The French Energy Regulatory Commission (CRE) is consulting market participants.

PUBLIC CONSULTATION N°2019-005 OF 27 MARCH 2019 ON THE STRUCTURE OF THE NEXT TARIFFS FOR USE OF NATURAL GAS DISTRIBUTION NETWORKS

Articles L.452-2 and L.452-3 of the French Energy code empower the French Energy Regulatory Commission (CRE) to specify the method for establishing the tariffs for use of the natural gas transmission networks. CRE can make changes to the tariff levels and structure which it deems justified following, notably, an analysis of operators' accounts and any expected changes in operating or investment costs.

The current equalised tariffs for use of the public natural gas distribution networks, termed "ATRD5 tariffs", came into effect on 1 July 2016 for GRDF, in accordance with CRE's deliberation of 10 March 2016[1], and on 1 July 2018 for the local distribution companies (LDCs), in accordance with the deliberation of 21 December 2017[2]. The deliberation of 7 February 2018[3] defines the tariff rules applicable to the management of the new natural gas distribution networks, for which a "non-equalised" ATRD tariff applies.

All of these ATRD tariffs share the same tariff structure. In addition, the LDCs' tariff schedules have been made proportional to those of GRDF, since 2018 for seven LDCs at the specific tariff[4] and the LDCs at the common tariff, and from 2021 for Régaz-Bordeaux and R-GDS, excluding the "TP" tariff option for R-GDS and Veolia Eau. The non-equalised ATRD tariffs are proportional to that of GRDF by construction.

The equalised tariffs are designed to apply over a period of four years. CRE has therefore begun work to define the next tariff for use of GRDF's natural gas distribution networks, termed the "ATRD6 tariff", which will come into force on 1 July 2020. Decisions on the level of the tariff and the regulatory framework would apply from the date. Changes to the tariff structure could also be implemented with effect from 1 July 2020. However, given the challenges posed by any change to the structure of the ATRD tariffs, the calendar for implementing structural changes could be delayed in order to give market participants sufficient visibility. For example, the calendar could be delayed to 1 July 2022, when the LDCs' ATRD6 tariffs come into effect.

In view of the need for forward visibility expressed by market participants and the complex nature of the issues concerned, CRE launched an initial public consultation on 14 February 2019, on the regulatory framework applicable to operators of regulated infrastructures for the next generation of tariffs. Following the workshop organised on

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[1] CRE deliberation of 10 March 2016 forming a decision on the equalised tariff for the use of GRDF's public natural gas distribution networks.
[2] CRE deliberation n°2017-281 of 21 December 2017 forming a decision on the equalised tariff for the use of the public natural gas distribution networks.
[3] CRE deliberation n°2018-028 of 07 February 2018 forming a decision on the tariff rules applicable to the management of the new natural gas distribution networks.
[4] GreenAlp (formerly GEG), Vialis, Gedia, Caléo, Gaz de Barr, Veolia Eau and Sorégies.

18 December 2018 with market participants, CRE is now also seeking, through this public consultation, to gauge the opinions of the parties concerned regarding its initial orientations on the structure of the ATRD6 tariffs.

Paris, 27 March 2019.

For the Energy Regulatory Commission

A commissioner,

Christine CHAUVET

To participate in the consultation

CRE invites all interested parties to submit their contributions, by 30 April 2019 at the latest:

- by email to the following address: dr.cp5@cre.fr;
- by contributing directly on CRE's website (www.cre.fr) in the "Documents/Public Consultations" section;
- by post to: 15, rue Pasquier - F-75379 Paris Cedex 08 - France;
- by requesting an audience with the Commission.

For the purposes of transparency, contributions will be published by CRE.

If your contribution contains elements that must remain confidential, a version masking these elements shall also have to be provided. In this case, only that version will be published. CRE reserves the right to publish elements that could be essential for all participants, provided that they are not secrets protected by law.

If no redacted version is provided, the full version shall be published, with the exception of information considered secret by law.

Interested parties are invited to provide well-grounded answers to the questions above.

CONTENTS

1. BACKGROUND AND OBJECTIVES OF THE PUBLIC CONSULTATION

1.1 CRE's powers

Article L. 132-2, 4° of the Energy Code empowers CRE to specify the rules concerning the "*conditions for the use of natural gas transmission and distribution networks [...], including the methodology for establishing the tariffs for the use of these networks [...] and tariff evolutions [...]*".

Articles L.452-1 and L. 452-1-1, L. 452-3 of the Energy Code provide a framework for CRE's powers in terms of tariffs. In particular, article 452-2 states that CRE shall define the methods used to set the tariffs for the use of natural gas networks. In addition, article L. 452-3 states that the "*the Energy Regulatory Commission debates and decides on tariff developments [...] with, where appropriate, modifications to the tariff level and structure which it deems justified with regard to, in particular, an analysis of operators' accounts and any expected changes in operating and investment expenses. [...]* ".

1.2 Gas infrastructure in France

Natural gas is imported and shipped to consumption areas by gas infrastructure essential for the proper functioning of the market and for security of supply:

- the transmission networks have multiple roles: they enable gas to be imported from land interconnections with adjacent countries and LNG terminals, and to be exported to certain land interconnections, to be shipped to distribution networks and certain direct customers, and to be injected into/withdrawn from underground storage facilities;
- gas storage facilities contribute heavily to managing seasonal changes in consumption, to the flexibility necessary and to security of supply;
- the LNG terminals enable import of liquefied natural gas and diversification of natural gas supply sources;
- distribution networks ship gas from transmission networks to end customers who are not directly connected to the transmission networks.

1.2.1 Gas transmission networks in France

There are two natural gas transmission system operators (TSOs) in France:

- GRTgaz, 75% owned by Engie and 25% by the Société d'Infrastructures Gazières (SIG), a public consortium comprising CNP Assurances, CDC Infrastructure and Caisse des Dépôts, operates, maintains and develops a high-pressure gas transmission network of over 32,414 km covering a large part of the French territory with the exception of the south west. GRTgaz ships approximately 646 TWh of gas per year;
- Teréga, owned by a consortium comprising Snam[5] (40.5%), GIC[6] (31.5%), EDF Investissement (18%) and Prédica[7] (10%), operates, maintains and develops a high-pressure gas transmission network of 5,056 km located in the south west of France. Teréga ships approximately 124 TWh of gas per year.

The natural gas transmission network, infrastructure comprising pipelines and compression stations, is composed of:

- a main network (upstream), which includes all the high-pressure and large-diameter pipelines connecting the interconnection points with neighbouring networks, underground storage and LNG terminals. The regional network and the largest industrial customers are connected to it. It is more than 9,500 km in length. Flows are generally bidirectional;
- a regional network (or downstream) which ships natural gas to distribution networks and to customers directly connected to this network. It is more than 28,000 km in length. Flows are unidirectional.

[5] Snam: Italian gas infrastructure operator
[6] GIC: company governed by Singaporean law, specialised in capital investment
[7] Prédica: life insurance company fully owned by Crédit Agricole Assurances S.A.

Users of the GRTgaz and Teréga networks use the gas transmission network for several purposes: transit, which consists in having gas enter these networks (through an entry point - network interconnection point (PIR) or LNG terminal/transmission interface points (PITTM) to ship it to another country (through an exit point - PIR), and domestic transmission, which consists in shipping gas intended for consumption in France. The gas shipped in these networks can be injected into underground natural gas storage facilities, from which it is then withdrawn.

Lastly, the gas shipped in the transmission networks can be the object of transactions (purchase/sale) between shippers in the single marketplace (gas exchange point – PEG).

The transmission network ships gas to 1,123 transmission/distribution interface points (PITD) in the GRTgaz network and 151 PITD in the Teréga network.

739 end customers are directly connected to the GRTgaz network, including 13 gas plants, and 116 are connected to the Teréga network.

1.2.2 Gas distribution networks in France

Approximately 11.5 million customers are connected to the natural gas distribution networks. They are supplied by 26 natural gas distribution system operators (DSOs), of varying sizes:

- GRDF distributes 96% of the natural gas distributed and ships natural gas across most of the French territory;
- 22 smaller DSOs, also called local distribution companies (LDCs):
    - Régaz-Bordeaux and R-GDS which each represent roughly 1.5% of gas volumes distributed and ship natural gas respectively for the city of Bordeaux and 44 other municipalities in the Gironde department, and for the city of Strasbourg and 118 other municipalities in the Bas-Rhin department (including 80 in an equalised tariff zone);
    - 20 other DSOs which represent a total of 1% of gas quantities distributed and are not required by law to legally separate their distribution activities from their production or supply activities;
- 3 DSOs termed "new players" for natural gas distribution in France: Antargaz since October 2008, SICAE de la Somme et du Cambraisis since April 2010 and Séolis since July 2014 whose original business is respectively the distribution of propane and butane gas and the distribution of electricity.

1.2.3 Underground natural gas storage infrastructure in France

The 11 underground natural gas storage sites in operation provides a working gas storage volume of 138.5 TWh and a total withdrawal flow of 2,375 GWh/d for 45% fill level of the working volume. Most winter modulation is provided by this storage infrastructure which covers almost 40% of gas volumes consumed in France during winter. This infrastructure is also a key element for France's gas supply, since interconnections and French LNG terminals are not sized to import all natural gas needs during a cold peak.

There are three underground natural gas storage operators:

- Teréga, owned by a consortium composed of Snam (40.5%), GIC (31.5%), EDF Investissement (18%) and Prédica (10%), operates a natural gas storage site comprising the Lussagnet and Isaute reservoirs, for a working volume of 33.1 TWh;
- Storengy, a subsidiary fully owned by Engie, owns and operates 12 sites in France (including 3 under limited operation), for a working volume in operation of 102.1 TWh;
- Géométhane, owned by Storengy (50%), CNP (49%) and Géostock (1%), owns the Manosque storage site, which has a working volume of 3.3 TWh.

1.2.4 LNG terminals

LNG terminals are port gas infrastructure that receive liquefied natural gas (LNG) shipped by boat, stock it in liquid form and regasify it in order to inject it into the natural gas transmission network. Four LNG terminals are currently in operation in France, including the Dunkirk terminal, which is not regulated.

