COMMISSION DE RÉGULATION DE L'ÉNERGIE

DELIBERATION NO 2020-012

Deliberation by the French Energy Regulatory Commission of 23 January 2020 deciding on the tariffs for the use of GRTgaz's and Teréga's natural gas transmission networks

Translated from the French: only the original in French is authentic

Present: Jean-François CARENCO, Chairman, Christine CHAUVET, Catherine EDWIGE, Ivan FAUCHEUX, commissioners.

Articles L. 451-1 and L. 452-2 to L. 452-3 of the French energy code empower the French energy regulatory commission (CRE) to define the methodology for establishing the tariffs for the use of the natural gas transmission networks. CRE can make changes to the tariff levels and structure which it deems justified with regard to, in particular, an analysis of the operators' accounts and any expected changes in operating or investment expenses.

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

Due to the entry into effect of (EU) regulation 2017/460 establishing a network code on harmonised transmission tariff structures for gas (hereinafter "Tariff network code"), the ATRT6 tariff must be revised in 2019. Therefore, in accordance with the provisions of the Tariff network code, in particular its articles 26, 27 and 28, the ATRT6 tariff will cease to apply as from 31 March 2020. The ATRT7 tariff will apply as from 1 April 2020.

Given the need to provide visibility to market participants and the complexity of the issues to be addressed, CRE ran four public consultations:

- the first, launched on 14 February 2019, concerned the regulatory framework applicable to regulated infrastructure operators for the next generation of tariffs. 41 answers were received;
- the second, launched on 27 March 2019, aimed to collect interested parties' opinions on CRE's initial guidelines concerning the structure of the ATRT7 tariff and on the storage tariff charge. 66 answers were received;
- the third, dated 23 July 2019, concerned the conditions for injecting biomethane into the natural gas transmission and distribution networks. 43 answers were received;
- the fourth, launched on 23 July 2019, aimed to collect interested parties' opinions on all of the guidelines concerning the ATRT7 tariff. 91 answers were received.

The non-confidential responses to these four public consultations are published on CRE's website.

The present decision is based, in particular, on the tariff proposals of system operators as well as on the numerous exchanges with the latter, on internal analyses, on external auditors' reports[2] and on feedback from market participants in the different public consultations. CRE also held discussions with system operators, their shareholders,

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

[2] An audit of GRTgaz's and Teréga's proposal concerning operating expenses for the 2020-2023 period and an audit of GRTgaz's and Teréga's proposal regarding the remuneration rate for natural gas transmission system operators' regulated assets, both of which are published on CRE's website.

and organised on 7 November 2019, a round table with the main shippers and customers that answered to the last public consultation.

In addition, in accordance with the provisions of Article L.452-3 of the energy code, CRE's decision took into account the energy policy guidelines forwarded by the minister of state, minister of the ecological and inclusive transition by a letter dated 15 July 2019. These guidelines are published on CRE's website together with the present decision.

In compliance with the provisions of the Tariff network code, the consultation of 23 July 2019 was forwarded to the Agency for the Cooperation of European Regulators (ACER), which delivered its opinion on 4 December 2019. CRE took this opinion into account in its final decision, in compliance with the reflections it had itself started on this topic following market participants' feedback.

Main challenges

In addition to simplicity, foreseeability and continuity objectives, CRE considers that the ATRT7 tariff provides answers to the four main priority issues below:

1. Proper functioning of the wholesale gas market

Pricing of gas transmission networks, and more widely all of the rules for accessing these networks, play a major role in the proper functioning of the wholesale gas market.

2. Controlling the evolution of tariffs in a context marked by the expiration of certain long-term contracts and the end of major investment projects

A certain number of long-term entry and exit subscriptions at network interconnection points (PIRs) will reach the end of their term during the ATRT7 period. Since the actual level of use of the points concerned by these drops is currently lower than the level of capacity subscribed, the transmission system operators (TSOs) expect that a portion of the capacity newly available will not be booked upon the expiration of these commitments. Therefore, they anticipate drops in the capacity levels subscribed at all of GRTgaz's and Teréga's network interconnection points between 2019 and 2023.

In addition, the assessment made by CRE in its public consultation of 14 February 2019 shows that the gas system operators' operating expenses increased faster than inflation over the last ten years. This is due mainly to major network developments to support the opening of markets (interconnection development, network enhancement to create the single market zone) and to their total separation from their parent companies (e.g. operating systems, R&D activities, support functions which are no longer shared).

The creation of the single market zone in 2018 marked the end of this long cycle of investments. CRE considers that the size of the French transmission system is now sufficient. In addition, stagnation of gas consumption over the last ten years and its foreseeable development for 2030, particularly within the framework of energy transition objectives, lead CRE to be particularly vigilant in the future when examining any new investment project that may be submitted by the TSOs.

In this context, control of the gas TSOs' expenses is an essential issue. The ATRT7 tariff, which sets in particular the OPEX trajectories of the TSOs based on their performance in 2018, meets this challenge.

3. Supporting energy transition: enabling biomethane injection

The energy transition is a challenge for gas infrastructure operators, particularly with the development of biomethane injection into the networks, which requires certain adaptations to gas infrastructures.

The present ATRT7 tariff gives operators the means to conduct this transition, particularly regarding resources allocated to the reception of biomethane in the networks and to research and development.

4. Maintaining the gas transmission network at a maximum security level

Guaranteeing the security of people and property is a major issue for GRTgaz and Teréga.

The ATRT7 tariff gives TSOs the means to keep their infrastructures at a high security level, regarding for example cybersecurity or taking into account the ageing of physical networks. It also enables them to implement their network investment policy, which contributes to this objective.

Tariff level

The TSOs GRTgaz and Teréga each formulated a tariff development demand describing their predicted costs for the 2020-2023 period.

Consideration of the elements in the tariff dossiers addressed to CRE by GRTgaz and Teréga, after taking into account certain structure effects, would have led to a major increase in the average unit tariff by an average +4.6% per year for GRTgaz and an average +6.6% per year for Teréga over the entire tariff duration.

These proposals presented, in particular, a considerable increase in net operating expenses deemed excessive by CRE, while gas consumption is on a downward path and the size of the network is sufficient.

To make its decision, in addition to its own analyses, broad consultation of participants and exchanges with operators, CRE drew on external auditors' assessments. These assessments covered the following topics:

- an audit of GRTgaz's and Teréga's proposal concerning operating expenses for the 2020-2023 period;
- an audit of TSOs' proposal concerning the remuneration rate of regulated assets. GRTgaz and Teréga respectively request a weighted average cost of capital of 5.25% and 5.5% (real before tax), compared to 5.25% in the ATRT6 tariff, whereas the government has planned for a drop in corporate tax[3].

Following its analyses and additional discussions held with operators after the publication of the public consultation of 23 July 2019, CRE adopts a less significant increase than that requested by the TSOs.

It plans to limit the TSOs' increase in operating expenses, while leaving them with the financial leeway to maintain a high level of security and the ability to be in actor in the energy transition.

In particular, for GRTgaz, CRE adopted an operating expenses trajectory taking into account:

- stable headcount (excluding insourcing of resources concerning information systems), enabling the operator to meet new challenges (biomethane in particular), by redeploying its current resources because of the expiration of major network development projects, as well as its request concerning its wage policy;
- an increase in expenses related to the industrial system in order to face network ageing;
- an increase in IT-related resources to meet cybersecurity challenges;
- reinforcement of R&D, in particular concerning the arrival of new gas in the networks;
- a concrete response enabling development of biomethane (roughly €6 million/year on average over the ATRT7 period).

For Teréga, CRE adopted, in particular:

- additional resources for the successful transformation of the company by adapting information systems in particular, and taking into account recruitments already made in 2019;
- a wage policy equivalent to that of all other gas operators;
- a maintenance programme as requested by Teréga;
- reinforcement of R&D, in particular concerning the arrival of new gas in the networks.

The trajectory of net operating expenses set by CRE corresponds to an overall envelope. Therefore, the TSOs have the freedom to distribute this envelope among the different types of expenses as they choose.

Moreover, as a reminder, TSOs' "network" investments are covered by the tariff, based on completed work, fully through the expenses and revenues clawback account (CRCP), and TSOs are protected against inflation by the tariff.

CRE adopts a change in the weighted average cost of capital (WACC), which stands at 4.25% (real before tax). The method used to establish this rate is the same as that used for the ATRT6 tariff. It is based on a standard-structure WACC and guarantees reasonable remuneration of capital investment, maintaining the attractiveness of energy infrastructures in France, with regard to other European countries.

This level, down 1 point compared to the ATRT6 tariff, takes into account, with the same method as for the previous tariffs:

- the downward change in financing costs against a very significant and sustainable drop in interest rates in the markets;
- the planned decrease in corporate tax, which will drop from an average 34.43% to 28% over the tariff period;
- an increase in asset beta to reflect the consideration of an increased financial risk, particularly stranded costs, which places the burden of the energy transition on gas infrastructure shareholders.

The average level of costs to be covered over the ATRT7 period will total:

[3] Draft finance law for 2020

- an average €1,812 million/year for GRTgaz. Therefore, over the 2018-2023 period, it will increase by an average +0.6% per year, as a result of a +1.6% increase in operating expenses and an average -0.1% drop in capital expenses per year;
- an average €258 million/year for Teréga. Therefore, over the 2018-2023 period, it will increase by an average +1.8% per year, as a result of a +3.4% increase in operating expenses and an average +1.6% rise in capital expenses per year.

With regard to transmission capacity subscription assumptions, CRE globally adopts GRTgaz's and Teréga's requests, which lead to changes of -1.5%/year at GRTgaz's main network points, and -0.9% at its regional network points, and -2.1%/year at Teréga's main network points, and -0.4%/year at its regional network points, compared to 2019.

Therefore, the change in the ATRT7 unit tariff stands at an average +1.4% per year for GRTgaz and at +0.7% for Teréga. The difference with the tariff developments associated with the TSOs' request is mostly due to the WACC level envisaged, lower than that requested by the TSOs.

Tariff regulatory framework

For the ATRT7 tariff, CRE is maintaining the main incentive regulation mechanisms in effect, adjusting them when necessary: incentive regulation for the control of operating and investment expenses, incentive regulation for service quality, and *an ex post* coverage of certain differences through the CRCP account. CRE is eliminating the incentive for interconnection development.

In addition, for Teréga, CRE is implementing an experiment on a TOTEX-style (OPEX and CAPEX trajectory, total expenditure) incentive regulation within the scope of its IS expenses, as proposed by Teréga itself.

Main network tariff structure

The structure of the ATRT7 tariff is set so as to reflect the costs generated by users, particularly to avoid cross-subsidisation among user categories. In addition, CRE makes every effort to meet the requirements of the Tariff network code and to take into account ACER's opinion.

CRE has maintained a tariff grid globally building on that of the ATRT6 tariff, under which transit costs and national customer supply costs are aligned.

Nevertheless, following a study of responses to the public consultation and consideration of ACER's opinion, CRE furthered its work on flow scenarios to ensure that the flows adopted correspond to a physical reality. As a result, even though the Pirineos entry point is subscribed, it hardly serves to supply France. Therefore, CRE adopts in its decision, a re-balancing between the costs for transit use and for domestic use, resulting in a drop in the exit tariff charge at the Oltingue PIR (-6%) and the Pirineos PIR (-7%).

Regional network tariff structure

CRE has made changes to the pricing of domestic networks:

- elimination of the short-notice interruptible transmission (IAPC) offer;
- elimination of the delivery charge for highly modulated sites;
- elimination of the proximity charge;
- improvement in the progressivity of intra-annual tariffs.

Biomethane injection charge

Reaching biomethane network injection objectives (the draft decree relating to the multi-annual energy plan (PPE) submitted for consultation in January 2019 aims for 6 TWh of biogas injected into the natural gas networks for 2023 and sets an objective of 14 to 22 TWh by 2028) will require major investments in the gas transmission and distribution networks. CRE considers that the proper development of methanisation is a major issue for energy transition. Given the costs for adapting the networks, the development of biomethane must follow the principle of economic efficiency so that the cost is optimised for the community. However, biomethane project promoters' decision to invest must also be made within the context of visible and stable economic conditions surrounding injection into the networks.

Therefore, within the framework of the deliberation of 14 November 2019, CRE defined the terms for implementing the right to inject biomethane, as provided for by the Egalim law[4] and the decree of 28 June 2019[5]. These provisions bring visibility to project promoters concerning their connection conditions, and enable coverage by the tariff of network reinforcement costs within the framework of connection schemes optimised at the community level.

To complement these provisions, in particular regarding the coverage of the operating expenses associated with these investments, CRE considers that it is necessary to introduce an additional signal for project promoters so that they take into account the costs resulting from their choice of location. In that regard, it has introduced a tariff injection charge in the ATRT7 tariff (and the ATRD6 tariff), based on the definition of three injection charge levels, depending on the necessary adaptations planned in the connection zone. This charge ranges between €0 and €0.7/MWh injected.

Storage tariff charge

Since the reform of the regime for third-party access to underground natural gas storage infrastructure, in effect as of 1 January 2018, the difference between storage operators' allowed revenue and the income they receive directly, particularly through auctioning their capacity, is offset via the ATRT tariff, by a specific charge referred to as the storage tariff charge. This storage tariff charge currently applies to clients not subject to load shedding and interruptions connected to the public gas distribution networks, depending on their winter modulation.

CRE has modified the formula for calculating winter modulation for "subscription-based" clients to a formula based on the difference between the average winter consumption and the annual average consumption of these clients. Although these clients consume more on average in winter than in summer, they contribute differently to peak consumption compared to profile-based clients: their peak consumption is mainly related to business processes and does not necessarily occur at the same time as peak winter consumption, which is more related to the thermosensitivity of certain gas uses.

As indicated in its public consultation of 27 July 2019, CRE considers that extending the scope of collection of the storage tariff charge to clients connected to the transmission network is desirable provided that the interruptibility mechanisms provided for by Articles L. 431-6-2 and L. 431-6-3 of the energy code are implemented. CRE stresses that once the regulatory implementing texts related to interruptibility are published, a minimum period of 12 months will be necessary to ensure that network users can contract interruptible capacity.

Transparency

CRE publishes on its website:

- the elements to be published within the framework of the final tariff decision provided for by Articles 29 and 30 of the Tariff network code: capacity reserve prices, parameters used in the method for calculating reference prices (in particular justification of flow scenarios), financial information concerning the expenses to be covered and their distribution, evolution of tariffs, etc.;
- the external audit of GRTgaz's and Teréga's proposal concerning operating expenses for the 2020-2023 period;
- the external audit of GRTgaz's and Teréga's proposal concerning the remuneration rate of natural gas transmission system operators' regulated assets;
- the non-confidential responses to the four public consultations (of 14 February, 27 March and 23 July 2019);
- a summary of the responses to the consultation of 23 July 2019, aimed at collecting interested parties' opinions on all of the guidelines concerning the ATRT7 tariff;
- a simplified tariff model;
- an English translation of the tariff deliberation.

The Conseil supérieur de l'énergie, consulted by CRE on the draft decision, delivered its opinion on 14 January 2020.

[4] Law no. 2018-938 of 30 October 2018 for achieving a balance in trade relations in the agricultural and food sector and for healthy, sustainable and accessible food for all
[5] Decree no. 2019-665 of 28 June 2019 relating to natural gas transmission and distribution network reinforcements necessary to enable injection of biogas produced

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1. POWERS AND THE TARIFF ELABORATION PROCESS

1.1 CRE's powers

Article L. 134-2, 4° of the French energy code empowers CRE to specify the "*conditions for the use of natural gas transmission and distribution networks […], including the methodology for establishing the tariffs for the use of these networks […] and tariff evolutions […]*".

Articles L.452-2 and L.452-3 of the French Energy Code provide a framework for CRE's powers in terms of tariffs.

Article L. 452-1 states in particular that these tariffs "*are established in a transparent and non-discriminatory manner to cover all costs borne by the transmission network operators and the storage infrastructure operators […], insofar as these costs correspond to those of efficient operators. These costs take into account the characteristics of the service rendered and the costs related to this service, and include the obligations established by law and regulations as well as those costs resulting from the execution of public service missions and contracts mentioned in I of Article L. 121-46*".

Article L. 452-2 states that CRE shall define the methods used to set the tariffs for the use of natural gas networks.

In addition, Article L. 452-3 provides that CRE shall deliberate on changes to the tariff "*with, where applicable, the modifications to the level and structure of the tariff that it deems justified in view, in particular, of the analysis of the operators' accounts and any forecast changes in operating and investment expenses*". CRE's deliberation may provide for a "*multi-annual framework for the changes in tariffs as well as appropriate short- or long-term incentive measures to encourage operators to improve their performance related in particular, to the quality of service provided, integration of the internal gas market, the security of supply and productivity efforts*".

Article L. 452-3 also specifies that CRE shall "*consult energy market participants, based on the modalities that it determines*".

In the present deliberation, CRE defines the methodology for establishing the tariff for the use of GRTgaz's and Teréga's natural gas transmission networks, and sets the "ATRT7" tariff.

1.2 Tariff elaboration process

1.2.1 Consultation of stakeholders

Given stakeholders' need for visibility and the complexity of subjects, CRE carried out four public consultations, published in French and English, prior to taking the present decision:

- the first, launched on 14 February 2019, concerned the regulatory framework applicable to regulated infrastructure operators for the next generation of tariffs. 41 answers were received;
- the second, launched on 27 March 2019, aimed to collect interested parties' opinions on CRE's initial guidelines concerning the structure of the ATRT7 tariff and on the storage tariff charge. 66 answers were received;
- the third, dated 23 July 2019, concerned the conditions for injecting biomethane into the natural gas transmission and distribution networks. 43 answers were received;
- the fourth and last consultation, launched on 23 July 2019, questioned stakeholders about CRE's initial guidelines concerning the level of expenses to be covered and the resulting tariff level. It also aimed to present, based on CRE's analyses and market participants' feedback, the guidelines envisaged concerning the proposals presented in the public consultations of 14 February and of 27 March 2019. In compliance with the provisions of Articles 26, 27 and 28 of the Tariff network code, this final consultation lasted two months and was forwarded to ACER; it was notified by email to the members of the Gas Working Group. 91 answers were received.

The non-confidential responses to these four public consultations, as well as a summary of the responses to the final consultation, are published on CRE's website.

Following the second public consultation, CRE held discussions with the TSOs. After the third public consultation, on 7 November 2019, CRE held a round-table with shippers and customers that took part in the consultation. It also had new discussions with GRTgaz and Teréga and their respective shareholders.

1.2.2 Energy policy guidelines

In accordance with the provisions of Article L. 452-3 of the French energy code, CRE took into account the energy policy guidelines forwarded by the minister of state, minister of the ecological and inclusive transition by letter dated 15 July 2019. These guidelines address, in particular:

- the necessary control of costs against a drop in gas consumption through a more careful selection of future investments which should mainly cover security and integration of renewable gas, particularly biomethane;
- the assumptions to be taken into account in terms of biomethane development are those set by the draft multi-annual energy programme currently under consultation, i.e. a biomethane volume injection of 6 TWh for 2023;
- consideration of the costs of the assessments related to the conditions for injecting hydrogen into the networks;
- continuity between the tariffs borne by a site connected to a transmission network and a similar site connected to a distribution network;
- consideration of the costs related to the conversion of the low-calorific gas network (L gas);
- TSOs' new analysis and forecasting requirements.

1.2.3 Transparency

CRE endeavours, within the framework of tariff work, to ensure transparency for all stakeholders as concerns the methods, tools and data that it uses.

To elaborate the ATRT7 tariff, in its public consultations, CRE published all of the information set out in Article 26 of (EU) regulation 2017/460 (the Tariff network code), covering the configuration of the transmission network, the methodology for determining tariff charges and its comparison with the reference method of the Tariff network code. All of these data are summarised in Annex 4 of the public consultation of 23 July 2019.

In the present deliberation, CRE publishes all of the information set out in Articles 29 and 30 of the Tariff network code: capacity reserve prices, parameters used in the method for calculating reference prices (in particular justification of flow scenarios), financial information concerning the expenses to be covered and their distribution, evolution of tariffs, etc. This information is summarised in Annex 4 of the deliberation.

Moreover, CRE has published the external assessments conducted within the framework of the elaboration of the ATRT7 tariff. These assessments cover the following topics:

- an audit of GRTgaz's and Teréga's proposal concerning their operating expenses for the 2020-2023 period[6];
- an audit of GRTgaz's and Teréga's proposal concerning the remuneration rate of natural gas transmission system operators' regulated assets[7].

Lastly, CRE will publish a simplified tariff model on its website.

1.2.4 ACER's opinion

In compliance with the provisions of the Tariff network code, ACER gave its opinion on CRE's final public consultation on 4 December 2019. This opinion is available on ACER's website[8].

2. TARIFF REGULATORY FRAMEWORK

2.1 Main tariff principles

The elaboration of the ATRT7 tariff is based on the definition, for the upcoming tariff period, of an allowed revenue for each TSO (GRTgaz and Teréga) and of forecast capacity subscriptions in their respective networks.

The ATRT7 tariff also defines a regulatory framework aimed, on the one hand, at limiting TSOs' and/or users' financial risk for certain predefined expense items or income, through an expenses and revenues clawback account (CRCP), and on the other hand, at encouraging the TSOs to improve their performance thanks to incentive mechanisms.

[6] Audit of GRTgaz's and Teréga's proposal concerning operating expenses for the 2020-2023 period
[7] Audit of the proposal concerning the remuneration rate of natural gas transmission system operators' regulated assets
[8] ACER's opinion: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/Agency%20Report%20-%20analysis%20of%20the%20consultation%20document%20for%20France.pdf

All of these elements are used to establish the tariff applicable as at 1 April 2020, and the modalities for their yearly evolution.

2.1.1 Determination of allowed revenue

In the present deliberation, based on the tariff dossier forwarded by operators and its own analyses, CRE sets the forecast allowed revenue of each TSO for the 2020-2023 period. Allowed revenue covers the operators' costs on a calendar basis as longs as those costs correspond to those of an efficient operator.

This forecast allowed revenue comprises forecast net operating expenses (CNE), forecast normative capital expenses (CCN), reconciliation of the balance of the expenses and revenues clawback account (CRCP) and forecast inter-operator payment between GRTaz and Teréga:

$$RA = CNE + CCN + CRCP + INT$$

Where:

- RA: target allowed revenue for the period;
- CNE: target net operating expenses for the period;
- CCN: target normative capital expenses for the period;
- CRCP: reconciliation of the CRCP balance;
- INT: forecast inter-operator financial payment flow.

The tariff framework guarantees that TSOs receive their allowed revenue.

2.1.1.1 Net operating expenses

Net operating expenses are defined as gross operating expenses minus operating income (capitalised production and non-tariff income in particular).

Gross operating expenses are mostly composed of energy costs, external consumption, staff expenses and taxes.

The level of net operating expenses adopted is determined based on all of the costs necessary for the TSOs' business, insofar as, pursuant to Article L. 452-1 of the French energy code, these costs correspond to those of an efficient system operator.

2.1.1.2 Normative capital expenses

Normative capital expenses (CCN) consist of the return on and depreciation of fixed capital. These two components are calculated from the valuation and development of assets exploited by GRTgaz and Teréga - the regulated asset base (RAB) - and of fixed assets under construction (AuC), i.e. investments made that have not yet led to the commissioning of assets.

The CCN equates to the sum of the depreciation of assets from the RAB and the return from the fixed capital. This corresponds to the product of the value of the RAB and the weighted average capital cost (WACC) plus the product of the value of the AuC and the cost of debt.

$$CCN = \text{Annual depreciation of the RAB} + (RAB \times WACC) + (AuC \times \text{cost of debt})$$

2.1.2 Return on assets and coverage of investments

2.1.2.1 Method for the calculation of the rate of return

For the ATRT7 tariff period, CRE is readopting the method used to set the rate of return on assets in effect for the ATRT6 tariff, which is based on the WACC with a normative financial structure. The operator's return must in fact enable it to service its debt interest and provide it with a return on equity that is comparable to that which it could obtain for investments with similar risk levels. This cost of equity is estimated based on the capital asset pricing model (CAPM).

Within the framework of its public consultations of 14 February and 23 July 2019, CRE looked into the possible introduction, for the ATRT7 tariff, of a differentiation between the rate of return on historic assets and on new assets. Given the slow evolution in the single rate of return, calculated from long-term calculation parameters, such a development could provide better signals for investment.

Operators and their shareholders have stated that the business is financed globally, without any earmarking between new assets and new debts for the year. They also highlight the complexity and the lack of clarity for investors with such a mechanism.

CRE considers that this complexity is limited and that it could be managed entirely by operators and the regulator. However, this development is of limited interest for the gas TSOs, against a marked drop in their investments over the next tariff period. Therefore, CRE has not adopted this development in the calculation of the rate of return for the ATRT7 tariff period.

2.1.2.2 Method for the calculation of the regulated asset base (RAB)

For the ATRT7 tariff period, CRE is readopting the RAB calculation method in effect for the ATRT6 tariff. The value of the RAB is established using a "current economic cost" method, the main principles of which were fixed by the special commission set up under article 81 of the amending Finance law of 28 December 2001, tasked with setting the price of transfer by the State of its natural gas transmission networks.

Since 2006, the conventional date for recording assets in the RAB is 1 January of the year following their commissioning. The gross values of assets are adjusted for valuation differences authorised in 1976 and subsidies received in respect of carrying out these investments.

Once they are recorded in the RAB, assets are revalued as at 1 January each year for July to July inflation. For this reason, CRE adopts a real WACC that does not include inflation. Since 2016, the revaluation index used is the index 1763852 for consumer prices, excluding tobacco, for all households residing in France.

Assets are depreciated using the straight-line method on the basis of their economic life. Land is recorded at its revalued undepreciated historical value. The lifetimes adopted for the main categories of assets are:

Asset category	Normative lifetime
Pipes and connections	50 years
Delivery, regulation and metering stations	30 years
Compression	30 years
Other ancillary installations	10 years
Constructions	30 years

Assets scrapped before the end of their economic lifetime are removed from the RAB and no depreciation or financial return is included for them.

2.1.2.3 Return on fixed assets under construction

CRE is readopting the principle of remunerating assets under construction (AuC) at the nominal cost of debt before tax, in line with the methodology generally used for interest during construction.

Within the framework of its public consultations of 14 February and 23 July 2019, CRE contemplated possibly restricting the AuC base to be remunerated, to stocks of assets corresponding to long-cycle investments (over one year).

CRE notes that, for the gas TSOs, almost all investments are long-cycle investments. The value of this is therefore limited given the complexity involved in following investments of a maturity of less than one year which could not be processed massively and would require treatment outside official accounting. Therefore, CRE has not adopted this possibility of changing the remuneration of assets under construction for the gas TSOs for the ATRT7 tariff.

The amount of these AuC is equal to the average, for each year the tariff is applied, between their level estimated on 1 January and that at 31 December, taking into account the investment expenses incurred and the amount of assets commissioned during the year.

2.1.2.4 Treatment of assets removed from inventory

2.1.2.4.1 Treatment of stranded costs

By "stranded costs", CRE refers to the residual book value of assets withdrawn from inventory before the end of their lifetime, as well as costs relating to technical studies and upstream processes that could not be immobilised if the projects concerned were not carried out.

Stranded costs are treated as follows, based on the submission of dossiers by the operators:

- recurring or foreseeable stranded costs, related to small assets that could be withdrawn from the asset inventory before the end of their accounting lifetime, have a tariff trajectory based on an annual envelope (defined in section 3.1.3.3 of the present deliberation);
- the cost of studies relating to large abandoned projects previously approved by CRE are covered by the tariff through the CRCP;
- coverage of other stranded costs will be examined by CRE on a case-by-case basis, based on substantiated requests submitted by the TSOs.

The costs to be covered, where applicable, by the tariffs, are taken into account at their book value minus any sales proceeds.

2.1.2.4.2 Treatment of disposed assets

When an asset is disposed of by an operator, it exits the RAB and therefore ceases to generate capital expenses (depreciation and remuneration). This disposal of the asset may generate a profit for the operator, equal to the difference between the income from the disposal and the book value of the asset.

In its public consultation of 23 July 2019, CRE questioned market participants about the treatment to be applied to sold assets. Most participants are in favour of a portion of the profit being taken into account in the tariff, considering that the tariff contributed to financing the assets sold.

For the ATRT7 tariff, in the case of a disposal of land or buildings:

- if the disposal gives rise to an accounting gain, the sales proceeds net of the sold asset's net book value are included at 80% in the CRCP so that network users can benefit from the greater part of the gains drawn from the disposal of these assets, given that these users bore the acquisition costs (operators' allowed revenue covering annual depreciation and remuneration of assets in the RAB), while maintaining an incentive for the system operator to maximise this gain. The operator in fact keeps the remaining 20% of the gains;
- a disposal giving rise to an accounting loss will be examined by CRE, based on a substantiated file submitted by the TSO.

2.1.3 Principle of the CRCP

CRE defines the ATRT tariff using assumptions about the level of forecast expenses and subscription income. An *ex post* adjustment mechanism, the expenses and revenues clawback account (CRCP), was introduced in order to take into account all or a portion of the differences between actual expenses and income, and forecast expenses and income for predefined items (see section 2.3.3). Therefore, the CRCP protects operators against the variation in certain cost or income items. The CRCP is also used for payments of financial incentives resulting from the application of incentive regulation mechanisms, as well as to take into account any capital gain on asset disposal or stranded costs once they are validated by CRE.

The CRCP balance is calculated as at 31 December each year. Within the framework of the ATRT6 tariff, the balance of this account is reconciled over a period of four years, in yearly instalments of equal size, taken into account within the framework of tariff changes implemented as at 1 April of each year, through a drop or increase in the revenue to be covered by the tariff.

The other network tariffs (TURPE for electricity and ATRD for gas distribution), also have a CRCP, which is reconciled differently: it is reconciled over a period of one year, within the limit of one annual tariff change associated with this adjustment limited at +/-2%; if the cap is reached, the balance not reconciled rolls over to the following year. At the end of the tariff period, the total balance of the CRCP is taken into account in the allowed revenue of the following tariff period.

In its public consultation of 14 February 2019, CRE proposed harmonising the gas TSOs' CRCP reconciliation mode with that applicable to other system operators. In addition, CRE considered that the 2% cap should be maintained at this level. Most contributors were in favour of this proposal.

For the present ATRT7 tariff, the CRCP balance will be calculated as at 31 December each year. For each TSO, the CRCP balance will be reconciled over a period of one year, within the limit of one tariff change associated with this reconciliation of +/-2%. If this limit is reached and will not enable the balance of the CRCP to be fully reconciled in the tariff change of the following year, the non-reconciled balance for the year in question will be deferred to the following year.

In order to ensure financial neutrality of the system, an interest rate equal to the risk-free rate applies to the CRCP balance (1.7%).

Moreover, in order to ensure a balance between the allowed revenue and the tariff income of each TSO, the ATRT7 tariff provides for compensation between the two operators, described in section 2.6.6 of the present deliberation.

Lastly, the entire CRCP balance remaining at the end of the tariff period will be taken into account to establish the allowed revenue of the following period. This is the case for the CRCP balance at the end of the ATRT6 period.

2.2 Tariff calendar

2.2.1 A tariff period of about four years

The ATRT7 tariff will apply for a period of roughly four years, as from 1 April 2020. It aims to cover the expenses of the calendar years from 2020 to 2023. It will change annually, as at 1 April of each year, based on the terms described in section 2.2.2 of the present deliberation.

In their responses to the consultation of 14 February 2019 relating to the tariff regulation framework, market participants were in favour of maintaining this duration of roughly four years, considering, like CRE, that it provides the market with visibility into the development of infrastructure tariffs and that it allows operators the time needed for undertaking productivity efforts.

In addition, the ATRT7 tariff provides for a *rendez-vous* clause, as was the case for the previous tariff, which can be activated by the TSO at the end of two years. Therefore, any consequences of new legal or regulatory provisions or a jurisdictional or quasi-jurisdictional decision may lead to a re-examination of the tariff trajectory for the last two years of the tariff period (2022 and 2023) if the level of net operating expenses adopted in the ATRT7 tariff is modified by at least 1%.

2.2.2 Calendar of changes to tariff charges

The ATRT7 tariff charges apply as of 1 April 2020 and will be revised annually following the rules below:

- the tariff charges at network interconnection points (PIRs) will change as at 1 October of each year, with an initial change in these charges as at 1 October 2020. The current tariff charges at PIRs will continue to apply between 1 April 2020 and 30 September 2020;
- the other tariff charges in the grid will change as at 1 April of each year.

This calendar maintains consistency between the transmission, LNG terminals and storage calendars, and complies with the requirement set out by the Tariff network code to have set, ahead of annual capacity auctions for interconnection points, the level of the tariff charges that will apply from October Y to October Y+1.

Most participants that answered the public consultation are in favour of CRE's proposal. They consider that it provides sufficient visibility to market participants and guarantees the proper functioning of auctions.

