25 February 2016

Public consultation by the French Energy Regulatory Commission concerning the new tariffs for the use of gas transmission networks of GRTgaz and TIGF and the new tariffs for the use of regulated LNG terminals

Articles L.452-2 and L.452-3 of the French Energy Code authorise the French Energy Regulatory Commission (CRE) to select the method for calculating the tariffs for the use of natural gas transmission networks as well as the methods for calculating the tariffs for related services performed exclusively by the operators of these networks. Article L.134-2(4) authorises the CRE to select the method for calculating the tariffs for the use of liquefied natural gas (LNG) terminals as well as the methods for calculating the tariffs for related services performed exclusively by the operators of these terminals. The CRE may amend the levels and structure of these tariffs in any way it considers necessary, in particular based on the accounts kept by the operators and foreseeable changes in operating costs and investments.

Tariffs for the use of GRTgaz and TIGF gas transmission networks

The current tariffs for the use of GRTgaz and TIGF natural gas transmission networks, known as the 'ATRT5 tariffs', came into force on 1 April 2013 and were to apply for approximately 4 years in application of the CRE's deliberation of 13 December 2012[1].

The CRE has begun working on the new tariffs for the use of GRTgaz and TIGF natural gas transmission networks, to be known as the 'ATRT6 tariffs', which will apply from 1 April 2017. Given the level of the visibility required by the market and the complexity of the issues at hand, the CRE wishes to hold a consultation on its initial proposals for the regulatory framework and the tariff structure for the upcoming ATRT6 tariffs.

The aim of the proposed changes to the tariff structure is to:

- continue simplifying the contractual structure of the French natural gas market, culminating with the creation of a single marketplace by 2018;
- improve the downstream offering of the transmission system operators, especially the regional network tariffs;
- reinforce the incentive regulation mechanisms introduced in previous ATRT tariffs;
- prepare for the introduction of the next European network codes, in particular the Tariff Network Code.

Tariffs for the use of regulated LNG terminals

The current tariffs for the use of regulated LNG terminals in Montoir-de-Bretagne and Fos Tonkin, which are operated by Elengy, and the Fos Cavaou terminal, which is operated by Fosmax LNG, are known as the 'ATTM4 tariffs' and came into force on 1 April 2013. They will apply for a period of approximately four years.

The CRE wishes to establish new tariffs for the use of regulated LNG terminals, known as the 'ATTM5' tariffs, which will apply from 1 April 2017.

The aim of the proposed changes to the tariffs for Elengy and Fosmax LNG is to:

[1] Deliberation of the French Energy Regulation Commission of 13 December 2012 deciding on the tariffs for the use of natural gas transmission networks

- adapt the services offered by the regulated LNG terminals to meet client expectations and changes in the market;
- anticipate the changes that will be caused by the future combining of the market's zones.

The aim of this public consultation is to request input from the market regarding the CRE's initial proposals for major changes to the ATRT6 and ATTM5 tariffs.

The CRE would like to invite all parties to submit their comments by no later than 25 March 2016:

Introduction: the transmission network operators and LNG terminal operators currently active in France

1. The transmission system operators (TSO)

1.1. GRTgaz

GRTgaz, which is 75% owned by Engie and 25% by Société d'Infrastructures Gazières (SIG), a public consortium made up of CNP Assurances, CDC Infrastructure and Caisse des Dépôts, operates, maintains and develops a high pressure gas transmission network of over 32,000 km, covering the vast majority of mainland France excluding the south west. GRTgaz transports around 600 TWh of gas per year. In 2014, it recorded a turnover of €2,051 million and had 2,965 employees.

1.2. TIGF

TIGF (Transport et Infrastructures Gas de France), which is owned by a consortium made up of Snam (40.5%), GIC (31.5%), EDF Investissement (18%) and Prédica (10%), operates, maintains and develops 5,000 km of high pressure gas transmission network in the south west of France. TIGF transports around 100 TWh of gas per year. It also operates some natural gas storage facilities. It keeps separate accounts for these two sides of its business. In 2014, TIGF recorded a turnover of €272 million for its transmission business and had a total workforce, for its transmission and storage activities combined, of nearly 570 employees.

2. The regulated LNG terminal operators

2.1. Elengy

Elengy, a wholly-owned subsidiary of Engie, operates the Montoir-de-Bretagne and Fos Tonkin LNG terminals.

The Montoir terminal, which opened in 1980, has a regasification capacity of 10 billion m^3/year and an LNG storage capacity of 360,000 m^3. The Fos Tonkin terminal, which opened in 1972, has a regasification capacity of 3 billion m^3/year and an LNG storage capacity of 80,000 m^3.

In 2014, Elengy recorded a turnover of €178 million for its regulated regasification activities and had 383 employees.

2.2. Fosmax LNG

Fosmax LNG, which is 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 capacities. It is operated and maintained by Elengy.

The Fos Cavaou terminal, which opened on 1 April 2010, has a regasification capacity of 8.25 billion m^3/year and an LNG storage capacity of 330,000 m^3.

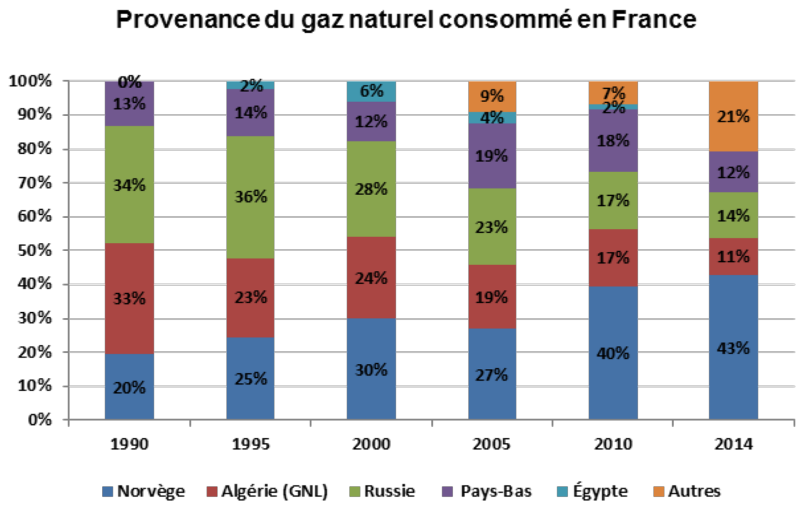
In 2014, Fosmax LNG recorded a turnover of €162 million for its regulated regasification activities.

I. The major issues underlying the introduction of the ATRT6 and ATTM5 tariffs

1. Changes in the global natural gas market

1.1. Recent changes in France's gas supply

France has no longer any conventional gas production capacities since 2013, and it is now wholly dependent on imports for its natural gas supply. Norway has for several years been France's leading supplier, followed in 2014 by Russia, the Netherlands and Algeria. Since the start of the century, several new sources of supply have appeared on the global LNG market, such as Nigeria and Qatar.



Source: Gas In Focus

This diversification of France's sources, which has improved the reliability of supply across the country and made it possible to develop competition on the gas market, was possible thanks to numerous investments into interconnection points, transits, LNG terminals as well as the flexibility of the national transmission network.

1.2. Fluctuations in global LNG prices have directly impacted the French market

France currently has three LNG terminals, in Fos Cavaou, Fos Tonkin and Montoir-de-Bretagne, which have a cumulative regasification capacity of 21 billion m^3/year (~230 TWh). The opening in 2016 of a terminal in Dunkirk, operated by Dunkerque LNG, will increase the country's regasification capacity to 34 billion m^3/year (~370 TWh).

Changes in global LNG prices have had a direct impact on the price of gas in France, especially in the South zone which must get its supplies from the Fos terminals. In particular, between 2012 and 2014, due to the very high global LNG prices linked to extremely high demand in Asia following the accident at Fukushima, there was a huge divergence in prices between the North and South zones in France.

Since the end of 2014, the price of LNG has been falling and this has almost completely neutralised the North-South price gap, but without any increase in the volumes of LNG being unloaded at French and European terminals.

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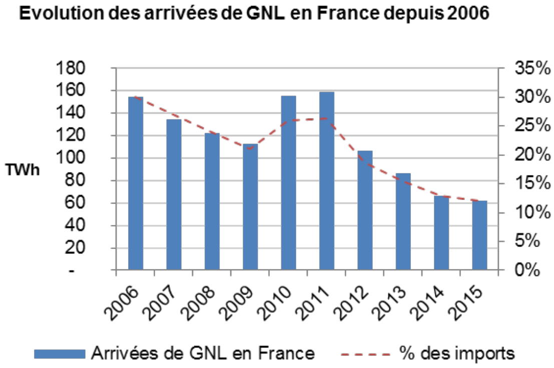


Sources: GRTgaz, TIGF

The recent increase in the USA's gas liquefaction capacity and the fall in oil and gas prices in 2015 could lead to a recovery of LNG in Europe.

1.3. Low gas prices in North America are affecting the competitiveness of gas-intensive industries

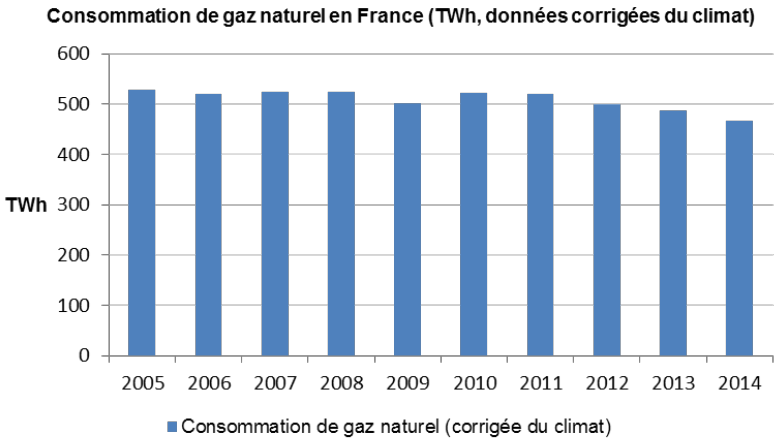
Since 2006, the USA has been steadily developing its unconventional gas resources (UGR), which currently account for nearly half the country's production. This growth in UGR production has led to a gas glut in North America, triggering a fall in gas prices at the Henry Hub. From an average of $3.9/MMBtu (€10.6/MWh) in 2009, the price of gas fell to an average of $2.6/MMBtu (€8.0/MWh) in 2015.

Gas prices in North America are therefore particularly competitive, which is having a direct impact on global competition, especially on the location of gas-intensive industries, in particular those in the petrochemicals sector.

2. The role of natural gas in France's energy transition

2.1. Stagnation of natural gas consumption in France

France and Europe's consumption of natural gas has stagnated over the past decade, under the triple effect of efforts to manage energy consumption, the economic crisis and the small volumes of gas-powered electricity generation: between 2005 and 2014, France's consumption of natural gas, corrected for climate conditions, fell 13% from 528 to 466 TWh.



Source: INSEE, MEDDE

For the period 2015-2014, GRTgaz expects an annual fall in consumption of around 0.3% per year, primarily due to a drop in residential (-0.8% per year) and industrial (-0.7% per year) consumption; this will be partially offset by a recovery in gas-powered electricity generation from 2017/2018[2]. In turn, TIGF is anticipating a fall in gas consumption of around 0.1% per year, due mainly to a fall in residential consumption (-0.3% per year) but which will be partially countered by an increase in industrial consumption in the south of France[3].

2.2. Gas must find its place during the energy transition

The French Law of 17 August 2015 concerning energy transition for green growth ('Energy Transition Act')[4] introduced a target of a 30% reduction in fossil fuel use (including natural gas) by 2030 compared to 2012. With this in mind, natural gas - whose combustion emits respectively 25% and 45% less CO_2 than fuel oil and coal - could become the fuel of choice, especially if we take into account:

- the replacement of coal and fuel oil by natural gas in the French electricity generation mix: between 2008 and 2015, a dozen combined cycle gas turbines (CCGT) were opened in France, and installed capacity is currently around 6 GW;
- the replacement of oil products with natural gas within the industrial sector, encouraged by the IED(Industrial Emissions Directive), especially for boilers;
- the use of natural gas for road transport, initially by buses and waste collection vehicles, and then by carriers;
- the use of LNG fuel by ships, which will reduce CO_2 emissions by over 20% compared to marine diesel. Article 52 of the Energy Transition Act states that "*the Government shall encourage, in particular by supporting pilot projects, the installation of quayside liquefied natural gas distribution systems and power supplies in ports for ships and boats*".

The Energy Transition Act also hopes to promote green gas by setting a target of 10% of the country's gas consumption to come from "clean" gas by 2030: the growth of the biomethane sector should make it possible to reduce the proportion of fossil gas whilst also meeting this target.

2.3. The persistently uncertain economic outlook for gas

Gas is a substitutable form of energy, and consumers are being encouraged to make a choice between it and other sources of energy, based on the economic climate and the competitiveness of the market:

- in the residential sector: in France, gas accounts for approximately one third of domestic energy use (heating, hot water and cooking). In 2013, 34% of single-family houses and 56% of residences in towns and cities used gas for these purposes. Gas is having to compete with electricity, especially for heating and cooking;

- in the industrial sector: gas is used as either a raw material or a source of energy for numerous industrial processes (accounting for 37% of France's total gas use). Fluctuations in the price of gas have a huge effect on the profitability of these industries, given the highly competitive market and the economic crisis;

- for electricity generation: France currently has 13 combined cycle gas turbines (CCGT) with an installed capacity of 5.7 GW, most of which were put into service between 2008 and 2012. Between 2011 and 2015, the CCGTs were underused: the gas market has been heavily penalised by, on the one hand, energy efficiency policies, the economic crisis and the growth of renewable energies which have been pushing down wholesale electricity prices; and on the other hand, by a rise in gas prices boosted by demand from Japan following the Fukushima nuclear accident, coupled with a fall in the price of coal, stocks of which are overflowing thanks to the development of shale gas in the USA. At the same time, CO_2 prices have not been high enough for the market to prefer gas-powered electricity generation over coal. In 2014, therefore, the CCGTs only accounted for 2.7% of France's electricity generation. More recently, the fall in gas prices in 2015 has improved the competitiveness of the CCGTs.

[2] Ten Year Development Plan for the GRTgaz Network 2015-2024 (in French)
[3] TIGF transmission grid 10-year development plan 2015-2024
[4] Law 2015-992 of 17 August 2015 concerning energy transition for green growth

3. Network codes and the creation of the European internal market

The European network codes are designed to harmonise the rules for how the market operates, as well as to encourage the development of an integrated gas market at European level: they therefore establish common rules governing the technical and commercial conditions for accessing the gas transmission networks.

Through its work and its deliberations regarding market rules, the CRE ensures that these codes are properly applied, in particular to ensure the market operates smoothly.

The network code on Balancing[5] came into force on 1 October 2015 in France, without need for the CRE to make use of the postponement available for markets which are not mature enough or are insufficiently prepared. The CRE has been preparing for this code since 2011[6], approving the various routes to achieving the target balancing regime proposed by GRTgaz and TIGF, and changes to this regime between 2012 and 2015.

Likewise, in its deliberation of 13 February 2014[7], the CRE decided to prepare for the introduction of the network code on Capacity Allocation Mechanisms (CAM)[8] concerning the rules for allocating capacities on the gas transmission network, which came into force on 1 November 2015. In particular, the CRE decided to replace the former system for allocating capacities proportionately to demand with the "ascending clock auction" system established by the CAM Network Code, and introduced new marketing rules in particular for the North-South link. In addition, in order to auction their transmission capacities, 20 transmission system operators from seven EU member states joined forces to create the PRISMA platform. This platform, which has been available since 1 April 2013, is currently used by 37 of the 43 European TSOs, including the two from France. It allows operators to sell their primary and secondary capacities in line with the harmonised auction calendar and terms established by the CAM Network Code.

The Tariffs Network Code should be examined by a comitology committee in the first half of 2016

The draft Tariffs Network Code[9] is designed to harmonise the methods for calculating the tariffs for natural gas transmission in Europe. It was prepared by ENTSOG (European Network of Transmission System Operators for Gas) based on framework guidelines[10] published on 29 November 2013 by the Agency for the Cooperation of Energy Regulators (ACER). A comitology committee should begin the procedure for adopting this code in the first half of 2016. The code should come into force on 1 January 2018.

The code will establish the need for transparency and non-discrimination in the calculation of gas transmission tariffs, whereby tariffs must reflect the costs actually paid by the TSOs. Using a transparent method will guarantee for the market that there are no cross subsidies between the various types of user of the transmission network (e.g. between shippers in charge of the transmission and those delivering to national consumers).

The draft code, in its wording at the time this public consultation was launched, suggests that the method of choice for calculating tariffs should be the capacity weighted distance methodology. This method is used to determine the tariffs for transiting capacities around the transmission network, using as cost drivers the distance travelled by the gas between the entry and exit point and the amount of contracted capacities. Member states should be able to select a different method if they wish, but if so they must compare the results with those of the reference price methodology.

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5 Commission Regulation (EU) No 312/2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Networks

6 Deliberation by the French Energy Regulatory Commission dated 1 December 2011 on the approval of changes in balancing rules on the gas transmission systems of GRTgaz and TIGF

7 Deliberation of the Commission de régulation de l'énergie of 13 February 2014 on rules for the progressive implementation of the European network code on the allocation of gas transmission capacity at interconnection points between entry-exit systems

8 Commission Regulation (EU) No 984/2013 of 14 October 2013 establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems

9 Network Code on Harmonised Transmission Tariff Structures for Gas, 31 July 2015

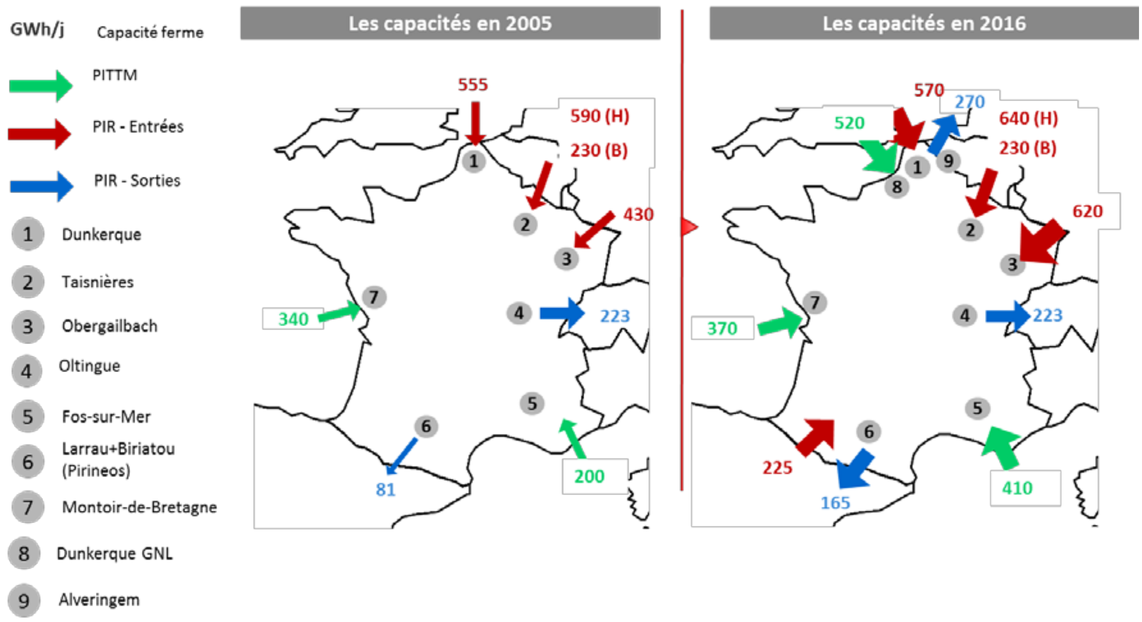
10 Framework Guidelines on rules regarding harmonised transmission tariff structures for gas

For several years the CRE has been helping draft this upcoming network code. The transmission tariffs applicable in France already meet most of the requirements of the draft code. In fact, the ATRT5 tariffs are based entirely on the entry-exit principle, and shippers pay the price of the capacities they book at the various entry and exit points around the network. In addition, the tariffs take account of the distance travelled by the gas when determining which costs to allocate to each tariff condition, as part of broader plans to equalise out the tariffs in line with the social cohesion targets set by law. Finally, the tariff decisions published by the CRE already largely meet the level of transparency required by the draft code, since the operators' authorised revenue is broken down in order to present an aggregate view of the various charges and receipts it comprises.

