs of Hydroelectricity Generation of PPC S.A.	€/MWh
Variable Costs of Hydroelectricity Power Generating Units	2.19

Table 17 Variable Costs of Lignite and Hydroelectricity Production (2019)

Based on the above, RAE issued its Opinion on the final minimum bid price of the auctioned electricity products, as follows: Final minimum bid price = Coefficient (α) X Variable Costs of Lignite Production + Coefficient (β) X Variable Costs of Hydroelectricity Production = **58.12 €/MWh**

For the third scheduled auction of 2019, RAE issued Decision 713/2019 (Gazette B’ 2953/17.07.2019) on the approval of technical characteristics and the auctioning terms of the electricity forward product to be auctioned on 17 July 2019, according to paragraph 1 citation D’ of Article 138 of Law 4389/2016 (Gazette A’ 94/27.05.2016) and of Article 16 of Forward Electricity Product Auction Code (Gazette B΄3164/30.09.2016). The third auction took place on 17 July 2019.

The fourth scheduled auction of 2019 was canceled after the issuance of a legislative act by the Ministry of Energy and Environment (Gazette A’ 145/30.09.2019) (from 30.09.2019) which pursuant to the provisions of Law No 4638/2019 permanently abolished future NOME auctions.

Table 18 shows the timetable of the auctions until the year 2019.

Forward Product	Quantity (MWh/h)	Volume (MWh)	Physical Delivery Period
2016A01P01	460	4.029.600	2016.12.01-2017.11.30
2017A01P01	145	1.270.200	2017.03.01-2018.02.28
2017A02P02	145	1.270.200	2017.06.01-2018.05.31
2017A03P03	145	1.270.200	2017.09.01-2018.08.31
2017A04P04	718	6.289.680	2017.12.01-2018.11.30
2018A01P01	400	3.504.000	2018.03.01-2019.02.28
2018A02P02	400	3.504.000	2018.06.01-2019.05.31
2018A03P03	400	3.504.000	2018.09.01-2019.08.31
2018A04P04	683	5.983.080	2018.12.01-2019.11.30
2019A01P01	350	3.074.400	2019.03.01-2020.02.29
2019A02P02	355	3.118.320	2019.06.01-2020.05.31
2019A03P03	549	4.822.416	2019.09.01-2020.08.31
TOTAL	**4.750**	**41.640.096**	**2016.12.01-2020.08.31**
~~2019A04P04~~[15]	~~1.029~~	~~9.038.736~~	~~2019.12.01-2020.11.30~~

Table 18 Timetable of the auctions until the year 2019

[15] This auction was canceled with the 30.09.2019 legislative act by the Ministry of Energy and Environment (Gazette A’ 145/30.09.2019)

3.2.2. Retail market

3.2.2.1. Description of the retail market

Electricity consumption for 2019 slightly increased compared to 2018 in the Interconnected System (46,969 GWh, compared to 45,898 GWh). Table 19 illustrates the evolution of electricity consumption in the Interconnected System during the last 7 years, which depicts a constant decreasing trend for the period 2013-2016, mainly due to the economic crisis in the country. In 2017 this trend was reversed with an increase in all customer categories, which proved to be only temporary, as in 2018 it followed a downward direction. In 2019, however, there was an increase of 2%.

	Year	Large Industrial Customers	Domestic customers	Small Industrial & Commercial customers)	Other (e.g. agriculture, public, traction)	TOTAL (GWh)
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**
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**
HV	2013	6,599	-	-	1,168	**7,767**
	2014	6,702	-	-	1,314	**8,016**
	2015	6,805	-	-	1,150	**7,955**
	2016	7,062	-	-	1,115	**8,177**
	2017	7,268	-	-	1,028	**8,296**
	2018	7,351	-	-	937	**8,288**
	2019	7,003	-	-	903	**7,906**
Total	**2013**	**6,599**	**15,973**	**18,464**	**6,295**	**47,331**
	2014	**6,702**	**15,569**	**17,702**	**6,526**	**46,499**
	2015	**6,805**	**15,817**	**17,596**	**5,900**	**46,118**
	2016	**7,062**	**15,048**	**17,835**	**5,978**	**45,923**
	2017	**7,268**	**15,651**	**18,108**	**5,849**	**46,876**
	2018	**7,351**	**14,767**	**18,374**	**5,407**	**45,898**
	2019	**7,003**	**15,633**	**18,775**	**5,557**	**46,969**

Table 19: Evolution of electricity consumption in the Interconnected System (2013-2019)

Regarding the supply market in the Interconnected System, 2 new companies with supply licenses actively entered the supply market in 2019:

1. «PETROGAZ S.A.»
2. «ELINOIL – GREEK OIL PRODUCTS COMPANY S.A.»

At the end of 2019, a total of 26 companies (including the Universal Service Provider) were active in the electricity supply market:

	Electricity Suppling Company
1.	VIENER
2.	VIOLAR
3.	PPC
4.	ECONOMIC GROWTH
5.	ELINOIL
6.	ELTA
7.	ELPEDISON
8.	ENEL GREEN POWER
9.	ZENITH
10.	EUNICE
11.	NATURAL GAS
12.	GREEN
13.	HERON
14.	TH. SOUMPASIS
15.	INTERBETON
16.	KEN
17.	MARKOU
18.	PROTERGIA
19.	NOVAERA
20.	NRG
21.	OTE ESTATE
22.	PETROGAZ
23.	Universal Service Provider (PPC S.A.)
24.	VOLTERRA
25.	VOLTON
26.	WATT & VOLT
~~27.~~	~~GREENSTEEL CEDALION COMMODITIES S.A.~~[16]

Table 20: Companies active in the electricity supply market (2019)

[16] GREENSTEEL CEDALION COMMODITIES S.A. ceased to be an active supplier at 30.09.2018.

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

• (3) requests for supply licenses, (10) requests for amendments of supply licenses, (7) requests for trading licenses, and (1) request for amendment of an electricity generation license of a 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 CCGT unit.

• (1) request for a supply license, (7) requests for amendment of supply license, (3) requests for trading licenses and (4) requests for amendment of trading licenses, submitted within 2019, are still pending for a final decision.

• (1) request for a supply license is still pending from 2018.

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 Europe. Regarding the main legal framework, the EU Directive 2014/94/EU on the deployment of alternative fuels infrastructure (AFID) foresees 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. The committee will work towards the publication of a Report concerning the e-mobility action plan for Greece, a list of incentives for electric vehicles penetration in the Greek market, the documentation of national and European funding sources, the regulatory framework of e-mobility in Greece, and the progress of Clean Mobility Package on European level under Clean Energy Package Program. This Report is expected to be completed until 30.06.2020.

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.

3.2.2.2. Competition and market shares

PPC remained the main supplier in the retail electricity market in 2019, representing 83.95% of the total number of connections in the Interconnected System at the end of 2019, and (71.13% of the total consumption in LV and MV).

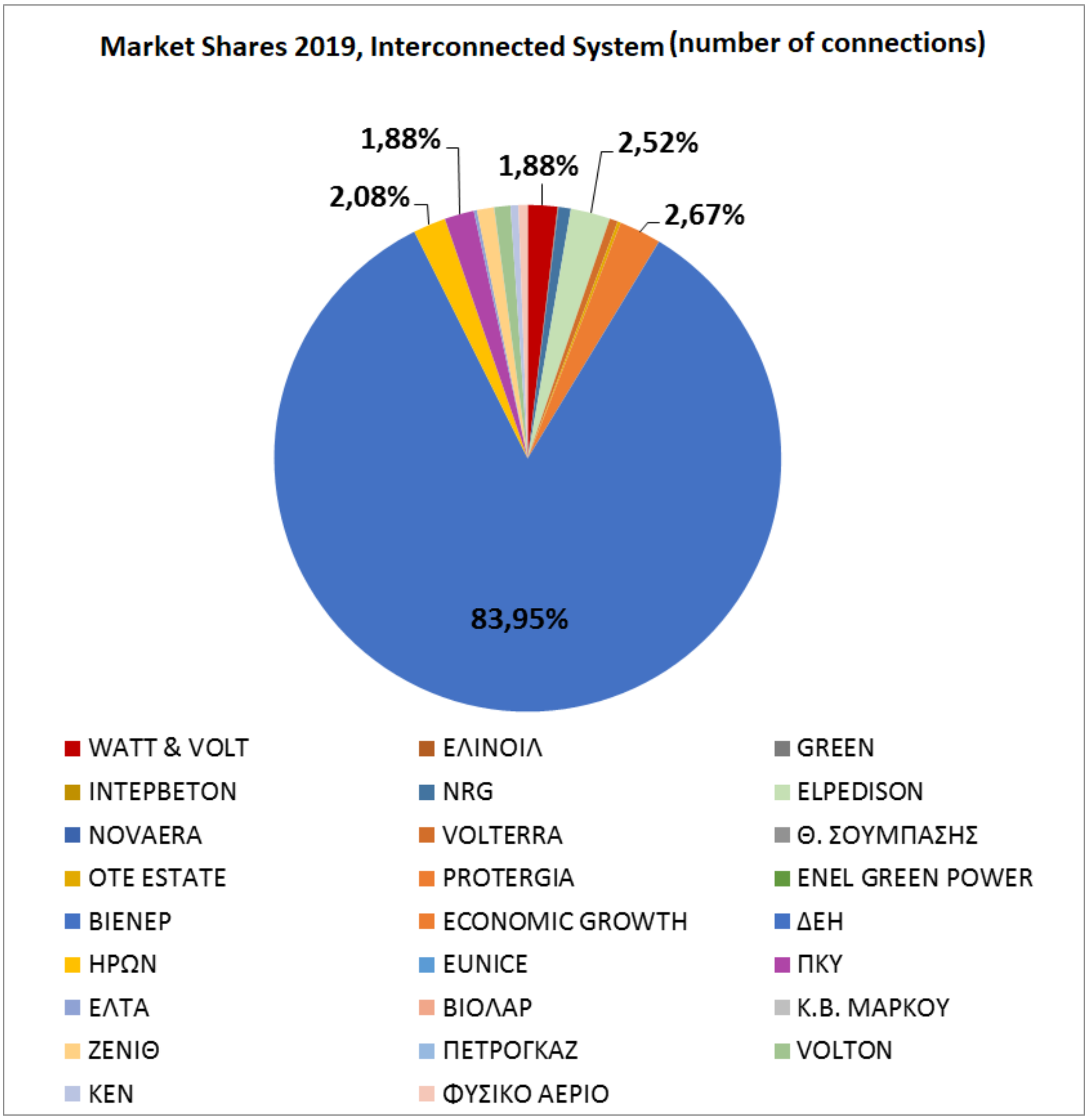


Figure 14: Market shares in Retail Electricity Market based on suppliers' total meter connections in the Interconnected System

(2019)

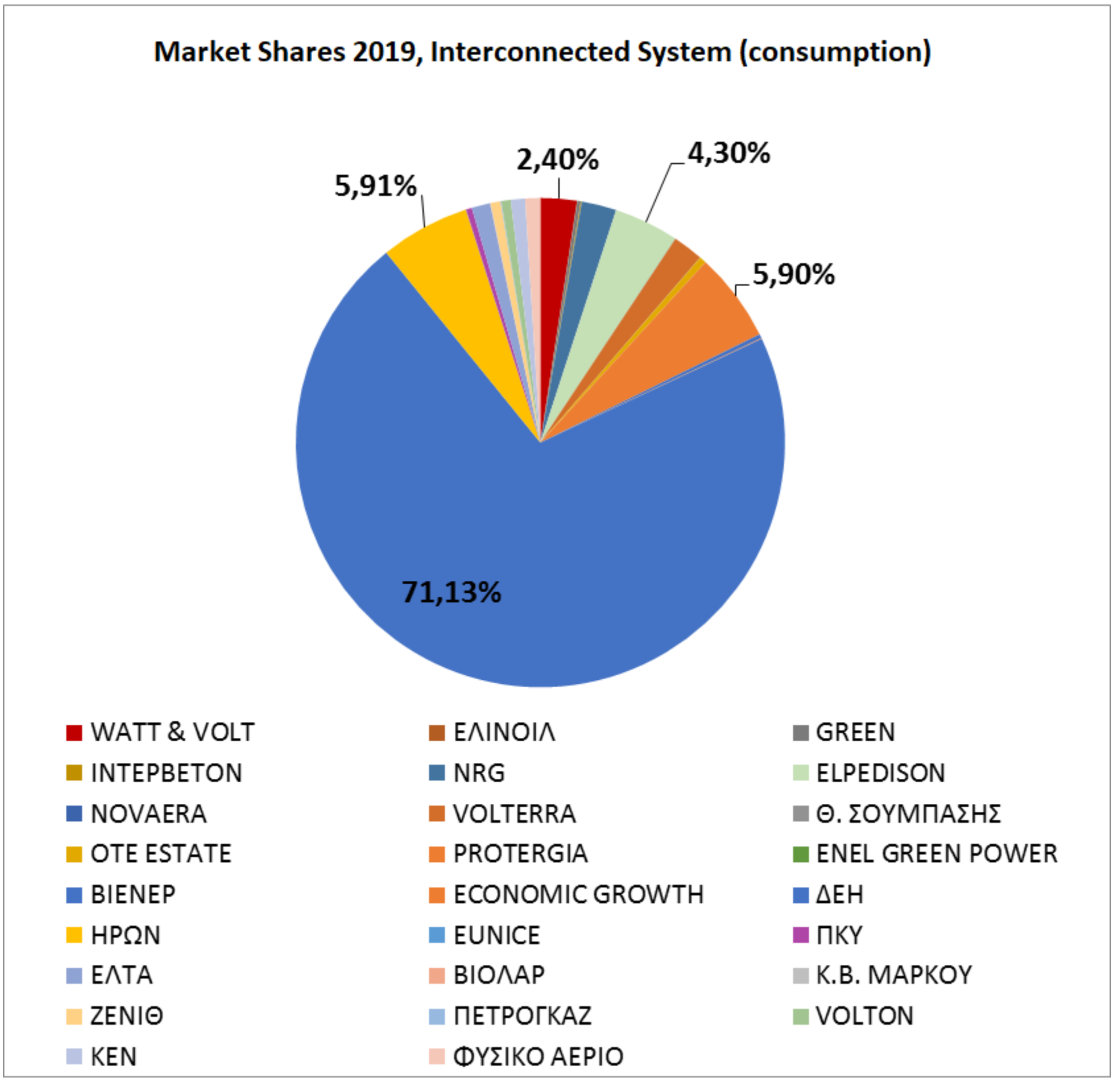


Figure 15: Market shares in Retail Electricity Market based on consumption volume (LV and MV) in the Interconnected System (2019)

The Herfindahl-Hirschman Index (HHI), at the end of 2019 amounted to 5,167 in the interconnected system per volume, surpassing considerably the 2.000 level (of a high concentrated market). However, the HHI is relatively lower than in 2018 (5,740). Regardless of the increasing number of the alternative suppliers over the past years in Greece, the supply market in 2019 remains highly concentrated.

Regarding suppliers switching rates, according to HEDNO's data, 8,50% of LV and MV customers switched their supplier in 2019 (2.21% of total consumption in the LV and MV market). The highest level of supplier switching is observed at household customers followed by 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 2018, the switching trend shows a great rise in terms of number of connections (+4.51%) which means a year-to-year increase of 89%, while in terms of volume) the switching trend was downward (-3.96%), i.e. a decrease of 44% within one year. This is mainly attributed to the considerable switching rate of household customers in 2019 who consume, however, low volume of electricity.

The following table includes data regarding customer switching (LV and MV) in the Interconnected system for 2019 (data of DEDDIE):

Customer Category	Number of Customers in the Interconnected System in 31.12.2019	Number of customers that switched supplier in 2019	Switching rates (% in number of customers)	Total Consumption in 2019 (MWh)	Consumption of customers that switched supplier in 2019 (MWh)	Switching rates (% of consumption volume)
Household customers (not including Social Tariff)	4,813,242	462,318	9.61%	13,831,816	204,742	1.48%
Household Customers under Social Tariff	483,710	2,740	0.57%	1,801,520	5,377	0.30%
Small industrial and commercial customers	1,169,360	104,826	8.96%	9,735,014	274,112	2.82%
Oher LV customers	305,991	5,705	1.86%	3,108,066	5,793	0.19%
Total LV customers	6,772,303	575,589	8.50%	28,476,416	490,024	1.72%
Commercial and Industrial customers	9,071	834	9.19%	9,040,441	367,030	4.06%
Oher MV customers	1,701	13	0.76%	1,546,065	5,051	0.33%
Total MV customers	10,772	847	7.86%	10,586,506	372,081	3.51%
Total number of LV and MV customers	6,783,075	576,436	8.50%	39,062,922	862,105	2.21%

Table 21: Number of metering points, consumption volume and switching rates per consumer category in the interconnected system's electricity retail market (2019)

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 and collects data related to:

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 distribution data from the DSOs (number of metering points, consumption per supplier, switching and disconnection applications).
4) Natural gas distribution data from the DSOs (number of metering points, consumption per supplier, switching and disconnection applications).
5) Data on consumers' complaints and requests management

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. RAE discovered that 8 companies were holding a high rate of overdue payments. Those companies were called for a hearing. The hearings finished in 2018 and in 2019, RAE published (7) infringement Decisions imposing penalties to electricity suppliers.

Moreover, the temporary monthly NII PSO Tariff was calculated for the years 2014, 2015 and 2016, per NII System, which were approved by RAE's Decision 688/2017 and modified by Decision 832/2019. The costs for providing services of general interest amounted to € 7,653,772.99 for 2014, € 7,728,804.11 for 2015, € 6,271,619.82 for 2016 and a total of € 21,654,196.92 for these three years. More specifically, from the evaluation of the expenses for the rental, transfer and installation of power generators to cover the extraordinary electricity needs in the NIIs that remained pending with the issuance of the RAE

Decision 688/2017, were recognized as additional costs that burden the PSO Account for the years 2014-2016. The costs for electricity producers of NIIs that had a production license amounted to € 765,471.88 for the year 2015 and € 1,038,609.50 for the year 2016. The other expenses of the power generators in NIIs without a production license remained pending. RAE Decision 200/2020 (Gazette B′ 509 / 19.2.2020) approved the (second) expenses of power generators in NII for the years 2014-2016, amending and supplementing RAE Decision 688/2017, amended and supplemented by RAE Decision 832/2019. With Decision 200/2020, RAE recognized further supplementary compensation to cover the costs of providing PSO for the years 2014, 2015 and 2016, amounting to € 1,668,515.98 for 2014, € 274,850.00 for 2015, € 3,824. € 047.32 for 2016 and a total of € 5,767,413.30 for these three years. Following the above, the final expenses that were recognised to the power generators, which are going to be covered by the PSO Special account, for the years 2014, 2015 and 2016 amounted to € 682,586,546.33 for 2014, € 609,809,262.75 for 2015 and € 492,741,896.12 for 2016. For 2017, the total expenses of the power generators, recognized by RAE, amounted to € 835,584.00 as follows: (a) Paros System: € 205,600, (b) Ikaria System: € 138,180, (c) Thira System: € 249,184, (d) Karpathos System: € 69,320, (e) Mykonos System: € 110,700 and (f) Samos System: € 62,600. Following the above, RAE with the Decision 1254 / 19.12.2019 (Gazette B '1049 / 27.3.2020) approved the amount of € 532,701,813.53 to cover the expenses of the electricity generators for providing Services of General Interest for the year 2017.

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, but has since decreased significantly.

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 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.

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 22 represents the evolution of annual electricity consumption and peak load demand in the interconnected system between 2009 and 2019, as reported by the TSO, ADMIE S.A., in its Adequacy Study 2020-2030. In 2019, electricity consumption was around 52,17 TWh.

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total electricity consumption excluding pump storage (GWh)	53,490	53,545	52,915	52,611	50,664	50,228	51,355	51,212	51,932	51,462	52,174
Peak load (MW)	9,809	9,872	10,105	10,438	9,161	9,263	9,813	9,207	9,674	9,062	9,634

Table 22: Energy and peak electricity demand in the interconnected system (2009-2019)

Table 23 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 23: Electricity consumption and peak load demand forecast in the interconnected system, for the period 2020-2030

Installed capacity and generation

Greece is currently undertaking significant energy system changes in order to achieve its long-term goals for decarbonization, energy efficiency and high penetration of renewable energy sources. Power system adequacy at periods of peak demand as well as integrating in the system larger shares of intermittent sources of electricity generation (RES) are therefore of key importance in order to ensure energy security.

Generation adequacy assessment

In the context of the current legislation, the ADMIE, submitted in December 2019 to RAE, the Generation Adequacy Report for the period 2020-2030. The purpose of this report is to highlight potential future risks with regard to the ability of the interconnected system to respond adequately to changes in electricity demand, foreseen for the time-period under consideration. In the 2019 Generation Adequacy Study several binding conditions are considered which are based on data presented in the National Energy and Climate Plan (NECP) concerning the power generation system (withdrawals/new entries of power units), RES penetration levels, and τηε evolution of electric power demand up to 2030. The adequacy of the Greek power system is estimated through probabilistic methods, by calculating the LOLE (Loss of Load Expectation) and EUE (Expected Unserved Energy) reliability indices. The basic methodology and assumptions used by the TSO in the national adequacy study have been aligned to a large extent with the methodology used in ENTSOE’ s European Midterm Adequacy Forecast (MAF), in 2019. In this regard, the assessment of the effect of climate factors (air, sunshine and temperatures) on the adequacy of the power system was also taken into consideration. Specifically, for each demand evolution scenario and year, different time series of loads and RES generation were developed, using the available historical data of the PECD 2.0 database maintained by ENTSO-E. These time series correspond to different climatic conditions, covering a wide range of potential, both "normal" and "extreme".

Main results of the adequacy study

For the purposes of the Adequacy Study, a baseline scenario (NECP) for the evolution of the power generation system for the period 2020-2030 is set. This scenario includes the new entries and withdrawals of thermal plants. The adequacy analysis presents the reliability indices for the period 2020 – 2030, considering the assumptions for the basic scenario for the evolution of the generation system and for load forecast (Reference Scenario-NECP), for three hydraulic scenarios (dry, normal, wet).