2.2.3 Principles of the annual tariff change

The ATRT7 tariff implements tariff principles that enable a stable distribution of costs among the different network user categories. In particular, in order to preserve the balance during the tariff period between the main network costs borne by the users that access the network for transit purposes on the one hand, and by users supplying domestic consumption on the other hand, the annual evolution must be identical for all of the main network tariff charges.

However, since the expenses and income of each operator can evolve for reasons specific to each network, GRTgaz's and Teréga's CRCP balance at the end of the year will be different.

Therefore, in the ATRT tariff, the calculation of each operator's CRCP will lead to a coefficient k_{GRTgaz} for GRTgaz and $k_{Teréga}$ for Teréga. The main network charges will be adjusted each year for the same national coefficient, the $k_{national}$ coefficient, corresponding to the average of the k_{GRTgaz} and $k_{Teréga}$ coefficients weighted by capacity subscription revenues. GRTgaz's regional network charges will be adjusted for the coefficient k_{GRTgaz} and those of Teréga's regional network will be adjusted for the coefficient $k_{Teréga}$.

Lastly, payment between the two TSOs will compensate the differences in income generated by the application of an average $k_{national}$ coefficient to the main network charges.

The ATRT7 tariff will change annually, as from 2021, on 1 April of each year, according to the following principles:

- for the main network charges in effect as at 31 March of year Y, by applying the following percentage variation:

$$Z = CPI + X + k_{national}$$

Where:

  - Z is the change in the tariffs as at 1 April of year Y, expressed as a percentage and rounded off to the nearest 0.01%;
  - CPI is, for an update of the tariff grid as at 1 April of year N, the forecast inflation rate for year N taken into account in the draft budget bill for year N ;
  - X is the annual rate of change in the main network tariff, equal to -0.36%.

- $k_{national}$ is the change in the tariff, expressed as a percentage, capped at +/-2%, equating to the average of the k_{GRTgaz} and $k_{Teréga}$ coefficients weighted by capacity subscriptions.

By way of exception, the change in the tariff charges relating to PIRs will apply as from 1 October of each year.

- for GRTgaz's regional network charges in effect as at 31 March of year Y; the following percentage variation will be applied:

$$Z_{GRTgaz} = CPI + X_{GRTgaz} + k_{GRTgaz}$$

Where:

- Z_{GRTgaz} is the change in the tariffs as at 1 April of year Y, expressed as a percentage and rounded off to the nearest 0.01%;
- CPI is, for an update of the tariff grid as at 1 April of year N, the forecast inflation rate for year N taken into account in the draft budget bill for year N;
- X_{GRTgaz} is the annual rate of change in GRTgaz's regional network tariff, equal to -0.18%.
- k_{GRTgaz} is the change in the tariff, as a percentage, capped at +/-2%, coming mainly from the reconciliation of the balance of GRTgaz's CRCP account.

- for Teréga's regional network charges in effect as at 31 March of year Y, the following percentage variation will be applied:

$$Z_{Teréga} = CPI + X_{Teréga} + k_{Teréga}$$

Where:

- $Z_{Teréga}$ is the change in the tariffs as at 1 April of year Y, expressed as a percentage and rounded off to the nearest 0.01%;
- CPI is the change in the average value of the consumer price index excluding tobacco, as calculated by the French national statistics office INSEE, for all households in the whole of France (INSEE reference 1763852), recorded for calendar year Y, compared to the average value of the same index recorded for calendar year Y-1;
- $X_{Teréga}$ is the annual rate of change in Teréga's regional network tariff, equal to -1.34%.
- $k_{Teréga}$ is the change in the tariff, as a percentage, capped at +/-2%, coming mainly from the reconciliation of the balance of Teréga's CRCP account.

By way of exception, these terms do not apply to the biomethane injection charge, which remains constant.

In addition, CRE may take into account, for changes to the annual ATRT7 tariff, developments in tariff structure related to, in particular:

- implementation of European network codes and/or guidelines;
- functioning of the single France market zone;
- changes in the TSOs' offering;
- developments in the incentive regulation for operators' service quality.

Lastly, the storage tariff charge will evolve based on the level set in an ad hoc deliberation by CRE following the annual auction campaign for gas storage capacity.

2.2.4 Calculation of the CRCP balance as at 1 January of year Y

The overall CRCP balance is calculated before the definitive closure of annual accounts. It is the amount to be paid into or deducted from the CRCP (i) for the year passed, based on the best estimate of annual expenses and income (termed "estimated CRCP"), and (ii) for the previous year, by comparison between the actual expenses and income and the estimate made one year earlier (termed "final CRCP"), to which is added the CRCP balance not reconciled for former years.

The projected CRCP balance as at 31 December 2019 was taken into account to define the projected revenue of the ATRT7 tariff reconciled over the four-years tariff period and is therefore reset to 0 as at 1 January 2020.

The definitive differences to be paid into the CRCP for the year 2019 will be taken into account with the annual tariff update as of 1 April 2021. The reference amounts and the coverage rates used to calculate this definitive balance are defined in the ATRT6 tariff deliberation of 15 December 2016[9], and in the deliberation of 13 December 2018.

[9] https://www.cre.fr/Documents/Deliberations/Decision/atrt62 and https://www.cre.fr/en/content/download/15339/18060

The amount to be paid into or deducted from the CRCP is calculated by CRE, as at 31 December of each year, based on the actual difference, for each item concerned, compared to the reference amounts defined in section 3.1.1. All or part of the difference is paid into the CRCP; the portion is determined based on the coverage rate specified by the present deliberation.

The expenses and income fully or partially covered through the CRCP for the ATRT7 tariff period are defined in section 2.3.3 of the present deliberation.

2.2.5 Calculation of the k coefficients in view in particular of the reconciliation of the CRCP balance

The annual tariff change takes into account three coefficients, $k_{national}$, k_{GRTgaz}, and k_{Terega}, which aim to reconcile, as at 31 December of year N, the CRCP balance as at 31 December of year Y-1. The coefficients $k_{national}$, k_{GRTgaz}, k_{Terega} are capped at +/-2%.

The k_{GRTgaz} and k_{Terega} coefficients are determined so as to enable the actual tariff change implemented to cover, for each TSO, within the limit of the k coefficient caps, the amount of the following costs to be covered:

- the updated projection of smoothed allowed revenue (see Annex 8 of the deliberation);
- the CRCP balance.

The $k_{national}$ is defined as the average of k_{GRTgaz} and $k_{Teréga}$ weighted by the subscriptions to which they apply for each TSO. This weighted average introduces a different income difference for each operator which is compensated through the adjustment of inter-operator flow for the year N (these flow principles are defined in section 2.6.6 of the present deliberation).

The projected income resulting from the tariffs actually implemented over this period is based on the projected subscriptions considered in the present deliberation.

2.3 Incentive regulation for controlling costs

2.3.1 Incentive regulation for operating expenses

The ATRT6 tariff provided for a 100% incentive for net operating costs, with the exception of certain predefined items difficult for operators to control.

Given the positive results over the last ten years and the favourable feedback from participants expressed within the framework of the public consultations of 14 February and of 23 July, CRE plans to renew this principle for the ATRT7 tariff.

Therefore, with the exception of the types of expenses and income fully or partially covered through the CRCP, presented in section 2.3.3 of the present deliberation, the operator will bear or benefit from any difference compared to the trajectory set for the ATRT7 tariff period.

2.3.2 Incentive regulation for investments

Over the last 15 years, GRTgaz and Teréga have significantly developed their networks, through the creation of new interconnection capacity with neighbouring countries, the development of entry capacity from LNG terminals and the reinforcement of the national network to eliminate congestion and reduce the number of market zones. These developments have enabled customers to access diverse supply sources and have strengthened the integration of France within the European gas market.

CRE considers that the size of the French transmission system is now sufficient. In addition, with consumption stagnant for the last ten years and its projected evolution for 2030, CRE will be particularly vigilant in its examination of any new investment project submitted by the TSOs. In that regard, CRE reiterates that such projects must be subject to robust cost/benefit analyses so that unnecessary costs are not passed on to end customers.

This objective pursued by CRE is in line with the energy policy guidelines forwarded by the minister of state, minister of the ecological and inclusive transition, which call for "*greater selectivity in future investments. They must prioritise security and integration of renewable gas. Network extensions must be controlled in order to avoid stranded costs which will inevitably be passed on to gas customers and then to all of the national community.*"

2.3.2.1 Incentive for controlling costs for investments with a budget of over €20 million

The ATRT6 specified that all projects with a budget of more than €20 million were to be subject to an audit allowing a target budget to be set, with a bonus or penalty allocated to the operator depending on the difference between that target budget and the actual expenses, with a neutrality range of +/- 10% around the target budget.

In its public consultations of 14 February and 23 July 2019, CRE proposed to maintain this mechanism, with a small adjustment: the terms currently in effect for the ATRT6 tariff period will continue to apply for the ATRT7 tariff, with the exception of the scope of the neutrality range, which CRE proposes to limit to +/-5% of the target budget. However, with regard to interconnection projects subject to a cross-border cost allocation decision on the basis of article 12 of regulation (EU) no. 347/2013 of the European Parliament and of the Council of 17 April 2013, CRE considered that it is appropriate to maintain the neutrality range of 10%. Almost all of the participants are in favour of the mechanism proposed by CRE.

Therefore, for ATRT7, with regard to investment projects for which the decision to undertake costs will be taken as from the entry into effect of the present deliberation, and whose estimated budget is higher than or equal to €20 million:

- CRE will audit the budget presented by the TSO and will set a target budget taking into account, where applicable, the hot rolled coil (HRC) index;
- regardless of the investment expenses made by the TSO, the asset will be entered into the regulated asset base at its real value when it is commissioned (minus any subsidies);
- if the investment expenses incurred by the TSO for this project are between 95% and 105% of the target budget, no bonus or penalty will be applied;
- if the investment expenses incurred are less than 95% of the target budget, the TSO will receive a bonus corresponding to 20% of the difference between 95% of the target budget and the actual investment expenses;
- if the investment expenses incurred are higher than 105% of the target budget, the TSO will have a penalty of 20% of the difference between the actual investment expenses and 105% of the target budget.

The projects for which incentive regulation was defined during the ATRT6 period will keep the mechanism implemented during this tariff period. At this stage, the envelope for the projects in question for GRTgaz during the ATRT7 tariff is estimated at roughly €248 million (reinforcement Bretagne Sud, Vindecy, phase 1 of the H-L conversion). The envelope for Teréga's projects is estimated at €58 million (Capens-Pamiers project).

For GRTgaz, the projects concerned by this mechanism are, in particular:

- the connection of the Landivisiau combined-cycle gas turbine (approximately €29 million);
- the "Canal Seine Nord" waterway project, for a budget estimated between €25 and €30 million by GRTgaz, including €20 million over the ATRT tariff period.

For Teréga, the new project concerned by the mechanism is phase 1 of the Moissac security and maintenance project, for a budget estimated at €17 million by Teréga, including €2 million over the ATRT7 period. This phase 1 is part of an overall project whose budget is estimated at €45 million by Teréga.

These lists are not exhaustive, since new projects may emerge over the period covered by the ATRT7 tariff.

2.3.2.2 Incentive for controlling costs of projects with a budget lower than €20 million

The incentive system for controlling costs of projects of an amount greater than or equal to €20 million described in section 2.3.2.1 of the present deliberation concerns a limited number of projects.

The present deliberation introduces an incentive mechanism based on CRE's selection, without any predefined criteria, of a few projects or categories of projects whose budget is below €20 million, in order to audit them and apply an incentive regulation identical to that applicable to investment projects with a budget greater than or equal to €20 million.

This mechanism was proposed in the public consultations of 14 February and 23 July 2019. Almost all contributors to the public consultation of 23 July 2019 that gave their opinion on this topic are in favour of the mechanism proposed by CRE.

2.3.2.3 Incentive for projects to create interconnection capacity

The ATRT6 tariff provided for an incentive mechanism to create new interconnection capacity. This mechanism was not applied during the 2017-2019 period because of the lack of projects.

In its public consultation of 23 July 2019, CRE considered eliminating this mechanism for the ATRT7 tariff period, seeing that this mechanism was no longer adapted to the context as described in section 2.3.2 of the present deliberation.

Almost all of the contributors to the public consultation share CRE's views and are in favour of CRE's proposal. Therefore, CRE confirms the elimination of any incentive for the creation of new interconnection capacity.

2.3.2.4 Incentive for controlling costs for "non-network" investments

In the ATRT6 tariff, CRE introduced a mechanism encouraging TSOs to control their capital expenditure in the same way as their operating expenses within a scope of so-called “non-network” investments comprising assets such as buildings, vehicles and information systems (IS).

By nature, these expense items are in fact likely to give rise to trade-offs between investments and operating expenses. Therefore, this mechanism encourages TSOs to globally optimise all of their expenses. In consists in defining, for the tariff period, a trajectory of the estimated capital costs for this type of investments, which would then be excluded from the scope of the CRCP. The gains or losses made are therefore kept fully by the operators during the tariff period, both for operating expenses and for investments. At the end of the tariff period, the effective value of assets will be taken into account in the RAB, which, for the following tariff periods, allows the sharing of gains or extra costs with users.

In its public consultations of 14 February and 23 July 2019, CRE proposed readopting this mechanism, considering that the feedback about its effectiveness was still too limited for conclusions to be drawn. Most contributors were in favour of CRE’s proposal. However, GRTgaz and the distribution system operators requested coverage in the CRCP of capital costs relating to information systems.

Therefore, for the ATRT7 tariff, CRE is readopting the incentive for controlling non-network investment costs described above. In particular, with regard to IS investment expenses, CRE considers that these costs can generally be controlled by operators and can be traded for operating expenses. During the ATRT7 tariff, the capital expenses for these categories of assets will be calculated using the projected values defined in the present deliberation.

At the end of the tariff period, CRE will analyse the commissioning trajectories of the different investments concerned in order to ensure that any gains made during the tariff period do not result in an increase in expenses for the following tariff periods, because of certain project delays for example.

The estimated amount of investments subject to this incentive regulation is an average €94 million per year for GRTgaz, and €8.3 million per year for Teréga (vehicles and buildings only).

In addition, Teréga proposed experimenting, for its IS expenses, a TOTEX (common OPEX and CAPEX trajectory) incentive mechanism, in which the assets would enter the operator’s RAB at an amount fixed *ex ante* in the TOTEX trajectory, and not on the basis of the actual expenses incurred. Teréga considers that this experiment would serve to assess the feasibility of a solution in which only the core business solutions would be maintained wholly by the operator (which results in a substitution of CAPEX towards more OPEX). CRE considers that this experiment can meet the flexibility needs identified within the framework of the digital transformation of information systems. CRE considers it relevant to experiment on this system with Teréga within the scope of its information systems (operating expenses and investments) for the ATRT7 tariff period. In addition, it sets the operator’s sharing rate for its gains and losses at 50%. Differences in the overall trajectory are covered at a rate of 50% through the CRCP. The trajectory subject to the incentive is defined in section 3.1.3.3.2 of the deliberation.

At the end of the tariff period, CRE will also conduct a comparative analysis of the classic “non-network” expense mechanism and the pilot proposed by Teréga to assess its relevance regarding the costs and quality of the service provided.

2.3.3 Coverage of certain items in the CRCP

Network tariffs are calculated using income and expense assumptions that serve to define trajectories for the different items over the entire period covered by these tariffs.

As indicated in section 2.1.1 of the present deliberation, an *ex post* adjustment mechanism, the expenses and revenue clawback account (CRCP), takes into account the differences between actual expenses and income and projected expenses and income for certain items previously identified, which are difficult for gas TSOs to predict and control.

In its public consultation of 14 February 2019, CRE wished to specify the principles concerning the incentive for different expense and income items in the infrastructure tariffs. Therefore, including an item in the CRCP is based on the following two factors:

- predictability: a predictable item is an item for which it is possible, for the operator and for CRE, to predict with reasonable confidence, the level of costs incurred and the revenues perceived by the operator over a tariff period;
- control: a controllable item is an item for which the operator is able to control the level of expenditure/income during a year, or has a power or influence with regard to its level, if it results from a third party.

The contributors to the public consultation widely shared these principles.

On this basis, CRE consulted about the scope of the CRCP to adopt for the ATRT7 tariff in its public consultation of 23 July 2019. Participants are globally in favour of the scope proposed, with alternative proposals for certain items to be included in or withdrawn from the CRCP. In particular, CRE has not adopted the inclusion of taxes in the CRCP, requested by certain shippers and infrastructure operators on the grounds that they would not be able to be predicted or controlled sufficiently by operators. As stated in the public consultation of 14 February 2019, CRE considers that it is a relatively predictable item.

The items included within the scope of the CRCP for the ATRT7 tariff, which do not change compared to the ATRT6 tariff, are as follows:

- capital expenses, taken into account at 100%, with the exception of those that are the subject of the incentive regulation mechanism for "non-network" capital expenses and for which only the difference between projected and actual inflation is taken into account (see section 2.3.1);
- energy costs (gas and electricity) and purchases and sales of CO_2 emission allowances. To encourage the TSOs to control these expenses, the differences in this item are 80% covered by the CRCP: the reference trajectory is updated annually. The difference between the updated trajectory and the initial trajectory is fully covered by the CRCP;
- the difference between the projected inflation taken into account by CRE for operating expenses and actual inflation, fully covered by the CRCP;
- certain tariff income difficult to control by the TSOs, fully covered in the CRCP:
    - income from the sale of domestic exit capacity from the main network, regional network transmission capacity and delivery capacity, and biomethane injection capacity;
    - income from the sale of storage entry and exit capacity;
    - income from H gas to L gas peak conversion;
- transmission income from the main upstream network at interconnection entry points and from LNG terminals (PITTM) are 80% covered, to encourage TSOs to maximise subscriptions. The same applies for the following additional expenses and income:
    - income from access and transactions at the gas exchange point (PEG);
    - income from the Alizés balancing services for GRTgaz and SET for Teréga;
    - income received in application of the use-it-or-lose-it (UIOLI) and use-it-or-buy-it (UBI) mechanisms;
    - income from the auction of daily capacity.

  The reference trajectory is updated annually. The difference between the updated trajectory and the initial trajectory is fully covered by the CRCP;
- income from connections to the transmission network of the combined-cycle gas turbines (CCGTs) and combustion turbines (CTs) are fully covered by the CRCP, since the project execution schedule is uncertain;
- income from services for third parties, whose execution is uncertain and over which the TSOs have no influence (for example related to land-use planning), are fully covered;
- expenses for GRTgaz and income for Teréga related to the agreement between GRTgaz and Teréga for GRTgaz's use of Teréga's network. The amount of these expenses and income is fully covered by the CRCP. The impact of a variation in the contract amount is zero for the overall cost of gas transmission in France;
- the costs related to, where applicable, remuneration by the TSOs of the consumers connected to the transmission networks that have signed an interruptibility contract on the basis of Article L. 431-6-2 of the energy code are fully covered;
- R&D operating expenses, with special treatment (see section 2.5): at the end of the tariff period, an assessment of the amounts actually spent by each TSO is carried out taking into account actual inflation. If the TSO has spent less than the forecast trajectory, the difference is fully returned to users via the CRCP. If the TSO has spent more than the forecast trajectory, the difference remains the responsibility of the operator[10];
- the income and expenses generated by congestion removal mechanisms within the framework of the single market area are fully covered. Certain participants wish for these costs to not be fully covered in the CRCP, considering that the operators have partial control and must be encouraged to optimise the performance of congestion removal mechanisms. CRE indeed considers that the TSOs have partial control over congestion removal mechanisms. Nevertheless, these are relatively new within the framework of the single market area

[10] In the case of a request for a mid-period update of R&D operating expenses, the additional amount approved by CRE will be added to the forecast trajectory

which went live recently. The congestion costs for the ATRT7 period therefore appear difficult to predict. Therefore, CRE considers it appropriate to include them fully in the CRCP, for the ATRT7 period;

- the costs of studies for large abandoned projects previously approved by CRE or other stranded costs addressed on a case-by-case basis for which CRE approved coverage, are fully covered in the CRCP.

In addition, CRE is modifying two items that are currently included in the CRCP:

- as a result of the new terms for accessing the zone supplied with L gas defined by CRE in its deliberation of 13 December 2018[11], all of GRTgaz's expenses relating to the H gas to L gas conversion service are fully covered in the CRCP (and no longer only those resulting from changes in the volumes converted). Some participants do not wish for these expenses to be fully covered, so as to encourage GRTgaz to optimise the use of this service. However, the change in these expenses depends on factors that are difficult to predict and over which GRTgaz has little control;
- the differences between the forecast and actual payment between Teréga and GRTgaz for a portion of the income received at the Pirineos interconnection point, following the creation of the single market area as at 1 November 2018, are fully covered by the CRCP. For the ATRT7 tariff, CRE has adapted the coverage of Teréga's income at the Pirineos interconnection point, for which the difference between the forecast and actual amount is 80% covered by the CRCP. Therefore, the 20% incentive for this difference is maintained on the share of income maintained by Teréga, while the share of income paid back to GRTgaz is fully covered, to avoid an undue gain or loss for Teréga.

Lastly, the new expense and income items included within the scope of the CRCP in the ATRT7 tariff are as follows:

- transmission network connection income from biomethane production units and NGV station, fully covered. The income from this emerging sector is in fact difficult to predict due to the uncertainty concerning connection trajectories;
- the capital gain made on the disposal of real estate asset, 80% covered (see section 2.1.2.4.2);
- income associated with penalties received by the TSOs for the exceeding of capacity subscribed, full inclusion in the CRCP (see section 4.3.1.3);
- the expenses and income associated with contracts with other regulated operators, in particular, storage operators, fully covered;
- costs for consumables (THT), 80% covered in the CRCP. The reference trajectory is updated annually. The difference between the updated trajectory and the initial trajectory is fully covered by the CRCP;
- the payment made by DSOs to TSOs for the portion of the biomethane injection charge collected from producers connected to the distribution network aimed at covering the OPEX associated with TSO backhaul (see section 2.6.5 of the present deliberation), fully covered in the CRCP;
- inter-operator transfer between the two TSOs associated with the distribution of the national k tariff change coefficient (see section 2.6.6 of the present deliberation), fully covered in the CRCP;
- differences with the reference trajectory of Teréga's TOTEX experiment, calculated at the end of the ATRT7 period, 50% covered in the CRCP.

In addition, the bonuses and penalties resulting from the different incentive regulation mechanisms (see section 2.3 and 2.4 of the deliberation) are allocated to the TSOs through the CRCP.

2.4 Incentive regulation for quality of service

The incentive regulation for the TSOs' quality of service aims to improve the quality of the service provided to transmission system users in the fields deemed important for the proper functioning of the gas market.

In its public consultations of 14 February and 23 July 2019, CRE presented an assessment of the incentive regulation mechanism for service quality since 2009, date at which it was implemented for the first time for the TSOs. In that assessment, CRE noted that the quality of operators' service had improved in the fields of particular importance for network users.

In their responses, market participants shared this positive review and considered that it was a pillar of the tariff regulation framework, which ensures that economic efficiency is not at the expense of services provided by the networks. They also consider, like CRE, that this is an important issue for the next tariffs and approve CRE's approach concerning the pursuit of ambitious service quality objectives.

[11] Deliberation by the French Energy Regulatory Commission no. 2018-258 of 13 December 2018 deciding on the terms for accessing the zone supplied with low calorific gas ("L gas")

Globally, over the last tariff periods, following and placing incentives on service quality indicators have led to the improvement of TSOs' performance in target fields. To remain efficient, the indicators and associated incentives must be adapted to the market context and needs. The present tariff decision updates the incentive regulation for service quality.

The service quality indicators as well as the objectives set and the associated financial incentives are described in detail in Annex 2 of the present deliberation.

2.4.1 Adaptation of the mechanism for the ATRT7 period

The incentive regulation for quality of service has evolved to take into account the results obtained as well as feedback. The incentives and objectives defined for operators have been reinforced progressively in order to improve their performance.

GRTgaz and Teréga consulted with market participants and proposed changes aimed at meeting the expectations formulated by market participants within the framework of the preparation of ATRT7. Two topics stood out in particular:

- access to data and the quality of these data;
- quality of the customer service.

2.4.1.1 Simplification of the mechanism: elimination of two indicators

In its public consultation of 23 July 2019, CRE proposed eliminating the indicators whose quality is sufficiently high to no longer feature among the priority needs expressed by market participants:

- **the availability of the five pieces of information most useful for balancing at the TSOs' sites.** This indicator, introduced as at 1 April 2016 within the framework of the implementation of the balancing network code[12], has been incentive-based since 1 April 2017. During the consultation, market participants noted that the quality of this information was now satisfactory and prioritised other information (see section 1.3.4.2.4);
- **the availability rate of user portals.** This indicator has not been incentive-based since 1 April 2018. During the consultation, market participants noted that the availability rate was satisfactory and prioritised other indicators (see section 1.3.4.2.4).

Contributors were in favour of CRE's proposal to simplify the mechanism, which therefore eliminates these two indicators for the ATRT7 tariff period, presented in detail in Annex 2.

2.4.1.2 Reinforcement of the mechanism

In order to maintain a high level of service quality, CRE proposes to modify the indicators below. Contributors were in favour of CRE's proposal to reinforce the mechanism, and therefore the following indicators for the ATRT7 tariff period are modified:

- **quality of intraday quantities telemetered at points of delivery to customers connected to the transmission network and sent during the day.** For the ATRT7 period, the calculation of the indicator has been improved;
- **quality of day-ahead and within-day global consumption forecasts**;
- **accuracy of the projected linepack indicator published by the TSOs on their website.** For the ATRT7 period, projected linepack published at time T is considered non-compliant if at least one of the data that has been used to calculate it is not compliant or if the result of the calculation is non-compliant. A component is considered non-compliant if the deviation[13] for each component is greater than 30 GWh and analysed as being abnormal. The main components of the calculation are:
    - consumption forecasts;
    - quantities scheduled;
    - the physical working stock calculated at 6:00 a.m.

Furthermore, the results on the **indicator of the quality of quantities telemetered at customer delivery points and sent the following day** are greater than the objective set by the ATRT6 tariff. CRE considers that the performance level reached is satisfactory and must be maintained. As a result, for the ATRT7 tariff period, an asymmetric incentive is set up based on the following terms:

[12] Regulation (EU) No 2017/459 of the Commission of 16 March 2017 establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing regulation (EU) No 984/2013
[13] The differences are calculated between each hour.

- the maximum bonus amount which GRTgaz can receive is set at €300 k and the penalty is maintained at €600 k;
- the maximum bonus amount which Teréga can receive is set at €150 k and the penalty is maintained at €300 k.

2.4.1.3 Development of indicators relating to maintenance programmes

The indicators relating to maintenance programmes, aim, on the one hand, to provide visibility to all network users to better anticipate the network's unavailability and, on the other hand, to globally reduce unavailability, to the benefit of users.

The five indicators relating to maintenance programmes in the ATRT6 tariff were as follows:

- reduction of available capacity;
- reduction of subscribed capacity;
- compliance with the annual maintenance programme published at the start of the year by the TSO;
- compliance with the binding maintenance programme published M-2 by the TSO;
- compliance with the best planned maintenance, non-binding, published M-2 by the TSO.

These indicators were calculated monthly, with a value for each network point for each TSO. The categories of points adopted were the PIR in the dominant direction, the entry at PITTMs, the entry and exit at PITS and the GRT-gaz/Teréga interface in both directions.

In order to take into account the principle of auctioning storage capacity since 1 January 2018, CRE proposed to modify the schedule for publishing the maintenance programme and the indicators relating to maintenance programmes. Contributors were in favour of CRE's proposal which modifies the indicators relating to maintenance programmes as follows:

- elimination of the **indicator relating to the reduction of available capacity.** This indicator is not deemed useful by market participants;
- maintenance of the **indicator of the reduction of subscribed capacity**;
- the three indicators relating to compliance with maintenance programmes are replaced by the following indicators, described in detail in Annex 2:
    - **compliance with the annual maintenance schedule published in October and February.** This indicator is calculated based on two global values (October and February) with, for each value, a distinction between positive differences and negative differences[14];
    - **compliance with the probable values published in October and February.** This indicator is calculated based on two global values (October and February) with, for each value, a distinction between positive differences and negative differences.

These indicators are calculated annually and are aggregated for each category of points[15] (PIR, PITTM, PITS) in the dominant flow direction, with a level of detail enabling the origin of maintenance to be specified.

2.4.1.4 Introduction of new service quality indicators

The new indicators introduced in the ATRT7 tariff are not subject to financial incentives as of the start of the tariff period, but could be within the framework of an annual tariff update.

The implementation of the single market zone since November 2018 have led shippers to use a certain amount of information, as a priority, which was not monitored specifically in the ATRT6 tariff. Given the challenges of the proper functioning of the single market zone, in its public consultation of 23 July 2019, CRE proposed the introduction of two indicators to ensure the availability of information useful to shippers relating to the functioning of the single market zone. Contributors were in favour of CRE's proposal. CRE maintains its proposal and introduces the following two indicators:

- **an indicator for following the availability of the most useful information to shippers** whose components are described in detail in Annex 2:
    - imbalance settlement price;

[14] A difference is said to be positive or negative respectively, when the capacity has been added, respectively withdrawn, in relation to the maintenance schedule published.
[15] Restrictions on superpoints (groups of points within which shippers can optimise their nominations during periods of maintenance or pooled restrictions) are passed on to the contractual points making up the superpoint (in proportion to the capacity subscribed).

  - publication of data to customers (notice, slips, etc.);
  - substitution of measurements using back-up data for PITD data;
  - rate of availability of short-term firm capacity sales;
  - transparency in calls for locational spread;
  - vigilance information on the state of the network (green/orange/red, etc.) for the following day and up to D+5: the value monitored is the rate of availability of the vigilance information on the TSOs' websites.
- a **monthly indicator to follow the functioning of the single market zone**, whose components are as follows:
  - average end-of-day spread between the PEG and the TTF;
  - number of active participants at the PEG;
  - occurrence of the appearance of congestion in the network;
  - number of pooled restrictions;
  - total cost of locational spreads;
  - average cost of locational spreads;
  - impact of maintenance on the network on the days that congestion occurs in the network.

The monitoring of claims is a focus of attention by CRE in its 2017-2018 Report on the compliance of codes of good conduct and independence of system operators published in February 2019[16]. In particular, CRE requested GRTgaz to harmonise the definition of the concept of "claim" and to provide greater transparency with regard to the number of actual requests from network users and on the response that was provided. The topic is a strong expectation by market participants, who responded favourably to CRE's proposal to introduce an **indicator to follow the number of claims and the timeframe for processing complaints** as part of the quality of customer service.

The indicator is calculated using the following two components:

- the number of claims recorded by the TSOs;
- the timeframe for processing claims based on the complexity of the request (simple, complex, study).

2.4.1.5 Environmental indicators

The ATRT6 tariff had two indicators relating to the environment, which were not subject to financial incentives:

- annual greenhouse gas emissions (in CO_2 equivalent);
- monthly greenhouse gas emissions in relation to the volume of gas transported.

These greenhouse gas emission indicators encompass both emissions proportional to the volumes of gas transported over which the TSO has partial control and are based mainly on the optimisation of gas flows, escape of methane, which results more directly from the network management mode, such as the use of gas recompression and reinjection operations during maintenance work (rather than discharge into the atmosphere).

Contributors were in favour of CRE's proposal to separately follow methane emissions, and CRE therefore introduces an **indicator to follow methane emission in the networks** (including the scope of diffuse losses, venting and accidents/incidents), in relation to the volume of gas transported.

This indicator is not subject to a financial incentive.

2.5 Incentive regulation for research, development and innovation (R&D&I)

Against a rapidly changing energy landscape, CRE attaches particular importance to the development of smart networks and the adaptation of networks to the energy transition. System operators must have the necessary resources to successfully carry out their research and development (R&D) and innovation projects, which are essential for providing an efficient and high-quality service to users and developing their network operations tools. In return, they must have a transparent and effective use of these resources.

The incentive regulation defined by the ATRT6 tariff introduced a system specifically for expenses related to the field of R&D&I:

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[16] 2017-2018 report on natural gas and electricity system operators' compliance with codes of good conduct and independence : https://www.cre.fr/Documents/Publications/Rapports-thematiques/Rapport-2017-2018-sur-le-respect-des-codes-de-bonne-conduite-et-l-independance-des-gestionnaires-de-reseaux-d-electricite-et-de-gaz-naturel

- a trajectory of R&D&I costs, with an asymmetrical incentive: at the end of the tariff period, the amounts not spent during the period are returned to customers while the operators bear the costs of exceeding the trajectories;
- preparation of a detailed annual report to be sent to CRE, which assesses the R&D&I actions undertaken, supplemented by a bi-annual public report.

In addition, a smart grid counter was set up for electricity operators, allowing them to obtain additional funding during the tariff period, in particular for their smart grid demonstrator projects.

In its public consultations of 14 February and 23 July 2019, CRE proposed to maintain the incentive for actual spending on R&D&I and to increase transparency in the associated projects and expenses, combined with the possibility to revise the expenses associated with smart grids mid-period. Most participants that answered the public consultation were in favour of CRE's proposals. Several participants however stated that the activities financed by the transmission tariff should be limited to system operators' missions only.

