COMMISSION
DE RÉGULATION
DE L'ÉNERGIE

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

PUBLIC CONSULTATION NO 2019-006 OF 27 MARCH 2019 RELATING TO THE STRUCTURE OF THE NEXT TARIFF FOR THE USE OF THE NATURAL GAS TRANSMISSION NETWORKS OF GRTGAZ AND TEREGA

Articles L. 452-2 and 452-3 of the French Energy Code empower the French Energy Regulatory Commission (CRE) to specify the methodology 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 with regard to, in particular, an analysis of the operators' accounts and any expected changes in operating or investment expenses.

The current tariffs for the use of GRTgaz's and Teréga's natural gas transmission networks, termed "ATRT6 tariffs", entered into effect on 1 April 2017, for a period of approximately four years, in accordance with CRE's deliberation of 15 December 2016[1].

The ATRT6 tariff, given the implementation of regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures for gas (hereinafter "Tariff network code"), must be revised in 2019 and the new ATRT7 tariff must enter into effect as at 1 April 2020 at the latest. In accordance with the provisions of the Tariff network code, in particular its articles 26, 27 and 28, CRE intends to shorten the ATRT6 tariff by one year: instead of applying to the 2017-2020 period, it will apply to the 2017-2019 period.

CRE has undertaken work to define new tariffs for the use of the natural gas transmission networks of GRTgaz and Teréga, termed "ATRT7" tariffs, which would apply as from 1 April 2020.

With regard to storage, the tariff for the use of the underground natural gas storage of Storengy, Teréga and Géométhane, termed "ATS1 tariff", entered into effect as at 1 January 2018 for a period of approximately two years, i.e. until 31 December 2019. Articles L. 421-5-1 and L. 452-1 of the Energy Code specify that the difference between storage operators' authorised income and the revenue collected directly by storage operators is to be compensated through the ATRT tariff, by a specific storage tariff charge. CRE has undertaken work to define new tariffs for the use of the natural gas storage infrastructure of Storengy, Teréga and Géométhane, termed "ATS2 tariffs", which would apply as from 1 January 2020.

Given the visibility requirements expressed by market participants and the complexity of the issues to be addressed, CRE launched a public consultation on 14 February 2019 concerning the regulatory framework applicable to regulated infrastructure operators for the next tariff generation. CRE would also like, in the present public consultation, to collect the views of the parties concerned on its initial guidelines concerning the structure of the ATRT7 tariff, as well as on storage compensation. Moreover, another public consultation, covering the structure of the next tariffs for the use of natural gas distribution networks, has been launched at the same time.

<u>Tariff structure of the ATRT7 tariff</u>

The structure of the ATRT7 tariff must be set in a transparent and non-discriminatory manner. It must reflect the costs generated by users so as to, in particular, avoid cross-subsidisation between user categories.

The ATRT6 tariff already meets most of the requirements of the Tariff network code, although that code had not yet entered into effect at the time of its elaboration. This tariff was elaborated so as to cover transmission system operators' authorised income while ensuring that the relative charge level was consistent and did not involve any cross-subsidisation between the different categories of transmission network users.

[1] Deliberation by the French Energy Regulatory Commission of 15 December 2016 deciding on the tariffs for the use of GRTgaz's and TIGF's natural gas transmission networks

The French Council of State confirmed CRE's decision concerning the ATRT6 tariff in the case of ENI S.p.A against CRE. The Council of State considered in particular that CRE's deliberation is non-discriminatory and does not create any cross-subsidisation between shippers supplying national customers and shippers using the network for the purposes of transit to other countries since the unit cost of the use of the transmission network is the same for each use.

For the ATRT7 tariff, CRE plans to elaborate a tariff framework building on the ATRT6 tariff, so that unit transit costs are aligned with national customer supply costs, in accordance with the Tariff network code.

CRE also intends to make changes concerning transmission system operators' upstream and downstream offers, in particular for the purposes of simplification and continuity with the tariff for the use of the gas distribution networks. In addition, the TSOs also propose changes to offers to enable transfer of capacity from one point to another of the transmission network, under certain conditions. CRE would like to gather participants' opinions about the changes envisaged.

Storage compensation charge

Lastly, the difference between storage operators' authorised income and the revenue collected directly by storage operators, at auctions in particular, is compensated through the ATRT tariff, by a specific storage tariff charge. Compensation is covered by applying a storage tariff charge depending on winter modulation to clients not subject to load shedding and interruptions connected to the public gas distribution networks. This collection base was defined against tight deadlines for implementing the reform with a dual objective of economic continuity and consideration of the contribution of storage for gas network users whose supply cannot be interrupted if there is a supply crisis. This scope however is not in line with the scope adopted by the French directorate for climate and energy with regard to the safety net and the scope of the regulation. Therefore, CRE wishes to have participants' views on aligning these scopes.

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 at the following address: dr.cp7@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.

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1. BACKGROUND AND PURPOSE 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[2] (40.5%), GIC[3] (31.5%), EDF Investissement (18%) and Prédica[4] (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.

[2] Snam: Italian gas infrastructure operator
[3] GIC: company governed by Singaporean law, specialised in capital investment
[4] 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.

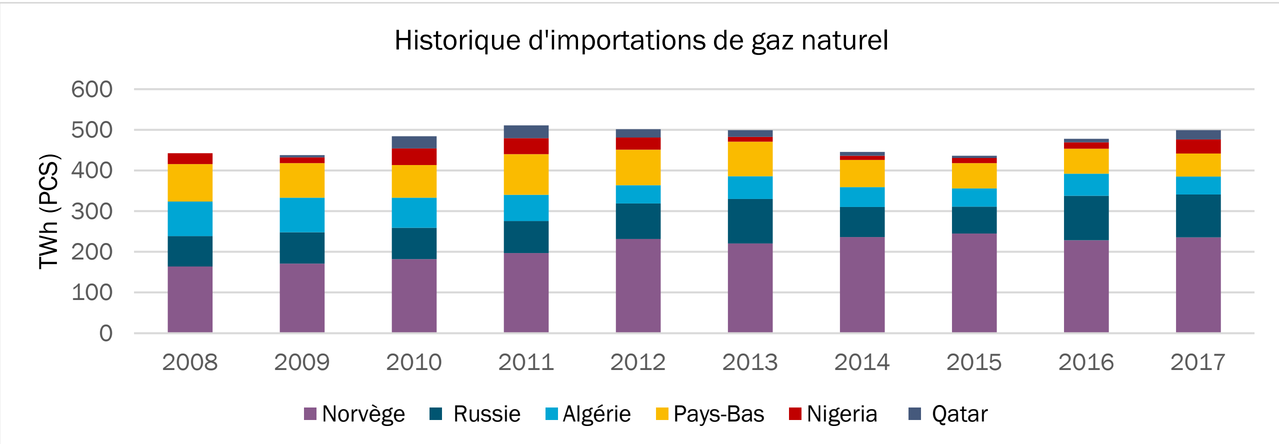
With regard to regulated operators:

- 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

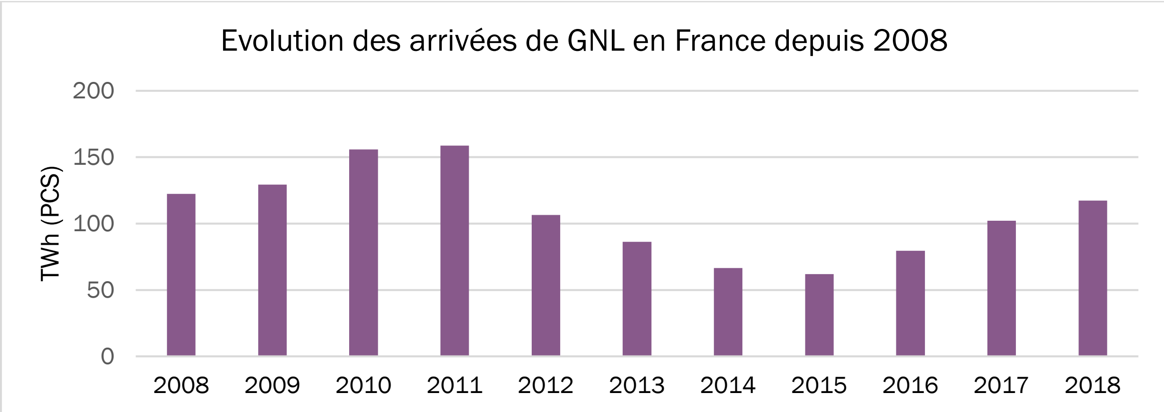
France is completely dependent on imports for its natural gas supply. For several years now, Norway has been France's main supplier, followed by Russia, the Netherlands and Algeria. Since the early 2000s, the development of the global LNG market had led to the emergence of new supply sources, such as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

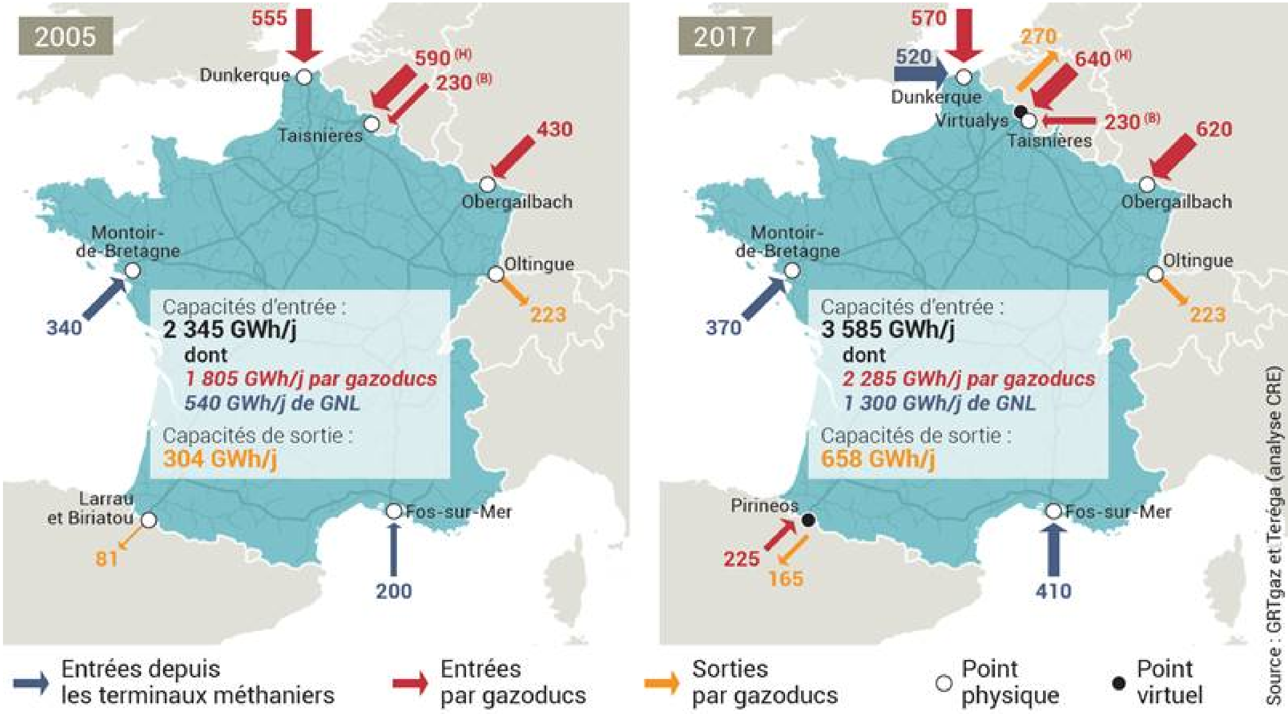
Investments were done with all neighbouring countries to strengthen interconnections. Since 2005, CRE has supported the development of gas interconnections using open season procedures to secure project funding. These open seasons led to the creation of considerable firm entry and exit interconnection 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.

Question 1 Do you agree with CRE's conclusion regarding the dimensions of the French natural gas transmission networks and the caution necessary with the launch of new investment projects?

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).