The adequacy analysis of the TSO, assuming a LOLE reliability criterion of 3 hours per year, justifies the following conclusions:

- Under the conditions described in the NECP Reference Scenario (significant energy savings, high level of RES penetration, complete decarbonization and withdrawal of lignite-fired power stations), the operation of the power generation system can be characterized as sufficient throughout the period 2020 - 2030.
- However, for the year 2021, during which some lignite power plants will be withdrawn, without new conventional generation added to the system, the adequacy of the system will be vulnerable to the prevailing climatic and hydrological conditions. Under adverse conditions there is a possibility that the power generation system will not be able to adequately meet the peak loads.
- The expected integration of the new units of Ptolemaida V (2022) and the new Combined-Cycle NG units (2022 and 2023), under the assumptions of the NECP Scenario, combined with the start of

commercial operation of the second interconnection with Bulgaria (2023), seems to offset the withdrawal of all existing lignite power units, significantly improving the security of supply the system.

- From 2025 onwards, the introduction of new pumped-storage units, as well as the continuous increase of the installed capacity of RES, result in low values of LOLE. It is confirmed that the contribution of energy storage to power adequacy is important, especially when combined with high penetration of variable RES.
- From the results of the sensitivity analysis it appears that the most critical period for the adequacy of the system is the period 2021-2024 during which the complete withdrawal of the existing lignite power units is foreseen. In the event that the energy saving measures are not such effective as provided in the NECP, and the demand for electricity increases further or the planned new units are not included in the system in time, the system's adequacy will become notably vulnerable to climatic and hydrological conditions, and it appears that there may be an increased possibility that the production system will not be able to adequately meet the peak loads during this period, despite the considered new capacity for international interconnections.
- A possible delay in the integration of the new units beyond 2025 significantly increases the risk of unsatisfactory demand coverage, especially if there is no stabilization of the electricity demand at the levels provided by the NECP.

Taking into consideration the above findings of the Adequacy Study of the interconnected electricity System for the period 2020-2030, it is concluded that the decarbonization of the power generation sector should be achieved in parallel to the addition of new power units, as otherwise, despite the new capacity of international interconnections, there is a possibility that the production system will not be able to adequately meet the peak loads under adverse climatic conditions.

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.

In this framework, on 7 February 2018, the European Commission adopted a decision approving the prolongation of the interruptibility scheme for the Greek electricity system (2018) 604 final/7.2.2018 in State aid case "SA 4870" - Prolongation of the Greek interruptibility scheme). Under this scheme, the TSO contracts large energy consumers to be available to reduce their consumption at times of system stress, also referred to as demand response.

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. In order 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.

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 24: Interruptible load services (ILS)

In the above Decision, the duration of the measure was set at 2 years, i.e. until 31.12.2019 and the beneficiaries are customers whose premises are connected to HV and MV with intermittent power of at least 3MW, after being recorded in the register of interrupted load held by ADMIE. Two different types of interrupted load service ILS1 and ILS2 (depending on time the maximum duration of the order and the maximum total duration per year) were recognized and their price was formed through an auction where beneficiaries with the lowest prices were selected, with their compensation (exclusively for reduction capacity) to be determined on the basis of the marginal price. In total, the Greek TSO can contract up to 1600 MW of so-called interruptible loads, i.e. demand response from medium-sized and large energy users with a stable load profile. The 1600 MW are split in two separate segments: 1000 MW of capacity can be contracted for ILS1 and 600 MW for ILS2. The maximum price at which the auction can clear is EUR 70000/MW for ILS1 and EUR 50000/MW for ILS2.

In 2019 the Greek TSO (ADMIE) organized five (5) pairs of auctions (one auction for each type of ILS). The four pairs of auctions covered the period from January to December 2019 and the fifth pair of auctions covered the first two months of 2020. For ILS1 auctions the capacity asked by the TSO was 600MW and for ILS2 auctions was 430MW. 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)
01.01.2019 - 31.03.2019	59.350	23	661	600	61
01.04.2019 - 30.06.2019	59.120	23	696	600	96
01.07.2019 - 30.09.2019	63.000	23	697,7	600	97,7
01.10.2019 - 31.12.2019	62.200	22	696,9	600	96,9
01.01.2020 - 06.02.2020	65.800	22	693,8	600	93,8

Table 25: Type 1 of Interruptible load capacity services (ILS 1 services) Auctions in 2019

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)
01.01.2019 - 31.03.2019	49.800	18	482,1	430	52,1
01.04.2019 - 30.06.2019	49.900	18	538,2	430	108,2
01.07.2019 - 30.09.2019	49.900	17	520,6	430	90,6
01.10.2019 - 31.12.2019	49.900	20	527,6	430	97,6
01.01.2020 - 06.02.2020	49.900	18	526,7	430	96,7

Table 26: Type 2 of Interruptible load capacity services (ILS 2 services) Auctions in 2019

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[17].

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

[17] 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.

According to RAE Decision 785/2019, the Interconnection of Dodecanese islands and the islands of Northern Aegean Sea, are also requested to be included in the next TYNDP after submitting a documented proposal, which means that the Development Plan (2020-2029) should be updated and re-submitted to RAE for approval.

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, considering also 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.

By the end of 2019, 19 suppliers (including the Universal Service Provider and the Supplier of Last Resort) were active in the Non-Interconnected Islands:[18]

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

Table 27: Companies active in the electricity supply market of Non-Interconnected Islands (2019)

PPC remained the dominant supplier in the non-interconnected system representing at the end of 2019, holding 88.24% and 79.58% in terms of consumption volumes of LV and MV customers), this is a decrease of PPC's share by 5% in terms of both number of connections and of consumption volumes compared to 2018 (93.3% and 84.5% accordingly). Figure 16 shows the shares of all suppliers in the non-interconnected system in terms of number of connections according to DEDDIE's data for 2019.

[18] 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.

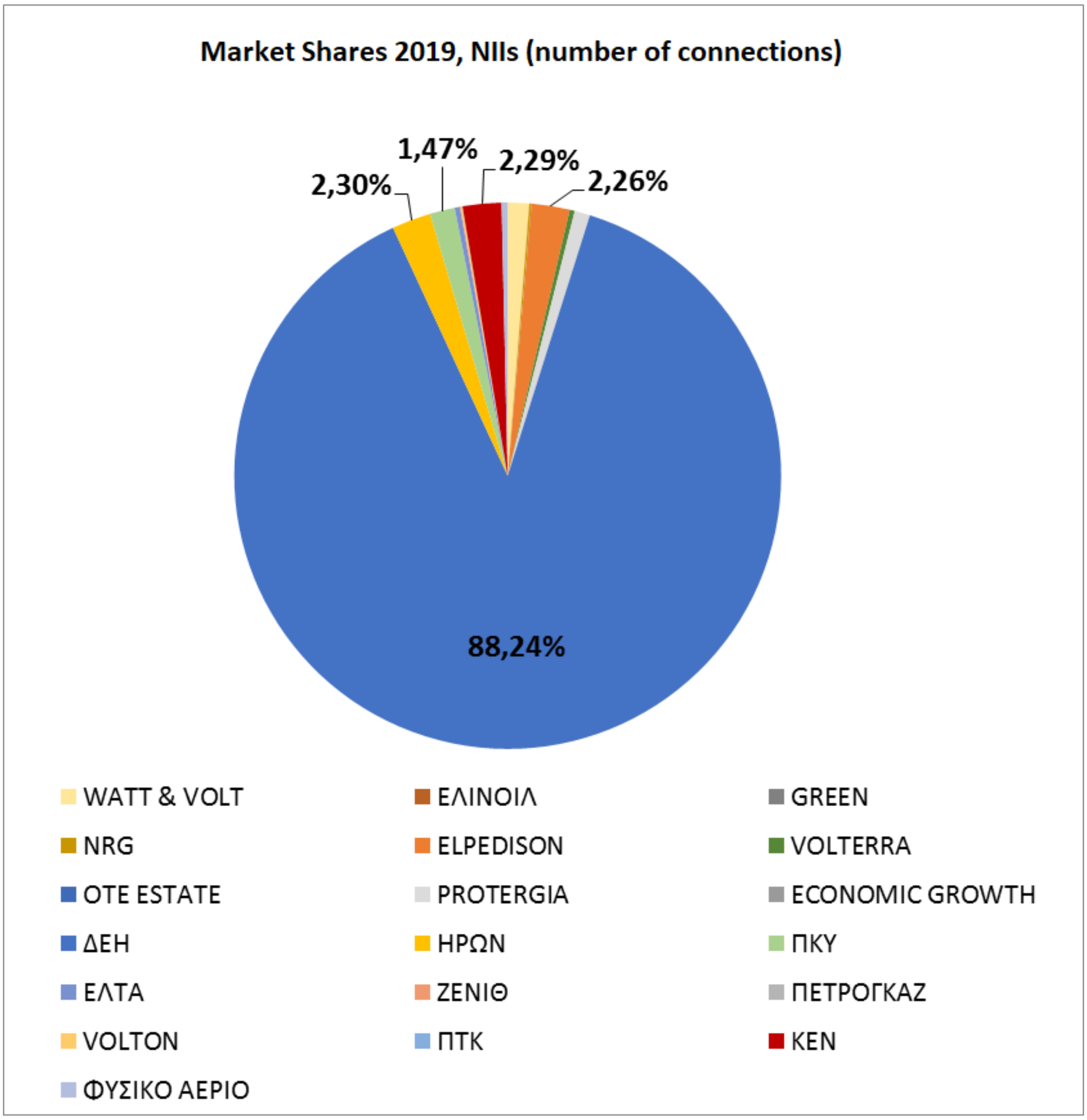


Figure 16 Market shares in Retail Electricity Market based on suppliers' total meter connections in the Non-Interconnected Autonomous Systems (2019)

Alternative suppliers show better results in terms of consumption volumes. Figure 17 shows the market shares in the non-interconnected system per volume rates in the low and medium voltage according to DEDDIE's data for 2019.

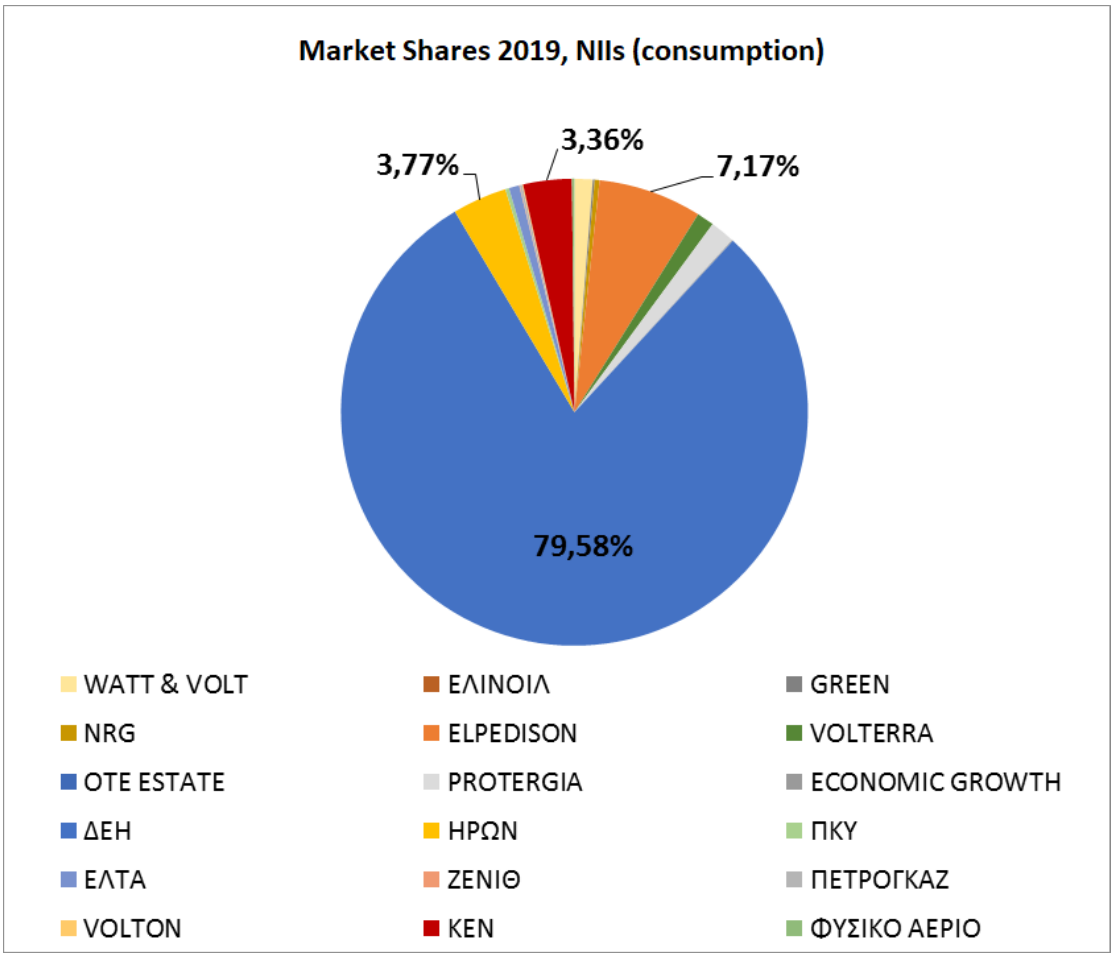


Figure 17: Market shares in Retail Electricity Market based on based on consumption volumes (LV and MV) in the Non-Interconnected System (2019)

The Herfindahl-Hirschman Index (HHI), measuring market concentration, amounted to 6,146 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 2018, when market concentration reached 7,179. All in all, the retail electricity market of the NIIs is rightly characterized as still very concentrated.

Regarding supplier switching in the NNIs, according to DEDDIE's data 6% of LV and MV customers switched their supplier in 2019 (2.28% of total consumption in the LV and MV market). The greatest level of supplier switching is observed at MV (commercial and industrial) customers in terms of both number of customers and consumption volume.

The following table portrays data of customer switching (LV and MV) in the NIIs in 2019 (data of DEDDIE):

Customer Category	Number of Customers in the Non-Interconnected System in 31.12.2019	Number of customers that switched supplier in 2019	Switching rates (% in number of customers)	Total Consumption in 2019 (MWh)	Consumption of customers that switched supplier in 2019 (MWh)	Switching rates (% of consumption volume)
Household customers (not including Social Tariff)	567,578	35,328	6.22%	1,574,327	16,231	1.03%
Household (including Social Tariff)	28,903	119	0.41%	120,348	384	0.32%
Small industrial and LV Customers	154,314	11,490	7.45%	1,674,457	38,406	2.29%
Oher LV customers	42,942	503	1.17%	426,741	680	0.16%
Total LV customers	**793,737**	**47,440**	**5.98%**	**3,795,873**	**55,701**	**1.47%**
Commercial and Industrial MV customers	995	148	14.87%	1,089,872	60,009	5.51%
Oher MV customers	187	0	0.00%	183,111	34	0.02%
Total MV customers	**1,182**	**148**	**12.52%**	**1,272,983**	**60,043**	**4.72%**
Total no of LV and MV customers	**794,919**	**47,588**	**6.00%**	**5,068,856**	**115,744**	**2.28%**

Table 28: Consumer Switching (LV and MV) in NIIs (2019)

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 16.77% in 2019. In Crete, the largest island of the non- interconnected system, the share of RES in total generation was 20,92%. The level of demand of the 29 autonomous non-interconnected islands varies significantly:

- 19 out of 29 have a peak demand level less than 10 MW.
- 8 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 30).

	Non-interconnected autonomous power systems (islands)	Final Electricity Production from Conventional Plants (MWh)	Electricity Produced from RES and rooftop PV's (MWh)
1	St Eustratios	1,123	0.00
2	Agathonisi	765	0.00
3	Amorgos	10,843	439.25
4	Anafi	1,358	0.00
5	Antikythera	300	0.00
6	Arkie	412	0.00
7	Astepalaia	6,737	531.37
8	Gavdos	512	0.00
9	Donoussa	1,125	0.00
10	Erikoussa	820	0.00
11	Thira	216,686	418.68
12	Ikaria	24,475	4,052.38
13	Karpathos	35,272	4,532.17
14	Crete	2,438,384	645,042.90
15	Kythnos	9,606	393.64
16	Kos-Kalymnos	356,598	48,786.81
17	Lesbos	254,642	45,280.82
18	Lemnos	51,555	9,169.02
19	Megisti	3,866	0.00
20	Melos	45,780	6,699.12
21	Othonei	629	0.00
22	Patmos	16,748	2,821.39
23	Rhodes	759,375	107,895.69
24	Samos	112,612	28,017.48
25	Serifos	9,018	165.16
26	Sifnos	17,585	1,759.03
27	Skeros	15,694	432.08
28	Semi	14,649	250.79
29	Chios	187,818	19,089.43
	TOTAL	4,594,990	925,777

Table 29: Electricity Generation in Non-Interconnected Islands (NII) for 2019

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

Table 30: Annual Electricity Consumption (Demand) in NII, 2012 – 2019 (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.

Economic efficiency criteria for the electrification of the NNIs

RAE with Decision 469/2015, which was later amended by Decision 169/2018, set up the "Committee for the alternative ways of electricity supply to the non- interconnected islands" consisting of members of all relevant Operators (ADMIE, DEDDIE, NIIs Operator and DESFA) with a mandate to explore of technical and economic choices for non-interconnected islands and the publication of a decision with regard to the most economical way of electrification of NIIs through their interconnection with the National Electricity Transmission Network or the interconnected Distribution Network on the basis of the most economically feasible interconnection solution, or by continuing its electrification as NIIs[19]. In December 2017, the Committee submitted to the relevant Operators ADMIE and DEDDIE the First part of the Second Conclusion concerning the islands of the Southern Aegean (Dodecanese).

The second part of the Conclusions, concerning the Northern Aegean islands, was submitted in December 2018. It is noted that while initially looking at a single transmission network solution configuration which would include all the islands of the Aegean Sea, and would be connected to the National Transmission Network in more than one points, it was found that the most appropriate solution is the provision of two separate systems - interconnections, namely: One which includes all the islands of the Southern Aegean (Dodecanese) and is the subject of the first part of the Conclusions, and another concerning the islands of the Northern Aegean, part of which needed more analysis and would be submitted shortly. Consequently, the examination of the islands of the Northern Aegean is not dependent on that of the islands of the Southern Aegean.

RAE, in 2019, approved with Decision 785/2019 the implementation of High Voltage and Medium Voltage interconnection of most of the Aegean Sea islands with the interconnected system or with the network of islands which is interconnected to the later. RAE, based on the Conclusions of the above Committee examining the economic efficiency of the project and the proposals of Operators, approved the interconnection of some islands initially not included in the TYNDP of ADMIE to the interconnected system as the most efficient way.

[19] The Committee submitted its First Study to RAE, in March 2016. The study examines alternatives for electricity supply to the NIIs from the technical and the economic perspectives. The development of additional studies and reports regarding the needed software in NIIs, data monitoring and analysis techniques, the managing flows and congestions in NIIs decided by RAE in 2016 (Decision no 147/2016). The Committee's work continued in 2017, with a test of autonomous interconnection systems of the southern and northern Aegean islands.

Emergency response system

In the context of implementing the provisions of the NIIs Code for Emergency Response, RAE held a public consultation for the amendment of articles 152 and 155 of the Electrical System Network Code of Non-Interconnected Islands to address emergencies.

Regarding the way of handling emergency needs, the installment of additional rented capacity and the approval of its cost, the following procedure was determined by decision of RAE:

1. The NIIs Operator shall immediately notify RAE in accordance with the NIIs Code, by the end of the next day of the event.
2. The NIIs Operator shall submit to RAE within the above specified time period a suggestion to grant a production license if an additional potential authorization is required by specifying the amount of additional capacity, its cost, and the time required to repair the damage.
3. The Producer, based on a recommendation of the NIIs Operator, should submit within a reasonable time period from the occurrence of the event, to RAE the necessary application for a license in order to cover the emergency.
4. The NIIs Operator shall submit within 30 days of the expiry of the Emergency to RAE for approval, an assessment report, in accordance with Article 155 of NIIs Code.

In any case, the NIIs Operator should be able to prove (through an adequacy study etc.) the necessity for renting additional capacity before RAE approves that extra cost.

It is considered necessary to publish a Manual for Emergency Cases in the Interconnected Islands as a part of the Network Operation Manual. This Manual will set a plan for the reimbursement, the granting of reserve services to the Network in case of emergency and the needs and the cost of leasing generators for the next year. In 2020, RAE along with DEDDIE will publish the relevant plan.

Emergency response plan

RAE will assess the response to emergency situations and as for their coverage cost, this will be decided in the clearing of Network Usage Tariff and PSO tariffs of NIIs for 2018 which will take place in 2020.

Pursuant to Article 154 of the NIIs Code the Operator submits to RAE for approval, and updates every five years or earlier, the Emergency Response Plan for the NIIs. With Decision 368/2018 (Gazette B' 5666/17.12.2018) the Plan was approved by RAE with certain additional conditions regarding mainly the costs of the measures prescribed therein.

2018 crisis management report

RAE, within the framework of the NIIs Code, was informed for the different ways of crisis management by the Operator of NIIs in 2018. Those incidents concerned damaged underwater cables between islands that happened in 2018. RAE will evaluate this crisis management process, the cost of covering those needs, the clearance of Network Tariffs and NIIs Public Service Obligations for 2018 which will take place in 2020.

Opinion for the prevention of delays in the implementation of interconnections

In 2018, RAE, within its remit, as provided in the provisions of the Article 108A of Law 4001/2011 and in the Decision 256/2018 for the approval of the TYNDP of ADMIE for 2018-2027, submitted Opinion 14/2018 to the Ministry of Energy concerning the procedure for calculating and enforcing a clause for the prevention of delays in the implementation of the interconnection of NIIs with the mainland electricity system based on the Non-Avoidable Cost of Public Service Obligation Tariff.

In essence, and with reference to specific timetable for the implementation of each project, penalties may be imposed in cases of delays in the implementation of different stages of each project to the Organization which bears the responsibility of implementing the relevant project.

Progress report of the Infrastructure Implementation Action Plan of DEDDIE S.A for the year 2019

In February 2019, DEDDIE submitted to RAE a progress report of infrastructure implementation Action Plan for NIIs for approval. RAE, with Decision 424/2019 highlighted the need for a timely submission of required infrastructure methodologies to RAE by DEDDIE according to RAE Decision 389/2015. Until all projects for the development of infrastructure is completed, DEDDIE should prepare this report and submit it to RAE for approval.

3.4.4. Security of supply in Crete

The security of supply of Crete has emerged as a major national priority over the past few years because of the EU environmental limitations and the termination of the exemption decision 2014/536/EU of the European Commission at the end of 2019. To this end, RAE has coordinated the relevant actions between the network operators and producer PPC S.A. trying to reach the most effective intermediate solution until the full interconnection of the island with the National Transmission Network.