For the ATRT7 tariff period, CRE has set up incentive regulation based on the following principles:

- the incentive for controlling costs relating to operators' R&D&I expenses is maintained, with the possibility for the TSOs to revise this trajectory halfway into the tariff period so that they may have more flexibility to adapt their programme. At the end of the ATRT7 period, the TSOs will present to CRE a financial report on R&D&I, and the amounts not spent during the period will be returned to customers (through the CRCP), while the operator bears the costs of exceeding the trajectory;
- transparency and verification of the efficiency of R&D&I spending are reinforced through two exercises, with the format to be determined conjunctively between CRE and the operators:
    - annual transmission to CRE of technical and financial information for all ongoing and completed projects, instead of the current report to CRE;
    - bi-annual publication by the operators of a report for the public, in line with the mechanism currently in place. The reports will need to be harmonised between the operators, in particular thanks to standardised indicators, and enhanced with concrete elements concerning the benefits of projects for network users, as well as systematic feedback on the demonstrator projects financed by the tariff;
- the smart grid counter is extended to the gas TSOs: provided that they present a favourable cost/benefit analysis, and for projects greater than €1 million falling within the scope of smart grid deployment, GRTgaz and Teréga can therefore request, halfway into the tariff period, for any extra operating costs related to this type of projects to be integrated into their trajectory. Where necessary, elements of incentive regulation associated with these projects may be introduced;
- the operators will consult market participants before summer 2021 concerning the major research topics they intend to develop.

2.6 Inter-operator financial flows

2.6.1 Repayment by Teréga to GRTgaz of a portion of the income received at the PIR Pirineos exit point

On the occasion of the creation of the single market zone, constantly maintaining the cost of the main transit routes led to the deferral of a portion of the income initially received at the North-South link (in GRTgaz's zone) to the Pirineos exit point (located in Teréga's zone). However, the costs generated by the use of this transit route are borne by both TSOs. In addition, the service provided by each TSO remains identical. Therefore, to avoid cross-subsidisation between the two TSOs, the deliberation of 15 December 2016 introduced, as from the creation of the single market zone, a financial flow from Teréga to GRTgaz.

This payment by Teréga to GRTgaz, corresponding to the costs borne by GRTgaz for the use of this transit route, was equal, at the creation of the single market zone, to the increase in the Pirineos tariff due to the deferral of North-South income to the Pirineos tariff. As at 1 April 2020, this repayment totals €121.6/MWh/d/year. It will then evolve as at 1 April of each year based on inflation.

This payment is fully covered in the CRCP.

2.6.2 Inter-operator contract for GRTgaz's use of Teréga's network

In order to transport gas from the Fos Tonkin and Fos Cavaou LNG terminals to the north of France, GRTgaz sometimes uses Teréga's transmission network. For that purpose, GRTgaz and Teréga signed a service contract, the amount of which (roughly €36 million per year) is included in the net OPEX trajectory of each TSO.

The costs of this contract are fully covered in the CRCP.

2.6.3 Fee paid by Fluxys to GRTgaz for shipping from the Dunkerque LNG terminal to the Belgian border

The open season conducted by GRTgaz between 2010 and 2011 in coordination with Fluxys enabled the launch of the investments necessary for creating the Alveringem interconnection point. Capacity at the Belgium entry point from the Dunkerque LNG terminal is sold by Fluxys, with transmission in the GRTgaz network being a service provided by GRTgaz to Fluxys.

In its deliberation of 12 July 2011[17], CRE stated, given the projected costs for the development of this capacity, that the tariff billed by GRTgaz to Fluxys for transmission from the terminal to Belgium would be €45/MWh/d/year. CRE provided for the possibility of re-evaluating this amount based on the actual level of investments.

In compliance with the abovementioned deliberation, CRE recalculated the price of the service taking into account the costs of the project at completion. Therefore, the price of the service will total, as at 1 April 2020, €46.18/MWh/d/year.

2.6.4 Distribution of income at the PEG of the Trading Region France

Since the creation of the single market zone as at 1 November 2018, income at the PEG France is distributed between the TSOs that operate the Trading Region France.

CRE has decided to distribute this income in proportion to the operators' allowed revenue, i.e. 12% for Teréga and 88% for GRTgaz. As such:

- when a shipper has signed a transmission contract with GRTgaz only, or with GRTgaz and Teréga, it must pay the tariffs for accessing the PEG to GRTgaz. GRTgaz returns 12% of this income to Teréga;
- when a shipper has signed a transmission contract with Teréga, it must pay the tariffs for accessing the PEG to Teréga. Teréga pays 88% of this income to GRTgaz.

2.6.5 Payment by DSOs to TSOs relating to biomethane backhaul

In its public consultation of 23 July 2019 relating to the conditions for injecting biomethane into the gas networks and the introduction of an injection charge, CRE proposed for this charge to be billed as follows:

- to shippers for installations injecting into the transmission network;
- to producers for installations injecting into the distribution network.

In addition, CRE proposed for the income received by the DSOs from producers to which coefficient 3 applies, mostly associated with the use of backhaul, to then be transferred to the TSOs to finance the OPEX of backhaul benefiting users of natural gas distribution networks.

Some contributors considered that this difference in billing, as well as the transfer of DSO's income to TSOs, could generate operational complexities with the collection of the injection charge.

CRE considers that the principles envisaged in the public consultation must be maintained since they are adapted to the respective operational realities of the transmission and distribution system operators.

CRE has set the portion of income received for the level 3 injection tariff, returned by the DSOs to the TSOs concerned, at €0.65/MWh corresponding to the share of backhaul OPEX. Payment will be done annually, based on the volume of injection income actually received during the year, for producers connected to distribution networks to which the level 3 injection tariff apply. The volumes associated with these inter-operator transfers are fully taken into account in the CRCP.

The principles governing the inclusion of biomethane in the ATRT7 tariff are defined in section 4.3.4 of the deliberation.

2.6.6 Inter-TSO payment relating to the annual national change in main network tariff charges

As described in sections 2.1.3 and 2.2.2 of the present deliberation, the main network tariff charges change annually taking into account a $k_{national}$ coefficient.

This coefficient, between +2% and -2%, corresponds to the average of the k_{GRTgaz} and $k_{Teréga}$ coefficients weighted by capacity subscriptions, and will be applied uniformly to all main transmission network tariff charges.

[17] Deliberation by the Energy Regulatory Commission of 12 July 2011 deciding on the conditions for the connection of the Dunkerque LNG terminal to GRTgaz's network and on the development of a new interconnection with Belgium at Veurne

Therefore, an imbalance might appear between forecast income and the income to be received by each TSO. To compensate for any imbalance, the ATRT7 tariff specifies that the TSOs will settle the imbalance between themselves: the TSO that receives excess income will return the excess to the TSO that has a shortfall in revenue.

This payment is fully covered in the CRCP.

2.6.7 Payment by TSOs to storage operators relating to storage compensation

Storage compensation corresponds to the difference between the forecast allowed revenue of natural gas storage operators and the income they receive directly, mainly from the auctioning of storage capacity.

It is collected by the TSOs, which return it to storage operators.

3. LEVEL OF EXPENSES TO BE COVERED AND TRAJECTORY OF THE TARIFF FOR THE USE OF GRTGAZ'S AND TERÉGA'S NATURAL GAS NETWORKS

3.1 Level of expenses to be covered

3.1.1 Operators' tariff request and main associated issues

3.1.1.1 GRTgaz

GRTgaz considers that its tariff proposal aims to address several challenges, in particular:

- adapting its infrastructure to accommodate in the short term, the quantities of biomethane provided for in the draft PPE, and in the longer term renewable or low carbon gases essential to reaching the complete decarbonisation objectives of the energy mix;
- identifying long-term network uses in the context of reduced consumption;
- adapting the computer system in a context of increasing risks of digital malicious acts on strategic infrastructures, rising use of digital tools and growth in the volume of data exchanged and shared;
- reducing the company's environmental footprint by limiting the escape of methane and optimising energy consumption;
- controlling investment trajectories;
- supporting customers wishing to improve the performance of their equipment or switch their uses to gas so as to reduce their environmental footprint.

Taking into account the above-listed issues has led GRTgaz to request, for 2020, a total of €1,898.2 million[18] for expenses to be covered, i.e. €112.3 million more than the expenses incurred in 2018 (i.e. +6.3%).

3.1.1.2 Teréga

Teréga built its tariff proposal for gas transmission in connection with its business transformation plan "Impact 2025" characterised by the following strategic drivers:

- accelerating the digitalisation of the company through the transformation of information systems;
- accelerating the adaptation of gas infrastructure to accommodate new gases and the study of synergies between the different types of energy and their infrastructure (Smart Grids Multi-Energies);
- strengthening security and cybersecurity;
- improving the recognition and presence of the company in France and Europe;
- improving the company's energy efficiency and environmental responsibility.

Taking into account the above-listed issues has led Teréga to request, for 2020, a total of €276.7 million[19] for expenses to be covered, i.e. €35.3 million more than the expenses incurred in 2018 (i.e. +14.6%).

3.1.2 Operating expenses

3.1.2.1 Operators' requests

[18] Excluding smoothing effects, CRCP reconciliation and inter-operator flow
[19] Excluding smoothing effects, CRCP reconciliation and inter-operator flow

3.1.2.1.1 GRTgaz

The forecast net operating expenses, presented by GRTgaz in its demand concerning the 2020-2023 ATRT7 period, are as follows:

In current €M	2018 Actual	2020	2021	2022	2023
Net operating expenses	769.6	832.5	851.8	874.8	890.1

For net operating expenses, including energy costs, GRTgaz's request would lead to an increase by €62.8 million in 2020, i.e. +8.2% compared to the actual 2018 value. Excluding energy, the increase between the actual figure for 2018 and the demand for 2020 is +5.6%. Over the 2020-2023 period, net operating expenses then increase by an average +2.3% per year (an average +2.7%/year excluding energy).

The main items showing an increase between 2018 and 2020 in GRTgaz's demand are as follows:

- "payroll": GRTgaz expects a significant increase in staff over the ATRT7 period, which it justifies by the insourcing of key IS skills and the development of biomethane and new gases;
- "other operational support": the upward trend in staff as well as the end of major works and the business and company transformation involve, according to GRTgaz, a greater need for training, expenses for commercial studies, strategy and forecasts;
- "industrial system excluding R&D": the increase in expenses is linked, according to GRTgaz, to cyclical events associated with preventive maintenance, and the number of dismantling and decommissioning operations;
- "energy": GRTgaz foresees an increase in its expenses, which it justifies, on the one hand, by higher north-south flows than in 2018 due to a forecast drop in LNG inflow at the Fos terminal, and a higher flow forecast at the PIR Pirineos exit, and on the other hand, by the need to acquire CO_2 allowances during the ATRT7 period.

3.1.2.1.2 Teréga

The forecast net operating expenses, presented by Teréga in its demand concerning the 2020-2023 ATRT7 period, are as follows:

In current €M	2018 Actual	2020	2021	2022	2023
Net operating expenses	72.5	85.7	91.0	93.0	96.3

For net operating expenses, including energy costs, Teréga's request would lead to an increase by €13.2 million in 2020, i.e. +18.2% compared to the actual 2018 value. Excluding energy, the increase between the actual figure for 2018 and the demand for 2020 is +17.3%. Over the 2020-2023 period, net operating expenses then increase by an average +4.0% per year (an average +4.0%/year excluding energy).

Within the framework of its business project, Teréga wishes to mobilise significant human and material resources, with an upward impact on operating costs. The following items show the most significant increases between the actual 2018 figures and the 2020 forecast:

- "Personnel costs": the increase is linked mainly to a major increase in the number of employees;
- "telecommunications and IT": the increase is linked to the expansion of services and subscriptions on the Cloud, as part of the implementation of the company's new IS strategy;
- "major maintenance": the increase is related to an expected increase in compressor station maintenance;
- "Energy": Teréga foresees an increase in its expenses linked on the one hand, to a growth in electricity consumption and its price because of the use of green electricity, and on the other hand, to the integration of the domestic consumption tax and CO_2 allowances in its trajectory.

3.1.2.2 CRE's analysis

3.1.2.2.1 Challenges identified by CRE and the approach adopted

- **Reduction of expenses related to the development of major projects**

The improved functioning of the gas market, which is a main objective pursued by CRE since its creation, has been made possible thanks to the increased integration with neighbouring markets on the one hand, and the simplification of the organisation of the French market on the other hand. These two areas have required significant reinforcement works on the transmission network, in particular to reduce congestion, but also the implementation of information systems. The final stage after 15 years of major investments was reached with the merging, as at 1 November 2018, of the TRS and PEG Nord market places ("merging of the zones").

CRE considers that the size of the French transmission network is now sufficient to ensure the efficient functioning of the gas market, and that the merging of the zones marked the end of a cycle of major projects. This change in the TSOs' activity must lead to a reduction in the expenses associated with major investment projects, and to redeployments of the resources concerned to other activities.

Furthermore, the energy policy guidelines forwarded by the minister of state, minister of the ecological and inclusive transition, underline the "*importance of cost efficiency in order not to, one the one hand, make customers bear excessive costs and in order to, on the other hand, avoid stranded costs over time*".

- **The energy transition affects infrastructure management and requires reinforced vigilance regarding future costs**

The energy transition requires all gas system participants, operators and regulators alike, to think differently.

System operators must reconcile two contradictory trends:

- the drop in gas consumption, driven in particular by control of energy demand;
- the emergence of new costs to allow in particular the integration of renewable gases in the networks.

In order to control the development of future tariffs, against a foreseeable drop in consumption, changes in the TSOs' missions must be implemented, as soon as possible, using the existing resources.

- **Innovation among operators must be encouraged**

Innovation and the new possibilities offered by the digital revolution are a lever to optimise the costs associated with the transformation of networks imposed by the energy transition. The TSOs must favour the use of such innovative solutions if they help to reduce total costs for the community and/or the risks of over-investment or stranded costs.

In addition, because of their central role in the gas system, the TSOs must also be the enablers of innovation for users of their infrastructure.

CRE considers that system operators must have the necessary resources to successfully carry out these innovation projects, which are essential for providing an efficient and high-quality service to users of networks rapidly being modernised, and in particular, the resources to upgrade their network operation tools. In return, they must use these resources effectively and in a transparent manner.

- **Approach adopted by CRE for the analysis of net operating expenses**

Incentive regulation for operating expenses aims, by leaving operators 100% of any difference between the actual trajectory and the tariff trajectory, at encouraging them to improve their efficiency over the tariff period. The efficiency level revealed during the ATRT6 tariff period must be taken into account to establish the ATRT7 tariff, so that network users benefit from these productivity gains over time.

The trajectory of net operating expenses set by CRE corresponds to an overall envelope. Therefore, the TSOs have the freedom to distribute this envelope among the different types of expenses as they choose.

For these reasons, CRE requested the operators to submit their tariff proposals in light of the latest actual figures, justifying any significant difference in relation to the actual 2018 figures, and by breaking down each item of the tariff matrix.

CRE appointed the Schwartz and Co consultancy firm to audit the operating expenses of the natural gas transmission operators. Work was conducted between April and July 2019. The auditor's report, based on the initial version of the operators' requests, was published for each of the operators together with the public consultation document of July 2019.

This audit enabled CRE to have a clear and complete picture of the TSOs operating expenses and revenues recorded during the ATRT6 period and the estimated net operating expenses presented by the operators for the upcoming tariff period (2020-2023 period). The results of this audit have the following objectives:

- provide expertise on the relevance and justification of the operators' operating expenses trajectory for the next tariff period;

- assess the level of actual expenses (2018) and forecast expenses (2020-2023);
- formulate recommendations about the efficient level of operating expenses to be taken into account for the ATRT7 tariff.

CRE also conducted its own analyses regarding specific items, in particular research and development (R&D) expenses, energy costs and congestion management costs.

The conclusions of the audit report gave rise to debate with the TSOs during the month of June 2019. The TSOs were therefore able to express their observations about the results of the auditor's work.

Following the public consultation, discussions were continued between the TSOs and CRE on a certain number of net operating expense items. The level finally adopted by CRE is the result of these exchanges with the TSOs and its own analyses concerning the adjustments recommended by the auditor.

3.1.2.2.2 GRTgaz

At the end of its work, the auditor recommended the following trajectory for GRTgaz's operating expenses over the ATRT7 period:

GRTgaz, in current €M	2020	2021	2022	2023
Trajectory requested by GRTgaz	832.5	851.8	874.8	890.1
Actual costs (2018 inflated)	791.3	804.0	817.7	832.4
Auditor's trajectory (before productivity)	784.2	801.2	821.0	832.0
Auditor's trajectory (after productivity)	**784.2**	**800.8**	**814.6**	**822.8**
Impact on GRTgaz's request (after productivity)	-48.3	-51.0	-60.2	-67.3

The main adjustments recommended by the auditor relate to the costs associated with personnel, the information system and the industrial system. Following work conducted since the public consultation of 23 July 2019, CRE made a certain number of adjustments to this trajectory. The main adjustments it adopts compared to GRTgaz's proposal are presented below.

Personnel costs

Over the 2020-2023 period, GRTgaz wishes to carry out a net staff increase of 122 FTE employees (current headcount of roughly 3,000 FTE). According to GRTgaz's proposal, this net increase results from the need to open 230 positions, to be filled partly through 108 inhouse redeployments (redeployment of 59 persons previously assigned to other activities that have ended, such as the major network development projects, and 49 redeployments related to the operators' productivity efforts).

The auditor considers that the number of job openings (excluding those associated with the insourcing of IS skills, which is the subject of an *ad hoc* treatment) requested by GRTgaz is overestimated. Among the 230 position openings requested by GRTgaz, only 152 are considered by the auditor, for the following reasons:

- the increase in staff linked to development of biomethane (66 FTE requested) seems to be largely overestimated given the number of connections planned for the ATRT7 period (15 to 20 connections per year);
- the current stage of development of hydrogen and power to gas, as well as in the next four years, does not justify, according to the auditor, the recruitments planned by GRTgaz.

After an analysis of the historical evolution in the number of average FTE and the drop in capitalised production presented by GRTgaz, the auditor retains an estimate of inhouse redeployments of 65 FTE. In addition, it accepts the productivity target proposed by GRTgaz.

<u>CRE's analysis</u>

CRE agrees with the general analysis of the auditor, but made several adjustments in light of its discussions with the operator.

CRE considers, like the auditor, that with the end of major investment projects conducted by GRTgaz during the previous periods, staff can be redeployed to activities that create a need to open posts. It also accepts the productivity target proposed by GRTgaz concerning staff.

With regard to the request for recruitments related to biomethane development, CRE made several adjustments compared to GRTgaz's proposal:

- the energy policy guidelines forwarded to CRE by the minister of state, minister of the ecological and inclusive transition, specify that the assumptions to be taken into account concerning biomethane development "*shall be based on the multi-annual energy programme currently under consultation. It sets and an objective for biomethane injection into the gas networks of 6 TWh HHV for 2023 and between 14 to 22 TWh HHV for 2028.*" CRE adopts, in connection with these guidelines, a total volume of 6 TWh of biomethane injected within 2023, as specified by the draft PPE, which accounts for a -40% adjustment to the trajectories proposed by the system operators.

For GRTgaz, this adjustment equates to retaining 1.1 TWh of biomethane injection for 2023 (compared with 1.8 TWh in its proposal) and an annual average pace of 12 new connections per year over the ATRT7 tariff period (compared with 20 per year in GRTgaz's proposal). As proposed by the auditor, the staff expenses adopted by CRE are reduced in due proportion to this volume adjustment.

- The auditor had in fact considered that the resources per connection anticipated by GRTgaz were excessive. CRE only partially adopted the adjustment proposed by the auditor concerning this point.
- Lastly, given the major work that TSOs will have to undertake in the upcoming months to implement the provisions relating to the "injection right" and the high number of current connection requests, CRE adopts, for the year 2020, a specific additional envelope of €14 million.

In addition, CRE accepts part of GRTgaz's proposal concerning the recruitments for the operation of the pilot Power to gas Jupiter 1000 project and to conduct R&D studies in connection with the consequences of the injection of hydrogen into the networks.

Lastly, CRE adopted GRTgaz's proposal concerning assumptions of the evolution of the national base salary for the electricity and gas regime. It also adopts the operator's *Avantage Nature Energie* trajectory.

The trajectory adopted by CRE corresponds to a stable headcount over the ATRT7 period (excluding GRTgaz's IS insourcing project).

Information system

GRTgaz presented a project to insource key skills relating to the information system, which the auditor did not challenge. The auditor considered that the costs associated with insourced staff should be taken into account in the analysis of costs related to the information system. On the basis of a total cost approach, the auditor retained lower IS cost trajectories than those of GRTgaz (labour + operating expenses + investments).

Therefore, the auditor considered that the IS projects planned by GRTgaz fall within the scope of continuous transformations of the information system. In its opinion, these transformations are not, with the exception of cybersecurity projects, likely to constitute a major change justifying exceptional additional costs, and will have to be carried out as part of the recurring budget allocated to IS expenses.

The auditor proposed a total IS cost trajectory (labour + operating expenses + investments) equal to the actual figure for 2018 in current euros, to which it added the new operating costs related to cybersecurity proposed by GRTgaz.

<u>CRE's analysis</u>

CRE agrees with the auditor's analysis and therefore adopts the adjustment it recommends, i.e. an average -€7.1 million per year compared to GRTgaz's request.

Industrial system

The auditor elaborated the trajectory for most of the sub-items under this heading by indexing the actual 2018 figure to inflation. The auditor did so by taking into account the exceptional increase of some costs (in particular the costs related to the treatment and replacement of air compressors) and disregarding the €costs not justified by the operator (in particular the costs related to the obsolescence management programme). The trajectory proposed by the consultant is therefore in line with the actual 2018 figure (in current euros) on average over the ATRT7 period.

This results in an adjustment of an average -€12.6 million per year for industrial system costs, since GRTgaz's proposal was significantly higher than the actual 2018 costs.

<u>CRE's analysis</u>

CRE partly adopts the adjustment proposed by the auditor.

GRTgaz highlighted a net increase in its volume of delivery stations which have been in operation for more than 30 years, as well the risk of the occurrence of malfunctions at these stations over the ATRT7 period. Therefore, CRE adopts GRTgaz's demand regarding expenses for addressing the ageing of the network (i.e. an average €10.9 million per year in Network expenses). Other industrial system expenses (in particular management of obsolete PLCs) fall under, after discussions with the operator, investment costs. Therefore, CRE does not adopt them in the trajectory of net operating expenses; however, the tariff does provide GRTgaz with the resources to carry out these projects. CRE considers that the ageing of network assets must be examined by the operators when it comes to arbitration between maintenance operating costs to extend the lifetime of assets and investments to replace them.

GRTgaz also provided a detailed description of maintenance operations for compressors. This maintenance is regulatory and mandatory above 30,000 hours of operation. CRE therefore adopts the costs associated with this maintenance (i.e. €1.6 million/year between 2021 and 2023).

However, in order to ensure that the maintenance programmes associated with the trajectory set by CRE will be implemented, CRE requests GRTgaz to submit to it, at the end of the tariff period, a report on the maintenance programmes actually performed and the associated expenses, comparing them to the programmes presented by GRTgaz in its tariff proposal. If applicable, the expenses associated with maintenance that will not be implemented will be deducted from the net operating expenses to be covered by the next tariff.

In addition, CRE adopts a trajectory of expenses generated by investments (mainly dismantling costs related to work for third parties) at a level equal to that recorded in 2018, adjusted for inflation (i.e. an average €9.8 million per year).

Energy expenses

GRTgaz's request concerning energy costs (gas, electricity, CO_2) is based on a significant increase in North to South flows compared to 2018. GRTgaz foresees for 2020:

- a drop in entry flows in the Fos terminals (-37% compared to 2018);
- a growth in flows to Teréga (+62%) in connection with the merging of zones which enables the Spanish market to increase its ability to arbitrate between LNG, gaseous gas from the north of Europe and gaseous gas from Algeria. GRTgaz assumes a saturation of exit capacity at Pirineos (up to the firm capacity subscribed).
- a drop in consumption in the south zone (for GRTgaz's zone) based on consumption forecasts for the blue scenario in gas prospects[20] (-4% in 2023 compared to 2018).

	2018 actual	2020	2021	2022	2023	ATRT7 average
Gas (€M) *Volumes (GWh)*	43 *2,768*	56 *2,869*	54 *2,757*	56 *2,655*	56 *2,533*	**55** *2,703*
Electricity (€M) *Volumes (GWh)*	35 *430*	44 *539*	42 *507*	40 *475*	37 *443*	**41** 491
CO_2 (€M)	-	-	5	5	6	**4**
Domestic consumption tax (€M)	7	8	8	7	7	**8**
Total energy costs (€M)	**85**	**109**	**109**	**108**	**105**	**108**

CRE has adopted several adjustments to this request:

- the energy consumption volumes are reduced, given less conservative assumptions regarding the send-out of LNG at the Fos PITTM: taking into account the trends observed in the markets and estimates concerning the evolution of global LNG supply with the commissioning of Russian, American and Australian liquefaction plants, CRE adopts an annual average flow of 170 GWh/d at Fos, i.e. the average recorded over the last two years;
- consideration of a lower increase than that forecast by GRTgaz in delivery flow to Teréga compared to 2018 (+33% instead of +62%). A 62% increase in flows to Teréga, as forecast by GRTgaz, would in fact be technically difficult to reach. The increase estimated by CRE takes into account the increase in flows at Pirineos since the merging of zones (but not up to saturation as forecast by GRTgaz), and a slight drop in consumption in Teréga's zone;

[20] Natural gas and renewable gas prospects for 2018-2035: http://www.grtgaz.com/fileadmin/plaquettes/fr/2019/Perspectives-Gaz-2018.pdf

- the adjustment of gas volumes leads to correcting the trajectory of the domestic consumption tax (TIC) and the trajectory of CO_2 emissions in line with the drop in consumption;
- taking into account the future prices observed in the gas markets for the years from 2020 to 2023;
- consideration of a trajectory of the differences between the quantities of gas exiting and entering GRTgaz's network (EBT) in line with the latest actual figures observed and stable over the ATRT7 period.

These adjustments lead to the following trajectory:

	2018 actual	**2020**	**2021**	**2022**	**2023**	**Average ATRT7**
Gas (€M) *Volumes (GWh)*	43 *2,768*	49 *2,669*	48 *2,684*	45 *2,518*	45 *2,507*	**47** *2,595*
Electricity (€M) *Volumes (GWh)*	35 *430*	38 *458*	38 *460*	34 *405*	34 *404*	**36** 432
CO_2 (€M)	-	1	6	5	5	**4**
Domestic consumption tax - TIC (M€)	7	7	8	7	7	**7**
Total energy costs (€M)	85	96	99	91	91	**94**

Energy costs are 80% covered in the CRCP. Furthermore, the reference trajectory is updated annually. The difference between the updated trajectory and the initial trajectory is fully covered by the CRCP.

Research and development (R&D)

GRTgaz requests, for the ATRT7 period, a net operating expenses budget (excluding income from its research and innovation centre (RICE) and indirect expenses) of €134 million (i.e. €33 million per year over the period), divided into three goals:

- industrial safety (€29 million): to ensure the safety of property and people and the integrity of infra-structure;
- energy transition (€61 million): to promote the development of new gases, hydrogen and new gas uses, manage smart grids, and develop a long-term view of the energy sector;
- operational performance (€44 million): to increase the company's attractiveness, optimise the design and management of infrastructures, reduce environmental impacts and develop new materials.

For some programmes, the cost trajectories projected by GRTgaz have increased over the ATRT7 tariff, without any justification from the TSO.

CRE adopts the following adjustments:

- CRE considers that the studies linked to the accommodation of biomethane in the networks fall within the continuous developments undertaken at the start of the ATRT6 period and do not justify additional costs;
- CRE considers that GRTgaz's request for additional resources to develop more robust consumption models is relevant. These models are indeed inputs to works on gas operators' forecasts and medium-term investment plans. However, CRE considers that this item does not justify an increase in resources above the amount projected by GRTgaz in 2020 and therefore it maintains the envelope constant over the period:
- CRE does not accept the costs associated with certain programmes, in particular those aimed at promoting the role of natural gas in the energy mix, on the basis that they are not part of the TSOs' missions and are not intended to be covered by the tariffs. CRE does not accept either the programmes related to the attractiveness of the company and the integration of new generations, since CRE considers that they have no connection with R&D.

- CRE adopts an upward adjustment in RICE income: It is lower in GRTgaz's request compared to 2018. While CRE accepts the increase in expenses requested by GRTgaz for RICE activities, it considers that this increase must come with an effort by the company to promote its work externally. Therefore, CRE adopts an increase in RICE income equivalent to the increase in expenses requested by GRTgaz;
- lastly, CRE considered that "company attractiveness" did not correspond to R&D expenses and does not justify an increase in expenses. Therefore, it did not adopt the associated expenses.

As a result, CRE adopts the following R&D trajectory over the ATRT7 period:

GRTgaz, in current €M – R&D	2018	2020	2021	2022	2023
Research and innovation	8	14	15	17	18
RICE income	-8	-8	-8	-8	-8
Staff expenditure R&D	11	14	14	15	15
Indirect expenses	6	6	6	6	6
GRTgaz 2020 (excl. RICE)	10				
Trajectory adopted by CRE	27	26	28	29	31

The trajectory of R&D expenses is subject to an asymmetrical incentive described in section 2.5 of the deliberation.

Analysis of operator productivity

In addition to the item-by-item analysis, the auditor measured the change in GRTgaz's overall productivity concerning its operating expenses, by analysing the change in the ratio of net operating expenses per km of pipeline.

CRE's analysis

Following the item-by-item adjustments adopted by CRE, the level of GRTgaz's net operating expenses over the ATRT7 period is close to the actual expenses for 2018 adjusted for inflation. CRE considers that this trajectory takes into account the productivity efforts already undertaken by the operator, and therefore does not adopt any additional productivity effort.

Summary of CRE's analysis

The following tables summarise the trajectory of net operating expenses, resulting from the adjustments adopted by CRE for the ATRT7 tariff.

GRTgaz, in current €M	Actual 2018	2020	2021	2022	2023
GRTgaz's request		832.5	851.8	874.8	890.1
Adjustment adopted by CRE		-38.1	-47.6	-57.0	-57.5
Trajectory adopted by CRE	769.6[21]	794.4	804.1	817.8	832.6

GRTgaz, in current €M – Excl. energy	Actual 2018	2020	2021	2022	2023
GRTgaz's request		723.1	740.3	765.3	784.0
Adjustments adopted by CRE		-24.5	-35.7	-38.7	-42.4
Trajectory adopted by CRE	684.7[22]	**698.7**	**704.6**	**726.6**	**741.6**

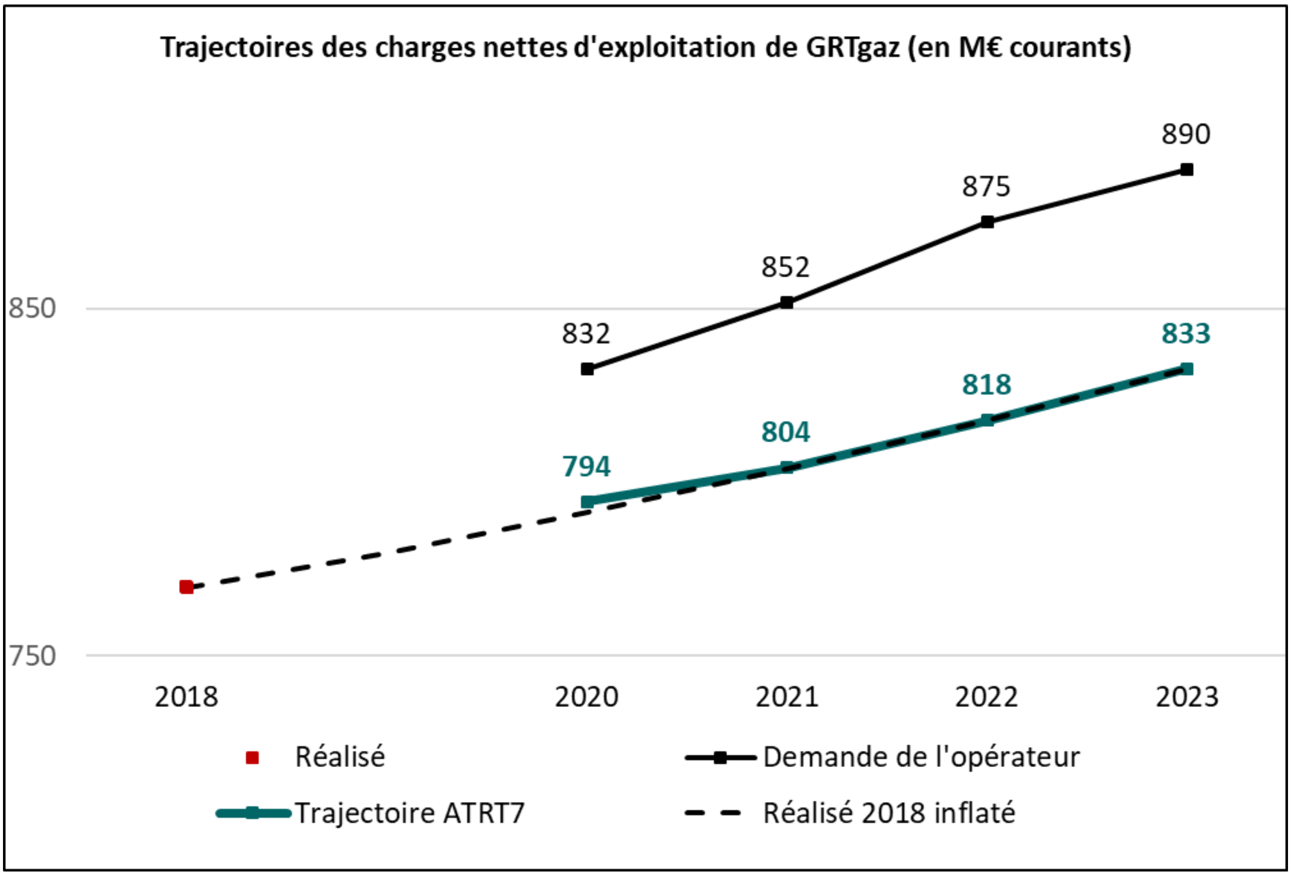
The trajectory adopted by CRE gives GRTgaz the means to:

- maintain the number of employees (excluding IS insourcing project);

[21] Actual expenses
[22] Actual expenses

- insource resources relating to information systems;
- meet new cybersecurity challenges;
- comply with the reinforcement of competences specified by the “security of supply” order;
- conduct R&D works, in particular concerning the accommodation of new gas into the transmission networks;
- have the necessary resources to enable the integration of biomethane into the networks in line with the objectives of the draft PPE and energy policy guidelines with, on the one hand, job openings, and on the other hand, an additional envelope to cope with a peak in activity related to the implementation of the injection right in 2020.