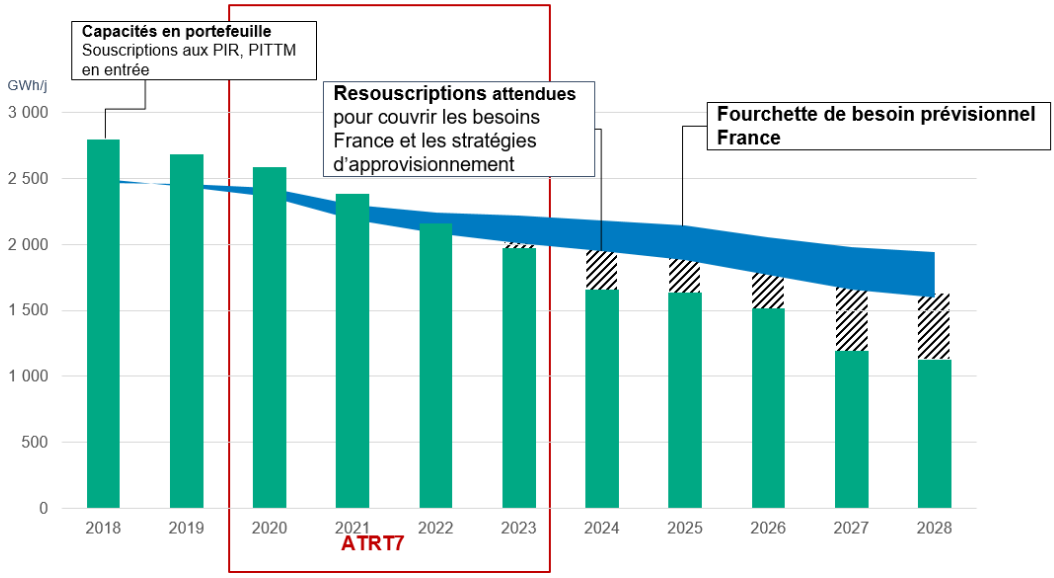
1.3.4 Long-term booking contracts at interconnections expiring over the ATRT7 period

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.

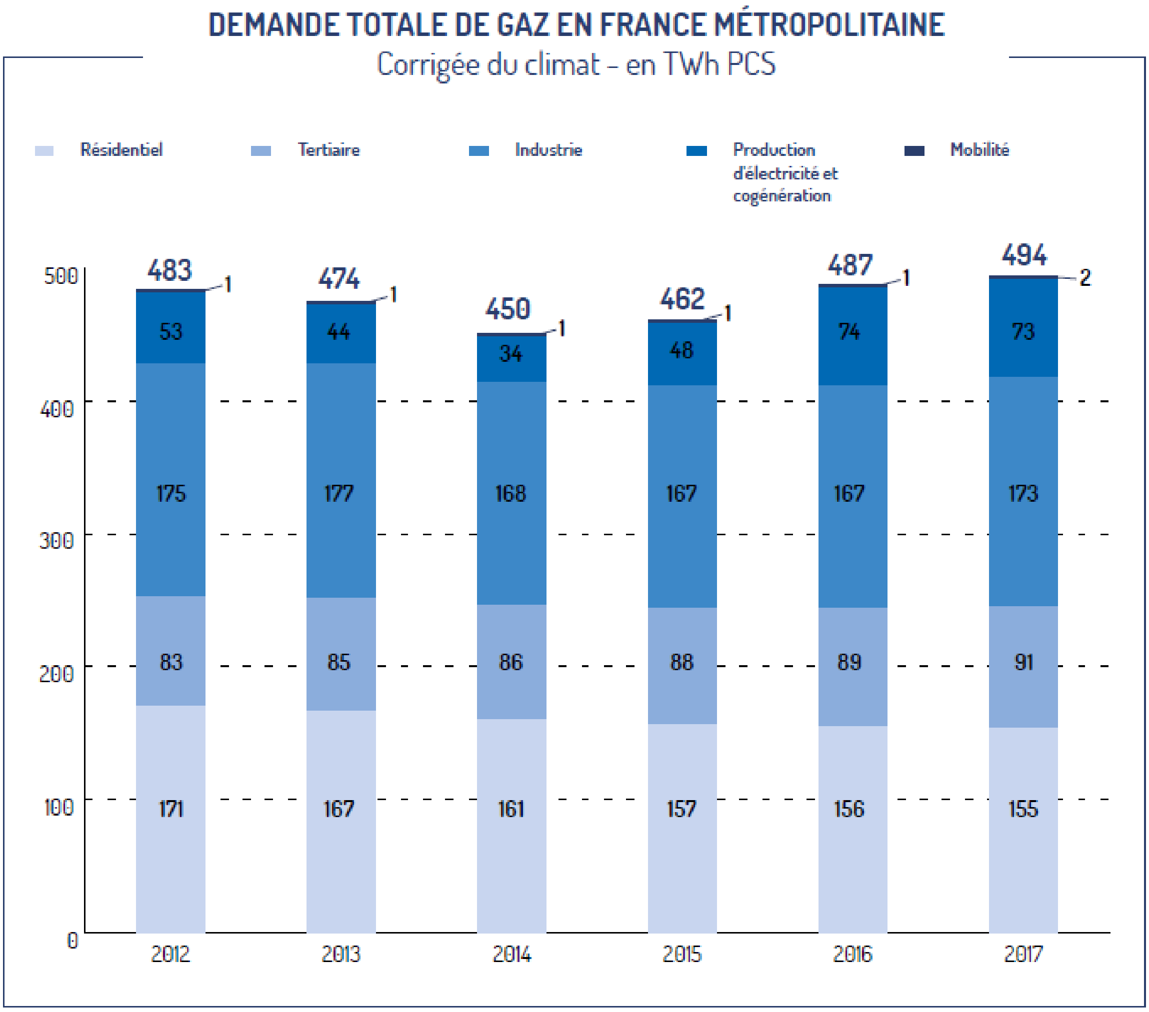
However, a certain number of these commitments will expire during the ATRT7 period. Since the actual level of use of these points was lower than the capacity booked, the TSOs expect that a portion of the capacity that will again be available will not be booked in the short term following the expiration 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: forecast multiannual gas assessment 2018-2035

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[5] 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[6], 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.

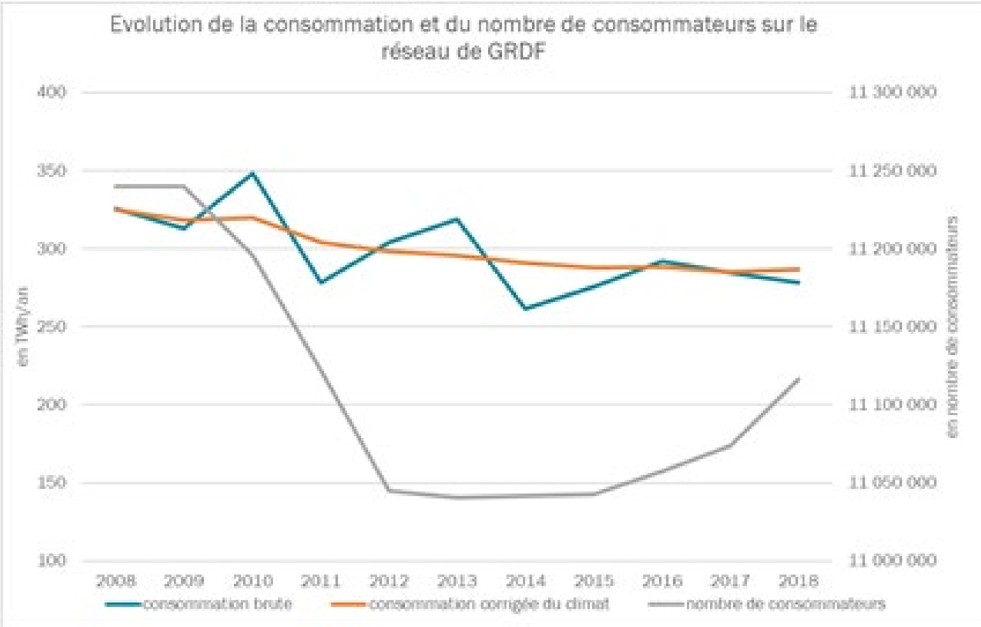
1.3.6 Energy transition, biomethane and new uses such as NGV

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.

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



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[7], CRE decided to prepare the implementation of the capacity allocation mechanism (CAM) code[8], 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 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[9], has applied since 1 October 2015 in France. To implement that code, CRE prepared as from 2011[10] 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.

[7] 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

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

[9] Regulation (EU) No 312/2014 of the Commission of 26 March 2014 establishing a network code on gas balancing of transmission networks

[10] Deliberation of the French Energy Regulatory Commission of 1 December 2011 approving the evolution of balancing rules for the GRTgaz and TIGF transmission networks

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[11].

This network code was elaborated by the European network of gas TSOs (ENTSOG, European Network of Transmission System Operators for Gas) based on guidelines[12] 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[13], 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[14].

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 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,

[11] 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)
[12] Framework Guidelines on rules regarding harmonised transmission tariff structures for gas
[13] Tariff proposal by the French Energy Regulatory Commission of 10 November 2006 for the use of natural gas transmission networks
[14] With the exception of the proximity charge for two DSOs

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[15]. 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:

- a public consultation, relating to the tariff regulation framework applicable to regulated infrastructure operators in France, which was launched on 14 February 2019[16];
- the present public consultation covering the main changes envisaged concerning the ATRT7 and ATS2 tariff structures, conducted alongside CRE's consultation on the structure of the ATRD6 tariff;
- 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

[15] RAB restricted to G1 accounting group (pipelines and connections)
[16] Public consultation of 14 February 2019 No 2019-003 relating to the tariff regulation framework applicable to regulated infrastructure operators in France

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 ATRT7 and ATS2 tariffs, regarding the tariff structure.

The changes envisaged for the structure of the next tariffs aim to:

- ensure conformity of the ATRT7 tariff with the requirements of the European network codes, in particular the Tariff network code;
- adapt TSOs' upstream and downstream offers;
- study the opportunity of changing the compensation base for storage costs.

2. LINES OF APPROACH AND PROPOSALS FOR CHANGES IN THE TRANSMISSION TARIFF STRUCTURE

2.1 Tariff structure of the main network (large-scale)

2.1.1 Consistency of the timetable with auctions organised in compliance with the CAM network code

Since the ATRT4 tariff, which entered into effect in 2009, the gas transmission tariffs change as at 1 April each year. This timetable, which had been defined by CRE after consultation, is in line with the storage gas year, which goes from 1 April of year N to 31 March of year N+1.

The CAM network code[17], which entered into effect in 2013, provides for annual transmission capacity at interconnections to be allocated from a period between 1 October of year N and 30 September of year N+1. Annual capacity auctions start on the first Monday of the month of July of year N. Therefore, for annual transmission capacity in the French networks sold at interconnections on the French transmission network, two tariff levels apply for a product booked within the framework of CAM auctions: a first level, known at the time of the auction, applies from 1 October N to 31 March N+1. The tariff level can then change at the time of the annual tariff update, and it applies to the same product from 1 April N+1 to 30 September N+1. However, without setting out a specific timetable for tariff changes, the Tariff network code requires the level of tariffs to be published, for interconnection points, at the latest one month before the start of annual capacity auctions in July for the period from October N to October N+1.

To give visibility to the market, CRE had envisaged, within the framework of the ATRT6 tariff, changing all the tariffs as at 1 October of each year. After consulting participants, this solution was not adopted, since most contributors were in favour of maintaining an April to April timetable, considered as the most consistent with the storage and LNG terminals timetable, and which avoided major tariff movements at the start of winter especially for the downstream network. CRE had therefore maintained the April to April timetable, and decided, that in order to give the visibility necessary for the proper functioning of interconnection capacity auctions, the tariffs at interconnection would change each year for inflation as at 1 April.

Building on the previous tariffs, CRE plans to maintain the current tariff timetable, going from April to April, so as to maintain consistency between the transmission, terminals and storage timetables. However, to comply with the requirement imposed by the Tariff network code to have, upstream of annual capacity auctions at interconnections, the tariffs that would apply from October N to October N+1, this timetable would include specific treatment for the tariffs applicable at the PIRs:

- on the one hand, at the start of the tariff period. The next capacity auctions at PIRs are scheduled for July 2019 and will allocate capacity covering the period from October 2019 to October 2020. However, the tariffs at the PIRs are known up to 31 March 2019;

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

- on the other hand, during annual updates.

For these reasons, CRE intends to only change the tariffs at the PIRs as at 1 October of each year, with an initial change in these tariffs as at 1 October 2020, with the other tariffs changing as at 1 April of each year.

> Question 2 Are you in favour of maintaining the current April to April timetable, with the exception of the tariffs applicable to the PIRs which would change as at 1 October each year?

2.1.2 Distribution of costs borne by the TSOs by network use

2.1.2.1 Classification of services provided by the TSOs

Article 4 of the Tariff network code distinguishes between the services provided by the TSOs, transmission services[18] and non-transmission services[19]. This article states that "*transmission services revenue shall be recovered by capacity-based transmission tariffs*" and that "*non-transmission services revenue shall be recovered by non-transmission tariffs applicable for a given non-transmission service*." The Tariff network code states that non-transmission services revenue must comply with the following principles: *"a) cost-reflective, non-discriminatory, objective and transparent; b) charged to the beneficiaries of a given non-transmission service with the aim of minimising cross-subsidisation between network users."*

This distinction aims to strengthen transparency in allocation of costs and revenues generated by the operation of the gas transmission networks.