In 2019, RAE, in order to guarantee the capacity adequacy of Crete, proceeded with the following measures:

- RAE's Decision 363/2019 approved an electricity production license for PPC S.A. The Permission concerns the installation and operation of 18 portable generators of 22.66 MW capacity in Crete for the period 2019-2023.
- RAE's Decision 672/2019 approved the granting of a production license for the installation of portable generators by PPC S.A. The capacity of those generators is 58 MW and concerns capacity adequacy for summer period of 2019 only.
- RAE's Decision 821/2019 approved the extension of an energy production license for PPC S.A. concerning the leasing of some portable generators of 20 MW for capacity adequacy only for September 2019 for the island of Crete.

In 2019, RAE in cooperation with National Technical University of Athens, proposed to the Ministry of Energy a series of measures including the increase of power production from renewable energy sources and natural gas to guarantee energy supply of Crete.

Furthermore, RAE elaborated proposals for the operation of the Electricity Market in Crete during the transition period between the completion of Phase I and II of the Interconnection of the island with the interconnected system (2020-2024). Intensive consultations took place between the competent bodies and operators (HENEX S.A. and IPTO S.A.) for the finalization of the model of Crete's electricity market as well as its details, such as the definition of a local bidding zone in Crete, the establishment of maximum bidding price and other energy market operation issues. A crucial issue is the establishment, as a distinct category of Public Service Obligations, of a special temporary local capacity adequacy mechanism, as well as its approval by the European Commission.

In addition, RAE has started the necessary preparations, in consultation with all stakeholders and using the findings of a special study conducted by the National Technical University of Athens, to develop a specific framework through competitive tenders, for the implementation of electricity generation solutions using natural gas for the period 2020-2024, in order to ensure the security of supply of Crete until the commissioning of the Crete-Attica interconnection (Phase II). In this framework, RAE has submitted to the Ministry of Energy the following proposals:

1) Conversion of the existing steam power plants ATM 1 and ATM 2 of the Atherinolakko substation of Crete, with a total capacity of 93 MW, so that they can operate using natural gas as a fuel.
2) Increasing the existing installed capacity of RES (Wind and PV) by a range of 150 – 200 MW.
3) Installation of electricity storage stations of 40 – 50 MW installed capacity.
4) Installation of additional thermal capacity of 100 MW, following the launch of a relevant public tender by RAE for additional capacity of conventional units that operate using natural gas, with criteria based on public interest, environmental compliance and minimal cost for the consumers.

3.5. RES

3.5.1. RES Installed capacity and generation

The installed capacity of RES units at the end of 2019 amounted to 6,729 MW (including those in NIIs), showing an increase of approximately 15.5% compared to the one recorded at the end of 2018 (5,828 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 746.9 MW (26.1% increase compared to the end of 2018) as shown by the distribution per technology presented in Table 31. This increase in the installed capacity of wind farms, which is by far the largest in the decade (second largest was in 2011 with 310.3 MW), 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[20] under the new support scheme of law 4414/2016 (sliding Feed-in-Premium). Additionally, there has been a substantial increase of PV capacity by 148.1MW (6.5% increase compared to 2018), a result of the completion of the projects that received operating aid during the pilot competitive tender procedure held by RAE in 2016 but also during the competitive tenders that followed. The capacity of biomass units also increased by 5 MW, an increase of 21.7 MW compared to 2018.

[20] These projects secured reference tariffs of 98€ / MWh.

Moreover, the usage of net metering for PV installations, in the context of the Ministerial Decision No 175067 (Gazette 1547 B'/05.05.2017) as amended and currently in force, continued to present great results. Based on data from DEDDIE S.A. by the end of 2019, 1,343 power stations with a total capacity of approximately 27.25 MW were installed under (pure) net metering (compared to 1,007 stations with a total capacity of 17.6 MW at the end of 2018) and 19 stations with a capacity of 1,058.63 kW (compared to 9 stations with a total capacity of 226.06 kW at the end of 2018), cumulatively, under virtual energy metering.

RES Technology	Installed Capacity in 2016 (MW)	Installed Capacity in 2017 (MW)	Installed Capacity in 2018 (MW)	Installed Capacity in 2019 (MW)	% change 2018-2019
Wind	2,371.60	2,624.60	2,860.49	3,607.40	26.11%
PV	2,229.70	2,229.90	2,269.60	2,417.77	6.53%
PV on roof (P > 10 kW)	374.30	374.80	375.04	375.21	0.05%
Hydro Small (P > 15 MW)	227.70	230.60	239.77	240.56	0.33%
Biomass - Biogas	58.70	61.50	83.15	87.89	5.70%
Hybrid RES	0.00	0.00	0.40	2.95	637.50%
CHP	230.10	228.10	228.67	233.37	2.06%
Total RES	5,262.00	5,521.40	5,828.05	6,728.83	15.46%
Total RES, Hybrid RES & CHP	5,492.10	5,749.50	6,057.12	6,965.15	14.99%

Table 31: Total RES installed capacity and percentage change (2016-2019)

In 2019, RES production in Greece amounted to 12,3 TWh in total, which was increased compared to 11,1 TWh in 2018, and represented a share of 22.3% of the total electricity consumption in the country.

	2014	2015	2016	2017	2018	2019
Biomass	206	222	253	280	298	367
Small Hydro <15 MW	661	707	722	586	718	688
PV on roofs <10 kW	520	494	512	511	489	494
PV	3,458	3,409	3,418	3,480	3,304	3,468
Wind	3,757	4,621	5,146	5,515	6,300	7,278
Hybrid RES	0	0	0	0	0,37	17
Total	8,602	9,453	10,051	10,374	11,110	12,312

Table 32: RES Generation excluding large hydroelectric plants (2014-2019) GWh

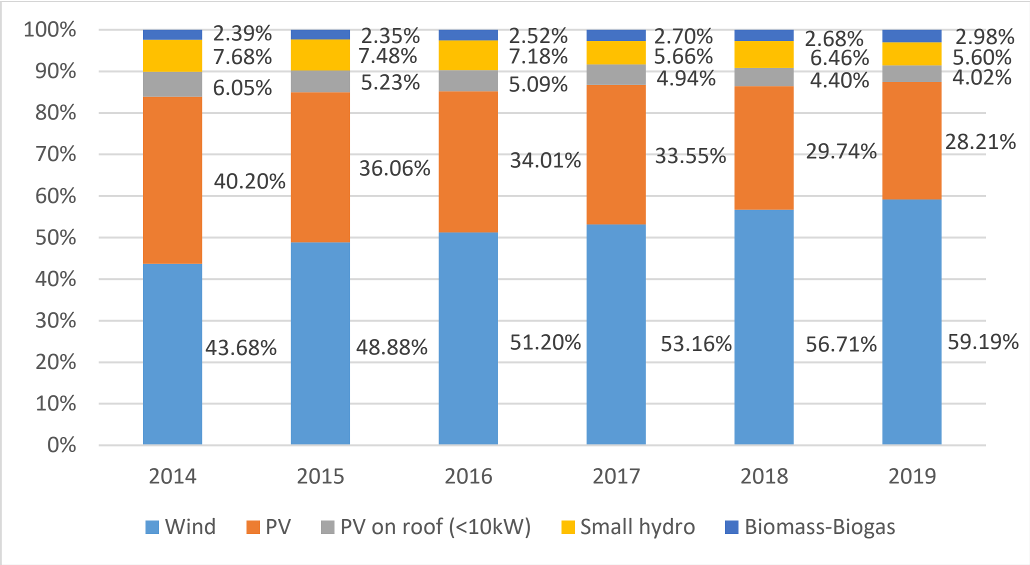


Figure 18: RES Generation percentage excluding large hydroelectric plants per technology (2014-2019)

3.5.2. RES and the electricity Market

In February 2019, RAE asked the Operators (ADMIE & DEDDIE) to inform the Authority about the pending applications for connection to the Network by RES producers in the region of Peloponnese and the Islands (Interconnected and non-Interconnected) considered as "saturated regions". Following the answer of the above operators, RAE submitted a proposal to a public consultation and based on the later's results proceeded to the issuance of Decision 663/2019. This Decision sets new limits on the safe RES power absorption in the saturated network of Peloponnese. Specifically, RAE decided:

1. The adjustment of the safe power absorption limits by the RES stations to 2,310 MW and their distribution based on the expressed investment interest as follows:
    a. 1,200 MW from wind turbines
    b. 900 MW from PV stations
    c. 100 MW from small hydro power stations
    d. 80 MW from biomass, biogas, geothermal, solar-thermal power plants and CHP plants
    e. 30 MW from RES stations operating under the provisions of article 60 (2) of Law 4546/2018
2. The possibility of new submission and evaluation of applications, submitted in December 2019 licensing cycle for obtainment of production license by small hydro, biomass, biogas, solar-thermal, geothermal power plants and the provision of connection offers to the above mentioned categories of plants by the competent operators until the thresholds under point 1 are met.
3. The examination and granting of binding connection terms, based on the time priority of the submitted requests, per technology, and within the limits mentioned under point 1.
4. The creation, by the competent operators, of a priority list, per RES technology, and the obligation of those operators to inform RAE every six months regarding the management of the applications, both in relation to the existing pending requests for the granting of a final connection offer but also for the new applications that will be submitted in accordance with the above thresholds.

5. Applications for a production license and / or for a connection offer, that will result in reserving capacity in the electricity network, for the development of RES installations that are part of special programs or are used by prosumers, are still considered outside the saturation decision.

3.5.3. RES projects' licensing

During 2019 there has been no amendments to the relevant legislative framework, although there are major changes planned for 2020 that will drastically simplify the licensing procedures. RAE issued a total of 642 administrative acts and sent 245 letters for supplementary data as part of the evaluation process. The total number of licenses and the number of RAE decisions per category in 2019 is presented in the tables below.

Type of Decision	**Number**
Decisions on Production License granting (accepted)	151
Decisions on Production License granting (denied)	52
Decisions on Production License modification / transfer	47
Decisions on Production License renewal for 25 years	3
Decisions on Production License extension	60
Administrative acts on Production License infringements	46
Decisions on Production License revocations	32
Decisions on modification of Production License Information	246
Decisions on modification requests	5
Total	642

Table 33: RAE's licensing activity in 2019

Technology	No of Granted Licenses	Installed Capacity (MW)
Wind	1,188	22,984.6
PV	566	2,914.1
Hydro (small)	376	863.8
Geothermal	1	8
Biomass	106	411.8
Solar	82	442.2
Hybrid	20	465.2
Co-generation (electricity & heat)	50	367.4
Total	2,389	27,624.5

Table 34: Projects with a license/permission of generation (operational & non-operational) approved by RAE, December 2019

Technology	2018				2019			
	Number of Applications for generation license		Decisions/ Permissions approved by RAE		Number of Applications for generation license		Decisions/ Permissions approved by RAE	
	No	Installed Capacity (MW)	No	Installed Capacity (MW)	No	Installed Capacity (MW)	No	Installed Capacity (MW)
Wind	294	2,621.6	55	776	283	3,249.9	123	1324
P/V	341	4,050.3	14	164	828	19,636.8	25	198.3
Hydro small	23	54.7	1	0.9	52	61.4	1	0.49
Biomass	5	15.3	12	55	6	19	1	1.7
Cogeneration electricity& heat	1	1.2	1	4	2	8	1	1.3
Hybrid	11	69.9	0	0	6	17.7	-	-
(Tele) heating	0	0	0	0	1	20	-	-
Total	675	6,813	83	999.9	1,178	23,012.8	151	1,525.79

Table 35: Number of RES applications and number of generation licenses (2018 - 2019)

Technology	No of Revoked Licenses	Installed Capacity (MW)
Wind	8	142.66
PV	2	6.74
Hydro (small)	21	26.72
Geothermal	0	0
Biomass	1	7.30
Solar	0	0
Hybrid	0	0
Co-generation (electricity & heat)	0	0
Total	32	183.4

Table 36: Revoked RES licenses per technology (2019)

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 is 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[21].

[21] 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[22]	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%

Table 37: Reference Tariffs of Law 4412/2016, Table 1 of Article 4.1(b)

[22] 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

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.

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.

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} ≤ 50 MW of installed capacity and 20 MW for projects with P_{wind} ≤ 60 kW
	COMMON COMPETITIVE PROCEDURES	500 MW
Total Maximum Capacity to be auctioned between 2019 - 2020		At least 1,950 MW

Table 38: Maximum auctioned capacity per RES technology

In 2019, five (5) RES auctions were held in Greece, the results of which are summarized in Table 39:

1st Cycle Auction, Technology Neutral, April 2019 - 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)
Technology Neutral	600	455.56	8	637.78	8	637.78	7	437.78	56	64.72	64.72	53	57.03
2nd Cycle Auction, Technology Specific, July 2019 - 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 $PV_{pv} \leq 20MW$	300	143.04	68	200.26	68	200.26	24	142.88	275	69.26	67.7	61.95	62.77
Wind stations $P_{wind} \leq 50$	300	186.96	12	261.75	12	261.75	9	179.55	37	69.18	69.18	59.09	67.31
3rd Cycle Auction, Technology Specific, December 2019 – 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 $PV_{pv} \leq 20MW$	287.11	105.46	44	148.64	43	147.65	27	105.09	130	66.02	65.99	53.82	59.98
Wind stations $P_{wind} \leq 50$	225.45	225.45	16	491	16	491	7	224.00	114	68.25	61.94	55.77	57.74

Table 39: Detailed results for all RES auctions held in 2019

The main conclusions of the RES Auctions in Greece can be summarized as follows:

- The whole process was innovative, simplified, transparent, valid and reliable.
- A specific online platform was established and adapted according to the decisions of RAE.
- Achievement of significant reduction in prices.
- The minimum level of competition (40%) led to a significant reduction of the prices.
- There were no problems understanding and using the applications during the users' training.
- The "virtual auctions" solved any questions about the procedure of the tenders.
- No mistakes in participants' registration process, procedure of application and suspension supporting documents in the online platform.
- The electronic submission of the applications → This made possible the immediate beginning of the evaluation of applications by RAE, by significantly reducing the time which would be required under any other conditions
- Approximately 100% of the auctioned Capacity was covered according to the tender procedure
- All selected candidates comply with the Rule of 4% for Performance Guarantees
- All the Projects connected to the grid according to the timetables of the tender.

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 market, (b) a revenue from the market clearing and settlement procedures of the day ahead 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 energy cost, (e) a revenue for CO2 emission rights and Levy on CO2 emission of conventional generation units also called special lignite fee.

However, the Suppliers Charge (ΠΧΕΦΕΛ) that was charged to Electricity Suppliers as well as the Special Lignite Production Fee charged to lignite electricity producers was abolished starting from January 1, 2019.

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. The new RES unit charges are available in the table below:[23]

[23] 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 40: New RES Levy Unit Charges (2019-2020)

In 2016, RES had appeared an estimated deficit of 238.48 million Euro (see Figure 19). However, on 22 December 2016, RAE adopted Decision 621/2017 with which a set of amendments to the methodology of the calculation of RES Levy were introduced. Specifically, RAE reallocated the cost of RES Levy financing among the different categories of consumers (HV, MV, LV). This reallocation resulted in a RES' account surplus of 42.49 million Euro by the end of 2017, a surplus of 191.24 million Euro at the end of 2018 and a surplus of 89.99 million Euro at the end of 2019.

	2018	2019[24]
Total Revenue (in million euros)	2,020.61	1,772.79
Day Ahead Market	583.51	554.49
Market Clearing and Settlements	8.08	42.82
Average Variable Cost of Generation	54.91	78.16
Average Variable cost of generation (NIIs)	141.61	136.29
RES Levy (ETMEAR)	631.09	670.13
Energy Charge (Suppliers)	237.93	-
Special Lignite Fee	29.81	-
CO2 emission Rights	328.34	284.36
Other (licenses fee)	-	-
Total Expenditure (in million euros)	-1,871.87	-1,726.80
Account Balance (end of year)	148.75	45.99

Table 41: RES' Financing Account (2017-2019)

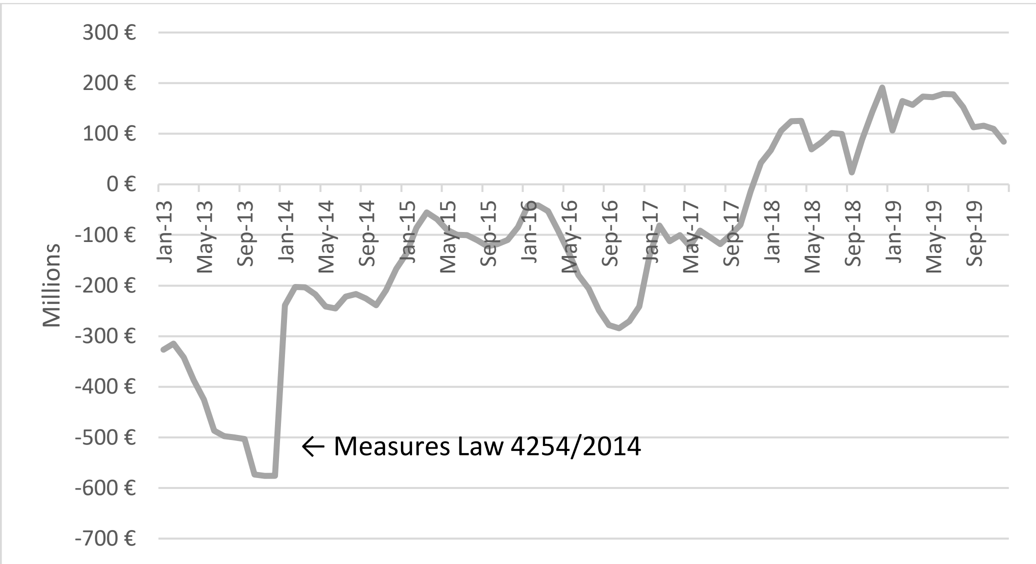


Figure 19: Special Account's Progress

The Methodology for calculating the Suppliers Charge (ΠΧΕΦΕΛ), as determined by RAE Decision 334/2016, aimed at effectively tackling a structural weakness of the market, meaning that the way of RES/CHP participation in the Day-Ahead Scheduling (DAS) leads to the formation of an SMP which is artificially lower than the price that would have emerged if RES did not participate in the DAS.

[24] The analysis for 2019 cover the months from January to October since the data for the months of November and December have not been published by the Operator of RES and Guarantees of Origin (DAPEEP) at the time this report was drafted

However, RAE observed that the amount of the Suppliers Charge (ΠΧΕΦΕΛ) debit was specifically formed in the first half of January 2017 at particularly high levels, mainly due to the increased levels of load requirements. For this reason, RAE with the Decision 31/20.1.2017 introduced, for a transitional and restricted time period, a maximum threshold on the the Suppliers Charge (ΠΧΕΦΕΛ). According to the provisions of the article 4 of Law 4585/2018 the Suppliers Charge (ΠΧΕΦΕΛ) that was charged to Electricity Suppliers and the Special Lignite Fee were abolished since 1st of January 2019.

3.5.6. New RES Legislation and Regulatory Development

In 2019, RAE and the Ministry of Energy cooperated closely by publishing Decisions and Opinions necessary for the successful implementation of RES auctions in 2019 and 2020.

Ministerial Decisions

- For the technology and the categories of RES and CHP production units to be included through the RES auctions in the Operating Aid regime through the RES auctions, RAE issued its Opinion on 10 January 2019 Opinion 1/2019 to the Ministry of Energy. More details about the categories of RES and CHP installations which were included in the above-mentioned regime can be found in the relevant Decision of the Ministry of Energy (**ΥΠΕΝ/ΔΑΠΕΕΚ/18135/511 (Gazette B’ 779/06.03.2019**).
- The Ministry of Energy published **Decision ΥΠΕΝ/ΔΑΠΕΕΚ/25511/882** (Gazette B’ 1021/27.03.2019) concerning the reference tariffs which determine the monthly Operating Aid granted to wind farm installations as a form of a premium or a fixed tariff.
- The Ministry of Energy published **Decision ΥΠΕΝ/ΔΑΠΕΕΚ/34495/1107** (Gazette B’ 1341/12.04.2019) which sets the maximum auctioned capacity per RES and HECHP technology, the minimum number of RES auctions 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 that in the first half of 2020 at least one common competitive procedure (PV & Wind) shall be executed. In addition, one auction shall be held for PV technology, one for the wind technology and one procedure shall be held for PV and Wind projects in a specific area.
- Furthermore, it should be noted that following the submission of RAE Opinion 15/2018, the **Ministerial Decision 15084/382** (Gazette 759 B’ 05.03.2019) was issued, concerning the revision of the operating framework of prosumers and energy communities regarding normal net-metering and virtual net-metering according to article 14A of law 3468/2006 and article 11 of law 4513/2018 respectively.

RAE's Opinions

- RAE issued **Opinion 1/2019** on 10 January 2020, on the amendment of Ministerial Decision ΑΠΕΕΚ/Α/Φ1/οικ.184573. Based on the above Opinion, it was deemed appropriate, in order to strengthen the competition and reduce the operating aid received by PV installations, for the benefit of consumers, to merge the two separate Categories of PV technologies (PV facilities $P_{pv} \leq 1$ MW and PV facilities 1 MW $< P_{pv} \leq 20$ MW) into one single Category of $P_{pv} \leq 20$ in the next RES competitive bidding procedure. The two categories were merged in March 2019 with Ministerial Decision ΥΠΕΝ/ΔΑΠΕΕΚ/18135/511 (Gazette B '779 / 06.03.2019).
- RAE issued **Opinion 2/2019** on 10 January 2020, regarding the amendment of Ministerial Decision Υ.Α.Π.Ε./Φ1/ οικ.2262. Specifically, the rationale for the above opinion was that the reference tariffs for the PV installations with an installed capacity of less than 500 kW, which do not participate in competitive bidding procedures and commenced their operations from January 2016 are compensated using the formula of Article 27A of Law 3734/2009, ie $1.2*SMP_{n-1}$ for PVs with installed capacity $P_{pv} < 100$ kW and $1.1*SMP_{n-1}$ for PVs with installed capacity $P_{pv} \geq 100$ kW. Given the above, it was deemed appropriate, especially for PV plants with installed capacity of $P_{pv} \geq 100$ kW, to link the calculation of the reference tariff for the compensation of those units with the weighted average price of the previous technology specific competitive auction related to the PV technology (ie $1.1*WART_{n-1}$, where $WART_{n-1}$ is the weighted average reference tariff value resulting from the last technology specific competitive bidding process for PV installations with $P \leq 20$ MW, which was carried out before the operational state of the unit, according to the provisions of article 7 of Law No. 4414/2016.
- RAE published **Opinion 4/2019** on 24 January 2019 concerning the reference tariff re-evaluation of wind units. The total weighted average decrease of reference tariffs in comparison with the starting price of the competitive procedure of July 2018 was 35%. In addition, in order for the competitive procedure to take place based on the proposed single PV category (units with an installed capacity $P_{pv}<20$ MW), it was necessary to set a starting celling price for bids submission for the new category. The starting price was set at 71.91 €/MW which was the lowest of the two celling prices of the two auctions, 74.18 €/MW for Category II and 71.91 €/MW for Category II. Based on RAE's Opinion, the Ministry issued Decision ΥΠΕΝ / ΔΑΠΕΕΚ / 25511/882 Υ.Α. (Gazette B '/ 27.03.2019) setting new tariffs for the wind farms which ranged from 65 €/MWh to 82 €/MWh.
- The auctioned RES capacity for each year is set to strict limits which are available at Table 38. RAE with **Opinion 14/2019** suggested to the Minister of Energy the increase of the auctioned capacity for 2020, and a possibility of transferring 1/3 of the total auctioned capacity of the year 2020 to 2019, in which case, respecting the rule of minimum competition level of 40%, the auctioned capacity for 2019 would increase to 350.71 MW, allowing additional 125 MW to be awarded to Category II (Wind Farms). This formula was successfully implemented in 2018 as a result of which more capacity was awarded to the wind farms that participated in competitive tenders in that year. However, Opinion 14/2019 was not endorsed by the Ministry of Energy, with the auctioned capacity to remain at 225.45 MW for 2019.