Therefore, the trajectory set by CRE projects a 3.2% increase in GRTgaz’s net operating expenses between 2018 and 2020 (+2% excluding energy). The net operating expenses then increase by an average +1.6% per year over the 2020-2023 period (+2% per year, excluding energy).



Forecast inflation considered: +1.3% in 2019; +1.5% in 2020; +1.6% in 2021; +1.7% in 2022; +1.8% in 2023

3.1.2.2.3 Teréga

At the end of its work, the auditor recommended the following trajectory for Teréga’s operating expenses over the ATRT7 period:

Teréga, in current €M	2020	2021	2022	2023
Trajectory requested by Teréga	85.7	91.0	93.0	96.3
Actual costs (2018 inflated)	74.6	75.8	77.0	78.4
Auditor’s trajectory (before productivity)	80.0	84.2	86.1	87.4
Auditor’s trajectory (after productivity)	**80.0**	**81.6**	**81.1**	**80.7**
Impact on Teréga’s request (after productivity)	-5.7	-9.4	-12.0	-15.6

The main adjustments recommended by the auditor are related to costs for personnel and shared resources.

Following work conducted since the public consultation of 23 July 2019, CRE made a certain number of adjustments to this trajectory. The main adjustments it adopts compared to Teréga's proposal are presented below.

Personnel costs

Personnel costs and shared resources are largely determined at an overall level for Teréga (transmission and storage), and are then broken down into Transmission and Storage activities using a distribution key. The adjustments considered by CRE follow this methodology.

In terms of personnel costs, in its tariff proposal, Teréga requested a net increase of 40 staff members for the ATRT7 period (based on a total staff of 561 FTE as at end 2018), including 19 employees to support the reorganisation of the operations division. The auditor considered that the 19 job positions to support the implementation of this reorganisation do not correspond to a long-term need and should therefore not be a motive for recruitment of internal personnel. Therefore, it considered that Teréga should plan for recruitments aimed at a stable headcount as from 2019, which involves coordinating recruitments and retirements. The auditor therefore retained a net increase of 21 personnel over the ATRT7 period compared to 2018.

Furthermore, it recommended not retaining Teréga's proactive policy concerning employee benefits. It considers that the operator should strive to avoid the voluntary significant increase in these costs, especially in the light of a growth context for the other operating expenses.

<u>CRE's analysis</u>

CRE agrees with the auditor's analysis concerning the trajectory of Teréga's personnel and adopts its adjustment. It considers that the recruitments made in 2019 enable Teréga to carry out the company transformation undertaken since 2018.

CRE also adopts the auditor's adjustment regarding Teréga's wage policy to harmonise it with that of other gas infrastructure operators.

Therefore, it adopts an adjustment of an average -€3.6 million per year compared to Teréga's request.

Shared resources

Most of the difference between the auditor's trajectory and that requested by Teréga is related to Telecommunications/IT. Teréga requests a considerably high increase in the IS cost trajectory which it justifies by the need to adapt the IS tool (digitalisation and reinforcement of cybersecurity).

The auditor considered that the IS projects presented by Teréga to justify the significant increase in expenses fall within a recurring need to adapt the IS tools rather than an extensive transformation project, and that for the purposes of cost efficiency, such projects should be carried out with a constant budget.

Therefore, the auditor recommended an IS cost trajectory lower than that of Teréga, on the basis of a total cost approach and aimed at, at the end of the tariff period, amounting to the 2017 envelope for such expenses (in constant euros).

Therefore, the auditor recommended an adjustment of an average -€5.6 million per year within the scope of the company for shared resources compared to Teréga's request.

<u>CRE's analysis</u>

CRE agrees with the total cost approach applied by the auditor to determine the envelope of expenses at the end of the ATRT7 period. However, it adopts a productivity objective in 2023 based on a longer period of observation: the 2015-2018 average instead of only the year 2017, since the latter represents a "low point" in Teréga's IS expenses.

In addition, CRE adopted stable communication expenses for Teréga compared to historical levels, and included in this trajectory a portion of the expenses for institutional relations and crisis management and on-call duty, for which Teréga justified the need.

Therefore, CRE adopted an adjustment of an average €3.1 million per year for the shared resources item.

In addition, CRE accepted, as indicated in section 2.3.2.4 of the deliberation, Teréga's request to experiment, regarding IS expenses, a TOTEX (common OPEX and CAPEX trajectory) incentive mechanism. Concerned assets would be taken into account the operator's RAB at an amount fixed *ex ante* in the TOTEX trajectory, and not based on the actual expenses incurred.

Revisions and major repairs

In its tariff proposal, Teréga projected expenses related to major maintenance work in 2023. Given the forecast maintenance plan provided by Teréga, the auditor proposed to retain only 50% of the considerable increase in expenses between 2022 and 2023, in order to materialise the risk of a deferral of this maintenance to the following tariff period.

CRE's analysis

CRE adopts Teréga's request for 2023 concerning its projected maintenance (i.e. €2.3 million in 2023).

However, in order to ensure that the maintenance programmes associated with the trajectory set by CRE are implemented, CRE requests Teréga to submit to it, at the end of the tariff period, a report on the maintenance programmes actually performed and the associated expenses, comparing them to the programmes presented by Teréga in its tariff proposal. If applicable, the expenses associated with maintenance projected for 2023 that will not be implemented will be deducted from the net operating expenses to be covered by the next tariff.

Production costs

The auditor recommended an adjustment of an average -€1.5 million per year to production costs, essentially linked to the consideration of the historical average observed or the actual 2018 level to establish its forecast of certain items.

CRE's analysis

CRE globally adopts the trajectory recommended by the auditor, to which it reincorporates additional expenses, in particular expenses related to Teréga's integrated management programme (SMILE), which aims at simplifying Quality processes and enable Teréga to be eligible for ISO certification.

Therefore, CRE adopts an adjustment of an average -€1.2 million per year for production costs compared to Teréga's request.

Energy expenses

The tariff proposal submitted by Teréga in March 2019 and updated in June 2019 concerning energy expenses (gas, electricity, CO_2), was based on the assumption of major flows to Spain and the partial substitution of Teréga's gas consumption for its compression needs by electricity consumption. Furthermore, in its proposal, Teréga introduced the domestic consumption tax on energy products – TICPE) as well as the purchase of CO_2 emissions.

	2018 actual	2020	2021	2022	2023	Average ATRT7
Total energy costs (€M)	6.5	8.1	8.0	8.4	8.5	**8.3**

Teréga wished to update its proposal in September 2019. It considered indeed that the major transfer of gas consumption to electricity consumption which it assumed, for several electrical compressors, might not be achieved to the level expected. According to Teréga, this situation is due to the major increase in quantities transported in its network since the merging of zones.

Teréga in fact expected lower quantities to be transported in summer after the merging of zones, which would have enabled it to use electrical compressors as planned at Barbaira and Lussagnet.

Teréga new request is summarised below:

	2018 actual	2020	2021	2022	2023	Average ATRT7
Gas (€M) *Volumes (GWh)*	4.6 *258*	4.9 *290*	5.0 *290*	5.0 *290*	5.0 *290*	**5.0** *290*
Electricity (€M) *Volumes (GWh)*	1.9 *19*	2.4 *27*	2.4 *27*	2.4 *27*	2.4 *27*	**2.4** 27
CO_2 (€M)	-	1.1	1.2	1.3	1.5	**1.3**

Domestic consumption tax - TIC (M€)	-	1.1	1.1	1.1	1.1	**1.1**
Total energy costs (€M)	6.5	9.5	9.7	9.9	10.0	**9.8**

CRE adopts, based on flow assumptions that are consistent with those envisaged for GRTgaz's energy costs, several adjustments in relation to this request:

- a downward adjustment in gas and electricity volumes for certain compressor stations: with the exception of the Lussagnet station for which Teréga's latest request has been adopted, the gas and electricity volumes consumed by Teréga's compressors are set at the average 2018-2019 level. This average takes into account both historical consumption and the increase in flows observed in 2019 in connection with the merging of zones;
- the adjustment of gas volumes leads to correcting the trajectory of the domestic consumption tax (TIC) and the trajectory of CO_2 emissions in line with the drop in consumption;
- the consideration of prices observed in the gas markets for the years 2020 to 2023 (average of the calendar prices observed at the end of 2019).

These adjustments lead to the energy expenses trajectory below:

	2018 actual	**2020**	**2021**	**2022**	**2023**	**Average ATRT7**
Gas (€M) *Volumes (GWh)*	4.6 *258*	4.4 *253*	4.5 *253*	4.5 *253*	4.5 *253*	**4.5** *253*
Electricity (€M) *Volumes (GWh)*	1.9 *19*	2.0 *24*	2.0 *24*	2.0 *24*	2.0 *24*	**2.1** 24
CO_2 (€M)	-	0.7	0.7	0.7	0.7	**0.7**
Domestic consumption tax - TIC (M€)	-	0.9	0.9	0.9	0.9	**0.9**
Total energy costs (€M)	**6.5**	**8.0**	**8.0**	**8.1**	**8.1**	**8.1**

Energy costs are 80% covered in the CRCP. Furthermore, the reference trajectory is updated annually. The difference between the updated trajectory and the initial trajectory is fully covered by the CRCP.

Research and innovation (R&I)

For the ATRT7 period, Teréga requested a net operating expenses budget for R&I of €11.1 million (an average €2.8 million per year over the period). This budget breaks down as follows:

- **Control of greenhouse gas emissions and Energy Efficiency (€0.9 million)**: deployment of solutions for the reduction of methane emissions, and energy optimisation;
- **Infrastructure integrity (€4.0 million)**: control and adaptation of methods for pipeline protection, implementation of innovative tools and methods for the inspection of inaccessible structures.
- **Operational Performance and Safety (€0.6 million)**: real-time automated network surveillance, deployment of predictive equipment maintenance, deployment of digital tools to safeguard and improve on-site operations.
- **New Gases (€1.7 million)**: maximisation of the integration of green gases in the networks and verification of their proper accounting;
- **Regional integration and environmental footprint (€0.2 million)**: biodiversity protection, environmental compensation and impact reduction measures in construction and/or operation;
- **Personnel and Shared Resources costs (€3.6 million).**

For some R&D programmes, CRE considers that the increases in expense trajectories requested by Teréga are not justified:

- the increase in expenses related to the study of the impact of biomethane on installations is not justified. These studies were indeed launched during the ATRT6 period and will continue over the ATRT7 period. For these studies, CRE adopts the average budget observed over the ATRT6 period;
- CRE does not adopt the expenses associated with projects that it considers as having no connection with the TSO's missions;
- lastly, the expenses related to energy production projections (thermal energy from turbines, energy released from gas pressure reduction) are not sufficiently justified by Teréga. Therefore, CRE adopts them only partially.

As a result, CRE adopts the following R&D trajectory over the ATRT7 period:

Teréga, in current €M – R&I	Actual 2018	2020	2021	2022	2023
R&I	1.5	1.7	1.7	1.7	1.8
R&I management	0.2	0.3	0.3	0.3	0.3
Staff expenditure	0.5	0.6	0.6	0.6	0.7
Trajectory adopted by CRE	2.2	2.5	2.6	2.6	2.7

Analysis of operator productivity

In addition to the item-by-item analysis, the auditor measured the change in Teréga's overall productivity concerning its operating expenses. To do so, it measured the level of productivity attained by Teréga during the 2017-2018 period and compared it to the level of projected productivity based on Teréga's tariff proposal. In order to analyse the productivity level, the auditor adopted a constant scope of activity from which the most variable income and expenses were excluded (income from services to third parties, income related to interconnections and transit, storage costs[23], energy expenses).

The auditor recommended aiming for at least the same level of productivity for 2023 as in 2018. It therefore recommended an average drop of -€3.6 million per year (i.e. -€14.3 million cumulated over the ATRT7 period) in net operating expenses.

CRE's analysis

Following CRE's item-for-item adjustments, Teréga's net operating expenses remain significantly high, above inflation. This increase is justified, according to Teréga, by the objective to transform the company, a large part of which was already undertaken in 2018 and 2019.

Nevertheless, Teréga did not quantify the gains brought by this transformation.

Therefore, CRE adopts a productivity objective for Teréga, equal to a 2.1% drop in net OPEX over the period, i.e. €7.3 million over the four years.

Summary of CRE's analysis

The following tables summarise the trajectory of net operating expenses adopted by CRE for the ATRT7 tariff:

Teréga, in current €M	Actual 2018	2020	2021	2022	2023
Teréga's proposal		85.7	91.0	93.0	96.3
Adjustment adopted by CRE		-3.3	-7.6	-8.5	-10.5
Trajectory adopted by CRE	72.5[24]	**82.4**	**83.4**	**84.5**	**85.9**

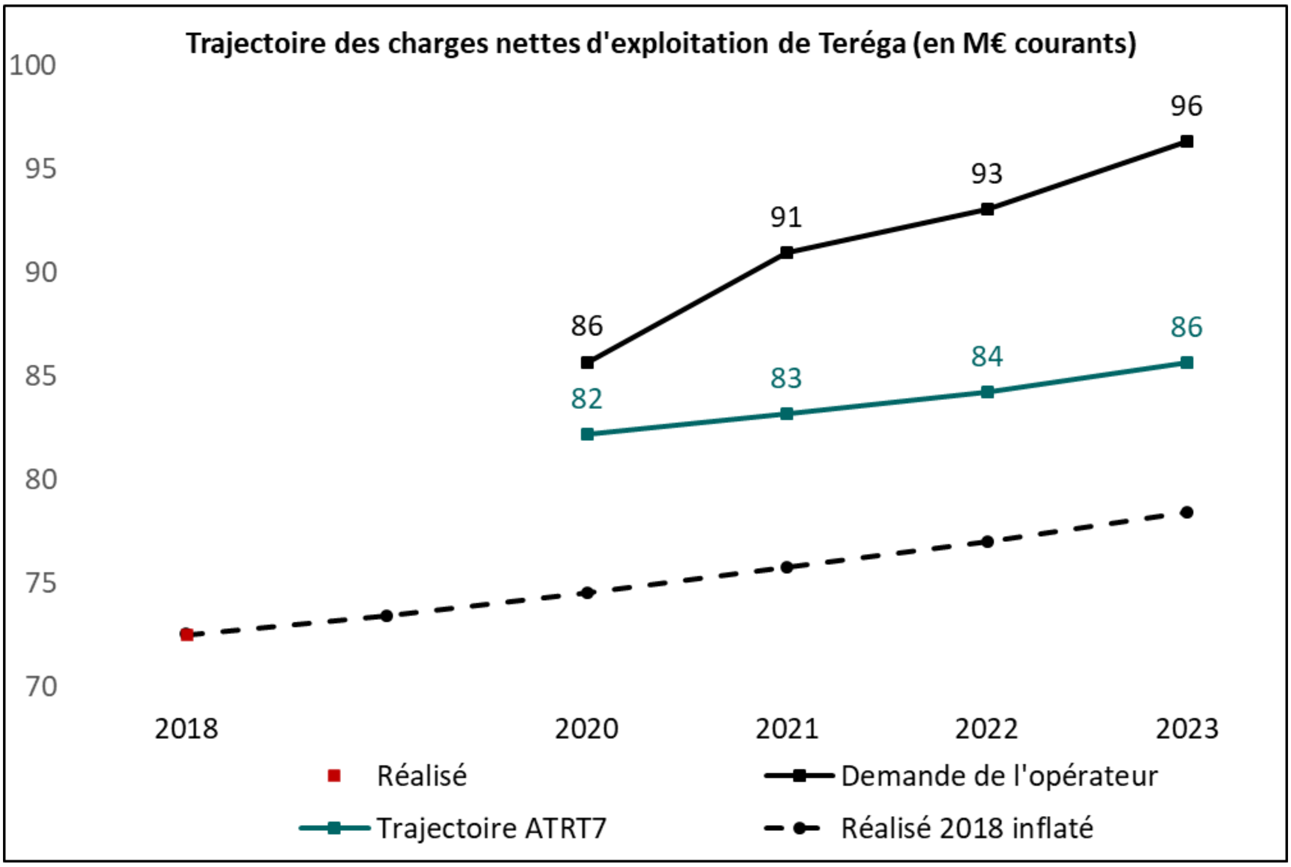
[23] Contract for rebilling between transmission and storage activities
[24] 2018 actual expenses

Teréga, in current €M – Excl. energy	Actual 2018	2020	2021	2022	2023
Teréga's proposal		77.5	82.7	84.1	87.2
Adjustments adopted by CRE		-3.0	-7.3	-7.7	-9.4
Trajectory adopted by CRE	66.0[25]	**74.4**	**75.4**	**76.4**	**77.8**

CRE made the proactive choice to support Teréga in its transformation project. The trajectory adopted by CRE will enable Teréga to:

- carry out the company transformation undertaken since 2018, through the adaptation of its information system, the recruitment of the skills necessary for the transformation and the capacity to participate in European groups and influential groups;
- implement the maintenance programme and operate its network under optimal safety conditions;
- conduct R&D works, in particular concerning the accommodation of new gas into the transmission networks and the development of multi-energy systems;
- implement a TOTEX experiment for information systems as proposed by the operator.

Therefore, the trajectory set by CRE projects a 13.6% increase in Teréga's net operating expenses between 2018 and 2020 (+12.7% excluding energy). The net operating expenses then increase by an average +1.4% per year over the 2020-2023 period (+1.5% per year, excluding energy).



Forecast inflation considered: +1.3% in 2019; +1.5% in 2020; +1.6% in 2021; +1.7% in 2022; +1.8% in 2023

3.1.3 Calculation of normative capital expenses

3.1.3.1 Weighted average cost of capital

The principles for calculating capital expenses (in particular the methodology for determining the different parameters that are the basis for calculating the WACC in a CAPM methodology (see section 2.1.2.1) were readopted during the previous tariff periods. However, in the different tariffs, CRE modified its assessment of the weighted average cost of capital (WACC) for the natural gas transmission activity.

[25] 2018 actual expenses

- **Operators' proposals**

For the ATRT7 tariff period, the operators' proposals were established using:

- a WACC identical to that of the current ATRT6 tariff, i.e. 5.25% (real, before tax), for GRTgaz;
- a WACC of 5.50% (real, before tax), higher than that of the ATRT6 tariff, for Teréga.

These proposals were based on the conclusions of a study commissioned by the gas operators with an external consultant, as well as on the results of a study ordered by Teréga from a second external auditor.

- **CRE's analysis**

CRE re-examined the various parameters used to calculate the WACC. In addition, it ordered an external consultant to audit GRTgaz's and Teréga's proposals concerning the return on capital. This report was published together with the public consultation of July 2019.

In the public consultation of July 2019, CRE stated that it was considering a WACC between 3.6% and 4.4% (real, before tax), down compared to the WACC in the ATRT6 tariff (5.25%).

A great number of participants in the public consultation stated that the range envisaged by CRE was justified, particularly given current market conditions, and supported the drop in WACC envisaged by CRE. The gas infrastructure operators and their shareholders requested the same WACC or a smaller reduction compared to that in effect over the ATRT6 period.

CRE re-examined the various parameters used to calculate the WACC.

The WACC is calculated by applying the following formulas:

$$\text{Nominal WACC before CT} = [(\text{RFR} + \text{debt spread}) \times (1 - \text{deductibility of financial costs} \times \text{CT}) / (1 - \text{CT})] \times g + (\text{RFR} + \beta \times \text{MRP}) / (1 - \text{CT}) \times (1 - g)$$

$$\text{Actual WACC before CT} = (1 + \text{nominal WACC before CT}) / (1 + \text{inflation}) - 1$$

For the ATRT7 tariff, CRE adopts the value of 4.25% as the WACC (real, before tax) to remunerate the gas operators' RAB. The values adopted by CRE for each of these parameters are shown in the table below:

Parameters of the ATRT7 WACC	
Nominal risk-free rate (RFR)	1.7%
Debt spread	0.9%
Asset beta	0.50
Equity beta (β)	0.86
Market risk premium (MRP)	5.2%
Leverage (debt/(debt + equity capital)) (g)	50%
Corporate tax (CT)	28.02%
Tax deductibility for financial expenses	100%
Cost of debt (nominal, before CT)	2.6%
Cost of equity (nominal, before CT)*	8.6%
WACC (nominal, before CT)	5.6%
Inflation	1.3%
WACC (real, before CT)	**4.25%**

**i.e. nominal remuneration of equity after CT of 6.2% (6.4% for ATRT6)*

Compared to the values taken into account to define the WACC in the ATRT6 tariff, the main modifications, in line with the evolution in macroeconomic and financial data, relate, in particular, to the change in the risk-free rate, the asset beta and taxation.

The risk-free rate adopted stands at 1.7%. It is down 100 points compared to that adopted for the ATRT6 tariff (2.7%). This drop is justified by the significant and long-term fall in interest rates. The method adopted by CRE to estimate the risk-free rate applicable in the calculation of the WACC for the ATRT7 tariff remains unchanged compared to that adopted for the ATRT6 tariff.

CRE bases its decision concerning the value of the risk-free rate on the observation of the yields of French government bonds ("OAT"), considered as the most low-risk investments, for a period of ten years, and for OATs with a maturity of 10 years. These parameters, used for all regulated infrastructure tariffs, had led to a risk-free rate of 2.7% in the ATRT6 tariff. The ten-year maturity of OATs is the most commonly used by sector regulators. A ten-year period of observation of ten-year OATs also makes it possible to take into account changes in the financial markets, while maintaining stable and foreseeable conditions for remunerating energy infrastructure in France.

The asset *bêta* – set at 0.50 – has increased compared to the level adopted for the ATRT6 tariff period (0.45).

CRE bases its decision concerning the asset *bêta* on market observations and the *bêtas* of the activity of gas operators in Europe. It also takes into account the significant increase in uncertainty concerning long-term gas prospects in France, particularly in the light of the anticipated drops in gas consumption envisaged in France and the risk of stranded costs within the framework of the draft PPE, and the national carbon neutrality objective for 2050 confirmed by the Energy climate law passed on 8 November 2019.

Furthermore, CRE takes into account the developments set out by the draft finance law for 2020, which modifies the normal corporate tax rate gradually until 2022, when the 25% normal corporate tax rate will apply uniformly to all companies. Therefore, for the ATRT7 period, CRE adopts a corporate tax rate of 28.02%, which is the average of the corporate tax rate applicable to the gas TSOs over the 2020-2023 period. The effect of this drop in the tax rate represents roughly 30 basis points in the drop in the WACC of the ATRT7 tariff compared to that in effect over the ATRT6 period.

In compliance with what was outlined in section 2.1.2.3, assets under construction (AuC) are remunerated at the nominal cost of debt before tax, i.e. 2.6% within the framework of the ATRT7 tariff.

3.1.3.2 Investments

The calculation of the RAB and capital expenses for establishing the forecast trajectory of the ATRT7 tariff takes into account the investment projections supplied by the TSOs.

3.1.3.2.1 GRTgaz

The trajectory of GRTgaz's investment expenses over the ATRT7 period is marked by the reduction in investment expenses, with average expenses of €436 million per year over the period, compared to roughly €530 million per year during the ATRT6 period. This reduction is mainly due to the end of large investments in transmission infrastructures development since the creation of the single market zone.

CRE considers that the trajectory proposed by GRTgaz reflects the change in the need for investments in the transmission networks and is in line with the end of a major investment cycle. Most large infrastructure projects were carried out successfully and GRTgaz is now entering a phase which will see a slowdown in its investments.

In its public consultation of 23 July 2019, CRE shared its analyses of certain evolutions in the investment trajectory requested by GRTgaz, in particular concerning the expenses associated with the development of biomethane, included in the Connections objective. Most participants shared CRE's analyses, and reiterated that the draft PPE set a biomethane objective of 6 TWh for 2020.

However, Articles L. 134-3 and L. 431-6-II of the energy code provide for the approval of the annual investment budgets of the natural gas TSOs. Therefore, GRTgaz's projects will be approved by CRE within the framework of the annual approval of the TSOs' investments and the differences with the forecast trajectory will be fully covered by the CRCP mechanism.

Therefore, CRE adopts the investment expenses trajectory requested by GRTgaz for the ATRT7 tariff period:

In current €M	2020	2021	2022	2023	Annual average ATRT7	Annual average ATRT6*
Fluidity enhancement	4.6	-	-	-	1.1	172.7
Public service obligations (PSOs)	65.1	114.0	47.0	39.6	66.4	34.4
Environment	8.1	8.6	8.5	8.1	8.3	10.0
Safety	91.2	91.2	91.5	90.4	91.1	97.0
Obsolescence	96.3	92.3	90.5	89.9	92.3	86.1
Connections, extensions and services for third parties	76.7	64.1	89.5	102.7	83.2	45.6
IS jobs	44.7	46.9	50.2	49.4	47.8	30.4
Support	48.1	47.2	44.8	42.6	45.7	54.2
TOTAL (excluding subsidies)	**434.8**	**464.3**	**422.0**	**422.7**	**435.9**	**530.3**

*Average of actual investment programmes for 2017, 2018 and approved for 2019

3.1.3.2.2 Teréga

The trajectory of Teréga's investment expenses over the ATRT7 period is marked by a small slowdown in investment expenses, with average expenses of €108 million per year over the period, compared to roughly €122 million per year during the ATRT6 period. This slowdown is mainly due to the end of large investments in transmission infrastructures development since the creation of the single market zone. This drop is largely offset by increases in certain expense items.

In its public consultation of 27 July 2019, CRE enquired about the significant increases in certain expense categories, particularly concerning security and maintenance items. Most market participants expressed their concerns about the sustainability of gas prices, and the need for vigilance concerning the TSOs' investment expenses.

However, Articles L. 134-3 and L. 431-6-II of the energy code provide for the approval of the annual investment budgets of the natural gas TSOs. If necessary, the projects will be approved by CRE within the framework of the annual approval of the TSOs' investments, and the differences with the forecast trajectory will be fully covered by the CRCP mechanism.

As for GRTgaz, and for the same reasons, CRE adopts the investment expenses trajectory requested by Teréga for the ATRT7 tariff period:

In current €M	2020	2021	2022	2023	Annual average ATRT7	Annual average ATRT6*
Developments	10.4	3.3	3.5	6.9	6.0	56.5
Reinforcements	-	-	-	0.2	0.0	6.1
Connections	1.9	1.2	1.1	-	1.1	0.8
Security and maintenance	77.8	83.8	83.6	86.2	82.8	40.9
IS jobs	12.7	10.0	7.6	7.8	9.5	12.2
General investments	11.3	11.6	5.9	4.2	8.3	5.9
TOTAL	**114.1**	**109.9**	**101.7**	**105.2**	**107.7**	**122.4**

*Average of actual investment programmes for 2017, 2018 and approved for 2019

3.1.3.3 Normative capital expenses

3.1.3.3.1 GRTgaz

- **Trajectory of capital expenses**

The table below presents the forecast trajectory of GRTgaz's RAB and assets under construction (AuC) for 2020 to 2023:

Regulated asset base (RAB) and assets under construction (AuC)

GRTgaz, in current €M	2020	2021	2022	2023	Average 20-23
RAB as at 01/01/Y	8,803.1	8,898.0	9,070.9	9,047.2	8,954.8
Commissioned*	458.5	545.7	356.0	406.7	441.7
Depreciation	-502.7	-522.0	-540.2	-533.2	-524.5
Revaluation	139.0	149.3	160.5	178.2	156.7
RAB as at 31/12/Y	8,898.0	9,070.9	9,047.2	9,098.9	9,028.8
Assets under construction (AuC)	432.6	409.1	290.2	336.3	367.0

*Investments entering the RAB

The forecast regulated asset base breaks down as follows:

Regulated asset base (RAB) as at 01/01/Y	2020	2021	2022	2023

GRTgaz	**8,803.1**	**8,898.0**	**9,070.9**	**9,047.2**
Pipes and connections	*5,451.0*	*5,413.0*	*5,479.2*	*5,451.8*
Compression	*1,435.5*	*1,477.0*	*1,481.1*	*1,480.8*
Delivery, regulation and metering stations	*581.6*	*651.6*	*734.2*	*763.7*
Property, construction, land	*693.1*	*719.3*	*750.8*	*767.3*
Other (material, tools, software, IS, etc.)	*641.9*	*637.1*	*625.7*	*583.7*

The table below outlines the forecast trajectory of GRTgaz's normative capital expenses for 2020-2023:

GRTgaz, in current €M	Average 17-19	2020	2021	2022	2023	Average 20-23
Depreciation of assets in service	475.9	502.7	522.0	540.2	533.2	524.5
Return on assets in service	514.7	451.5	452.7	458.5	456.4	545.8
Return on AuC	27.9	11.2	10.6	7.5	8.7	9.5
Return on subsidies	4.7	5.8	5.7	5.7	5.6	5.7
Coverage of small stranded costs	3.3	5.8	5.8	5.8	5.8	5.8
Tariff retreatment	-4.7	-2.2	-0.4	-0.4	-0.4	-0.8
Total normative capital expenses *of which "non-network" normative CAPEX*	**1,021.8**	**974.7** *89.4*	**996.4** *101.8*	**1,017.3** *112.0*	**1,009,3** *108,1*	**999.4** *102.8*

- **Trajectory of "non-network" capital expenses**

The table below outlines the specific trajectory of GRTgaz's RAB, AuC and normative CAPEX for 2020 to 2023, subject to a specific regulation defined in section 2.2.3.4 of the deliberation.

GRTgaz, in current €M	2020	2021	2022	2023	Average 20-23
RAB as at 01/01/Y	*357.5*	*400.1*	*426.4*	*423.1*	*401.8*
Depreciation of assets in service	71.7	82.6	91.9	88.1	83.6
Return on assets in service	15.4	17.2	18.3	18.1	17.2
Assets under construction (AuC)	*91.5*	*76.9*	69.8	*72.7*	*77.7*
Return on AuC	2.4	2.0	1.8	1.9	2.0
Total "non-network" normative CAPEX	**89.4**	**101.8**	**112.0**	**108.1**	**102.8**

3.1.3.3.2 Teréga

- **Trajectory of capital expenses**

The table below presents the forecast trajectory of Teréga's RAB and assets under construction (AuC) for 2020 to 2023:

Regulated asset base (RAB) and assets under construction (AuC)

Teréga, in current €M	2020	2021	2022	2023	Average 20-23

RAB as at 01/01/Y	1,574.6	1,617.4	1,681.8	1,775.3	1,662.3
Commissioned*	94.7	116.0	145.2	110.4	116.6
Depreciation	-77.4	-79.7	-83.1	-85.5	-81.4
Revaluation	25.5	28.1	31.4	-80.0	1.2
RAB as at 31/12/Y	1,617.4	1,681.8	1,775.3	1,720.2	1,698.7
Assets under construction (AuC)	98.5	116.2	106.7	67.3	97.2

*Investments entering the RAB

The forecast regulated asset base breaks down as follows:

Regulated asset base (RAB) as at 01/01/Y	2020	2021	2022	2023
Teréga	**1,574.6**	**1,617.4**	**1,681.8**	**1,775.3**
Pipes and connections	*1,137.4*	*1,180.6*	*1,243.1*	*1,349.0*
Compression	*217.9*	*214.8*	*214.3*	*205.9*
Delivery, regulation and metering stations	*63.9*	*67.8*	*68.8*	*76.9*
Property, construction, land	*47.9*	*48.2*	*47.5*	*46.7*
Other (material, tools, software, IS, etc.)	*107.4*	*105.8*	*108.1*	*96.8*

The table below outlines the forecast trajectory of Teréga's normative capital expenses for 2020-2023:

Teréga, in current €M	Average 17-19	2020	2021	2022	2023	Average 20-23
Depreciation of assets in service	69.8	77.4	79.7	83.1	85.5	81.4
Return on assets in service	90.5	85.4	87.1	89.5	90.9	88.2
Return on AuC	5.3	2.6	3.0	2.8	1.7	2.5
Return on subsidies	1.2	1.5	1.4	1.4	1.4	1.4
Coverage of small stranded costs	0	0.3	0.3	0.3	0.3	0.3
Tariff retreatment	-0.3	-0.2	-0.2	-0.2	-0.2	-0.2
Total normative capital expenses	**166.6**	**166.9**	**171.2**	**176.9**	**179.7**	**173.7**
of which "non-network property and vehicles" normative CAPEX		*5.4*	*6.5*	*7.7*	*7.9*	*6.9*
of which "information systems" normative CAPEX		*15.5*	*16.0*	*16.1*	*15.8*	*15.9*

- **Trajectory of "non-network" capital expenses**

The table below outlines the specific trajectory of Teréga's RAB, AuC and normative CAPEX under "non-network – property and vehicles" assets for 2020 to 2023, subject to a specific regulation defined in section 2.2.3.4 of the deliberation.