GRTgaz and Teréga operate two different types of networks:

- main networks (upstream networks): used to supply transit and domestic clients;
- regional networks (downstream networks): used only to supply domestic clients. These networks fall within the scope of DSOs in numerous European countries.

At this stage, CRE intends to classify the services provided by the TSOs as follows:

- transmission services: the services provided by the TSOs in the main network. Pricing in this network is done based on an exit-entry model and according to capacity and distance;
- non-transmission services: the services provided by the TSOs in the regional network. This network is not based on an entry-exit model since there is no entry charge. All the same, pricing in this network is transparent and takes into account in particular the distance compared to the main network. Moreover, since these networks are used only by domestic clients, their costs are borne fully by those clients, as in the ATRT6 tariff. Any cross-subsidisation between transit and domestic flows is therefore avoided.

The regulated asset base (RAB) and net operating expenses are distributed between the main and regional network of each of the two TSOs guaranteeing proper allocation of costs for each network category.

In addition, the storage tariff term (see 2.3 of the present public consultation) was introduced by CRE in its deliberation of 22 March 2018[20], because of the reform of third-party access to storage installations, to compensate for the difference between storage operators' authorised income and the revenues collected directly by them within the framework of their business. This compensation is collected by the TSOs from their clients and paid back to storage operators. The storage tariff therefore corresponds to a non-transmission service of storage compensation provided to gas transmission network users.

2.1.2.2 Balance between costs and revenues attributable to the main network and regional network of TSOs

As from the implementation of the initial gas transmission tariffs, CRE sought to ensure a balance, for each TSO, on the one hand, between revenues generated by the operation of the main network and the expenses charged to it, and on the other hand, between the revenues generated by the operation of the regional network and the expenses charged to it.

However, successive tariffs changes had led, at the end of the ATRT5 period, to a slight imbalance, within the

[18] "Transmission services", regulated services that are provided by the transmission system operator within the entry-exit system for the purpose of transmission
[19] "Non-transmission services", regulated services other than transmission services and other than services regulated by Regulation (EU) No 312/2014 that are provided by the transmission system operator
[20] CRE's deliberation of 22 March 2018 deciding on the introduction of a storage tariff charge in the tariff for the use of GRTgaz's and TIGF's transmission networks

perimeter of France, between the costs attributable to each network category and the revenues they generated. Therefore, for the ATRT6 tariff, CRE adopted a tariff change such that a balance between the revenues collected and the costs specific to each of these networks would be reached on average over the tariff period. The distribution of these costs, within the perimeter of France, over the 2017-2019 period, is as follows:

	Main network		Regional network	
	% revenue	% costs	% revenue	% costs
Average 2017-2019	47.5%	48.5%	52.5%	51.5%

Source: GRTgaz and Teréga

Therefore, on average over the ATRT6 period, the balance between costs and revenues of the main and regional networks is almost attained. For the ATRT7 tariff, CRE plans to maintain the principle of average balancing of expenses and revenues for the main and regional networks.

Question 3 Are you in favour of maintaining the classification of networks, main and regional, as envisaged by CRE?

Question 4 Are you in favour of maintaining the classification of storage compensation as envisaged by CRE?

2.1.3 Methodology for determining tariffs for large-scale transmission

2.1.3.1 Main principles of the Tariff network code

The Tariff network code aims to harmonise methodologies for calculating natural gas transmission tariffs in Europe. It sets transparency and non-discrimination objectives in terms of the calculation of gas transmission tariffs and states in article 6 that "*the reference price methodology shall be set or approved by the national regulatory authority*". Tariffs must be established so as to reflect costs actually borne by the TSOs. In addition, use of a transparent methodology guarantees the market that there is no cross-subsidisation between different categories of transmission network users (particularly between shippers performing transit and those delivering to domestic customers).

Article 8 of the Tariff network code defines a method for calculating tariffs, termed capacity weighted distance reference price methodology (CWD method), which adopts as cost drivers the distance covered by the gas between entry and exit points on the network as well as the level of contracted capacity.

Article 26 of the Tariff network code states that when the reference price calculation method proposed by the regulatory authority is different to the CWD method outlined in article 8, the regulatory authority must compare the two methods as well as the parameters used.

In addition, article 5 of the Tariff network code states that the regulatory authority must assess the distribution of transmission services costs (cost allocation test) to determine the degree of cross-subsidisation among the different network user categories. When this assessment results in a more than 10% difference between the costs borne by the different network users, the regulatory authority must justify these results in its tariff deliberation.

Lastly, chapter VII of the Tariff network code describes the market consultation process prior to tariff decisions, specifies the information about which to consult, and describes the process for publication and communication of the tariff decision to ACER.

The ATRT6 tariff already meets most of the requirements of the Tariff network code, although that code had not yet entered into effect at the time of its elaboration. Indeed, within the framework of work to prepare the ATRT6 tariff, CRE conducted analyses to ensure that the costs borne by the different user categories did not cause any discrimination or cross-subsidisation. CRE therefore compared unit costs of domestic routes and transit routes. Lastly, the tariff decisions published by CRE already comply with the level of transparency imposed by the Tariff network code.

2.1.3.2 Principle of capacity-based pricing

The gas transmission tariff is based fully on capacity booked. In other terms, shippers book capacity which they pay for, independently of the use they make of that capacity.

This pricing mode is compatible with the Tariff network code, which specifies, in its article 4, that transmission services revenues are recovered by capacity-based transmission tariffs.

In addition, it is also compatible with the objectives of article L.461-3 of the Energy Code, which states that "*the tariffs for the use of the natural gas transmission and distribution networks shall take into account the specific* *situation of gas-intensive businesses whose sites have a predictable and stable or anti-cyclical consumption profile. They shall take into account in particular the positive effects of these customers on the stability and optimisation of the gas system".* This method of pricing indeed takes into account the positive effect that predictable and stable sites have on the gas system, particularly in terms of investment reduction. Therefore, for the same level of consumption, the supplier of a thermosensitive customer must book more capacity, to cover peak consumption, which can be far from average consumption.

At this stage, CRE intends to renew the capacity-based pricing principle in the ATRT7 tariff.

2.1.3.3 Main network entry-exit system

The main network tariff structure is based on an entry-exit pricing principle. This principle enables network users to separately book their network entry and exit capacity, and therefore transport gas between the points of their choice. The tariffs paid by users for entry and exit on the French network are identical, regardless of the origin and destination of the gas.

This entry-exit pricing principle complies with the provisions of regulation (EU) 715/2009 of 13 July 2009 which specifies that the tariffs applicable to network users must be non-discriminatory and set separately for each transmission network entry and exit point.

CRE plans to maintain this pricing principle for the ATRT7 tariff.

2.1.3.4 Harmonisation of GRTgaz's and Teréga's tariffs

The ATRT6 tariff provides for a certain number of equalisations at national level. The entry tariff at the Dunkirk, Taisnières H, Obergailbach, Oltingue and Pirineos PIRs are identical; this is also the case for the entry tariffs of the Dunkirk, Montoir and Fos PITTMs. Main network infrastructure contributes equally to the availability of entry capacity within these two categories of points. Aligning these tariffs offers shippers the possibility of choosing the most competitive supply source.

In addition, the tariffs for main network exit to GRTgaz's and Teréga's regional networks are aligned with each other, along with the tariffs at the transmission/storage interface points (PITS) in the Teréga and GRTgaz networks. Lastly, with regard to exit points to neighbouring countries (at PIRs), tariff equalisation would not correspond to the reality of costs generated by these transit flows for the TSOs, given the very different distances covered by the gas in the GRTgaz and Teréga's networks depending on the exit point considered.

In addition, CRE ensured that the tariffs reflect the costs generated by the transit and domestic consumption activities, as specified by the Tariff network code (see 2.1.3.6. of the present consultation).

CRE plans to maintain, for the ATRT7 tariff, the principles in effect in the ATRT6 tariff described above.

Question 5 Are you in favour of maintaining the pricing principle (capacity-based pricing, based on an entry-exit model) and equalisation principle currently in effect in the ATRT6 tariff?

2.1.3.5 Distribution of costs and revenues between main network entry and exit points

Apart from seeking a balanced distribution of revenues and expenses between the main and regional networks, distribution of revenues must also be considered in terms of a split between main network entry and exit points.

The Tariff network code specifies an indicative 50%/50% split in these revenues. This split is in fact the default split applied within the framework of the CWD method, which is a reference method from which regulatory authorities may deviate provided that they compare it with the method adopted ultimately. Several other European regulators that have already implemented their tariffs for accessing the gas network within the framework of the Tariff network code have deviated from this indicative distribution method to take into account the configuration of their networks.

Because of the presence in France of major storage capacity ensuring that the winter peak is covered, capacity booked by shippers at entry points in the French transmission networks is significantly less than exit capacity booked. CRE therefore considers that a split other than 50%/50% is justified given the particular configuration of the French network.

Within the framework of the ATRT6 tariff, CRE had already adopted a different distribution method, building on the previous tariffs. Therefore, for the year 2019, the distribution of revenues in the main network is as follows:

Distribution by type of point in %	France

Entry points (PIR, PITTM)	34%
Exit points (PIR exit points and exits to the regional network)	66%

At this stage, CRE intends to maintain the entry/exit distribution principles currently in effect in the ATRT6 tariff. This distribution could however change depending on the evolution in capacity bookings (see 2.1.6. of the present consultation).

Question 6 Are you in favour of globally maintaining the current entry/exit distribution method?

2.1.3.6 Description of the tariff calculation method envisaged by CRE

The relative tariff charges of the ATRT6 tariff was set by CRE so as to not cause any cross-subsidisation between the different transmission network user categories. For that, CRE verified the consistency in the unit transmission costs borne for the France-Spain, France-Italy routes and to supply domestic customers.

The Eni S.p.A. company, a gas and electricity supplier, had contested this decision before the Council of State. It considered that CRE's deliberation ignored legislation and that it introduced cross-subsidisation between the different gas transmission network user categories, i.e. between shippers supplying national customers and shippers using the network for the purposes of transit to other countries.

In its decision of 18 March 2019[21], the Council of State confirmed CRE's deliberation of 15 December 2016 deciding on the ATRT6 tariff, considering in particular that it is non-discriminatory and that the principles adopted by CRE do not create any cross-subsidisation between main network user categories since the average transmission unit costs resulting from the tariffs set are equivalent for each network use.

For the ATRT7 tariff, CRE therefore plans to elaborate a tariff framework building on the ATRT6 tariff, so that unit transit costs are aligned with domestic customer supply costs, in accordance with the Tariff network code.

<u>Method envisaged by CRE</u>

In compliance with the objectives pursued by the Tariff network code, CRE worked to elaborate a tariff method based on capacity contracted and the distance between the different main network entry and exit points. The tariffs are then set so as to ensure that the unit transit costs and the domestic customer supply costs are aligned.

a. Distance calculation:

- <u>Case of transit:</u>

The Tariff network code specifies that when certain entry and exit points can be combined in a relevant flow scenario, the reference distance to be considered is the shortest distance of the pipeline route between an entry point or a cluster of entry points and an exit point or a cluster of exit points.

CRE considers that it is economically relevant to adopt the Dunkirk PIR as the main entry point for gas transiting through the Pirineos, Oltingue and Alveringem PIRs. The shortest pipeline distances between the Dunkirk and Pirineos PIRs, the Dunkirk and Oltingue PIRs, and the Dunkirk and Alveringem PIRs, are presented in the table below.

Route	Pipeline distances in km
Dunkirk - Pirineos	1,072
Dunkirk - Oltingue	762
Dunkirk - Alveringem	99

<u>Source: GRTgaz and Teréga</u>

- <u>Case of domestic customers:</u>

The evaluation of the distance covered by the gas to reach domestic customers' delivery points is more complex, particularly given the:

- high number of main network exit points to the regional network (approximately 700 in France);
- the diversification in the supply possibilities available to gas suppliers;

[21] https://juricaf.org/arret/FRANCE-CONSEILDETAT-20190318-411580

- large storage capacity in France meaning that gas can be bought at a cheaper price to be stored during summer for use in winter: a portion of the gas consumed in winter by domestic clients therefore travels a longer distance than the rest of the gas consumed with an "entry-storage" path in summer, then a "storage-exit" path in winter.