Primary Legislation

According to **Law 4602/2019**, new reference tariffs were introduced for PV installations as more categories were added. Participants with more than two (2) units of the same RES technology should enter the RES auctions for any incremental project regardless of its capacity.

Law 4643/2019 (Gazette 193 A') supplemented the RES operating framework established by Law 4414/2016, enabling RES Units to participate directly in the wholesale electricity market and to be remunerated by its mechanisms. In addition, following relevant proposals submitted by RAE, the framework for granting of individual operating aid to RES units with a total capacity of more than 250 MW was determined in accordance with the provisions of the "Guidelines for State Aid for environmental protection and energy (2014-2020)" of the European Commission. Furthermore, the regime of installation of PV power plants in agricultural land of high productivity was clarified, essentially enabling the development of PV power plants up to 1 MW but without exceeding 1% of the total cultivated area of each Regional Unit. Finally, in agreement with the new Renewable Energy Directive 2018/2001 and Regulation 2019/943 the RES and CHP power plants with installed capacity of more than 400 kW that operate under the Feed-in-Tariff regime beginning their operation as of 4 July 2019 become responsible for any imbalances they cause in the electricity system, effectively taking up balancing responsibilities starting from 01.01.2020, while this threshold is reduced to 200 kW for those units that begin commissioning or commercial operation from 01.01.2026.

3.5.7. Other developments in the RES sector

RES installations in Crete

For Crete, Decision 96/2007 on the saturation of the island's network is in place. However, taking into account (a) the large increase of electricity demand in the island in recent years combined with the emission restrictions of MCPD and IED Directives that interfere with the proper operation of its thermal units and (b) the planed interconnection of Crete (initially with the Peloponnese and then with Attica) that will gradually remove the electricity isolation of the island, RAE requested the submission of a proposal by the competent operators on the establishment of additional RES projects, as well as energy storage that can be gradually installed on the island. The operators responded by submitting their proposal, and RAE assesses possible regulatory measures for the optimal allocation of the available capacity.

The first aggregators in Greece

Since the issuance of RAE Decision 640/2018, fourteen (14) applications of aggregators were submitted to RAE. The provisions of Article 134 of Law 4001/2011, the Electricity Supply Code and Electricity Trading Code applied until the issuance of a Regulation of Representation licensing for the participants in the electricity market, according to the process of licensing, modification and revocation of licenses for the exercise of the activity of representing electricity producers in the market. In 2019, RAE issued eight 8 decisions granting an equal number of licenses to the first aggregators, while one application for granting a representation license was rejected.

Renewable Energy Storage Study

RAE, with Decision 1002/2019, assigned a study to an external consultant which concerned the assessment of future needs for energy storage infrastructure in the Greek interconnected system to achieve higher RES penetration. The study determines the appropriate size of storage systems, such as hydro pumped storage and accumulators, as well as the distribution of the necessary power and storage energy between these two technologies, so that the electricity system achieves the maximum possible benefit from the storage systems. The analysis of this study is based on the simulation of the operation of the interconnected system in the year 2030 with the focus on the de-lignification of the electricity generation and the general dependence level on fossil fuels. The study was completed in December 2019.

3.6. Consumer Protection

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 42 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	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.

tariffs and on standard terms and conditions in respect of access to and use of electricity services.		
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 of supplier, no later than six months after the change of supplier has taken place.	j)	Energy Suppliers are obliged to issue a final closure account, within 6 weeks after the contract termination/change of supplier.
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 42: 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. 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 B́ 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.

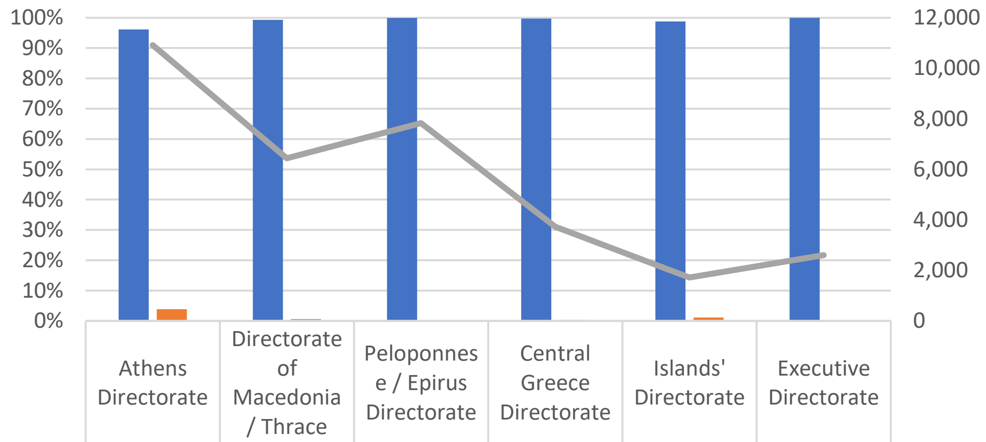
This tool is designed to reflect and compare as fully as possible, on the basis of the principles of transparency, accessibility, completeness of information and independence, the overall estimated cost of the Competitive part of the offers, while also calculating the corresponding cost of the regulated 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. RAE has also undertaken actions to further enhance the functionalities of the tool. Indicatively, the following actions will be completed by 2020: a) new capabilities such as quantifying and implementing different types of discounts, creating additional choices for the consumers, and b) inclusion of more LV consumers' categories to its user database. The PCT is expected to be available to the general public in 2020.

3.6.4. Quality of DSO Services

According to the data supplied by DEDDIE concerning requests and complaints for Guaranteed Services,[25] it is evident that the response of the later was generally satisfying. Athens Directorate lags compared to other Directorates. However, this lagging is reasonable due to the great number of customers in the region of Attica. The good progress of DEDDIE’s performance in the Directorate of Islands is considered as important despite the geographical difficulties in that area.

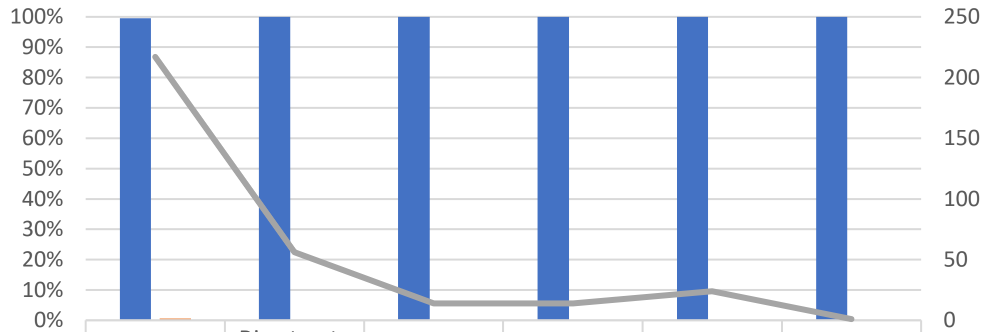


	Athens Directorate	Directorate of Macedonia / Thrace	Peloponnese / Epirus Directorate	Central Greece Directorate	Islands' Directorate	Executive Directorate
In-time	96.14%	99.36%	99.95%	99.70%	98.84%	100.00%
Delayed	3.86%	0.64%	0.05%	0.30%	1.16%	0.00%
Total	10,919	6,434	7,831	3,728	1,719	2,608

Figure 20: Response to Guaranteed Consumer Services by DEDDIE (2019)

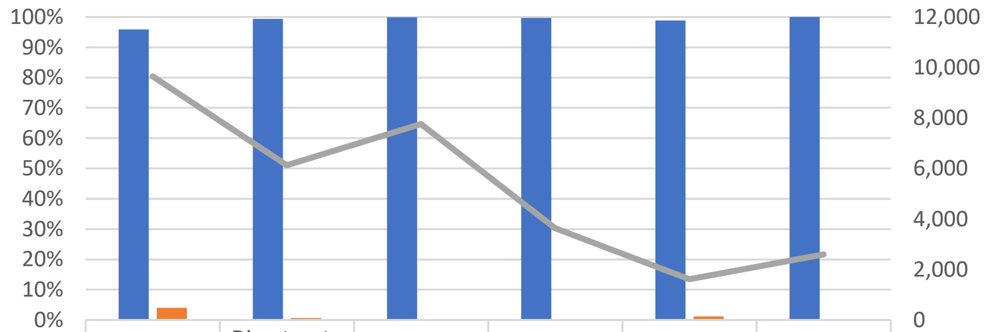
In particular, the results per category of the Guaranteed Services for 2019 is depicted in the Figures below:

[25] More information on the Guaranteed Consumer Services provided by the electricity DSO (DEDDIE) can be obtained from the website https://www.deddie.gr/en/eggyimenes-ypirisies-katanaloton/



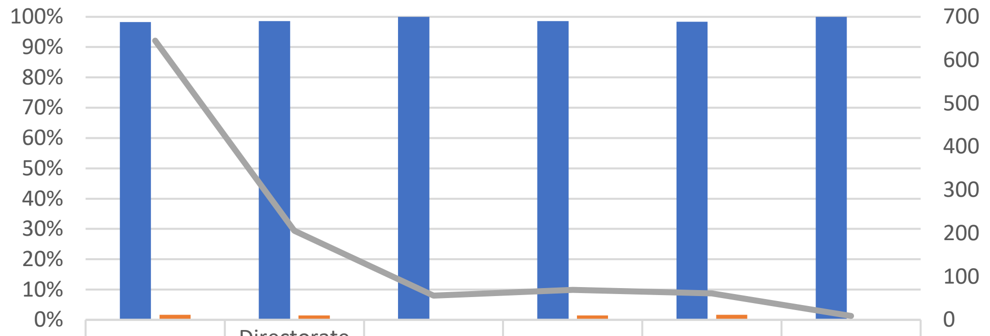
	Athens Directorate	Directorate of Macedonia / Thrace	Peloponnese / Epirus Directorate	Central Greece Directorate	Islands' Directorate	Executive Directorate
In-time	99.54%	100.00%	100.00%	100.00%	100.00%	100.00%
Delayed	0.46%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	217	56	14	14	24	1

Figure 21: Response to complaints concerning voltage quality by DEDDIE (2019)



	Athens Directorate	Directorate of Macedonia / Thrace	Peloponnese / Epirus Directorate	Central Greece Directorate	Islands' Directorate	Executive Directorate
In-time	95.93%	99.38%	99.95%	99.73%	98.84%	100.00%
Delayed	4.07%	0.62%	0.05%	0.27%	1.16%	0.00%
Total	9,648	6,134	7,757	3,635	1,615	2,598

Figure 22: Response to complaints or requests without the need for an on-spot transition by DEDDIE (2019)



	Athens Directorate	Directorate of Macedonia / Thrace	Peloponnese / Epirus Directorate	Central Greece Directorate	Islands' Directorate	Executive Directorate
In-time	98.29%	98.57%	100.00%	98.55%	98.36%	100.00%
Delayed	1.71%	1.46%	0.00%	1.45%	1.64%	0.00%
Total	645	206	56	69	61	9

Figure 23: Response to a request with the need for an on-the-spot transition by DEDDIE (2019)

3.6.5. Vulnerable customers and Energy poverty

In 2019, RAE focused on the protection of vulnerable customers looking in particular at issues like the transparency of utility bills, charges and terms of supply. In addition, a great part 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.

In 2018, a ministerial decision (Gazette B '242 / 01.02.2018) amended the categories of the beneficiaries of the Social Tariff (KOT), the criteria for its application and the discount granted. Following the above ministerial decision has been a priority for amending the methodology for the calculation of the remuneration of the suppliers for providing the Social Tariff. The final decision concerning the new methodology is expected to be issued in 2020.

	Residential Social Tariff 2011 - 2019		Economic crisis Program[26]	
Year	Number of customers	Total Energy (TWh)	Number of customers	Total Energy (kWh)
2011	247,666	548		
2012	250,568	404		
2013	412,883	1,582		
2014	522,760	1,251		
2015	656,834	1,315	70,002	232,886,076
2016	578,311	1,549	46,562	244,020,079
2017	693,487	1,651	NA	NA
2018	471,706	0,999	NA	NA
2019	483,710	1,801	NA	NA

Table 43: Number of customers and total consumption - Residential Social tariff 2011 – 2019

RAE, aiming at tackling energy poverty, actively participated 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, together with National Technical University of Athens.

In addition, RAE participated 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

Consumers can submit enquiries and complaints to RAE in writing through a personal visit to RAE office, by email to info@rae.gr, by 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.

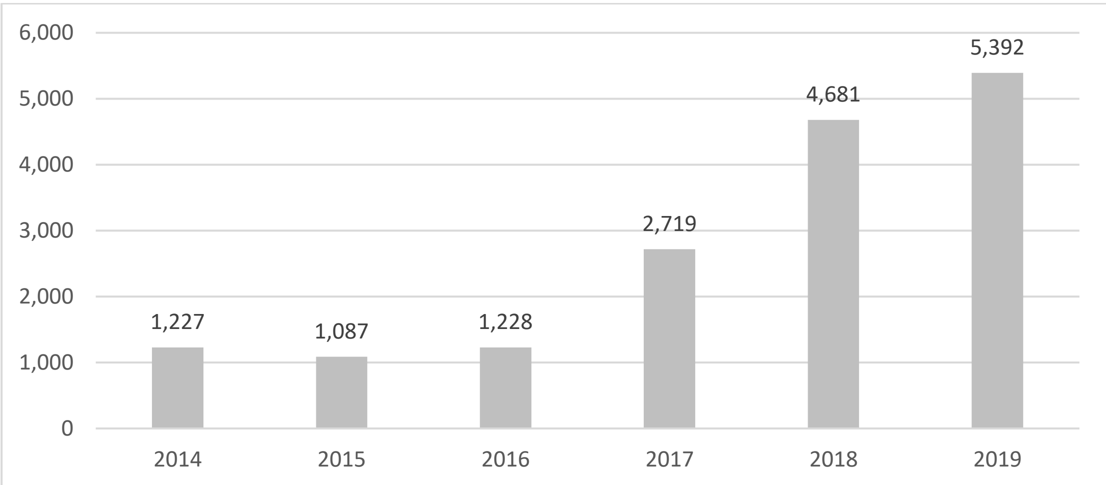


Figure 24: Consumer Complaints submitted to RAE (2014-2019)

[26] The Economic Crisis Program expired in 2016

The total number of consumer complaints submitted to RAE in 2019 amounted to 5,392, and hence it was significantly increased (by approximately 15.2%) compared to 2018 (4,681 reports), reaching the highest level of the last decade. The activation of many alternative electricity suppliers, but also the increased recognition of the role of RAE; were the main factors that have contributed to this phenomenon in the general public.

A great number of complaints submitted to RAE concerned the difficulty to understand the competitive charges of electricity tariffs, the methodology applied on them and the discrepancies of actual electricity charges compared to those included in the contract. Likewise, there were complaints concerning the ambiguity in some advertisements and marketing strategies of some suppliers which made it difficult for consumers to compare all offers.

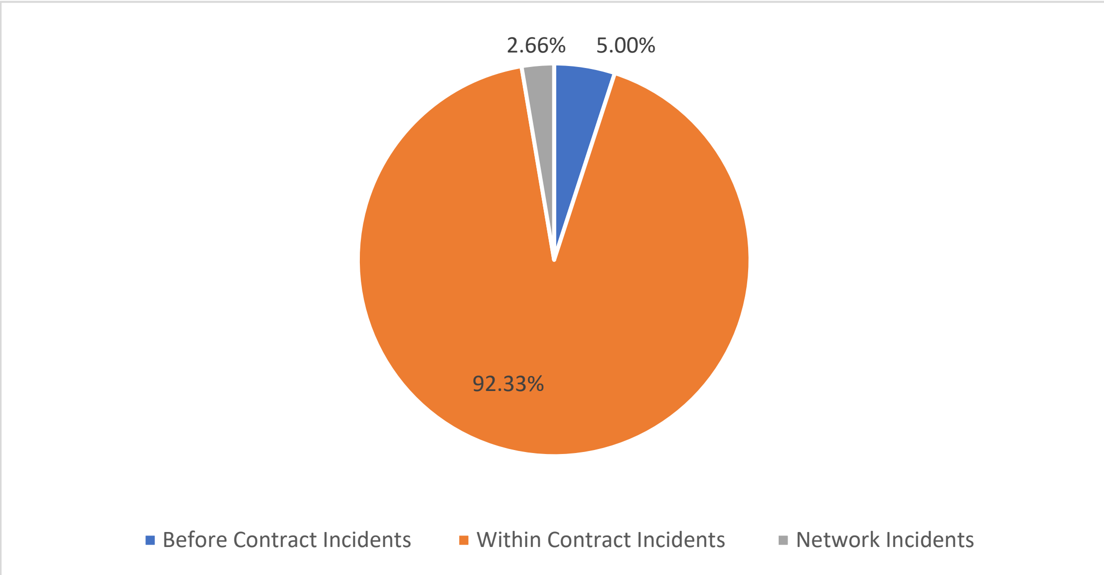


Figure 25: Percentage of total electricity and gas complains per category of complaints

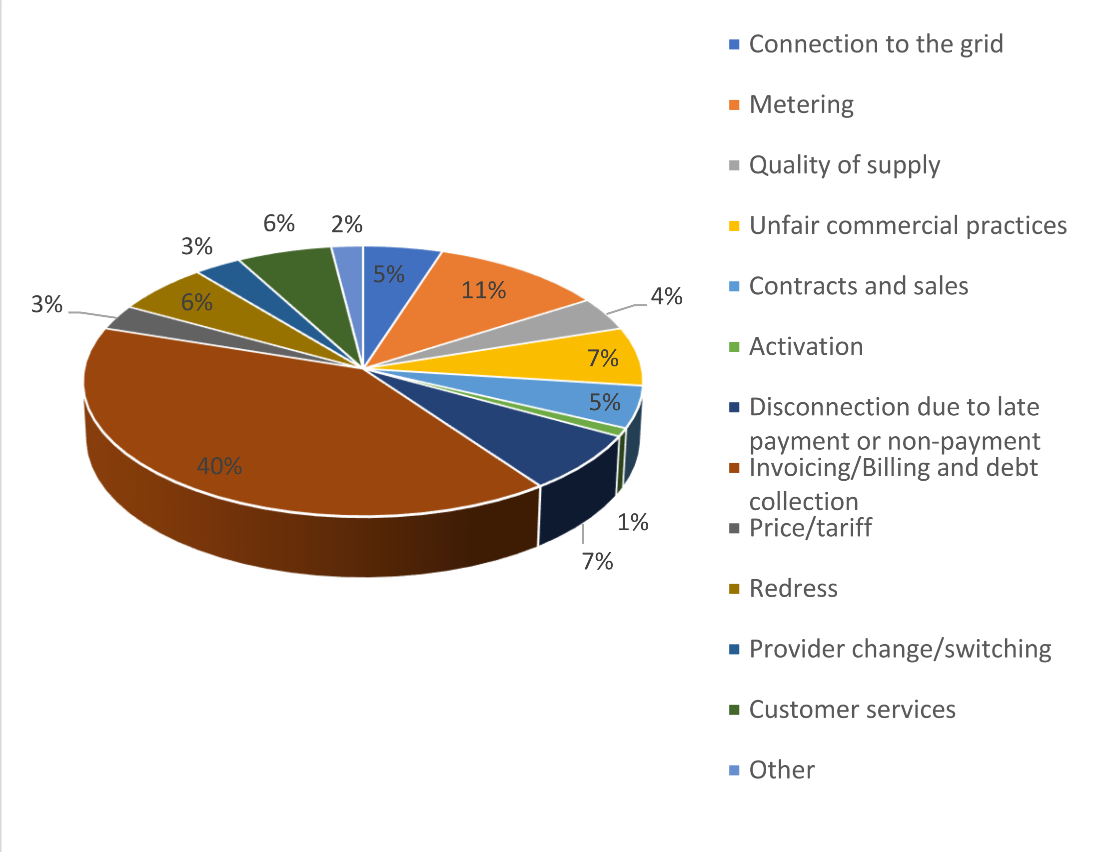


Figure 26: Total Number of consumers' complaints (Electricity 2019)

In 2019, the majority of them concerned disputes and clarifications over electricity tariffs for the conventional period. The dominant supplier had most of the complaints (56.19%). On the contrary, the market share of alternative suppliers is not proportional to the amount of complaints received.