4. The development of the French gas market

4.1. France has significantly developed its interconnections and its transmission and regasification capacities

Between 2005 and 2015, transmission capacity along the GRTgaz and TIGF networks rose considerably: interconnection capacities with neighbouring countries were increased, along with the entry capacities from its LNG terminals and its regasification capacities.



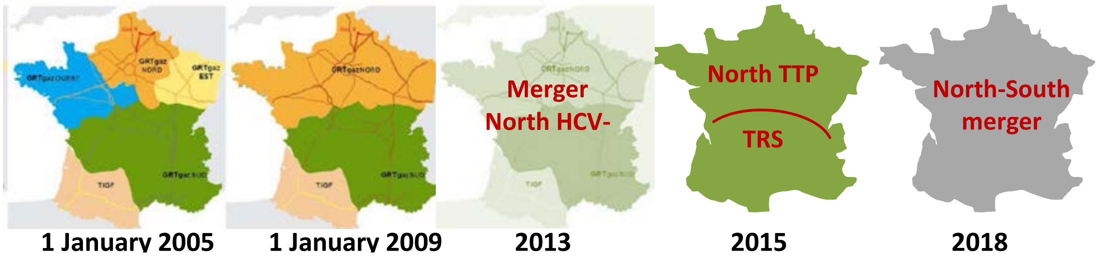
GWh/day	2005	2016	Change 2005-2016
Firm entry capacities	**2,345**	**3,585**	**+52%**
of which pipeline	1,805	2,285	+27%
of which LNG	540	1300	+141%
Firm exit capacities	**304**	**658**	**+116%**

Investment from the TSOs and LNG terminal operators has made it possible to increase entry capacities by 52%, exit capacities by 116% and regasification capacities by 141%. Two new interconnection points have been created, the Alveringem network interconnection point with Belgium, and the Biriatou network interconnection point with Spain. During this same period, two new terminals were also connected, in Fos Cavaou and Dunkirk. In addition, the existing interconnection points underwent major reinforcement (Larrau, Obergailbach, Taisnières H etc.).

All these developments were carried out on the basis of long-term booking commitments from shippers, which not only covered the costs but also made it possible to limit the rise in transmission tariffs. However, given the decade of stagnated consumption and the predicted fall by 2030, the French transmission network is probably now the ideal size.

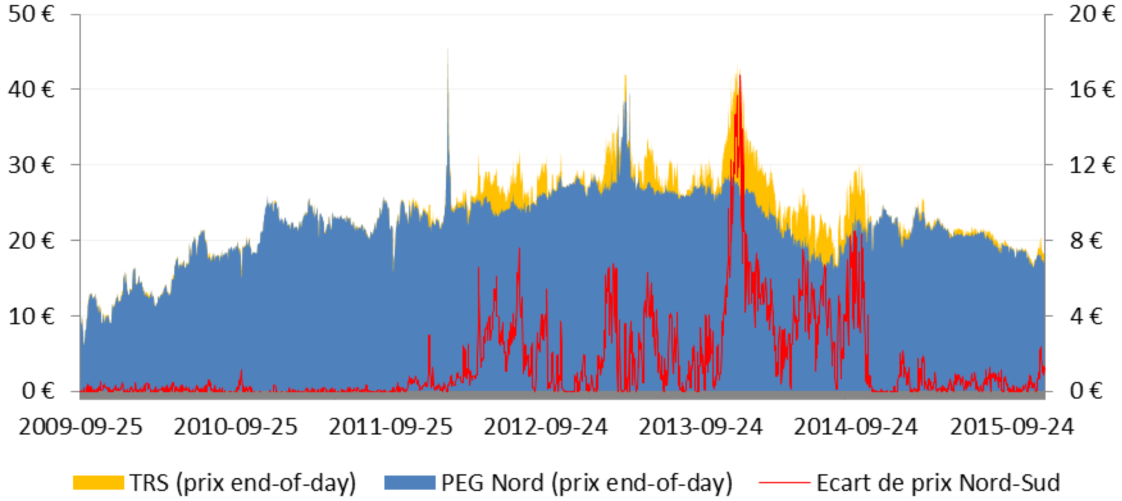
4.2. Reduction in the number of market zones

The French transmission network went from five marketplaces in 2005 to three in 2009; in 2013, the L gas zone was merged with the North title transfer point; then on 1 April 2015, the network was reduced to just two marketplaces, one of which, the Trading Region South (TRS) is shared between GRTgaz and TIGF. Since 2005, four merger phases have simplified the contractual architecture of the network, for the benefit of consumers.



Source: CRE

These mergers increased the liquidity of the French gas market and allowed end consumers to benefit from a greater range of sources of supply and make significant savings. For example, between 2010 and 2015, around €1.4 billion would have been saved if the South had been able to obtain its supplies at the cost of the North TTP.



Source: Powernext

The period covered by the ATRT6 tariff will see the creation of a single marketplace, following the merger of the GRTgaz North zone and the TRS zone, as decided by the CRE in its deliberation of 7 May 2014[11]. This project is based on a joint programme of investment from GRTgaz and TIGF, including the strengthening of the Bourgogne (GRTgaz) and Gascogne-Midi (TIGF) branches, as well as modification of the compression systems, for a total budget of €823 million. The deliberation of 30 October 2014[12] defined the incentive regulation that would apply to these investments.

11 Deliberation of the French Energy Regulatory Commission dated 7 May 2014 setting out guidelines for the creation of a single marketplace in France by 2018

12 Deliberation of the French Energy Regulatory Commission dated 30 October 2014 concerning the incentive regulation mechanism for the Val de Saône and Gascogne/Midi projects (in French)

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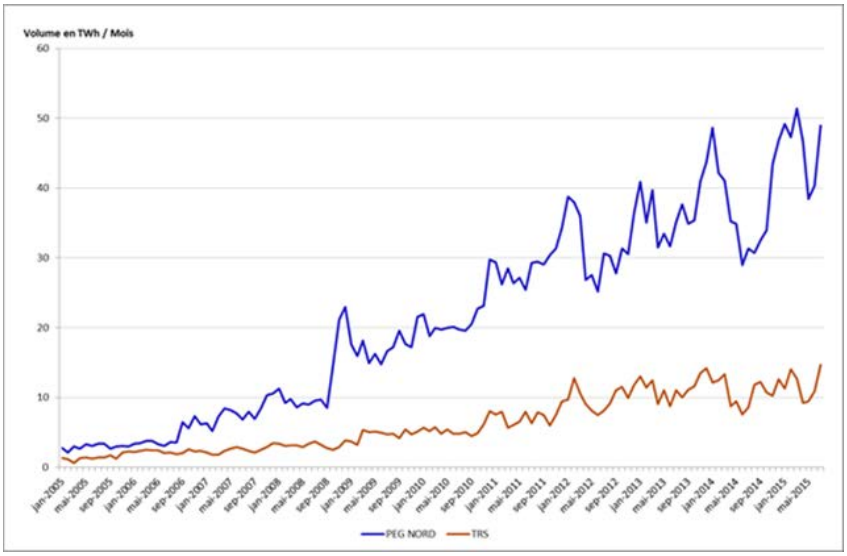
4.3. Improving liquidity on the wholesale markets

This reconfiguration of the network will make it easier to use and will simplify the balancing process for shippers, allowing the emergence of a more liquid wholesale market. The rate of gas exchanges at the North title transfer point and on the TRS demonstrates the dynamism on the wholesale market and the increase in arbitration opportunities.



Source: CRE (day-ahead products)

The concentration ratios for the French wholesale gas markets (Herfindahl-Hirschmann indexes[13]) show that, since 2014, concentration on the spot markets in the North and South of France has been highly satisfactory for purchases (HHI of nearly 500 in the first half of 2015 at the North TTP and in the TRS zone) and good for sales (HHI around 1200 at the North TTP and 1000 for the TRS zone). This marks a clear improvement on previous years. On the futures markets, concentrations are still relatively high, particularly for sale, in the south of France. The introduction of the TRS zone on 1 April 2015 ought to gradually lead to the emergence of a more liquid futures market.

Finally, the North title transfer point has integrated excellently with the other markets in North West Europe. Prices are very closely correlated with other marketplaces in the zone. In addition, average price differences have been gradually reducing since 2014, due in particular to the lifting of tensions on the global LNG market:

Année	2012	2013	2014	S1 2014	S1 2015
PEG Nord / Zeebrugge	0,48	0,70	0,53	0,46	0,49
PEG Nord / NCG	0,34	0,48	0,36	0,31	0,28
PEG Nord / TTF	0,49	0,63	0,52	0,42	0,42
PEG Nord / NBP	0,56	0,90	0,65	0,63	0,33
Moyenne	0,47	0,68	0,51	0,46	0,38

Sources: Powernext, ICIS Heren

4.4. Long-term capacity bookings

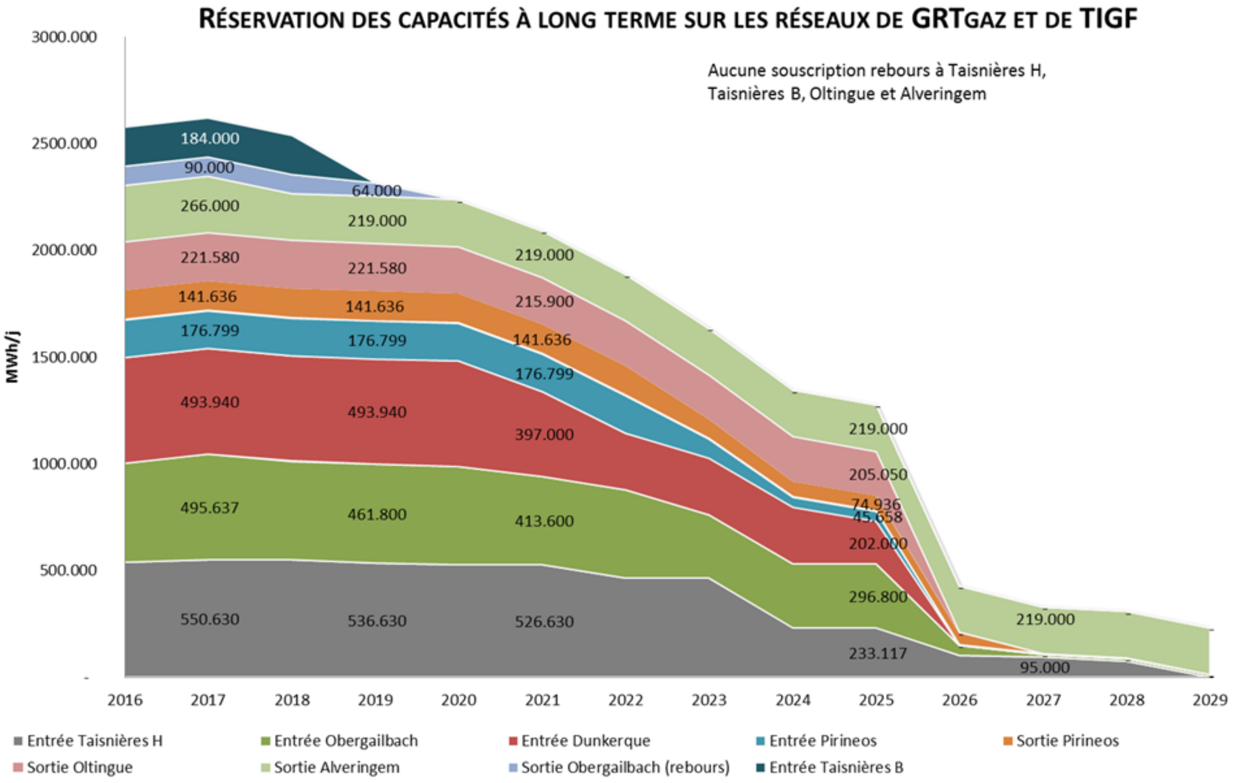
Long-term commitments from shippers have made it possible to increase capacity at the interconnection points with Belgium, Germany and Spain.

[13] As the energy markets are being opened up to competition, it is important to monitor market concentration ratios. The lower the number of players on the market, the higher the concentration ratio:

- 0 - 1000: not very concentrated market;
- 1,000 - 2,000: concentrated market.

The change in the HHI for the French wholesale gas markets since 2012 is presented in the [CRE report on the functioning of the wholesale electricity, CO2 and natural gas markets - 2014-2015](#) (in French).

There have been very high levels of long-term bookings which last until the end of the ATRT6 tariff period: over 75% of the annual firm entry capacity has been booked at the Taisnières, Dunkirk, Obergailbach and Pyrenees network interconnection points, and over 80% of the annual firm exit capacity has been booked at the Alveringem, Oltingue and Pyrenees interconnection points. The TSOs therefore expect to receive a relatively steady income from contracted capacities over the next tariff period compared to 2016.



Sources: GRTgaz, TIGF

However, beyond the ATRT6 tariff period, capacity bookings are down at all interconnection points. This fall is a result of the expiry of the capacities that were contracted during the open seasons.

4.5. Increased competition on the retail market

The smooth running of the wholesale markets is essential in order to develop competition on the retail market: greater liquidity and access to diversified sources of supply will allow suppliers to be more competitive in their pricing. Since July 2007, the gas market has been open to competition for all clients, professionals and individuals alike.

As at 30 September 2015, 41% of sites had signed up to a market offer (82% of national consumption). Alternative suppliers supply 20% of clients, accounting for 49% of national consumption[14]. Nevertheless, at the end of September 2015, 61 % of residential sites were still benefitting of the regulated tariffs.

5. Conclusions

Over the past decade, the French gas transmission network has undergone significant change, designed to create an efficient gas market, offering suppliers and consumers the greatest possible flexibility in their transit routes in order to benefit from the cheapest gas prices. These changes have required considerable investment.
Over this same period, France's gas consumption has stagnated and even declined, falling to below 500 TWh per year, at a time when:

- the economic crisis is holding back any increase in the demand for gas;

[14] In December 2015 the CRE published its retail market observatory for the third quarter 2015 (in French).

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- the country's combined cycle gas turbines are being underused;
- the competitiveness of the North American gas market compared to Europe is encouraging certain gas-intensive industries to relocate to the other side of the Atlantic;
- there are multiple initiatives for developing new uses for gas as part of the country's energy transition, in particular for biomethane and vehicle gas, but their impact at a large scale is not visible yet.

Question 1 Do you believe that the CRE has correctly understood the major issues affecting natural gas transmission tariffs between now and 2020?

II. The ATRT6 Tariff

A. Schedule

1. Schedule proposed by the CRE for preparing the ATRT6 tariffs

As it prepares the new ATRT6 tariffs, the CRE wishes to ensure visibility for the whole market and consult everyone involved in advance of its tariff decision. It is therefore planning to hold two public consultations in 2016:

- this first consultation, which concerns the general regulatory framework for the ATRT6 tariffs and the main proposed changes to the tariff structure;
- a second public consultation in the summer of 2016 which will be based on the feedback from this first consultation and will allow the CRE to present its proposals for changes to the way the ATRT6 tariffs are regulated and structured, the demands of the TSOs and its first assessment of those demands. If necessary, the CRE will offer a number of different scenarios, accompanied by impact studies.

The CRE plans to adopt a deliberation regarding the tariffs for the use of gas transmission networks by the end of 2016, after having consulted the French Higher Energy Council, with a view to the new ATRT6 tariffs coming into force on 1 April 2017.

Question 2 Do you have any comments on the programme of work and schedule proposed by the CRE for the ATRT6 tariffs?

2. Compatibility of the ATRT6 tariff schedule with the calendar established by the CAM Network Code for selling capacities

Ever since the ATRT4 tariff period, gas transmission tariffs have been revised on 1 April each year. This schedule, which was decided by the CRE after a consultation, allows it to stay in line with the gas storage year, which runs from 1 April in year N to 31 March in year N+1.

However, under the CAM Network Code, transmission capacities at interconnection points are calculated annually from October in year N to September in year N+1. Yearly capacity products offering capacity for no longer than the upcoming 15 years will be auctioned in the first week of March in year N, and in the first week of June in year N there will be auctions for four quarterly capacity products for the upcoming year.

In order to make the French wholesale market more attractive and aide its integration into the European market, for the ATRT5 tariff period the CRE decided to increase the tariffs at the interconnection points every year in line with inflation, which meant that shippers bidding at the capacity auctions had greater visibility regarding the regulated tariffs beyond just that tariff year.

The draft Tariff Network Code says that the tariffs for the capacities sold at interconnection points must be known before the auctions for the yearly capacities begin. In addition, the European Union is studying a proposed amendment to the CAM Network Code whereby the annual yearly capacity auctions will begin on the first Monday in July of each year, rather than the first Monday in March. There are currently no plans to align the CAM Code with the gas storage year of April-March.

There are two possible options for bringing the ATRT6 tariff calendar in line with the capacity auctions calendar established by the CAM Code:

- aligning the ATRT tariff calendar with the CAM Code: the CRE would publish its annual deliberations no later than June, for the changes to come into effect on 1 October;

- continue implementing the annual changes to the ATRT tariff on 1 April, whilst at the same time ensuring the ATRT6 tariff deliberation creates visibility for the market regarding the annual changes in capacity tariffs at interconnection points, as was done for the ATRT5 tariff period.

The CRE currently favours the second option, since it continues the principles established for ATRT5. This solution, which ensures greater visibility for the market but without shifting the transmission tariff calendar away from the storage calendar, has worked well for a number of previous tariff changes.

Question 3 Are you in favour of continuing the calendar used for ATRT5 i.e. revising the transmission tariffs on 1 April of each year, accompanied by information concerning the changes in the tariffs at the interconnection points over the whole ATRT6 tariff period?

3. Calendar for tariff evolutions at the creation of the single marketplace

On 1 November 2018, France will see the creation of a single marketplace, subject to the necessary investment being made into Val de Saône and Gascogne-Midi. This will mean:

- the extension of the operators' regulated asset base on 1 January 2019 to include capital expenses for starting up the Val de Saône and Gascogne-Midi projects;
- the disappearance of tariff conditions at the North-South link, and hence of income from market coupling[15], which will mean a loss of revenues for GRTgaz.

This event, which will take place in the middle of a tariff period, raises the issue of the calendar for tariff rate changes for ATRT6.

At this stage, the CRE is planning to retain the annual price changes on 1 April each year, at which point, as was done for ATRT5, the CRE will adjust the tariff using pre-determined rules and make the necessary changes.

In addition, in order to deal with the newly-formed single marketplace, the CRE is planning a one-off price movement on 1 November 2018, when it will change all tariff conditions across the board in order to offset the revenue lost from the disappearance of the North-South link and the increase in capital expenditure resulting from the start-up of the Val de Saône and Gascogne-Midi projects. The general structure of the tariffs at the time the single zone is created will be established by the CRE in its ATRT6 Tariff deliberation, which is due to be issued at the end of 2016. The exact level of the various tariff conditions at the time the single marketplace comes into effect will be established by the CRE in its deliberation establishing the price changes for 1 April 2018, planned at the end of 2017.

[15] Established in a deliberation on 19 April 2011, market coupling is when North-South capacities and the molecule are auctioned in combination. This mechanism is based on a "South TTP-North TTP spread" product, a gas swap between the two zones (purchase of gas from one zone and sale of the same volume of gas in the other).

Question 4 Are you in favour of an annual rise in the ATRT6 tariffs on 1 April, and a one-off increase when the single marketplace is created, under the conditions proposed by the CRE?

B. Regulatory framework

1. General Framework

1.1. Overview of the regulatory framework for the ATRT5 period

Our overview of the regulatory framework for the ATRT5 tariff is based on a study led by the CRE into the incentives offered to European electricity and gas operators, conducted in 2015 by Schwartz and published on the CRE website[16], as well as on the CRE's own analysis of the situation.