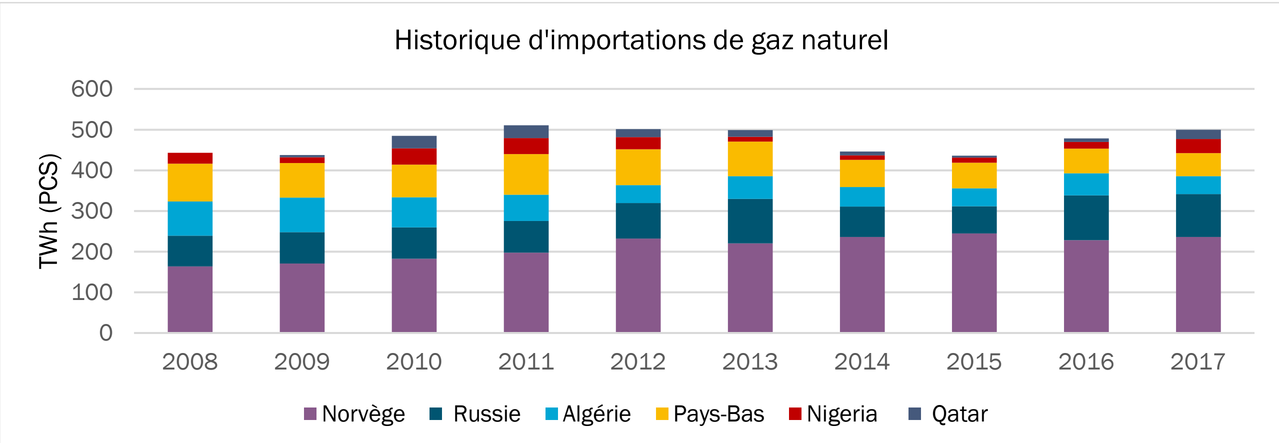
With regard to regulated operators:

- the Elengy company, a subsidiary fully owned by GRTgaz, owns and operates the Montoir-de-Bretagne and Fos Tonkin terminals. The Montoir terminal, brought on stream in 1980, has a regasification capacity of 10 billion m^3 per year. The Fos Tonkin terminal, brought on stream in 1972, has a regasification capacity of 3 billion m^3 per year. Long-term subscriptions in this terminal expire at the end of 2020: early 2019, Elengy launched a call for interest for the subscription of new capacity for the 2021-2030 period;
- the Fosmax LNG company, a subsidiary 72.5% owned by Elengy and 27.5% by Total Gaz Electricité Holding France (TGEHF), owns the Fos Cavaou terminal. Fosmax LNG sells the terminal's regasification capacity. Its operation and maintenance are entrusted to Elengy. The Fos Cavaou terminal, brought on stream as at 1 April 2010, has a regasification capacity of 8.25 billion m^3 per year.

1.3 Major issues underlying the elaboration of transmission and distribution tariffs

1.3.1 Little evolution in France's gas supply over the past few years

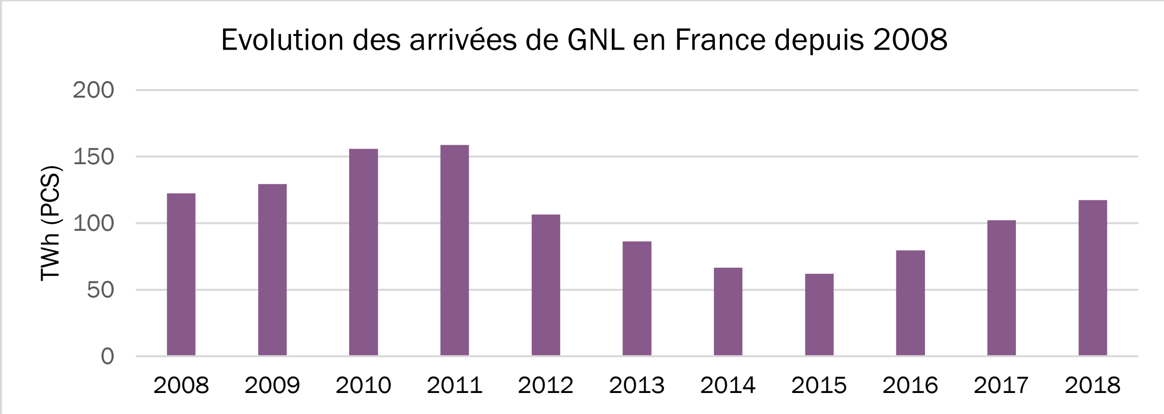
France is completely dependent on imports for its natural gas supply. For several years now, Norway has been France's main supplier, followed by Russia, the Netherlands and Algeria. Since the early 2000s, the development of the global LNG market had led to the emergence of new supply sources, such as Nigeria and Qatar.



Source: general commission on sustainable development

Fluctuations in the valuation of LNG, particularly in Asia, have a direct impact on LNG arrivals in France, since cargo is directed by participants to the most profitable outlets. High LNG prices in Asia, promoted by growth in the zone's demand, in particular following the Fukushima accident and demand for electricity production in China, led to a sharp decline in LNG deliveries in France between 2012 and 2015.

Before the creation of a single marketplace in France, fluctuations in the global price of LNG had a direct impact on the price of gas in the south marketplace (Trading Region South, TRS), the supply of which was 40% dependent on LNG in the Fos terminals, sometimes leading to major de-correlations in prices at the PEG Nord and the TRS.



Source: general commission on sustainable development

The drop in crude oil prices, to which many contracts in Asia are indexed, seen as from 2015, led to a drop in gas prices in Asia, promoting a relative increase in the attractiveness of the European market, and therefore a return of LNG. This trend was enhanced by the development of new gas liquefaction capacity as from 2016, particularly in the USA and Australia. Send-out from European LNG terminals therefore reached a level in January 2019 that had not been seen since June 2011.

In addition, commissioning of American and Australian liquefaction capacity could lead, in the upcoming years, to a supply excess compared to global LNG demand, which could more sustainably confirm the return of LNG seen since 2018.

1.3.2 End of a major investment cycle with merging of zones

The improvement in the functioning of the gas market, which has been a main goal pursued by CRE since its creation, was made possible thanks to the strengthening of integration with neighbouring markets on the one hand, and the progressive simplification of the organisation of the French market on the other hand. These two axes required significant reinforcement work in the transmission network, particularly to reduce bottlenecks, or to facilitate new assets brought on stream.

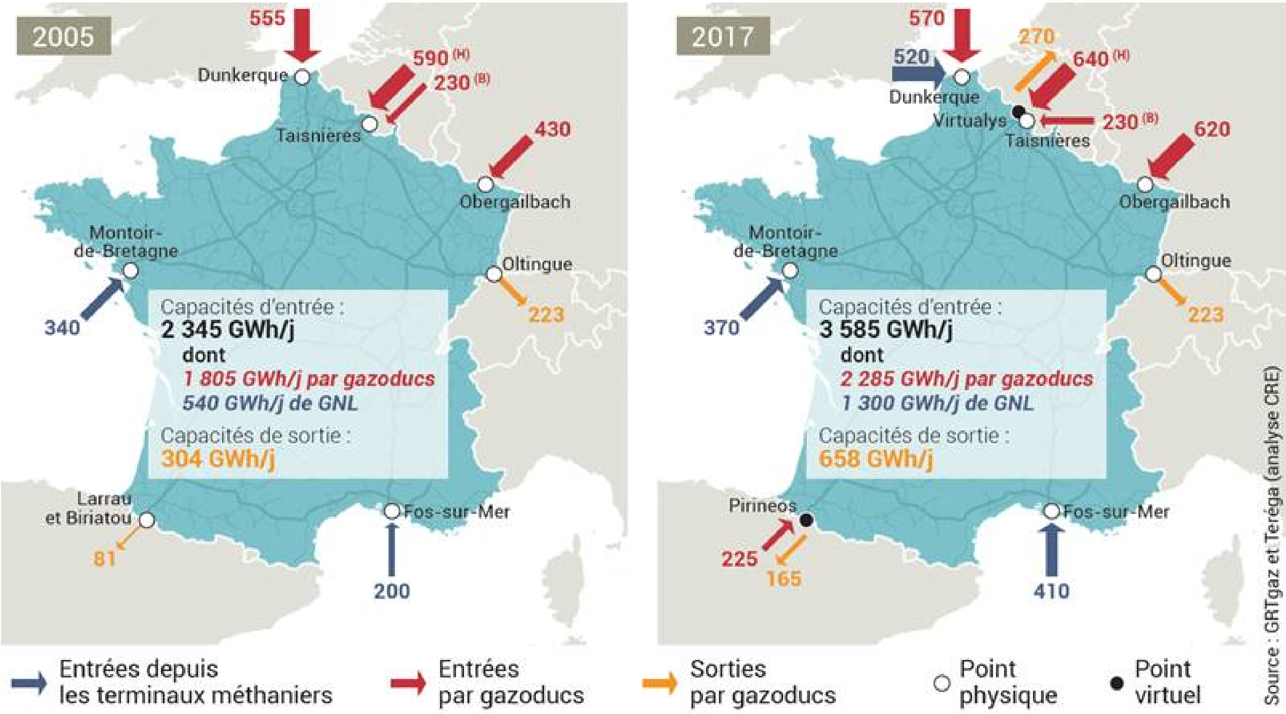
Investments were done with all neighbouring countries to strengthen interconnections. Since 2005, CRE has supported the development of gas interconnections using open season procedures to secure project funding. These open seasons led to the creation of considerable firm entry and exit interconnection capacity with Germany, Belgium and Spain. Today, the French gas system is flexible and well-integrated into the rest of European market. Market participants can therefore choose between different gas sources and efficiently handle any changes in flow patterns.

In addition, commissioning of the Fos Cavaou terminal in 2010 and the Dunkirk terminal in 2016 contributed to increasing and geographically diversifying natural gas entry sources in the transmission network.