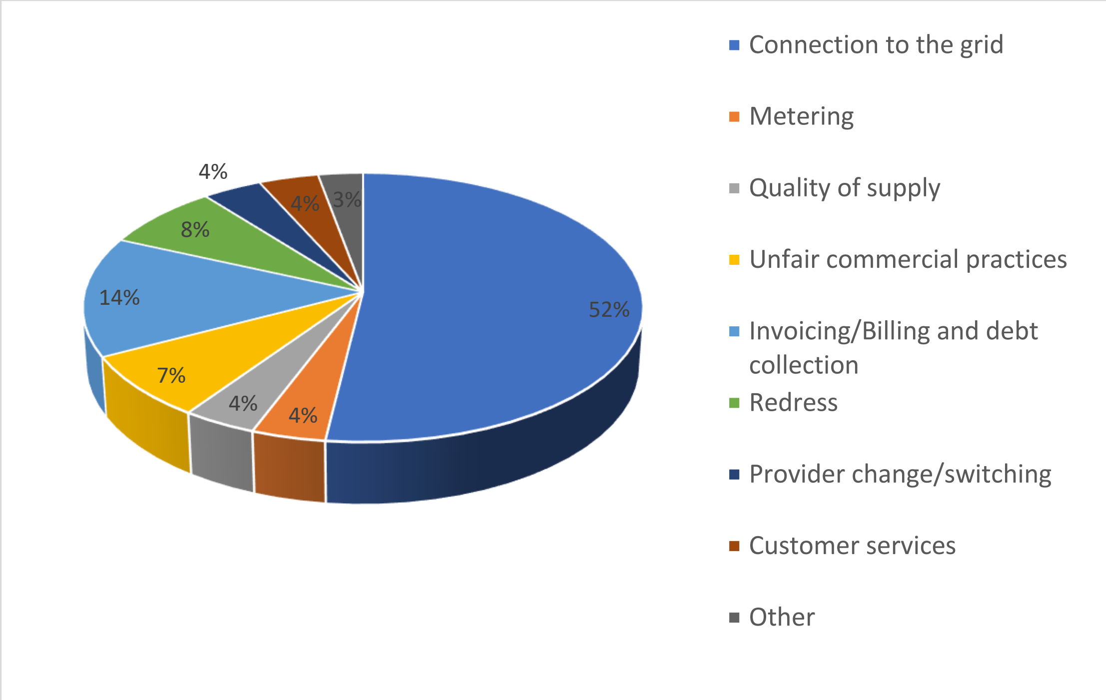


Figure 27: Total Number of consumers' complaints (Gas 2019)

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 28 represents the results of the Weighted Complaint Index (WCI) per Supplier for 2019.

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

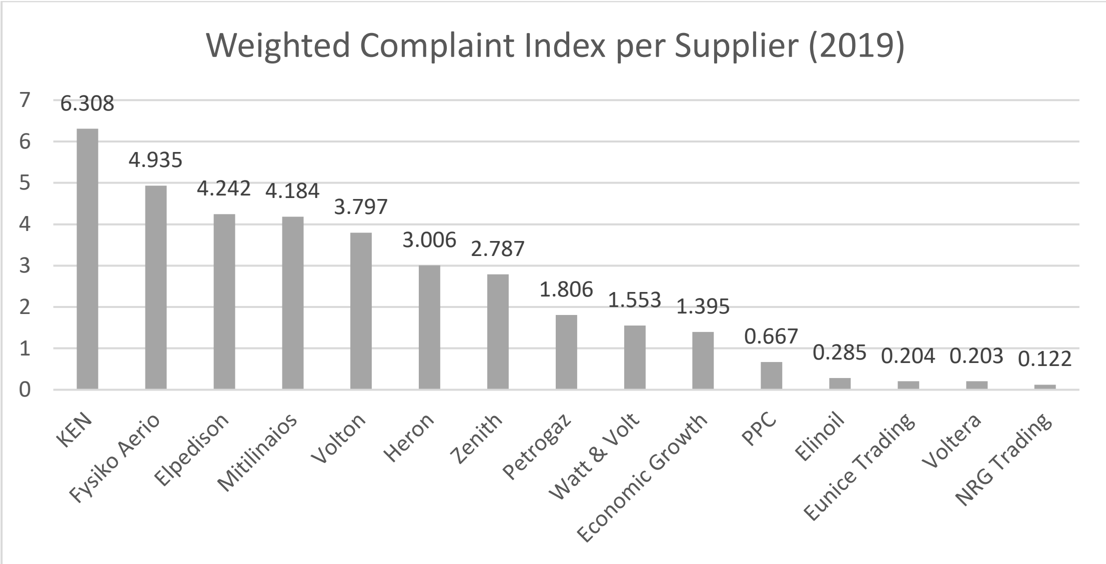


Figure 28: Weighted Complaint Index per Supplier (2019)

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

- **RAE Proposal on the reform of the Services of General Interest for the nighttime consumption**

The legislative framework concerning the "PSO Tariff" for nighttime electricity consumption changed from 1 January 2018 (Gazette A 200/22.12.2017), both in terms of the unit charges and the method of calculating these charges. In particular, the new calculation method provided for tiered charges depending on the energy consumed in each tier. The introduction of tiered charges in the "Services of general interest" is compatible with the Directive 2012/27/EU on Energy Efficiency, and Law 4342/2015 which transposed the above Directive into national law, as they are a clear incentive for energy savings and energy efficiency.

RAE, following the implementation of the above charging system, received many complaints from both consumers and various consumer organizations about the "PSO" excessive nighttime charges since most of the consumers fell into the two largest billing tiers.

After taking into account the status of the "PSO" account, as well as the income recovered from the nighttime consumption, it provided an Opinion to the Minister of Energy (Opinion 16/2018 on "Reforming the framework of Services of general interest for the nighttime consumption"), for the reduction of the "Services of general interest" charges for the nighttime consumption in order to rationalize the charges on the households. Furthermore, RAE advised for the above charges to have a retroactive effect from 1.11.2018 in order to cover the 2018-2019 winter season. RAE's proposal was incorporated in the national legislation in 2019 (Gazette 193/a/3-12-2019).

- **Consumer abusive behavior**

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.

- **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, to the Minister of Energy, the importance of drafting the relevant legislative framework also for the natural gas market.

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.

- **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.

- **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 reports 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.

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 shall 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 also 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 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.

Furthermore, RAE called the incumbent company to include detailed data and methodology for the calculation of the "CO_2 debt 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.[27] The general framework for the application of the above clause will be further explored by RAE in 2020.

In addition to the contents of the relevant Opinion to the Minister of Energy (RAE Opinion No 2/2019), the following are highlighted:

Concerning the protection of vulnerable consumers, RAE considers that due to the importance of providing electricity for the physical, mental, moral and social situation of the consumer, the measure of disconnection even in the event of a legal default, must be exercised within the limits imposed by good faith and the economic and social purpose of the right to access electricity. Specifically for vulnerable consumers, given their financial and health situation, this measure should be an extreme form of recovery and should be applied after failure to pay debts settled for the usual 4-month consumption taking into account the consumer's current financial situation, as well as the absolute need for electricity to achieve the condition of necessary living if such is applicable. Since a large number of vulnerable consumers appear to be unable to meet even the favorable arrangements under Art. 34 of the relevant Electricity Supply Code, the following three interventions: (a) relevant provisions concerning the maximum amount of the monthly installment which must be at the level of 40% of the respective monthly charge of the vulnerable customer's electricity as well as the non-prepayment requirement for the debt settlement procedure, (b) for vulnerable consumers in need of mechanical support, it is proposed to prohibit the application of a disconnection due to consumer's debts, with the Universal Service Provider taking care of their electricity, (c) due to the need for proportional treatment of natural gas vulnerable customers with the consumers of electricity, taking into account the fact that natural gas is an increasingly necessary alternative energy source for the daily living of many users, the

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

above proposals and recommendations are extended to the Natural Gas Supply Code to customers. RAE will hold a public consultation of these proposals in 2020 for all interested parties to submit their views on the Framework for Consumer Protection and finalize the content of the above-mentioned opinion to the Ministry.

Following a significant number of reports from both consumers and suppliers, regarding incorrect consumption metering measurements both in terms of switching suppliers and normal measurements, the Authority decided that it would be appropriate to amend the content details of consumption meter declarations and the specific control over legal documents will be subject to the competent operator. At the same time, following RAE's investigation in 2018 concerning abusive consumer behavior during the process of switching of supplier, it proceeded with the preparation of a specific methodology which must be followed by the DSO after a "switching supplier " request by the consumer, in order to ensure the full implementation of the regulatory framework specified in Article 42 of the Electricity Supply Code. The above decisions will be finalized after the completion of the relevant public consultation on the Consumption Declaration Manual in the first half of 2020.

4. Regulation and Performance of the Natural Gas Market

4.1. Network Regulation

4.1.1 Unbundling

A) TSO Unbundling

At the beginning of 2019, DESFA[28] submitted to RAE a request for the revision of Decision 1220/2018 on specific terms set by the regulator to facilitate the monitoring of DESFA's continued compliance with the ownership unbundling model. Following DESFA's request, RAE issued Decision 460/2019 in April 2019 amending Decision 1220/2018. The main amendments concerned the monitoring mechanism of DESFA's compliance with the ownership unbundling model, the sharing of sensitive information, DESFA's obligation to submit to RAE a Development Program based on Law 4001/2011 and its obligations on the security of supply of the country. In addition, a new condition was added whereby DESFA must report to RAE every six months on the development of its non-regulated activities. If the provision of such services is intended for a company-shareholder of DESFA with its shares exceeding the 5% of the total share capital, then the approval of the regulator is required.

Furthermore, in August 2019, DESFA informed RAE about a change in its shareholding. Damco S.A. expressed an interest to obtain shares equal to 10% of the share capital of Senfluga S.A. without any voting rights. RAE assessed the above request and informed the European Commission about this development. The Commission expressed the view that Damco S.A. could enter as a passive shareholder of Senfluga S.A. without acquiring any direct or indirect control of any other rights. Furthermore, the Commission indicated that it fully agrees with RAE's thorough analysis and with the necessity to prevent any disclosure of commercially sensitive information.

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[28] DESFA S.A. is the owner and operator of the national network gas system (NNGS), which is comprised of the main high-pressure pipeline and its branches, as well as the LNG Terminal at Revithoussa island, and is a certified ITO under the unbundling rules of the Third Energy Package. DESFA S.A. has exclusive rights for the operation, maintenance, development and exploitation of the NNGS and is currently the only gas transmission system operator in the country. In 2018, according to the provisions of paragraph 4 of article 64 of Law 4001/2011, DESFA SA announced to RAE the sale of 66% of its share capital in the joint venture of Snam S.p.A, Enagas Internacional S.L.U. και Fluxys S.A. In fact, in July 2018 DESFA S.A. applied to RAE for a new certification this time under the model of Ownership Unbundling. Following the assessment of DESFA's application, RAE issued its first certification Decision 767/2018 with which DESFA S.A. was preliminarily certified under the model of ownership unbundling as it is defined in Law 4001/2011 ensuring de jure and de facto compliance with the requirements of Article 9 and 10 of Directive 2009/73 and Article 62 of Law 4001/2011. Subsequently, the Authority, taking due account of the opinion of the European Commission and following a thorough analysis, with its final Decision 1220/2018 (Gazette B '5740 / 19.12.2018) certified DESFA S.A. under the model of ownership unbundling. The Decision established the compliance framework of DESFA S.A. and it specifically included that any breach of national or EU law or the conditions set under the Ownership Unbundling model would dead to a revision of the certification decision. In December 2018, 66% of DESFA's shares were transferred to Senfluga S.A., with the Government of Greece holding the remaining 34% of its shares.

Based on the above, RAE with Decision 1100/2019 approved the intended acquisition by Damco S.A.of 10% of the share capital in Sanfluga S.A..

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,[29] 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 competencies RAE may issue instructions and guidance on matters related to the certification process in order to ensure the proper and uniform application of the regulatory framework and to provide full information to the stakeholders. RAE, by its decision, is responsible to define the specific documents and data that have to accompany the application of the DSO for its certification.

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.

[29] 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.

4.1.2 Technical functioning

The National Natural Gas System (NNGS) transports Natural Gas to consumers connected to the NNGS in the Greek mainland from the Greek-Bulgarian borders, the Greek-Turkish borders and the Liquefied Natural Gas (LNG) terminal, which is installed at Revithoussa island at Megara (Athens/Attica region). More specific, there are three entry points into the national gas system:

Interconnection Point	Imports (MWh)	Exports (MWh)	Active Transmission Users	Technical transmission capacity (MWh/day)
Sidirokastro (Greece Bulgaria border)	18,144,167	15,121	12	121,600
Kipi (Greece - Turkey border)	8,110,788	0	2	49,000
Agia Triada (Greece - Revithoussa LNG)	31,495,459	0	7	150,000
Total	**57,750,414**	**15,121**	**21**	**320,000**

Table 44: Natural gas import and export deliveries to the interconnection points, Active Transmission Users and technical transmission capacity per Interconnection Point in 2019

LNG Origin:	2016	2017	2018	2019	(%) 2019
Algeria	671,677	1,185,933	796,266	513,098	19%
Norway	77,975	50,313	0	514,449	19%
Egypt	0	0	0	244,241	9%
Nigeria	0	0	0	409,093	15%
Trinidad	0	0	0	24,319	1%
Qatar	0	158,858	79,963	483,373	18%
USA	0	0	95,883	217,837	8%
France	0	0	0	85,640	3%
Netherlands	0	0	0	78,975	3%
Angola	0	0	0	85,471	3%
Total:	**749,652**	**1,395,104**	**972,112**	**2,656,497**	**100%**

Table 45: LNG imports by Greece at Revithousa LNG terminal in Million Cubic Meters (2016-2019)

According to the provisions regarding gas balancing services, as set in the relevant Greek legislation, DESFA prepares and submits every year for approval to RAE an annual balancing plan. The balancing 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 balancing contracts for the next year. To this effect, DESFA can either procure balancing gas through the balancing platform, directly from the long-term LNG contract of the incumbent (in line with an interim – transitional – provision of the Greek Energy Law), or procure balancing gas through a market-based approach, in the form of an international tender procedure (in line with the basic provisions of the Energy Law).

In this context, with Decision 1130/2019 (Gazette B’ 4819/2019), RAE approved the annual balancing plan submitted by DESFA for 2019, which included the TSO’s estimated balancing needs as well as an evaluation of possible balancing gas supply sources for 2020. According to this plan, the TSO proposed to acquire balancing gas (in the form of LNG) through an international tender procedure, according to the main provisions of the Greek Energy Law. Furthermore, RAE with the same Decision, approved the monthly capacity reserved by the TSO for balancing services. For 2020, TSO estimated that the balancing natural gas needs will amount to 2% of the total estimated gas consumption (1,258,883 MWh). All costs arising from the provision of balancing services are recovered by the TSO through the system tariffs, so that the TSO is cash neutral.

RAE is also responsible for approving the balancing costs and the methodology for allocating these costs to the Transmission System users. With Decision 1093/2019, RAE approved the balancing cost allocation scheme and the relevant shippers’ charges, which include all costs arising from the provision of balancing services for 2019. 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.

Regarding the application of the European Network Code on Balancing 312/2014 (BAL NC), at the end of the first quarter of 2015 DESFA submitted to RAE an interim measures report per the provisions of Chapter X of the above Network Code, as the absence of sufficient liquidity in the Greek natural gas market was not conducive to the full application of the provisions of the Balancing Network Code in 2015. RAE evaluated the interim measures report per the provisions of articles 46 and 27 of the BAL NC and approved it with Decision 274/2015. The proposed interim measures included the continuation of the existing balancing scheme, the creation of a balancing platform per article 47 of the BAL NC and further proposals in the regulatory framework with the purpose of alignment with the BAL NC. The interim measures were in force for a duration of 5 years after their approval, which expired on 15 April 2019 when the BAL NC entered into full force.

According to BAL NC, the interim measure relating to the operation of a Balancing Platform may be maintained for a additional period which may not exceed five years, upon the approval of the relevant NRA. In this context, DESFA submitted a relevant recommendation to RAE for the approval of the 2nd Interim Measures Report taking into account the comments of the public consultation held by the company during the period from 17 December 2018 to 18 January 2019, as set in Article 46 (2) of the BAL NC.

Prior to the adoption of Decision 774/2019, RAE followed the procedure provided for in the BAL NC, consulting EWRC on the 2nd Interim Measures Report for which it received a favorable opinion. RAE communicated its Decision to the European Commission and ACER.

Moreover, throughout 2019, RAE participated actively in the planning and implementation of the new gas markets and monitored the progress on the HENEX report which was completed in 2019. According to this report, there is a strong interest in the creation of a gas trading system in Greece by the existing gas market participants and potential participants, taking into account the positive prospects for the development of a competitive natural gas market. In the light of the above, the cooperation between RAE and HENEX is expected to get closer, especially on the organization of the natural gas market with a goal to launch the trading platform at the beginning of 2021.

Moreover, on 31 January 2018, RAE issued Decision 123/2018 with which it approved the 4th amendment of the National Natural Gas System Administration Code (Gazette B’ 788/7.3.2018). The 5th revision of the National Natural Gas System Administration Code focuses on congestion management tools until the completion of the technical upgrade of the System. DESFA's proposal for the 5th revision of the Code was submitted to RAE in October 2019, and was set for a public consultation between December 2019 and February 2020.

The main points of DESFA's proposal were as follows:

- Allocation of competing capacity to the transmission users in a group of entry points of the NNGS. The existing technical restrictions of the system result in a maximum amount of natural gas that can flow from the northern to the southern part of the transmission system, through the Nea Mesimvria compressor station. To avoid any discrimination between the NNGS entry points, instead of setting the maximum capacity available through each of the entry points, the combined offer and auction of the capacity from the north zone to the total maximum capacity available was proposed. This would allow access to the entry points, with an expressed interest, rather than an ex ante identification of the interest.

- Introduction of the service that permits the transport of natural gas exclusively from a specific Entry Point to a particular Exit Point of the transmission system, through conditional capacity. This provision covers the case of a network user who expresses interest to move a quantity of natural gas between Entry and Exit points that are located at the northern part of the transmission system. Although, according to the EU Regulations, capacity reservation must be made separately at the entry and exit point of the system and the user should not obliged to state the flow of gas through the system, in order to achieve trade anonymity everywhere in the system, but in case of a congestion, if a user is willing to commit that his imported gas through an Entry Point in the northern part if the system will be consumed or exported also through the northern part, and thus would not contribute to the congestion of Nea Mesimvria, it was proposed to introduce the possibility for Conditional Capacity in addition to the maximum capacity set for the northern part of the transmission system.

In addition, DESFA's recommendation for the 5th revision of the Code also included modifications to specific provisions that would improve the management of the Revithousa LNG facility. These changes, including the other amendments to Chapter 11 of the Code, "LNG Facility Management and LNG Services", would be considered in their entirety and independently of the other provision changes in the 5th revision of the Code.

The approval of the 5th Amendment of the National Natural Gas System Administration Code is expected in April 2020.

Furthermore, amendments to the Natural Gas Balancing Manual were also submitted for a public consultation together with the amendments to the National Natural Gas System Network Code. According to the methodology described in Article 53A of the Code, and which is specified in detail in the Manual, when calculating the Marginal Daily Buying Price and the Marginal Daily Selling Price of balancing natural gas to settle the Daily Imbalances of the Network Users, the minimum and the maximum prices of the transactions made in the Balancing Platform are used. In the occurrence that there were no auctions made, or the stakeholders failed to submit any bids, then "substitute values" should be used. The proposed amendment concerns the methodology for the calculation of those "substitute values". Specifically, for the "substitute values" to be based more on market mechanisms, the following amendments are proposed:

- In the scenario that during one Natural Gas Trading Day no auctions are being carried out, the calculation of the "substitute values" should be made based on the Balancing Gas Reference Price (i.e. based on international prices) and not the price trends preceding the auction day which may deviate significantly from the real market picture.
- If during one Natural Gas Trading Day there was an auction carried out but no successful bids were submitted by the participants, the "substitute values" are set equal to the minimum/maximum offer quota applicable for that day, in order to reflect the actual market conditions and to act as an incentive to attract users to the Balancing Platform.

The approval of the amendments of the Natural Gas Balancing Manual is expected in April 2020.

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 is 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. The regulator decided to amend the National Natural Gas System Administration Code specifically for the Annual LNG Planning Scheme, setting the Annual LNG Program Unit Charge[30] at 200,000 €. Furthermore, DESFA was requested to submit to the regulator a proposal addressing a comprehensive response to the issues arising from the management of the LNG Facility and the provision of LNG services. After having received this proposal, RAE initiated a public consultation which will be completed in January 2020. The main amendments concern Chapter 11 of the National Natural Gas System Administration Code and the Standard LNG Transmission Agreement.

Currently, eighty (80) System Users are registered and can transfer gas in the NNGS:

[30] The Annual LNG Program Unit Charge concerns the LNG cargos that were declared to be imported using Revithoussa LNG terminal but was never physically unloaded.

	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	GDF SUEZ	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.	Eligible Customer
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
68	ENERGIKO EOOD	Eligible Customer
69	Petrogaz S.A.	Natural Gas Supplier
70	SYMETAL S.A.	Eligible Customer
71	OMV PETROM GAS SRL	Eligible Customer
72	GS GAS AEBEY	Natural Gas Supplier
73	Chipita S.A.	Third Party
74	Sentrade S.A.	Third Party
75	WIEE ROMANIA SRL	Third Party
76	Dioriga Gas S.A.	Third Party
77	Vitol Gas & Power BV	Eligible Customer
78	KOLMAR NL BV	Third Party
79	RWE Trading GMBH	Third Party
80	Blue Grid Gas & Power S.A.	Third Party

Table 46: Companies officially registered as NNGS users

DESFA's TYNDP

- RAE with Decision 1086/2018 approved the Ten-Year Network Development Plan (2017-2026) under specific conditions, and called on DESFA to resubmit the Development Plan under the terms of the Decision. The consistency of the NDP was checked against both the regional and the European TYNDP. DESFA submitted to RAE a revised TYNDP in January 2019. RAE with Decision 236/2019 approved the revised TYNDP (2017-2026) in February 2019.[31]

- Furthermore, after the conclusion of the first public consultation held by DESFA for the TYNDP (2020-2029), RAE received DESFA's proposal on the TYNDP (2020-2029). Taking into account the investment needs raised by DESFA, as well as the general assessment of the submitted TYNDP, RAE required for certain amendments in the TYNDP 2020-2029.

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 will end in 17 January 2020, and RAE is expected to make its final Decision on the plan during the first months of 2020.

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.[32] The DSOs must construct the distribution network in accordance with the approved

[31] RAE Decision 236/2019 is available at https://www.depa.gr/wp-content/uploads/2019/07/fek-v-2436_20.06.19-apof.-rae-540_2019egk.-apait-esodoy-metaf.-yfa-kai-.._.pdf
[32] Gazette B 3067/26.09.2016

development plan[33] 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.