The current transmission tariffs

The ATRT4 and ATRT5 tariffs created a stable regulatory framework, with incentive-based regulation mechanisms relating to cost management and quality of service. This framework gave good visibility to the whole market and reduced the risks borne by GRTgaz and TIGF. The regulatory framework for the ATRT5 period was based on the following principles:

- a tariff period of approximately 4 years (starting 1 April 2013);
- an annual revision of net operating costs using the formula "IPC +/- Z";
- the TSO to retain/suffer all gains and losses made in comparison to the target net operating expenses trajectory (excluding motive power);
- the creation of an expenses and revenues clawback account, in particular to cover differences in capital expenditure (investments) and some of the differences in booking income and energy costs borne by the TSOs;
- a financial incentive for improving quality of service;
- an asset remuneration mechanism, in particular incorporating an average weighted cost of capital (AWCC) fixed at 6.5% (actual, before tax), remuneration for non-current assets in progress at the nominal cost of debt (4.6%) and a bonus for making certain investments of 3% over 10 years;
- a mid-period review clause making it possible, under certain conditions, to adjust the net operating expenses trajectory of GRTgaz and TIGF upwards or downwards for the years 2015 and 2016.

Forecasts for capacity bookings and energy charges will be reviewed every year, with tariffs changing on 1 April of each year.

[16] Critical analysis of the incentive regulation mechanisms for natural gas and electricity infrastructure and network operators. *Schwartz and Co.* 23 November 2015 (in French).

Gas transmission tariffs over the past 10 years

The ATRT tariff has been increased annually, initially on 1 January and then, since 2010, on 1 April each year. The table below charts these changes:

		GRTgaz			TIGF		
		Authorised revenue (€m)	Change in authorised revenue	Tariff increase on 1 Jan. (until 2009) or 1 Apr. (since 2010)	Authorised revenue (€m)	Change in authorised revenue	Tariff increase on 1 Jan. (until 2009) or 1 Apr. (since 2010)
ATRT2	2005	1217	+13.7%	+0.0%	123	+19.4%	+5.0%
	2006			-			-
ATRT3	2007	1236	+1.6%	-2.1%	149	+21.1%	+9.2%
	2008			-			-
ATRT4	2009	1335	+8.0%	+6.0%	180	+20.8%	+10.0%
	2010	1367	+2.4%	+3.9%			-
	2011	1414	+3.4%	+2.9%	161	-10.6%	-10.2%
	2012	1483	+4.9%	+4.5%	174	+8.1%	-
ATRT5	2013	1662	+12.1%	+8.3%	205	+17.8%	+8.1%
	2014	1710	+2.9%	+3.9%	228	+11.2%	+7.7%
	2015	1773	+3.7%	+2.5%	237	+3.9%	+3.1%
	2016	1842	+3.9%	+4.6%	246	+3.8%	+5.0%
Total 2004-2016			**+51.5%**	**+39.9%**		**+99.7%**	**+36.0%**

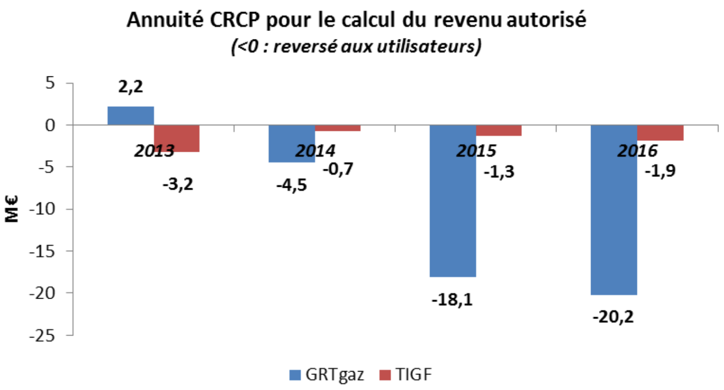
On 31 December 2015, gas transmission accounted for about 9% of the net bill of an average B1 customer.

The tariff mechanisms introduced for ATRT5 worked as expected:

- the average annual price increase was 3.7% over 3 years for GRTgaz and 5.2% over 3 years for TIGF, compared to the average annual increases of 3.8% and 3.6% which had been predicted by the ATRT5 tariff for GRTgaz and TIGF respectively. For TIGF, the significant difference between the expected increase and the actual increase can be explained mainly by capacity bookings which rose on average 1.1% over 3 years, when a 2.5% rise was expected ;

- The balance of the expenses and revenues clawback account was calculated each year by the given deadline and without any difficulties, insofar as the rules for calculating the various accounting entries were clearly defined in the tariff rules.

Clawback account credits	2013 actual (€M_{2013})	2014 actual (€M_{2014})	2015 forecast (€M_{2015})
GRTgaz	-9.3	-62.2	-23.5
TIGF	6.9	-6.5	-2.5



- the quality of the service received by users of the GRTgaz and TIGF networks improved, especially in aspects most important for market success. The majority of the targets set for the 2013-2016 period were achieved; GRTgaz and TIGF therefore received a bonus for the ATRT5 tariff period. The CRE Annual Report gives a summary of the performance of the transmission service operators[17];

- the review clause was not activated.

Over the past ten years, gas transmission tariffs have risen sharply (by approximately 40% for GRTgaz and TIGF). These rises were largely the consequence of work to reinforce the network. Thanks to these reinforcements, suppliers have been able to benefit from greater flexibility when selecting their transit routes, thus improving liquidity on the wholesale markets and encouraging competition on the retail market (see parts §I-4.3 and §I-4.5). Consumers have therefore benefited from more competitive gas prices.

The creation of the single marketplace in 2018 should conclude this effort to reinforce the transmission networks, which will lead to the stabilisation of the level of the investments in transmission networks.

Conclusions of the ATRT5 overview

The feedback we have received demonstrates that the ATRT5 tariff achieved what it set out to do:
- the tariff trajectory was made visible for the whole market;
- the TSOs were protected against inflation as well as against the risks of their investments and of a reduction in bookings at certain network points;
- GRTgaz and TIGF made the necessary investment to make the network run more efficiently, and have begun making the investment required for France's single marketplace;
- service quality improved over the period.

As a result, the CRE hopes to repeat, for the ATRT6 tariff period, the same principles as were used for ATRT5, in particular the incentives for the TSOs to become more efficient, as regards both cost management and their quality of service.

1.2. Main aims of the CRE for the ATRT6 regulatory framework

At this stage, the CRE plans to retain the majority of the principles used for the ATRT5 tariffs and carry them over for the ATRT6 tariffs, by applying the recommendations made by its consultant in a report into the incentive regulation mechanisms for network operators:

[17] 2014 Report on the incentive regulation regarding the service quality of electricity and natural gas network operators (in French)

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- a multi-year tariff intended to apply for a period of approximately four years from 1 July 2017, with the tariffs for each TSO to be revised every year according to predefined rules;

- incentives for the operators to manage their expenditure (operating costs and investments);
    - changes will be made to the incentive regulation mechanism for investments (see Section 2 *Incentive Regulation Mechanism for Investments*);

- incentives to improve the quality of service for network users;

- an expenses and revenues clawback account, used to correct, for certain predetermined accounting entries, some or all of the differences between the actual expenditure and income and the forecast expenditure and income that were used to establish the tariffs for the TSOs;

- a review clause that can be activated in the same way as for ATRT5.

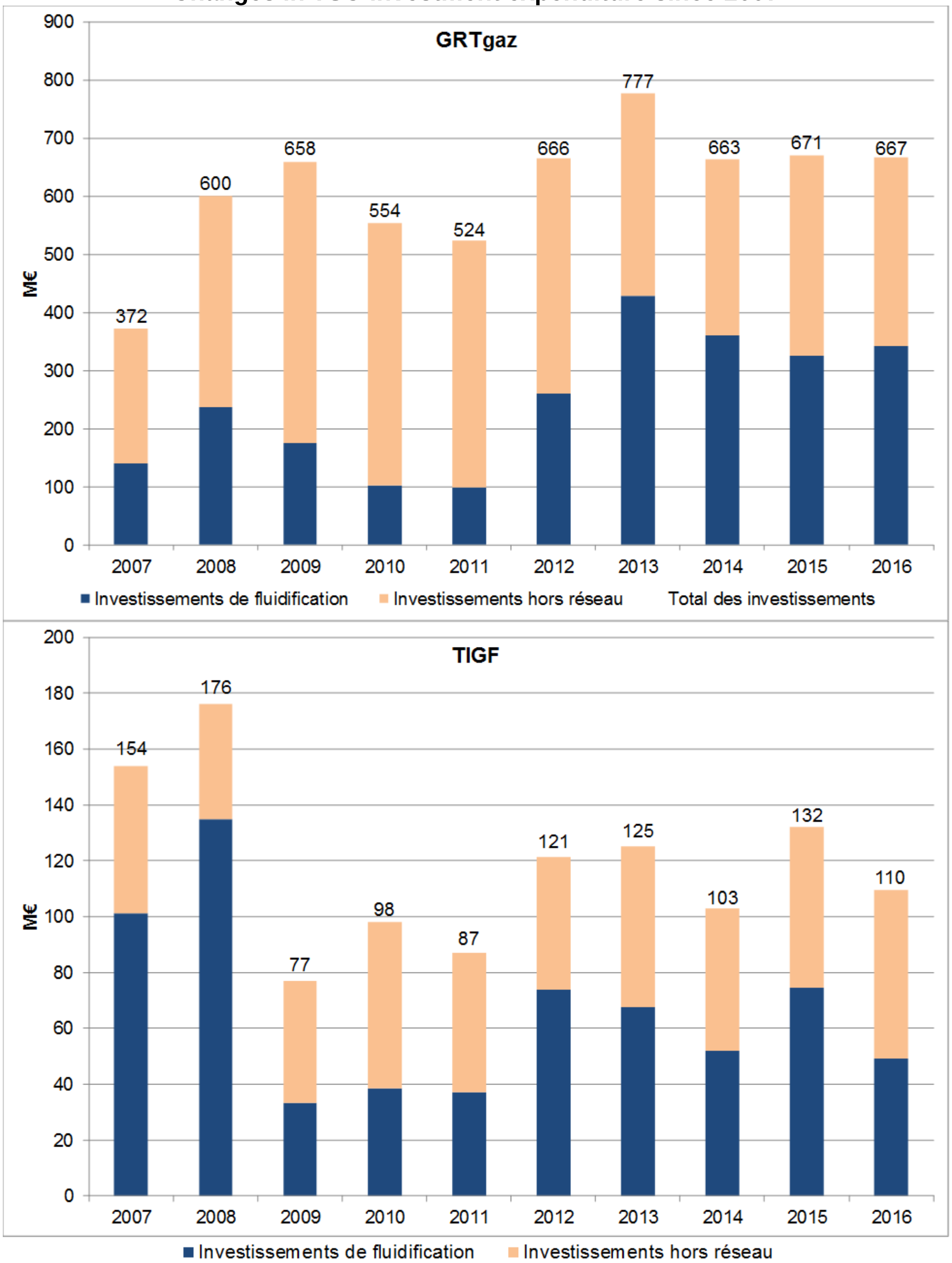
This regulatory framework is designed to motivate the TSOs to become more efficient, whilst at the same time limiting the risks inherent to uncertainties over bookings, inflation and any changes to laws or regulations that could affect their business. The aim is also to ensure the market has sufficient visibility to be able to form appropriate supply strategies and commercial offers.

Question 5 What is your opinion of the ATRT5 tariff? Are you in favour of the CRE's preliminary orientations for the regulatory framework for the ATRT6 period?

2. Incentive Regulation Mechanism for Investments

In 2015, normalised capital expenditure accounted for around 56% and 67% of the authorised revenues of GRTgaz and TIGF, respectively. Over the past decade, this expenditure has increased considerably due to major investments, which in turn has had an effect on the transmission network access tariffs. The CRE wishes to reinforce the incentive regulation mechanism for investments by GRTgaz and TIGF.

Changes in TSO investment expenditure since 2007



Source: data from GRTgaz, TIGF – CRE analysis

NB: The 2016 investment figures are the amounts approved by the deliberations of 17 December 2015.

2.1.1. *Incentive Regulation Mechanism for Investments*

Each year, the TSOs submit their investment programmes and budgets. These get approved by the CRE, and major projects may be audited and given financial incentives.

When the first tariff for the use of transmission network was introduced, the CRE included a 125 basepoint bonus for all TSO investments, and a 300 basepoint bonus over 5 or 10 years for investments that created capacity at interconnection points and reduced the number of balancing zones in France.

The ATRT5 tariff offered an investment cost management incentive. The special incentive that was put in place for the connection of the Dunkirk LNG terminal was then extended to all projects with a budget over €50 million or which represented over 20% of the average annual investment over the tariff period.

Overview of the change in the rate of return on investments

<table>
<tr><th rowspan="2"></th><th colspan="2">ATRT1</th><th rowspan="2">ATRT2</th><th rowspan="2">ATRT3</th><th rowspan="2">ATRT4</th><th rowspan="2">ATRT5</th></tr>
<tr><th>Assets in service before 1 January 2004</th><th>Assets put into service after 1 January 2004</th></tr>
<tr><td>WACC</td><td>7.75%</td><td>7.75%</td><td>7.75%</td><td>7.75%</td><td>7.25%</td><td>6.50%</td></tr>
<tr><td>+ 125 bps bonus</td><td>no</td><td colspan="3">yes</td><td>no</td><td>no</td></tr>
<tr><td>+ 300 bps bonus</td><td>-</td><td>yes, for 5 or 10 years</td><td>yes, for 5 or 10 years subject to conditions*</td><td>yes, for 5 or 10 years subject to conditions*</td><td>yes, for 10 years subject to conditions*</td><td>yes but limited to 3 projects, for 10 years</td></tr>
</table>

*Reduction in number of balancing zones or increase in interconnection point capacity

These incentives for investment are designed to develop the interconnection points and the entry capacities from the LNG terminals, and to reduce the number of balancing zones.

- Debottlenecking investments

Debottlenecking investments have resulted in a reduction in the number of balancing zones in France, and an increase in entry capacities from the LNG terminals. On 1 January 2009, the GRTgaz West, East and North zones were merged, creating a single large North zone.

The connection of two new LNG terminals also further strengthened the network, with the commissioning in 2010 of the Fos Cavaou terminal, and the Dunkirk terminal due to open in 2016.

On the basis, in particular; of the results of the study[18] it ordered in 2014, the CRE approved the new programme of investment for the Val de Saône project on the GRTgaz network, and the Gascogne-Midi project on the GRTgaz and TIGF networks, in preparation for the creation of a single marketplace in 2018. The CRE, in its deliberation of 30 October 2014, extended the 300 basepoint bonus to the Gascogne-Midi project.

In that same deliberation, the CRE introduced an incentive mechanism regarding the deadline for completing the Val de Saône and Gascogne-Midi projects, since they are both prerequisites for the creation of France's single marketplace in 2018.

- Development of interconnection points

Capacities along the French/Spanish border have increased considerably in recent years, with the creation of entry capacities in France and of a new interconnection point in Biriatou. The firm capacity from Spain to France rose from 0 to 225 GWh/day, with the firm exit capacity from France to Spain increasing from 80 to 165 GWh/day. These developments were possible thanks to the capacities that were contracted during the

[18] Final Report on the cost/benefit study conducted by Pöyry (in French)

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2009 and 2010 open seasons. However, the 2010 open season was insufficient to justify a third interconnection point to the east of the Pyrenees.

In December 2008 and then in 2009, following on from an open season in 2006, firm entry capacities at the France/Germany interconnection rose from 430 to 530 GWh/day in the first year, then to 620 GWh/day by the end of 2009.

There have also been significant developments at the France/Belgium interconnection point. After the open season in 2008, the firm entry capacity rose from 590 to 640 GWh/day by 1 December 2013. In 2011, the CRE approved the addition of 270 GWh/day in firm exit capacities towards Belgium at the Alveringem interconnection point.

Finally, GRTgaz is currently experimenting with decentralised odorisation in several pilot towns. This project, recognised as a Project of Common Interest by the European Commission, may eventually result in the creation of firm exit capacities to Germany.

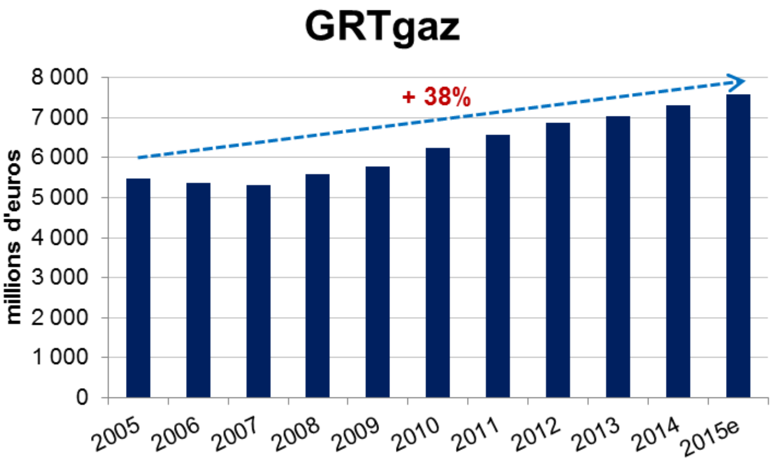
Over the past decade, GRTgaz and TIGF have significantly developed their networks, creating new interconnection capacities with neighbouring countries and increasing entry capacities from the LNG terminals. These improvements have allowed consumers to benefit from a more diverse range of sources and have reinforced France's integration within the European gas market. The creation of the single marketplace in 2018 will mark the end of a major programme of investments, the majority of which came with financial incentives.

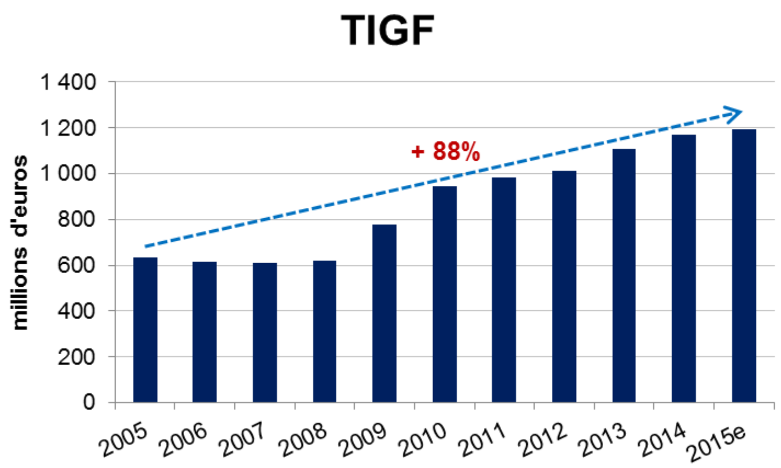
Overall, the TSOs will have invested about €3 billion in creating a vaster, more liquid and better interconnected market.

- Consequences on the RABs of TSOs

These investments have markedly increased the RAB of these two TSOs. The RAB of GRTgaz is currently €7,579 million, up 38% compared to 2005, and that of TIGF is €1,248 million, up 88%.

Change in the regulated asset bases of the TSOs since 2005

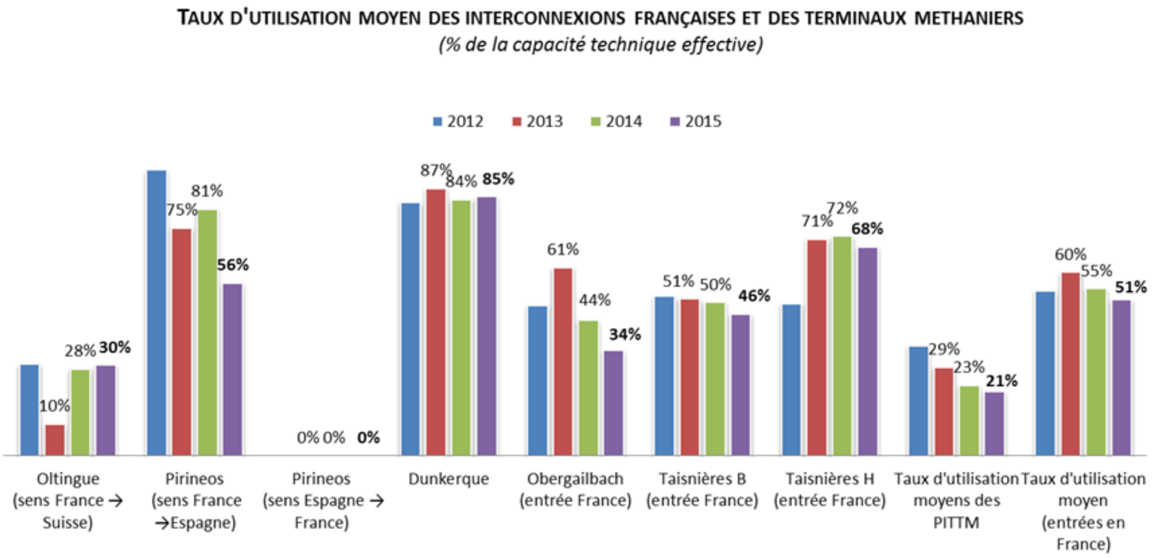




Source: data from GRTgaz, TIGF, CRE

As a result, the GRTgaz and TIGF tariffs for the use of transmission networks have increased by 40% and 36% respectively over the past ten years, compared to inflation of 13% over this same period.