The final stage in 15 years of major investments was achieved with the merging of the TRS and PEG Nord marketplaces as at 1 November 2018, which was based on a joint investment programme between GRTgaz and Teréga consisting in strengthening the Val-de-Saône and Gascogne-Midi pipelines. The 190 km of the Val-de-Saône project have increased gas transit capacity between the north and south of France to up to 250 GWh/d. The strengthening of Gascogne-Midi has ensured a capacity of 140 GWh/d from the south-west to the south-east thanks to 62 km of pipeline and new compression capacity.

This single marketplace, operational since 1 November 2018 closed a major cycle of investments, which served to introduce a single price in the French wholesale markets, to the benefit of all French customers, and to strengthen France's security of supply, by improving access to different gas sources. Spain and Portugal, supplied in particular by gas flowing through France, also reap the benefits.

In 2019, France has land interconnection points with Belgium, Germany, Switzerland and Spain, and it is directly connected by the Franpipe pipeline to the Norwegian production fields located in the North Sea. France also has four LNG terminals (Fos Tonkin, Fos Cavaou, Montoir-de-Bretagne and Dunkirk LNG).



CRE considers that the dimensions of the French transmission network are currently sufficient. In addition, stagnation of consumption for the last ten years and the drop envisaged based on the different scenarios by TSOs for 2030, particularly within the framework of energy transition goals, leads CRE to be particularly vigilant in the future when examining any new investment project that will be submitted by the TSOs. They will be subject to a robust cost/benefit analysis in order to prevent useless costs from being passed on to end customers.

1.3.3 Regulation of underground natural gas storage to guarantee security of supply

The law of 30 December 2017 ending the search for and operation of hydrocarbons introduced regulation of natural gas storage, in order to guarantee filling of storage facilities necessary for security of supply, while making storage costs transparent. The Energy Code states henceforth that:

- the storage capacity necessary for the territory's security of supply is set by the government in the multiannual energy programme (PPE);
- storage operators' revenue corresponding to this capacity has been regulated as from 1 January 2018: CRE determines this revenue and can implement incentive measures;
- storage capacity is sold at auctions to reflect market value of natural gas storage, based on modalities approved by CRE proposed by storage operators;
- the difference between revenue collected directly by storage operators (mainly through auctions) and their authorised income is compensated by the gas transmission tariff.

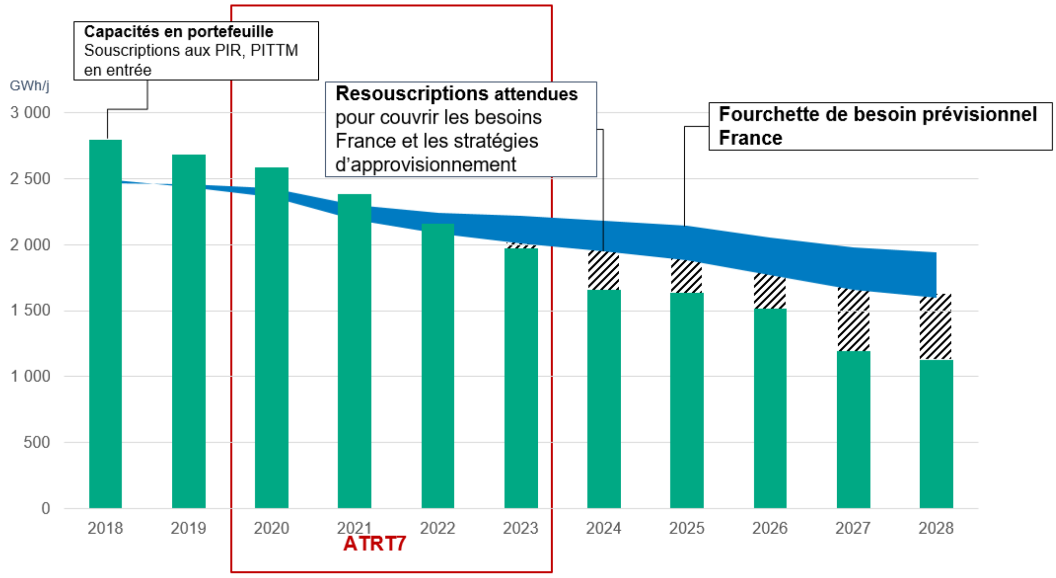
The initial results of the implementation of the reform are positive, with, on the one hand auction modalities which led to the booking of storage capacity necessary to ensure security of supply, and on the other hand, an almost 30% drop in the unit cost of storage (these costs were reduced to €5.2/MWh in 2018 instead of an average €7.5/MWh in 2016).

1.3.4 Long-term booking contracts at interconnections expiring over the ATRT7 period

Transmission capacity at the interconnections with Belgium, Germany and Spain were developed based on shippers' long-term booking commitments within the framework of open seasons. In addition, long-term capacity had been booked at certain interconnections in the initial years of market opening to competition.

During the ATRT6 tariff period, these long-term booking contracts were still in effect, maintaining the rate of capacity booking at interconnections at high levels: firm annual entry capacity at the Taisnières, Dunkirk, Obergailbach and Pirineos PIRs were 75% booked, while firm annual exit capacity at the Alveringem, Oltingue and Pirineos PIRs were over 80% booked.

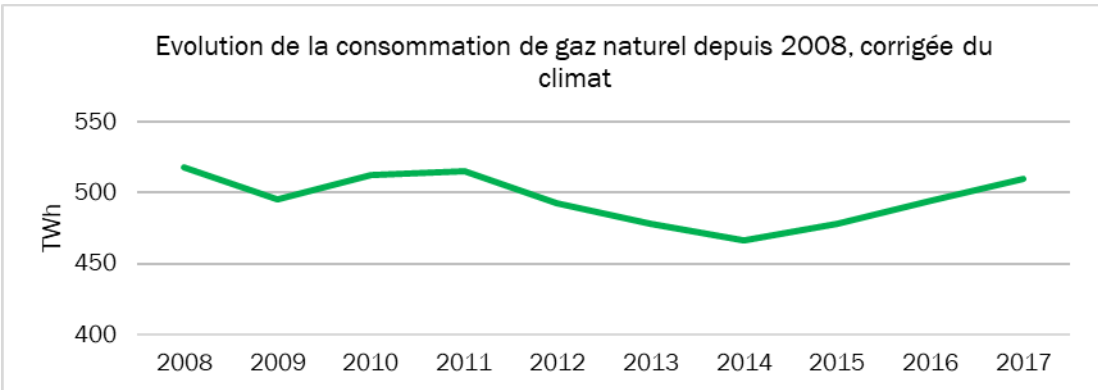
However, a certain number of these commitments will expire during the ATRT7 period. Since the actual level of use of these points was lower than the capacity booked, the TSOs expect that a portion of the capacity that will again be available will not be booked in the short term following the expiration of these commitments. Significant drops in the levels of capacity booked should therefore be observed at all interconnections in the GRTgaz and Teréga networks between 2019 and 2023.



Source: GRTgaz

1.3.5 Natural gas consumption prospects in France on a downward trend

In 2017, total gas consumption (adjusted for climate) in France reached 494 TWh, up 1.4% compared to 2016. After a decline in consumption at the start of the decade, the years 2015-2017 were characterised by an increase in gas demand. This increase is due mainly to greater use of gas for electricity production. Between 2008 and 2017, French natural gas consumption, adjusted for climate, dropped by about 4%.



Source: general commission on sustainable development

The first multiannual energy programme (PPE) covered the periods 2016-2018 and 2019-2023. The next PPE will cover the periods 2019-2023 and 2024-2028. The draft PPE[8] was published on 25 January 2019 for consultation. This draft includes in particular:

- the lowering of primary consumption of fossil natural gas by 19% compared to 2012 to reach 387 TWh[5] in 2028;
- total gas consumption of 420 TWh in 2028, thanks to energy demand management.

In the forecast report done in 2018[9], GRTgaz and Teréga elaborated four scenarios based on two axes (momentum of energy transition and complementarity of electricity and gas networks). The TSOs anticipate a drop in consumption in three of the four scenarios and an almost constant consumption in one scenario. The four scenarios feature a major consumption reduction in the residential and tertiary sectors and a development of gas mobility.

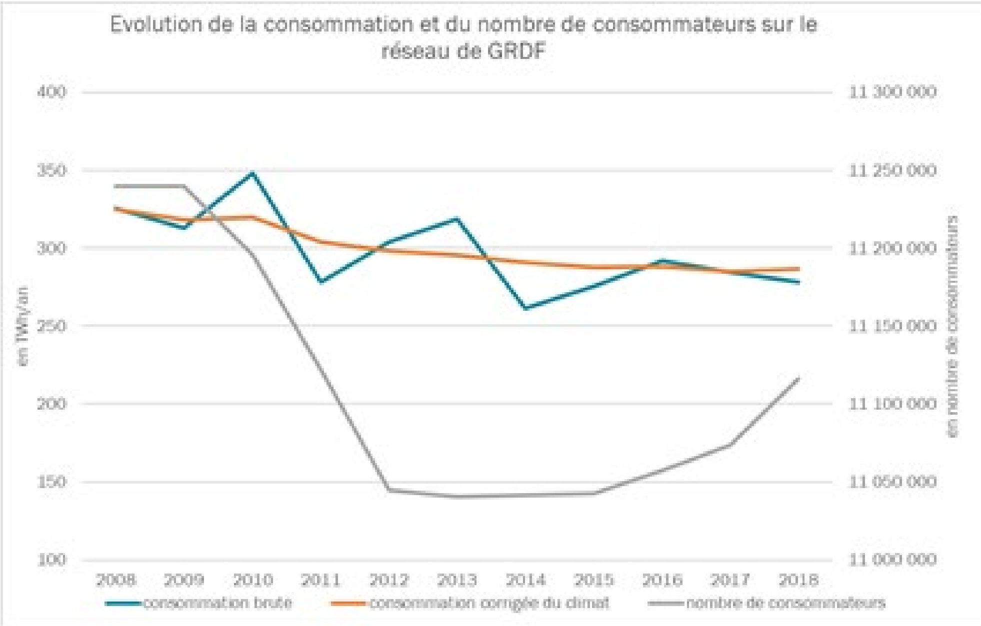
[8] Draft PPE for consultation
[9] http://www.grtgaz.com/fileadmin/plaquettes/fr/2019/Perspectives-Gaz-2018.pdf

1.3.6 Energy transition, biomethane and new uses such as NGV

The prospect of a drop in gas consumption is part of a larger context of energy transition and goals to lower the production of greenhouse gases.