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 2019, as well as the percentage change compared to 2018:

	2018	**2019**	**%**	**2018**	**2019**	**%**
	Medium Pressure (km)	Medium Pressure (km)	Percentage change (%)	Low Pressure (km)	Low Pressure (km)	Percentage change (%)
Attica	328.00	332.20	1.28%	3.148.00	3.266.60	3.77%
Thessaloniki	135.98	137.16	0.87%	1.187.85	1.241.51	4.52%
Thessaly	105.37	106.00	0.60%	893.98	941.12	5.27%
DEDA (rest of Greece)	334.85	334.85	0.00%	175.24	175.24	0.00%
Total	**904.20**	**910.22**	**0.67%**	**5.405.07**	**5.624.46**	**4.06%**

Table 47: Distribution Network Development per category/region (2018-2019)

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

[33] 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 1096/2019 and 860/2019 approved the development plans of EDA Attikis and EDA Thesalonikis that were submitted to the NRA for the period 2019-2023. RAE didn't approve any updated development plan for DEDA, the existing development plan in force is the one approved with RAE's Decisions 1318/2018 and 1319/2018.

4.1.3 Network and LNG Tariffs for Connection and Access

A. Transmission System and LNG terminal access tariffs

In May 2019, RAE, in accordance with the provisions of Regulation (EU) 2017/460 on the establishment of a network code on harmonized transmission tariff structures for gas, adopted a new transmission system tariff regulation. In the context of the 4th Amendment of the Tariff Regulation for the Basic Activities of the National Natural Gas System (NNGS) and its harmonization with the provisions of European Regulation (EU) 2017/460, RAE put DESFA's proposal on public consultation from 11.10.18 to 31.01.2019. DESFA's proposal suggested to apply a postage stamp methodology to calculate the tariffs.

On the above proposal, ACER published a report, as with every member state, entitled *"Analysis of the Consultation Document on the Gas Transmission Structure for Greece".* The report included ACER's observations and suggestions for modifications and improvements in order to bring DESFA's proposal in line with Regulation (EU) 2017/460. One of the most important suggestions of ACER concerned the "postage stamp" methodology. Specifically, ACER made clear remarks as to the full or partial compatibility of the DESFA's suggested methodology with respect to the provisions of the Regulation and in particular with regard to the principles of transparency, cost-reflectivity and the avoidance of cross-subsidization. In this regard, ACER called for the necessary adjustments to the benchmark methodology based on the principle of cost orientation, taking into account the specificities of the Greek gas system and the national energy policy goals, and it suggested to RAE to adopt a "Cost Weighted Distance Methodology" which could capture the actual costs based on distance in a more pragmatic way. Furthermore, ACER also suggested that RAE should handle the amount of socialization of the allowed revenue of the LNG facility in Revithoussa in a manner similar to that of non-transportation services, as well as the need to use a cost benefit analysis. Finally, ACER raised the issue of a distinct methodology for the non-transport related services' regulated tariffs, as well as for the separate representation of the regulated and non-regulated services provided by DESFA.

RAE took into consideration the above suggestions made by ACER, as well as those of all the participants that participated in the first public consultation and decided to adopt a Capacity Weighted Distance (CWD) methodology for the calculation of the reference price by holding a second (additional) public consultation from 25.04.2019 to 10.05.2019.

In light of the above, in May 2019, RAE, with Decision 539/2019, approved the 4th Amendment of the Tariff Regulation for the Basic Activities of the National Natural Gas System (NNGS). The main points of the new methodology are summarized as follows:

- The Capacity Weighted Distance (CWD) methodology to calculate the transmission tariffs is adopted. The Allowed Revenue is mainly recovered through capacity-based transmission tariffs and only the amount of Old Recoverable Difference is retrieved by a commodity-based transmission tariff which is applicable only to the Exit Points of the natural gas transmission system.
- The capacity charges in the Entry Points at Sidirokastro and Kipi is the same since both of those Entry Points now lead to the same cluster.
- Two Exit Point clusters are created, the "North Zone" and the "South Zone".
- For reasons related to the contribution of the LNG facility in Revithoussa to the balancing of the natural gas, the security of supply, and the facilitation of the natural gas market accessibility by new suppliers, 50% of the Required Revenue of the LNG service is recovered

through separate “tariff for LNG dispersion” charged at the Exit Points of the transmission system.

- A 30% discount is applied to the capacity charge at the Agia Triada Entry point, pursuant to Article 9 (2) of Regulation (EU) 2017/460, as it is an entrance to an infrastructure system specifically developed for the purpose of ending the energy isolation of Greece and it operates towards the enhancement of the security of supply of the country.

The Decision for transmission tariffs according to the new tariff regulation (Decision 566/2019) will be in force from 1.1.2020.

DESFA S.A. publishes on its website the current and historical tariffs, as well as a relevant calculator, in both Greek and English.

Transmission System for each Entry and Exit	**MMSi$_i$ (€/kWh GCV /Day/Year)**	**TQEi$_i$ (€/kWh GCV)**
Entry Sidirokastro	0.1612019	0.0001495
Entry Kipi	0.1612019	0.0001495
Entry Ag. Triada	0.0644131	0.0000235
Exit Northeast Zone	0.2081846	0.0002997
Exit North Zone	0.2192507	0.0002573
Exit South Zone	0.4735978	0.0005035
LNG Tariffs	LCE (€/kWh GCV /Day/Year)	LQE (€/kWh GCV)
LNG Facility	0.0967888	0.000126

Table 49: Natural Gas Transmission Tariffs coefficients for 2019

Transmission System for each Entry and Exit	**MMSi$_i$ (€/kWh GCV /Hour/Year)**	**TQEi$_i$ (€/kWh GCV)**	**SDDY ((€/kWh GCV /Hour/Year)**
Entry Sidirokastro	6.2970141	-	-
Entry Ag. Triada	1.9531578	-	-
Exit North Zone	3.9144732	0.0002991	1.6373589
Exit South Zone	4.4657693	0.0002991	1.6373590
LNG Tariffs	LCE (€/kWh GCV /Hour/Year)	-	-
LNG Facility	4.4683315	-	-

Table 50: Natural Gas Transmission Tariffs coefficients for 2020

In May 2019, RAE adopted Decision 540/2019 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[34]	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

Table 51: Required Revenue per basic NNGS service (€/year)

Furthermore, in May 2019, RAE adopted Decision 566/2019 which set the Allowed Revenue for the Transmission System and LNG Facility in Revithoussa for 2020. 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)	Basic LNG storage service	Transmission of LNG service	Total Sum
50,549,205	50,549,205	41,112,281	101,098,410	243,309,101

Table 52: Allowed Revenue per basic NNGS service for the year 2020 (€)

B. Distribution System access tariffs

In 2016, RAE approved the gas distribution tariff regulation (RAE's Decision 328/2016) which provided the methodology for calculating gas distribution tariffs for the distribution system operators (covering a regulated period of 4 years, starting in 2017). The calculation of the regulated tariff is based on the methodology of the Allowed Revenue [Allowed Revenue = Allowed Return on the Regulated Asset Base + Annual Depreciation of Assets + Operating Costs – Other Revenue + Any Under / Over Recovery].

Total WACC (nominal, pre-tax)	9.23%
Market Risk Premium	5.23%
Beta	0.42%
Gearing (loan)	0%
Country Risk Premium	4%
Cost of equity post tax	6.55%
Tax rate	29%
Cost of equity pre-tax	9.23%
Debt rate	0%

Table 53: Main parameters of WACC- Gas Distribution 2019 (Decisions 345,346,347,348 /2016)

In 2019, the distribution tariffs were adjusted based on the annual Consumer Index of 2018, as per the Distribution Code provisions, which at the end of 2018 amounted to 0.6%. Therefore, the regulated distribution tariffs of 2019 were the following:

[34] 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.

	Attica	Thessaloniki	Thessaly	Central Greece	Corfu	Central Makedonia	Eastern Macedonia-Thrace
Pricing	**Capacity charges €/MW h/h (2019)**						
Households	1,129.04	452.76	524.87	1,236.75	0.00	795.91	549.72
Commercial	1,129.04 20	452.76	524.87	1,248.14	0.00	833.78	600.79
Industrial	4,548.93	1,811.26	2,099.76	7,322.79	5,823.86	4,588.89	4,894.73
A/C, Cogeneration	1,128.40	0.00	0.00	0.00	0.00	0.00	0.00
	Energy charges €/MWh (2019)						
Households	14.48	11.94	13.01	13.52	0.00	11.64	11.91
Commercial	14.48	11.94	13.01	11.41	0.00	7.57	7.38
Industrial	0.69	0.29	0.29	0.57	1.18	0.42	0.49
A/C, Cogeneration	3.81	0.00	0.00	0.00	0.00	0.00	0.00

Table 54: Capacity and energy charges per distribution network per pricing category

4.1.4 Cross-border issues

Natural gas in Greece is imported through three Entry Points of the NNGTS: Sidirokastro (Greek-Bulgarian borders), Kipi (Greek-Turkish borders) and Agia Triada (Revithousa LNG Entry Point). Downstream, natural gas is received by the NNGS users at 44 Entry Points. In 2019, gas imports amounted to 57.7 TWh, which is an increase of 9.4% compared to 2018 (52.7 TWh).

Figure 29 shows the progress of imports of natural gas per NNGTS Entry Point for the time period 2010-2019. Furthermore, Figure 30 shows the natural gas percentages for imports per NNGTS Entry Point for 2019.

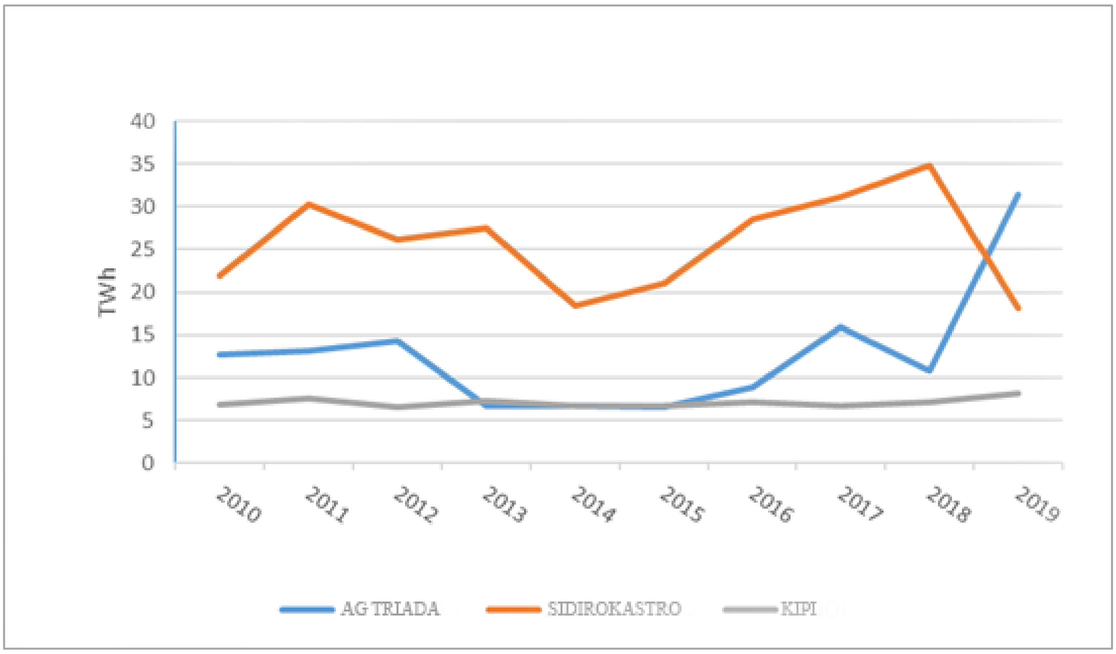

Figure 29: Imports of Natural Gas per NNGTS Entry Point (2010-2019)

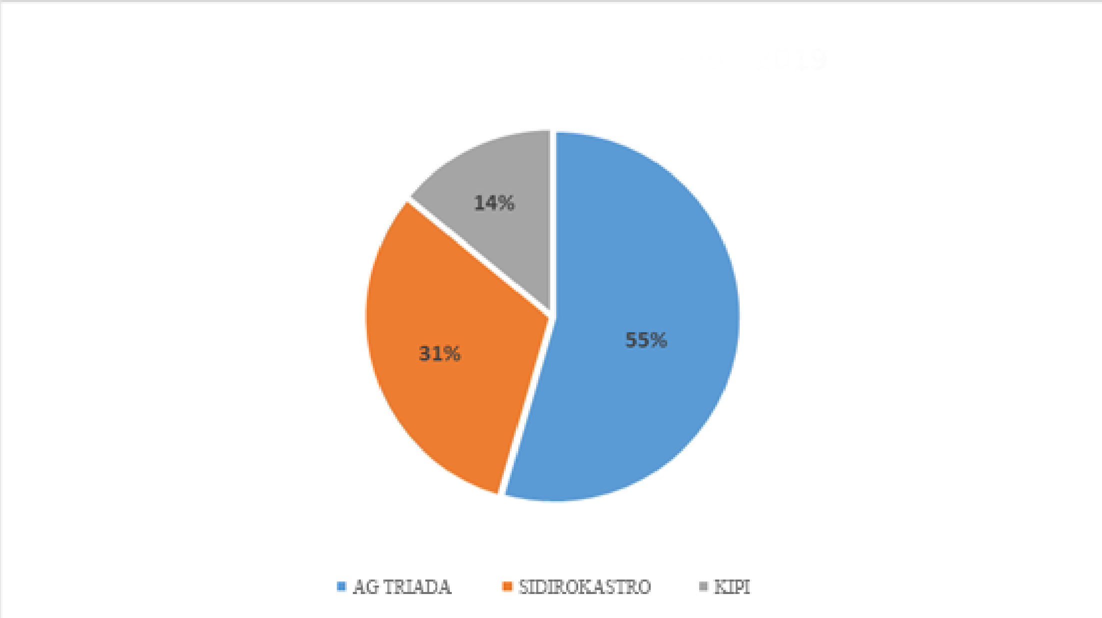

Figure 30: Percentages for imports of natural gas per NNGTS Entry Point for 2019

"Kipi" Interconnection Point

With the 4th Amendment of the National Natural Gas System Network Code, RAE, upon TSO's proposal, decided to apply the capacity allocation procedure in accordance with the provisions of the Regulation (EU) 2017/459 of 16 March 2017 on establishing a network code on capacity allocation mechanisms in gas transmission systems, also at the "Kipi" entry point from a third country (Turkey). Consequently, on the Greek side of the “Kipi” point, the capacity reservation is thereafter made through auctions and thus the first-come, first served rule was abolished. In this framework, pursuant to RAE Decision No. 747/31.07.2018 (Gazette 3810/04.09.2018) on "Auction Procedure for Bidding and Allocation of Capacity at the Kipi Interconnection Point", DESFA announced in August 2018 the launch of auctions at the Regional Booking Platform (RBP) for the Kipi Interconnection Point. The first results of the capacity auctions were encouraging as more Users except the dominant player, booked capacity and imported gas, for the first time, from Turkey. In 2019, although LNG prices were very attractive, two Users consistently imported natural gas through Kipi Interconnection Point. The next important step will be the conclusion of an Interconnection Agreement between DESFA and BOTAS.

The IGB pipeline

Pursuant to article 4.3 point 1 of the Final Exemption Decision, ICGB AD was obliged, not later than 3 months from the adoption of the decision, to submit for approval to the Regulatory Authorities a final tariff methodology (IGB Tariff Code), which they did in November 2018. The Tariff Code proposal was put on public consultation by the two Regulators together with the IGB Network Code in Q3 of 2019, and the final approval of the IGB Network Code as well as the IGB Tariff Code was taken in October 2019.

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. According to the current timetable, the commercial operation of the pipeline is scheduled for the end of 2020, with a deadline of July 2021. The final Decision of EWRC and RAE is expected to be published in the first quarter of 2020.

The TAP pipeline

The construction of the TAP is at a very advanced stage. TAP AG reports a completion rate of 92% of the total length of the pipeline at the end of 2019. The projects on the Greek side have been completed and the land along the pipeline route has already been restored. The pipeline is expected to operate commercially in the first quarter of 2020. The regulation of access to the TAP pipeline was set out 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 and it constitutes the Exemption Decision under Article 36 of Directive 2009/73/EC and it was approved by RAE’s Decision No. 269/2013. The conditions laid down for TAP operation, as a result of the cooperation between the three national Regulatory Authorities as well as the European Commission and the Energy Community, safeguard competition in the European Single Market in the best possible way.

On 25 November 2019, TAP began importing the first quantity of natural gas into a 2km section of the pipeline in Greece, between the Evros River and the compression station in Kipi. This is the initial commissioning phase of the pipeline, which ensures that the infrastructure is safe and ready to operate in accordance with the national and international operating and safety standards. Following the commission of the first section of the pipeline, the gradual introduction of gas will continue to other parts of TAP in Greece and then, in the coming months, to Albania and Italy. The commercial operation of the pipeline is scheduled to begin in the fourth quarter of 2020.

During 2019, 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

The code must be submitted at least 12 months prior to the commercial operation of the pipeline, which is set for the fourth quarter of 2020, to the Regulatory Authorities for approval. The network code is the main regulatory framework that will define the rules of third-party access to the pipeline for the capacity that is not exempted under the FJO.

In this context, TAP AG has already begun, since 2015, the procedures for the formulation of the regulatory text of the TAP Network code and to this end there is constant communication between the company and the national regulatory authorities of energy of Italy, Greece and Albania.

During 2018, three meeting between the representatives of TAP AG and the three Regulatory Authorities were held to resolve any pending network code specific issues. The draft Code was submitted by the company for public consultation from August 7 to September 18, 2018. RAE posted a notice on its website to inform interested parties about their participation in the consultation. The final TAP proposal, together with the comments made during the public consultation, were submitted to the Regulators for approval in December 2018. Subsequently, three more meetings were held during 2019, which elaborated on the comments made as well as the proposed amendments to the draft of the network code. Following those meetings, the company submitted its final proposal in December 2019. The three regulators are in close cooperation with each other in order for the final draft of the network code to be approved within April 2020.

2. Amendment of the TAP Tariff Code

RAE Decision 708/2018 (Gazette B'3661 / 2018), and corresponding decisions of ARERA and ERE, approved the amendment of the TAP Tariff Code in 2013 under the authority of the FJO. TAP AG recognized the need for a limited amount of modification to the code and submitted a proposal to the Regulatory Authorities in June 2018. Specifically, the proposed amendments to the code are summarized as follows:

a. Adjusting the formula for the Required Revenue, in order for the revenue during the leap year to be a little higher so as the unit tariff to remain stable between leap years and normal years.

b. The consumer price index which is used for the annual adjustment of the Revenue to be replaced by the one adopted by the European Commission with Regulation (EU) 2016/792.

c. The redistribution of the excess Revenue to the Users to be on an annual basis rather than on a semi-annual basis

The draft TAP Tariff Code was submitted by the company to a public consultation from 7 August to 18 September of 2018. The final proposal of TAP AG, accompanied by the comments made during the public consultation and the company's view on them, were submitted to the competent Regulatory Authorities for approval in December 2018. Three more working meetings were held during 2019, in which all the comments and the identified amendment to the Code were processed. TAP AG submitted its final proposal in December 2019 and the three competent NRAs are in close cooperation to issue a final approval Decision on the TAP Tariff Code within April 2020.

3. New Market Test Approval

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,[35] 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	
2033/24-2040	36,500,000	5,500,000	42,000,000	
2041/42	5,500,000	5,500,000	11,000,000	

Table 55: Non-binding requests for forward firm long-term capacity in TAP-DESFA Interconnection Point in Nea Mesimvria

[35] RAE Decision 651/2019

(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.[36]

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.

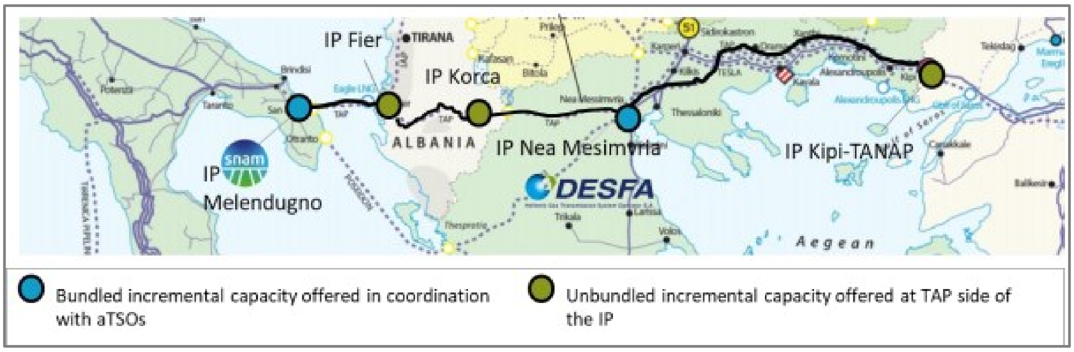

Figure 31: Interconnection points where incremental capacity is offered by the Operators TAP, DESFA and SRG

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.

The proposed incremental capacity project is set for a joint public consultation by the Operators starting from 20.01.20 to 21.02.2020. Subsequently, the final draft will be submitted to the three NRAs so that the Operators will be able to continue to the next phase of the Market Test.

4. Obligations arising from the ITO Model

[36] Albania as a Contracting Party of the EnC, will apply the NC CAM Regulation from 28 February 2020.

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.

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 and its approval is expected within the first quarter of 2020.

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.[37] Subsequently, it issued a Notice to any interested parties to submit bidding offers.[38] 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.

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 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.

[37] RAE Decision 596/2019

[38] RAE Decision 1145/2019

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	37.26 TWh	33.49	102.08 TWh	64.79 TWh	58%

Table 56: Transactions in the Virtual Trading Point (VTP) in 2019

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. During 2015 and 2016, RAE provided an extensive opinion to the HCC on ways to optimize the functioning of the gas release programs in the framework of an extensive consultation run by HCC to which all gas stakeholders participated[39].

Amongst the innovations introduced there RAE was attributed the duty to validate the reserve price of the auctions. In this regard, in 2019, based on the methodology for setting the auction reserve price, by Decision 1094/20.11.2019 RAE approved DEPA's overhead cost at 0.0071 €/MWh for the annual auction (which for 3,206 TWh equals to 22,720 €) and at 0.0283 €/MWh for each of the quarterly auctions (which for 2,137 TWh each equals to a total of 60,480 €) of 2020. Also, natural gas quantities purchased in DEPA's auctions are delivered only to the Virtual Trading Point (VTP). Since 2016, DEPA has been obliged by law to a gradual increase in total quantities available as a percentage of sales of the previous year as follows: 16% in 2017, 17% in 2018, 18% in 2019 and 20% in 2020. Additionally, the auction process has been modified as each action will now take place in two phases. In the first phase both suppliers and eligible customers have the right to participate, while in the second phase of each auction, where more than 10% of the gas is auctioned, only gas suppliers are eligible to participate.