- Average usage rates of French interconnection points



Source: data from GRTgaz, TIGF – CRE analysis

The CRE believes that demand is being met by the available transmission capacities: interconnections with neighbouring countries are currently being used at below their technical capacity, allowing the market to optimise arbitration between different sources of gas, and the remaining capacities are free to be booked by the market.

The CRE also notes that the demand for gas transmission capacities has stagnated or even fallen, from both shippers and consumers:

- the market has not expressed any need for increased capacities along the GRTgaz and TIGF networks;
- capacity sales on Prisma remain very poor, except at the North-South link, and for several years have been showing no need for investment;
- the TSOs, in their 10-year development plans, have predicted a fall in domestic consumption (of -0.3% and -0,1% per year for the GRTgaz and TIGF zones respectively over the period 2015-2024);

- over recent years, the number of connections to the gas transmission networks has remained very low (approximately three connections per year within France between 2012 and 2015).

Summary

The CRE believes that its incentive mechanisms for investing in the transmission network need to be adapted to the changing environment.

- Investments over the past decade have considerably strengthened the French gas transmission network.
- Entry capacities have risen by over 50%, exit capacities have doubled, and the heart of the network has been reinforced making, for the upcoming creation of a single marketplace in 2018.
- These investments have resulted in sharp hikes in transmission tariffs, which will stop when the investment needed to create the single zone will be achieved.
- At the same time, the demand for gas in France has been falling since 2005, and forecasts remain modest, especially given the target of a 30% reduction in fossil fuel consumption by 2030 set by the Energy Transition Act.

In these circumstances, the CRE is currently not planning to continue its financial incentives for debottlenecking investments into the ATRT6 period.

Question 6 According to you, does the non-renewal of the 300 basis points bonus for the period ATRT6 seem appropriate?

2.1.2. Incentive regulation mechanism for the unit cost of investment into the networks

The external study, ordered in 2015 by the CRE, concluded that the incentive mechanisms used for the current tariffs are efficient[19]. However, they did identify areas for improvement regarding the monitoring of investment costs. Several regulators across Europe have already put in place incentives for better regulation of investment costs. This study advises the CRE to investigate the possibility of an incentive regulation mechanism for the unit cost of investment into the networks.

Insofar as capital expenses are wholly covered by the expenses and revenues clawback account, and in the absence of any incentive to manage costs, the TSOs could end up over-investing or not taking sufficient care to control their costs.

The CRE wishes to investigate the possibility of an incentive regulation mechanism based on the unit cost of investment into the transmission networks. This incentive would be based on a reference cost model for the facilities commissioned by GRTgaz and TIGF, taking into account their technical features and changes in costs over time. Since there is only a limited number of transmission network projects at the moment, the main challenge would be to define, implement and update reference unit costs that are sufficiently relevant to discourage operators from cutting costs and sacrificing quality. The CRE has asked GRTgaz and TIGF to send their proposed unit costs.

Question 7 Are you in favour of considering an incentive for encouraging GRTgaz and TIGF to manage the unit cost of their investments into the networks?

[19] External study related to international benchmark of the incentive regulation mechanisms applied by electricity and natural gas system operators in Europe – Schwartz & Co.

2.1.3. *Incentive regulation for non-network expenditure*

In line with one of the recommendations made in the Schwartz study and following its decision regarding the framework for the next tariffs for the use of GRDF distribution networks, the CRE wishes to offer an incentive for managing investments into "non-network" elements e.g. assets such as real estate, vehicles and information systems. Since these expenditure line items are susceptible to arbitration between investments and operating costs, the CRE thinks that the time has come for the capital expenses and operating costs relating to these line items to be governed by the same principles of incentivised regulation.

The proposed mechanism will involve determining a target trajectory for these capital costs over the ATRT6 tariff period, and excluding them from the clawback account. Any gains (or losses) that may be made will therefore be retained (or suffered) 100% by the operators.

In addition, the CRE wants to conduct an ex-post analysis of the trajectories of the investments in question in order to ensure that any gains made over the tariff period are not offset by higher outlay in subsequent tariff periods.

Question 8 Are you in favour of an incentive for encouraging GRTgaz and TIGF to manage their capital expenditure on non-network assets and the operating costs of those assets? What do you think of the mechanism proposed by the CRE?

Question 9 Do you have any other suggestions for how to change the incentive for GRTgaz and TIGF to invest?

3. Incentive regulation mechanism for research and development (R&D) costs

Like the distribution network operators, the TSOs are facing a stagnation and even a decline in gas consumption. New uses for the TSO networks are needed to be investigated. The CRE has approved[20] the Jupiter 1000 project, to be coordinated by GRTgaz, involving the construction of a "Power to Gas" pilot project designed to convert or store electricity as hydrogen (via electrolysis) or methane, which would then be injected into the gas network.

For the next tariff period, the CRE wants to ensure that the TSOs have sufficient resources for their R&D projects and that those resources are used efficiently.

The regulatory framework for the current ATRT5 tariff does not include any particular incentive for R&D. These expenses fall under a section of the budget for which the operator has a productivity target and so they may be arbitrated by the TSOs to the detriment of their R&D programmes.

The CRE wants the ATRT6 tariff to include an R&D incentive for the TSOs, similar to that introduced by TURPE4 for electricity and that decided for the new distribution tariff (ATRD5):

- any differences between the target trajectory for allocated R&D expenses and the actual expenditure would be returned to users at the end of the tariff period via the clawback account. If the TSOs exceed the allocated trajectory, they would bear the difference. Operators will therefore have to submit a report to the CRE, which may undergo a routine audit;
- an annual overview of R&D projects would be published in order for users to learn about the innovations being taken by the TSOs. The operators would in particular be required to provide:
    - a description of the projects they have been carrying out and the partnerships they have made, together with a list of related expenses and the results obtained;
    - a list of current and upcoming projects, together with the expected results;
    - the amounts spent over the past year;
    - expenditure forecasts for each year until the end of the tariff period;

[20] Deliberation of 22 July 2015 analysing the 2014 programme of investment and approving the amended 2015 programme of investment for GRTgaz (in French)

- the number of full time equivalents allocated to their R&D programmes;
- any support and grants received.

Question 10 Are you in favour of introducing an incentive for GRTgaz and TIGF concerning their R&D expenditure, where any amounts allocated for R&D but not spent by the operators would be returned to users at the end of the tariff period?

Question 11 What do you think of an annual report of the operators' R&D projects each year?

4. Service quality incentive regulation

4.1. The current system is designed to motivate the TSOs to improve the quality of service received by shippers, in certain key areas

The ATRT5 tariff includes an incentive that encourages TSOs to improve their performance, whilst managing their costs. The aim of the incentive regulation mechanism for quality of service is to ensure that users receive a good quality of service in return for the network access tariffs they pay.

The quality of the service given by the TSOs is measured using twenty-three performance indicators:

- Six incentivised performance indicators:
  - They concern the quality of the consumption measurement data provided to the shippers and needed for their balancing operations: consumption data quality, consumption forecasts quality and portals availability.
- Seventeen non-incentivised performance indicators:
  - Five indicators designed to monitor more closely published information and the ways in which the TSOs are operating on the markets, as part of the new balancing system that was instigated by the CRE deliberations of 15 January 2015 and 10 September 2015[21].
  - Six indicators relating to the operators' maintenance schedule and compliance with the forecasts provided to the shippers.
  - Three indicators concerning the quality of the relationship between the operators and the shippers.
  - Three indicators for monitoring the environmental impact of the operators' activities.

The results of these performance indicators are published on the operators' websites each month. In addition, every year since 2009 the CRE has been publishing a report[22] on the quality of service incentives, which contains the consolidated results, a financial assessment and explanations for the performance of the TSOs. Starting in 2016, the TSOs will also be producing their own qualitative analysis of their performance.

4.2. Performance indicators designed in collaboration with the stakeholders

The service quality incentives have gradually evolved in order to take account of the results obtained and feedback from the market. The incentives and targets for the operators have been gradually increased in order to support, and even strengthen, their performance.

During the ATRT5 tariff period, the CRE decided, following a public consultation, to focus on the quality of the data needed by the shippers for their balancing operations.

In 2014, it therefore introduced a financial incentive concerning the quality of the consumption forecasts published by the TSOs. An improvement in quality was in fact essential given the evolution of the target balancing system and the introduction of the European gas balancing network code in 2015.

In 2015 and following demands from certain players, two new indicators were created concerning the

[21] Deliberation of the French Energy Regulatory Commission of 15 January 2014 approving the balancing rules for the GRTgaz and TIGF transmission networks as from 1 April and 1 October 2015 and Deliberation of the Regulatory Commission of Energy of 10 September 2015 relating to developments of the balancing rules on gas transport networks on 1st October 2015

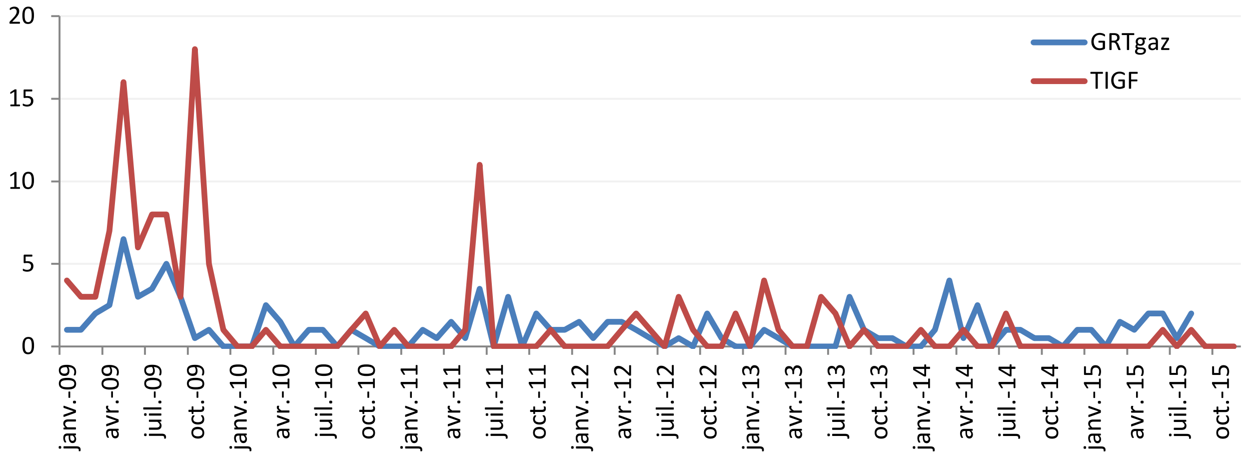
[22] The report for the period from 1 January 2014 to 31 December 2014 is available from the CRE website (in French).

operators' maintenance schedule.

4.3. A real improvement in TSO performance over the period

Between 2009 and 2015, the TSOs made significant progress, especially regarding their consumption figures which are needed by the shippers to conduct their balancing operations.

For example, the graph below shows the number of days per month on which the difference between the predicted consumption figure at transport distribution interface points and the actual figure (submitted to the DSO on the 20th of month M+1) was greater than 2%. The figures for both GRTgaz balancing zones have been averaged out in order to provide just a single figure per TSO.



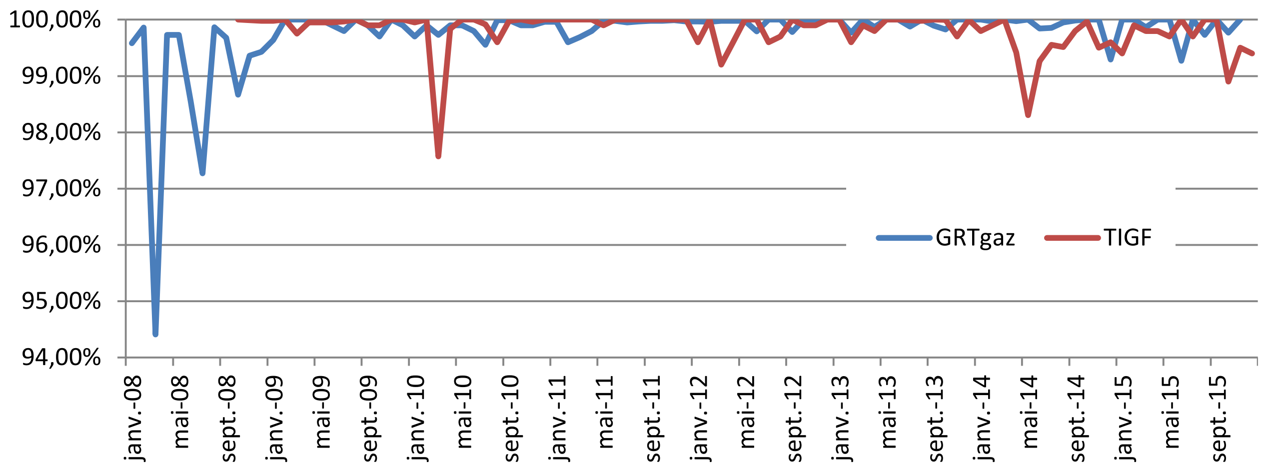
In order to achieve the quality standards required by the CRE, the TSOs have established procedures for improving the consumption figures they publish. GRTgaz has invested in consumption data, and in particular launched a new customer portal, TRANS@ctions, in 2012. This portal allows customers to monitor changes in their consumption and to enter and edit their nominations, for day-ahead and within-day products.

Likewise, TIGF has considerably improved the quality of its consumption measurements. In particular, it has reduced the time it takes to repair faults and introduced better remote metering technology for its industrial customers.

Both TSOs will be using a new metering system, which should help them continue improving the quality of their consumption measurements.

Likewise, by monitoring their service quality, they have been able to improve the quality and availability of their portals: TRANS@ctions for GRTgaz and Tetra for TIGF. Since 2013, they have also been monitoring their public information portals, SMART for GRTgaz and Datagas for TIGF. These portals allow the whole market, whether customers of the transmission networks or otherwise, to obtain aggregated consumption data, information about capacity usage and the overall balancing of the network. Aware of the importance of having access to this data, in 2015 GRTgaz launched a mobile application, GRTgaz+, which offers an overview of this public information.

Availability of the GRTgaz and TIGF portals, in number of hours



4.4. The financial incentives for the TSOs are helping improve the quality of service

The incentive regulation mechanism is based partly on financial incentives relating to service quality.

The TSOs have been awarded a bonus each year since the mechanism was introduced, although in varying amounts, depending on their performance in each of the indicators compared to the standards required by the CRE:

€K	2010	2011	2012	2013	2014	2015
GRTgaz	3,880	1,367	1,197	909	1,515	42
TIGF	678	241	365	47	202	428

Question 12 Are you in favour of continuing the incentive regulation mechanism for service quality?

4.5. Proposed changes to the incentive for quality of service

4.5.1. Simplification

- Removal of the least relevant performance indicators

In order to simplify the system for monitoring service quality, the CRE is proposing to abandon the following non-incentivised indicators, since it believes they are no longer relevant:

- connection completion deadlines: the number of days actually needed to power up new connection facilities in relation to the deadline stated in the contract with the customer. In fact, the paucity of new connections over the past five years (less than three per year in France) has made this indicator superfluous;
- the reliability of information on the customer portals, based on the number of complaints regarding information reliability. The TSOs are in direct contact with their customers, of which there are less than a thousand for the GRTgaz network, and they only rarely use the complaints procedure;
- the time taken to send to the distribution system operators (DSOs) the files concerning withdrawals at the transport distribution interface points, i.e. the number of days during a given month on which the TSO sent the file for the provisional daily withdrawals at the interface points to the DSO without delay. There is already an incentive for the quality of data from the transport distribution interface points; any late submission is monitored in relation to the DSOs, this indicator is therefore redundant.

Question 13 Are you in favour of removing three indicators concerning the deadlines for completing connections, the number of complaints and the delay for sending the files regarding withdrawals at transport distribution interface points to the DSOs?

4.5.2. Introduction of new financial incentives

- Improving the data needed by shippers for their balancing

The CRE wishes to introduce a financial incentive regarding the availability of the five most useful pieces of information for shippers and their balancing operations: projected linepack, expected imbalances, the imbalance settlement price, total consumption forecasts by zone (D and D+1) and allocations at the Pirineos interconnection point.
For each of these five pieces of information, and for each month, the TSO will receive a bonus if the information is made available by the required time each day. If any information is missing on more than two occasions, the TSO will suffer a penalty.

Question 14 Are you in favour of introducing a financial incentive regarding the availability of the five most useful pieces of information for shippers balancing operations?

- Availability of firm capacities during works

Since 1 April 2012, the CRE has been monitoring the availability of firm capacities, by month and at each type of point (network interconnection points, LNG terminal interface points and transmission system operators) on the GRTgaz and TIGF networks, on an aggregate basis.

The indicators relating to the operators' maintenance schedule show that GRTgaz has frequently disrupted its firm capacities during the period, usually due to major works (Hauts de France II, Arc de Dierrey, connecting the Dunkirk LNG terminal). This has drawn regular criticism from the market. In response, GRTgaz published a benchmark on Concertation Gaz, explaining the specific nature of its network and suggesting ways for improvement.

Annual availability of firm capacities, by type of network point

GRTgaz	**2012**	**2013**	**2014**	**2015**
Network interconnection points	93%	88%	90%	92%
North South (N→S)	100%	100%	99%	99%
LNG terminal interface points	94%	96%	96%	96%
Transport storage interface point - injection	93%	95%	96%	95%
Transport storage interface point - draw-off	97%	95%	96%	97%

TIGF	**2012**	**2013**	**2014**	**2015**
Network interconnection points	97%	98%	98%	99%
Transport storage interface point - injection	80%	100%	100%	100%
Transport storage interface point - draw-off	100%	100%	100%	100%

The very low availability rate of the GRTgaz network interconnection points in 2013 can be explained by the work to reinforce the Hauts de France line. Over the period, there does seem to be room for improvement in GRTgaz' performance. TIGF has performed satisfactorily for this same indicator since 2013.

The CRE wants to modify this indicator according to two options:

- keeping current indicator, but detailing it for each network point (instead of an average by type of point) in order to obtain details of firm capacity availability at each individual point. The network entry points will be given priority, but the CRE will also study the possibility of extending these indicators to the LNG terminal interface points, transport storage interface points and network exit

points.
- introducing a new indicator, replacing the existing one, on the number of days per month on which the actual technical capacity is lower than the theoretical maximum firm capacity (firm capacity profile) for each point. The results of this indicator, for the same period and per year, are as follows:

Number of days in the year when actual technical capacity was less than the theoretical maximum firm capacity

	2012	2013	2014	2015
Dunkirk interconnection point	78	198	156	70
Obergailbach interconnection point	140	164	207	144
Oltingue interconnection point	22	39	35	39
Taisnières LCV interconnection point	18	25	52	41
Taisnières HCV interconnection point	16	227	208	149
North South	5	9	19	23

Whichever indicator is chosen, the CRE shall establish thresholds for its monthly monitoring of firm capacity availability.

Question 15 Are you in favour of introducing a service quality indicator for the number of days on which actual technical capacity is less than the theoretical maximum firm capacity, or would you prefer to keep the current indicator with detailed results by point?

Finally, the CRE wants to introduce a financial incentive regarding the availability of firm capacities, linked either to the current indicator or the new one it is proposing. This incentive would only be for certain critical aspects, to be determined after this consultation and further planning.

For example, the incentive could work as follows. Based on the availability of firm capacities, per month, and by point:
- when firm capacity availability is above a threshold to define at a particular point over a month, the bonus will be €30k per month for GRTgaz and €15k for TIGF;
- when firm capacity availability is less than a threshold to define at a particular point over a month, the penalty will be €20k per month for GRTgaz and €10k for TIGF;
- if firm capacity availability is between the two threshold, the indicator is neutral;
- an annual cap would be applied at each point of +/- €100k for GRTgaz and +/- €50k for TIGF;
- TSOs require that disruptions to TIGF firm capacities caused by works undertaken by GRTgaz would not be taken into account when calculating the indicator for TIGF, and vice versa.