Achieving the objectives of the PPE will require a reduction in energy consumption, particularly of fossil origin, an adaptation of infrastructure to new uses, and a progressive change in the energy mix, including the development of renewable gas.

A reduction in energy consumption is already underway, particularly with residential customers who adopt new behaviours to control their gas demand.



Source: GRDF

In the global downward trend in gas consumption by historic sectors mentioned above, there are however some new uses which should attenuate this drop, without challenging the greenhouse gas emission reduction goals related to all thermal energy sources. The natural gas for vehicles sector (NGV and bioNGV) in particular must be developed.

The draft PPE submitted for consultation in January 2019 sets a goal of 14 to 22 TWh of biogas injected into networks by 2028. Reaching goals concerning biomethane injected will require a substantial budget commitment from the State (between €7 and 9 billion in additional public spending for the development of renewable gas between 2019 and 2028) as well a considerable volume of investment in networks to adapt them to facilitate numerous production sites.

Lastly, operators are working to create a synergy between electricity and gas systems, in particular with the Power to gas demonstrators, which could enable storage of renewable electric energy.

1.3.7 European network codes

European network codes aim to harmonise market operation rules in order to create an integrated gas market at European level: in that regard, they introduce common rules concerning the technical and commercial conditions surrounding access to the gas transmission network. In its work and decisions relating to market rules, CRE ensures proper implementation of these codes.

In its deliberation of 13 February 2014[10], CRE decided to prepare the implementation of the capacity allocation mechanism (CAM) code[11], relating to gas transmission capacity allocation rules, in particular by replacing the old capacity attribution system proportional to demand by the ascending auction system specified by the CAM code. In addition, for the selling of transmission capacity at auctions, the PRISMA platform was created jointly by 20 TSOs from seven European Union member states. This platform, accessible since 1 April 2013, is currently used by most

[10] CRE deliberation of 13 February 2014 deciding on the progressive implementation of the European gas transmission capacity allocation code at interconnection points between entry/exit zones

[11] Regulation (EU) No 984/2013 of the Commission of 14 October 2013 establishing a network code on capacity allocation mechanisms in gas transmission systems

European TSOs, including GRTgaz and Teréga. It is used to sell primary and secondary capacity, based on the harmonised timetable and under conditions set by the CAM code.

The "Balancing" network code[12], has applied since 1 October 2015 in France. To implement that code, CRE prepared as from 2011[13] its entry into effect, approving the trajectories towards the target balancing system proposed by GRTgaz and Teréga, and the evolutions in this system, between 2012 and 2015.

The Interoperability and Congestion Management Procedure (CMP) codes have also been applied by the TSOs since 2015.

In addition to these four network codes already implemented in France, a fifth code, relating to harmonisation of methodologies for calculating gas transmission tariffs entered into effect on 4 April 2017[14].

This network code was elaborated by the European network of gas TSOs (ENTSOG, European Network of Transmission System Operators for Gas) based on guidelines[15] published on 29 November 2013 by the Agency for the Cooperation of Energy Regulators (ACER).

It sets transparency and non-discrimination objectives in terms of the calculation of gas transmission tariffs. Tariffs must be determined so as to reflect costs actually incurred by the TSOs. Use of a transparent methodology guarantees the market that there is no cross-subsidisation between different categories of transmission network users (for example, between shippers performing transit and those delivering to national customers).

The current transmission tariffs in France meet most of the requirements of the code and already largely comply with the level of transparency imposed by the Tariff network code, even though this code was not yet in effect at the time.

1.3.8 Development of competition in the retail market

Proper functioning of the wholesale markets is essential for the development of competition in the retail market. Improvement in liquidity and access to diversified supply sources enable suppliers to propose competitive offers. Since July 2007, the gas market has been open to competition for all clients, both businesses and households.

As at 31 December 2018, alternative suppliers supplied 29% of customers, which represents 58% of national consumption. At the same date, 61% of sites had booked a market offer (i.e. 90% of national consumption):

- 6,392,000 sites out of a total 10.7 million residential sites henceforth have market offers, i.e. 60% of residential sites;
- almost all non-residential sites have market offers: 595,000 sites out of a total 659,000, i.e. 90% of sites.

1.3.9 Stability in the structure of tariffs for the use of networks for downstream network customers

The tariff structure for national customers, whether directly connected to the transmission network or connected to the distribution network, was stable over the last tariff periods.

In the transmission network, since the equalisation of the main network exit charge decided in the ATRT3 tariff[16], the structure of tariffs for customers has been stable, comprising a single main network exit charge, a regional network transmission charge weighted by the level of the regional tariff and a delivery charge.

Two developments were introduced within the framework of the ATRT6 tariff, with regional tariff levels being limited to 10 and a discount on connection being introduced, to encourage new connections which would reduce the unit tariff. New developments aiming in particular to simplify the tariffs for industrial customers are envisaged (see 2.2. of the present public consultation).

With regard to distribution, the tariff structure has remained the same since its creation in 2003. To facilitate suppliers' access to the market in the service areas of all DSOs, the tariff structure is common to all DSOs, and as from 2021, all ATRD tariffs will be homothetic to that of GRDF[17].

This structure has the advantage of being simple and robust and opened up the gas market. Nevertheless, the evolution in customer behaviour, in particular the drop in their unit consumption in connection with their efforts to

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[12] Regulation (EU) No 312/2014 of the Commission of 26 March 2014 establishing a network code on gas balancing of transmission networks
[13] Deliberation of the French Energy Regulatory Commission of 1 December 2011 approving the evolution of balancing rules for the GRTgaz and TIGF transmission networks
[14] Regulation (EU) 2017/460 of the Commission of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas (Text with EEA relevance)
[15] Framework Guidelines on rules regarding harmonised transmission tariff structures for gas
[16] Tariff proposal by the French Energy Regulatory Commission of 10 November 2006 for the use of natural gas transmission networks
[17] With the exception of the proximity charge for two DSOs

control their gas demand, justifies considering a change in some aspects of the distribution tariff structure. In addition, the impact of the arrival of biomethane production installations connected to the distribution networks must be studied.

Lastly, a certain continuity between transmission and distribution tariffs must be sought so as to not hinder the competitiveness of large industrial sites connected to the distribution networks.

1.3.10 Summary: stakes regarding the tariff structure of gas networks

For gas distribution networks, the stakes are relatively limited

First, since gas consumption is following a downward trend, gas networks are developing less than before and are therefore not in a phase of extension to meet consumption needs. In the upcoming years, investments related to the integration of biomethane production installations into the networks will partially offset this effect. In addition, there is less compensation between positive and negative consumption differences for gas networks than for electricity, making it useless to send tariff signals that are too complicated. However, despite these observations, the analysis of GRDF's accounts shows that the volume of investments in "network developments" has remained relatively constant, leading to a stable or even slight increase in the "network" RAB[18]. Sending signals to control the winter peak, and therefore avoid network enhancements that would be useless in the long term, should therefore be studied.

The main stake for the tariff structure of gas distribution networks is however societal, and does not concern network costs: it is about energy management, particularly important for gas which is a high-carbon energy source. Pricing of gas networks must conserve a significant portion proportional to energy to serve as an incentive to consumption management.

The other major stake, in general, of network pricing is the allocation of costs among users. It must be ensured that the different categories of customers pay for their use of the networks in relation to the costs that they generate for the networks. This is traditionally a delicate exercise, since it is a matter of allocating among customer categories costs of networks that are already built, which are by nature used by very large groups of customers. A large proportion of these costs cannot be attributed to a specific category of customers and therefore must be distributed by coefficients whose relevance is always up for debate. In the end, multiple methods exist to allocate these costs, which often lead to varied results. These methods can serve to identify trends and prevent any excesses in the coverage of costs that might occur.

The other objectives pursued by CRE in network pricing are: simplicity, readability, predictability and continuity. For several tariff exercises, CRE adopted a simple and stable tariff structure for gas distribution. It intends to continue in this direction for gas distribution, while making adjustments necessary for the changes in the uses of these networks.

Greater stakes for the gas transmission networks

The same characteristics exist for the pricing of gas transmission networks. However, gas network pricing, and more broadly, all the rules for accessing this network, play a major role in the proper functioning of the wholesale gas market. With France importing almost all of the gas it consumes, the conditions for accessing the French market and its attractiveness are essential for the liquidity and depth of this market, and therefore for its capacity to reveal gas prices reflecting the balance between demand and supply.

For several years, CRE's strategy has consisted in simplifying the tariff framework and strengthening interconnections so as to build a liquid market well correlated with the north-west European wholesale markets. The creation of a single market zone in 2018 market was an important milestone. However, it remains very important for the French market, on the one hand, to maintain and enhance its attractiveness for LNG, and on the other hand, to remain correlated with north-west European markets.

CRE considers that the pricing of gas transmission networks must take into account these stakes, in addition to the traditional objectives of simplicity, predictability and continuity already listed above.

1.4 Work schedule

In accordance with the provisions of the Tariff network code, in particular its articles 26, 27 and 28, CRE plans to shorten the ATRT6 tariff by one year, which should therefore end in 2020 and not in 2021. Shortening the ATRT6 tariff is also an opportunity to harmonise the entry into effect of the transmission tariffs (ATRT7), distribution tariffs (ATRD6) and storage tariffs (ATS2). CRE is therefore conducting work in parallel to prepare the next ATRT7, ATRD6 and ATS2 tariffs. For that purpose, it has already organised or is planning to organise several public consultations in 2019:

[18] RAB restricted to G1 accounting group (pipelines and connections)

- a public consultation, relating to the tariff regulation framework applicable to regulated infrastructure operators in France, which was launched on 14 February 2019[19];
- the present public consultation covering the main changes envisaged concerning the ATRD6 tariffs structure, conducted alongside CRE's consultation on the structure of the ATRT7 and ATS2 tariffs;
- a public consultation relating to the consideration of the development of biomethane in the networks in spring 2019;
- a public consultation in summer 2019, in which CRE will present, taking into account the contributions it will have received within the framework of the previous consultations, its proposals for the evolution in the regulation framework and structure of the ATRT7 tariff, as well as the TSOs' tariff demand and its analyses of this demand and of the level of the ATRT7 tariff. This consultation will last two months and will be submitted to ACER for its opinion, in compliance with the provisions of the Tariff network code. In parallel, CRE will run a public consultation on the level and the regulation framework of the storage tariff (ATS2), as well as a consultation, in autumn, on the level and the regulation framework of GRDF's ATRD6 tariff.