Therefore, CRE considered two flow patterns, a "summer" pattern and a "winter" pattern in order to model the routes supplying domestic customers:

- in the "summer" pattern, the PIR and PITTM entry points serve to fill underground gas storage capacity, and to supply domestic customers in proportion to their annual reference consumption, as well as the Pirineos, Oltingue and Alveringem exit points.
- in the "winter" pattern, domestic customers' peak consumption is supplied by gas coming from the PIR and PITTM entry points as well as storage facilities. The Pirineos, Oltingue and Alveringem exit points are supplied by the Dunkirk PIR.

On the basis of these patterns, a model serves to determine the entry points that supply each exit point, based on the following principle:

- each delivery exit point is supplied first of all by the entry point closest geographically, while it still has available contracted capacity;
- when the closest point no longer has available capacity, the exit point completes its supply by the second closest entry point while it still has capacity available, and so on and so forth until all consumption is satisfied.

After the establishment of flow patterns supplying domestic customers in summer, then in winter, the average summer and winter distances are calculated.

A single average distance for all delivery points is then calculated by weighting by the number of months of each season (seven summer months, 5 winter months).

Taking into account the forecast bookings at GRTgaz's and Teréga's main network entry and exit points, and forecast annual consumption and peak consumption for delivery points in 2018, provided by GRTgaz and Teréga, the average distance for supplying domestic clients from entry points is about 280 km.

b. Adjustment of tariffs at storage entry and exit points

Article 9 of the Tariff network code specifies a discount of at least 50% to be applied to capacity-based transmission tariffs at entry points coming from storage and exit points towards storage facilities.

CRE plans to maintain the global relative tariff level at the PITS compared to those at the network entry and exit points so as to not affect the attractiveness of storage facilities, maintain an incentive to their being filled, and to take into account their role in the proper functioning of the system. This means an implementation of about 80%, as for the ATRT6 tariff.

c. Determination of tariffs

Given the inapplicability, in its current state, of the CWD method specified by the Tariff network code since one entry point can supply can supply several exit points (see 2.1.3.8), CRE plans to proceed as follows based on a distribution of revenues between entry and exit points in line with the split adopted in the ATRT6 tariff:

- first, the revenues to be collected at entry points are split between the different entry points based on the ratios of distances covered by the gas by type of entry point (PIR/PITTM/PITS);
- second, the revenues collected at exit points are split so that the unit transit and domestic client supply costs are identical. The use of this methodology guarantees the absence of cross-subsidisation and discrimination between the different transmission network user categories.

d. Unit costs

The methodology for elaborating the tariff framework proposed by CRE results in an identical unit cost for the different transit routes and domestic client supply (taking into account use of storage). Taking into account the capacity booked in 2018 at the different GRTgaz and Teréga main network entry and exit points, this unit cost is roughly €0.70/MWh/d/y/km.

e. Specific case of the Alveringem PIR exit

The Alveringem PIR was created within the framework of the commissioning of the Dunkirk terminal in 2016, and enables non-odourised gas to be shipped from France to Belgium. Two types of capacity are sold:

- direct entry capacity in Belgium from the Dunkirk LNG terminal, sold by Fluxys, which, for that purpose, contracts with GRTgaz a shipping service between the Dunkirk terminal and the Alveringem PIR;
- interconnection capacity between the PEG Nord and the Belgian market sold by GRTgaz and Fluxys in co-ordination.

Given the little distance covered in France by non-odourised gas going to Belgium, a distance-based pricing principle cannot be adopted because it would not cover the development costs of the interconnection created.

In its deliberation of 12 July 2011[22], CRE adopted exit capacity pricing at Alveringem based on the actual cost of the investment observed at the end of work and the total capacity level. In addition, CRE has stated that the tariff at this point will change in compliance with the rest of the GRTgaz tariff.

CRE plans to maintain this pricing principle for the Alveringem PIR.

2.1.3.7 Main lessons drawn from the methodology proposed by CRE

In summary, the methodology for elaborating the tariff framework envisaged by CRE for the ATRT7 tariff shows that:

- the tariff framework based on this methodology should be relatively stable compared to the tariff framework in effect in the ATRT6 tariff. The tariff levels shall be set in the tariff deliberation at the end of 2019 and will mainly depend on the level of booking and expenses to be covered for each TSO.
- PITTMs supply more, in proportion, domestic consumption points: the average distance covered by the gas from these points is less than the average distance covered between a PIR entry point and a domestic consumption point. For this reason, their tariff should be lower than that of PIRs.

Question 7	Are you in favour of the pricing principles envisaged by CRE for the main network?

2.1.3.8 Comparison with the reference method (CWD) of the Tarff network code

In article 8, the Tariff network code describes in detail the method for calculating the reference prices at entry and exit points based on capacity booked and distances covered by the gas as weighting factors (capacity weighted distance reference price methodology (CWD). CRE presents a comparative analysis in Annex 1.

2.1.4 Requalification of the Jura PIR as a PIRR

The ATRT6 tariff defines a PIR as a "*physical or notional interconnection point on the main networks of two transmission system operators (TSOs)*" and a PIRR as a "*physical or notional interconnection point between a regional transmission network and the network of a foreign operator*".

The Jura network interconnection point was created in 1989, thanks to an extension of the regional network from the Etrez compression station, to supply, similarly to the interconnection point on the Savoie regional network interconnection point (PIRR), end customers connected to the Gaznat network (Swiss TSO) from France. The Gaznat network between these two Jura PIR and Savoie PIRR interconnection points is interconnected.

CRE examined the modalities for the use of the Jura point to determine whether the qualification of the PIR in effect in the ATRT6 tariff is the most relevant. It observed:

- on the one hand, that the Jura point was considered as of its construction as a PIR, but that, after discussions between GRTgaz and Gaznat, it turns out that this point does not supply Germany and Italy but only end customers in the Gaznat network;
- on the other hand, that the Jura PIR is interconnected with the Savoie PIRR and supplies the same regional network in Switzerland: these two points are therefore comparable in terms of their use.

[22] CRE's deliberation deciding on the conditions for the connection of the Dunkirk LNG terminal to GRTgaz's network and on the development of a new interconnection with Belgium at Veurne

Therefore, CRE plans to requalify the Jura PIR as a PIRR. Given the configuration of the GRTgaz network, a regional tariff level (NTR) of 1 would apply. The Jura PIR tariff would be €217.83/MWh/d/y[23] instead of the current €96.53/MWh/d/y.

Question 8	Are you in favour of the requalification of the Jura PIR as a PIRR?

2.1.5 Pricing of interruptible capacity

The Tariff network code specifies that interruptible capacity tariffs[24] shall be calculated by multiplying the firm capacity tariffs by the difference between 100% and a discount level calculated *ex ante*. The discount level depends on the probability of interruption of interruptible capacity and an adaptation coefficient A defined by the regulatory authority.

Article 16 of the Tariff network code states that the interruption probability can be calculated either per point or per cluster of points.

The tariff discounts in effect in the ATRT6 tariff are summarised in the table below:

Main network entry-exit points	Discount
PIR entry	50%
PIR exit at Oltingue and Pirineos	25%

CRE considers that the interruption rates observed over the last few years can be used. Prior to the merging of zones (as at 1 November 2018), capacity interruptions and limitations were mainly applied to the North-South link, which led to lower interruption rates at the different PIRs.

In addition, in order to verify the consistency of these discounts with interruption probabilities, GRTgaz and Teréga estimated the interruption rate of interruptible capacity at their main networks' entry and exit points, applying the Tariff network code method.

At this stage, CRE plans to adopt a single interruption rate for the entry points where the entry tariffs are identical. Moreover, CRE has noted that the interruption rates estimated by the TSOs at each of these points are an average 52%. Therefore, CRE plans to maintain a 50% discount at the PIR entry points.

With regard to exit points, the TSOs' calculations lead to an interruption probability of interruptible capacity of 15.3% for Oltingue and 11.6% for Pirineos. CRE plans to maintain the current rate of 25% and obtain feedback in the light of the merging of zones.

The tariff discounts envisaged by CRE at this stage for the ATRT7 tariff are therefore as follows:

Main network entry-exit points	Discount
PIR entry	50%
PIR exit at Oltingue and Pirineos	25%

Question 9	Are you in favour of maintaining the tariff discounts envisaged by CRE for interruptible capacity?

2.1.6 Change in tariffs

Current principle

[23] In accordance with the tariff in effect as at 1 April 2019
[24] Gas transmission capacity that can be interrupted by the TSO based on the conditions set out in the transmission contract. For example, the main parameters affecting the availability of capacity are the level of consumption and the configuration of the network.

For the ATRT6 tariff, CRE adopted a tariff evolution principle that would give visibility to market participants. The tariffs of the upstream network have changed only to take into account inflation, and the tariffs of the downstream network have evolved to cover the change in authorised income.

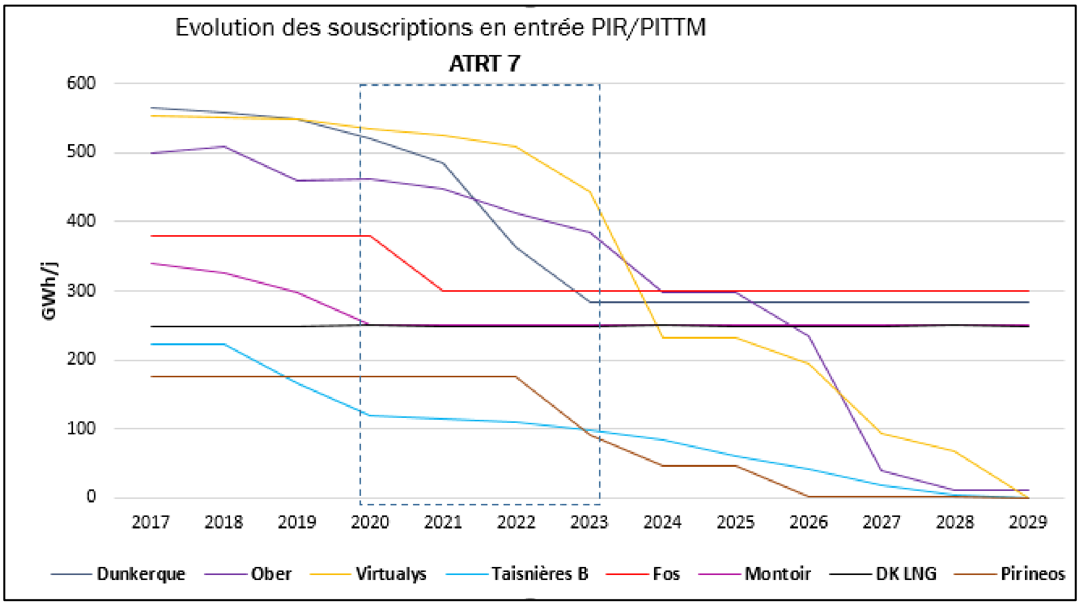
This tariff evolution principle gives visibility to the change in upstream network tariffs (PIR, PITTM and PITS), which is valuable since upstream capacity can be booked for several years. The disadvantage is that only the tariffs of the downstream network are subject to uncertainties related to changes during the tariff period in operators' authorised income, resulting in particular from the clearance of the balance of the income and expenses clawback account (CRCP). Such a principle can also lead to an imbalance between costs and revenues for these two networks at the end of the tariff period.

For the ATRT7 tariff, CRE is envisaging the possibility of applying CRCP balance clearance at the upstream network points as well.

> **Question 10** Are you in favour of CRCP clearance for all tariffs or do you prefer maintaining clearance only for the downstream network tariffs?

Expiration of long-term contracts

A portion of multiannual main network capacity bookings will expire during the ATRT7 period. For example, the figure below shows GRTgaz's and Teréga's forecast changes in bookings at the main network PIR and PITTM entry points. The capacity that will remain in shippers' portfolio will however still be higher than the capacity needed to supply the French network. Therefore, the TSOs do not anticipate any new significant long-term bookings during the ATRT7 period.



Source: GRTgaz and Teréga

Bookings at the PIR exit points should also decrease based on the TSOs' forecasts, but in lesser proportions than the drop in entry bookings. The drop in bookings at Pirineos would be, according to Teréga, partially offset by new shorter-term bookings.

In addition, capacity bookings at the TSOs' main network exit points towards regional networks could experience a more or less marked drop depending on consumption evolutions. In the forecast report done in 2018, 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 drop in bookings at the different network points will represent a loss for the TSOs. CRE considers that the increases in unit tariffs that will have to be implemented during the ATRT7 period to offset these drops in bookings must not modify the distribution of costs between transit and domestic consumption: unit costs (in €/km/d/year) of transit and domestic consumption must remain identical. However, an increase in tariffs in equivalent proportions to the drop in bookings of these same tariffs would lead to an overly high increase in entry tariffs (greater than 30% cumulated over the ATRT7 period). Such an option is not desirable. CRE proposes to discard it.