Teréga, in current €M	2020	2021	2022	2023	Average 20-23
RAB as at 01/01/Y	*40.3*	*46.2*	*53.2*	*53.1*	*48.2*
Depreciation of assets in service	3.5	4.4	5.3	5.6	4.7
Return on assets in service	1.7	2.0	2.3	2.3	2.1
Assets under construction (AuC)	*4.6*	*5.6*	*2.1*	*1.3*	*3.4*
Return on AuC	0.1	0.1	0.1	0.1	0.1
Total “non-network - property and vehicles” normative CAPEX	**5.4**	**6.5**	**7.7**	**7.9**	**6.9**

- **Trajectory of IS TOTEX**

The table below outlines the specific trajectory of Teréga’s commissioning of assets, its normative CAPEX, and TOTEX under “non-network – property and vehicles” assets for 2020 to 2023, subject to a specific regulation defined in section 2.2.3.4 of the deliberation.

Teréga, in current €M	2020	2021	2022	2023	Average 20-23
RAB as at 01/01/Y	*44.6*	*45.5*	*42.9*	*37.5*	*42.6*
Depreciation of assets in service	13.4	13.9	14.2	14.1	13.9
Return on assets in service	1.9	1.9	1.8	1.6	1.8
Assets under construction (AuC)	*6.8*	*5.3*	*4.1*	*4.2*	*5.1*
Return on AuC	0.2	0.1	0.1	0.1	0.1
Total "non-network–IS” normative CAPEX	**15.5**	**16.0**	**16.1**	**15.8**	**15.9**

Teréga, in current €M	2020	2021	2022	2023	Average 20-23
IS commissioned	13.6	10.6	8.2	8.3	10.2
IS OPEX	10.2	11.7	13.4	13.3	12.2
IS TOTEX	**23.8**	**22.3**	**21.6**	**21.6**	**22.3**

3.1.4 CRCP as at 31 December 2019

3.1.4.1 GRTgaz

<u>Operator's request</u>

In its tariff proposal, GRTgaz estimated the CRCP balance as at 31 December 2019 at €5.2 million, to be deducted from the expenses to be covered, including -€34.6 million for previous remaining CRCP amounts, -€3.6 million for the final 2018 CRCP and €36.8 million for the provisional 2019 CRCP. The latter mainly consists of:

- lower subscription income for 2019 than the tariff forecasts in GRTgaz's request, in particular for subscriptions at the PITS and exits to the regional network, as well as regional network transmission and delivery income;
- expenses for the H-L gas conversion service higher than forecast following CRE's deliberation of 13 December 2018 deciding on the terms for accessing the zone supplied with low calorifc gas ("L gas")[26];

CRE's analysis

The CRCP balance as at 31 December 2019 estimated by CRE in the calculation of GRTgaz's allowed revenue amounts to €33.5 million, which will be added to the expenses to be covered. The difference compared to GRTgaz's request is related mainly to:

- for the final 2018 CRCP: the inclusion of costs incurred for congestion management;
- for the provisional 2019 CRCP:
    - stranded costs related to Eridan project studies: CRE, as it indicated in its deliberation of 11 July 2019, adopts GRTgaz's proposal to abandon the Eridan project and therefore to no longer undertake any additional expenses to extend the authorisations associated with this project. Therefore, the studies relating to this project, which represent €36.7 million, are considered as stranded costs for GRTgaz. In compliance with the tariff framework applicable to stranded costs, these costs are covered in the tariffs;
    - the adjustment of assumptions concerning energy costs and congestion management costs.

[26] CRE deliberation of 13 December 2018 deciding on the terms for accessing the zone supplied with low calorific gas ("L gas")

GRTgaz	GRTgaz request (€M)	Amounts adopted by CRE (€M)
Remainder from previous CRCPs	**-34.6**	**-34.6**
Difference between the CRCP estimated for end 2018 and the final CRCP for 2018	**-3.6**	**-4.0**
Estimated differences between expenses and income for 2019	**33.1**	**72.2**
of which transmission income covered 100%	24.3	24.3
of which transmission income covered 80%	-4.8	-4.9
of which income for connection of CCGTs and CTs	1.8	1.8
of which normative capital expenses	*0.1*	*38.3**
of which energy expenses	-0.4	-3.6
of which inter-operator contract	0.6	-0.1
of which income related to inter-operator payment	0.0	-1.3
of which difference in OPEX due to inflation	0.0	0.1
of which service quality	*0.0*	*1.8*
of which H-L gas conversion service (variation in volumes)	10.8	10.8
of which pilot conversion of the L zone to H gas	0.0	-0.3
of which separation of R&D activities from the parent company	-0.1	-0.1
of which income from services to third parties related to major land-use planning projects	0.7	0.7
of which congestion management costs	0.0	4.6
CRCP balance as at 31 December 2019	-5.2	33.5 **

*integrating Eridan stranded costs

**The CRCP balance as at 31 December 2019 therefore corresponds to the return of a sum of €33.5 million to the TSO.

The amount of the CRCP balance as at 31 December 2019 will be spread across four years and included in the allowed revenue for the ATRT7 period. Since the amount for differences for the year 2019 are provisional, the final value will be included in the CRCP balance as at 31 December 2020.

3.1.4.2 Teréga

<u>Operator's request</u>

In its tariff proposal, Teréga estimated the CRCP balance as at 31 December 2019 at €3.0 million, to be added to the expenses to be covered, including €4.0 million for the previous remaining CRCP amounts, €1.3 million for the final 2018 CRCP and €-2.3 million for the provisional 2019 CRCP. The latter mainly consists of:

- 2019 subscription income higher than tariff forecasts, particularly regarding income from the PIR Pirineos exit;
- capital expenses higher than forecast mainly in connection with the inflation rate used to re-evaluate the RAB which is higher than the forecast rate used in the tariff trajectory;
- inter-operator payments higher than the tariff forecasts;
- income from services to third parties higher than tariff forecasts;
- the amount for the domestic consumption tax for 2019 for which Teréga considered that it was not eligible.

<u>CRE's analysis</u>

The CRCP balance as at 31 December 2019 estimated by CRE in the calculation of Teréga's allowed revenue amounts to €0.9 million, which will be added to the expenses to be covered. The difference compared to Teréga's request is related mainly to:

- for the final 2018 CRCP: the inclusion of income related to services for third parties received in 2018
- for the provisional 2019 CRCP: the adjustment of assumptions concerning energy costs, subscriptions and congestion management costs.

In addition, Teréga requested, after it had submitted its tariff proposal, the coverage of €2.4 million for the risk of a tax adjustment: Since it did not pay any domestic consumption tax over the ATRT6 period, it believes it may be required to pay €2.4 million for the years 2016-2018. CRE considers that it is the responsibility of each infrastructure regulator to comply with the tax framework in effect, and that Teréga's expenses were covered globally over the tariff period. It does not retain this request.

Teréga	Teréga's request (€M)	Amounts adopted by CRE (€M)
Remainder from previous CRCPs	**4.0**	**4.0**
Difference between the CRCP estimated for end 2018 and the final CRCP for 2018	**1.3**	**-1.3**
Estimated differences between expenses and income for 2019	**-0.8**	**-1.8**
of which transmission income covered 100%	0.3	0.3
of which transmission income covered 80%	-6.3	-6.7
of which normative capital expenses	*2.2*	*2.2*
of which energy expenses	*0.9*	*0.5*
of which inter-operator contract	*0.1*	*0.1*
of which inter-operator payment	*1.3*	*1.3*
of which difference in OPEX due to inflation	*0.0*	*0.0*
of which service quality	*0.6*	*0.6*
of which congestion management costs	*0.8*	*0.6*
of which income from services to third parties related to major land-use planning projects	*-0.7*	*-0.7*
CRCP balance as at 31 December 2019	**4.4**	**0.9***

*The CRCP balance as at 31 December 2019 therefore corresponds to the return of a sum of €0.9 million to the TSO.

The amount of the CRCP balance as at 31 December 2019 will be spread across four years and included in the allowed revenue for the ATRT7 period. Since the amount for differences for the year 2019 are provisional, the final value will be included in the CRCP balance as at 31 December 2020.

3.1.5 Allowed revenue for the 2020-2023 period

GRTgaz's and Teréga's allowed revenue for the 2020-2023 period is defined as the sum of the following elements:

- net operating expenses (see section 3.1.2);
- normative capital expenses (see section 3.1.3);
- the financial flow of inter-operator payment, from Teréga to GRTgaz, for the partial deferral of income received at the Pirineos exit (see section 2.6.1);
- reconciliation of the CRCP balance calculated as at 31 December 2019 (see section 3.1.4).

3.1.5.1 GRTgaz

GRTgaz's forecast allowed revenue breaks down as follows:

GRTgaz, in current €M	2020	2021	2022	2023	Average 20-23
Net operating expenses	794,4	804,1	817,8	832,6	**812,2**
Normative capital expenses	974,7	996,4	1017,3	1009,3	**999,4**
Reconciliation of the CRCP balance (remainder from previous CRCPs + 2018 balance + 2019 estimate)	8,7	8,7	8,7	8,7	**8,7**
Allowed revenue, excluding inter-operator payment	1 777,9	1 809,3	1 843,8	1 850,7	**1 820,4**
Inter-operator payment	-19,6	-19,8	-20,1	-20,2	**-19,9**
ATRT6 smoothing (remainder)	-6,3	-6,3	-6,3	-6,3	**-6,3**
Allowed revenue	**1752,0**	**1783,2**	**1817,4**	**1824,2**	**1 794,2**

Excluding Teréga's payment, GRTgaz's allowed revenue therefore changes by -0.7% between 2018 and 2020 (mainly related to the drop in the rate of return), and by +1.4% per year on average over the ATRT7 period.

3.1.5.2 Teréga

Teréga's forecast allowed revenue breaks down as follows:

Teréga, in current €M	2020	2021	2022	2023	Average 20-23
Net operating expenses	82,4	83,4	84,5	85,9	**84,0**
Normative capital expenses	166,9	171,2	176,9	179,7	**173,7**
Reconciliation of the CRCP balance (remainder from previous CRCPs + 2018 balance + 2019 estimate)	0,2	0,2	0,2	0,2	**0,2**
Allowed revenue, excluding inter-operator payment	**249,5**	**254,9**	**261,6**	**265,8**	**258,0**
Inter-operator payment	19,6	19,8	20,1	20,2	**19,9**
ATRT6 smoothing (remainder)	-0,8	-0,8	-0,8	-0,8	**-0,8**
Allowed revenue	**268,4**	**273,9**	**281,0**	**285,2**	**277,1**

Excluding payment to GRTgaz, Teréga's allowed revenue therefore changes by +2.3% between 2018 and 2020 (mainly related to the drop in the rate of return), and by +2.1% per year on average over the ATRT7 period.

3.2 Forecast capacity subscriptions

3.2.1 Operators' proposals

GRTgaz and Teréga have established forecast subscription trajectories for the ATRT7 period. They take into account, on the one hand, capacity subscriptions in their portfolio, and, on the other hand, their assumptions concerning the development of natural gas consumption for 2023 and new capacity subscriptions at the different network points during the ATRT7 period. CRE analysed the trajectories forwarded by the TSOs and made the adjustments it deemed necessary, which are presented below.

3.2.1.1 GRTgaz

GRTgaz submitted two trajectories of capacity subscriptions differentiated by the evolution in peak consumption in the regional network. These two scenarios lead to an average drop in subscriptions of -2.3% per year and -1.4% per year on average respectively.

In October 2019, GRTgaz forwarded its best estimate to date, in which the initial forecasts are globally revised downwards, with the exception of subscriptions at the Montoir PITTM. GRTgaz's new trajectory is based on the following assumptions:

- additional subscriptions at the Montoir PITTM, and a drop in subscriptions at Fos Tonkin;

- a downward revision for subscriptions at the PITS in compliance with Storengy's sale forecasts;
- a drop in industrial clients' subscriptions which GRTgaz justifies by (i) the non-anticipated closure of several sites in 2019, and lower than expected development. GRTgaz assumes that the drop observed in 2019 will continue into the ATRT7 period;
- a drop in subscriptions at the PITDs in connection with the drop in the projected winter peak;
- a drop in CCGT subscriptions related to the elimination of the short-notice interruptible offer.

% of change in capacity subscriptions per year	2020	2021	2022	2023	Average change
Main network (PIR, PITTM, PITS), exit to regional network	-3.2%	-1.8%	-1.7%	-1.0%	-1.9%
Regional network	-1.4%	-1.4%	-0.8%	-1.3%	-1.2%

Apart from the subscriptions at points upstream and downstream of the network, GRTgaz included in its subscription income:

- an income from penalties for exceeding subscriptions downstream (based on the latest actual figures);
- income forecasts at the PEG[27] up an average 5% per year over the ATRT7 period;
- other forecast income (UIOLI, *Alizés* service, etc.) stable over the ATRT7 period;
- a cost of roughly €4.0 million/year related to the possible introduction of the guaranteed interruptibility mechanism.

In addition, GRTgaz integrated in its scenario, as from 2020, the elimination of the short-notice interruptible offer (IAPC) which had been envisaged by CRE in its public consultations.

3.2.1.2 Teréga

Teréga submitted a forecast subscription scenario based on the following assumptions:

- a drop in entry subscriptions at Pirineos in 2023 related to the expiration of certain long-term contracts;
- a drop in subscriptions at the PITDs in connection with the drop in the projected winter peak;
- a high level of subscription at the PITS.

% of change in capacity subscriptions per year	2020	2021	2022	2023	Average change
Main network (PIR, PITS), exit to regional network	-1.1%	-0.1%	-0.1%	-6.9%	-2.1%
Regional network	+0.4%	-0.7%	-0.7%	-0.7%	-0.4%

Apart from the subscriptions at points upstream and downstream of the network, Teréga included in its subscription income:

- forecast income at the PEG stable over the ATRT7 period;
- other income forecasts (UIOLI, SET, etc.) down -8% in 2020 then stable over the ATRT7 period.

3.2.2 CRE's analysis

3.2.2.1 GRTgaz

CRE adopts the subscriptions corresponding to the scenario proposed by GRTgaz termed the "best estimate", with the exception of:

- firm annual subscriptions at the Montoir and Fos PITTMs;
- subscriptions of industrial clients and CCGTs: CRE has retained the actual level of subscriptions for the last few months of 2019, in order to take into account the drops observed by GRTgaz;

[27] Income at the PEG are distributed according to the key 12% (Teréga)/88% (GRTgaz)

Therefore, the forecast subscription trajectory is as follows:

% of change in capacity subscriptions per year	2020	2021	2022	2023	Average change
Main network (PIR, PITTM, PITS), exit to regional network	-2.9%	-0.9%	-1.6%	-0.6%	-1.5%
Regional network	-0.9%	-1.0%	-0.5%	-1.1%	-0.9%

Lastly, CRE does not retain the cost related to the possible implementation of the interruptibility mechanism. Any costs related to the remuneration by TSOs of customers connected to the transmission network that have signed an interruptibility contract will be fully covered in the CRCP.

3.2.2.2 Teréga

The subscriptions adopted by CRE, at points upstream and downstream of the network correspond globally to Teréga's scenario. Teréga's forecasts are deemed reasonable and in compliance with the historical trends observed and reflect the positive effects on the one hand, of the merging of zones (a high level of exit subscriptions at the PIR Pirineos) and on the other hand, of the reform of third-party access to storage (a high level of subscriptions at the PITS). However, CRE adopts an average annual 5% increase in income trajectory at the PEG[28], in line with GRTgaz's trajectory, and a trajectory of income from non-transmission services (PEG and SET) at the level of the average observed for 2018 and 2019.

Therefore, the forecast subscription trajectory, at points upstream and downstream of the network, adopted by the ATRT7 tariff, is as follows:

% of change in capacity subscriptions per year	2020	2021	2022	2023	Average change
Main network (PIR, PITS), exit to regional network	-1.0%	+0.0%	-0.2%	-7.1%	-2.1%
Regional network	0.4%	-0.7%	-0.8%	-0.7%	-0.4%

3.3 Trajectory of the tariff for the use of the natural gas transmission network

CRE is committed to the principle of tariff continuity. Therefore, to avoid major variations, sometimes of opposite direction, between tariff periods, or from one year to another, it smooths the change in tariff charges based on the trajectory of expenses to be covered and the forecast subscriptions for the tariff period.

3.3.1 GRTgaz

The tariff applicable as at 1 April 2020 is defined in part 5 of the present deliberation. It corresponds to an average 1.4% increase in the unit tariff compared to the current tariff.

The tariff change as at 1 April 2020, as well as the annual changes to the tariff over the years 2021 to 2023, are determined so that the total projected income, resulting from the application of the ATRT7 tariff to capacity subscription assumptions, are equal, in present value terms for 2020 to 2023, to the total allowed revenue for the period. The principles governing the annual change in tariff charges are defined in section 2.2.3 of the deliberation.

Given the balance between forecast subscription income and allowed revenue over the 2020-2023 period and annual changes in the tariffs, annual differences between income and allowed revenue may exist. The sum discounted at the risk-free rate of 1.7%, of these annual differences over the period is, by construction, equal to 0. The principles governing the annual change in charges are defined in section 2.2.3 of the deliberation.

Therefore, for the ATRT7 tariff period, the forecast allowed revenue and estimated income are as follows:

[28] Income at the PEG are distributed according to the key 12% (Teréga)/88% (GRTgaz)

GRTgaz, in current €M	2020	2021	2022	2023	Net discounted value
Forecast allowed revenue	1752,0	1783,2	1817,4	1824,2	6 879,8
Forecast tariff income equal to the smoothed allowed revenue used to calculate the annual change in the tariff (excluding reconciliation of the CRCP balance)	1795,9	1782,1	1794,8	1802,1	6 879,8
Annual difference between forecast income and the projected allowed revenue	43,9	-1,0	-22,6	-22,2	0,0

Teréga

The tariff applicable as at 1 April 2020 is defined in part 5 of the present deliberation. It corresponds to an average 0.7% increase in the unit tariff compared to the current tariff.

The tariff change as at 1 April 2020, as well as the annual changes to the tariff over the years 2021 to 2023, are determined so that the total projected income, resulting from the application of the ATRT7 tariff to capacity subscription assumptions, are equal, in present value terms for 2020 to 2023, to the total allowed revenue for the period.

Given the balance between income and allowed revenue over the 2020-2023 period and annual changes in the tariffs, annual differences between income and the allowed revenue may exist. The sum discounted at the risk-free rate of 1.7%, of these annual differences over the period is, by construction, equal to 0. The principles governing the annual change in charges are defined in section 2.2.3 of the deliberation.

Therefore, for the ATRT7 tariff period, the forecast allowed revenue and estimated income are as follows:

Teréga, in current €M	2020	2021	2022	2023	Net discounted value
Forecast allowed revenue	268,4	273,9	281,0	285,2	1 062,4
Forecast tariff income equal to the smoothed allowed revenue used to calculate the annual change in the tariff (excluding reconciliation of the CRCP balance)	280,1	278,5	279,7	269,3	1 062,4
Annual difference between forecast income and the projected allowed revenue	11,8	4,6	-1,3	-15,8	0,0

4. STRUCTURE OF THE TARIFFS FOR THE USE OF THE NATURAL GAS TRANSMISSION NETWORK

4.1 Representation of the network and scope covered by the ATRT7 tariff

The transmission network is associated with a single market zone, the Trading Region France (TRF).

The transmission network comprises, on the one hand, the main network, and on the other hand, the regional network. Users of GRTgaz's and Teréga's networks make several uses of the gas transmission network: transit, which consists in having gas enter the networks to ship it to another country; and domestic transmission, which consists in shipping gas to be consumed in France. Users may also use underground natural gas storage.

Moreover, in the north of France, there is an "L gas" zone supplied in low calorific gas (called "L gas"), whose network is physically separated from the rest of the French transmission network.

The French natural gas transmission network in 2019

CRE defines the gas transmission tariffs to avoid any cross-subsidisation between the different categories of transmission network users, particularly between users accessing the network for transit and those supplying domestic consumption. It also ensures the absence of cross-subsidisation between the two network categories, main and regional, by guaranteeing that the income received at each network corresponds to the expenses generated by their use.

The structure of the ATRT7 tariff covers three categories: the main network, the regional network and the storage compensation.

- Main network

The main network is composed of network elements that connect the interconnection points with (i) adjacent transmission networks (ii) exits to the regional network, (iii) LNG terminals and (iv) storages. It covers more than 9,500 km. Flows are generally bi-directional.

The tariff structure of the main network is based on an entry/exit pricing principle per market place. Gas can be bought and/or sold directly in the market place or gas exchange point (PEG). In this case, the user pays the specific tariff charges at the PEG.

Users can bring gas into France by interconnections through pipes (network interconnection points, or PIRs) or by LNG terminals (transmission/LNG terminal interface points, or PITTMs) and for this they pay entry charges at these points. These charges are identical regardless of the destination of the gas (transit, storage or domestic consumption).

The gas exits the main network at different points, based on its destination:

- to ship the gas to a neighbouring country, in particular for transit uses, users pay an exit charge at the PIR;
- to supply national consumption, users pay a charge for exit to the regional network.

Underground natural gas storage facilities are located on the main network. Network users access those facilities by paying entry and exit charges at the transmission/storage interface points (PITS).

The pricing principles of the main network are described in section 4.2 of the deliberation.

- Regional network

The regional network is composed of network elements that enable gas to be shipped from the main network to end customers or distribution networks. It covers more than 28,000 km. Flows are generally uni-directional.

Supply of each delivery point requires the subscription, on the one hand, of transmission capacity, and on the other hand, of delivery capacity. There are three types of delivery points:

- transmission/distribution interface points (PITDs) which represent the interface between the transmission network and one or several exits to the distribution network;

- sites of industrial customers directly connected to the transmission network;
- interconnection points on the regional network (PIRRs) which enable delivery to foreign regional networks.

The pricing principles of the regional network are described in section 4.3 of the deliberation.

- Storage compensation

Introduced in the ATRT tariff in 2018, within the framework of the regulation of the conditions for accessing natural gas storage infrastructure, storage compensation corresponds to the difference between forecast allowed revenue of natural gas storage operators and the income they receive directly, mainly for auctioning storage capacity. It is collected by the TSOs, which return it to the storage operators. The principles for collecting compensation are presented in section 4.4 of the deliberation.

4.2 Main network tariff structure

4.2.1 Methodology for calculating reference prices

4.2.1.1 Distribution of main network and regional network costs, and storage compensation

4.2.1.1.1 Classification of services provided by the TSOs

Article 4 of the Tariff network code distinguishes between the services provided by the TSOs, the transmission services[29], and those that are ancillary services (non-transmission services)[30]. This article specifies that "*the transmission services revenue shall be recovered by capacity-based transmission tariffs*" and that "*the non-transmission services revenue shall be recovered by non-transmission tariffs applicable for a given non-transmission service*." The Tariff network code specifies that the non-transmission services tariffs shall comply with the following principles: *"a) cost-reflective, non-discriminatory, objective and transparent; b) charged to the beneficiaries of a given non-transmission service with the aim of minimising cross-subsidisation between network users."*

The services provided by the TSOs are classified as follows:

- transmission services: the services provided by the TSOs in the main network. Pricing in this network follows an entry/exit model and is based on capacity and distance;
- non-transmission services:
  - the services provided by the TSOs in the regional network. This network does not follow an entry/exit model since there is no entry charge. However, pricing in this network takes into account the distance compared to the main network. In addition, since only domestic clients use these networks, they bear 100% of the costs, as in the ATRT6 tariff. Any cross-subsidisation between transit flows and flows destined for domestic consumption are therefore avoided;
  - storage compensation: collected by the TSOs from their clients and paid back to storage operators, this compensation does not aim to reflect the costs of a service provided by the TSO, but to compensate storage operators' allowed revenue in compliance with Article L. 452-1 of the energy code.

4.2.1.1.2 General principles of the reference method

During the past tariff periods, the ATRT tariff was defined to meet several objectives, in particular:

- non-discrimination: network users incur the same costs for the same use of the network (the level of the tariff charges borne by users at a given entry or exit point in the French network remains identical regardless of the use of the point in question);
- reflect costs: the tariff aims to reflect the costs and send a relevant economic signal to network users, through, on the one hand, the use of relevant cost drivers (including capacity and distance) to set the tariff charges, and on the other hand, the launch of open seasons for long-term capacity reservations in order to ensure financing of network developments;
- acceptability of updates: tariff updates must be progressive and structural changes in the tariff must be duly justified and addressed in public consultations so that all stakeholders have sufficient and necessary visibility for the market to function properly.

[29] "Transmission services", the regulated services that are provided by the transmission system operator within the entry-exit system for the purpose of transmission
[30] "Non-transmission services", the regulated services other than transmission services and other than services regulated by Regulation (EU) No 312/2014 that are provided by the transmission system operator

CRE's methodology for calculating reference prices is based on the observation that a large majority of TSOs' costs are fixed costs that remain constant in the short term even if the use of the network varies (they represent roughly 90% of total costs in France). These costs are, for the most part, costs directly related to the level of investments and are therefore closely linked to investment strategy. This investment strategy is planned taking into account the network limits that must be lifted in order to guarantee the main flow scenarios and configurations.

In principle, in order for the tariff paid by each network user to perfectly reflect the costs, these costs must be distributed among network users generating investment needs. However, since the French transmission network is complex and heavily meshed, perfect reflectivity of costs is difficult to attain. A compromise must be found to maintain a sufficiently simple and stable transmission tariff. For that purpose, CRE defines in particular relevant flow scenarios which are described in the sections below.

4.2.1.1.3 Distribution of main network and regional network costs, storage compensation and connection with relevant flow scenarios

The costs related to the transmission network are distributed to avoid any cross-subsidisation between the different categories of network users:

- main network costs (roughly €900 million/year) are considered as costs associated with transmission services[31] and are therefore allocated to two categories of network users (users accessing the network for transit, and those supplying domestic consumption);
- regional network costs (roughly €1,100 million/year) are considered as costs associated with non-transmission services[32], allocated only to users supplying domestic consumption, which are the only users;
- storage compensation costs (roughly €500 million in 2019) are considered as non-transmission services costs, allocated to domestic consumption.

However, it must be noted that the abovementioned distribution of costs is closely linked to and consistent with the definition of the relevant flow scenarios adopted to distribute the main network costs among the different categories of network users. In fact, the flow scenarios adopted by CRE in its methodology are those that enable the allocation of regional network costs and storage compensation to only domestic customers:

- with regard to the regional network: the flow scenarios adopted by CRE take into account only the distance to reach the main network exit and not the distance to reach the end customer by crossing the entire regional network. Therefore, CRE has chosen to attribute regional network costs to domestic consumption, and the distance calculated to supply domestic consumption is reduced accordingly;
- with regard to the storage compensation: full gas storage facilities benefit all network users, including those transiting gas through France, because of a higher level of security of supply. However, CRE chose to exclude storage from the relevant flow scenarios for transit and therefore did not distribute the storage compensation costs across the different transit exit points.

Therefore, different flow scenarios would inevitably involve a different distribution of main network costs, regional network costs and storage compensation.

4.2.1.1.4 Balance between costs and income attributable to the main network and the regional network

Since the first gas transmission tariffs were implemented, CRE has sought to ensure a balance, for each TSO, on the one hand, between costs assigned to the main network and the income its operation generates, and on the other hand, between the costs assigned to the regional network and the income its operation generates.

For the ATRT7 tariff period, CRE maintains the principle of an average balance over the tariff period between main network and regional network costs and income.

Therefore, CRE requested the TSOs to distribute their costs between those relating to the main network and those relating to the regional network. This distribution is based on the following two principles:

- investment expenses and most operating expenses can be directly allocated to one of the networks by the TSOs and therefore are assigned to them;
- for a minor part of operating expenses that are too general for direct assignment (e.g. head office costs), the TSOs apply a distribution key: the expenses in question are distributed in proportion to network kilometres.

[31] As defined by the Tariff network code
[32] As defined by the Tariff network code

In accordance with these principles, over the ATRT7 period, the TSOs make the following forecast cost distributions, within the perimeter of France:

	Perimeter of France	
	% of main network expenses	% of regional network expenses
Average ATRT7	46%	54%

The level of tariff charges is therefore set in the ATRT7 tariff so that income collected in the main network represent 46% of total income and income collected in the regional network represent 54% of total income.

4.2.1.2 Methodology for determining tariffs for large-scale transmission

4.2.1.2.1 Main principles of main network pricing

- **Capacity-based pricing**

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

This pricing principle is compatible with the Tariff network code, which specifies, in its Article 4, that transmission services revenue is recovered by capacity-based transmission tariffs. This pricing method takes into account, in particular, the positive effect that predictable and stable sites have on the gas system, particularly in terms of investment reduction. Therefore, for equal consumption, the supplier of a thermosensitive customer must book more capacity, to cover peak consumption, which can be far from average consumption.

CRE's proposal to maintain the principle of pricing fully based on capacity was supported by all contributors to the public consultations of March and July 2019.

For the ATRT7 period, CRE maintains the principle of 100% capacity-based pricing.

- **Entry-exit system**

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

This entry-exit pricing principle complies with the provisions of (EC) regulation No. 715/2009 of 13 July 2009 concerning conditions for access to the natural gas transmission networks, which set out that the tariffs applicable to network users will be non-discriminatory and fixed separately for each transmission network entry and exit point.

Contributors to the public consultations of March and July 2019 are in favour of the re-adoption of this entry-exit pricing system in the ATRT7 tariff.

For the ATRT7 period, CRE readopts the entry-exit pricing system.

- **Harmonisation of GRTgaz's and Teréga's tariffs**

The ATRT6 tariff provided for the harmonisation of a certain number of tariffs on a national scale. The tariffs at the Dunkerque, Virtualys, Obergailbach, Oltingue and Pirineos entry points are identical. This is also the case for the entry charges at the Dunkerque, Montoir and Fos entry points. The alignment of these charges offers shippers the possibility of choosing the most competitive source of supply.

In addition, the tariffs at the exits from GRTgaz's and Teréga's main networks to their regional networks are aligned, as are the tariffs at the PITS in Teréga's and GRTgaz's networks.

CRE's proposal to maintain the principle of harmonising tariffs was supported by all contributors to the public consultations of March and July 2019.

For the ATRT7 tariff, CRE maintains the principle of harmonisation of some of GRTgaz's and Teréga's tariffs in effect in the ATRT6 tariff.

- **Distribution of costs and income between main network entry and exit points**

In addition to seeking a balanced distribution of income and expenses between the main and regional networks, the distribution of income between main network entry points and main network exit points must also be considered.

In France, the entry/exit income ratio, calculated based on the capacities subscribed at entry and exit points and the tariff terms in force on 1 April 2019, is 34/66 in 2019.

The current distribution rate is the result of the presence in France of major storage capacity that covers winter peak consumption. Therefore, entry capacity subscribed by shippers in the French transmission networks is significantly lower than exit capacity booked.

Most contributors to the public consultations of March and July 2019 are in favour of maintaining this ratio. Some participants were in favour of a distribution that would reduce the entry charges by increasing the exit charges. On the contrary, other participants supported a ratio close to 50/50 considering that the current ratio penalises main network exit points.

The 50/50 distribution of income is included in the Tariff network code only for indicative purposes. This distribution is not relevant in a country such as France that has significant storage capacity.

For the year 2019, distribution of main network income specified by the ATRT6 tariff is as follows:

Distribution by type of point in %	France
Entries (PIR, PITTM)	**34%**
Exits (PIR exits and exits to the regional network)	**66%**

CRE maintains this distribution for the ATRT7 tariff.