CRE intends to adopt at the end of 2019 decisions concerning the next tariffs for the use of the transmission, networks, distribution networks, and storage infrastructure, for entry into effect of the ATRT7 tariff as at 1 April 2020, of GRDF's ATRD6 tariff as at 1 July 2020, and of the ATS2 tariff as at 1 January 2020.

1.5 Purpose of the public consultation

CRE wished to gather market participants' opinion on its initial guidelines envisaged concerning the major evolutions to be taken into account in the ATRD6 tariffs, regarding the tariff structure.

2. CURRENT STRUCTURE OF THE ATRD TARIFFS AND ISSUES INVOLVED

2.1 History of the current ATRD tariff schedule

The existing ATRD structure was established in 2003 when the first ATRD tariff was created. It had been designed so that each tariff option covers the costs generated by the consumers concerned, taking into account the structure of regulated sale tariffs to promote competition and the correct operation of the market.

The structure has changed very little since 2003. Successive annual changes to the level of the tariff have been applied in equal proportions to all of the terms in the tariff schedule, except for years when the CTA rate was introduced and updated (see 3.1), and also the introduction on 1 January 2018 of a tariff term R_f for the financial compensation paid to suppliers for management of customers under a single contract. This term R_f changes according to specific rules.

The current structure is therefore very similar to that proposed in 2003 and is common to all of the DSOs. The tariff includes four main options:

- three options labelled T1, T2, T3, each comprising two components, namely a subscription term and a term proportional to the quantities delivered:
    - T1: annual consumption between 0 and 6,000 kWh (approx. 3 million consumers representing 9% of GRDF’s authorised revenue);
    - T2: annual consumption between 6,000 and 300,000 kWh (approx. 8 million consumers representing 68 % of GRDF’s authorised revenue);
    - T3: annual consumption between 300,000 and 5,000,000 kWh (approx. 100,000 consumers representing 16% of GRDF’s authorised revenue);
- one option labelled T4, which includes three components: a subscription term, a term proportional to the daily capacity subscribed, and a term proportional to the quantities delivered, scaled for consumers with annual consumption in excess of 5,000,000 kWh (approx. 2,700 consumers, representing 5% of GRDF’s authorised revenue).

A special tariff option referred to as the “proximity tariff”, which includes three components (distance to transmission network, capacity and annual subscription) is designed for major consumers who are based close to the gas transmission network and already supplied via the distribution networks. The distance-based term is allocated to a multiplier, based on the population density of the municipality in which the delivery point concerned is situated. Around fifty consumers are currently covered by this option.

[19] Public consultation of 14 February 2019 No 2019-003 relating to the tariff regulation framework applicable to regulated infrastructure operators in France

For a given delivery point, the supplier is free to choose the tariff option on behalf of the consumer concerned. The tariff is applied by delivery point.

Finally, there is also a penalty mechanism for cases where subscribed capacity is exceeded, for tariff options T4 and TP.

For consumers without an individual meter (i.e. around 150,000 consumers), billing arrangements are as follows:

- for all end consumers in a residential building or group of housing units without an individual meter but with a collective meter, and who have collectively signed a supply contract, a subscription equal to that of option T1 is billed, applied to the number of homes supplied with gas, and a proportional component equal to that of tariff option T1 is applied to the gas consumption measured by the collective meter;
- for a consumer with neither a collective nor an individual meter, a fixed price based on annual consumption of 660 kWh is applied.

Since 2016, CRE has updated the rules on allocation of standard frequencies for reading metering and estimation points (PCEs), using the annual reference consumption (CAR) value as a criterion for allocating the standard frequency, replacing the previous method which was based on the tariff option subscribed.

The table shows certain characteristics of GRDF's customer portfolio in 2016:

Tariff option	T1	T2	T3	T4	TP
N° of consumers at end of 2016	3 million	7.8 million	98,000	2,700	33
"Theoretical" annual consumption type	Cooking and/or domestic hot water	Individual heating	Collective heating + small-scale tertiary	Large-scale tertiary and industrial	
Theoretical annual consumption threshold	< 6 MWh	Between 6 and 300 MWh	Between 300 and 5,000 MWh	Above 5,000 MWh	n/a
% of quantities shipped	Approx. 2%	Approx. 48%	Approx. 30%	Approx. 20%	
Current regulated sale tariff	Base (cons. ≤ 1 MWh) or B0	B1 and B2i	n/a	n/a	
Theoretical consumption profile	P011	P012	P013 to P019		
Type of reading	6M (biannual)*	6M (biannual)*	MM (monthly)	JJ or JM (daily)	
% of authorised revenue	9%	68%	18%	5%	

* 1M (monthly) reading for consumers with Gazpar meters.

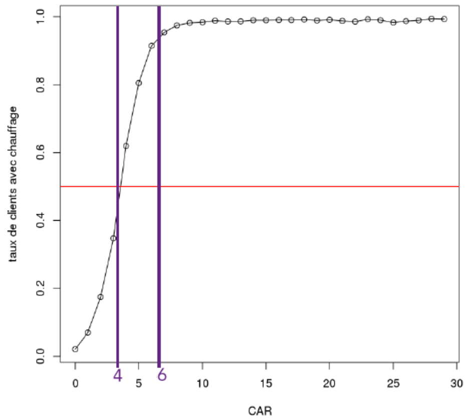
Source: GRDF

2.2 Changes since 2003

Since the first tariffs were introduced in 2003, GRDF's customer portfolio has changed, notably in terms of the distribution of consumers between the different tranches of consumption. This has caused the volume of each of these options to vary, and resulted in changes in average behaviour within these options.

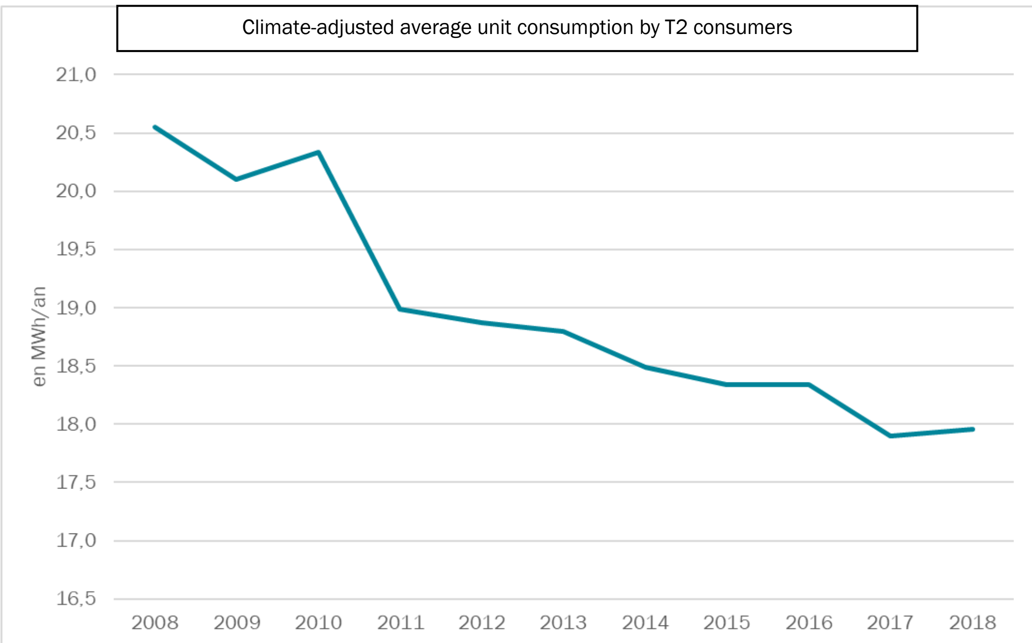
The most significant changes include:

- the arrival of heating customers (who are thermosensitive) in option T1 (traditionally non-thermosensitive, since linked to uses such as cooking and domestic hot water); the diagram below, produced following a survey carried out by GRDF in 2016 (based on self-evaluation), shows that above 4 MWh, over half of consumers use gas for heating:



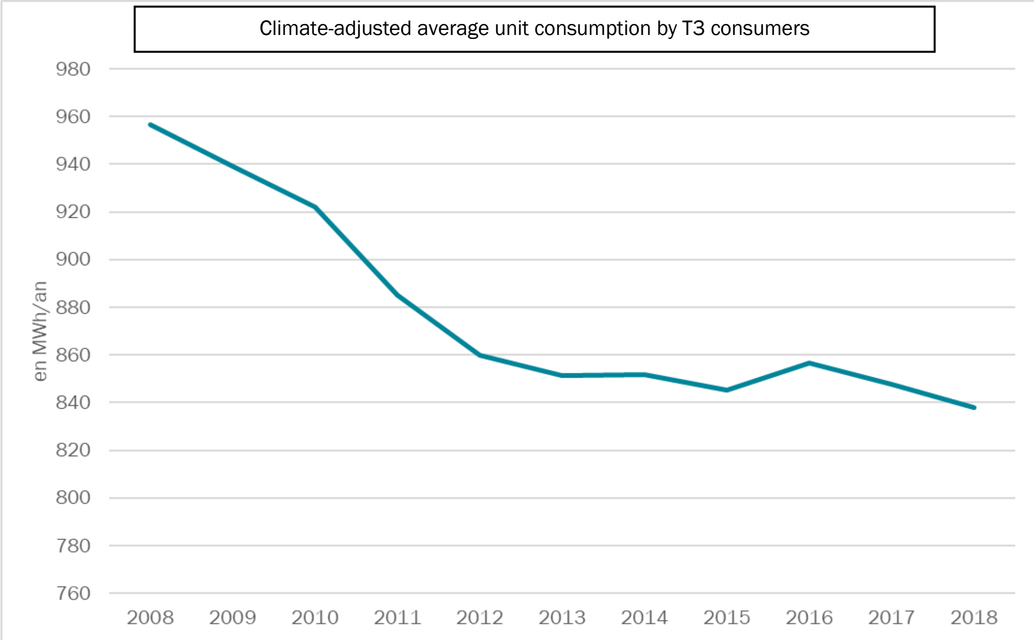
Source: GRDF

- a decline in unit consumption by consumers under options T2 and T3, largely due to energy savings: the diagram below shows how the total CAR values of consumers on the GRDF network with a P012 profile have changed in recent years (a fall of around 19% over ten years). A T2 option was subscribed for the vast majority of these consumers.