[39] Thus, to offer Suppliers and Customers the ability to put together a flexible portfolio for the supply of natural gas and in addition to the current system of quarterly auctions, DEPA has undertaken to make natural gas available on an annual basis in the electronic auctions, i.e. with an absorption period of one calendar year (annual auctions). Additionally, to further reduce dependence of DEPA Customers by DEPA and to equally treat all participants in the auctions, irrespective of the supply contract that they have concluded with DEPA (with or without transmission services), DEPA undertook (as of 01.01.2015) to make all quantities available through the annual and quarterly auctions solely at the Virtual Nomination Point (VNP) of the National Natural Gas System (NNGS).

Moreover, in July 2018, the Balancing Platform was launched, in line with the provisions of the 4th amendment of the National Natural Gas System Administration Code and the Balancing Manual. The TSO, using market mechanisms, through daily or intraday auctions, purchases and sells the quantities of natural gas required to cover the imbalances of the natural gas system.

The auctioned natural gas amount by the TSO (natural gas buying and selling balancing auctions) for 2019 corresponded to 5.2 TWh which is the 9% of the total quantities injected into the NNGTS. The contracted volume of natural gas amounted to 900 GWh approximately. Fourteen Users (14) have participated in the auctions so far but their number is increasing.[40]

Table 57 represents the amount of transactions between DESFA and the Users of the Balancing Platform in 2019, 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	
402 Trades	613.90 GWh	207 Trades	279.33 GWh	1.10 Trades/Day	1.68 GWh/Day	0.57 Trades/Day	0.77 GWh/Day

Table 57: Transactions in the Balancing Platform for the year 2019

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. 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 32 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 2019 to December 2019.

[40] In 2018 the Balancing Platform was used by 9 Users.

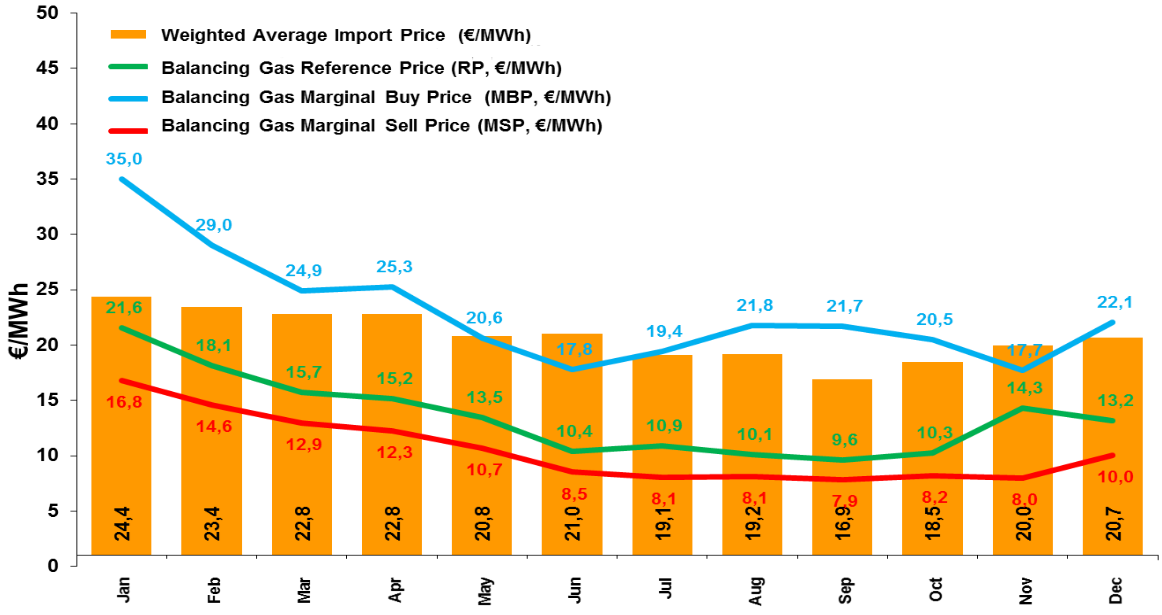

Figure 32: Price Monitoring in the Wholesale Natural Gas Market for the year 2019

Furthermore, RAE, in 2019, assessed DESFA's proposals concerning the NNGS and published the following Decisions:

- Decision 1093/2019 for the approval of parameters' price included for the calculation of NNGS balancing tariff for 2019 (Gazette B' 4519/10.12.2019)
- Decision 1130/2019 for the approval of Annual Scheduling of NNGS Balancing Services for 2020 (Gazette B' 4819/24.12.2019)

4.2.2. Monitoring the level of transparency

Market Opening and Competition

There was no new major infrastructure, such as new entry points, LNG or storage facilities, commissioned in 2019. As explained in previous National Reports, there is no indigenous gas production in Greece. Furthermore, there are no storage facilities and the LNG storage tanks are used exclusively for temporary LNG storage. Therefore, as has been noted in the past, the Revithoussa LNG terminal remains the main channel/opportunity for new entrants in the Greek gas market. This remains valid regardless of the fact that, as already explained above, in 2019 more 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, provide useful information on the price conditions in the Greek natural gas market which 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 2019, a total of 25 suppliers were active in the retail market of natural gas:

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

Table 58: Suppliers active in the retail market of natural gas (2019)

The Herfindahl-Hirschman Index (HHI) at the end of the year is estimated at 2.401, (calculated by consumption volumes). To a certain extent similar to the electricity market, the gas market is considered to be moderately concentrated.

The total consumption of natural gas in 2019, as it is determined by the deliveries to the NNGTS, amounted to 57,6 TWh (4.9 bcm), an increase of 10% compared to the consumption of natural gas in 2018 which amounted to 52,45 TWh (4.7 bcm). The consumption of natural gas in 2019 remained at higher levels than the consumption during the 7-year period 2010-2016, where, due to the prolonged economic crisis a persistent fall in natural gas consumption was recorded.

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 37.5 million MWh in 2019, an increase of 13% compared to 2018 (33.2 million MWh). At the same time, consumption for other uses increased slightly by 4% and amounted to 20.1 million MWh in 2019, compared to 19.3 million MWh in 2018.[41]

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 4.96 bcm in 2020 to 5.82 bcm in 2029.

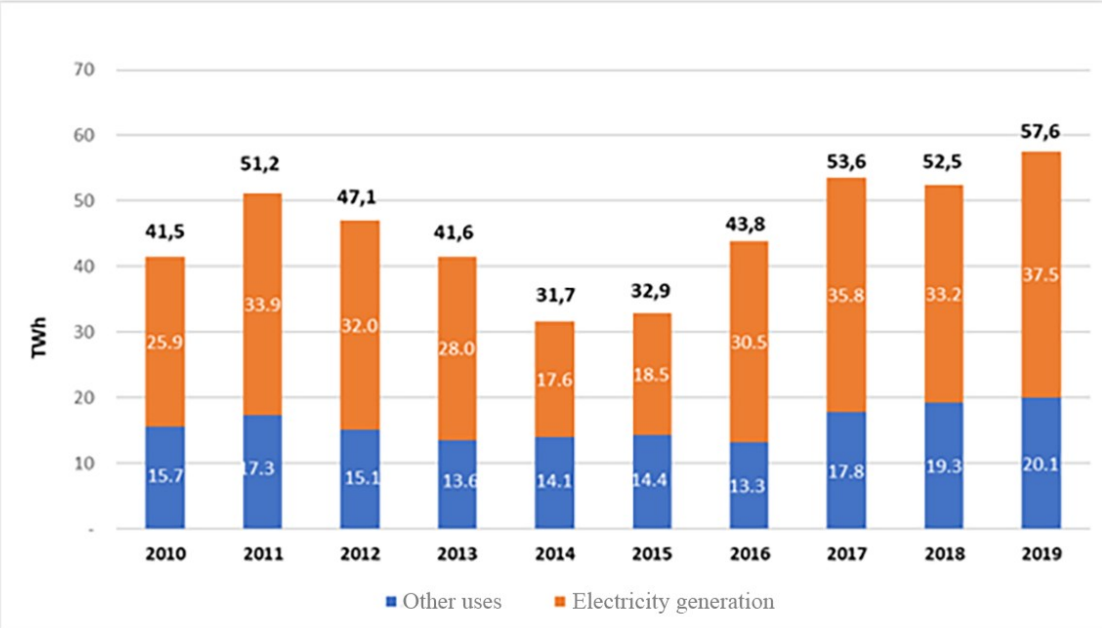

Figure 33: Natural Gas Consumption in Greece

The total volume of gas consumption in the distribution networks in 2019 did not show any particular variation compared to 2018. The consumption of natural gas was at 11,16 TWh (compared to 10.25 TWh of 2018), showing an increase of 8.15%.

Table 59 portrays the number of customers who switched supplier in 2019, as well as their corresponding consumption. As it turns out, the highest switching rate was that of commercial

[41] For a more detailed outlook with historic data please see Figure 36.

customers (5.72% by number of customers and 4.46% by consumption volumes), followed by domestic and industrial customers.

Customer Category	Total number of active customers, 2019	Number of customers switching Supplier in 2019	Percentage of switching (Number of customers) (%)	Customers' total consumption in 2019 (MWh)	Customers' consumption switching Supplier, 2019 (MWh)	Percentage of switching (in volume) (%)
Household	465,018	19,180	4.12%	4,981,503	160,854	3.23%
Commercial	16,505	944	5.72%	1,805,175	80,465	4.46%
Industrial	315	10	3.17%	4,374,144	54,325	1.24%
Total number	**481,838**	**20,134**	**4.18%**	**11,160,823**	**295,644**	**2,65%**

Table 59: Customers switching their natural gas supplier per consumer category, 2019 (Source: Natural gas DSOs' data)

The companies "Zenith SA" and "Attiki Natural Gas Distribution Company SA" were the prevailing natural gas suppliers in the retail gas market (residential, commercial and industrial consumers), representing 65.51% and 25.76%, respectively, of the total number of connections at the end of 2019 and the 35.95% and 31.13% of the total natural gas volume consumed.

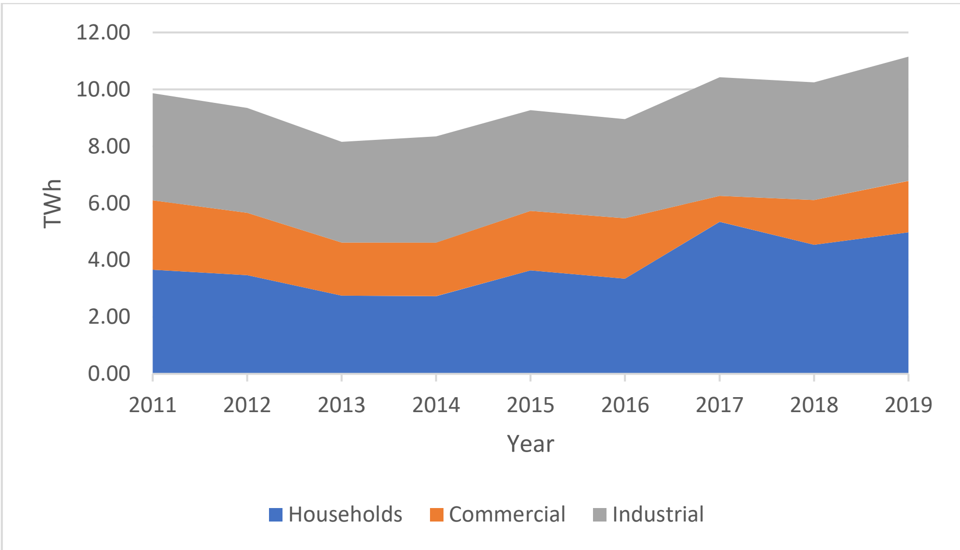

Figure 34: Natural Gas Consumption per customers' category in the distribution networks (2011-2019)

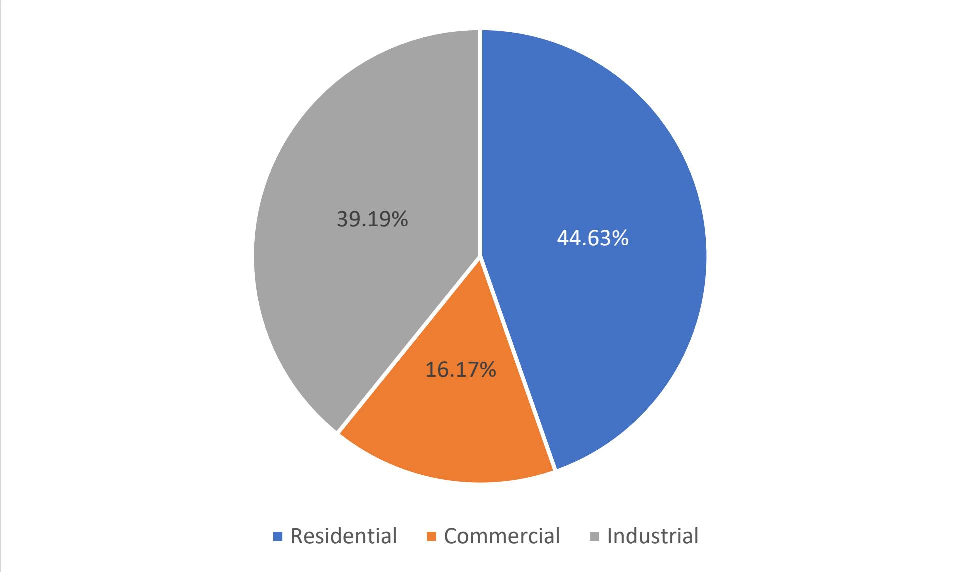

Figure 35: Natural Gas Consumption percentage per consumer category in the distribution networks (2019)

Households' share reached 44.63%, industrial users share amounted to 39.19% and commercial users to 16.17% in the gas Distribution Networks in the country. More specifically, in 2019 household consumption increased by ten per cent (10%), from 4.54 TWh to 4.98 TWh, and the industrial sector by six per cent (5.8%) from 4.13 TWh to 4.37 TWh. The commercial sector increased its consumption by 13,92%, from 1.58 TWh to 1.80 TWh.

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

Natural Gas Distribution Company	Category	Number of contracts	Number of orders executed	Average implementation time (business days)
EDA Attica S.A.	Households	19,653	17,930	52.8
	Commercial	552	463	45.6
	Industrial	2	1	-
EDA Thessaloniki – Thessaly S.A	Households	56,052	24,882	35.8
	Commercial	1.086	576	43.3
	Industrial	11	5	133.2
DEDA S. A.	Households	674	459	40.0
	Commercial	29	10	40.0
	Industrial	8	3	10.0
Source: Natural Gas Distribution Companies				

Table 60: Statistical data of new natural gas connections (2019)

In 2017, separate transmission, distribution and supply tariffs were applied in the bills of the gas consumers. RAE Decisions 345/2016, 346/2016, 347/2016 and 348/2016 approved the tariffs the distribution tariffs for natural gas in the distribution networks of Attica, Thessaloniki, Thessaly and the rest of Greece. In 2019. the above distribution tariffs were further amended pursuant Article 16 of the Distribution Network Tariff Regulation, multiplying the adjusted charges of 2018 with the average annual Consumer Price Index for 2018 (0.6%). The adjusted distribution tariffs for 2019 are shown in the table below:

2019							
	Attica	Thessaloniki	Thessaly	Central Greece	Corinth	Central Macedonia	Eastern Macedonia and Thrace
	Capacity Charge (€/MWh/h)						
Residential	1,129.042	452.75842	524.8681	1,236.7474	0	795.9100836	549.7192911
Commercial	1,129.042	452.75842	524.8681	1,248.1412	0	833.7801293	600.7861749
Industrial	4,548.9261	1,811.26121	2,099.7597	7,322.7898	5,823.8591	4,588.894492	4,894.725933
Cogeneration/ air conditioning	1,128.4007	0	0	0	0	0	0
	Energy Charge (€/MWh)						
Residential	14.481799	11.943	13.0139697	13.523011	0	11.63645552	11.91085993
Commercial	14.481799	11.943	13.0139697	11.409955	0	7.571852957	7.385119639
Industrial	0.6927237	0.28885	0.28885	0.5662006	1.1828478	0.423709696	0.49358213
Cogeneration/ air conditioning	3.8056576	0	0	0	0	0	0

Table 61: Distribution tariffs per Distribution Network

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.

4.4. Other regulatory developments

4.4.1. The regulatory framework for Remote Distribution Networks

The conditions for the development of Remote Distribution Networks and the conditions of access to Compressed Natural Gas (CNG) or Liquefied Natural Gas (LNG), as well as any other specific issue and implementation detail were presented at the public consultation set up by RAE on 07.05.2018, with 5 stakeholders participating therein.

The specific provisions were set out in RAE's Decision 643/2018 about the "Framework for the development of Remote Distribution Networks using Compressed Natural Gas / Liquefied Natural Gas". Specifically, the DSO of the gas network may construct Remote Distribution Networks within the geographic area under its license. During the submission of the Natural Gas Distribution Network Development Program for approval, the competent Operator may recommend the construction of a Remote Distribution Network. This proposal must be accompanied by a cost-benefit study, including the projected consumption (the number of connections per category of consumers and the volume of the natural gas), the projected construction cost of the Remote Distribution Network, the projected cost of the connection of the Remote Distribution Network to the existing Transmission or Distribution Network through a pipeline (if its technically feasible) and the evaluation results of the criterion of the Article 12 of the Pricing Regulation, and in particular the impact on the Average Distribution Charge. Provided that all distribution users have equal terms in their access to the Remote Distribution Network, it may be supplied either directly by them or by the Network Operator (Virtual Network).

As far as the access to the Remote Distribution Network through the Virtual CNG pipeline, the Compressed Natural Gas decompression station, after which the gas is fed to more than one final customer, is not a Distribution Network Entry Point but a continuation of the Distribution Network. The Operator has in his possession but does not own the natural gas during the entire process of compression, CNG transportation and decompression of the gas. The Operator shall, also, ensure that the natural gas imported into the Remote Distribution Network has the same properties with the existing gas in the distribution network. The Operator shall receive Compression and Transmission Services of Compressed Natural Gas following competitive tenders with natural or legal persons, based on transparent economic, objective, non-discriminatory and technical criteria.

The total cost of the Virtual Network service per Remote Distribution Network is determined by the quantities of the Natural Gas measured by the meter, which is installed after the decompressor and is injected into the Remote Distribution Network. The DSO monitors any losses that occur during the compression, transmission and decompression process and informs RAE about the results. RAE, in the context of the approval of the Network Development Program, evaluates the Operator's recommendation and decides on the Development of the Remote Distribution Network as well as the way the Remote Network is powered. In addition, in the case of the approval of supply through the virtual pipeline, RAE approves the maximum price per kWh, incrementally depending on the distance covered by the virtual CNG/LNG pipeline for the next year, it also approves the terms and conditions of the tender carried out by the Operator.

The methodology for setting the maximum price is cost oriented. The previous year's maximum price is valid up until RAE determines the maximum price for the Virtual Pipeline service for the following year. RAE may impose additional conditions on the Operator for the construction and supply of a Remote Distribution Network (e.g. installation of a second compressor, construction of an alternative Entry-Point). In case of approval of the construction of a Remote Distribution Network through Virtual Pipeline, the Operator shall immediately conduct a tender for each Remote Distribution Network separately and informs RAE of its results.

4.4.2. Methodology for setting typical consumption curves

Pursuant to par. 1 of art. 21 of the Distribution Code, after a long preparation and consultation with the relevant stakeholders and in particular with the DSOs, RAE approved a common methodology for the non-metered customers by Decision 125/2018.

4.4.3. Metering Code for the Distribution Networks

After several revisions of the initial draft originally submitted in 2016, RAE put in public consultation the latest draft on 7 July 2018, to which 3 interested parties participated. RAE adopted with Decision 235/2019 (Gazette B '4818 / 24.12.2019) a single Metering Code for all the natural gas distribution networks in 2019. The Metering Code specifies the methodology of measurement of the amount of natural gas delivered to the Distribution Network and exported from it, the accuracy of the meters, the dispute resolution process, the data sharing procedures, so that accuracy, transparency and the right to access the data by all parties that have legitimate interest is ensured.

4.5. 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

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, as 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 Trans-Balkan 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.

RAE has also been designated as the coordinator for the Trans-Balkan Risk Assessment, which is currently under development in collaboration with DESFA, IPTO, JRC and the other Competent Authorities of the Member States of the risk group (i.e. Bulgaria and Romania). The Common Risk Assessment of the Trans-Balkan region identifies all relevant risk factors with a regional impact, using structured questionnaires prepared by RAE and JRC. Especially for Greece, an analysis of demand and temperature data is carried out by the JRC to draw conclusions about the correlation between demand and temperature and the assessment of reference temperature (1-in-20 years). The hydraulic simulation method of the NG transmission network of Greece and Bulgaria is selected to assess the effects of the examined scenarios and the risk analysis. Romania's NG transmission system is approached with a mass balance analysis due to the country's limited dependence on NG coming from Ukraine through the Trans-Balkan Transit Pipeline. The Joint Research Center of the European Commission contributes significantly to the elaboration of the CRA of the Trans-Balkan Risk Group. The submission to the European Commission of the final report is expected in early 2020 after the completion of the consultation of its content with the Competent Authorities of Bulgaria and Romania.

In addition, RAE, applying the relevant provisions of Regulation (EU) 2017/1938, in 2019, collaborated with DESFA, IPTO, the DSOs, the NNGS Users and the Ministry of Environment and Energy and developed the National Risk Assessment report in accordance with Article 7 of Regulation. The report analyzed all available data and information to identify and examine the risks that could affect the security of the country’s gas supply over the next three years. In this context, crisis scenarios that took into consideration the potential disruptions in the gas supply with specific demand profiles for each consumer category were simulated and examined. Specifically, the report included the following:

- A summary of the basic European and national regulatory framework on the security of gas supply in Greece.
- A summary on the parties involved in the risk assessment and, in general, the security of the country’s gas supply.
- A brief presentation of the national and regional system of natural gas.

- A revision of historical data and quality characteristics of demand, as well as usage data of the NNGS.
- Simulation scenarios taking into account the most recent gas demand estimates for the years 2019-2020, 2020-2021 and 2021-2022, the completion of the second upgrade of the Revithoussa LNG Terminal and the commercial operation of the TAP pipeline in 2020.
- The impact calculation of the scenarios under consideration on industrial consumers and on electricity generation and risk assessment.
- Calculation of the N-1 formula for the years 2019, 2020 and 2021 at national and regional level
- The actions taken in the framework of the cross-border cooperation with Member States in the region.