4.2.1.2.2 Method for calculating main network tariff charges

a) Stages in the calculation of reference prices

1) CRE retains capacity and distance as the main cost drivers. Capacity booked is considered to determine the relevant flow scenarios used and to calculate the different distances (see point c).

2) The income received at the entry points and those received at the exit points are distributed based on the current ratios, which are as follows: 34% at entry points and 66% at exit points. This historical ratio is due to the presence of significant storage capacity in France that leads to considerably less capacity booked at entry points than at exit points (see section 4.2.1.2.1).

3) Entry points are considered by CRE as three homogenous groups of points (PIR, PITTM, and PITS) and CRE decided to equalise the tariff charges at these points. Therefore, entry tariffs are determined by taking into account:

   i. forecast subscribed capacity at the different entry points;

   ii. a 10% difference between the charges at the PITTMs and the charges at the PIRs resulting from the fact that the distance covered by the gas from the PITTMs is on average lower than that covered from a PIR entry point (see point e) below);

   iii. maintenance of the overall relative tariff charge at the PITS compared to that at main network entries and exits, by applying an 80% discount to them, in order to take into account the role of storage facilities in terms of security of supply (see point d) below).

4) Exit tariffs are determined following a methodology based on capacity and distance:

   i. first, CRE defined the economically relevant flow scenarios to supply each exit point (see Annex 6 of the deliberation);

   ii. CRE then determined the shortest pipeline distance between the entry points and the exit points for each relevant flow scenario;

   iii. this capacity-weighted distance is used to define the exit tariff charges in order to avoid cross-subsidisation between the different categories of network users. The unit costs (€/MWh/d/year/km) for cross-border customers and domestic customers are therefore identical;

   iv. main network exits to regional networks are considered as a homogenous group of points and the tariff charges that are applied are equalised. This equalisation has no impact on the distribution of costs between transit and domestic customers.

b) Determination of relevant flow scenarios for calculating distances

Summary of responses to the public consultation

CRE considers a set of economically relevant flow scenarios to define the tariff charges at the different main network entry and exit points. These scenarios aim to reflect the use of the network through predictable supply and consumption patterns.

Most participants that answered the public consultations of 27 March and 23 July 2019 are in favour of CRE's proposal. These participants agree with a network tariff that passes on costs to the users that generate them and consider that CRE's proposal goes along those lines.

Some participants consider that the pricing principles envisaged by CRE, in particular the methodology used to calculate distances, penalise transit.

First, these participants consider that the use of different flow scenarios for transit and for supply of domestic consumption is not compatible with the Tariff network code, or with the entry-exit system. In their opinion, it is not relevant, in a well-connected entry-exit system with an increasingly fluid gas exchange point (PEG), to consider the PIR Dunkerque as the only entry point in the network for transit.

Second, they consider that CRE's approach does not reflect costs since it results in different tariff charges for points located near each other (in particular domestic customers in the south of France located near the PIR Pirineos).

Lastly, these participants consider that the methodology proposed by CRE constitutes a barrier to cross-border trade since the resulting exit tariffs at Pirineos and at Oltingue are high.

CRE's analysis

- **Compliance with the Tariff network code**

The use of relevant flow scenarios is compatible with the Tariff network code. This code specifies:

- In its Article 8 (1) that: "*the parameters for the capacity weighted distance reference price methodology shall be as follows:* [...] *c) where entry points and exit points can be combined in a relevant flow scenario, the shortest distance of the pipeline routes between an entry point or a cluster of entry points and an exit point or a cluster of exit points d) combinations of entry points and exit points, where some entry points and some exit points can be combined in a relevant flow scenario".*
- In its Article 3 (20): "*flow scenario' means a combination of an entry point and an exit point which reflects the use of the transmission system according to likely supply and demand patterns and for which there is at least one pipeline route allowing to flow gas into the transmission network at that entry point and out of the transmission network at that exit point, irrespective of whether the capacity is contracted at that entry point and that exit point".*

CRE determines the relevant flow scenarios for transit and domestic customers in compliance with the abovementioned provisions.

- **Compliance with an entry-exit system**

In an entry-exit system, network users must be able to buy entry and exit capacity separately. They can therefore transport gas from any entry point to any exit point, with the TSO being responsible for the management of flows in its network. The tariff charge at a given entry and exit point in the network must be identical, regardless of the origin and destination of the gas.

In that regard, using relevant flow scenarios in no way calls into question the principle of pricing based on an entry-exit system. Not only will network users still be able to book their network entry and exit capacity separately, and therefore, transport gas from any entry point to any exit point, the level of charges that users will pay at a given entry and exit point in the French network will also remain identical regardless of the origin and destination of the gas.

The relevant flow scenarios are only taken into account by CRE to define the level of these tariffs. This level is set to reflect the costs borne by the TSOs for the use of the network and the associated investments, which depend mainly on two factors: capacity and distance.

- **Description and justification of the different flow scenarios considered**

As previously stated, CRE's methodology for calculating the reference prices is based on the observation that a large majority of TSOs' costs are fixed costs closely linked to the TSOs' investment strategy. This investment strategy is planned taking into account the network limits that must be lifted in order to guarantee the main flow scenarios and configurations.

Therefore, CRE defines the relevant flow scenarios so that they are based on predictable supply and consumption patterns and, in addition, so that they are consistent with the TSOs' investment strategy, which means:

- that the flow scenarios are based on capacity subscriptions, with these subscriptions themselves being used to define the TSOs' main investment decisions;
- that CRE also checks to make sure that the flow scenarios considered correspond to a reality.

  - Relevant flow scenarios for domestic customers

With regard to domestic flows, CRE considers that, from an economic point of view, there is no reason to favour one entry point over another to supply domestic customers. The entry points were in fact all decided on, at least in part, if not fully, to ensure supply of domestic consumption.

Given, on the one hand, the configuration of the French network where main network entry points are well distributed across the French territory and, on the other hand, the fact that domestic consumption is mainly located close to borders, CRE considered in the public consultations of March and July 2019, that each domestic client is supplied by the closest entry point as long as that point has available subscribed capacity remaining.

Following the comments made by participants in the public consultation, some of which consider that the flow scenarios adopted by CRE for domestic consumption appear too optimal, CRE has deepened its work on the flow scenarios to ensure that the flows considered correspond to a reality. Additional analyses showed that the PIR Pirineos entry point is very little used to supply France although there is a high level of capacity subscribed at this point. This very low level of use reflects the reality of the price difference between the Spanish and French gas market. CRE therefore considers that it is not relevant to adopt the PIR Pirineos entry point in its flow scenarios to supply France. This point is the only entry point in the French network with capacity subscribed but almost no physical flow[33].

Therefore, CRE adopts flow scenarios in which each domestic customer is supplied by the closest entry point as long as it has available subscribed capacity remaining, with the exception of the entry point at Pirineos.

CRE considers two flow patterns, a "summer" pattern (seven months) and a "winter" pattern (five months) to model the different flow scenarios:

- in the "summer" pattern, the PIR Dunkerque supplies the transit exit points, and the PIR and PITTM entry points serve to fill underground gas storage capacity, and to supply domestic clients in proportion to their annual reference consumption;
- in the "winter" pattern, the PIR Dunkerque supplies the transit exit points, and domestic clients are supplied in proportion to their peak consumption with gas coming from the PIR and PITTM entries as well as storage.

On the basis of these patterns, more than 600 relevant flow patterns have been defined (one for each exit point to the regional network). For each scenario, the distance is calculated as the shortest distance between the relevant entry point and exit point. The list of flow scenarios is presented in Annex 6 of the deliberation. The distances obtained range between 1 km and 938 km.

Since the tariffs for exit to the regional network are equalised, CRE adopted the capacity-weighted average distance to supply domestic customers, i.e. **253 km**. It should be noted that this equalisation means that a single distance (equal to 253 km) must be adopted for the supply of all points in the territory, including for those located close to exit points at interconnections for which a different distance is adopted within the framework of flow scenarios (see following paragraph). However, using a single average distance and therefore equalising tariffs for exit to the regional network has no effect on the overall distribution between costs allocated to transit flows and those allocated to domestic flows.

  - Relevant flow scenarios for transit users

CRE considered the PIR Dunkerque as the entry point of gas transiting the French networks up to the PIR Pirineos and to the PIR Oltingue to determine the relevant flow scenarios for transit.

These flow scenarios reflect the network configurations that justified the level of investments in the network, and therefore, the TSOs' fixed costs. These investments were decided based on flow scenarios, considering that to ensure firm capacity at cross-border exit points, the network must be able to ensure sufficient internal capacity in the French network to ship gas from Dunkerque.

The infrastructure development costs could have been significantly lower if CRE had chosen to downgrade firm exit capacity by converting it to interruptible or conditional capacity, which could have been an efficient mean of managing network congestions at a limited cost, but to the detriment of transit to countries located downstream of the French network.

In addition, CRE compared these flow scenarios with the actual use of the network and noted, in particular, that the PIR Dunkerque entry point has been booked completely for about ten years, with a rate of use of more than 85%

[33] The PIRs having firm contracted entry capacity are Dunkerque, Taisnières B, Virtualys, Obergailbach and Pirineos. Oltingue has no entry capacity contracted and therefore is not one of the points considered by CRE in the flow scenarios. The PITTMs all have contracted capacity.

over those same years. In addition, these capacities booked and quantities shipped are higher than the capacities and flows observed at the Oltingue and Pirineos exit points.

Furthermore, CRE considers that the other flow scenarios are not economically relevant for transit. These flows are not the ones taken into account to make investment decisions. They are also excluded for the reasons below:

- Exclusion of LNG terminals (PITTMs) as relevant entry points for transit

Since Spain and Italy have their own LNG terminals, it is more relevant to consider that LNG would be shipped directly to those two countries rather than passing through France, in situations where LNG is economically attractive compared to gas shipped by pipeline.

Although LNG can be offloaded occasionally in France to be shipped to Spain or Italy, these flows do not justify investments to reinforce the network or to create cross-border capacity. In fact, no structural congestion justifying investments can be caused by the inflow of LNG in France to be shipped to Spain or Italy, since this congestion could be circumvented at a lower cost by sending the LNG directly to these two countries.

- Exclusion of the PIR Obergailbach as a relevant entry point for transit to Italy through the Oltingue exit point

Historically, the PIR Oltingue was developed in response to a transit need in order for gas to be shipped from Norway to Italy through the PIR Dunkerque, as an alternative to a possible reinforcement of the German network (which would allow gas to be brought from Russia). Not only was the route through France more competitive than the route through Germany, the development of this entry point also reinforced Italy's security of supply by offering access to another source of supply.

In addition, since the PIR Obergailbach is essentially supplied by gas from Russia, passing through this PIR to ship gas to Italy would involve paying an entry tariff at the PIR Obergailbach then an exit tariff at the PIR Oltingue, whereas it is possible to adopt a shorter and less costly route by passing through other routes such as Germany-Switzerland-Italy or Austria-Italy. These latter routes are less costly even with a tariff charge of zero at Oltingue. In 2019, to ship gas from Russia, a shipper paid the following amounts:

In €/MWh/d/year

"Germany – France – Switzerland" route	"Germany -> Switzerland" route
Czech Rep exit (Waidhaus): 135.05	Czech Rep exit (Waidhaus): 135.05
Germany entry (Waidhaus): 156.95	Germany entry (Waidhaus): 156.95
Germany exit (Medelsheim): 164.25	Wallbach exit (Medelsheim): 164.25
France entry (Obergailbach): 104.97	-
France exit (Oltingue): 407.02	-
Switzerland transit: 427.05	Switzerland transit: 427.05
Italy entry (Passo Gries): 178.85	Italy entry (Passo Gries): 178.85
TOTAL: €1,574.14 *€/MWh/d/year*	**TOTAL: €1,062.15 €/MWh/d/year**

N.B.: these data are public data, taken in particular from ACER's report, to which CRE had access. They may, particularly for Switzerland, be different from the actual tariffs that shippers pay.

As long as investments were necessary to ensure firm exit capacity at the PIR Oltingue in order to ship gas from Dunkerque, the consideration of a flow scenario from the PIR Obergailbach to the PIR Oltingue will not reflect costs.

- Exclusion of the PIR Virtualys as a relevant entry point for transit to Italy through the Oltingue exit point

In order to supply Italy with gas from Norway, a route through Belgium then the Taisnières H entry point is also technically possible. However, it is more economically relevant to ship gas through the entry point at Dunkerque and to use Oltingue for its exit (see table below)

- *In €/MWh/d/year*

"Belgium – France – Switzerland" route	**"France – Switzerland" route**
Belgium entry: 36.5	-
Belgium exit (Blaregnies): 73	-
France entry (Taisnières): 104.97	France entry (Dunkerque): 104.97
France exit (Oltingue): 407.02	France exit (Oltingue): 407.02
Switzerland transit: 427.05	Switzerland transit: 427.05
Italy entry (Passo Gries): 178.85	Italy entry (Passo Gries): 178.85
TOTAL: €1,227.39 €/MWh/d/year	*TOTAL: €1,117.89 €/MWh/d/year*

N.B.: these data are public data, taken in particular from ACER's report, to which CRE had access. They may, particularly for Switzerland, be different from the actual tariffs that shippers pay.

CRE therefore did not retain the PIR Virtualys as a relevant point for transit to Italy.

- Exclusion of the other PIRs of the north of France to supply Pirineos

In the case of Pirineos, the economic competitivity and flows observed from the entry point at Dunkerque are such that maintaining firm capacities from Dunkerque to Pirineos has served, to a large extent, for the size of the investments necessary for the merging of zones. However, considering one of the other two entry points in the north of France would only slightly change the distances covered by gas to supply Pirineos.

- Distance from Taisnières H to Pirineos: 1,014 km
- Distance from Obergailbach to Pirineos: 1,132 km

Resulting distances

Once the relevant flow scenarios were determined, CRE considered, as for the calculation of distances to exit points to the regional network, the shortest pipeline distances among the different pipeline configurations leading to Oltingue and Pirineos from Dunkerque.

- CRE adopted a distance of 762 km[34] for the Dunkerque – Oltingue flow scenario.
- CRE adopted a distance of 1,072 km[35] for the Dunkerque – Pirineos flow scenario.

Lastly, for both transit and the supply of domestic consumption, the flow scenarios had to be re-evaluated in later ATRT tariffs, based in particular on the evolution of subscribed capacity.

- **Decision by the Council of state of 18 March 2019**

In its decision dated 18 March 2019, the Council of state validated this method considering that it "*took into account the actual use of network infrastructure by each category of shippers, with the PIR Dunkerque in fact being the entry point for gas in the main network for the purpose of transit. It therefore is not likely to create discrimination between users of transit routes and users of domestic routes.*"

The Council of state confirmed CRE's deliberation of 15 December 2016 deciding on the ATRT6 tariff, considering, in particular, that it was non-discriminatory and that the principles adopted by CRE did not create any cross-subsidisation among categories of main network users, since the average unit costs of transmission resulting from the tariff set are equivalent for each of the network uses.

- **Conclusion**

In the light of the abovementioned elements, CRE considers that its methodology for calculating reference prices complies with the Tariff network code. These scenarios reflect the use of the network through predictable supply and consumption patterns for which CRE verifies the consistency and the reality. The set of flow scenarios taken into account by CRE enable the allocation to each category of network users the costs related to the constraints they generate.

c) Subscribed capacity considered

The subscribed capacity considered by CRE to set the 2020 tariffs are presented in the table below:

[34] Several routes can be used to ship gas from Dunkerque to Oltingue: their distances range from 762 to 822 km.
[35] Several routes can be used to ship gas from Dunkerque to Pirineos: their distances range from 1072 to 1640 km.

MWh/d/year	Entry capacity subscribed	Exit capacity subscribed
PIR Virtualys	534,100	0
PIR Taisnières B	[Confidential]	0
PIR Dunkerque	500,600	0
PIR Obergailbach	462,000	0
PIR Oltingue	0	229,500
PIR Pirineos	176,800	148,300
PIR Dunkerque	250,000	
PITTM Fos	380,000	
PITTM Montoir	364,000	
PITS Nord Ouest	277,800	143,500
PITS Atlantique	558,200	331,100
PITS Sud-Est	597,500	99,100
PITS Nord B	230,000	102,900
PITS Nord Est	181,900	111,800
PITS Sud-Ouest	556,000	300,000
Exit to regional network		*4,209,500*

d) Adjustment of the tariffs at storage entry and exit points

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

In its public consultation of 23 July, CRE proposed to maintain the overall relative level of tariffs at the PITS compared to those for network entry and exit points, so as to not affect the attractiveness of storage facilities, maintain an incentive for filling them and take into account their role in ensuring the proper functioning of the system and the security of supply. An 80% discount is applied, building on the ATRT6 tariff.

In their responses to the public consultations of March and July 2019, certain participants considered that a 100% discount should apply to storage facilities in order to ensure that they are filled, including in cases where the winter/summer spread in the gas markets is close to zero. On the contrary, other participants are in favour of a 0% discount so that these tariffs strictly reflect the costs for the transmission network associated with these storage facilities.

CRE considered that setting the tariffs at the PITS at zero is not justified given the service provided by the TSOs which make injection and withdrawal capacity available at these points. CRE adopts a discount of 80% which reflects the savings on investments and the flexibility offered by storage facilities to the transmission network.

e) Adjustment of LNG terminal entry tariffs

In its public consultation of 23 July, CRE proposed a 10% differentiation between PITTM entry tariffs and PIR entry tariffs, to take into account the fact that the average distance covered by gas from PITTMs is lower than the average distance covered from PIRs.

Most participants that answered the public consultation are in favour of this proposal. Some participants state that a greater differentiation should be considered, in particular to increase security of supply and the competitivity of French LNG terminals compared to the terminals in neighbouring countries.

One participant considers that France does not need to increase its security of supply. Another participant considers that the discount should not exceed 6%.

CRE adopts a 10% differentiation between the entry tariffs at the PITTMs and those at the PIRs.

f) Consistency of unit costs

Article 5 of the Tariff network code specifies that an assessment of the allocation of transmission services revenue must be performed in order to measure the degree of cross-subsidisation between intra-system (domestic consumption) and cross-system network use, based on the reference price calculation methodology proposed. This article also specifies that any difference in the allocation of these costs, exceeding 10% must be justified.

The result of the cost allocation comparison indexes defined in this article and in application of the reference price's calculation model proposed by CRE, is equal to 0%. The methodology for elaborating the tariff framework proposed by CRE results in an identical unit cost for the different transit routes and for the supply of domestic clients.

The calculation of comparison indexes is summarised below:

- Case of domestic consumption

The supply of 1 MWh/d/year of a domestic clients requires, on average, taking into account storage capacity subscriptions, the subscription of 0.58 MWh/d/year of entry capacity in France (PIR/PITTM), 0.26 MWh/d/year of injection capacity at the PITS, and 0.57 MWh/d/year of withdrawal capacity at the PITS. These ratios are calculated based on capacity subscribed.

$$Ratio_{cap}^{intra} = \frac{\text{Revenue}_{cap}^{intra}}{\text{Driver}_{cap}^{intra}} = \frac{(entry\ tariffs\ + TCS) * exit\ capacity\ to\ regional\ network}{\text{Domestic consumption supply distance} * \text{ capacities}}$$

$$= \frac{(0.58\ \times\ TCE\ _{PIR/PITTM} + 0.26\ \times\ TCSS\ _{PITS}\ + 0.57\ \times\ TCES\ _{PITS} + TCS\ _{to\ RR}) * 4{,}209{,}500}{4{,}209{,}500 * 253} = 0.64$$

Where:

- $Revenue_{cap}^{intra}$ is the revenue defined in a monetary unit such as the euro, which is obtained from capacity tariffs and charged for intra-system network use;
- $\text{Driver}_{cap}^{intra}$ is the value of capacity-related cost driver(s) for intra-system network use, such as the sum of the average daily forecasted capacities contracted at each intra-system entry point and intra-system exit point, or cluster of points, and is defined in a measurement unit such as MWh/day. The cost drivers considered by CRE are capacity and distance;
- TCE: tariff at PIR entry;
- TCES: tariff for entry from PITS (withdrawal);
- TCSS: tariff for exit to PITS (injection);
- TCS: tariff for exit to regional network.

- Case of transit:

The supply of 1 MWh/day/year of a transit user requires the subscription of 1 MWh/day/year of entry capacity at the PIRs.

$$Ratio_{cap}^{cross} = \frac{\text{Revenue}_{cap}^{cross}}{\text{Driver}_{cap}^{cross}} = \frac{(\text{entry tariffs} + \text{exit tariffs}) * \text{transit exit capacity}}{transit\ supply\ distances * transit\ capacities}$$

$$= \frac{(TCE\ _{Dunkerque} +\ TCST\ _{Oltingue}) * 229{,}500 + (TCE\ _{Dunkerque} +\ TCST\ _{Pirineos}\ ) * 148{,}300}{229{,}500 * 762 + 148{,}300 * 1{,}072} = 0.64$$

Where:

- $\text{Revenue}_{cap}^{cross}$ is the revenue, defined in a monetary unit such as the euro, which is obtained from capacity tariffs and charged for cross-system network use;
- $\text{Driver}_{cap}^{cross}$ is the value of capacity-related cost driver(s) for cross-system network use, such as the sum of the average daily forecasted capacities contracted at each cross-system entry and exit point, or cluster of points, and is defined in a measurement unit such as MWh/day. The cost drivers considered by CRE are capacity and distance.
- TCE: tariff at PIR entry;

- TCST: tariff at PIR exit;

$$Comp_{cap} = \frac{2 * (Ratio_{cap}^{intra} - Ratio_{cap}^{cross})}{Ratio_{cap}^{intra} + Ratio_{cap}^{cross}} = \frac{2 * (0.64 - 0.64)}{0.64 + 0.64} = 0$$

The methodology for calculating reference prices adopted by CRE results in an identical unit cost for the different categories of network users.

4.2.1.2.3 Specific case of the PIV Virtualys

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

- a direct entry capacity in Belgium from the Dunkerque LNG terminal sold by Fluxys, which, for that purpose, contracts a service with GRTgaz for shipping between the Dunkerque and Alveringem terminal;
- an interconnection capacity between the TRF and the Belgian market sold in a coordinated manner by GRTgaz and Fluxys within the Virtualys virtual interconnection point (PIV).

Given the short distance covered in France by the non-odourised gas being shipped to Belgium, a distance-based pricing principle cannot be adopted because it would not cover the development costs for the interconnection created. In addition, since exit capacity at the PIV Virtualys is no longer contracted as from 2020, a "Capacity x Distance" model cannot be applied.

In its deliberation of 12 July 2011[36], CRE adopted a pricing system for exit capacity at Alveringem based on the actual cost of investment observed at the end of work and on the total capacity level. In other words, the exit tariff at the PIV Virtualys was calculated based on an economic test so that subscriptions at this point in the network cover a sufficient part of the related costs. This reasoning is in line with the spirit of the provisions adopted retrospectively on 16 March 2017, in the Tariff network code (chapter IX) and the CAM network code (chapter V) concerning the development of incremental capacity. The deliberation of 12 July 2011 specifies that the exit tariff at the PIV Virtualys will change in compliance with the rest of GRTgaz's tariff.

These principles will continue to apply for the ATRT7 tariff.

4.2.1.2.4 Level of multipliers

Multipliers are applied to the main network tariffs: they mainly aim to maintain a high level of long-term subscriptions, by encouraging participants to book annual capacity rather than short-term capacity.

Article 13 of the Tariff network code specifies that for quarterly and monthly capacity products, the level of multipliers "*shall be no less than 1 and no more than 1.5*". For daily and within-day capacity products, the level of multipliers is no less than 1 and no more than 3, except in duly justified cases.

The Tariff network code also specifies that several aspects should be taken into account to define these multipliers, including in particular:

- the balance between facilitating short-term gas trade and providing long-term signals for efficient investments in the transmission network;
- the impact on the transmission services revenue and its recovery;
- situations of contractual or physical congestion.

The coefficients applicable to the interconnection points in the ATRT6 tariff are presented in the table below:

[36] Deliberation by the French Energy Regulatory Commission deciding on the conditions for the connection of the Dunkerque LNG terminal to GRTgaz's network and on the development of a new interconnection with Belgium at Veurne

Capacity	Special conditions	Coefficient	Multipliers
Quarterly	In the event of congestion*	1/4th of the annual tariff	1
	No congestion	1/3rd of the annual tariff	1.33
Monthly	In the event of congestion	1/12th of the annual tariff	1
	No congestion	1/8th of the annual tariff	1.5
Daily	In the event of congestion	1/30th of the monthly tariff	1
	No congestion	1/30th of the monthly tariff	1.5

*A point is considered congested if, upon allocation of the annual firm products at auctions, the capacity sale price is strictly above the reserve price.

The current multipliers, which vary between 1 and 1.5, are within the limits set by the Tariff network code. These multipliers have been set, on the one hand, to maintain a high level of long-term capacity subscriptions, and on the other hand, to facilitate short-term trades and promote the integration and liquidity of the market.

CRE considers that these objectives, which have until now been reached with regard to the short-term and long-term subscription levels observed over the last few years, comply with those set out in the Tariff network code.

CRE's proposal to maintain, for the ATRT7 period, the level of multipliers in effect in the ATRT6 tariff, was supported by the vast majority of contributors to the public consultation of July 2019.

The multipliers applicable to the interconnection points in the ATRT6 tariff are maintained in the ATRT7 tariff.

4.2.1.2.5 Tariff list

The tariffs applicable in 2020 are summarised below:

€/MWh/d/year	Current tariffs	Tariffs as at 1 April 2020	Tariffs as at 1 October 2020
PIR entries	104.97	104.97	105.18
PITTM entries	99.14	94.66	94.66
PITS entries	9.15	9.17	9.17
PIR Oltingue exit	407.02	407.02	384.95
PIR Pirineos exit	626.95	626.95	584.31
PIR Virtualys exit	41.37	41.37	41.92
PITS exits	21.39	21.43	21.43
Exits from main network to regional network	91.78	94.73	94.73
Regional network transmission (GRTgaz)	83.43	84.53	84.53
Regional network transmission (Teréga)	79.64	79.77	79.77

These tariffs then change, excluding structure effects and CRCP reconciliation, by:

- +1.3% for the main network tariffs;
- +1.5% for GRTgaz's regional network tariffs, and +0.4% for Teréga's network.

Afterwards, the tariffs will change annually, as at 1 October, for the PIRs, and as at 1 April for the other tariffs, by application of a coefficient Z = CPI + X + k, as described in section 2.2.2 of the deliberation.

4.2.2 Requalification of the PIR Jura as a PIRR

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

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

CRE examined the terms for using the Jura point to determine whether the qualification as a PIR in effect in the ATRT6 tariff was still relevant. It observed:

- on the one hand, that the Jura point was considered, as of its construction, as a PIR, but based on exchanges between GRTgaz and Gaznat, it appears that this point cannot supply Germany and Italy but only end customers connected to the Gaznat network;
- on the other hand, that the PIR Jura is meshed with the PIRR Savoie and supplies the same regional network in Switzerland: these two points are therefore comparable from the point of view of their use.

Therefore, as from the entry into effect of the ATRT7 tariff, the PIR Jura is requalified as a PIRR. Given the configuration of GRTgaz's network, a level tariff (NTR) of 1 will apply at this PIRR.

4.2.3 Pricing of interruptible capacity

In its public consultation of July 2019, CRE proposed to adopt:

- a single interruption rate and therefore a single discount of 50% for entry points;
- A 15% discount (compared to the current 25%) in line with the probabilities of interruption calculated by the TSOs at the Pirineos and Oltingue exit points.
- a 50% discount for interruptible capacity at the PITS.

Most contributors to the public consultation are in favour of these proposals. Some participants consider that the discounts envisaged at the exit points are too low.

CRE considers it relevant to bring applicable discounts closer to the interruption rates observed and maintains its proposals made in the public consultation. The discounts applicable to interruptible capacity for the ATRT7 period are as follows:

Main network entry-exit points	Discounts
PIR entries	50%
Exits at PIR Oltingue and Pirineos	15%
Exits at PITS	50%

Feedback will be gathered by the TSOs to determine the impact of the drop in long-term subscriptions on probabilities of interruption.

Finally, a coefficient of 20% is applied to the terms of firm entry capacities to determine the terms of reverse exit capacities at the Obergailbach PIR, the Taisnières B PIR and the Virtualys PIV. A coefficient of 125% is applied to the terms of firm exit capacities to determine the terms of backhaul entry capacities at the Virtualys PIV. These rates are unchanged compared to the ATRT6 tariff..

4.2.4 Method for contracting capacity at PITTMs

4.2.4.1 Day-ahead capacity subscriptions at PITTMs

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

In its public consultation of 27 March 2019, CRE proposed to enable shippers to modulate their level of capacity the day before for the following day, while maintaining the entire volume of capacity initially contracted for the period. CRE considers that this development would provide flexibility to capacity allocations at PITTMs, without any risk for operating the network. CRE considers that LNG shippers should be able to react to price signals and update their nominations daily at PITTMs. Lastly, this change will bring the capacity subscription terms at PITTMs closer to those at PIRs, whose capacity can be contracted the day before for the following day (day-ahead).

Almost all contributors to the public consultation were in favour of this development, which would enhance the attractiveness of French LNG terminals. CRE maintains its proposal.

In the ATRT7 tariff, a shipper will be able to update their capacity subscription at a PITTM the day before for the following day, provided that over the send-out period, they honour the full volume of capacity initially booked.

4.2.4.2 Pooling offer at PITTMs

GRTgaz proposed to set up a pooling service between all PITTMs, including that of Dunkerque. Any capacity not used at a PITTM could be transferred to another PITTM, as part of a subscription made after the 20th of month M-1 for month M. The cost of this transfer would be 10% of the initial price of the new entry capacity contracted. CRE presented this proposal in its public consultation of 27 March 2019.

Almost all contributors to the public consultation are in favour of this development. Several shippers however considered that the price of the offer at 10% of the initial price of the capacity contracted should be lower.

CRE considers that the terms of the pooling offer proposed by GRTgaz would attract additional LNG cargo to France, but not as a substitute for other subscriptions, for the benefit of the French market. This offer is suitable for LNG, for which specific logistical constraints can justify a change in route, unlike land-based networks.

In addition, since subscriptions at PITTMs are automatic once regasification capacity in the corresponding terminal is contracted, this offer would supplement the offer concerning pooling of regulated LNG terminal capacity already introduced in the ATTM5 tariff.

With regard to the price of the offer, it must generate an additional revenue, contributing to the coverage of GRTgaz's costs, while remaining attractive for shippers. CRE considers that the price of 10% of the initial price of the capacity contracted, proposed by GRTgaz, is appropriate.

The pooling offer at PITTMs is therefore introduced in the ATRT7 tariff.

4.3 Structure of the regional network

Pricing of transmission in the regional network depends on:

- the shipping capacity contracted;
- the unit tariff for transmission in the regional network multiplied by a regional tariff level (NTR), specific to each delivery point, which takes into account the disparity in transmission costs on the regional network for each delivery point, which depends mostly on the distance to the main network.

Pricing of delivery depends on:

- the delivery capacity contracted;
- the unit delivery tariff (TCL) which differs depending on the type of delivery point;
- the number of delivery stations for industrial customers or industrial customers with major variations in consumption.

4.3.1 Capacity pricing terms

4.3.1.1 Pricing of intra-annual capacity

At the main network exit and for transmission in the regional network and delivery, customers connected to the transmission network can book capacity for an annual, monthly or daily duration. These subscriptions give rise to an hourly delivery capacity equal to 1/20th of the daily delivery capacity contracted. They can also request additional hourly capacity, by paying an additional price.

The gas transmission network is sized to be able to ship the quantity of gas necessary to get through a 2% consumption peak risk (termed "P2"), i.e. the consumption peak at an extremely low temperature reached on three consecutive days, which occurs statistically once every 50 years.

This means that the network costs for a customer present only in the coldest months are close to the costs generated by a customer present all year. Therefore, CRE adopts pricing principles that encourage shippers to book mainly on an annual basis. It is possible to book intra-annual capacity by paying the cost of the annual capacity multiplied by a certain coefficient that depends on the duration of the product and the time of the year (with a higher coefficient in winter than in summer).

In addition, article D 452-1-2 of the energy code specifies that "*Tariffs for the use of the transmission networks applicable during the months of November to April can be set at a level higher than that enabling strict coverage of network costs, provided that they are adjusted downwards in the months of May to October, so as to maintain over the year the coverage of costs [...]*".

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

In its public consultation of 27 March, CRE proposed, following work conducted by the TSOs within the framework of Concertation gaz, to drop the coefficients of January and February from 8/12th to 4/12th. The TSOs assessed the costs and benefits of such a development. This development would result in, other things being equal, a drop in the current revenue from intra-annual subscriptions (income from January and February are mechanically halved), and could lead certain customers to optimise their subscriptions. However, the TSOs consider, on the one hand, that this change in multipliers could lead to a gain in the form of additional subscriptions compared to the existing situation, and, on the other hand, that it could prevent drops in subscriptions or disconnections for certain customers whose economic situation has deteriorated over the past few years. In sum, the TSOs consider that this development presents economic value for the transmission tariff.