Source: GRDF

- a decline in unit consumption of T3s:



Source: GRDF

These changes to the consumer portfolio have several implications:

- the tariff options now cover more varied consumer typologies than was previously the case;
- it is not certain that the current tariff schedule continues to reflect the costs generated by changes in consumer behaviour.

Consequently, there are legitimate grounds for CRE to carry out an in-depth analysis of the tariff schedule, and to consider making changes. In accordance with the ATRD5 tariff deliberations, CRE and GRDF began work in 2017 to analyse the structure of GRDF's portfolio and cost allocation. Similar work was undertaken with the LDCs. This work resulted in the various proposals outlined in the next chapter.

The arrival of data from smart meters (in mid-March 2019, with around 3 million consumers now equipped with Gazpar meters) will provide a clearer picture of the behaviour of T1 and T2 consumers, and contribute to work on the structure of the ATRD tariffs.

2.3 Calendar for implementation of possible structural changes

Any changes to the tariff structure ultimately adopted could be rolled out on 1 July 2020, when GRDF's ATRD6 tariff is also due to come into effect. However, CRE is mindful of the challenges involved in modifying the structure of the ATRD tariffs, particularly as regards the time needed for DSOs and suppliers to upgrade their information systems, and the need to maintain proportionality between the LDCs' tariffs and that applicable to GRDF. Consequently, the calendar for implementing tariff structure changes could be delayed, for example to 1 July 2022, the date on which the LDCs' ATRD6 tariffs are due to come into effect, in order to provide market participants with sufficient visibility. In this case, the changes to the tariff structure would be defined in the tariff deliberation to be published at the end of 2019, but the current structure would continue to apply until 1 July 2022.

Q1 : In your opinion, what would be the most suitable calendar for implementing the changes adopted to the ATRD tariff structure?

3. SUGGESTIONS AND PROPOSALS FOR CHANGES TO THE STRUCTURE OF DISTRIBUTION TARIFFS

3.1 Continuity between tariff options

Since the first ATRD tariff came into effect, the terms of tariff options have been defined to ensure continuity at the consumption thresholds separating each tariff option. For each of the consumption thresholds between different tariff options (6 MWh/year between options T1 and T2, 300 MWh/year between options T2 and T3, and 5 GWh/year between options T3 and T4), the annual tariff paid by the consumer will be identical, whether he is in the option above or below the threshold. This principle of continuity across thresholds is designed to prevent creating differences in level between options at those threshold, and to provide suppliers with an incentive to choose the most appropriate tariff option for the consumer's consumption.

It is worth noting that continuity is only strictly possible between two options with the same number of tariff terms. For example, in GRDF's ATRD5 tariff, the continuity between option T3, which includes two terms (subscription component and volume-based component) and option T4, which includes three terms (with the addition of annual subscription for daily capacity) cannot be exact[20].

Law n°2004-803 of 9 August 2004, on public service electricity and gas and electricity and gas companies, introduced a tariff contribution on electricity and natural gas transmission and distribution services (known as the "CTA"), with the proceeds being paid into the National Electricity and Gas Industries Fund ("*Caisse nationale des industries électriques et gazières*"). This contribution is intended to finance specific entitlements under the special pensions regime of the electricity and gas industries, excluding changes introduced after 31 December 2004, and applies to the non-consumption-based portion of tariffs (for the ATRD tariff: annual subscription, capacity terms, annual distance-based term and fixed term, with a current rate of 20.8%). The CTA's introduction resulted in a fall in pension costs borne directly by the DSOs. In 2005, during work to establish the ATRD2 tariffs, CRE took account of this new contribution whilst seeking to ensure continuity with the tariff schedules of the ATRD1 tariff. Tariff continuity at the thresholds between options was thus established, taking into account the application of the CTA, to ensure that it did not significantly alter the total amount of the distribution bill.

A number of market participants have told CRE they would like to see this method changed in the future tariff schedule, so that continuity is established across the terms of the ATRD tariff only, without taking account of the CTA, as the historic reason for this continuity has waned over the years.

At this stage, CRE is of the opinion that including the CTA is not entirely consistent with the rationale whereby network costs are reflected in the terms of the tariff schedule for GRDF's tariff. Since the CTA is based on the non-consumption-based portion of tariffs, its inclusion in calculations of threshold continuity actually creates discontinuity in tariff revenue, when strictly considering the ATRD tariff (i.e. not including the CTA). This could lead to cross-subsidies between consumers with different tariff options. For example, with the ATRD5 tariff schedule, a large T1 consumer pays a higher ATRD tariff than a small T2 consumer for a similar volume of consumption. The bill changes resulting from inclusion of continuity without the CTA are examined in the next paragraph.

Q2 : Are you in favour of establishing tariff continuity between two tariff options without including the CTA?

3.2 Consideration of thresholds between tariff options

3.2.1 Threshold between options T1 and T2

Consumption by most of the 11 million residential or small-scale professional consumers connected to GRDF's distribution network is read biannually, or monthly in the case of consumers equipped with a Gazpar meter. For these consumers, GRDF produces a daily consumption estimate using the profiling system.

The profiling system, defined under the aegis of the Gas Working Group (GTG), is comprised of nine profiles adapted to reflect the different consumer/consumption typologies. Two consumption profiles are specifically associated with consumers whose meters are read biannually, and are allocated on the basis of the annual reference consumption (CAR) of the PCE[21]:

- profile "P011" for consumers whose meters are read biannually or with a smart meter and whose CAR is below 6 MWh per year. This profile is used to estimate consumption by consumers whose consumption statistically does not depend on the climate to any great extent, being largely for cooking and/or domestic hot water;
- profile "P012" for consumers whose meters are read biannually or with a smart meter and whose CAR exceeds 6 MWh per year. This profile is used to estimate consumption by consumers whose consumption is statistically heavily dependent on the climate, largely owing to the use of heating.

This 6 MWh per year CAR threshold between profiles P011 and P012 is the same as the threshold between tariff options T1 and T2.

Since the profiles were first created, demand side management efforts, such as improvements to home insulation, have resulted in a lowering of unit consumption values, notably among consumers whose meters are read biannually. Consequently, smaller thermosensitive consumers shifted into consumption profile P011 as a result of their

[20] In GRDF's ATRD5 tariff, the continuity between options T3 and T4 is based on a hypothetical modulation of 178 days for option T4.
[21] PCE: metering and estimation point.

lower consumption, while continuing to use gas for heating purposes. This trend gradually introduced bias into the calculation of their estimated consumption by GRDF.

In 2011, GRDF carried out studies that were subsequently presented to the GTG working group, proposing changes to the profiling system to take account of this trend. The preferred solution for ensuring that changes in consumption are reflected most accurately is to lower the CAR threshold between profiles P011 and P012 from 6 MWh per year to 4 MWh per year.

Alongside this, the subject of lowering the threshold between tariff options T1 and T2 was examined. A question was first posed concerning this topic in 2011, in the public consultation on GRDF's ATRD4 tariff which came into effect on 1 July 2012, raising the possibility of implementing this measure in tandem with a lowering of the CAR threshold between profiles P011 and P012. At the time, CRE ultimately decided not to alter the threshold between options T1 and T2, as this would have resulted in a significant rise in gas bills (up to 10%) for around 500,000 consumers (those in the consumption band between 4 and 6 MWh per year). However, in response to the public consultation, some suppliers had indicated that they did not want the threshold between profiles P011 and P012 lowered from 6 to 4 MWh as long as the threshold between tariff options T1 and T2 remained at 6 MWh, largely due to difficulties with the suppliers' information systems.

Consequently, profile P011 was revised in order to better reflect the fact that some of these consumers use gas for heating, while the threshold between profiles P011 and P012 was maintained.

During work to establish GRDF's ATRD5 tariff, which came into effect on 1 July 2016, CRE once again consulted market participants regarding the threshold between tariff options T1 and T2. Given the improvements seen in estimates of daily consumption under the profiling system, following the changes to profile P011, CRE proposed maintaining the threshold between tariff options T1 and T2 at 6 MWh per year.

However, while the change to profile P011 allowed for more reliable estimates for smaller consumers, it did not satisfy the need to make the profiles and tariff options more homogeneous in terms of the behaviour of their respective consumer populations. Incidentally, the share of heating consumers in the band 4-6 MWh continues to rise. Maintaining a cut-off threshold at 6 MWh per year therefore introduces a degree of heterogeneity into the population group of consumers under option T1, and could result in cross-subsidies within that group. For this reason, for the next ATRD6 tariffs, CRE is keen to re-examine the relevance of this threshold between options T1 and T2.

In addition, implementing this change to the structure of the ATRD tariffs on 1 July 2022 would allow a possible similar change to profiles P011 and P012 to be introduced at the same time. Although it is not strictly necessary for CAR values to be uniform between tariff options and profiles, CRE shares the view that it is nonetheless desirable for reasons of consistency and ease of management.