A total of 84 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, two different demand profiles were examined: (a) the withdrawal of two lignite power units and (b) the withdrawal of six lignite power units. From the analysis of the above scenarios some of the main conclusions are listed below:

- Protected Consumers are not expected to have any impact in their supply, in any of the scenarios considered. However, this requires the activation of the demand-side management measures provided in the Preventive Action Plant (2018) and, in some cases the activation of the Emergency Plan (2019) for interruption/restriction of gas consumption to Non -Protected customers
- From the analysis of the 14 scenarios for the examined years when taking into account the withdrawal of the two lignite power units there have been cases of low, medium or high risk in the gas supply for electricity generation and industrial consumers, while the withdrawal of 4 additional lignite power units significantly increases the overall risk.
- The analysis of the characteristics of the scenarios concludes that the condition that significantly increases the risk is the interruption of supply by Russia via the Ukrainian route. The study proposes a review of this possibility when drafting the updated Preventive Action Plan to take into account possible developments in the EU-Russia-Ukraine tripartite negotiations on the renewal of the gas transit agreement by Russia.
- There was a need to improve the demand estimation methodology for all categories of consumers, 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 results are improved by implementing the market demand measures provided in the Preventive Action Plan.

Preventive Action Plan

During 2019, RAE's activities regarding security of supply (SoS) were also focused on the implementation of the Preventive Action Plan (PAP), which was developed in 2018 (approved with Decision No. 500/2018), in accordance with the provisions of Articles 8 and 9 of Regulation (EU) 2017/1938 and in collaboration with DESFA, IPTO, the Ministry of Environment and Energy and the JRC of the European Commission. The Plan includes appropriate measures (actions) to reduce or eliminate the risks that may affect the security of supply of the country with natural gas.

RAE completed all the necessary actions for the implementation of Action D6 of the Preventive Action Plan in order to ensure the transparent operation and the cost-effectiveness of the alternative fuel in crisis situations in the NNGS. In the end of 2018, RAE had issued Decision 1299/2018 which amended the System Operation Code of the Greek Electricity Transmission System and the Electricity

Transactions Code in order to, in a crisis scenario in NNGS, during the resolution of Daily Ahead Schedule (DAS) and the Dispatch Program, (a) to be given the ability to introduce restrictions on the availability of natural gas in the NNGS for electricity generation (b) to give the ability to the generators to submit bids for two type of fuels for the units that have the functionality to use alternative fuel. Following that Decision, RAE adopted a new Decision No. 175/2019 which sets out the methodology for converting the above restrictions on the availability of natural gas into restrictions on the injection of electricity from natural gas plants in order to introduce them as energy restrictions in the DAS and in the Dispatch Program.

Emergency Plan

RAE, within its competencies with regard to safeguard the security of supply of the country with natural gas, pursuant to article 12 of Law 4001/2011, after a relevant public consultation as provided in Article 29 of Law 4001/2011, as well as consultation with the Competent Authorities of Bulgaria and Romania, in 2019, approved the updated Emergency Plan (Decision RAE 567/2019). The Emergency Plan was conducted by DESFA in accordance with Regulation (EU) 2017/1938 and in particular with articles 8 and 10, as well as in accordance with the provisions of articles 12 and 73 of Law 4001/2011 and Chapter 10 of the National Natural Gas System Administration Code, as applicable. The Plan entered into force in June 2019 (Gazette B '2501) and included the implementation of the measures / actions approved by RAE's Preventive Action Plan (2018) as well as a description of the procedure for applying the interruptibility measures. Specifically, the Emergency Plan:

- contains the measures to be taken to remove or mitigate the impact of a potential gas supply disruption and builds upon the three crisis levels: Early Warning, Alert and Emergency;
- defines the role and responsibilities of System Operators, RAE, Competent Authorities and Natural Gas market participants at each of the crisis level;
- ensures that Natural Gas undertakings and Major Natural Gas Customers are given sufficient opportunity to respond at each crisis level;
- identifies the measures to be taken to mitigate the potential impact of a gas supply disruption;
- establishes detailed procedures and measures to be followed for each crisis level;
- defines procedures to implement non-market-based measures, ensuring that non-market-based measures are to be used only when market-based mechanisms alone can no longer ensure supplies, in particular to protected customers;
- mentions the reporting obligations imposed on natural gas undertakings at alert and emergency levels;
- describes the mechanisms used in case of requiring assistance from the European Union and its Member States.

In this Emergency Plan, particular emphasis was given to the implementation procedure of demand side measures, such as the Interruptible by Priority customers and also the activation of the dual fuel availability of PPs.

Solidarity Mechanism

Regarding the obligations set out in Article 13 of Regulation (EU) 2017/1938 on the implementation of a Solidarity Mechanism, RAE has, since April 2019, initiated a consultation with the stakeholders of the Greek energy market on the necessary measures and the determination of reasonable compensation for their application to provide solidarity to a neighboring Member State. In this regard, RAE has consulted the parties concerned on the feasibility of the national actions of the Preventive Action Plan, and specifically the actions D5 (Storage of LNG seasonal reserve) and D6 (Introduction of additional rules in the electricity market for the connection of fuel availability of five alternative fuel power units) in combination with D2 (enhancing the use of alternative fuels) for the purposes of the Solidarity Mechanism and to determine the cost of the actions' implementation. RAE further investigates the determination of compensation for the Solidarity Mechanism in case of natural gas disruptions in the industrial and power generation sectors. RAE has sent relevant letters on the above issues to the owners of the gas-fired power plants, the Greek industrial consumers of natural gas, the suppliers / importers of natural gas and DESFA. It is expected that the first half of 2020, RAE will make a proposal on the necessary arrangements (technical, legal and financial), in agreement with the neighboring Member States, for the implementation of the Solidarity Mechanism.

Exchange of information

In accordance with the obligations laid down in Regulation (EU) 2017/1938, in 2019, RAE has communicated to the European Commission the long-term cross-border natural gas supply contract data, as set out in Article 14 (6) of the Regulation. The Authority has shared updated data on consumption of natural gas by Protected Customers with the Commission for 2017 and 2018, in accordance with Article 6 of the Regulation. Further, RAE participated in simulations and provided all the information requested in the context of the evaluation of the gas supply situation at the end of 2019, and in particular the preparation of technical reports with simulation results for a potential gas supply disruption via the Ukrainian gas supply route. The evaluations considered 3 possible different scenarios with the cooperation of ENTSOG, DG ENER and JRC.

Content of Emergency Plans

In accordance with Article 14 of Regulation (EU) 2017/1938, the measures, actions and procedures included in the Emergency Plan shall be tested at least once every four years. In December 2019 a pilot exercise was carried out in cooperation with ADMIE, HEnEx and DESFA. The purpose of the exercise was to identify early, any failures, technical or regulatory issues that could impede the implementation of the measure D6, as well as to check the effectiveness of the flow of information between the stakeholders in accordance with the provisions of the Action Plan. The results of the exercise were submitted by HEnEx to RAE for evaluation.

4.5.1. Monitoring Balance of Supply and Demand

4.5.1.1. Current demand

The following graph presents the gas volume consumption in Greece from 2016 to 2019, 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.

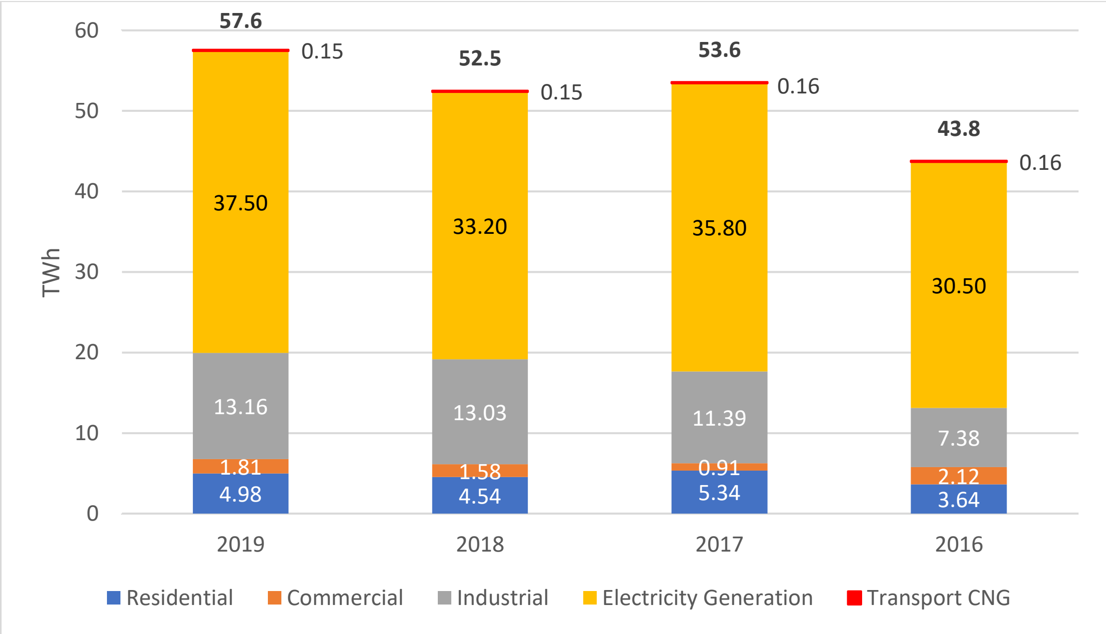

Figure 36: Natural Gas Consumption volume 2006-2019 (TWh)

The demand for Natural Gas in 2019 was slightly increased compared to 2018 (by 9.7%) from 52.5 TWh to 57.6 TWh, out of which about sixty five percent (65.1%) was used for electricity generation, as shown in Figure 36.

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 Algeria for the LNG. As shown in Figure 37, 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, with the participation of the LNG being almost 54% of the total imported natural gas and the corresponding percentage of natural gas from Russia being limited to 32%.

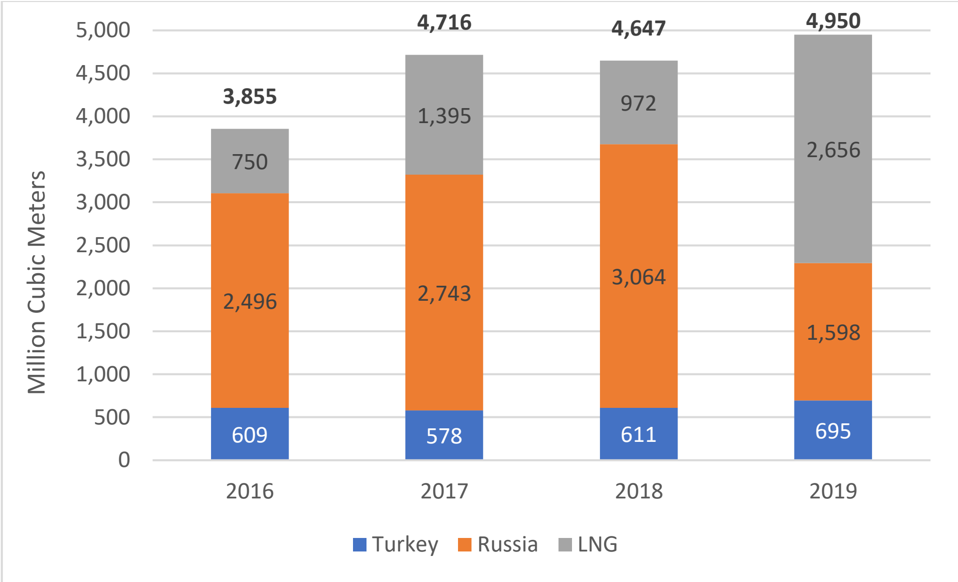

Figure 37: Evolution of natural gas imports per source of origin in Million Cubic Meters (2016-2019)

Figure 38 shows the main sources of LNG that have been imported the last four years. The decrease in LNG's prices in the world market in 2019, resulted, in addition to the increase in the imported quantities, to the increase in the differentiation of the LNG's sources of origin.

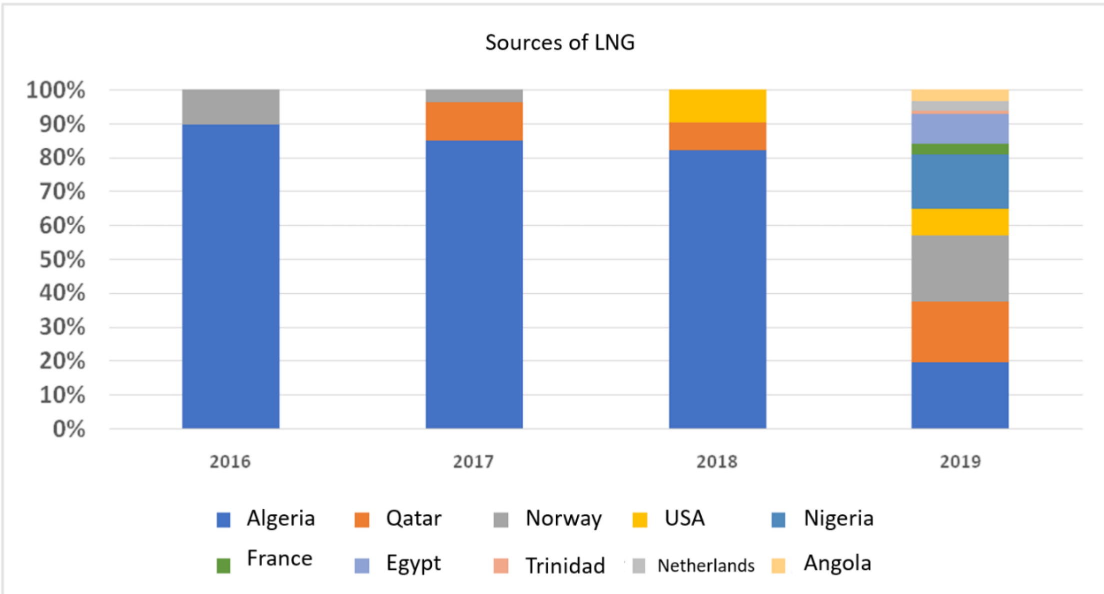

Figure 38: Share of LNG supply sources per country (2016-2019)

Country:	2016	2017	2018	2019
Algeria	671,677	1,185,933	796,266	513,098
Norway	77,975	50,313	0	514,449
Egypt	0	0	0	244,241
Nigeria	0	0	0	409,093
Trinidad	0	0	0	24,319
Qatar	0	158,858	79,963	483,373
USA	0	0	95,883	217,837
France	0	0	0	85,640
Netherlands	0	0	0	78,975
Angola	0	0	0	85,471
Total:	**749,652**	**1,395,104**	**972,112**	**2,656,497**

Table 62: LNG imports per partner country in Millions of Cubic Meters (2016-2019)

4.5.1.2. Projected demand

DESFA's projections (NNGS Development Study for the period 2020-2029, basic scenario) of natural gas demand for the next three years (2020 to 2022) are summarized in the table below.

	2021	**2022**	**2023**
Power generation	3,371	2,868	3,213
Consumers connected to High Pressure	816	817	874
Distribution Networks	1,065	1,132	1,169
Reverse flow / Exports	350	350	430
Total	5,602	5,167	5,687

Table 63: Future natural gas demand in mNm^3 (DESFA's estimates)

5. International cooperation

RAE cooperates on a constant basis with the National Regulatory Authorities of the EU member states within ACER and CEER, but also with the National Regulatory Authorities of third countries within MEDREG, ECRB/EnC and recently in the Balkan Advisory Forum, as well as with international institutions and other bodies created under international law (OECD, UfM etc). Moreover, RAE has concluded over the years, cooperation agreements bilaterally with other national regulatory authorities. In this respect, our aspiration is to actively commit towards the creation of a harmonized regulatory framework, with adequate safeguards for the promotion of security of supply, consumer empowerment and healthy competition at national, regional and European level.

- **Agency for the Cooperation of Energy Regulators (ACER)**

In 2019, a revised Regulation on the Agency for the Cooperation of Energy Regulators (ACER) was adopted by the European Institutions. The revised Regulation 2019/942 strengthened the monitoring responsibilities of ACER over the European Electricity and Gas Transmission Operators (ENTSOs), the newly provided European Electricity Distribution Operators (ENDSOs), as well as over the Network Electricity Market Operators, the Regional Coordination Centers.

RAE continued to actively participate in ACER activities with due representation at all levels, most notably the Board of Regulators, the Working Groups and the Task Forces.

- **Council of European Energy Regulators (CEER)**

CEER's strategy for the period 2019-2021 is based on the 3Ds (Digitalization, Decarbonization & Dynamic Regulation). In the core of this strategy there is a benefit for the consumer and the public interest.

In 2019, RAE continued its active participation in CEER's General Assembly, Working Groups and Working Streams. On its part, CEER continued to offer support to its members concerning their duties on implementing a competitive, sustainable, and secure energy market in Europe. At the same time, the cooperation between the Council and NRAs of third countries aims at the exchange of best practices and the maintenance of excellent relations between European and neighboring countries in the field of energy.

- **European Commission**

The **Connecting Europe Facility (CEF**) is a key EU funding instrument that aims to promote jobs, growth and competitiveness through targeted infrastructure investment at EU level. It supports the development of high performing, sustainable and efficiently interconnected trans-European networks in the fields of transport, energy and digital services.

In 2019, Decision C (2014)2080 which established the multiannual work programme for granting financial aid in the field of trans-European energy infrastructure under the Connecting Europe Facility for the period 2014-2020, was amended by the legislator bodies of the EU. This amendment aims at implementing the program to guarantee financial aid for inter-European infrastructure projects under the auspices of “Connecting Europe” Initiative.

Central and South Eastern Europe energy connectivity (CESEC) works to accelerate the integration of Central eastern and South Eastern European gas and electricity markets. The CESEC high-level working group was set up by Austria, Bulgaria, Croatia, Greece, Hungary, Italy, Romania, Slovakia and Slovenia and the EU in February 2015. They were joined later by Ukraine, the Republic of Moldova, Serbia, the Republic of North Macedonia, Albania, Bosnia and Herzegovina, Kosovo (in line with UNSCR 1244 and the ICJ Opinion on the Kosovo declaration of independence) and Montenegro.

During the 6th ministerial meeting in April 2019, the following issues were underlined:

- Rule convergence among the countries which participate in CESEC in relation to market coupling projects.
- Regional cooperation among countries on RES investments
- Abolition of rules which impede RES integration
- Enhancement of energy stock markets’ role as there are still markets which are not coupled
- Guarantees of access to the transmission system for a wide range of candidate participants for transparency reasons
- Use of innovative tools to attract private sector investments and ameliorate energy efficiency

In 2019, RAE participated in the Working Groups of CESEC.

- **Energy Community (EnC)**

In 2019, RAE continued to participate in Energy Community Regulatory Board (ECRB) and to cooperate with EnC Secretariat over all issues of regional importance. RAE also actively participated in the tasks of the Working Groups, Task Forces and other fora such as “Athens Electricity Forum” and “EnC Gas Forum in Ljubljana”.

In May 2019, the “24th Athens Electricity Forum” took place within the framework of Energy Community. According to the conclusions of the Forum, the contracted countries should try to converge their regulatory frameworks with that of the Energy Community. Energy markets’ coupling between both the members on ECRB and its neighboring countries together with the development of power production from renewable energy sources, reducing, at the same time, the carbon footprint of those energy markets, will push all of them towards integration. In addition, ECRB encourages its member states to actively participate in all other energy related institutions (ACER, CEER, MEDREG and Energy Community) and intensify their cooperation through the exchange of best practices. Challenges in cybersecurity sector were discussed as well, especially in the field of smart grids as it is considered a common goal for all countries.

- **Association of Mediterranean Energy Regulators (MEDREG)**

In 2019, RAE continued to actively participate in the activities of the MEDREG Working Groups. In addition, RAE held the presidency of the Institutional Working Group (INS WG) of MEDREG throughout 2019. The INS WG organized several trainings which aimed at exchanging knowledge and best practices with the other NRAs participating in MEDREG and drafted two reports that concerned the impacts of establishment of a NRA in Lebanon and the regulatory challenges faced and optimal solutions to promote waste-to-energy electricity generation in Egypt. RAE, also, actively contributed to the national reform program of MEDREG.

- **Balkan Advisory Forum (BAF)**

The National Authority of Albania (ERE) and the 3 Authorities of Bosnia and Herzegovina (SERC – RERS – FERC) joined the Forum as Members in October 2019 during the 2nd Annual Meeting. The Members approved a Study including all the necessary parameters for the creation of a regional natural gas market and a Study concerning electricity market monitoring. The Bulgarian National Authority delivered the Balkan Advisory Forum's presidency to RAE in October 2019 for one year.

- **Bilateral Cooperation**

Cooperation with the Commission de régulation de l'énergie (CRE)

Within the framework of the Memorandum of Understanding between the RAE and CRE, the two Authorities continued to cooperate by exchanging best practices and creating synergies concerning issues of common interest and more specifically on renewable energy sources, the energy transition of the islands and electricity storage.

In this context, in 2019 the two Authorities organized the 3rd Islands Forum which took place in Rhodes. Greece presented the innovative policies about islands including autonomous power systems and the potential for creating smart technologies in favor of both consumers and the national economy. National Authorities and stakeholders exchanged ideas and best practices on regulatory issues and security of supply in terms of sustainability and RES integration.

Cooperation with Italian Regulatory Authority for Energy, Networks and Environment (ARERA)

In February 2019, a meeting between the Presidents of RAE and ARERA took place in Milan. Issues of common interest between the two NRAs were discussed at the meeting.

- **Twinning Programmes**

The Twinning Project entitled "Development of Incentive Based Regulation for Service Quality and Regulatory Strategy to Support Roll-out of Smart Metering"[42] in Georgia successfully continued in 2019. The first component was completed with the active participation of RAE together with the Austrian and

[42] For more information please visit "Development of Incentive Based Regulation for Service Quality and Regulatory Strategy to Support Roll out of Smart Metering GE 15 ENI EY 03 18 R"

French Regulatory Authorities. The purpose of this Twinning Project is to develop the institutional framework for the implementation of regulation of Georgia's energy market in line with the Union acquis and to strengthen the capabilities of Georgian National Energy and Water Supply Regulatory Commission (hereinafter, GNERC) as the independent national regulatory authority through the development of tools and mechanisms based on the best-EU practice with regard to designing incentive-based regulation for service quality and developing regulatory strategy to support roll-out of smart metering.

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