At this stage, CRE plans to adopt a principle of offsetting the loss by an equivalent increase in all main network tariffs. This option would enable, on the one hand, a more moderate change in all upstream network tariffs (roughly +14%[25] cumulated over the ATRT7 period) while guaranteeing that the unit costs of transit and domestic consumption supply remain identical. Because of the change in bookings, this option would lead, at the end of the ATRT7 period, to a 30%/70% split in revenues between the main network entries and exits.

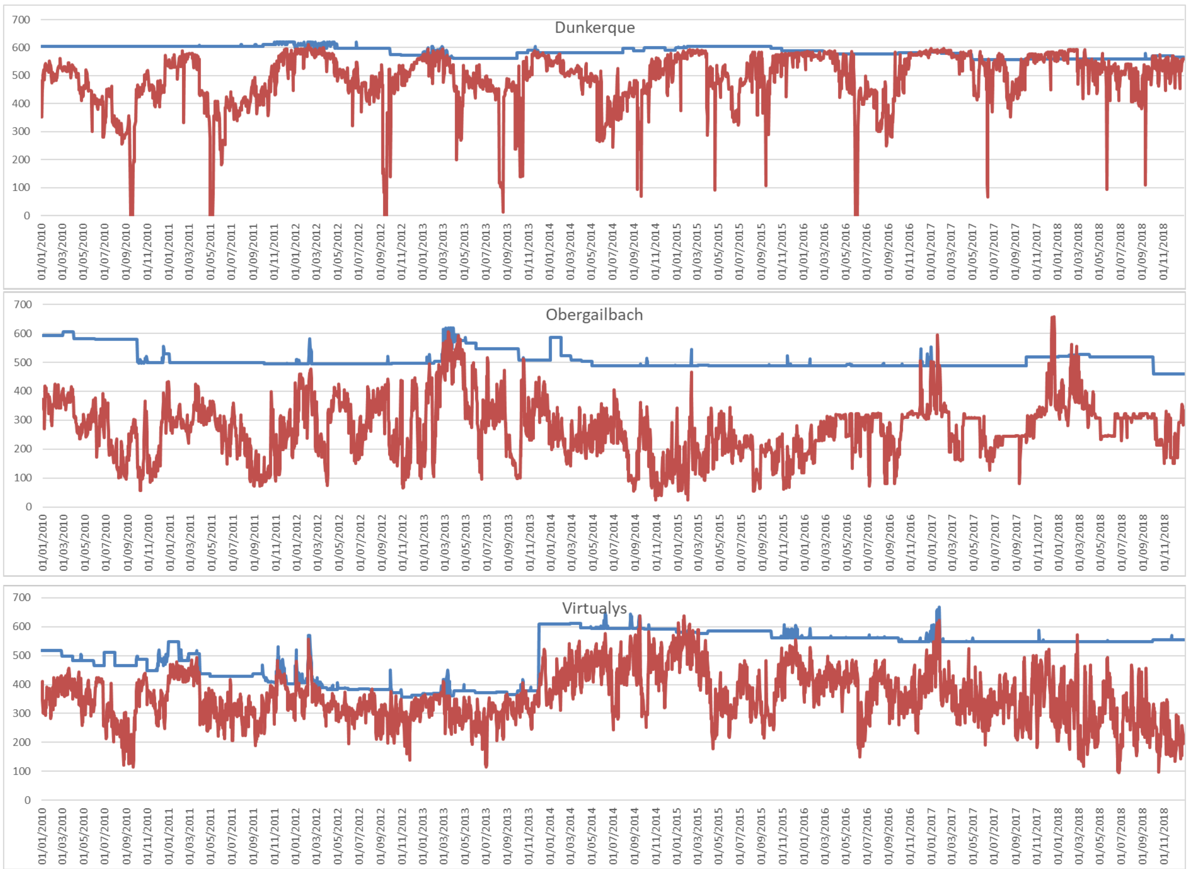
Question 11 Are you in favour of CRE's proposal to pass on the drop in network entry and exit bookings equivalently to all upstream network tariffs?

2.1.7 Capacity transfer offer at a preferential price

For several years now, the PEG price has been well-correlated to that of markets located upstream on the import route, in particular TTF in the Netherlands, as well as the neighbouring markets ZTP in Belgium and NCG in the south of Germany. However, many factors play a role in the formation of prices in these marketplaces and in particular of the PEG: the price of LNG, the level of consumption in the Iberian Peninsula, local weather conditions, etc.

The PEG price does not have to be identical to that of the TTF and NCG marketplaces. It should however be quite close, increased by the cost of the interconnections between these marketplaces. Currently, capacity at these interconnections is booked, based on long-term commitments (see 1.3.4), at levels higher than the use made of these interconnections, as shown by the following graphs:

Graphs = daily capacity booked (in blue) and daily capacity used (in red) over 2010-2018, at the Dunkirk, Virtualys (ex-Alveringem) and Obergailbach PIRs, based on data published on Smart GRTgaz



In this context, the price difference between the PEG and the TTF and NCG marketplaces is structurally low, and there are few new capacity bookings. However, the price differences can sometimes be greater.

In order to facilitate arbitrage when these price differences appear, and therefore to increase the PEG's liquidity, GRTgaz wishes to propose a capacity transfer offer between PIRs at a preferential price.

This offer would enable a shipper to take part in the PRISMA auctions to book capacity at a PIR entry (target point), and to exchange it afterwards with equivalent capacity that it has already booked at another PIR entry (source point).

[25] Estimates made with an assumption of constant revenue

To prevent this offer from representing an opportunity gain for shippers that would have bought the capacity at the target point in any case, the transfer would have to meet the following conditions:

- the target point could only be an interconnection point with a low probability of re-booking, i.e. a point for which the capacity booked has been higher than the maximum capacity used 10% of the time over the last few years. GRTgaz estimates that only the Virtualys and Obergailbach points are concerned:
- the transfer could only be done for annual, quarterly or monthly capacity, and not daily capacity, since daily capacity bookings already exist.

The price of this offer would be equal to 10% of the capacity's initial price.

For example, a shipper wishes to purchase 20 GWh/d at Virtualys for a year. At an entry tariff at the PIR of €104.97/MWh/d/y, it must pay €2.1 M. However, it already has 20 GWh/d of annual capacity at another PIR which it considers that it does not need (for example, Obergailbach). It can therefore decide to transfer its capacity to the Virtualys PIR by giving up what it owns at Obergailbach, at a cost of 10% of the capacity, i.e. €0.21 M, in addition to the capacity that it will continue to pay for at Obergailbach.

The expected impact on the transmission tariff is marginal, corresponding to the revenues from the additional capacity booked at a price of 10% of the tariff. The expected gain is essentially better liquidity at the PEG and better correlation with west European markets.

CRE shares the goal of having a market with the best possible liquidity and of controlling as much as possible the price at the PEG, for the benefit of end customers. However, it is not certain that the offer proposed by GRTgaz meets this objective since:

- if the price of gas at the point concerned is not marginal in the constitution of the price at the PEG, then the additional capacity bookings allowed thanks to the capacity transfer at a preferential price will not lower the price of the PEG. In addition, the capacity transfer at a preferential price could reduce GRTgaz's revenues from daily bookings. Even if the transfer is not proposed for daily capacity, monthly capacity bookings at a reduced price through transfers will still have an impact on subscriptions of lower time frames;
- the offer would be limited to shippers that have booked long term and having capacity that they do not use.

Therefore, CRE has reservations about the capacity transfer offer between PIRs at a preferential price proposed by GRTgaz.

Question 12 What is your opinion about the capacity transfer offer between PIRs at a preferential price according to the modalities proposed by GRTgaz?

2.1.8 Modalities for booking capacity at PITTMs

2.1.8.1 Modalities for booking capacity at PITTMs

The ATRT6 tariff specifies that the holding of regasification capacity at an LNG terminal confers the right and obligation to book entry capacity on the transmission network for corresponding durations and levels.

At the Dunkirk PITTM, firm entry capacity in the GRTgaz network is booked by shippers in the form of an annual band, for a period presenting a whole number of years, or in the form of bands of a duration higher than or equal to 10 days.

At the Montoir and Fos PITTMs, all shippers having booked capacity with LNG terminal operators are allocated by the TSO firm daily entry capacity, for the period of subscription of corresponding regasification capacity:

- in the case of multiannual regasification capacity bookings, the level of firm daily entry capacity attributed corresponds to a share of total firm daily entry capacity at the PITTM. This share is determined by the ratio:
  - of annual regasification capacity booked by the shipper at the terminals;
  - to total firm annual technical regasification capacity of the Montoir LNG terminal for the Montoir PITTM or the sum of total firm annual technical regasification capacity of the Fos Cavaou LNG terminal and the total firm annual regasification capacity booked at the Fos Tonkin terminal for the Fos PITTM;
- in the case of regasification capacity bookings of a duration lower than one year, the shipper is allocated one or several firm entry capacity bands for its subscription period, of a minimum duration of 10 days. The capacity level attributed corresponds to the quantity of regasification capacity booked, expressed in GWh.

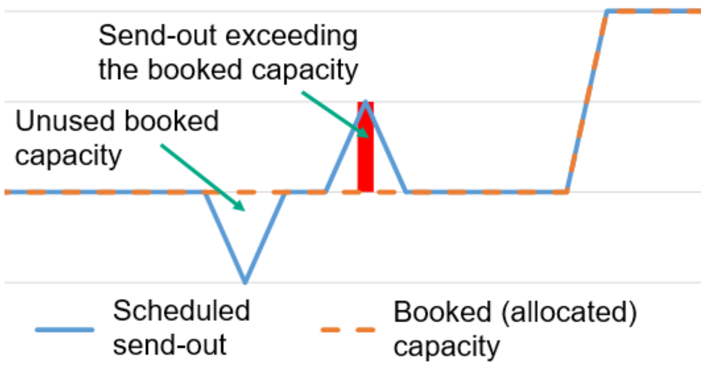
A shipper having regasification capacity bookings for a duration lower than a year has the possibility of deferring the date and duration of its booking, with three days' notice and provided that it keeps the full capacity volume initially booked.

At the beginning of each month, the TSO calculates for each shipper the daily send-out for each day of the previous month. If, for a given day, it exceeds the capacity held by the shipper, this shipper is billed for an additional daily capacity booking, at the daily capacity tariff, equal to the positive difference between the daily send-out and the capacity allocated by the shipper.

Automatic allocation of capacity at the Montoir and Fos PITTMs ensures that these terminals' users bear the costs related to the use of the network.

In addition, in the current tariff for the use of the regulated LNG terminals[26], shippers that wish to offload at the terminal automatically book regasification capacity.

Automatic allocation of flat capacity bands, at a constant daily level, does not necessarily correspond to a modulated send-out profile, with different send-out each day. This system, which leads shippers to pay for greater capacity than what they really need, can be summarised in the chart bellows:



Legend: the orange dotted lines represent when a shipper books a band. However, while sending out the same quantity in the network in total, its daily send-out, in blue, is different to the level of daily capacity booked.

Therefore, a shipper's send-out in the network on certain days can be lower than capacity booked, and higher on other days. The shipper must pay for the additional capacity for the days where its send-out is higher than its booking. The additional cost generated has been limited since the ATRT6 tariff, with the additional capacity being billed at the daily capacity tariff, without application of a penalty. The additional cost for exceeding capacity has represented roughly €200 k/year since 2015, a small amount compared to the volume sent out in the network from LNG terminals (104 TWh in 2017, 120 TWh in 2018). However, this allocation mode brings uncertainty and an additional cost on shippers that send out on the network from LNG terminals.

The problem with the current situation is that shippers do not have the possibility of more flexible booking. CRE therefore plans to enable shippers to modulate their level of capacity the day before, while keeping the full volume of capacity initially booked over the period. Shippers could therefore book capacity which is finally higher or lower than that initially allocated in a band for the following day, while conserving in total the capacity allocated to them initially over the entire period. If they reserve capacity which is lower overall over the entire period, they will still have to pay for the capacity initially allocated. If they reserve capacity which is higher overall, they will have to pay for the additional capacity compared to the capacity initially allocated.

Question 13 Are you in favour of the possibility for a shipper to change their capacity booking at the PITTM the day before, while keeping the full volume of capacity initially booked?

2.1.8.2 Capacity bookings at the Fos PITTM after 2020

The end of operation of the Fos Tonkin LNG terminal is scheduled for 2021. Elengy launched a call for capacity bookings[27] to pursue the operation of the terminal beyond that date. If this call for capacity bookings is conclusive, operation will be extended, but with reduced regasification capacity compared to current capacity.