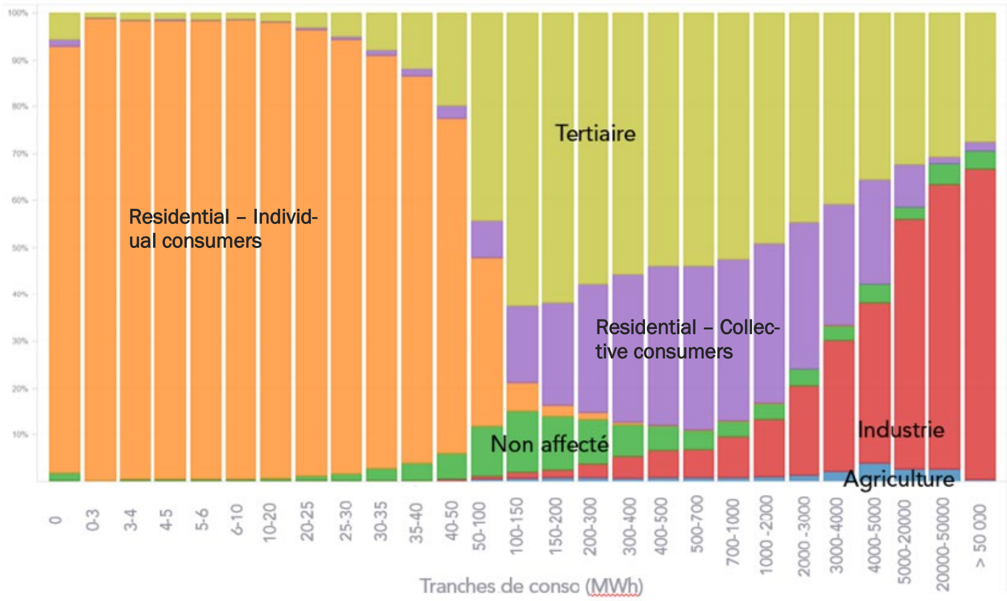
CRE has analysed the effects of the two structural changes envisaged affecting options T1 and T2 (i.e. lowering the threshold between options T1 and T2 and excluding the CTA for the purpose of calculating threshold continuity), by testing several tariff schedules. Initial findings show that both changes can be introduced while limiting the impact on the overall bill, since the maximum gas bill rise is between 4.5 and 6% depending on the simulations (notably taking into account the effect of a profile change on the other terms of the gas chain). Smaller T2 consumers from the new structure (i.e. those with annual consumption slightly above 4 MWh) would see the biggest increase in their overall bill.

Q3 : Are you in favour of lowering the cut-off threshold between tariff options T1 and T2 from 6 MWh to 4 MWh?

Q4 : Do you share CRE's view that changes to the threshold between tariff options T1 and T2 should be concomitant with changing the threshold between profiles P011 and P012?

3.2.2 Splitting option T2

Tariff option T2 includes more consumers than any other, approximately 8 million, with annual consumption of between 6 and around 300 MWh. Studies by GRDF have identified a threshold between 30 and 50 MWh, representing the distinction between a relatively homogeneous population of individual residential consumers (with a thermosensitive profile) on the one hand, and the rest of the consumers within that option as defined currently, with much more varied consumption behaviour (collective heating, tertiary businesses and small-scale industry, in particular):



Source: GRDF (2016 data)

A question was posed on this issue in 2011, in the public consultation on GRDF's ATRD4 tariff, which came into effect on 1 July 2012. At the time, CRE proposed to split the tariff option in two, with a cut-off threshold at 30 MWh per year. However, this change was not adopted, as the IT upgrades necessary were judged too costly when compared with the expected benefits. Some market participants called for consumption profile P012 to be split also, with an identical consumption threshold, in order to allow a better estimate of daily consumption in these two categories.

Since the diverse consumption behaviour within option T2 is still in evidence, CRE is looking again at the possibility of splitting this option in two, in its preparatory work on the future structure of the ATRD tariffs. Such a split would be designed to differentiate the tariffs applicable to these consumers and better reflect the diverse nature of their behaviour, through two separate tariff schedules.

The majority of these consumers are currently equipped with meters that are read biannually. With the roll-out of Gazpar meters, all of these consumers will be equipped with a meter read monthly by mid-2023, and the data collected will contribute to the discussion regarding the profiles.

If splitting this option is found to be an appropriate solution, two implementation calendars could be envisaged:

- either when the next change is made to the structure of the ATRD tariffs, by opting for a cut-off threshold situated between 30 and 50 MWh per year. This threshold could subsequently be refined based on data obtained from the Gazpar meters;
- or when the Gazpar meters have collected sufficient data, to determine the threshold(s) and/or criteria for segmenting the option most suitable for establishing tariffs for these consumers.

In any event, the data obtained from the Gazpar meters will also be useful for the work done by the GTG working group on profiles.

Q5 : Are you in favour of the principle of splitting tariff option T2?

Q6 : Are there any other changes you would like to see considered, regarding the thresholds between tariff options?

3.3 Tariff balance between options

As indicated above, the initial structure was based on an allocation of costs between options. The level of the tariff terms was then fixed so that the revenue generated by each option covers the costs generated by the consumers concerned, taking into account the structure of the regulated sale tariffs (TRVs).

During work done in preparation for this public consultation, GRDF and CRE sought to check whether applying the schedule currently in force would satisfy the objective of covering costs for each option.

GRDF and CRE also re-examined the cost allocation method. They found a finer degree of granularity in cost items, with allocations to 24 major net operating expenses and standard capital expenses items, compared with five items in the ATRD1 method.

Where the direct allocation of costs to each of the tariff options was not possible, GRDF and CRE used consistent allocation criteria applied to each of the cost items studied. While the use of such allocation hypotheses is necessarily open to debate, the different variants tested identified trends for each tariff option.

In the different allocation methods tested during preparatory work (including the ATRD1 method), it was found that consumers under option T1 could tendentially find themselves paying more than their costs. Inversely, revenue linked to consumers under option T3 would be insufficient to cover the costs generated by them, for similar financial volumes.

Consequently, CRE believes there are good grounds to consider re-balancing these two tariff options, in order to reflect their costs generated by their respective consumers. This re-balancing, if adopted, would need to be applied gradually, to ensure that the resulting bill changes are acceptable.

Q7 : Do you share the concerns identified by CRE regarding the re-balancing of costs borne by consumers under each tariff option?

3.4 Addition of a capacity-based term for option T3

Tariff option T3 comprises around 100,000 consumers with very varied behaviours, including annual consumption ranging between 300 MWh and 5 GWh. It encompasses not just consumers with steady consumption such as industry, but also those whose consumption is climate-dependent, such as collective heating plants of large buildings, and also those whose consumption rises in non-winter periods, such as grain dryers. Most of these have their meters read monthly. Tariff option T3 has two components, specifically a subscription and a term proportional to quantities delivered, i.e. the site's consumption.

As in the case of consumers whose meters are read biannually, GRDF produces a daily consumption estimate using the profiling system. The diverse behaviours of consumers whose meters are read monthly are reflected in the seven consumption profiles associated with them. These profiles are assigned not on the basis of their level of consumption, as is the case for consumers read biannually with profiles P011 and P012, but rather according to the proportion of their consumption concentrated over the winter period (between November and March) as a ratio of their annual consumption. This is referred to as the "winter portion"[22]. Thus, the seven profiles assigned to consumers who are read monthly range from profile P013 (for consumers whose "winter portion" is less than or equal to 39% of their annual consumption) to profile P019 (for consumers whose "winter portion" is strictly above 81%)[23].

The diverse nature of these behaviours means that the population group comprised of consumers under option T3 is heterogeneous. As with the proposal to split option T2 (*see* 3.2.2), CRE believes there could be grounds for doing more to differentiate the tariffs applied to consumers under option T3, in order to better reflect these behaviours. The existing tariff, which includes a fixed term and a consumption-based term, for all of these consumers, may not strictly reflect the costs generated by each consumer within this population group.

Since these consumers are already characterised in terms of their winter consumption in the profiling system, it might be relevant to introduce a daily capacity-based term into the option T3 tariff, such as for consumers under options T4 and TP. The addition of this term would serve to differentiate the tariffs applicable to these consumers based on their consumption profile. So with tariff revenue for option T3 unchanged, and for consumers who use the same quantity of gas annually, the terms of the tariff schedule for option T3 would be revised to ensure that this change results in a lower ATRD tariff for consumers not contributing to peak winter demand, and a higher ATRD tariff for those whose consumption is concentrated more during the winter period.

Without daily readings of these consumers' consumption, it is difficult to determine the level of daily capacity to be subscribed. Moreover, were these consumers able to determine this capacity level, there would be no observable daily consumption data to identify any instances where subscribed capacity is exceeded. Nonetheless, this notion of daily capacity does exist for these consumers for storage capacity to be reserved and tariffs for transmission up to the distribution network. This daily capacity is said to be "standardised" (CJN), since it is determined on the basis of the consumption profiles established by the profiling system. This standardised daily capacity is used for all consumers whose consumption is not read daily. These are known as "non-subscription" consumers. Conversely, consumers whose consumption is read daily and who have subscribed to options T4 and TP are said to be "subscription consumers", since they themselves reserve the capacity level they need and which is then used to bill the tariff terms for use of the transmission and distribution networks, and for the storage requirement.

[22] The winter portion is climate-adjusted and averaged over three years (PHcm).
[23] P013 if PHcm ≤ 39%; P014 if 39% < PHcm ≤ 50%; P015 if 50% < PHcm ≤ 58%; P016 if 58% < PHcm ≤ 69%; P017 if 69% < PHcm ≤ 75%; P018 if 75% < PHcm ≤ 81%; P019 if PHcm > 81%.

The additional term envisaged for the tariff applicable to consumers under option T3 could therefore be applied to these consumers' standardised daily capacity. This capacity would thus be determined on the basis of the profiling system, and would not be subject to the rules on capacity subscription and exceeding subscribed capacity.

Moreover, GRDF is set to gradually equip all consumers whose meters are read monthly with new meters allowing daily readings, as part of a project known as "Satellite". Once this project is complete (the roll-out process is due to be completed by 2024), the possibility of giving these consumers access to a capacity subscription system could be examined. The switch to daily meter readings will give them a clearer view of their consumption, allowing them to then optimise their daily capacity subscription based on their consumption profile.