In the response to the public consultation, most participants were in favour of this development.

In its consultation of 23 July 2019, CRE considered that the risk of seeing annual subscriptions disappear in favour of monthly subscriptions remains limited. This because the level of the coefficient for winter months remains dissuasive: once a customer needs to book capacity beyond three months of winter, which is the case for the vast majority of sites connected to the transmission network, they will have an interest in favouring subscription of annual capacity. CRE is in favour of the TSOs' proposal.

For the ATRT7 tariff, the coefficients that apply to the tariff for capacity in January and February are therefore set at 4/12th of the annual tariff.

4.3.1.2 Adaptation of penalties for exceeding capacity

Each day, penalties applies for exceeding daily capacity at the main network exit, regional network transmission and delivery, and hourly capacity for the regional network transmission and delivery, for the supply of end customers connected to the transmission network.

The ATRT6 tariff specified penalty rules for exceeding the following capacity:

	Daily capacity (D)	**Hourly capacity (h)**
penalty cap	3%	10%
penalty - 1st threshold	1st threshold: 3% - 10% Penalty = daily price of daily capacity x 20	1st threshold: 10 % - 20% Penalty = daily price of hourly capacity x 45
penalty - 2nd threshold	2nd threshold: > 10% Penalty = daily price of daily capacity x 40	2nd threshold: > 20% Penalty = daily price of hourly capacity x 90

In total, penalties represent an average €2.4 million/year in GRTgaz's network, and €0.2 million/year in Teréga's network (i.e. 0.1% of the total annual allowed revenue of each of the two TSOs).

Following the work conducted by the TSOs and presented in Concertation gaz, in its public consultation of 27 March 2019, CRE proposed to eliminate the second penalty threshold. Therefore, for all cases of exceeding capacity beyond the 3% cap for daily capacity and 10% for hourly capacity, there would be a single penalty rate calculated by multiplying the price of the capacity subscription, corresponding to the first threshold currently in place, i.e. 20 for daily capacity and 45 for hourly capacity. The goal of this development is to simplify calculation and penalise to a lesser extent major exceeding of capacity, which is often caused by a specific incident within a site, over which the customer has little control.

Almost all contributors to the public consultation are in favour of this development.

Some participants however expressed reservations about the combined drop in the monthly coefficients of January and February and the elimination of this second penalty threshold, which would lead to a major reduction in penalties over these months.

CRE considers that the current levels provide sufficient incentive. Indeed, exceeding daily capacity in January or February is still penalised at 20 times the price of daily capacity.

In addition, several participants wish for the exceeding of daily and hourly capacity to not be cumulative. However, it is a matter of different capacities, corresponding to different constraints: a balancing constraint over the entire balancing zone for daily capacity, and a linepack constraint for hourly capacity. Moreover, a customer can exceed their hourly capacity without exceeding their daily capacity, and vice versa. Therefore, it appears necessary for the proper functioning of the gas networks to ensure that customers keep up with each of these constraints. CRE therefore maintains penalties for the two timeframes.

In the ATRT7 tariff, exceeding daily and hourly capacity is therefore penalised as follows:

- for exceeding daily capacity, the calculation of penalties is based on the price of firm daily subscription of daily capacity;
    - for the portion in excess that is less than or equal to 3% of the daily capacity contracted, no penalty will be applied;
    - for the portion in excess that is greater than 3%, the penalty is equal to 20 times the price of the firm daily subscription of daily capacity[37];
- for exceeding hourly capacity, the excess is calculated by considering the maximum value of the hourly average of the quantities delivered at the given delivery point over four consecutive hours. Calculation of penalties is based on the price of the daily subscription of hourly capacity:
    - for the portion in excess that is less than or equal to 10% of the hourly capacity contracted, no penalty will be applied;
    - for the portion of the excess that is greater than 10%, the penalty is equal to 45 times the price of the firm daily subscription of hourly capacity.

The penalty rules for the ATRT7 tariff can be summarised as follows:

	Daily capacity (D)	Hourly capacity (h)
penalty cap	3%	10%
penalty	> 3% Penalty = daily price of daily capacity x 20	> 10% Penalty = daily price of hourly capacity x 45

4.3.1.3 End of the redistribution of penalties for exceeding capacity

In the ATRT6 tariff, each TSO redistributes to shippers the amount of penalties for exceeding capacity collected each year, in the month of June of the following year at the latest.

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

In its public consultation of 27 March 2019, CRE proposed to end this penalty redistribution. These would therefore be directly integrated in the tariff, through the expenses and income clawback account (CRCP), following the same functioning as with distribution tariffs. Therefore, each year, the penalties received by the TSOs would be paid into the CRCP.

Most participants are in favour of this development for the purposes of simplicity and transparency.

In the ATRT7 tariff, the penalties received by the TSOs for exceeding contracted capacity will therefore be paid into the CRCP.

4.3.2 Pricing of sites with major consumption variations and the short-notice interruptible offer (IAPC)

In its public consultation of 27 March 2019, CRE stated that it was considering eliminating the short-notice interruptible offer (IAPC), currently used by certain combined-cycle gas turbines (CCGTs).

[37] In the case of highly modulated sites, calculation is based on the level of the delivery tariff applicable to customers connected to the transmission network (see section 4.3.2 of the deliberation).

It confirmed this intention in the public consultation of 23 July 2019, and also planned to reduce, or set to zero, the delivery charge for highly modulated sites, in order to take into account the specific constraints imposed on these sites for the purpose of network management.

Most industrial customers are in favour of the elimination of the IAPC but are against the reduction in the delivery charge for highly modulated customers, which, in their opinion, would introduce a difference in treatment among network users. They also state that industrial sites performing day-ahead nominations or with stable and therefore predictable consumption provide an equivalent service to GRTgaz compared to that provided by highly modulated sites.

The views of shippers that have sites currently benefitting from the IAPC offer are divided.

CRE considers that the elements presented in the public consultation of 27 March and reiterated in the public consultation of 23 July justify the elimination of the IAPC offer. This mechanism has never been activated since its creation, and operators consider that it will not be activated in the future:

- on the one hand, CCGTs are electricity generation resources necessary during cold peaks, which makes their interruption complicated in practice. GRTgaz must first coordinate with RTE to ensure that this interruptibility does not jeopardise the balance of the electricity transmission network;
- on the other hand, the French gas transmission network has been heavily reinforced since 2007. Two new LNG terminals became operational during this period (Cavaou and Dunkerque LNG). Furthermore, in order to implement the single market zone as at 1 November 2018, GRTgaz and Teréga made significant investments to strengthen the main network (Val de Saône and Gascogne-Midi). Therefore, the constraints anticipated in 2007 for the supply of new CCGTs have been considerably reduced.

CRE considers that the differentiation in tariffs for highly modulated clients and for other clients is justified, because highly modulated sites are customers that are different from other clients because of their size, consumption profile and the specific role they play for electricity and gas systems. Indeed, their planning obligations vis-à-vis the TSO given them more limited access to the transmission network. As such, setting the delivery charge at zero for this category of customer appears relevant.

CRE has decided to eliminate the IAPC offer and to set the delivery charge at zero for highly modulated sites as from 1 April 2020.

Lastly, the terms for calculating the subscription of additional hourly capacity and daily penalties depend especially on the tariffs for transmission in the regional network and the delivery charge. The tariff for transmission in the regional network itself depends on the level of the regional tariff, which varies from 0 to 10 according to the location of the customer compared to the main network. Therefore, for a highly modulated site with a regional tariff level of 0, the hourly capacity and daily penalties would be very low, if not zero. To avoid a disincentive to complying with capacity subscriptions, the delivery tariff taken into account for hourly capacity subscriptions and to calculate daily penalties for highly modulated sites is the same as that for industrial customers connected to the transmission network.

4.3.3 Proximity tariff discount

In its public consultation of 27 March 2019, CRE proposed eliminating the proximity tariff discount, currently set at €0.23/MWh for H gas, and at €0.17/MWh for L gas, which is deducted from the monthly bill of each shipper, for the quantities of gas consumed in certain main network exit zones close to the following interconnection entry points: Dunkerque, Taisnières B, Virtualys and Obergailbach.

The total deduction of the bill generated by the proximity discount represents a total of roughly €2.5 million per year for all customers in the zones concerned. The return of this deduction by shippers to their clients, both in the transmission and distribution network, is not automatic.

In the light of these elements, CRE proposed in its public consultation of 27 March 2019 to extend the principle of national equalisation of the main network exit charge, and therefore to eliminate the proximity discount in the ATRT7 tariff.

Almost all industrial clients and a portion of shippers are in favour of the elimination of the proximity discount. The industrial clients in favour consider that it is a matter of national fairness, and that this elimination is in line with the dynamic sought with the single market zone.

The industrial clients that benefit from the proximity discount would prefer that it be maintained, with an obligation for shippers to return it to customers.

Another portion of shippers, as well as local distribution companies that benefit from the proximity discount, and a few other participants, are opposed to its elimination. They are concerned about a resulting drop in competitivity of the zones concerned.

Shippers opposed to the elimination consider that this discount reflects the lower costs generated for the network by customers close to the entry points.

According to the pricing principle of the main network adopted by CRE, the tariff for exit from the main network to supply domestic customers is harmonised within the perimeter of France. Therefore, regardless of the main network exit zone in which the customer is located, the customer pays the same capacity-based tariffs.

The proximity discount, implemented for the purpose of pricing continuity in the regions concerned during the transition from distance-based pricing to an entry-exit pricing system in 2003, is an exception to this single capacity-based pricing principle at the main network exit in France, since it is proportional to the quantities shipped and differentiates the exit zones.

CRE has eliminated the proximity discount as from 1 April 2020.

4.3.4 Consideration of the development of biomethane

Reaching biomethane network injection objectives (the draft decree relating to the multi-annual energy plan (PPE) submitted for consultation in January 2019 aims for 6 TWh of biogas injected into the natural gas networks for 2023 and sets an objective of 14 to 22 TWh by 2028) will require major investments in the gas transmission and distribution networks.

Gas infrastructure was in fact built to transport gas from very few network entry points (domestic production zones almost inexistent today, interconnections with neighbouring countries, LNG terminals) to areas of consumption and storage facilities. From the transmission network, grid squares (or pockets) of the distribution network ensure the delivery of gas to customers at increasingly low pressures. Gas infrastructure does not enable, except for specific investments, gas pressure levels to be increased, which can require the development of decentralised production, since a facility can only inject only the amount corresponding to the level of consumption of the network pocket in which it is injecting (including the lower pressure levels to which it is attached). Therefore, the current networks can only accommodate a portion of the volumes contained in the objective for the development of biomethane injection. Accommodation capacity will be, in the short term in certain areas, limiting and will require reinforcement investments, evaluated at roughly €500 million for 2028 in the transmission and distribution networks (for an objective of 22 TWh), to which will be added connection investments estimated at over 1 billion euros.

CRE considers that the proper development of methanisation is of major importance for the energy transition. Given the costs for adapting the networks, the development of biomethane must follow the principle of economic efficiency so that the cost is optimised for the community. However, operators' investment decision must also be made within the context of visible and stable economic conditions surrounding injection into the networks.

To ensure efficiency of projected investments, while guaranteeing visible and stable economic conditions surrounding injection over time, CRE, in its deliberation of 14 November 2019[38], specified the terms for implementing and governing the different mechanisms associated with this injection right as provided for by Articles L. 453-9 and D. 453-20 to D. 453-25 of the energy code.

This deliberation aims to bring visibility to project promoters concerning their connection conditions and specifies the terms for coverage of network reinforcement costs by the tariff within the framework of zoning connection schemes optimised at community level, in compliance with the abovementioned provisions of the energy code.

In addition, in order to supplement these provisions and send a relevant signal to producers to encourage them to make optimal location choices for the community, CRE looked into the introduction of an injection tariff.

In the two public consultations of March and then July 2019 addressing the subject, many contributions were against the introduction of an injection tariff. The participants concerned consider that the introduction of a location signal through this tariff is useless since (i) this signal is already given through other mechanisms, (ii) project promoters have little freedom in the choice of their location and (iii) the injection tariff reduces the location signal compared to a direct payment at the time of connection. Some participants also consider that this introduction could hinder the development of the sector and therefore recommend deferring the introduction of an injection tariff to the tariff period after the ATRT7 period. Certain participants were however in favour of the introduction of an injection tariff charge, so as to not pass on biomethane development costs to gas customers, particularly industrial customers.

While CRE takes note of the concerns expressed by participants about the additional expense this tariff represents for project promoters, it nevertheless considers that:

- it is necessary to introduce an additional signal, enabling project promoters to take into account the network reinforcement costs generated by their choice of location (and more specifically the OPEX that are not taken into account in mechanisms that already exist);

[38] https://www.cre.fr/Documents/Deliberations/Decision/mecanismes-encadrant-l-insertion-du-biomethane-dans-les-reseaux-de-gaz

- it is preferable, in terms of visibility for the sector, to introduce this tariff presently rather than when the sector will be more developed and the majority of projects will have already been decided without taking into account this tariff.

It therefore adopts the introduction of an injection tariff in the ATRT7 and ATRD6 tariffs which will be billed:

- to shippers for installations injecting into the transmission network;
- to producers for installations injecting into the distribution network.

Principles for constructing the injection tariff and level adopted

CRE worked to construct a tariff based on the following principles:

- sending a location signal to project to encourage them to choose zones that generate the least operating expenses for adapting the network to the accommodation of biomethane;
- setting up a mechanism that ensures stability to the producer, and which enables each producer to be protected, once their connection terms are defined, from a deterioration in injection conditions in their zone.

The mechanism proposed by CRE in its public consultation is based on the definition of three injection tariff levels, to differentiate the amount paid by producers and shippers according to the cost generated by their choice of location. Three types of zones are distinguished:

- the zones requiring backhaul[39] or pooled compression will be attributed level 3;
- the zones not requiring backhaul will be attributed level 1 or level 2. The distribution between levels 1 and 2 will be performed based on the length of pipeline in the zone, in relation to the number of projects.

In order to ensure stability in the amount paid by each producer over the lifetime of the biomethane production installation, CRE proposed to attribute a level to each production site which will not be modified in the medium term. Therefore, if the technico-economic injection conditions in a zone deteriorate, it will not directly impact the level of producers that are already injecting, or modify the economic balance of their installation. Along the same line of reasoning, production sites that inject annually will be attributed level 1.

CRE adopts, in the present tariff deliberation, the general principle of a tariff at three levels, attributed to each production site during the D2 connection study[40], based on the connection zoning scheme[41] in effect in the zone, and remaining unchanged in the medium term. It can however decide, for production sites to which level 3 is attributed, to re-examine their situation at the end of five years, if backhaul (or pooled compression) is not actually implemented.

Classing of zones by level type is done based on the connection zoning scheme in effect in the zone and is updated at the same time as the zoning scheme update:

- if zoning provides for backhaul or pooled compression, the zone’s future production sites are attributed level 3;
- if zoning does not provide for backhaul or pooled compression:
    - if the zoning scheme includes meshing[42] and/or a shared extension[43], the zone's production sites are attributed level 2;
    - for the other zones, the zone’s production sites are attributed level 1.

With regard to the levels proposed in the public consultation, based on an estimate of target costs associated with the injection objective of 22 TWh in 2028, these were not welcome by contributors, on the grounds that such a method of construction proposed by CRE to reduce variability in the level of the injection tariff between tariff periods, would be disconnected from the costs estimated for subsequent tariff periods.

[39] Compressor used for injecting gas into a higher-pressure network
[40] Sites queued that have already exceeded the D2 milestone, but are not yet injecting biomethane, will be attributed an injection tariff level when the connection contract is signed, following identical principles.
[41] Result of the study, done jointly by the system operators, determining the optimal network configuration based on the technico-economic zoning criteria.
[42] Two distribution grid squared of equivalent pressure are connected physically.
[43] Extension of a gas network enabling connection of new sites, shared between several sites

In order to respond to concerns expressed by producers, while taking into account the responses in favour of the principle of an injection tariff and of a tariff that covers the operating costs associated with the development of biomethane, CRE has modified the calculation method.

CRE studied the operating expenses associated with the development of biomethane, with the exception of general OPEX, particularly those related to management of biomethane activities and functioning of information systems, which are not directly connected to producers' choice of location.

For each category ("backhaul OPEX" relating to backhaul and pooled compression, and "pipeline OPEX" relating to meshes and other pipelines), the following methodology was applied:

- estimation of the OPEX volume over the 2020-2023 period, based on the volume of investments related to the development of biomethane presented by the operators in their tariff proposal, adjusted in line with the 6 TWh objective for 2023 set in the draft PPE. The estimated volumes are as follows:
    - 4% of investment costs (excluding studies) for backhaul and pooled compressions;
    - 0.2% for pipelines (meshes, shared extensions and other connection structures);
- allocation of costs at the different zones, based on whether or not they include backhaul, and in line with the pipeline investments they require, in the zoning scheme of the connection;
- estimate of the projected volumes for the 2020-2023 period for each type of zone, excluding from the analysis the capacity already installed, which will be attributed level 1;
- calculation of the ratio between total OPEX anticipated over the period for each of the three types of zones and the total volumes associated for 2023.

In addition, CRE has decided, as presented in the public consultation, given the low operating expenses estimated for level 1 to set this level at 0.

The tariff resulting from this methodology, and its breakdown is as follows:

	Tariff adopted (€/MWh injected)	Total OPEX (€/MWh)	*of which backhaul OPEX (€/MWh)*	*of which pipeline OPEX (€/MWh)*
Level 3	0.7	0.71	*0.65*	*0.06*
Level 2	0.4	0.35	*0.00*	*0.35*
Level 1	0	0.09	*0.00*	*0.09*

4.4 Terms for collection of storage compensation

4.4.1 Principle of coverage for storage costs

The energy code specifies that storage operators will receive their allowed revenue, defined by CRE:

- on the one hand, through the income they receive directly, mainly from the auctioning of their storage capacity;
- on the other hand, in the event that the income they receive directly is lower than their allowed revenue, through compensation collected by the transmission system operators (TSOs) from shippers and transferred to storage operators in compliance with Article L.452-1 of the energy code[44].

It is within this framework that CRE introduced an additional charge in the ATRT6 tariff ("storage charge").

Compensation is recovered from shippers present in GRTgaz's and Teréga's transmission network, by applying the storage charge, which depends on the winter modulation of their clients connected to the public gas distribution networks that are not interruptible and not subject to load shedding.

4.4.2 Calculation of winter modulation

The storage charge is currently paid by two types of consumers connected to the distribution network:

- "profile-based" clients (which correspond to clients connected to the distribution network under tariff option T1, T2 or T3): these clients' transmission capacities are automatically calculated by system operators and booked by shippers to cover peak need based on a consumption profile and annual consumption;

[44] If auction income is greater than the storage operators' allowed revenue, the storage tariff is negative and results in a payment to shippers.

- "subscription-based" clients (which correspond to clients connected to the distribution network under tariff option T4 or TP): these clients choose the level of their capacity subscriptions, to cover their peak needs. These are mainly industrial customers.

In its public consultation of 23 July 2019, CRE proposed to differentiate between these two types of consumers regarding the method for calculating their winter modulation. Even if industrial "subscription-based" clients consume more in winter than in summer on average, there is no direct correlation between their maximum consumption and the cold peaks, as is the case for profile-based clients; their consumption is associated more with the needs of their industrial processes, with each sector having their own characteristics. In order to take into account these characteristics specific to subscription-based clients, CRE proposed to calculate their modulation by comparing their average winter consumption with their annual average consumption. With regard to profile-based clients (T1, T2, T3), CRE proposed to maintain the current formula.

Most contributors to the public consultation of July 2019 are in favour of CRE's proposal, particularly all industrial participants which consider that the formula proposed takes into account their consumption particularities. Some participants however highlighted that industrial events such as heavy maintenance or regulatory shutdowns could considerably alter their modulation based on the historical depth adopted by CRE to perform the calculation. Others were concerned about the lack of climate correction in the formula proposed and the financial impact that a particularly code winter could represent in that case. Lastly, some shippers and customers shared their concerns about the provision of the consumption data concerned.

As from 1 April 2020, the calculation of winter modulation will depend on the type of client, and will apply based on the terms below.

- "Subscription-based" clients

For subscription-based clients, winter modulation of each of the last three years is calculated as follows:

$$\textbf{Client modulation (MWh/d)} = \mathrm{Max}\left(0; \frac{\text{Winter consumption}}{151} - \frac{\text{Annual consumption}}{365} - \mathrm{Int}\right)$$

Where: - Winter consumption: consumption of the site from 1 November Y-2 to 31 March Y-1[45]

- Annual consumption: consumption from 1 November Y-2 to 31 October Y-1

- Int: interruptible capacity contracted by the client for the year Y-1.

The interruptible capacity taken into account to be deducted from the comparison between winter consumption and annual consumption correspond to:

- interruptible capacity contracted between system operators and their shipper clients to meet technical supply constraints for given geographical grid square;
- interruptible capacity that will be contracted with system operators once the interruptibility mechanisms specified by Articles 431-6-2 and 431-6-3 of the energy code[46] are implemented;
- interruptible capacity that will declared as subject to load shedding without risk following the investigation performed by distribution system operators[47]. Once the interruptibility mechanisms are implemented, capacity declared as subject to load shedding will exit the scope of interruptible capacity taken into account in the calculation.

Furthermore, in order to take into account heavy maintenance or regulatory shutdowns, which are in fact part of the industrial reality of subscription-based clients, calculation of the winter modulation of these sites will be performed on the basis of the previous three years. As at 1 April of each year Y, the modulation adopted for billing the storage tariff will consist in the average of the two lowest values among the last three available values (those of years Y, Y-1 and Y-2). Taking into account the two "best" years of the last three years will mitigate the financial impact of a particularly cold winter.

[45] A client's modulation must be updated as at 1 April of each year; CRE however considers it difficult from an operational point of view to take into account the actual consumption data up to 31 March of the same year. The "winter consumption" of a year Y will therefore correspond to consumptions from 1 November Y-2 to 31 March Y-1. The "annual consumption" of this same year Y will correspond to consumption from 1 November Y-2 to 31 October Y-1.

[46] In the absence of a sufficient record for the first two years of existence of this mechanism, the capacity taken into account for the calculation of the Int charge will be identical for the calculation of the three annual modulations, and will correspond to capacity booked for the billing year in progress.

[47] GRDF's questionnaire on load shedding positions

In the case of a new site connected under the “subscription-based” option, with no history of actual consumption, the site’s modulation will be determined by the DSOs based on the best estimate of the reference annual consumption (CAR) and of the consumption profile communicated to the DSO within the framework of the connection by the site’s supplier.

Lastly, to answer the concerns formulated in the responses to the public consultation concerning the availability of data, CRE requests the TSOs to be able to supply a modulation value that can be effective and forwarded to the supplier of any client that makes such a request. In addition, in all cases other than that of a new site connected under a “subscription-based” option, it is the responsibility of the system operators to ensure continued billing of the storage compensation by referring to the record of consumption data in their possession.

- <u>“Profile-based” clients</u>

For “profile-based” clients, modulation of a year Y is calculated as follows:

$$\textbf{Client modulation}\ \ (\mathbf{MWh/d}) = \ \mathrm{Max}\left(0; \mathrm{CJN} - \frac{\mathrm{CAR}}{365} - \mathrm{Int}\right)$$

Where: - CJN: normalised daily capacity of the profile-based site;

- CAR: reference annual consumption of the site;

- Int: interruptible capacity contracted by the client.

By way of exception, client Modulation is set at 0 MWh/d for the following clients:

- clients that declared themselves open to load shedding during the investigation conducted by distribution system operators[48], with this exception ending with the effective implementation of texts relating to the interruptibility mechanisms;
- counter-modulated: clients with a P013 profile (Winter portion lower than or equal to 39%) or P014 profile (Winter portion between 39% and 50%). Profiles are attributed by the DSOs according to the methodology published on the website of the gas working group[49].

4.4.3 Scope of the storage compensation

In its deliberation of 22 March 2018, CRE defined the scope of the basis of the storage compensation collection. With gas storage coming under regulation, with, on the one hand, very tight deadlines for implementing the reform, and on the other hand, the absence of contractual interruptibility mechanisms that can be applied to clients directly connected to the transmission networks, CRE pursued the dual objective of economic continuity and consideration of the benefits of storage for gas network users whose supply cannot be interrupted in the event of a supply crisis.

Therefore, it adopted, as at 1 April 2018, a basis for collection of the compensation corresponding (i) to residential consumers, including households residing in a building collectively heated by gas, (ii) to non-residential consumers performing missions of general interest to fulfil the essential needs of the country, connected to the distribution network and (iii) to consumers that have not contractually accepted supply that can be interrupted, or that have not declared themselves subject to load shedding, connected to the distribution network.

The energy code specifies that the storage capacity necessary for ensuring security of supply are defined under:

- Article L. 421-3-1 of the energy code, which states that the multi-annual energy programme will define underground storage infrastructure that guarantee security of supply in the medium and long terms;
- and Article L. 421-4 of the energy code which specifies the definition, by order of the minister of energy, of the minimum natural gas stocks necessary as at 1 November to ensure security of natural gas supply during the period between 1 November and 31 March.

In both cases, no distinction is made between consumers connected to the transmission network and those connected to the distribution network.

Lastly, Article L. 421-6 of the energy code provides for a mechanism for building additional natural gas stocks in the event that storage capacity subscriptions at auctions do not suffice to guarantee security of supply, referred to as a

[48] GRDF’s questionnaire on load shedding positions
[49] Table of profiles applicable from 1 April 2018 to 31 March 2019

"safety net". The implementing decree[50] of this mechanism specifies in particular the types of consumers that would bear the costs related to the activation of the safety net.

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

However, as from 2019, the basis of the safety net defined by the decree covers all non-interruptible consumers, including those connected to the transmission network. Therefore, the scope of the safety net and that of the compensation for storage costs are no longer aligned.

As a result, CRE considers it appropriate to extend the basis to all consumers that cannot interrupt or curtail their consumption during the winter peak, but maintains that this extension can only be envisaged if the interruptibility mechanisms provided for by Articles 431-6-2 and 431-6-3 of the energy code are implemented. In that regard, CRE reiterates that the draft order for the application of the Articles above, for which CRE rendered an opinion on 24 July 2019, was submitted to the higher energy council on 23 July 2019 and received a favourable opinion.

CRE had presented this intention in the public consultation of 27 March, and confirmed it in the consultation of 23 July 2019. While numerous industrial participants remain opposed to the extension of the basis for storage compensation and highlight the technical difficulty to implement interruptibility mechanisms, most participants approve the formula proposed by CRE in the public consultation of July and agree with the position to link the extension of the calculation basis to the publication of the order relating to interruptibility mechanisms.

In addition, the energy policy guidelines forwarded to CRE by the minister of state, minister of the ecological and inclusive transition specify that "*reflections must be undertaken when preparing the tariffs for the use of the natural gas transmission and distribution networks concerning the means of ensuring better continuity between the tariffs borne by a site connected to a distribution network and the tariffs borne by a similar site connected to a transmission network.*" Billing of the storage compensation to clients directly connected to the transmission network will be done by applying the same terms for calculating the specific winter modulation only for "subscription-based" clients, as described in section 4.4.2 of the present deliberation.

Lastly, CRE reiterates that the TSOs consider that a minimum period of 12 months as from the official publication of the order relating to interruptibility will be necessary to ensure the contracting of interruptible capacity with network users. This order was published in the Official Journal of the French Republic on December 19, 2019. Therefore, CRE expects that the extension of the compensation basis to clients directly connected to the transmission network will be implemented as of the first update of the ATRT tariff that is on April 1, 2021. CRE will conduct a public consultation in the second half of 2020 in preparation of this evolution.

5. TARIFFS FOR THE USE OF GRTGAZ's AND TERÉGA's NATURAL GAS TRANSMISSION NETWORKS

5.1 Tariff rules

5.1.1 Definitions

Network Interconnection Point (PIR):

Physical or notional interconnection point between the main transmission systems of two transmission system operators (TSOs)

Regional Network Interconnection Point (PIRR):

Physical or notional interconnection point between a regional transmission system and a foreign operator's network

LNG Terminal-Transmission Interface Point (PITTM):

Physical or notional interconnection point between a transmission system and one or more LNG terminals

Storage-Transmission Interface Point (PITS):

Physical or notional interface point between a transmission system and a storage group

Production-Transmission Interface Point (PITP):

Physical or notional interface point between a transmission network and a gas production facility under a mining concession

[50] Decree No 2018-221 of 30 March 2018 relating to the constitution of additional natural gas stocks mentioned in Article L. 421-6 of the French energy code

Distribution-Transmission Interface Point (PITD):

Physical or notional interface point between a transmission system and a public distribution system

TCE: capacity charge for entry in the main network, applicable to the subscription of daily capacity at main network entry points from a PIR or PITTM

TCES: capacity charge for entry in the main network from storage, applicable to the subscription of daily capacity for entry in the main network from a PITS

TCST: capacity charge for exit at the transmission system interconnection points, applicable to the daily capacity subscription for exit to a network interconnection point (PIR)

TCS: capacity charge for main network exit, applicable to the subscription of daily exit capacity from the main network, except to a PITS or PIR

TCSS: capacity charge for exit from the main network to storage, applicable to the subscription of daily exit capacity from the main network to a PITS

TCR: transmission capacity charge in the regional network, applicable to the subscription of daily capacity for transmission in the regional network

TCL: delivery capacity charge, applicable to the daily capacity subscription for delivery to a delivery point

Storage charge (TS): Unit tariff charge aimed at covering a portion of the revenue of underground natural gas storage operators, applicable to shippers, based on the winter modulation of their clients

Biomethane injection charge: charge applicable to quantities of biomethane injected into the gas transmission network

Firm capacity:

Gas transmission capacity, the use of which is guaranteed under contract by the TSO, except in the event of works or force majeure.

Climatic firm capacity:

Gas transmission capacity, guaranteed under contract by the TSO as uninterruptible, depending on domestic consumption. This definition applies in particular to injection and withdrawal capacity at the PITS.

Backhaul capacity:

Capacity allowing the shipper to make nominations in the opposite direction to the dominant direction of gas flow when the gas flow can run in only one direction. It can only be used on a given day if the overall flow resulting from all shippers' nominations is in the dominant direction of the flow.

Interruptible capacity:

Gas transmission capacity that can be interrupted by the TSO according to the conditions set out in the gas transmission system supply agreement

Returnable capacity:

Firm capacity which the shipper agrees to return to the TSO at any time upon request

Shipper:

Natural or legal person that enters into a transmission contract with a TSO on the gas transmission system. The shipper is, depending on the case, the eligible customer, the supplier or their representative.

Delivery point (PDL):

Exit point from a distribution network where a distribution system operator delivers gas to an end customer in fulfilment of a supply contract on the distribution network. Each PDL is generally associated with a metering and estimate point (PCE), with a 14-figure reference to identify it. By way of exception, a PDL can combine several PCEs, if these are downstream of the same individual connection.

Annual reference consumption (CAR):

Estimate of the quantity of gas consumed over a year, under average weather conditions, for a metering and estimate point (PCE)

"Non-subscription based" client:

Client under options T1, T2, and T3 of the tariffs for the use of the distribution networks. Since these options do not include a capacity subscription charge, the PDLs of these clients are therefore "non-subscription based". Each "non-subscription based" PDL is associated with a “standardised” capacity, determined based on their CAR, profile, the temperature of the 2% cold peak risk scenario of the weather station to which the PITD in question is attached, and an adjustment coefficient “A”.

“Subscription-based” client:

Client under options TF, T4 and TP of the tariffs for the use of the distribution networks. For these PDLs, the supplier freely books the capacity requested

Winter Portion (PH):

The ratio between the client’s consumption of the months of November to March inclusive and their consumption over the entire calendar year

5.1.2 Capacity subscriptions

5.1.2.1 PIR capacity subscription at auctions

Daily transmission capacities at network interconnection points (PIRs) at Taisnières B, Virtualys (Taisnières H and Alveringem), Obergailbach, Oltingue and Pirineos, can be subscribed at auctions via the PRISMA capacity trading platform. These capacities are sold at auctions according to the terms laid out by (EU) regulation no. 984/2013 establishing a network code on capacity allocation mechanisms in gas transmissions systems known as the “CAM network code”. The details on auction procedures and products on offer are published by GRTgaz and Teréga on their respective websites or on the PRISMA auction platform.

Examples of available products are firm, interruptible and backhaul daily transmission capacities for annual, quarterly, monthly, daily and intraday durations.

The auction reserve price is the same as the price fixed by the present tariff.

Contracting and billing for the PIRs at Taisnières B, Virtualys (Taisnières H and Alveringem), Obergailbach and Oltingue are carried out by GRTgaz.

Contracting and billing for the PIR Pirineos are carried out by Teréga.

5.1.2.2 Capacity subscriptions at the PIR Dunkerque

Daily capacity subscriptions at the PIR Dunkerque are subject to specific mechanisms, which are defined in accordance with rules set out by CRE and made public on the GRTgaz website.