[26] Deliberation by the French Energy Regulatory Commission of 15 December 2018 deciding on the change in the tariffs for the use of regulated liquefied natural gas terminals as at 1 April 2019
[27] https://www.elengy.com/en/news/news/commercial/335-fos-2021-start-of-open-season.html

Therefore, regardless of the outcome of the call to the market, total regasification capacity of the Fos terminals will be reduced. Therefore, send-out capacity in the network at the Fos PITTM (410 GWh/day), which will not change, will become higher than this regasification capacity.

With the current capacity booking modalities, shippers having multiannual regasification capacity bookings in the Fos terminals, in particular at Cavaou, would be allocated capacity at the PITTM which would potentially be higher than the capacity that could actually be sent out by the terminal.

To take into account the change in regasification capacity, the rule shall therefore have to be changed as from 2021.

CRE proposes that, in the case of multiannual regasification capacity bookings at a Fos terminal, the level of firm daily entry capacity allocated at the PITTM be calculated based on the maximum technical daily regasification capacity of the terminal in question, to which would be applied the ratio:

- of annual regasification capacity booked by the shipper at the terminal;
- to the total firm annual technical regasification capacity of this terminal.

For example, if the maximum daily technical regasification capacity of the Cavaou terminal is 330 GWh/day, shippers that have booked a multiannual regasification annual capacity equal to 20% of total firm annual technical regasification capacity of Cavaou will be allocated daily entry capacity at the PITTM of 66 GWh/day.

Question 14 Are you in favour of the change in the rule for allocating capacity at the Fos PITTM as from 2021 proposed by CRE, to take into account the reduction in regasification capacity at Tonkin?

2.1.8.3 Pooling offer at the PITTMs

In the LNG market, shippers choose between different marketplaces at global scale. To decide where to ship gas, they take into account both its price in the destination markets and the cost of shipping, composed of maritime transport, use of the regasification terminal and access to the transmission network.

The differences in the cost of maritime transport between the liquefaction terminal and the different French regasification terminals create situations of potential arbitrage between these terminals for shippers. Therefore, financial arbitrage between the PEG and another marketplace can be jointly unfavourable for the PEG if it is accessed by a given French terminal, but favourable to the PEG if it is accessed by another French terminal.

A pooling service was created at the end of 2015[28] between the Elengy and Fosmax LNG regulated terminals to enable shippers that have bookings in at least one of the three regulated terminals and not intending to use them all in month M, to use a portion of this capacity in one of the other regulated terminals, by accessing, based on a specific tariff, capacity still available after the 20th day of the month M-1 in this second terminal. This offer, which was tested initially, was continued in the ATTM5 tariff[29]. Shippers that transfer their capacity between two terminals must pay for only 10% of the capacity transferred.

GRTgaz would also like to propose a pooling service, between all PITTMs, including the Dunkirk PITTM. Any capacity not used at a PITTM could be transferred to another PITTM, within the framework of a subscription made after the 20th of month M-1 for month M. Therefore, shippers that have capacity at a PITTM that they do not use could send out gas at another PITTM by paying only 10% of the initial capacity price. The goal pursued is to attract more LNG cargos in France and thus contribute to lowering the price at the PEG.

Potentially interested shippers are those that have long-term capacity in a terminal, but also shippers that have a short-term booking and want to optimise their shipping.

This offer would therefore be the equivalent at the PITTMs of the capacity transfer at a preferential price between PIRs (see 2.1.7). The benefits expected of pooling at PITTMs are very limited. Cases where only the difference in the maritime cost between a French LNG terminal and another makes it profitable to change a ship's destination from one French LNG terminal to another should be rare.

Therefore, at this stage CRE has reservations about the pooling offer at PITTMs.

[28] CRE's deliberation of 17 December 2015 deciding on the experimentation, by regulated LNG terminal operators, of the intra-monthly capacity pooling service

[29] Deliberation by the French Energy Regulatory Commission of 18 January 2017 deciding on the tariffs for the use of regulated liquefied natural gas terminals

Question 15 Are you in favour of the pooling offer at PITTMs proposed by GRTgaz?

2.2 Regional network tariff structure

2.2.1 Regional network pricing

Pricing of transmission in the regional network depends on:

- the shipping capacity booked;
- the unit tariff for transmission in the regional network multiplied by a regional tariff level between 0 and 10 (since the reform implemented in the ATRT6 tariff), specific to each delivery point, which takes into account the disparity in transmission costs in the regional network for each delivery point.

Delivery pricing depends on:

- delivery capacity booked;
- the unit delivery tariff which differs based on the type of delivery point;
- the number of delivery points for industrial customers or highly modulated industrial customers, with a set delivery charge applying to each delivery point.

CRE plans to renew, for the ATRT7 tariff, the regional network pricing principles in effect in the ATRT6 tariff.

Question 16 Are you in favour of maintaining in the ATRT7 tariff the regional network pricing principles in effect in the ATRT6 tariff?

2.2.2 Change in capacity booking modalities

2.2.2.1 Intra-annual capacity tariff

At main network exits and for transmission in the regional network and delivery, customers connected to the transmission network can book capacity for an annual, monthly or daily duration. These bookings ensure hourly delivery capacity equal to 1/20th of the daily delivery capacity booked. Customers can also request additional hourly capacity, by paying an additional fee.

The dimension of the gas transmission network is such that it can transport a certain quantity of gas during the 2% risk scenario "P2", i.e. the consumption peak at an extremely low temperature recorded three days in a row, as occurs statistically every 50 years.

This means that the network costs for a customer present only in the coldest months are close to the costs generated by a customer present all year. It is possible to book intra-annual capacity but by paying the cost of annual capacity multiplied by a certain coefficient depending on the duration of the product and time of the year (with a higher coefficient in winter than in summer).

In that regard, article D452-1-2 of the Energy Code specifies that the "*tariffs for the use of transmission networks applicable during the months of November to April can be set at a level higher than that enabling strict coverage of network costs, provided that, during the months of May to October, they are reduced in order to maintain coverage of costs over the year […]*."

Therefore, CRE adopted pricing principles encouraging shippers to book mainly on an annual basis. It is possible to book intra-annual capacity by paying the cost of annual capacity multiplied by a certain coefficient depending on the duration and time of the year. The coefficients in effect in the ATRT6 tariff are as follows:

Capacity	Specific conditions	Coefficient
Monthly	January - February	8/12 of the annual charge
	December	4/12 of the annual charge
	March - November	2/12 of the annual charge
	April – May – June – September – October	1/12 of the annual charge
	July - August	0.5/12 of the annual charge
Daily	N/A	1/30 of the monthly charge

Therefore, customers that book capacity only for the month of January will bear 8/12th of the cost for the same capacity booked for the whole year.

Intra-annual capacity bookings are limited because the great majority of customers have their consumption peak in winter: they represent less than 4% of capacity booked by customers connected to the transmission network.

GRTgaz proposes to lower the January and February coefficients from 8/12 to 4/12. This would cause a drop in current revenues from intra-annual bookings (revenues from January and February bookings are mechanically divided by two). In addition, this could lead to an optimisation of their bookings by certain customers, for whom it would then be more beneficial to book intra-annually rather than annually as is the case currently. These effects would increase the average capacity tariff to offset the loss in revenue.

CRE notes that for Teréga, the effect would be limited, since intra-annual capacity only represents 0.5% of total capacity booked.

On the contrary, the drop in monthly coefficients could lead to a gain in the form of additional bookings compared to the situation where coefficients would be maintained at the current level. In particular, GRTgaz considers that a certain number of un-subscriptions of customers can be avoided by lowering the January and February coefficients.

GRTgaz foresees a net positive effect for the tariff, with the gains from un-subscriptions avoided being higher than the drop in revenues following optimisation of bookings. At this stage, CRE is in favour of this measure.

CRE would like the coefficients to remain the same for transmission and distribution. If a change in coefficients is decided, it will therefore apply both to the tariff transports and the distribution tariffs.

Question 17 Are you in favour of a drop from 8 to 4 in the monthly coefficients of the capacity tariff for January and February?

2.2.2.2 Penalties for exceeding capacity

Each day, exceeding daily exit capacity on the main network, transmission capacity on the regional network and delivery capacity is subject to penalties.

For the portion in excess that is less than or equal to 3% of the daily capacity subscribed, no penalty is applied.

For the portion in excess greater than 3%, the calculation of penalties is based on the price of the firm daily booking of daily capacity, as follows:

- for the portion in excess comprised between 3% and 10%, the penalty is equal to 20 times the price of the firm daily booking of daily capacity;
- for the portion in excess greater than 10%, the penalty is equal to 40 times the price of the firm daily booking of daily capacity.

In addition, each day, exceeding hourly transmission capacity on the regional network and delivery capacity, to supply end customers connected to the transmission network, is subject to penalties. For a given day, exceeding hourly capacity is calculated by considering the maximum value of the hourly average of quantities delivered at the delivery point in question over four consecutive hours.

For the portion in excess less than or equal to 10% of the hourly capacity booked, no penalty is applied.

For the portion in excess greater than 10%, the calculation of penalties is based on the price of the daily subscription of hourly capacity, as follows:

- for the portion in excess comprised between 10% and 20%, the penalty is equal to 45 times the price of the daily booking of hourly capacity;
- for the portion in excess greater than 20%, the penalty is equal to 90 times the price of the daily booking of hourly capacity.

These penalty rules for exceeding capacity can be summarised by the table below:

	Daily capacity (J)	Hourly capacity (h)
Starting excess level for penalty application	3%	10%
Penalty – 1st threshold	1st threshold: 3% - 10% Penalty = daily capacity price J x 20	1st threshold: 10% - 20% Penalty = daily capacity price h x 45
Penalty – 2nd threshold	2nd threshold: > 10% Penalty = daily capacity price J x 40	2nd threshold: > 20% Penalty = daily capacity price h x 90

When capacity exceeding is observed by a TSO, both for daily and for hourly capacity, shippers can correct their capacity booking a posteriori.

In total, penalties represent an average €2.4 M/year in GRTgaz's network (i.e. 0.1% of total annual authorised income). For Teréga, they represent 0.2 M/year (i.e. 0.1% of total annual authorised income).

Following work conducted by the TSOs and presented within the framework of Concertation gaz, GRTgaz proposes to eliminate the second penalty threshold. Therefore, for all exceeding of capacity beyond the 3% minimum for daily capacity and 10% for hourly capacity, the penalty rate calculated by multiplying the capacity booking price would be a single rate, corresponding to the current 1st threshold, i.e. 20 for daily capacity and 45 for hourly capacity.

This change aims to simplify calculation and penalise to a lesser extent major exceeding of capacity, which is often caused by a particular incident within a site, over which the customer has little control.

For its part, Teréga proposes to implement a linear penalty calculation, which would no longer depend on the initial capacity cost, i.e. the tariffs for main network exit capacity, for transmission in the regional network (multiplied by the regional tariff level) and for delivery. The penalty level would be determined in €/MWh of exceeding of capacity, based on a record of the level of penalties over the past few years.

CRE is in favour of GRTgaz's proposal, which simplifies the mechanism while keeping the current calculation mode based on the cost of capacity booked. In addition it recommends that the two TSOs' calculation mode be identical, for the purposes of readability and simplification.

Question 18 Are you in favour of the elimination of the 2nd threshold of penalties for exceeding of capacity as proposed by GRTgaz?

2.2.2.3 Redistribution of penalties for exceeding capacity

In the current system, each TSO redistributes the amount of penalties for exceeding capacity collected each year, during the month of June of the following year at the latest.

The amount of penalties to be redistributed is divided between shippers in proportion to the quantities of gas delivered to end customers connected to the transmission network and to PIRRs. Once a year, each TSO publishes on its website the unit amount of penalties redistributed, expressed in euros per MWh consumed by end customers connected to the transmission network.

CRE plans to terminate this redistribution of penalties. They would be integrated directly in the tariff, through the CRCP account, based on the same functioning as for distribution tariffs. Therefore, each year, the penalties collected by the TSOs would be paid into the CRCP, which would lower the tariff. CRE considers that this functioning would be more simple and more transparent.

Question 19 Are you in favour of the termination of the redistribution of penalties, which would be paid back by the TSOs through the tariff?

2.2.3 Short-notice interruptible transmission offer

The short-notice interruptible transmission offer was created in the ATRT3 tariff[30], which entered into effect on 1 January 2007, against numerous connections of new combined-cycle gas turbines (CCGTs). CCGTs are very big clients for the gas network, both for their capacity booked (20 GWh/d per unit of 400 MW) and for their capacity to go very quickly (in 20 to 30 minutes) from 0 to their maximum power.

The goal of this offer was to encourage CCGTs to be installed close to network entry points, so that GRTgaz does not have to make major investments to enable supply of these sites under all network conditions.