In addition to providing a more accurate picture of consumers under option T3, the addition of a capacity-based term would also reduce the windfall effects for certain consumers whose shipper subscribe to option T3 on their behalf, whereas the annual consumption exceeds the 5 GWh threshold. The number of consumers in this situation has gradually fallen since CRE's deliberation of 3 March 2016 amending the rules on allocation of meter-reading frequencies (the frequency was then directly linked to the tariff option chosen, and some shippers subscribed to option T3, which included monthly readings, in order to optimise all of the components making up their customer's overall bill). These new rules failed to fully resolve the issue, however, and so the addition of this capacity-based term may help to mitigate these windfall effects.

In any event, the introduction of these daily capacity-based term for consumers with option T3 would mean reviewing all of the tariff terms currently applicable to those consumers (subscription and consumption-based term). Such a change could have the drawback of generating potentially significantly higher bills for the most heavily modulated consumers.

When establishing tariffs, CRE must seek to reconcile two objectives: making tariffs as simple as possible, and ensuring that costs are allocated accurately and appropriate market signals sent. Given the diverse nature of T3 consumers and their often substantial contribution to peak winter demand, which represents the main factor in determining the size of the gas networks, the issue of introducing a tariff structure that reflects this characteristic is worth examining. Since gas consumption is on a downward trend, the gas networks are being developed less than was previously the case, and are therefore not presently being expanded to meet the needs of consumption. Consequently, the costs to be allocated are largely historic costs. Incidentally, there is less of a pooling effect in the gas sector than in the electricity sector, obviating the need for overly complicated tariff signals. However, despite these observations, an analysis of GRDF's accounts shows that the volume of investments in "network developments" has remained relatively constant, leading to stability - and even a slight increase - in the "network[24]" regulated asset base (BAR). It may nonetheless be useful to send a signal to ensure the winter peak is managed and thereby avoid reinforcements to the network which ultimately prove unnecessary.

In any event, if the shape of the tariff schedule for option T3 were modified, any such change would need to be while maintaining continuity. For this reason, CRE is considering a tariff schedule aimed at limiting the average rise in the ATRD bill for consumers with a P019 profile (the most heavily modulated profile) to a maximum of 10%. The first simulations carried out by CRE show that, with tariff revenue for option T3 unchanged, the variation in the ATRD bill could range from -7% for consumers with steady year-round consumption, up to +18% for those whose consumption fluctuates most heavily. Given the share of the ATRD tariff in the consumer's overall bill, these changes could be between -1.5% and +2.5%.

Q8 : What is your view of the principle of differentiating the tariffs for T3 consumers, to reflect their heterogeneous nature?

Q9 : Are you in favour of the addition of a capacity-based term for the T3 option? What do you think about using standardised daily capacity?

3.5 Tariffs for options T4 and TP and continuity between tariffs for use of the transmission and distribution networks

The largest consumers (i.e. those who have subscribed to tariff options T4 and TP and those with annual consumption in excess of 5 GWh, regardless of their tariff option) represent a group of approximately 4,000. They are mainly large industrial consumers.

The TP option (proximity tariff) was created for large industrial consumer with sites located close to the gas transmission network (less than 400 metres away, on average) and already supplied via the distribution networks. It includes a subscription, a subscribed daily capacity-based term, and a term based on the straight-line distance between the delivery point and the closest transmission network, to which is allocated a multiplier based on the population density of the municipality in which the consumer's site is situated.

[24] BAR restricted to the grouping compatible with G1 (pipelines and connections)

Option T4 includes a similar population group to that of option TP in terms of consumption behaviour, but the distance between their sites and the transmission network is greater. There are three components to this tariff option, namely a subscription, a subscribed daily capacity-based term, and a consumption-based term.

Currently, certain incumbent consumers under tariff option T4 are connected to the distribution network, although it would be more in their interest to be connected to the transmission network. From a tariff perspective, CRE takes the view that for these incumbent consumers, it would make sense to instil greater continuity between the tariffs charged for using the distribution and transmission networks. This was the thinking behind the creation of the TP option, aimed at deterring consumers from adopting behaviours designed to optimise their individual economic situation, but which were not economically appropriate for the wider community of natural gas consumers.

Consequently, although cost allocation work found no clear trend in terms of over- or under-coverage of costs for consumers under option T4, CRE is considering lowering the tariff for the largest consumers under this option. To this end, CRE is looking at the possibility of making the daily capacity-based term of the TF option degressive on a sliding scale, over and above a threshold of 500 MWh/day of subscribed capacity. The level of subscribed capacity is a good criterion for identifying consumers who share similar characteristics with consumers directly connected to the transmission network. This subscription level corresponds to that beyond which the subscribed capacity increases sharply for a small number of very large consumers. This degressive sliding scale would involve only limited loss of ATRD revenue, as it would only apply to a small number of consumers, and the loss would not be significant compared with GRDF's authorised revenue.

Q10 : Are you in favour of applying a degressive sliding scale to capacity tariffs under option T4 over a certain threshold?

4. CONSIDERATION OF BIOMETHANE DEVELOPMENT IN THE NETWORKS

4.1 Ongoing development of biomethane

France has great methanisation potential and the public authorities have defined ambitious objectives for biomethane injection into the gas networks and for reducing the carbon footprint of transportation means. The current decree relating to the multiannual energy programme[25] defined an objective of 8 TWh of biogas injected in 2023. The draft decree relating to the multiannual energy programme submitted for consultation in January 2019 currently specifies a slight reduction in these objective for 2023 (6 TWh of biogas injected) but sets a goal of 14 to 22 TWh of biogas injected into the networks by 2028. In addition, the law on energy transition for green growth[26] raised to 10% the portion of gas consumption from renewable energy by 2030.

At the end of 2018, 76 sites were injecting biomethane into the natural gas transmission and distribution networks for a volume of more than 714 GWh in 2018.

In order to lift certain legislative obstacles to the development of methanisation in France, a "right of injection" was introduced in the "EGAlim"[27] law of 30 October 2018. A decree, taken following CRE's opinion, shall specify the conditions for exercising this right.

4.2 Adaptation of networks to support the development of biomethane

Reaching biomethane injection goals will require a significant budget commitment by the government (between €7 and 9 billion in additional public spending for the development of renewable gas between 2019 and 2028 according to the draft multiannual energy programme) and major investments in the gas transmission and distribution networks, of about €2 billion for a goal of 30 TWh in 2030.

The current characteristics of the natural gas networks, which do not cover the territory heterogeneously, and whose capacity of accommodation varies heavily from one region to another, will require an adaptation of the natural gas transmission and distribution networks to enable them to accommodate numerous production sites. The connection of new injection facilities will mechanically lead to an extension of the network (these extensions represent one-third of the projected volume of investment related to biomethane development), while the existing network shall have to be reinforced, with the use of interconnections or backhaul, to bear and distribute the excess volume injected in certain zones. GRDF considers at this stage that only 30% of the projects identified can be completed without any reinforcement.

While these investments appear to be justified to support the development of biomethane, specific attention must be paid to their volume, in order to adopt on a case-by-case basis the most efficient solution from the community's perspective in terms of the use of the biogas produced. While injection into the networks has major advantages in

[25] Decree No 2016-1442 of 27 October 2016 on the multiannual energy programme
[26] Law No 2015-992 of 17 August 2015 on energy transition towards green growth
[27] Law No 2018-938 of 30 October 2018 for achieving a balance in trade relations in the food and agricultural sector and healthy and sustainable food

terms of energy efficiency, it cannot be envisaged for all of the territory given the connection costs that that would generate. This is even more so against the drop in gas consumption and therefore in the basis for collecting costs borne by all gas customers.

Therefore, to enable development of biomethane at a controlled cost for the community, CRE considers it important to:

- introduce a technical and economic criterion to validate whether it is relevant or not to connect the different facilities to the gas network (by comparing the investments necessary with the volumes injected). CRE is working with stakeholders to build such a criterion and intends to use this tool to ensure that investments related to biomethane correspond to those of efficient system operators. CRE plans to consult market participants on the methodology envisaged in spring of 2019;
- to send to biomethane producers an economic signal based on location and injection capacity, either at the time of connection or through an injection tariff defined in the tariffs for the use of the networks.

Q11 : Are you in favour of sending an economic signal to biomethane producers concerning the location of facilities, in order to prioritise facilities causing the least constraints in the network?

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Q12 : Do you have any other suggestions or remarks regarding the structure of ATRD tariffs?

5. LIST OF QUESTIONS

Q1 : In your opinion, what would be the most suitable calendar for implementing the changes adopted to the ATRD tariff structure? *(page 16)*

Q2 : Are you in favour of establishing tariff continuity between two tariff options without including the CTA? *(page 17)*

Q3 : Are you in favour of lowering the cut-off threshold between tariff options T1 and T2 from 6 MWh to 4 MWh? *(page 18)*

Q4 : Do you share CRE's view that changes to the threshold between tariff options T1 and T2 should be concomitant with changing the threshold between profiles P011 and P012? *(page 18)*

Q5 : Are you in favour of the principle of splitting tariff option T2? *(page 19)*

Q6 : Are there any other changes you would like to see considered, regarding the thresholds between tariff options? *(page 19)*

Q7 : Do you share the concerns identified by CRE regarding the re-balancing of costs borne by consumers under each tariff option? *(page 20)*

Q8 : What is your view of the principle of differentiating the tariffs for T3 consumers, to reflect their heterogeneous nature? *(page 21)*

Q9 : Are you in favour of the addition of a capacity-based term for option T3? What do you think about using standardised daily capacity? *(page 21)*

Q10 : Are you in favour of applying a degressive sliding scale to capacity tariffs under option T4 over a certain threshold? *(page 22)*

Q11 : Are you in favour of sending an economic signal to biomethane producers concerning the location of facilities, in order to prioritise facilities causing the least constraints in the network? *(page 23)*

Q12 : Do you have any other suggestions or remarks regarding the structure of ATRD tariffs? *(page 23)*