Question 16 Are you in favour of introducing a financial incentive for the availability of firm capacities? At what points along the GRTgaz and TIGF networks do you think a financial incentive would be most relevant?

- Forecasts for capacity availability

When questioned as part of a public consultation into the tariff updates due to come into force on 1 April 2016, most of the market believed that the maintenance forecasts published by the TSOs were too conservative and did not allow them to plan accurately for future disruptions.

In its deliberation of 10 December 2015, the CRE asked the TSOs to publish, along with their binding maintenance schedule, their best (non-binding) forecasts for capacity availability. At the same time, it added an indicator regarding the quality of these non-binding forecasts, whereby they are compared to the actual figures.

It may be possible to attach a financial incentive to this new indicator. For each percentage point difference between the actual figures and the TSO's non-binding forecasts, the operator would have to pay a penalty; alternatively, if its predictions match up to the actual figures, it would receive a bonus. The incentive would be capped. In order for the overriding need to maximise available capacities to take precedence over the reliability of the maintenance forecasts, the financial incentive attached to this indicator would be smaller than the incentive for firm capacity availability.

Question 17 Are you in favour of introducing a financial incentive for non-binding maintenance forecasts?

5. Incentive regulation mechanism for capacity sales

5.1. Incentive to provide additional capacities at the North-South link

In preparation for France's single marketplace, an indicator was introduced for GRTgaz in 2014 encouraging it to maximise the firm capacities it sold each day at the North-South link. GRTgaz managed to supply the market with 7.4 TWh/d/year in firm capacities above the technical firm capacity of the North-South link, thus receiving a bonus of €1.2 million for 2014.

Congestion at the North-South link subsided in autumn 2015, and the CRE has therefore not repeated the financial incentive attached to this indicator.

5.2. Incentive to sell capacities on the main network

- For the ATRT5 tariff, 50% of the income from capacity bookings on the upstream network is covered by the expenses and revenues clawback account. This has encouraged the TSOs to develop a dynamic commercial offer. GRTgaz in particular has been encouraged, for the ATRT5 period, to develop (i) contractual mechanisms allowing it to offer greater capacities at the North-South link, (ii) market coupling, (iii) the JTS[23], (iv) discounts at the Jura interconnection point and (v) better distribution of entries onto the TIGF network at Cruzy and Castillion;

- additional monthly firm capacities at Dunkirk for winter 2015-2016[24].

The mandatory introduction of the CAM Network Code on 1 November 2015 means that all interconnection point capacities are now sold using the ascending clock auction system, via the PRISMA platform. In addition, the creation of the single marketplace in 2018 will mean capacities are no longer sold at the North-South link. As a result, the TSOs will lose much of their room for manoeuvre, reducing the appeal of a financial incentive.

The CRE currently sees two possibilities:
- removing the existing incentive, and making the income from capacity bookings on the upstream network wholly covered by the expenses and revenues clawback account;
- covering 80% of this income by the clawback account, in order to leave a residual incentive for the TSOs.

Question 18 Would you like the existing incentive for selling capacities to be removed, or would you prefer for the amount of the income from capacity bookings covered by the clawback account to be increased to 80%?

[23] Joint Transport Storage: In its deliberation of 23 May 2013, the CRE authorised GRTgaz to sell, as part of a pilot scheme, additional North-to-South capacities starting in summer 2013 ("Summer" JTS). To provide this service, GRTgaz uses the injection capacity not used on any given day by shippers at the South-East transport/storage interface point. Since 1 April 2014, 20 GWh/day has been put up for auction on PRISMA under the JTS scheme.

[24] Deliberation of the French Energy Regulatory Commission of 24 September 2015 concerning the sale of additional capacities at the Dunkirk entry point on the GRTgaz network (in French)

C. Tariff structure

1. Relative tariff terms

In this public consultation, the CRE wants to present the relative constraints and circumstances that will affect the tariff structures applied to GRTgaz and TIGF during the ATRT6 tariff period.

The draft Tariff Network Code states that the income received by the TSOs from the upstream and downstream networks should be distributed in such a way as to reflect the distribution of the costs borne by these two networks. It also mentions that the default target is for the income received at the entry and exit points on the upstream network to be distributed equally, and any deviations from this reference target must be explained. Finally, the future code recommends that the reference price method used to calculate the tariff terms should be the capacity weighted distance methodology. This method is used to determine the tariffs applicable at different points on the transmission network, using as cost drivers the distance travelled by the gas between the entry and exit point and the subscribed capacities.
The CRE considers that the ATRT6 tariff should take account of the recommendations of the future Tariff Network Code.

In addition, the creation of the single marketplace at the end of 2018 will mean a loss of revenue for GRTgaz, due to the disappearance of income from the North-South link, and greater capital expenditure for both operators due to the Val de Saône and Gascogne-Midi projects. We therefore have to study the way in which the expenditure and lost earnings will be shared between the different tariff terms.

The CRE has already decided, in its previous transmission tariffs, to equalise several terms within the tariff for each TSO, and between the tariffs for GRTgaz and TIGF. In preparation for the single marketplace in 2018, it is necessary to examine the possibility of balancing out the GRTgaz and TIGF tariffs in general.

1.1. Equalising the GRTgaz and TIGF tariffs

Looking ahead to the creation of France's single marketplace, the CRE wishes to obtain the market's input about the possibility of equalising the tariff terms applicable at some of the points along the French gas transmission network.

There is already a large degree of equalisation between the current transmission tariffs. Capacities at the Dunkirk, Taisnières H, Obergailbach, Jura and Pirineos entry points all have the same tariff; this also applies to the entry capacities at the Dunkirk, Montoir and Fos LNG terminal interface points. Differentiating between the tariffs would have been very difficult because it is impossible to distinguish, within the main network, which works contribute entirely or partially to the availability of the entry capacities at a given point.
In addition, in the lead-up to the merging of the market zones, with each tariff update the CRE has been gradually bringing the terms of exit to the GRTgaz and TIGF regional networks into alignment, and they were finally equalised on 1 April 2015.
Finally, tariffs at the transmission storage interface points between the TIGF and GRTgaz South networks were equalised when the TRS zone was created. The Pöyry study on the tariffs at the transmission storage interface point in GRTgaz and TIGF[25] zones concluded that a multiplier in a [1.33-2] range would reflect the difference in the firmness of the capacities at the transport storage interface points. The CRE chose the minimum multiplier to take into account this aspect.
This equalisation has until now made it possible, for each of the two operators, to even out the revenue received during the tariff period and the authorised revenue to be covered by the tariff: there has therefore been no need to make any refunds between GRTgaz and TIGF.

Once all the zones have merged, consumers connected to the GRTgaz and TIGF regional networks will all have access to a single marketplace, and will benefit from diverse sources of supply. At this time, the CRE intends to even out the tariffs across the country by equalising the other tariff terms applicable to the GRTgaz and TIGF regional networks. In this way, all users of the network will contribute equally to the investments needed to create the single marketplace and any other investment that may be needed to strengthen the network and develop the interconnection points.

[25] Pöyry study on the tariff terms at transmission storage interface points in GRTgaz and TIGF, October 2013.

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The storage sites in the GRTgaz North and South zones have similar interruptibility factors and so they provide an equivalent service to their users. Therefore, when the single marketplace is created, the CRE intends to equalise tariff terms at the transmission storage interface points between the two zones. The CRE may also take the opportunity to consider revising the 1.33 multiplier between the GRTgaz and TIGF transmission storage interface points, based on changes in the services provided, in particular if the hypothesis used by Pöyry in the study do no longer match the reality.

As regards exit points to neighbouring countries, the CRE considers that equalising the tariffs would not reflect the actual cost of transit for the TSOs, due to the very different distances travelled by the gas around the GRTgaz and TIGF networks depending on the exit point in question. The CRE will ensure that all tariff terms reflect the costs actually generated by the transit and domestic consumption, as required by the future Tariff Network Code.

Equalising tariffs nationally could lead to an imbalance between the income received by each TSO and the amount of costs to be met by their tariffs. The CRE is currently planning to introduce inter-operator refunds.

Question 19 Are you in favour of equalising the GRTgaz and TIGF tariffs, under the conditions proposed by the CRE?

1.2. Transit tariffs

The CRE plans to anticipate the requirements of the draft Tariff Network Code regarding distance-based tariffs, in preparation for the creation of France's single marketplace. The CRE has begun comparing the tariffs and costs of the main gas routes across France, using for the main network the capacity weighted distance methodology recommended by the future Tariff Network Code.

An initial analysis of France's two main transit routes shows that the tariffs paid by a shipper to transport one megawatt hour/day of gas over one kilometre are relatively similar:

- a shipper who brings gas from Norway destined for the Italian market will pay the entry tariff at the Dunkirk network interconnection point (€114.30/MWh/day/year) and the exit tariff at the Oltingue interconnection point (€398.79/MWh/day/year), meaning a cost of approximately €0.73/MWh/day/year/km[26];

- a shipper who takes Norwegian gas to the Spanish market will pay the Dunkirk entry tariff (€114.30/MWh/day/year), the tariff at the North-South link (€208.04/MWh) and the Pirineos exit tariff (€496.89/MWh/day/year), making a total cost of €0.78/MWh/day/year/km[27].

The entry tariffs at Dunkirk and the exit tariffs to Spain and Italy have changed over the past ten years in order to counter the disappearance of the link tariffs following the creation of the large North zone and the TRS. In total, between 2008-2015, tariffs for the Dunkirk-Oltingue route and Dunkirk-Pirineos route have remained stable at constant euro values, increasing by an average of only 1.1% and 1.4% respectively.

1.3. Main balances in the split in revenue received by the operators

1.3.1. <u>Split of costs and revenue between the TSOs' upstream and downstream networks</u>

Unlike many TSOs in Europe, GRTgaz and TIGF operate regional networks (or downstream networks), in addition to the main networks (or upstream networks). In other countries, regional networks are usually included in DSOs perimeter.

The future Tariff Network Code is expected to include stronger transparency obligations for European

[28] Final report of the cost/benefit study carried out by Pöyry

[28] Final report of the cost/benefit study carried out by Pöyry

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regulators for the allocation of costs and revenue from operating the gas transmission networks. The tariffs at the different points must be set in a way that reflects the actual costs borne by the TSOs.

Since the first gas transmission tariffs were implemented, the CRE has sought to ensure a balance, for each TSO, between, on the one hand, the revenue from operating the upstream network and the costs allocated to the upstream network and, on the other hand, between the revenue from operating the downstream network and the costs allocated to the downstream network.

Successive tariff changes that occurred during the ATRT4 and ATRT5 periods led to a slightly unbalanced split in the revenue and costs between the upstream and downstream networks, when considering France as a whole: the regional network generates only 49% of revenue whereas it accounts for nearly 53% of the TSOs' costs. In 2016, the percentages of costs and revenue allocated respectively to the main network and the regional network are as follows:

	Main network		Regional network	
	% of revenue	**% of allocated costs**	**% of revenue**	**% of allocated costs**
2016	51.0%	47.4%	49.0%	52.6%

Source: GRTgaz and TIGF

For the ATRT6 tariff period the CRE intends to seek a balance between costs and revenue on the upstream and downstream networks.

1.3.2. *Split of costs and revenue between the TSOs' entry and exit points*

As well as searching for a balanced split of revenue and costs between the upstream and downstream networks, the way revenue is split must also be considered from the aspect of the split between the entry and exit points on the upstream network.

The draft Tariff Network Code proposes that national regulatory authorities use an indicative default 50/50 split of revenue between entries and exits.

In 2016, the weighted average level of entry tariffs (for network interconnection points and LNG terminal interface points) on the main network was €110/MWh/d/year, whereas the weighted average level of exit tariffs (for network interconnection points and exits to the regional network) was €120/MWh/d/year. The relative levels of the entry and exit tariffs are therefore close to a 50/50 balance.

Because of the large quantity of storage facilities in France, the entry capacities contracted by shippers into France are much lower than the exit capacities contracted. This results in the following revenue split for 2016:

Split of revenues by point type as %	France
Entries (network interconnection points, LNG terminal interface points and transport storage interface points)	**35%**
Exits (network interconnection points and exits to the regional network)	**65%**

The CRE considers that this balance is satisfactory, at this stage. It sees no reason to change it significantly in the ATRT6 tariff.

1.4. Removal of charges at the North-South link and commissioning of new facilities

When the single marketplace is created in France, the removal of the charges at the North-South link will lead to a loss of revenue for GRTgaz of around €60 to 70M per year, representing nearly 4% of GRTgaz's authorised revenue for 2016 (excluding auction surpluses, which are paid back directly to shippers in proportion to their consumption in the South zone).

As well as this loss of contract revenue, there is a rise in capital and operating costs related to the commissioning of infrastructures needed to create the single marketplace, with an estimated budget of €823M. This represents an annual charge for the tariff of approximately €100M per year in 2019 and 2020 (approximately 5% of GRTgaz and TIGF's costs).

The CRE wishes to analyse how these costs are split between the different tariff conditions, with the aim of giving clear information to market players.

1.5. Summary: changes to tariff terms when the single marketplace is created

The CRE considers that how costs are allocated for creating the single marketplace must be consistent with the benefits to the market from this merger.

1.5.1. Transit and domestic consumption

At this stage, the CRE considers that the transit tariffs (Dunkirk-Pirineos and Dunkirk-Oltingue flows) should not change significantly as a result of setting up a single marketplace, provided that ATRT tariffs comply with the reference methodology (capacity weighted distance reference price methodology) described in the Tariff code draft.

1.5.2. Balancing revenue between the upstream and downstream networks

At this stage, the CRE proposes maintaining, or re-establishing if necessary, an equal split of costs and revenue between GRTgaz and TIGF's upstream and downstream networks, in order to avoid any cross-subsidisation between the different kinds of users, in accordance with the purposes of the future Tariff Network Code.

Subject to the forecasts that the TSOs will send the CRE for the ATRT6 period, any rebalancing required could lead to collecting more revenue on the regional network.

1.5.3. Revenue split between main network entries and exits

At this stage, the CRE proposes to maintain the current split of revenue generated by main network entries and exits, which would involve the regional network entry and exit tariff conditions rising by the same amount. Such a rise in the entry tariff conditions can be justified by the fact that, after the merger of the GRTgaz North and TRS zones, the gas brought by a shipper to an interconnection point or an LNG terminal will benefit from a much larger market, offering more outlets for shippers. Similarly, increasing the exit tariff term to the regional network can be justified insofar as domestic consumers will benefit from the creation of the single marketplace in terms of market liquidity and the competitiveness of commercial offers that might be made.

1.5.4. Tariff for the transmission storage interface points

The current transmission storage interface point tariffs benefit from a reduction of about 85% compared with other entry and exit points. This reduction is justified by the savings on investments in the transmission networks and the flexibility that the storage facilities offer the transmission network[28]. However, it exceeds the indicative discount proposed in the future Tariff Network Code, which is a 50% reduction.

After the single marketplace is created, transmission storage interface points will benefit, in the same way as network interconnection point entries, from a much larger marketplace and will be able to serve more customers from the same point. As a result, the CRE considers that the tariff terms for transmission storage interface points must change in the same proportion as similar network points: consequently, at this stage, it proposes applying to the entry tariff terms from transmission storage interface points the same change as will apply to network interconnection point and LNG terminal interface point entries; as regards exit tariffs to transmission storage interface points, the CRE foresees a similar change to the one that will apply to other main network exits.

[28] Final report of the cost/benefit study carried out by Pöyry

1.5.5. *Implementation timetable*

Regarding the shortfall to make up related to the removal of revenue at the North-South link, one proposal could be to prepare for the single marketplace by gradually reducing the tariff on North-South capacities so that it reaches 0 by the time of the merger, as happened during the ATRT5 period for the removal of the Midi network interconnection point. The gradual removal of revenue at the North-South link would be offset by transferring the shortfall to be made up to other network tariff terms. This would make it possible to smooth the impact of the removal of GRTgaz revenue at the North-South link over several tariff years.

The capital costs related to the Val de Saône and Gascogne-Midi projects commissioning will be borne by the TSOs only from 1 January 2019 and will be covered by the following authorised revenue.

As this last impact accounts for nearly 60% of the costs to recover, at this stage the CRE is in favour of a single change to the tariff terms on the date that the single marketplace is created (see part II-A-3, p.15 of this consultation).

1.5.6. *Illustration*

As an illustration, the CRE carried out four simulations, corresponding to the following combinations of hypotheses:

<table>
<tr><th>Treatment of transit</th><th>Entry/exit balance</th><th>Upstream/downstream balance</th><th>No.</th></tr>
<tr><td rowspan="4">Costs of transit to Spain and Italy kept constant compared to 2016</td><td rowspan="2">Same increase for main network entries and exits</td><td>Re-balancing of revenue between the upstream and downstream networks</td><td>1</td></tr>
<tr><td>No re-balancing of revenue between the upstream and downstream networks</td><td>2</td></tr>
<tr><td rowspan="2">No increase of entry tariffs</td><td>Re-balancing of revenue between the upstream and downstream networks</td><td>3</td></tr>
<tr><td>No re-balancing of revenue between the upstream and downstream networks</td><td>4</td></tr>
</table>

The impacts of these scenarios on the main network tariff conditions are presented below (simulated tariff level and change compared with the condition level as of 1 April 2016). The tables also show, for each scenario, how revenue is split between the main network and the regional network, compared with how the charges borne by the TSOs are split (based on the split for 2016 plus the charges for creating the single marketplace) and how revenue is split between main network entries and exits.

This table gives the orders of magnitude, everything else being equal (in particular, the changes in operators' authorised revenue other than the changes due to the zone merger are not taken into account).

	2016	1		2		3		4	
	€/MWh/j/an	€/MWh/j/an	%	€/MWh/j/an	%	€/MWh/j/an	%	€/MWh/j/an	%
Entrée PIR (Dunkerque, Taisnières, Obergailbach, Pirineos)	**114**	**118**	*3%*	**136**	*19%*	**114**	*0%*	**114**	*0%*
PIR Oltingue (sortie)	**399**	**395**	*-1%*	**377**	*-5%*	**399**	*0%*	**399**	*0%*
PIR Pirineos (sortie)	**497**	**701**	*41%*	**683**	*37%*	**705**	*42%*	**705**	*42%*
PITTM (Dunkerque, Fos, Montoir)	**108**	**111**	*3%*	**128**	*19%*	**108**	*0%*	**108**	*0%*
PITS entrées (en moyenne)	**9**	**10**	*3%*	**11**	*19%*	**9**	*0%*	**9**	*0%*
PITS sorties (en moyenne)	**21**	**22**	*3%*	**25**	*19%*	**22**	*5%*	**28**	*32%*
Liaison Nord-Sud	**208**	**-**	*-100%*	**-**	*-100%*	**-**	*-100%*	**-**	*-100%*
Sortie réseau principal	**100**	**103**	*3%*	**119**	*19%*	**105**	*5%*	**132**	*32%*
Transport réseau régional (ex : TCR GRTgaz)	**72**	**81**	*12%*	**72**	*0%*	**81**	*12%*	**72**	*0%*
% recettes réseau principal	50%	50%		56%		50%		55%	
% recettes réseau régional	50%	50%		44%		50%		45%	
% recettes entrées	35%	35%		37%		34%		30%	
% recettes sorties	65%	65%		63%		66%		70%	

Question 20 Are you in favour of the CRE's position of aligning the way the TSOs' revenue is split between the upstream and downstream networks with the way the charges borne by these two network categories are split?

Question 21 Are you in favour of maintaining the TSOs' revenue stable between the main network entries and exits?

Question 22 Are you in favour of the CRE's proposed approach to reflect the transit costs to Italy and Spain?

Question 23 Are you in favour of allocating part of the costs for creating the single marketplace to the transmission network entry points or just on the exit of upstream network points?

Question 24 Are you in favour of changing of the tariffs at the transport storage interface points in the same proportion as the other main network entry and exit tariff conditions?

Question 25 Are you in favour of taking into account the impacts on tariffs at the time when the single marketplace is created or do you wish a gradual evolution?