Characteristics of the short-notice interruptible transmission offer

This offer is reserved to new sites with a large capacity booked (threshold of 10 GWh/day) and located in the immediate vicinity (less than 50 km as the crow flies) of an entry point in the H-gas network. The offer provides for a reduction or interruption in the supply of the sites concerned at the request of GRTgaz, with a minimum notice of 2 hours, when the following two conditions are met:

- the quantity of gas physically injected into the network at the nearest entry point is less than the daily delivery capacity booking of the sites benefitting from this interruptible offer within the perimeter of this entry point;
- the day's temperature is lower than the average daily temperature likely, statistically, to be reached or negatively exceeded more than 20 days per year, with the 2% cold peak risk scenario.

  In return, shippers subscribing to this offer receive a tariff reduction equal to the delivery capacity that they have booked for this delivery point multiplied by the sum of:

- 50% of the main network exit capacity charge;
- 50% of the main network entry capacity charge at the nearest entry point.

The offer has been in effect for about ten years now and benefits roughly half of the existing CCGTs, with the other half having been connected to the network before the creation of the offer or not meeting the condition of close proximity to an entry point on the H-gas network. It represents a reduction in the gas transmission invoice of approximately €1.8 M/year for a 400 MW CCGT.

Feedback and analysis by CRE

In conjunction with GRTgaz, CRE obtained feedback on the implementation of the short-notice interruptible transmission offer in existence since 2007.

It appears that GRTgaz has never activated interruption of plants, for several reasons:

- on the one hand, CCGTs are electricity production resources necessary during cold peaks, which makes their interruption very complicated. Indeed, GRTgaz must coordinate with RTE beforehand to ensure that this interruption does not jeopardise the balance in the electricity transmission network. ;
- on the other hand, the French gas network has been greatly reinforced since 2007. Two new LNG terminals were brought on stream during this period: Cavaou in 2010 and Dunkirk LNG in 2016, which increased and geographically diversified sources of gas entry in the transmission network. In view of the connection of the new Dunkirk LNG terminal, GRTgaz completed the Hauts de France II and Arc de Dierrey projects in the north-east of France (see 1.3.2). In addition, to enable go-live of the single market zone as at 1 November 2018, GRTgaz and Teréga completed the Val de Saône and Gascogne-Midi projects respectively. In total, GRTgaz and Teréga have respectively invested an average €250 M/year and €68 M/year over the 2007-2017 period to develop the main network. Therefore, the network has been greatly reinforced, with additional transmission capacity. Over the same period, the French gas market went progressively from five zones to a single zone, simplifying transmission of gas in the French network. Therefore, the constraints anticipated in 2007 for the supply of new CCGTs have been heavily reduced.

In addition, with the implementation of the single marketplace, network operation and mechanisms for addressing bottlenecks have evolved: CCGTs can contribute to resolving residual bottlenecks, by participating in calls for tenders covering the purchase/sale of gas on both sides of a bottleneck (locational spread). They are the only customers that can do so and be paid for it.

Lastly, a paid regulatory interruptibility mechanism is being studied (see 2.3.4 of the present consultation), which would be based on simpler activation modalities that those in the short-term interruptible transmission offer and would also risk being a duplicate of that system.

[30] Proposition tarifaire de la Commission de régulation de l'énergie du 10 novembre 2006 pour l'utilisation des réseaux de transport de gaz naturel

For all of these reasons, CRE plans to terminate the short-notice interruptible transmission offer. This termination could enter into effect parallel to the introduction of the interruptibility mechanism.

Question 20 Are you in favour of the elimination of the short-notice interruptible transmission offer? If so, do you consider that its elimination should occur parallel to the implementation of interruptibility?

2.2.4 Proximity tariff discount

A proximity discount was introduced in the ATRT2 tariff[31], which entered into effect on 1 January 2005. It was implemented to reflect actual transmission costs for users located in the immediate vicinity of the Belgian and German borders, by replacing the main network exit quantity charge: this charge, eliminated in the ATRT2 tariff, was different according to the exit zones and was therefore lower for zones bordering the network entry[32]. The main network exit quantity charge depended on the exit tariff level, which varied according to the main network exit zone.

In the following tariff (ATRT3), which entered into effect on 1 January 2007, CRE introduced equalisation of capacity-based main network exit charges, by setting, for each TSO, a single exit charge, regardless of the main network exit zone.

The proximity discount is deducted from the monthly bill of each shipper concerned. It is applied for each shipper, to the quantity of gas equal, each day, to the minimum between the quantity of gas injected at the transmission network entry point and the quantity of gas withdrawn in the associated exit zone. The discount level in effect as at 1 April 2019[33] is as follows:

Perimeter	Entry point	Associated exit zone	Proximity discount (€/MWh)
GRTgaz	Taisnières B	Taisnières B region	0.17
GRTgaz	Taisnières H	Taisnières H region	0.23
GRTgaz	Dunkirk	Dunkirk region	0.23
GRTgaz	Obergailbach	Obergailbach region	0.23

Total deduction of the bill relating to the proximity discount represents a total of approximately €2.5 M/year for all beneficiaries. Shippers are not required to pay back this deduction to their clients: it is therefore not certain that it is passed on to customers located in the immediate vicinity of the entry points at the Belgian and German borders.

Given these elements, CRE plans to extend the principle of national equalisation of exit charges, and therefore eliminate the proximity discount in the ATRT7 tariff.

Question 21 Are you in favour of the elimination of the proximity discount?

2.2.5 Connection discount (cost share)

The discount on connection was introduced in the ATRT6 tariff, which entered into effect on 1 April 2017, in order to facilitate the connection of new clients or the increase in bookings through the adaptation of existing stations.

Previously, gas transmission network users paid the full costs for connection and station infrastructure, in return for access to this infrastructure.

The connection discount modifies the distribution of connection costs between new clients connected and the other users of the network: a share of the connection infrastructure costs is pooled in the ATRT tariff, and not paid directly by the user, who in return makes commitments concerning future capacity bookings. Therefore, the financial participation requested of the customer for their connection corresponds to the cost of the connection minus the future

[31] Proposition de la Commission de régulation de l'énergie du 27 octobre 2004 pour les tarifs d'utilisation des réseaux de transport de gaz naturel
[32] Public consultation on the pricing principles for the use of gas transmission networks of 8 July 2004
[33] Deliberation by the French Energy Regulatory Commission of 13 December 2018 deciding on the evolution of the tariff for the use of GRTgaz's and Teréga's natural gas transmission networks as at 1 April 2019

transmission revenue that the client will pay over a period of ten years maximum. In all cases, the customer must pay for at least 50% of the connection cost.

Feedback on this mechanism is limited since it was implemented recently. However, the TSOs have noted an increase in connections compared to the previous tariff period. Within GRTgaz's perimeter, 35 connection projects or projects to strengthen existing infrastructure were granted the development discount since its creation. In addition, the mechanism guarantees that the booking revenues from the site connected cover the portion of the connection costs pooled over a period of less than or equal to ten years.

CRE proposes to not change this mechanism.

Question 22 Are you in favour of maintaining the connection discount based on the current modalities?

2.3 Modalities for collecting storage compensation in the ATRT tariff

2.3.1 Principle of storage cost coverage

The Energy Code states that storage operators shall collect their authorised income, set by CRE:

- on the one hand, through the revenues that they reiceive directly, mainly from the sale of underground natural gas storage capacity, whose modalities are defined by CRE in accordance with the provisions of article L. 421-5-1 of the Energy Code;
- on the other hand, in the case where the revenues they receive directly are lower than their authorised income, through compensation collected by the transmission system operators (TSOs) from their clients and paid back to the storage operators in compliance with article L. 452-1 of the Energy Code.

It is within this framework that CRE introduced in its deliberation of 22 March 2018[34] an additional tariff charge in the ATRT tariff ("storage tariff charge").

The compensation is collected from shippers present in the GRTgaz and Teréga transmission networks, through the application of a storage tariff charge based on the winter modulation of their clients not subject to load shedding or capacity interruption that are connected to the public gas distribution networks.

Modulation of each shipper corresponds to the difference, when it is positive, between firm capacity booked for each of their clients at each transmission/distribution interface point (PITD) on the one hand, and on the other hand, the sum of the average daily consumption of each client and the portion of their capacity declared interruptible.

The storage tariff charge is calculated as the ratio between the projected compensation amount within the perimeter of France and the projected value of the basis of collection of this compensation. The value of the basis of compensation corresponds to the sum, within the perimeter of France, of shippers' modulations.

2.3.2 Basis of the storage tariff charge

In its deliberation of 22 March 2018, CRE defined the scope of the basis of collection of the storage compensation.

Against the entry of gas storage into the regulation, with, on the one hand, time constraints for implementing the reform, and on the other hand, the absence of contractual interruptibility mechanisms that could be applied to clients directly connected to the transmission network, CRE pursued a dual objective of economic continuity and consideration of the value of storage for gas network users whose supply cannot be interrupted in the event of a supply crisis.

Therefore, as at 1 April 2018, it adopted a basis of compensation collection corresponding to the following user categories:

- residential customers, including customers living in buildings with collective gas heating;
- non-residential customers performing missions of general interest related to meeting the essential needs of the nation, connected to the distribution network;
- customers that have not contractually accepted supply that can be interrupted, or who have accepted to be subject to load shedding, connected to the distribution network.

The Energy Code states that the storage capacity necessary for ensuring security of supply are defined under:

[34] CRE's deliberation of 22 March 2018 deciding on the introduction of a storage tariff charge in the tariff for the use of GRTgaz's and TIGF's transmission networks

- article L. 421-3-1 which specifies that the multiannual energy programme must define underground storage infrastructure that guarantee medium- and long-term security of supply;
- article L. 421-4 of the Energy Code which specifies the definition, by order of the minister of energy, of the minimum natural gas stocks necessary as at 1 November for ensuring security of supply of natural gas during the period between 1 November and 31 March.

In these two cases, no distinction is made between customers connected to the transmission network or to the distribution network.

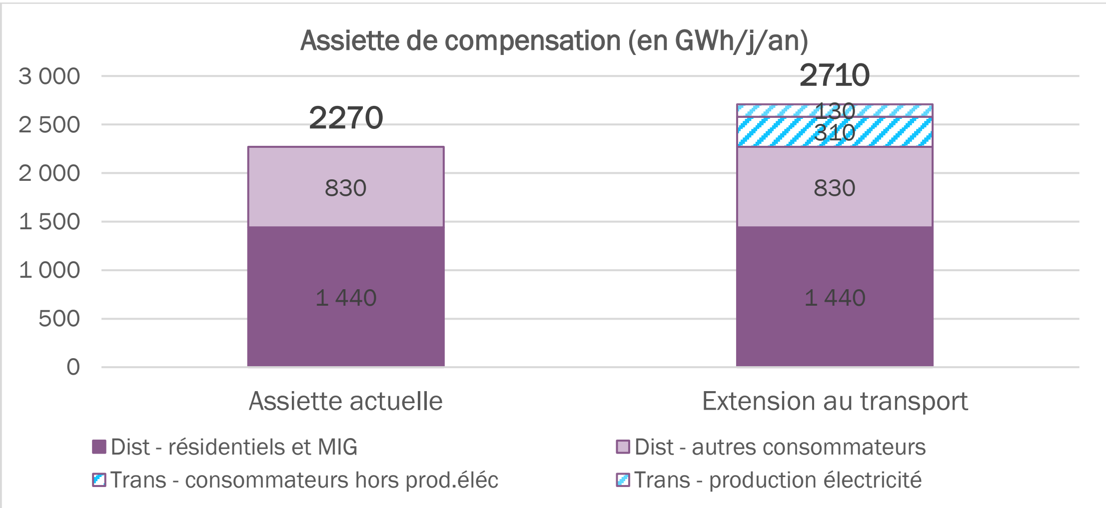
Lastly, article L. 421-6 of the Energy Code specifies a mechanism for building additional natural gas stocks in the event that the storage capacity bookings at auctions do not suffice to ensure security of supply, termed as a "safety net". The implementing decree[35] of this mechanism specifies in particular the customers that would bear the costs related to activation of the safety net.

For the year 2018, this decree stated that only customers connected to the distribution network that have not accepted to be subject to load shedding would be taken into account: this scope of application was therefore in line with that adopted by CRE for the payment of the storage compensation.

As from 2019, the basis of the safety net defined by the decree now covers all non-interruptible customers, including those connected to the transmission network. The scope of application of the safety net and the storage cost compensation are therefore no longer aligned.

2.3.3 Impact of an extension of the storage tariff charge to customers connected to the transmission networks

A change in the scope of the basis of compensation collection so that it applies also to customers connected to the transmission network would represent, based on the current calculation, a 19% increase in the basis, excluding exemptions associated with interruptibility, as shown in the graph below (based on 2019 data): such a development would lead to, all else being equal, a 15% drop in the storage tariff charge (TS).



For example, based on the results of the 2019-2020 storage year, a basis of compensation collection extended to all transmission customers and excluding exemptions associated with interruptibility, would lead to a TS of about €180/MWh/d/year (compared with €213.4/MWh/d/year as at 1 April 2019). Storage compensation would represent an annual amount of almost €80 M for all customers connected to the transmission network, who until now have not paid these costs, neither in the current regime in effect for the last ten years, nor in the first two years of the regulation. Such a development would lead to an average increase of roughly 40% in transmission customers' transmission bill with an impact that can be more or less considerable depending on customers' modulation. Plants using gas to produce electricity would be particularly affected with a transmission bill with double the usual amount.

2.3.4 CRE's analysis

CRE considers that customers that can reduce and/or interrupt their gas consumption their gas consumption in the event of a supply crisis do not enjoy the benefits of the storage regulation in terms of security of supply. Therefore, they should be exempted, fully or partially, from the storage compensation payment.

[35] Decree No 2018-221 of 30 March 2018 on the constitution of additional natural gas stocks mentioned in article L. 421-6 of the French Energy Code

Such a principle was implemented within the framework of the implementation of the gas storage regulation in 2018: customers connected to the distribution network that accept load shedding (i.e. they are willing to reduce their consumption by 90% if they DSO so requests) are exempt from the storage compensation payment.

According to the same principle, CRE considers that in the case of a change in the basis also applying the compensation payment to customers connected to the transmission network, these customers should have access to a similar mechanism. However, this is not the case at this stage, due to absence of transmission load shedding.

In reality, customers connected to the transmission network are currently faced with a greater risk of being interrupted than distribution customers, as is specified for example in the order of 28 November 2013[36] which sets out the modalities of the functioning of the gas emergency plan: "In terms of load shedding, a distinction shall be made between the procedures applicable by the TSOs and those applicable by the DSOs, since the latter are not technically or humanly able to proceed to simultaneous large-scale selective load-shedding [...]. As a result, load shedding in the distribution network is reserved to critical force majeure situations for which load shedding of clients directly connected to the transmission network is not sufficient for ensuring continuity of public distribution supply".

A certain number of customers connected to the transmission network are therefore able, or required, to reduce their consumption in the event of a supply crisis: therefore, they would not fully enjoy the guarantee of security of supply enabled by gas storage, and in that regard, should be able, as in the case of distribution, to be exempt, at least partially, from the storage compensation payment.

In addition, for subscription-based customers (who represent 10% of volumes consumed in the distribution network, but the entire volume in the transmission network), the transmission capacity booking level is free. This means that:

- on the one hand, the link between the capacity booked and the cold peak is less evident that for profile-based customers whose standardised subscription is based on a standard calculation of cold peak consumption. It could therefore be envisaged, for subscription-based customers, modifying the calculation of this storage compensation, based on the capacity booked, to better reflect the reality of these sites' participation in the cold peak and winter modulation. This is the case, in particular, for customers using gas as a back-up;
- on the other hand, there are possible arbitrages regarding the capacity booked: shippers can reduce their capacity bookings to not pay the storage charge taking the risk of paying penalties for exceeding capacity, if those penalties are lower than the storage cost.

The TSOs are working, for example, to adopt a calculation based not on capacity booked but on consumption in winter.

In conclusion, while CRE considers that the scope adopted for determining the regulated scope of application and the implementation of the safety net could lead to retaining in the compensation basis all customers that cannot interrupt or reduce their consumption during the winter peak demand period, it also considers that this change cannot be envisaged without having measures to allow certain customers that would accept a reduction in their consumption in the event of a supply crisis, to be exempt, at least partially, from the compensation payment. Articles L. 431-6-2 and L. 431-6-3 of the Energy Code, which specify the introduction of remunerated or non-remunerated interruptibility mechanisms and whose implementing provisions are being discussed, must enable the implementation of these exemptions.

In addition, in the case of a modification of the scope of compensation collection, a change in the calculation of winter modulation appears desirable to accurately take into account sites' actual participation in modulation and the winter peak.

Question 23 Do you consider, like CRE, that an extension of the scope of storage compensation to customers connected to the transmission network can be envisaged only with an interruptibility mechanism enabling partial or full exemption from the storage compensation?

3. CONSIDERATION OF BIOMETHANE DEVELOPMENT IN THE NETWORKS

3.1 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

[36] Order of 28 November 2013 adopting the emergency gas plan pursuant to regulation (EU) No 994/2010 of the European Parliament and of the Council of 20 October 2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC

decree relating to the multiannual energy programme[37] 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[38] 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"[39] law of 30 October 2018. A decree, taken following CRE's opinion, shall specify the conditions for exercising this right.

3.2 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 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.

Question 24 Are you in favour of the sending of 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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Question 25 Do you have any other proposal or comment about the structure of the ATRT7 tariff?

[37] Decree No 2016-1442 of 27 October 2016 on the multiannual energy programme
[38] Law No 2015-992 of 17 August 2015 on energy transition towards green growth
[39] 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

4. LIST OF QUESTIONS

Question 1 Do you agree with CRE's conclusion regarding the dimensions of the French natural gas transmission networks and the caution necessary with the launch of new investment projects?

Question 2 Are you in favour of maintaining the current April to April timetable, with the exception of the tariffs applicable to the PIRs which would change as at 1 October of each year?

Question 3 Are you in favour of maintaining the classification of networks, main and regional, as envisaged by CRE?

Question 4 Are you in favour of maintaining the classification of storage compensation as envisaged by CRE?

Question 5 Are you in favour of maintaining the pricing principle (capacity-based pricing, based on an entry-exit model) and equalisation principle currently in effect in the ATRT6 tariff?

Question 6 Are you in favour of globally maintaining the current entry/exit distribution method?

Question 7 Are you in favour of the pricing principles envisaged by CRE for the main network?

Question 8 Are you in favour of the requalification of the Jura PIR as a PIRR?

Question 9 Are you in favour of maintaining the tariff discounts envisaged by CRE for interruptible capacity?

Question 10 Are you in favour of CRCP clearance for all tariffs or do you prefer maintaining clearance only for the downstream network tariffs?

Question 11 Are you in favour of CRE's proposal to pass on the drop in network entry and exit bookings equivalently to all upstream network tariffs?

Question 12 What is your opinion about the capacity transfer offer between PIRs at a preferential price according to the modalities proposed by GRTgaz?

Question 13 Are you in favour of the possibility for a shipper to change their capacity booking at the PITTM the day before, while keeping the full volume of capacity initially booked?

Question 14 Are you in favour of the change in the rule for allocating capacity at the Fos PITTM as from 2021 proposed by CRE, to take into account the reduction in regasification capacity at Tonkin?

Question 15 Are you in favour of the pooling offer at PITTMs proposed by GRTgaz?

Question 16 Are you in favour of maintaining in the ATRT7 tariff the regional network pricing principles in effect in the ATRT6 tariff?

Question 17 Are you in favour of a drop from 8 to 4 in the monthly coefficients of the capacity tariff for January and February?

Question 18 Are you in favour of the elimination of the 2nd threshold of penalties for exceeding of capacity as proposed by GRTgaz?

Question 19 Are you in favour of the termination of the redistribution of penalties, which would be paid back by the TSOs through the tariff?

Question 20 Are you in favour of the elimination of the short-notice interruptible transmission offer?

Question 21 If so, do you consider that its elimination should occur parallel to the implementation of interruptibility?

Question 22 Are you in favour of the elimination of the proximity discount?

Question 23 Are you in favour of maintaining the connection discount based on the current modalities?

Question 24 Do you consider, like CRE, that an extension of the scope of storage compensation to customers connected to the transmission network can be envisaged only with an interruptibility mechanism enabling partial or full exemption from the storage compensation?

Question 25 Are you in favour of the sending of an economic signal to biomethane producers concerning the location of facilities, in order to prioritise facilities causing the least constraints in the network?

Question 26 Do you have any other proposal or comment about the structure of the ATRT7 tariff?

ANNEX 1: COMPARISON WITH THE REFERENCE METHOD (CWD) OF THE TARIFF NETWORK CODE

The parameters for the capacity weighted distance reference price methodology shall be as follows:

1) the part of the transmission services revenues to be recovered from capacity-based transmission tariffs;

The method proposed by CRE uses capacity-based tariffs.

2) the forecasted contracted capacity at each entry point or a cluster of entry points and at each exit point or a cluster of exit points;

The method proposed by CRE is based on capacity contracted at each entry point or a cluster of entry points.

3) where entry points and exit points can be combined in a relevant flow scenario, the shortest distance of the pipeline routes between an entry point or a cluster of entry points and an exit point or a cluster of exit points;

The method proposed by CRE is based on relevant flow scenarios:

- *for transit: supply from the Dunkirk PIR is economically relevant;*
- *for domestic consumption: two flow scenarios are considered, a "summer" pattern and a "winter" pattern in order to model domestic customers' supply.*

In all cases, the shortest pipeline distance is used.

4) the combinations of entry points and exit points, where some entry points and some exit points can be combined in a relevant flow scenario;

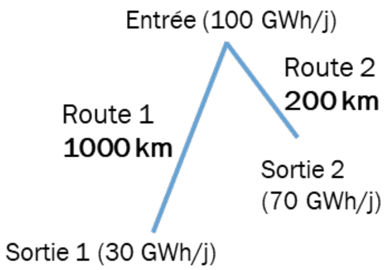
The method proposed by CRE is based on combinations of points in particular for domestic use pricing.

5) the entry-exit split shall be 50/50.

The method proposed by CRE is based on the current entry-exit split, closer to 35/65, justified given the particular configuration of the French network.

The CWD method aims, in spirit, to lead to homogenous unit costs (€/MWh/d/year/km) for the different users of the gas transmission network. However, its practical application, once a same entry point can supply several exit points, does not lead to this result. The example below illustrates the intrinsic error of this method:

- Income to be covered: €20M, of which €10 M for entry, and €10 M for exit, for a network having a single entry and two exits



- Booking assumptions:
-

Points	Booking assumptions (GWh/d)
Entry point	100
Exit 1	30
Exit 2	70

- Routes considered:

Routes	Pipeline distances (km)
Route 1: Entry – Exit 1	1,000
Route 2: Entry – Exit 2	200

Results of the application of the formulas described in article 8 of the Tariff network code:

Points	Reference price[40] (€/MWh/d/year)
Entry point	100.0
Exit 1	227.3
Exit 2	45.5

These results lead to price of route 1 of €327.3/MWh/d/year (i.e. a unit cost of €0.33/MWh/d/km) and a price of route 2 of €145.5/MWh/d/year (i.e. a unit cost of €0.73/MWh/d/year/km).

The CWD reference price calculation method described in the Tariff network code therefore cannot be applied as is to the French transmission network without the risk of creating major cross-subsidisation between user categories.

[40] The price at the entry point is equal to the entry revenue divided by the entry capacity, and the exit 1 and exit 2 prices are determined so that the Price 1 x capacity 1 + price 2 x capacity 2 is equal to the exit revenue. The price at exit 1 is equal to five times the price at exit 2, with the distance covered to reach exit 2 being 5 times lower.

ANNEX 2: DATA PUBLISHED BY THE TSOs

1. Structural representation of the transmission network

GRTgaz: Map of GRTgaz's network

Teréga:
https://www.Teréga.fr/nos-offres/transport.html
https://www2.terega.fr/nous-connaitre/nos-metiers/chiffres-cles.html

2. Technical data (length and diameter of pipelines, power of compression stations)

GRTgaz: http://www.grtgaz.com/fr/notre-entreprise/nos-chiffres-cles.html « rubrique données techniques »

Teréga: https://www2.terega.fr/fileadmin/Qui_sommes-nous/Qq_chiffres/Longueur_du_reseau_Terega_par_DN_et_par_classification.pdf

3. Standard interruptible capacity products and interruption probability

GRTgaz: http://www.grtgaz.com/en/acces-direct/customer/supplier-trader/upstream/capacity-subscription.html, rubrique principes généraux

Teréga:

https://www2.terega.fr/nos-offres/transport/commercialisation-de-capacites/mode-de-commercialisation.html

4. Technical capacity available at entry and exit points

GRTgaz: http://www.grtgaz.com/fileadmin/GRTgaz/reseau/documents/Capacite-technique-points-entree-et-sortie-et-hypotheses-correspondantes.pdf

Teréga: https://www2.terega.fr/nos-offres/transport/commercialisation-de-capacites/calcul-des-capacites/optimisation-de-la-capacite-technique.html