2. Changes to the downstream offer

*2.1. Changes to regional tariff levels (***niveaux de tarif régional** *or NTR in French)*[29]

2.1.1. <u>The current regional tariff levels, inherited from the past, are no longer always suitable for the network conditions</u>

Unlike electricity, with which the entire territory must be served, for a long time the objective for gas has been to develop it where it is economically relevant compared with other energy sources. This is because natural gas competes with other energy sources for all its uses. Therefore, there is no perfect way to equalize, at a national level, regional terms of gas transmission tariffs. The regional tariff level of each delivery point is established on the basis of the cost of transporting gas from the main network to the delivery point in question, which depends in particular on the distance to the main network. This level expresses the different costs of accessing the main network across the country.

In France, the maximum difference in the transmission tariff, i.e. the sum of the regional network and main network charges, between two sites is high compared to other European countries. The maximum tariff on

[29] The regional tariff levels are used to calculate the regional capacity charge. The following calculation is used to determine the level that each site must pay: Contracted capacity at delivery point A x regional tariff level of delivery point A x regional capacity charge

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the transmission network (case of one site whose level is 29) is about eleven times higher than the minimum tariff (case of one site whose level is 0).

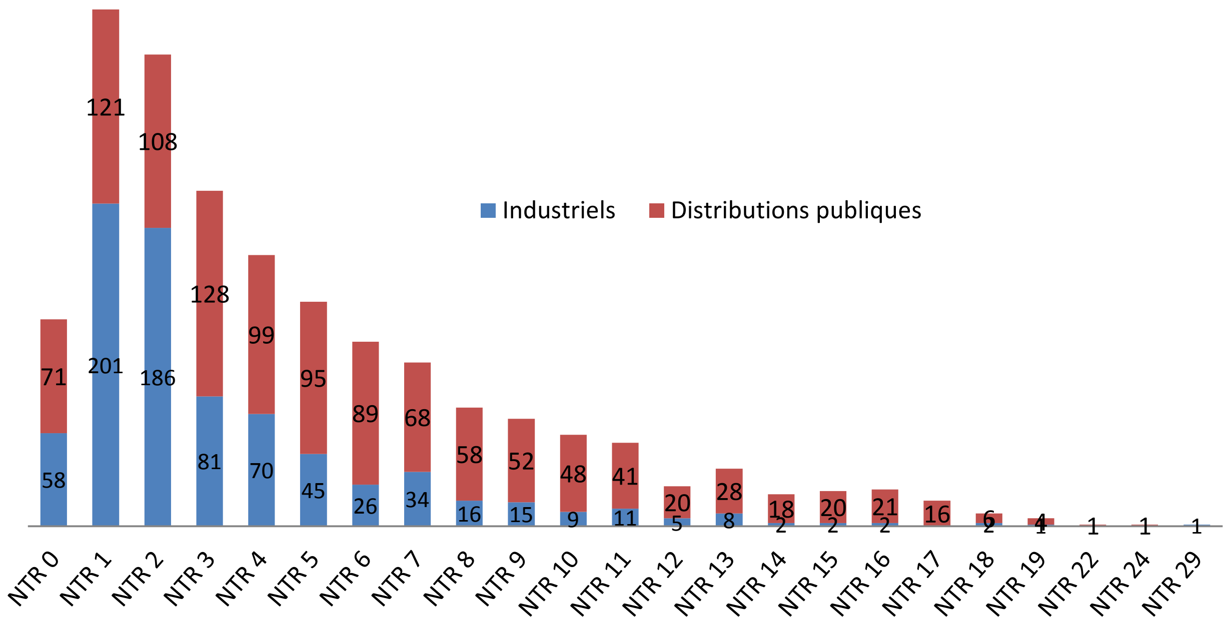
The current levels, which are for approximately 1,200 transport distribution interface points and 1,000 customers connected to the transmission network, are inherited from the past and have never been revised for sites connected to the transmission network for a long time. When the first transmission tariffs were developed in 2000, they were calculated in order to ensure that the transmission tariff part of the regulated sale tariff was kept stable. The regional tariff levels of more recently connected sites are calculated on the basis of a method published by GRTgaz and TIGF, which was approved by the CRE. In addition, the regional tariff levels of public distribution networks were grouped into 1,200 transport distribution interface points (whereas approximately 9,000 municipalities are connected to the gas network) when the distribution network market was opened up in 2004.

Over the years, the transmission network has been developed, leading to changes in how the network operated: the main network was expanded in places; in others, former portions of the main network were reclassified as regional network. As a result some regional tariff levels are not correlated correctly to their current distance to the main network.

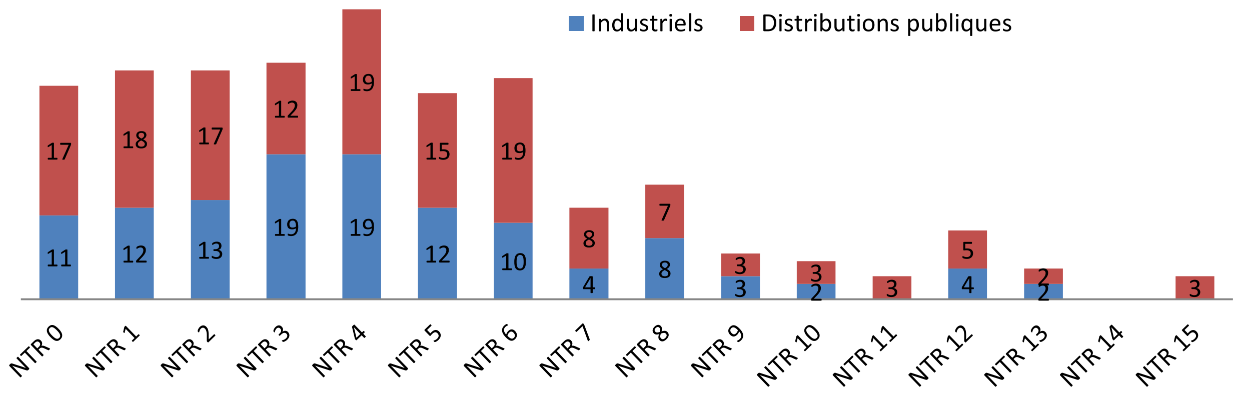
So that the transmission tariffs reflect costs most closely, the CRE proposes carrying out an overhaul of regional tariff levels for the ATRT6 tariffs.

The current distribution of sites per NTR, for GRTgaz, is as follows:

Number of sites per NTR on the GRTgaz network

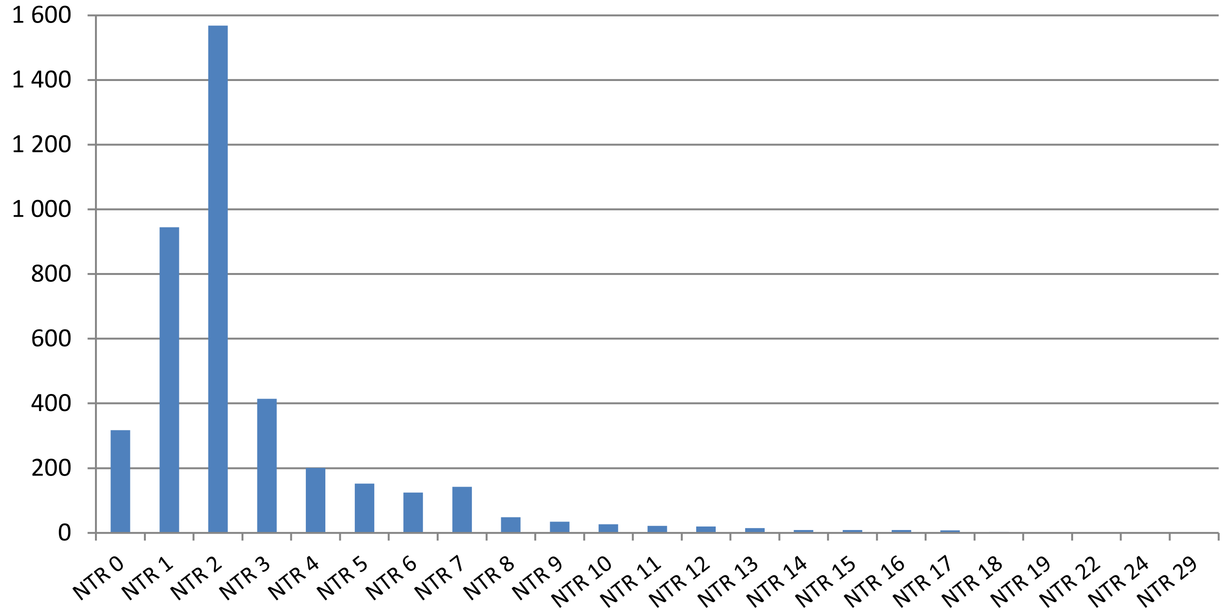


The current distribution of sites per NTR, for TIGF, is as follows:
Number of sites per level on the TIGF network

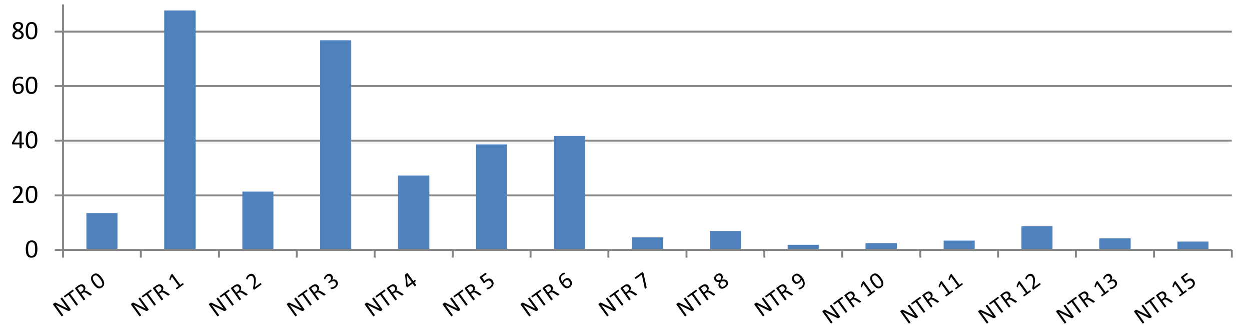


The average NTR per number of sites is 4.71 for GRTgaz and 4.40 for TIGF.

Volume of booked capacity per NTR on the GRTgaz network, in GWh/d



Booked volume per NTR on the TIGF network, in GWh/d



The average NTR by capacity is 2.67 for GRTgaz and 3.75 for TIGF.

2.1.2. *Principles of the proposed overhaul of regional tariff levels*

At this stage, the CRE proposes applying the following principles:

- the distance of sites to the main network must remain the main parameter for defining the regional tariff levels as it is the main cost driver;
- a certain amount of equalisation must be introduced as the purely multiplicative system in force introduces large differences in tariffs and does not reflect in full the progressiveness of costs;
- the new system must retain some continuity with the current system, in order to preserve the sites' financial balance, respect the principle of continuity and predictability of the tariff regulatory system and ensure that the reform is acceptable.

CRE foresees, at this stage, that the overhaul would not have any impact on other tariff terms but the regional capacity term.

Question 26	Are you in favour of overhauling the regional tariff levels?
Question 27	Are you in favour of the principles for overhauling the levels proposed by the CRE?

2.1.3. *Presentation of the three methods being examined*

The CRE has analysed with the TSOs three possible methods for changing the regional tariff level system. These methods are based on measuring the distance between the sites and the main network, as distance is the main cost driver. As it is keen to ensure continuity with the calculation method published on its website, TIGF also proposes taking account, on a secondary basis, of pipeline diameters when calculating the levels as well as distance to the main network.

The three methods being examined take into account the CRE's desire to reduce tariff differences between sites, by limiting the range of levels from 0 to 8 or, alternatively, from 0 to 12. As the method 1 doesn't involve any rise of the regional capacity term, methods 2 and 3 would have to be compensated by a rise of the regional capacity term.

- **Method 1: new calculation of all regional tariff levels on the basis of distance to the main network**

The first method examined involves allocating a new level to each site, based exclusively on its current distance to the main network, and on the diameter for TIGF, limited to 8 or 12 levels. Thus, the sites located near a recently developed pipeline of the main network would benefit from a decrease of their regional level tariff, reflecting the investments achieved during the last years.

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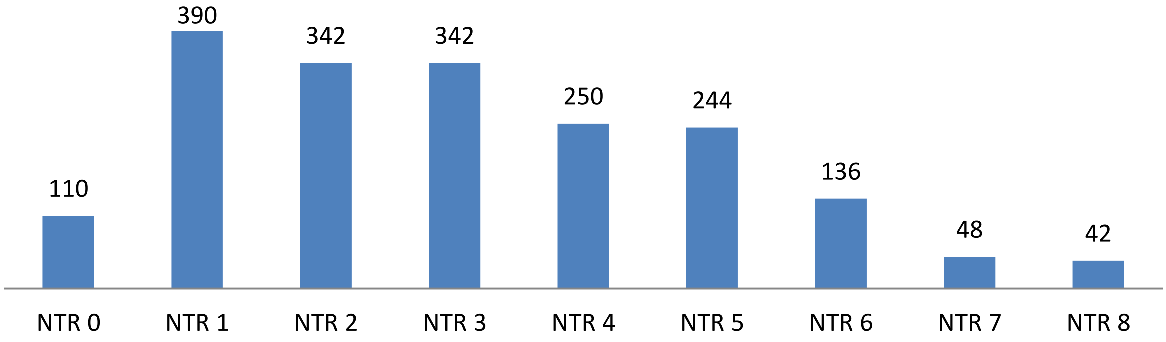
For the GRTgaz network, the distribution of sites per NTR could then be modified as follows:

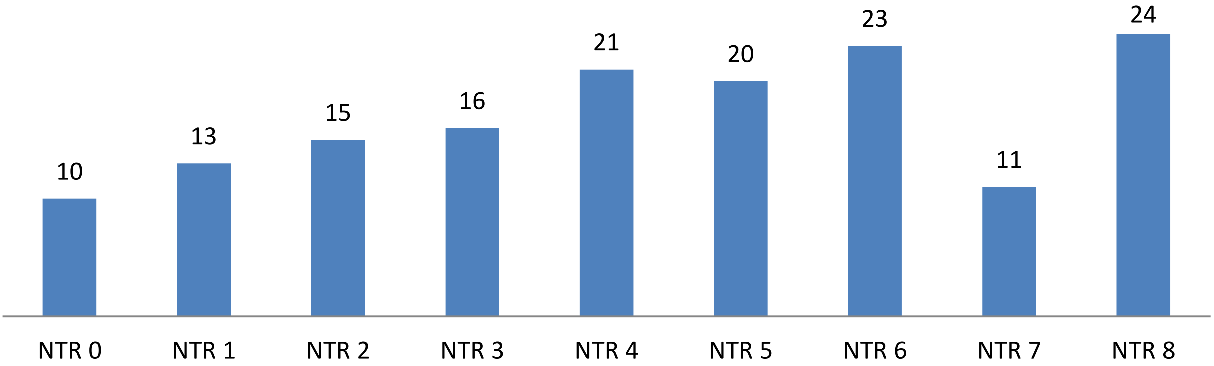
Distribution of sites per NTR – method 1 - illustration for GRTgaz for a range from 0 to 8



For the TIGF network, the distribution of sites per NTR could then be modified as follows:

Distribution of sites per NTR – method 1 - illustration for TIGF for a range from 0 to 8

This simulation for TIGF is based exclusively on distance to the main network, whereas the formula currently used by TIGF includes pipeline diameter as well as distance to the main network. TIGF is in the process of carrying out a new simulation that takes both distance and diameter into account.



Nevertheless, this method could lead to a very large number of changes to levels, upwards and downwards. According to the first estimates made by the TSOs, this method would lead to increasing the level of nearly one-third of sites on the GRTgaz network and of nearly half of the TIGF network sites, with some increases being significant (+5 levels). There is therefore an acceptability problem with this method and it also goes against the principle of keeping the regulatory framework stable: sites that chose to connect to the transmission network did so knowing their level so they are entitled to enjoy some stability of this factor. Consequently, at this stage, the CRE is not in favour of this first method for revising the regional tariff levels.

- **Method 2: Simply limiting the number of regional tariff levels to 8 or 12**

This method involves changing the maximum level value, currently 29 on the GRTgaz network and 15 on the TIGF network, and reducing it to 8 (or 12). All sites with a level above this new limit would get a level equal to this limit.

If this limit was set at 8, the level of 18% of GRTgaz network customers would fall as well as 11% of TIGF network customers. Fixing the maximum level at 8 would lead to a shortfall to make up of €39M for GRTgaz and €2.5M for TIGF. This would need to be offset by increasing the regional capacity termby 5.1% on the GRTgaz network and 3.0% on the TIGF network.

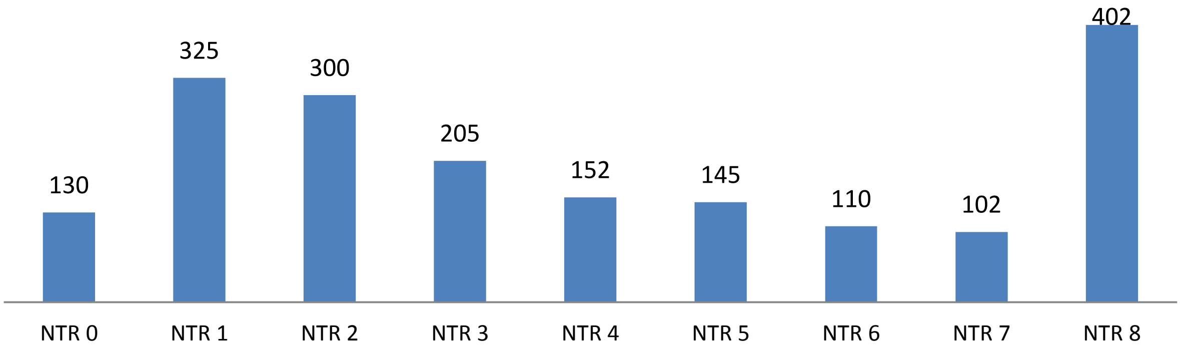
This method ensures continuity with the existing system, by keeping most historic levels, except for those above 8, which would then be allocated a level of 8. However, by keeping the levels of 8 and under unchanged, this method would not correct some anomalies noticed. These anomalies are mostly related to changes to the main network: the levels of some sites are not fully correlated to their distance to the main network.

Moreover, having 8 levels would lead all sites with a NTR of 8 or under to see their regional capacity term increased whereas none of these sites would benefit from any reduction in their NTR.

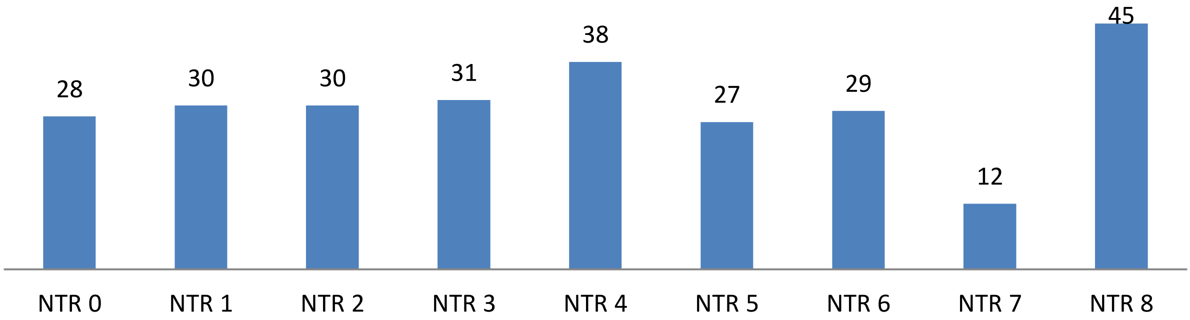
Finally, this method removes any correlation to distance for sites with a NTR of more than 8.

For these reasons, at this stage, the CRE is not in favour of this second method.

Distribution of sites per NTR – method 2 - illustration for GRTgaz with 8 levels



Distribution of sites per NTR – method 2 - illustration for TIGF with 8 levels



- **Method 3: new calculation of all regional tariff levels on the basis of distance to the main network, with no levels rising**

This last method, like the first, is based on calculating a new NTR for each site (between 0 and 8 or between 0 and 12) defined according to the distance to the main network, and to diameter for TIGF. The NTR allocated to the site would be the lower of the newly calculated NTR and the historicNTR. Using this method would not lead to a higher NTR for any site.

Method 3 takes into account the investments made on the main network which improved access to the main network for some sites. It offers the advantage of establishing a more consistent regional tariff level system which is better correlated to the distance to the main network than the current system, without leading to increases in levels, unlike method 1. It means that sites that have invested based on having a low level avoid being subject to a substantial increase, due to changes in the network structure (e.g. reclassification of pipelines from main network to regional network).

For the same maximum NTR, method 3 would reduce the NTR of more sites than does method 2.

This method could be done with a maximum NTR of 8 or 12:

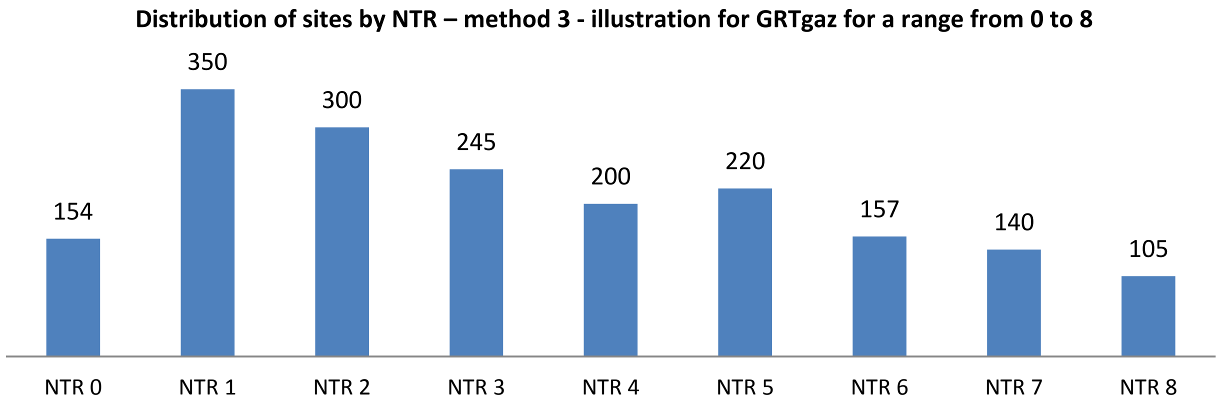
- with a maximum NTR of 8, approximately 33% of GRTgaz sites would see their NTR go down;
- with a maximum NTR of 12, approximately 27% of GRTgaz sites would see a fall in their NTR.

The third method leads to a loss of income for TSOs, which must be compensated by increasing the regional capacity term. For the same maximum NTR, the rise in regional capacity term is higher than that caused by method 2 and therefore depends on the parameters proposed by the TSOs:

- with a maximum NTR of 8, the loss of turnover would be around €83M for GRTgaz, leading to a regional capacity term increase for GRTgaz of approximately 11%;
- with a maximum NTR of 12, the loss of turnover would be around €58M for GRTgaz, leading to a regional capacity term increase for GRTgaz of approximately 8%.

These estimates are the results of preliminary studies carried out by GRTgaz and will need to be refined further. The simulation of this new calculation with no NTR rises is currently being carried out for the TIGF network; this simulation is more complex because the current formula used by TIGF includes pipeline

diameters as well as distance to the main network. In all cases, if method 3 is implemented, the CRE will ensure that the rise in the regional capacity charge is reasonable.
At this stage, the CRE has a preference for method 3.



Question 28 Do you agree with the CRE's preference for method 3 "new calculation of all regional tariff levels on the basis of distance to the main network and pipeline diameter for TIGF, with no levels rising?

Question 29 Would you prefer the maximum NTR to be 8 or 12?

Question 30 Do you have any other comments concerning the proposed review of regional tariff levels?

2.2. Transfer of certain charges relating to transmission network connection facilities, currently invoiced to DSOs, to the charge for delivery capacity to transport distribution interface points included in the gas transmission tariffs

2.2.1. Presentation of the provisions in the DSO connection contract

When a natural gas DSO connects to the natural gas transmission network, an interface contract is entered into between the two operators. The stations and connections are owned by the TSOs. Contracts currently in force require the distributors to pay the costs incurred by transporters for repairs, replacements and renewals of delivery stations and the associated costs for the upkeep of the connections to the transport distribution interface points. These costs, known as 3R costs, are currently covered by the distributors' tariffs.

2.2.2. Taking account of the transfer of these costs in the ATRD5 tariff

The deliberation of 18 February 2016 on a draft decision on the equalised access tariff for the GRDF public natural gas distribution networks, proposes transferring the 3R costs, currently paid by GRDF, into the ATRT tariffs as of 1 January 2017, amounting to €15M per year for GRTgaz and €4M per year for TIGF.

- Scope of the transferred costs

The transfer refers to corrective maintenance costs (repair and replacement) and upgrade costs (renewal) of existing and future public distribution stations. These costs also include the operating costs of the connections as well as the upkeep, maintenance and partial renewal of the stations' utilities, civil engineering and environment, and electricity and telecommunications consumption.

- Sites concerned

The transfer of the 3R costs applies only to stations at the interface between the transmission and distribution networks. The purpose of the transfer is to enable better cost control between the two regulated operators. In return for transferring the 3R costs to the ATRT tariff, the ATRD tariff will be reduced proportionally: in all cases, as the DSOs historically have passed on these charges to their end customers, the transfer is cost neutral for the latter.

2.2.3. Impact on tariffs

In order to cover the 3R costs transferred, at this stage, the CRE proposes increasing the delivery capacity term to GRTgaz and TIGF's transport distribution interface points to make up the shortfall.

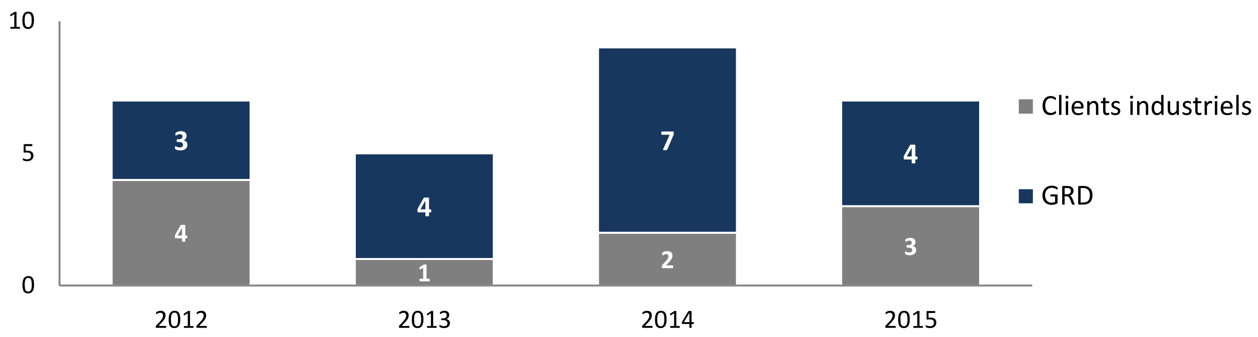
The impact of this transfer is 15% of the delivery capacity term for transport distribution interface points in the GRTgaz network and 39% for the TIGF network. The lower rise for GRTgaz can be explained in particular by the fact that some of the current maintenance of delivery stations is already covered by the GRTgaz tariff.

Question 31 Are you in favour of passing on the transfer of the 3R costs to the delivery capacity term to transport distribution interface points?

2.3. Changing the distribution of costs for new connections and for adaptations of existing stations

There have not been many connections to the gas transmission network in the last few years - in the order of two per year in France. Apart from the economic situation, one reason is the cost of investing in connection facilities.

Number of new projects – connections or adaptations of stations related to an increase of flows, for GRTgaz.



Currently, customers pay the TSOs for the cost of connection facilities, connection and stations, in return for these facilities being made available by the TSOs. If a station's flow is increased, the TSOs will adapt[30] it, at the customer's expense.

To make it easier to connect new customers or increase contracts by adapting existing stations, the TSOs propose to reduce the cost of the connection facilities paid by the customer, by making all consumers bear a part of the connection costs through the transmission tariff.

The TSOs' proposals came out of work carried out in Concertation Gaz.

2.3.1. Calculation principle

- GRTgaz's proposal

GRTgaz proposes that for each new connection or station adaptation, the customer is granted a "development discount". It would be calculated so that its cost for the tariff is made cost-effective, thanks to the transmission and connection revenue collected over a 10-year period, a mechanism similar to that used by DSOs for connections on their network.

[30] Adapting a station involves changing its technical features to increase its flow. This must not be confused with replacing a station, in the event of material defects, or renewing a station, in the event of obsolescence: replacement and renewal are done keeping the same flow.

During feasibility studies, GRTgaz will determine:

- the investment cost (I) required to build or adapt the connection and the delivery station;
- the transmission revenue (R) generated by the new customer over ten years, discounted at the GRTgaz WACC (main network exit tariff, tariff on the regional network and delivery tariff).

The development discount is equal to R, unless R > I. In this case, the discount is limited to the investment cost. The customer will therefore pay the higher of 0 and I-R for its connection.

The financial participation of the party requesting the connection is calculated so that the future additional transmission revenue that it will pay will be used to reduce the transmission tariff for network users, from the first year after the new project is put into service. The sum of the transmission revenue and connection revenue, even if reduced by the development discount, will be greater, each year, than the capital expenditure incurred for the connection or adaptation concerned.

- TIGF's proposal

TIGF proposes that the transmission tariff should cover 60% of the investment costs for the connection or station reinforcement, the remaining 40% being paid by the customers.
TIGF proposes reducing the proportion of the discount granted to the customer from 60% to 0%, according to the rate of return of the project over ten years.

2.3.2. Beneficiaries

The TSOs propose that the development discount could be offered to all the TSOs' customers.

2.3.3. Counterparties

- For industrial customers

In return for the discount, the TSOs propose that customers should sign a future capacity booking contract in which they undertake to book or get others to book the capacity used for to calculate the profitability period of its connection facilities (ten years maximum).

In addition, the TSOs propose that industrial customers should undertake to pay the 3R costs in the form of a fee.

- For public distribution networks

As DSOs' connections have different features from those of industrial consumers, the terms and conditions for applying the development discount must be adapted. Applying the TSOs' proposed scheme to DSOs poses two problems:

- as DSOs are not responsible for booking capacity, the TSOs cannot require future capacity booking contracts to be signed. In order to make booking capacity at transport distribution interface points secure, one option would be to ask industrial customers connected to the distribution network to make undertakings about their future consumption;
- for new supplies, and to a lesser extent for capacity increases of existing supplies, capacity is booked more gradually and is more uncertain than for an industrial site.

The TSOs therefore propose adapting the consideration in order to ensure the project's long-term profitability.

- In the case of new public service concessions, DSOs put together their response to calls for tenders based on consumption hypotheses. These have an impact on the DSO's investment decisions and choices. These hypotheses may be shared with the TSO and used as the basis for calculating the development discount.
- If a station is adapted for the benefit of a customer with a substantial flow, which wishes to be connected to an existing public distribution network, the DSO calculates a rate of return, as established by the decree of 28 July 2008 setting the reference rate for the profitability of gas supply

operations[31]. The DSO might share the expected profits used to calculate this rate of return with the TSO.

- In order to encourage DSOs to secure future consumption as much as possible by asking for consumption commitments from industrial sites connected to their network (new ones or those increasing their consumption), TSOs could apply a factor taking into account consumption to calculate different development discounts depending on whether or not customers have signed a consumption commitment.

In addition, GRTgaz proposes adapting the return on investment period by calculating profitability over 15 years instead of 10 years.

2.3.4. Special cases

- Development of existing facilities

The TSOs wish to prevent customers that wish to receive the “development discount” from leaving the distribution network to connect to the transmission network without increasing the amount of capacity that they book. This risk is limited by Article L.453-1 of the Energy Code, which specifies that all connections should be made as a priority on the distribution network unless the proposed consumption volume does not permit this. In this case, connection to the transmission network requires the DSO’s agreement.

GRTgaz therefore proposes that, if a site that is already connected to a distribution network wishes to be connected to the transmission network, with an increase in its capacities, only the increase will be used to calculate the discount, after the hypotheses have been validated by the DSO concerned.

- Connection or station reinforcement requiring an reinforcement of the transmission network

Currently, the costs of enhancing the transmission network to increase the flow of a branch are borne by all the customers connected to the transmission network. Putting a development discount in place should increase the number of connections, which could lead to costs rising for all the existing customers if network reinforcements are required.

To limit the costs for the local authority, the TSOs propose including the additional cost associated with enhancing the network in the calculation of the development discount, proportional to the customer’s needs. Thus, the investment cost (I) used to calculate the customer’s return on investment period (n=I/R) would be made up of the cost of the connection facilities plus the reinforcement cost, prorated to the customer's needs.

If the discount thus calculated is less than the prorated network reinforcement costs, then the customer will pay for all its connection facilities, as happens currently. The customer will not benefit from the “development discount”, but neither will it be charged for the reinforcement.

- Connection or station reinforcement requiring an expansion of the transmission network

Finally, in the rare cases of network expansions, for which at least two customers are connected to the same facilities, regional network expansions are currently paid for by increasing the regional tariff level.

The revision of the regional tariff levels proposed by the CRE would lead, whichever method is chosen, to a maximum level being put in place, set at 8 or 12 (see section 3.1). Thus, an expansion of the regional network could not lead to the level rising above this maximum value.

The TSOs propose that the portion of the costs associated with the expansion not covered by the level increase should be treated like a connection: these costs would be paid by the customers proportional to their capacities. In this case, the development discount calculation would include the cost of the expansion, prorated to the customer's needs.

2.3.5. The CRE’s preliminary analysis

- The creation of a “development discount” is part of the promotion of gas connections

As indicated in section 1 of this consultation, the current economic situation does not encourage increases

[31] Decree of 28 July 2008 setting the reference rate for the profitability of gas supply operations referred to in Article 36 of Law No. 2006-1537 of 7 December 2006 on the energy sector

in capacity bookings on the gas transmission network. In such a context, any tariff increase has to be borne by a constant or decreasing number of consumers. The TSOs' proposal would encourage connections to the transmission network and increased bookings from existing customers.

- The mechanisms proposed by the TSOs do not lead to a long-term tariff rise

The TSOs' proposal would admittedly lead to a fall in the connection revenue generated by each new project. However, the additional transmission revenue, linked to the increase in contracted capacities, will make it possible to reduce the transmission tariff for all existing customers. The calculation proposed by the TSOs guarantees a positive effect from the first year of the connection or station adaptation.

- The mechanisms proposed by the TSOs will lead to pooling up to all the connection costs of the ATRT tariff

The TSOs' proposal means pooling some or all of the costs of the connection facilities in the transmission tariff. The mechanism proposed by GRTgaz would mean that the cost of a customer's connection facilities is fully paid by the network users, up to a maximum of 10 years' expected tariff revenue.

This level of support may seem excessive. It could be limited to 50% of the connection or station adaptation cost, limited to 10 years' expected tariff revenue. Alternatively, a minimum lump sum could be left to be paid by the customer, as happens for distribution.

- The TSOs must ensure that the considerations requested from the customers are robust enough

The CRE is in favour for the "development discount", if it's adopted, to be offered to all customers.
The contractual framework must nevertheless be specified to enable public distribution networks to benefit from this discount while providing TSOs with the guarantees required to make the discount cost-effective in the long term.

At this stage, the CRE is in favour of the principle of the connection discount proposed by the TSOs. It proposes a scheme that would be limited to 50% of the connection costs and to 10 years' expected routing revenue.

Question 32 Are you in favour of creating a "development discount" aimed at reducing the cost of new connections and adaptations of existing stations?

Question 33 Are you in favour of the terms and conditions proposed by the TSOs for calculating and applying such a "development discount"?

3. Structural changes related to interconnection capacities

3.1. Creation of a virtual interconnection point for France-Belgium at Alveringem

Since the Alveringem network interconnection point was put into service on 1 November 2015, there have been two network interconnection points between France (PEG North) and Belgium (Zeebrugge Trading Point - ZTP): Alveringem and Taisnières H.

In 2015, GRTgaz and Fluxys began a joint project to create a single virtual interconnection point between PEG North and ZTP. From the end of 2017, this virtual interconnection point should enable shippers to buy their capacities from a single point (instead of two points as happens currently: Taisnières H and Alveringem) and to nominate at a single point (instead of three currently: Quévy, Blarégnies and Alveringem).

This change responds to a provision of the CAM Network Code, which specifies that when two contractual points co-exist, the possibility of setting up a virtual interconnection point at each interconnection should be studied. The study in progress should enable GRTgaz to make sure that a virtual interconnection point would not lead to a reduction in the capacities made available to the market.

At first analysis, the CRE is in favour of this change that will make it possible to buy and nominate capacities at a single point. It is asking GRTgaz to specify the impact that setting up a virtual interconnection point will have on the capacities made available to the market.

Question 34 Are you in favour of setting up a virtual interconnection point between France and Belgium?

3.2. Setting up France-Germany capacities at Obergailbach

3.2.1. GRTgaz's proposal

Currently, gas cannot be physically brought from France to Germany because of different odorisation practices, decentralised in Germany and centralised in France.

As well as the 150 GWh/d of backhaul capacities currently offered at the Obergailbach network interconnection point from France to Germany, GRTgaz proposes to offer 35 GWh/d of firm monthly capacities as of 1 April 2017.

This initiative is part of the European market gas target model, validated at the Madrid forum in March 2012, which advocates the reversibility of marketplace interconnections. It also aims to test market interest in firm capacity from France to Germany.

These new monthly firm capacities will be developed without any infrastructure investment, relying on the existence of a dominant flow from Germany to France.

These new capacities would be offered by GRTgaz, for the coming month, only when the expected flows from Germany to France are sufficient to operate a contractual flow. To guarantee the transmission of 35 GWh/d of firm capacity, the TSO proposes to put in place a system to hedge the risk of insufficient physical flow from Germany to France, which could be based on an agreement with storage facility operators on either side of the border. The occurrence of such a configuration is very low, however: 16 days in the last seven years.

GRTgaz proposes that these 35 GWh/d of France-Germany capacities should be auctioned on PRISMA. The proposed reserve price would be 40% of the Germany to France tariff, or twice the backhaul capacity tariff. As firm capacity has a higher priority than backhaul capacity, which is by nature interruptible, GRTgaz proposes to study the option, without obligation, for current holders of backhaul capacity to take part in the auctions and to pay only the difference between the award price on a given day and the regulated backhaul tariff.

3.2.2. The CRE's preliminary analysis

In the public consultation on the ATRT5 tariff update as of 1 April 2016, the CRE presented a proposal from GRTgaz, which wished to market 20 GWh/d of daily firm capacity.

The CRE did not accept this proposal as it considered that there was no immediate need and that it was a structural change that should be studied in the context of ATRT6.

At this stage, the CRE considers that selling monthly firm capacity is of greater interest than selling daily capacity. Unlike backhaul, which is by nature interruptible, the new monthly firm capacity would guarantee its holders a constant flow over a period long enough, for example, to unload an LNG cargo. In addition, this capacity would make it possible to set up trading strategies between PEG North and NCG (NetConnect Germany virtual trading post), in order to bring the prices of the two marketplaces closer together and increase the attractiveness of the French market.

At this stage, the CRE is therefore in favour of creating 35 GWh/d of monthly firm capacities from France to Germany. However, it would like GRTgaz to specify the cost of the system to hedge the risk of insufficient physical flow from Germany to France.

Question 35 Are you in favour of creating 35 GWh/d of firm capacity at Obergailbach from France to Germany?

Question 36 Do you have any comment or evolution suggestion regarding the ATRT6 tariff?

III. The ATTM5 tariff

A. Schedule

As it prepares the ATTM5 tariff (LNG terminal third-party access tariff), in order to respond to the need for visibility expressed by market players, the CRE is planning to launch two public consultations:

- this consultation on the general regulatory framework for the ATTM tariffs and the main proposed changes to the tariff structure;
- a second public consultation in the summer of 2016, in which the CRE will set out its proposals for changing the regulatory framework, the tariff structure and level of ATTM5, taking account of the feedback received from this first consultation and from the Concertation GNL working group. This second consultation will examine experiments in progress, the "pooling" service, evaporation recovery at the Montoir terminal, transshipment at Fos Cavaou and send-out flexibility at Montoir, with the aim of deciding whether or not they can be sustainable.

The CRE proposes to issue a deliberation giving a decision on the LNG terminal access tariff, after receiving an opinion from the French Higher Energy Council, at the end of 2016, with a view to the ATTM5 tariff coming into force as of 1 April 2017.

Question 37 Do you have any comments about the programme of work and schedule proposed by the CRE for developing the ATTM5 tariff?

B. Tariff regulatory framework

1. General framework

1.1. General assessment of the ATTM regulatory framework

The ATTM4 tariff period set a stable regulatory framework for a period of approximately four years as of 1 April 2013:

- individual tariffs for each terminal, to take account of the costs and specific features of each of these facilities;
- asset remuneration conditions with, in particular, a weighted average capital cost (WACC) set at 6.5%, increased by a specific premium of 200 base points to take account of the risks inherent to the LNG business;
- the Elengy and Fosmax LNG tariff trajectories were set for four years. Capacity contract and energy cost hypotheses were updated halfway through the tariff period (1 April 2015) for the Montoir and Fos Cavaou terminals. For the Fos Tonkin terminal, this update took account of bookings for the terminal stopping after 2020;
- a retrospective expenses and revenues clawback account for certain expenses and revenues (CRCP);
- an incentive system for additional regasification capacity contracts, enabling operators to keep 25% of the additional revenue related to the new contracts, 75% of the revenue being covered by the CRCP;
- an obligation to pay for 100% of contracted capacities ("ship or pay");
- a review clause halfway through the tariff period, aimed at taking account in the net operating cost trajectories of Elengy and Fosmax LNG of any consequences of legislative, regulatory, judicial or quasi-judicial changes.

The mechanisms put in place for ATTM4 worked as expected:

- calculating the balance of the CRCP, at the start of ATTM4 and at its update point, made it possible to refund to users of the regulated terminals the variances observed compared with the tariff forecasts (related to energy costs being lower than forecast and to additional revenue related to contracts);
- the review clause was not activated.

The following changes to terminal operators' authorised revenue have been made since 2006:

	Elengy (Fos Tonkin and Montoir terminals)		**Fosmax LNG (Fos Cavaou terminal)**	
	Authorised revenue (M€) *As of 1 January until 2012, as of 1 April since 2013*	Change of authorised revenue	Authorised revenue (M€) *As of 1 January until 2012, as of 1 April since 2013*	Change of authorised revenue
2006	140.7	-	140.7	
2007				
2008				
2009				
2010	147.0	+4.5%	150.1	-
2011	155.7	+5.9%	149.5	-0.4%
2012	161.9	+4.0%	154.7	+3.5%
2013	161.04	-0.5%	157.72	+2.0%
2014	165.97	+3.1%	157.85	+0.1%
2015	157.27	-5.2%	151.67	-3.9%
2016	158.06	+0.5%	153.18	+1.0%

1.2. Guidelines for the ATTM5 period regulatory framework

The CRE believes that the regulatory framework put in place for the ATTM4 tariff was effective. Consequently, for ATTM5, it proposes reusing the rules used for ATTM4. The ATTM5 tariff regulatory framework is thus likely to be based on the following rules:

- individual tariffs for each terminal, to take account of the costs and specific features of each of these facilities;
- a multi-year tariff intended to apply for a period of approximately four years from 1 April 2017, with a planned change, as of 1 April 2019, of each operator's schedule of tariffs, on the basis of the predefined rules;
- an obligation to pay for 100% of contracted capacities ("ship or pay");
- an expenses and revenues clawback account (CRCP), used, for certain accounts items identified in advance, to correct all or some of the variances between actual expenditure and income figures on the one hand and the forecast expenditure and income figures used to establish the operators' tariffs on the other;
- a review clause that can be activated after the tariff has been in use for two years, aimed at taking account, if appropriate, in the net operating cost trajectories covered by ATTM5, of any consequences of legislative or regulatory changes or judicial or quasi-judicial decisions for the period after this review clause is implemented.

This regulatory framework aims to encourage operators to improve their effectiveness, while minimising their risks related, in particular, to legislative and regulatory changes that might affect their business activity. It also aims to give market players sufficient visibility to put together medium and long-term supply strategies.

Question 38	Are you in favour of the regulatory framework proposed by the CRE for the ATTM5 period?

2. Tariff structure

Since the Fukushima accident, the usage rate of French LNG terminals has fallen. From nearly 160 TWh in 2011, LNG arrivals in France have fallen to approximately 60 TWh in 2015, which represents a usage rate of 25%.

In the light of these falling usage rates, the Montoir, Fos Tonkin and Fos Cavaou terminals have developed their commercial offer in order to offer complementary services to the main function of an LNG terminal, which is to regasify the LNG that it receives before injecting it into the downstream transmission network. These new services, in particular reloading, transshipment and truck loading, are aimed at strengthening the attractiveness of the terminals, by enabling shippers to enjoy a diversified offer in a context of major opportunities for international arbitrage of LNG cargo destinations. Use of these complementary services is rising: nearly 2,000 truck loading operations, more than 15 reloading operations and one transshipment were carried out during the two financial years, 2014 and 2015, at French terminals.

During the same period, gas liquefaction capacities have increased globally (in the United States, Australia, etc.) and demand has stabilised, especially in Asia, and this could lead to LNG returning to Europe during the ATTM5 tariff period.

In France, when the exempted Dunkirk terminal comes into service during 2016, regasification capacity will increase to 34 billion m^3/year (~370 TWh). In addition, beyond 2016, more than 16 TWh per year and more than 9 TWh per year are still available to be booked, on a first come, first served principle, at Montoir and Fos Cavaou terminals.

In view of the low usage rates in recent years and in order to attract new users in a context that might be more favourable to LNG imports, the CRE believes that it is desirable to increase the appeal of the offer from the regulated LNG terminals. To do this, the existing regasification services must be made more transparent and adapted to market needs, by offering more flexibility to the terminals' users not only for unloading operations but also for reloading, transshipment and truck loading operations, and by improving transparency when publishing the terminal operators' operational schedule.

2.1. Changes to regasification services

Under the ATTM4 tariff, the regulated LNG terminals offer three regasification services:

2.1.1. "Continuous" Service

The S-Smart continuous send-out service is for users that schedule more than one boat per month on average across the year. For this service, the daily send-out is set by the terminal operator in order to be as regular as possible, on the basis of the terminal's overall send-out schedule. This service can be booked from the first unloading.

The continuous service, which enables uninterrupted send-out to the transmission network for users that bring in cargoes on a regular basis, is intended to be the basic service offered by each terminal. It is currently the most booked service, by long-term users in particular.

2.1.2. "Band" Service

The S-30 band service is for users that schedule less than one boat per month on average across the year and which book a total annual capacity of less than 12 TWh for this service. In addition, for the Montoir and

Fos Tonkin terminals, the sum of the regasification capacities contracted, for each month, by all the S-30 service users, may not be higher than one-third of the terminal's total monthly capacity.

The send-out of a cargo using the band service is done with a constant send-out over 30 days. In addition, the CRE's deliberation of 17 December 2014 requires Elengy and Fosmax LNG to offer users of the regulated terminals that wish it, as of 1 April 2015 and temporarily until a single title transfer point is created:

- the option of sending out on the gas transmission network in a band with a duration of 20 to 30 days;
- for Fos terminal users, an interruptible service enabling them to send out on the gas transmission network in a band with a duration of 20 to 60 days. The send-out service with a band of 40 to 60 days can be offered only if it will have a low impact on send-outs by other users of the Fos terminals.

The tariff conditions applied to band service bookings are the same as those applied for the continuous service, except for the regularity charge, which is 10% only of the charge applied for continuous service bookings.

Despite these provisions, we note that there are no longer any bookings for this service.

2.1.3. "Spot" Service

The S-Spot "spot" service is reserved for unloading operations booked, for a given month M, after the 20th day of month M-1. Booking is done on the basis of the available capacities in the monthly schedule at the booking date.

The send-out profile of users that have booked the spot service tends to be for a band of 30 days as of the unloading end date, provided that the send-outs planned for other users in the monthly schedule do not change by more than 10% each day.

The tariff charged related to unloaded quantity is reduced by 25% for spot service bookings. The other charges applied to spot service bookings are the same as those applied for the continuous and band services. No regularity charge is applied to spot bookings.

2.1.4. Services evolution

Despite the fact that the continuous service is the basic service offered by the LNG terminals, the send-out provided by the operators for the users of this service may be greatly affected by the arrival of a band or spot cargo. Even if the terminal operator makes every effort to ensure a continuous service user the most regular send-out possible, it may be "distorted" in the event of the arrival of band or spot cargoes.

In addition, the coexistence of these three services in the regulated terminals' current offer creates constraints for the only service currently booked, the continuous service. Even though the band and spot services have not been booked for several years, the operators impose constraints on continuous service users so that they are able to accommodate any new band or spot bookings. This therefore reduces the visibility and flexibility of the continuous service users, even though they are currently the only ones that bear the terminal's costs via the regulated tariff.

During the LNG consultation, some players therefore considered that these services were no longer adapted to market needs. They want to see changes to the services offered by the regulated LNG terminals in order to standardise services for all those booking capacities and to give back more flexibility to those booking the continuous service. On these grounds, some players are proposing the removal of the band service. The long-term "continuous" service capacities could then be promoted more and could attract more users or even be sold on the secondary market.

The CRE takes note of this request from those who took part in the LNG consultation. It underlines that the LNG consultation participants are users that hold long-term capacities in the regulated LNG terminals and that, on this basis, they represent only a proportion of the potential users of the terminals. At this stage, it is not opposed to changing the services the operators offer but it will be vigilant to ensure that any new players wishing to book capacities in one of the regulated terminals can do so without discrimination. Therefore it wishes to gather opinions from all interested market players.

Question 39	Do you believe that the services currently offered by regulated LNG terminals are likely to attract new users? What changes to the offer would you propose?

2.2. Upstream/downstream arbitrage

Each LNG terminal has limited flexibility due to the features of its infrastructure, especially the limited capacity of the storage tanks.

During the consultation the terminal operators underlined the fact that it is not possible to have flexibility upstream (ship schedules, cancellations and rescheduling) and downstream (send-out into the transmission network) at the same time. Substantial flexibility for users on ship arrival dates leads to less flexibility for the send-out that they can be granted. Conversely, significant flexibility on send-out (which also requires users to store their LNG in tanks for a longer period) means that, for operational reasons, the upstream flexibility given to users has to be reduced.

Currently, terminal users have great upstream flexibility, i.e. on the choice of ship arrival dates, on rescheduling for different time intervals and on cargo sizes. This is to the detriment of downstream flexibility: shippers have less flexibility on send-outs. Thus, for example, a shipper that announces late the arrival of a ship has a good chance of being accepted by the terminal but that will lead to high send-out peaks for all shippers in order to free up the space required in the terminal's LNG storage tanks.

Question 40	As a user or potential user of the terminals, do you consider relevant to continue to favour upstream rather than downstream flexibility?

2.3. Changes to scheduling

Currently, during the fourth quarter of each year, each user of the regulated LNG terminals sends an annual schedule request to Elengy and Fosmax LNG, in order to plan its unloading operations for the next calendar year.

Reloading and transshipment operations cannot currently be booked when the annual schedules are drawn up. As part of the LNG consultation, some players stated that they would like to be able to book such operations at the time the annual schedule is drawn up. They also expressed the need for visibility of all the services proposed by the regulated terminals.

The CRE believes that responding to users' expectations, by giving the more visibility over all operations, would let Elengy and Fosmax LNG increase their revenue and thus limit the cost of the operations. With the aim of supply security, however, the CRE believes that, if there is a supply crisis, each terminal should be able to achieve its maximum capacity of injection into the French transmission network. It therefore asks the operators to reserve, in each terminal, an adequate number of unloading slots to be able to achieve this maximum if needed. The difference between the total number of slots that can be scheduled and the number of slots reserved for unloading could thus be made available for reloading and transshipment operations when drawing up the annual schedule, each reloading booking giving rise to the systematic booking of a loading operation outside the slots reserved for unloading.

Question 41	Do you think that it would be relevant to allow operations other than unloading to be booked when the annual schedule is drawn up? Under what conditions?

2.4. Developing truck loading

LNG transport by road, using trucks, is being developed. In particular, it means that LNG can be supplied to industrial sites not connected to the gas transmission network and to LNG fuel distribution stations for vehicles or ships.

With the existing infrastructure, trucks can be loaded at the Fos Tonkin and Montoir terminals. Elengy has offered an LNG truck loading service since 2013 at Montoir and since 2014 at Fos Tonkin. Montoir terminal has the capacity to accommodate 70 trucks a week and Fos Tonkin can accommodate 22. In 2015, more than 1,500 truck loading operations were carried out at the Elengy terminals.

The truck loading service is one of the terminals' complementary services. In its tariff deliberation of 13 December 2012, the CRE said that the operators should be free to set the cost of supplying this service and that they should invoice this activity separately. The CRE will carry out an assessment of this service and will check its strict neutrality for the regasification activity.

The CRE is in favour of each shipper that unloads LNG at a regulated terminal having access to a truck loading service. It therefore proposes asking the operators of the regulated LNG terminals to set up a mechanism so that users of the Fos Cavaou terminal can have access to loading trucks by using the Fos Tonkin terminal's infrastructure.

Nevertheless, the CRE is not in favour of shippers without any LNG in tanks being able to load trucks via a backhaul from the LNG terminal interface point, which would enable the virtual transformation of gaseous gas into LNG. These shippers have the option of buying LNG in tanks from a third party in order to access this service.

Question 42 What developments do you expect concerning truck loading and what changes could be put in place as part of ATTM5 in order to facilitate these developments?

2.5. Service quality for information published by operators

In its deliberation of 20 June 2013[32], the CRE asked Fosmax LNG and Elengy:

- to publish and update daily aggregated and anonymous data on unloading and loading operations and send-outs to the transmission network;
- to put in place a platform to be used for publishing insider information their users are likely to possess.

Then, in its deliberation of 5 February 2015, the CRE asked the operators to publish no later than the 10th day of month M-1 the aggregated schedules for unloading and reloading operations and send-outs for months M, M+1 and M+2. This publication must be updated daily for month M and each time a shipper's schedule is modified for months M+1 and M+2.

On initial analysis, the CRE observes that all the above data is published on the operators' websites. However, the CRE believes that the update frequencies of the various data do not comply with the CRE's requests.

In the same way as has been done for TSOs, the CRE proposes introducing service quality indicators on the availability of the operators' publication platforms and on the quality and regularity of the information published.

Question 43 Are you satisfied with the information published by the operators on their websites? Do you consider it relevant to monitor publications with service quality indicators?

Question 44 Do you have any other comments or suggestions for changes in the context of ATTM5?

[32] CRE deliberation of 20 June 2013 on the decision relating to the published information on the use of the LNG terminals

IV. Summary of questions

Question 1. Do you believe that the CRE has correctly understood the major issues affecting natural gas transmission tariffs between now and 2020?

Question 2. Do you have any comments on the programme of work and schedule proposed by the CRE for the ATRT6 tariffs?

Question 3. Are you in favour of continuing the calendar used for ATRT5 i.e. revising the transmission tariffs on 1 April of each year, accompanied by information concerning the changes in the tariffs at the interconnection points over the whole ATRT6 tariff period?

Question 4. Are you in favour of an annual rise in the ATRT6 tariffs on 1 April, and a one-off increase when the single marketplace is created, under the conditions proposed by the CRE?

Question 5. What is your opinion of the ATRT5 tariff? Are you in favour of the CRE's preliminary orientations for the regulatory framework for the ATRT6 period?

Question 6. According to you, does the non-renewal of the 300 basis points bonus for the period ATRT6 seem appropriate?

Question 7. Are you in favour of considering an incentive for encouraging GRTgaz and TIGF to manage the unit cost of their investments into the networks?

Question 8. Are you in favour of an incentive for encouraging GRTgaz and TIGF to manage their capital expenditure on non-network assets and the operating costs of those assets? What do you think of the mechanism proposed by the CRE?

Question 9. Do you have any other suggestions for how to change the incentive for GRTgaz and TIGF to invest?

Question 10. Are you in favour of introducing an incentive for GRTgaz and TIGF concerning their R&D expenditure, where any amounts allocated for R&D but not spent by the operators would be returned to users at the end of the tariff period?

Question 11. What do you think of an annual report of the operators' R&D projects each year?

Question 12. Are you in favour of continuing the incentive regulation mechanism for service quality?

Question 13. Are you in favour of removing three indicators concerning the deadlines for completing connections, the number of complaints and the delay for sending the files regarding withdrawals at transport distribution interface points to the DSOs?

Question 14. Are you in favour of introducing a financial incentive regarding the availability of the five most useful pieces of information for shippers balancing operations?

Question 15. Are you in favour of introducing a service quality indicator for the number of days on which actual technical capacity is less than the theoretical maximum firm capacity, or would you prefer to keep the current indicator with detailed results by point?

Question 16. Are you in favour of introducing a financial incentive for the availability of firm capacities? At what points along the GRTgaz and TIGF networks do you think a financial incentive would be most relevant?

Question 17. Are you in favour of introducing a financial incentive for non-binding maintenance forecasts?

Question 18. Would you like the existing incentive for selling capacities to be removed, or would you prefer for the amount of the income from capacity bookings covered by the clawback account to be increased to 80%?

Question 19. Are you in favour of equalising the GRTgaz and TIGF tariffs, under the conditions proposed by the CRE?

Question 20. Are you in favour of the CRE's position of aligning the way the TSOs' revenue is split between the upstream and downstream networks with the way the charges borne by these two network categories are split?

Question 21. Are you in favour of maintaining the TSOs' revenue stable between the main network entries and exits?

Question 22. Are you in favour of the CRE's proposed approach to reflect the transit costs to Italy and Spain?

Question 23. Are you in favour of allocating part of the costs for creating the single marketplace to the transmission network entry points or just on the exit of upstream network points?

Question 24. Are you in favour of changing of the tariffs at the transport storage interface points in the same proportion as the other main network entry and exit tariff conditions?

Question 25. Are you in favour of taking into account the impacts on tariffs at the time when the single marketplace is created or do you wish a gradual evolution?

Question 26. Are you in favour of overhauling the regional tariff levels?

Question 27. Are you in favour of the principles for overhauling the levels proposed by the CRE?

Question 28. Do you agree with the CRE's preference for method 3 "new calculation of all regional tariff levels on the basis of distance to the main network and pipeline diameter for TIGF, with no levels rising?

Question 29. Would you prefer the maximum NTR to be 8 or 12?

Question 30. Do you have any other comments concerning the proposed review of regional tariff levels?

Question 31. Are you in favour of passing on the transfer of the 3R costs to the delivery capacity term to transport distribution interface points?

Question 32. Are you in favour of creating a "development discount" aimed at reducing the cost of new connections and adaptations of existing stations?

Question 33. Are you in favour of the terms and conditions proposed by the TSOs for calculating and applying such a "development discount"?

Question 34. Are you in favour of setting up a virtual interconnection point between France and Belgium?

Question 35. Are you in favour of creating 35 GWh/d of firm capacity at Obergailbach from France to Germany?

Question 36. Do you have any comment or evolution suggestion regarding the ATRT6 tariff?

Question 37. Do you have any comments about the programme of work and schedule proposed by the CRE for developing the ATTM5 tariff?

Question 38. Are you in favour of the regulatory framework proposed by the CRE for the ATTM5 period?

Question 39. Do you believe that the services currently offered by regulated LNG terminals are likely to attract new users? What changes to the offer would you propose?

Question 40. As a user or potential user of the terminals, do you consider relevant to continue to favour upstream rather than downstream flexibility?

Question 41. Do you think that it would be relevant to allow operations other than unloading to be booked when the annual schedule is drawn up? Under what conditions?

Question 42. What developments do you expect concerning truck loading and what changes could be put in place as part of ATTM5 in order to facilitate these developments?

Question 43. Are you satisfied with the information published by the operators on their websites? Do you consider it relevant to monitor publications with service quality indicators?

Question 44. Do you have any other comments or suggestions for changes in the context of ATTM5?

The CRE would like to invite all parties involved to send their input by no later than 25 March 2016:

- by email to: dr.cp1@cre.fr;
- by post to: 15, rue Pasquier - F-75379 Paris Cedex 08.

The CRE will publish non-confidential contributions, subject to respecting privacy and confidentiality as required by law.

Please indicate in your response whether you wish your response to be considered as **confidential or anonymous**. Otherwise, your contribution will be considered not confidential and not anonymous. Interested parties are invited to send their observations justifying their positions.