5.1.2.3 Subscription of capacity at PITS

At each transmission-storage interface point (PITS), the TSO automatically allocates to the shipper entry and exit capacities in line with the nominal injection and withdrawal capacities the shipper holds for the corresponding storage group(s), within the limit of network capacities.

The level of firm exit capacity at PITS is defined by CRE. The remaining capacities allocated are interruptible.

5.1.2.4 Subscription of capacity at PITTMs

Holding regasification capacity at an LNG terminal confers the right and obligation to book entry capacity in the transmission network, for the corresponding durations and levels. In the specific case of the Dunkerque LNG terminal (the terminal is connected both to GRTgaz’s network and the Belgian network), this obligation applies to the sum of capacity booked in GRTgaz’s network at the Dunkerque PITTM and the capacity booked from the terminal to Belgium.

At the Dunkerque PITTM, the firm entry capacities in GRTgaz’s network are booked by the shipper in the form of annual bands, over a period representing a whole number of years, or in the form of intra-annual bands.

At the Montoir and Fos PITTMs, all shippers that have booked capacities with LNG terminal operators are allocated daily firm entry capacities by the TSO, for the entire subscription period for the corresponding regasification capacities:

- in the case of regasification capacity subscriptions falling within the framework of the terminal’s annual programme (in particular annual or multi-annual), the level of firm daily entry capacity attributed corresponds to a share of the terminal’s daily firm regasification capacity. This share is determined by the ratio between:
    - the annual regasification capacity contracted by the shipper at the terminal;
    - the total annual firm technical regasification capacity of this terminal;

  Up until 31 December 2020, the capacity allocated at the PITTM for the Fos Tonkin terminal is 80 GWh/d (cumulated regasification of the two Fos terminals being higher than that of the PITTM).

- in the case of spot regasification capacity subscriptions, the shipper is allocated a firm entry capacity band for its subscription period. The level of capacity allocated corresponds to the quantity of regasification capacity booked, expressed in GWh.

A shipper with capacity booked at a PITTM can change the level the day before for the following day, provided that they honour the entire level of capacity initially booked over the given period (subscription duration or calendar year, if the subscription has a duration of more than one year).

For each shipper, the TSO calculates the daily send-out for each day. Should it exceed the shipper's booked capacity, for a given day, the TSO will bill the shipper for an additional daily capacity subscription, at the daily capacity tariff, equal to the positive difference between the daily send-out and the capacity allocated to the shipper.

Shippers have the possibility of selling their capacity at PITTMs free of charge.

Furthermore, any capacity booked at a PITTM for the month M, and which the shipper does not plan to use after all, can be transferred after the 20th of month M-1 to another PITTM in that month M. The cost of this transfer corresponds to 10% of the initial price of the new capacity contracted.

5.1.2.5 Capacity subscription at main network exits and in the regional network

Booking of delivery capacities at delivery points and regional network interconnection points (PIRRs), of transmission capacities in the regional network and of capacities at the main network exit points are done with the TSOs following the terms published by the TSOs.

Firm delivery capacities at the distribution-transmission interface points (PITDs) are automatically allocated by the TSOs. These capacities are calculated by the TSOs using the information provided by the public gas distribution system operator. Standardised delivery capacities are calculated objectively and transparently, with no discrimination, and made public.

The shipper is allocated main network exit capacity and regional network transmission capacity equal, for each delivery point and for each PIRR, to the delivery capacity at that point.

5.1.2.6 Subscription of capacity at biomethane injection points

Shippers are allocated injection capacity equal to the production capacity of the site as it is recorded in the capacity register, for the duration of the purchase agreement they have signed with the production site.

5.1.3 Redistribution of surplus revenue from capacity auctions

For the period from 1 November 2019 to 30 September 2020, all surplus revenue from auctions received over this period will be redistributed in one payment, in proportion to the quantities of gas delivered to end customers connected to the transmission network or distribution network in France from 1 November 2019 to 30 September 2020.

The individual amounts for redistribution for the period from 1 November 2019 to 30 September 2020 will be calculated by each TSO and redistributed in the bill for November 2020 at the latest.

Each TSO will publish on its website the unit amount of surplus auction revenue so redistributed.

5.1.4 Transfer of transmission capacity in GRTgaz's network

The transmission capacity contracted at entry and exit points to PIRs can be transferred freely at no additional cost.

In the case of full transfer, the acquirer recovers all the rights and obligations tied to those subscriptions.

In the event of a transfer of the right of use, the initial owner keeps their obligations vis-à-vis the TSO. The right of use swapped may be as small as a daily time slot, regardless of the duration of the initial subscription.

The right of use of downstream transmission capacity, between the PEG and the delivery point at an industrial site directly connected to the transmission network, or between a PITP and the PEG, is transferable in cases where the industrial customer concerned has booked this capacity with the TSO.

The conditions governing these transmission capacity transfers are defined by the TSOs, on an objective and transparent basis, and are published by the TSOs on their websites.

5.2 Tariffs for the use of GRTgaz's and Teréga's natural gas transmission networks as at 1 April 2020

5.2.1 Forecast revenue to be collected by the transmission tariff

The tariffs and projected tariff changes are defined, based on capacity subscription forecasts, so as to cover the allowed revenues for each of the TSOs.

- GRTgaz:

GRTgaz, in current €M	2020	2021	2022	2023
Forecast revenue to be collected by the tariff	1795,9	1782,1	1794,8	1802,1

- Teréga:

Teréga, in current €M	2020	2021	2022	2023
Forecast revenue to be collected by the tariff	280,1	278,5	279,7	269,3

5.2.2 Tariffs applicable to annual subscriptions of daily delivery and transmission capacity

5.2.2.1 Pricing for network interconnection points (PIRs) before 1 October 2020

The tariffs applicable to annual subscriptions of daily capacity are defined in the tables below. When capacity is auctioned, the reserve prices of the auctions are equal to these tariffs.

- Charge for main network entry capacity (TCE)
-

Entry at	Balancing zone	TCE (€/MWh/day per year) *Firm annual*	TCE (coefficient for firm charge) *Interruptible annual*
Taisnières B	GRTgaz – Nord B	81.66	50%
Virtualys (Taisnières H)	GRTgaz	104.97	50%
Dunkerque (PIR)	GRTgaz	104.97	50%
Obergailbach	GRTgaz	104.97	50%
Oltingue	GRTgaz	104.97	50%
Pirineos	Teréga	104.97	75%

- Charge for PIR exit capacity (TCST)

Exit at	Balancing zone	TCST (€/MWh/day per year) *Firm annual*	TCST (coefficient for firm charge) *Interruptible annual*
Virtualys (Alveringem)	GRTgaz	41.37	N/A
Oltingue	GRTgaz	407.02	75%
Pirineos	Teréga	626.95	75%

- Charge for backhaul capacity at PIR

Exit at	Balancing zone	Coefficient for firm entry charge *Backhaul annual*
Taisnières B	GRTgaz	20 %
Virtualys (Taisnières H)	GRTgaz	20 %
Obergailbach	GRTgaz	20 %

Entry at	Balancing zone	Coefficient for firm exit charge *backhaul annual*
Virtualys (Alveringem)	GRTgaz	125 %

- Returnable capacity

The price of annual returnable capacity is equal to 90% of the price of the corresponding firm annual capacity.

5.2.2.2 Pricing for network interconnection points (PIRs) as from 1 October 2020

The tariffs applicable to annual subscriptions of daily capacity are defined in the tables below. When capacity is auctioned, the reserve prices of the auctions are equal to these tariffs.

- Charge for main network entry capacity (TCE)
-

Entry at	Balancing zone	TCE (€/MWh/day per year) *Firm annual*	TCE (coefficient for firm charge) *Interruptible annual*
Taisnières B	GRTgaz – Nord B	81.59	50%
Virtualys (Taisnières H)	GRTgaz	105.18	50%
Dunkerque (PIR)	GRTgaz	105.18	50%
Obergailbach	GRTgaz	105.18	50%
Oltingue	GRTgaz	105.18	50%
Pirineos	Teréga	105.18	50%

- Charge for PIR exit capacity (TCST)

Exit at	Balancing zone	TCST (€/MWh/day per year) *Firm annual*	TCST (coefficient for firm charge) *Interruptible annual*
Virtualys (Alveringem)	GRTgaz	41.85	N/A
Oltingue	GRTgaz	384.95	85%
Pirineos	Teréga	584.31	85%

- Charge for backhaul capacity at PIR

Exit at	Balancing zone	Coefficient for firm entry charge *Backhaul annual*
Taisnières B	GRTgaz	20 %
Virtualys (Taisnières H)	GRTgaz	20 %
Obergailbach	GRTgaz	20 %

Entry at	Balancing zone	Coefficient for firm exit charge *backhaul annual*
Virtualys (Alveringem)	GRTgaz	125 %

- Returnable capacity

The price of annual returnable capacity is equal to 90% of the price of the corresponding firm annual capacity.

5.2.2.3 Pricing of LNG terminal-transmission interface points (PITTMs)

- Charge for main network entry capacity (TCE)

Entry at	Balancing zone	TCE (€/MWh/day per year) *Firm subscriptions*
Dunkerque GNL	GRTgaz	94.66
Montoir	GRTgaz	94.66
Fos	GRTgaz	94.66

5.2.2.4 Pricing of storage-transmission interface points (PITS)

- Charges for storage entry and exit capacity (TCES and TCSS)

PITS	Balancing zone	Type of capacity	Entry - TCES (€/MWh/day per year) *Annual*	Exit - TCSS (€/MWh/day per year) *Annual*	Exit - TCES (coefficient for firm charge) *Interruptible annual*
Nord-Ouest	GRTgaz	Climatic firm	9.17	21.43	50%
Nord-Est	GRTgaz	Climatic firm	9.17	21.43	50%
Nord B	GRTgaz – Nord B	Climatic firm	9.17	21.43	50%
Atlantique	GRTgaz	Climatic firm	9.17	21.43	50%
Sud-Est	GRTgaz	Climatic firm	9.17	21.43	50%
Sud-Ouest	Teréga	Climatic firm	9.17	21.43	50%

5.2.2.5 Pricing of exit capacity from the main network to delivery points

- Charge for main network exit capacity

Exit from	TCS (€/MWh/day per year) *Firm annual*	TCS (coefficient for firm charge) *Interruptible annual*
GRTgaz	94.73	50%
Teréga	94.73	50%

5.2.2.6 Pricing of regional network transmission

- Charge for regional network transmission capacity (TCR)

Regional network	TCR (€/MWh/day per year) *Firm annual*	TCR (coefficient for firm charge) *Interruptible annual*
GRTgaz	84.53 x NTR	50%
Teréga	79.77 x NTR	50%

The charge applicable to firm annual subscriptions of daily regional network transmission capacity is the product of the unit charge defined and the regional tariff level (NTR) of the delivery point in question.

The list of delivery points in GRTgaz's and Teréga's network, along with their exit zone and their NTR value, is provided in Annex 7 of this document.

When a new delivery point is created, GRTgaz or Teréga calculates the value of the NTR in a transparent and non-discriminatory manner, on the basis of a calculation method published on their respective websites.

- Charge for delivery capacity (TCL)

Transmission network	**Type of delivery point**	**TCL (€/MWh/day per year)** ***Firm annual***	**TCL (coefficient for firm charge)** ***Interruptible annual***
GRTgaz	End consumer connected to the transmission network	33.64	50%
	PIRR	43.18	N/A
	PITD	49.66	N/A
Teréga	End consumer connected to the transmission network	28.91	50%
	PITD	52.23	N/A

If several shippers simultaneously supply a PIRR, the fixed charge is split in proportion to their delivery capacity subscriptions.

In accordance with the standardised subscription system for transmission capacity at PITDs, at each PITD, the firm annual delivery capacity ("standardised capacity") is allocated to each shipper by the TSOs. It is equal to the sum:

- of annual capacity booked in the distribution network for "subscription-based" delivery points (PDL) supplied downstream of the PITD in question;
- of capacity calculated by the TSOs for "non-subscription based" delivery points supplied downstream of the PITD in question, by multiplying the daily peak consumption of "non-subscription based" delivery points by the corresponding adjustment coefficient "A".

An update of the A coefficients is possible as at 1 April of each year via a deliberation by CRE on the proposal of the TSOs for their balancing zones and for each distribution system operator present in these zones.

- Fixed charges per delivery station

Shippers supplying end customers connected to the transmission network and PIRRs pay a fixed charge per delivery station:

Fixed charge per station	€/station per year
GRTgaz	6,490.80
Teréga	3,197.33

5.2.3 Storage tariff based on winter modulation

5.2.3.1 Amount of compensation to be received

The amount of compensation to be received by an underground natural gas storage infrastructure operator and which will be collected by the TSOs, corresponds to the difference between (i) the operator's allowed revenue for 2020, set by CRE in its deliberation of 23 January 2020, and (ii) the forecast income received directly by the operator for the year 2020. This calculation is performed for each operator. It defines the share of the compensation returned by each TSO to each operator by considering the ratio between the operator's forecast annual compensation and total annual forecast compensation.

The amounts that will be adopted by CRE to calculate the compensation for 2020 are as follows:

i. for allowed revenue, CRE adopts the amount defined in its deliberation of 23 January 2020;

ii. for forecast income directly received by the storage operators, CRE adopts in particular:

   a) the income received by the storage operators for storage capacity and additional services for 2019-2020, for the first three months of 2020;

   b) the income received by the operators for storage capacity and additional services for 2020-2021, for the last nine months of 2020.

The amount of compensation is calculated annually. It will be defined by CRE after the auction campaign, at the end of the month of March 2020.

5.2.3.2 Calculation of winter modulation

All shippers that are allocated firm delivery capacity at at least one distribution-transmission interface point (PITD) are applied a storage charge (TS) based on the winter modulation of their clients, connected to the public gas distribution networks, in their portfolio the 1st day of each month. This modulation is calculated using the information provided by the public gas distribution system operators. This charge aims to recover a portion of the income of underground natural gas storage operators.

The basis of collection of the compensation to be received from each shipper is defined as the sum of the bases of each of its clients eligible for payment of the storage compensation.

The level of winter modulation is determined on the 1st day of each month, for each client, by applying the calculation described below.

- <u>"Subscription-based" clients</u>

For subscription-based clients, winter modulation of each client for the last three years is calculated as follows:

$$\textbf{Client modulation (MWh/d)} = \mathrm{Max}\left(0; \frac{\text{Winter consumption}}{151} - \frac{\text{Annual consumption}}{365} - \mathrm{Int}\right)$$

Where:

- Winter consumption: consumption of the site from 1 November Y-2 to 31 March Y-1
- Annual consumption: consumption from 1 November Y-2 to 31 October Y-1
- Int: sum of interruptible capacity contracted for year Y-1 between system operators and their shipper clients to meet technical supply constraints, interruptible capacity that will be contracted with system operators once the orders relating to interruptibility mechanisms have been effectively implemented.

The modulation adopted for billing the storage compensation during year Y corresponds to the average of the two lowest values among the three values calculated. This takes into account any heavy maintenance or regulatory shutdowns, which are actually part of the industrial reality of subscription-based clients.

In the case of a new site connected under the "subscription-based" option, with no history of actual consumption, the site's modulation will be determined by the DSOs based on the best estimate of the reference annual consumption (CAR) and of the consumption profile communicated to the DSO within the framework of the connection by the site's supplier. Billing of the storage compensation will begin as from the first month following the connection of the site based on this estimate. Once, as at 1 April of a year Y, a complete year of calculation data is available (i.e. that the consumption data dating back up to 1 November of year Y-2 are available), billing will be performed based on this first year of actual consumption data. As at 1 April of the following year, modulation will be calculated as the average of the two modulation values available and lastly, as at the following 1st of April, the modulation adopted will correspond to the two lowest values among the three available values, as described in the present deliberation.

In the absence of the notions of reference annual consumption and profile in transmission, the first year of billing of a new client connected to the network will be done based on an estimate forwarded to the TSOs by the site supplier.

In addition, in all cases other than that of a new site connected under a "subscription-based" option, it will be the responsibility of the system operators to ensure continued billing of the storage compensation by referring to the record of consumption data in their possession.

- "Profile-based" clients

For "profile-based" clients, modulation of a year Y is calculated as follows:

$$\text{Client modulation (MWh/j)} = Max(0; CJN - \frac{CAR}{365} - Int)$$

Where:

- reference annual consumption (CAR) is the estimated annual consumption of a metering and estimate point (PCE) for an average weather year;
- standardised daily capacity (CJN) is such that:

$$\text{CJN} = A.zi.CAR$$

  Where:

  - A is a coefficient reflecting the ratio between "standardised" capacity, calculated by the TSOs for "non-subscription based" delivery points, supplied downstream of a given PITD, for each DSO in each balancing zone and, for the same perimeters, the daily peak consumption of these delivery points calculated by DSOs' profile algorithm;
  - coefficient Zi: conversion coefficient taking into account the weather station and the consumption profile of the client. The method for attributing profiles is available on the gas working group website[51].
- Int: sum of interruptible capacities which will be contracted with system operators once the orders relating to interruptibility mechanisms are effectively implemented.

Public gas distribution system operators send TSOs the data necessary for calculating the level of winter modulation, as defined above.

In certain cases, especially for certain DSOs not having information on the consumption profile of their longtime customers, certain data (reference annual consumption, profiles), might not be available. The TSOs can substitute the reference annual consumption with an equivalent based on the estimate of the overall reference annual consumption of the PITD.

If a DSO does not send the data necessary for the calculation of the collection basis for clients within its perimeter on time, the TSO will apply, for these specific clients, a method based on capacity booked. This calculation will be corrected *ex post*, once the DSO has forwarded the data.

By way of exception, Client modulation is set at 0 MWh/d:

- for clients that declared themselves open to load shedding during the investigation conducted by distribution system operators[52], with this exception ending with the effective implementation of texts relating to the interruptibility mechanisms;

[51] Calculation of Zi coefficients
[52] GRDF's questionnaire on load shedding positions: https://www.grdf.fr/entreprises/aide-contact/questions-frequentes/reponses

- for counter-modulated clients, i.e. clients with a P013 profile (Winter portion lower than or equal to 39%) or P014 profile (Winter portion between 39% and 50%). Profiles are attributed by the DSOs according to the methodology published on the website of the gas working group[53].

In the event of a change during the year from the T3 profile-based tariff option to a subscription-based tariff option in the distribution network, billing of the storage compensation will be adjusted as from the month following this change and will follow the formula specific to subscription-based clients. The "winter consumption" and "annual consumption" values will be calculated based on the T3 client's monthly meter readings. Similarly, changing from a subscription-based option to a profile-based option will lead to a change in the method for calculating modulation as from the following month.

The forecast value of the compensation basis for 2020 will be specified in a later deliberation by CRE, at the end of March 2020.

5.2.3.3 Calculation of the storage charge

The storage tariff is calculated as the ratio between the forecast amount of compensation within the perimeter of France and the forecast value of the basis for collection of this compensation. CRE will set the level of the storage charge applicable as at 1 April 2020 in March 2020 in order to take into the account the income from the 2020-2021 marketing year.

5.2.4 Tariff multipliers for transmission and delivery capacity subscriptions of less than one year

5.2.4.1 At network interconnection points (PIRs)

Capacity	Special conditions	Coefficient
Quarterly	In the event of congestion	1/4th of the annual tariff
	No congestion	1/3rd of the annual tariff
Monthly	In the event of congestion	1/12th of the annual tariff
	No congestion	1/8th of the annual tariff
Daily	In the event of congestion	1/30th of the "in the event of congestion" monthly tariff
	No congestion	1/30th of the "no congestion" monthly tariff
Intraday	N/A	Pro rata of the daily charge based on the number of hours remaining

A point is considered congested if, upon allocation of the annual firm products at auctions, the capacity sale price is strictly above the reserve price.

5.2.4.2 At LNG terminal-transmission interface points (PITTMs)

Capacity	Coefficient
Daily	1/365th of the annual tariff

5.2.4.3 At storage-transmission interface points (PITS)

Capacity	Coefficient
Quarterly	1/3rd of the annual tariff
Monthly	1/8th of the annual tariff
Daily	1/240th of the annual tariff

[53] Table of profiles applicable from 1 April 2018 to 31 March 2019: https://www.gtg2007.com/libre/donnees/index.php?IdDPDRType=3

5.2.4.4 At main network exits, on the regional network and delivery

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

- Daily short-notice subscription of daily delivery capacities

For clients connected to GRTgaz's transmission network, specific conditions apply for requests for daily delivery capacity subscription made on short notice.

When the subscription request reaches GRTgaz with a notice:

- between the standard notice set out in the contract for the use of GRTgaz's transmission network and 9.00 a.m. on the second working day preceding the day considered by the request, the tariff applicable is that defined in the present tariff;
- after 9.00 a.m. on the second working day preceding the day considered by the request and before 8.00 a.m. the day preceding the day considered by the request, the tariff applicable is increased by 20%;
- after 8.00 a.m. on the day preceding and up to 2.00 p.m. on the day considered by the request, the tariff applicable is increased by 30%. Daily capacity booked during the day of delivery is considered to take effect as from 6.00 a.m. that same day, regardless of the time at which it was booked.

- Subscription of hourly delivery capacity

Hourly delivery capacity applies only to end customers connected to the transmission network.

All annual, monthly or daily subscriptions of daily delivery capacity confers the right to an hourly delivery capacity equal to 1/20th of the daily delivery capacity booked (except in a particular case where that hourly capacity is not available).

To receive, where possible on the network, a higher hourly capacity, above the hourly capacity booked through the annual, monthly or daily subscription of daily delivery capacity, the shipper must pay a price supplement, which equates to 10 times the sum of the charges for daily delivery and regional network transmission capacity.

5.2.5 Tariffs applicable to gas injection capacities in the transmission network from a gas production facility

5.2.5.1 Production-Transmission Interface Points

The charges applicable to annual subscriptions of daily entry capacity in GRTgaz's network from the transmission-production interface points (PITPs) are as follows:

- for PITPs with a network entry capacity less than or equal to 5 GWh/d, the applicable charge is €9.75 MWh/day per year;
- for PITPs with a network entry capacity greater than 5 GWh/d, the applicable charge is defined through a special study and decision.

5.2.5.2 For biomethane injection points

The biomethane injection tariff introduced in the ATRT7 tariff is based on the definition of three levels of injection charges, to differentiate the amount paid by producers and shippers according to the costs generated by their choice of location. The levels are as follows:

	(€/MWh injected)
Level 3	0.7

Level 2	0.4
Level 1	0

Classing of zones by level type is done based on the connection zoning scheme in effect in the zone and is updated at the same time as the zoning scheme update:

- if zoning provides for backhaul or pooled compression, the zone's future production sites are attributed level 3;
- if zoning does not provide for backhaul or pooled compression:
  - if the zoning scheme includes meshing[54] and/or a shared extension[55], the zone's production sites are attributed level 2;
  - for the other zones, the zone's production sites are attributed level 1.

The charge level is attributed to each production site during the D2 milestone connection study[56], based on the connection zoning scheme[57] in effect in the zone.

5.2.6 Pricing of notional gas exchange points

The operating methods of the notional gas exchange point (PEG) are defined by the TSOs, on an objective and transparent basis, and published on their websites.

The tariff for access to the gas exchange point consists of:

- a fixed annual charge, equal to €6,000;
- a charge proportional to quantities exchanged equal to €0.01/MWh.

Gas exchanges made through an electronic platform may be delivered at a gas exchange point by an entity in charge of compensating the exchanges performed on that platform. Nominations at the PEG by such an entity for compensation purposes, neutral with respect to the market, are not subject to the charge proportional to the quantities exchanged.

5.2.7 Intraday flexibility service for sites with major consumption variations

The intraday flexibility service applies to clients connected to the transmission network that have a daily modulated volume greater than 0.8 GWh. The intraday flexibility service is not billed.

For existing sites, GRTgaz evaluates this criterion based on the consumption history for the previous year. For newly connected sites, this criterion is evaluated based on the daily modulated volume for the operating days declared by the site, and then based on a quarterly statement, with retroactive effect on the past period when the criterion is met.

The operator of the site for which the intraday flexibility service is contracted declares to the TSO an hourly consumption profile the day before for the following day, and where applicable, a new profile during the day in compliance with the published advanced notice deadlines. For any modification in the site's hourly consumption that is less than ± 10% of the hourly capacity subscribed, the site will benefit from a margin of tolerance enabling it not to notify GRTgaz of its new hourly consumption profile.

The delivery capacity charge for the delivery point concerned is not billed.[58]

5.2.8 Gas quality conversion

5.2.8.1 Peak H gas to L gas conversion service

A firm annual "peak" H gas to L gas conversion service is sold by GRTgaz. This service is accessible to all shippers having H gas in the TRF.

[54] Two distribution grid squares of equivalent pressure are connected physically.
[55] Extension of a gas network enabling connection of new sites, shared between several sites.
[56] Sites queued that have already exceeded the D2 milestone as at the time the present deliberation enters into effect, but which are not yet injecting biomethane, will be attributed an injection tariff level when the connection contract is signed, following identical principles.
[57] Result of the study, done jointly by the network operators, determining the optimal network configuration based on the technico-economic zoning criterion
[58] For subscriptions of hourly capacity and penalties for the exceeding of capacity by highly modulated sites, the calculation takes into account the TCL applicable to the end consumer connected to the transmission network (see section 5.2.2.6).

The level of this tariff is defined in the following table:

	Capacity charge (€/MWh/day per year)	Quantity charge (€/MWh)
"Peak" service	161.60	0.02

The operating rules of the H gas to L gas quality conversion service are defined by GRTgaz, on an objective and transparent basis preventing any discrimination, and are published on its website.

5.2.8.2 L gas to H gas conversion service

The L gas to H gas conversion service is accessible to all shippers shipping their own L gas from the PIR Taisnières B and/or the PITS Nord B, within the limit of the physical quantities of L gas concerned.

The tariff for the L gas to H gas quality conversion service is as follows:

- for the annual interruptible offer, a charge proportional to the annual capacity subscription equal to €23.59 MWh/day per year;
- for the monthly interruptible offer, a charge proportional to the monthly capacity subscription equal to €2.95 MWh/day per month;
- for the daily firm offer, a charge proportional to the daily capacity subscription equal to €0.20/MWh/day per day.

5.2.8.3 Penalty for daily imbalance within the L gas perimeter

The L gas perimeter is open to all shippers and is composed of Taisnières B, the Nord B storage facility, the peak H gas to L gas converter, L gas to H gas adaptors and the delivery point of the H gas to L gas swap service.

Shippers that use L gas infrastructure have a daily balancing obligation within the L gas perimeter. Penalties apply if they do not comply with their balancing obligation, whether their positions are short or long. The penalties that apply are as follows:

Balance within the L perimeter	Threshold	Price within the L perimeter
Positive imbalance (long) below the threshold	5 GWh	€1/MWh
Positive imbalance (long) above the threshold		€30/MWh
Negative imbalance (short) below the threshold	1 GWh	€3.35/MWh
Negative imbalance (short) above the threshold		€30/MWh

5.2.8.4 Verification of nominations in the physical infrastructure of the L network

GRTgaz may, in circumstances in which the physical balancing of the L network requires it, oblige shippers that have capacity in the physical infrastructure of the L transmission network, to revise their nominations upwards or downwards in these infrastructure.

5.2.9 Balancing service based on linepack

GRTgaz and Teréga sell a balancing service based on linepack, whose subscription tariff is equal to €0.12/MWh/d/month[59] for all delivery points of industrial sites directly connected to the transmission network or for all delivery points of non-profile based sites associated with a PITD. There is a 50% discount on the subscription price of this service for all delivery points of profile-based sites connected to a distribution network.

[59] For the details of this service, see CRE's deliberation of 9 September 2015 relating to the change in balancing rules in the gas transmission networks as at 1 October 2015

5.2.10 Penalties for exceeding capacity

5.2.10.1 Method for calculating exceedance of daily capacity and associated penalties

- Exceeding daily main network exit capacity

For a given day, the value of the daily capacity in excess taken into account is equal to the difference, if it is positive, between the following two values:

- the difference between the daily quantity of gas delivered and the corresponding daily main network exit capacity, if this difference is positive, or zero if this difference is negative;
- the difference between the sum of the daily quantities delivered in the exit zone to "non-subscription based" PDLs and the sum for the standardised capacity exit zone to "non-subscription based" PDLs, if this difference is positive, or zero if this difference is negative.

- **Exceeding daily regional network and delivery capacity for end customers connected to the transmission network and PIRRs:**

For a given day, the value of the daily capacity in excess taken into account is equal to the difference, if it is positive, between the quantity of gas delivered and the daily delivery capacity contracted.

- **Exceeding daily regional transmission and delivery capacity for PITDs**

For a given day, the value of the daily capacity in excess taken into account is equal to the difference, if it is positive, between the following two values:

- the difference between the daily quantity of gas delivered and the corresponding daily delivery capacity, if this difference is positive, or zero if this difference is negative;
- the difference between the sum of the daily quantities delivered at "non-subscription based" PDLs and the sum of standardised capacity for "non-subscription based" PDLs, if this difference is positive, or zero if this difference is negative.

If interruptibility is exercised by the TSO, the calculations for capacity excess presented above are carried out by reducing the interruptible capacity from the interrupted portion requested by the TSO.

- **Methods for calculating penalties for exceeding daily capacity**

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

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

For the portion of the excess that is greater than 3%, the penalty is equal to 20 times the price of the firm daily subscription of daily capacity.

The TSOs give shippers the possibility of rapidly adjusting their capacity subscriptions when the exceeding of the capacity limit is observed, subject to the network's availabilities.

5.2.10.2 Method for calculating exceedance of hourly capacity and associated penalties

- **Methods for calculating hourly excess**

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

- **Method for calculating exceedance of hourly capacity**

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

For the portion in excess greater than 10%, the penalty is equal to 45 times the price of the daily subscription of hourly capacity.

The penalties for exceeding hourly capacity are not applied by GRTgaz if the shipper corrects its annual subscription of hourly capacity to include the excess.

DECISION

CRE defines the tariff for the use of GRTgaz's and Teréga's natural gas transmission networks as from 1 April 2020, based on the methodology and parameters described in the present deliberation.

CRE defines, in particular:

- the tariff regulatory framework and the incentive regulation parameters applicable to GRTgaz and Teréga for a period of roughly four years (part 2);
- the trajectory of operating expenses, the WACC and the forecast change in the tariff (part 3);
- the tariff structure (part 4);
- the tariffs applicable as from 1 April 2020 (part 5).

The present deliberation will be published on CRE's website and forwarded to the minister of the ecological and inclusive transition, and the minister of economy and finance, and published in the Official Journal of the French Republic.

Paris, 23 January 2020

For the Energy Regulatory Commission,

The Chairman,

Jean-François CARENCO

ANNEX 1: 2020 TARIFF SUMMARY TABLE

This annex summarises the main tariffs presented in part 3 of the present deliberation.

Access to the notional gas exchange pint (PEG)

Fixed annual charge: **€6,000/year**
Variable charge: **€0.01/MWh traded**

Main charges applicable for the Main network

	Capacity charge (€/MWh/d/year)	
Entry at Network Interconnection Points (PIRs) (as at 1 October)	Firm	Interruptible
GRTgaz - Taisnières B	**81.59**	50%
GRTgaz – Virtualys (Taisnières H)	**105.18**	50%
GRTgaz – Dunkerque	**105.18**	50%
GRTgaz – Obergailbach	**105.18**	50%
GRTgaz – Oltingue	**105.18**	50%
Teréga – PIRINEOS	**105.18**	50%

	Capacity charge (€/MWh/d/year)	
Exit at Network Interconnection Points (PIRs) (as at 1 October 2020)	Firm	Interruptible
GRTgaz – Virtualys (Alveringem)	**41.85**	
GRTgaz – Oltingue	**384.95**	85%
Teréga – PIRINEOS	**584.31**	85%

	Capacity charge (€/MWh/d/year)
Entry at LNG terminal-Transmission Interface Points (PITTMs)	Firm
GRTgaz - Dunkerque GNL	**94.66**
GRTgaz - Montoir	**94.66**
GRTgaz - Fos	**94.66**

	Capacity charge (€/MWh/d/year)		
Entry/exit at Storage-Transmission Interface Points (PITS)	Entry	Exit	
		Firm	Interruptible
GRTgaz - Nord-Ouest, Nord-Est, Nord B, Sud-Est, Atlantique	**9.17**	**21.43**	50%
Teréga – Sud-Ouest	**9.17**	**21.43**	50%

	Capacity charge (€/MWh/d/year)	
Main network exit to delivery points (TCS)	Firm	Interruptible
GRTgaz	**94.73**	50%
Teréga	**94.73**	50%

Main charges applicable for the Regional networks

	Capacity charge (€/MWh/d/year)	
Regional network transmission capacity (TCR)	Firm	Interruptible
GRTgaz	84.53 x NTR	50%
Teréga	79.77 x NTR	50%

The Regional tariff level (NTR) is defined for each delivery point from 0 to 10

	Capacity charge (€/MWh/d/year)	
Delivery capacity (TCL)	Firm	Interruptible
GRTgaz - End consumer connected to the transmission network	33.64	50%
GRTgaz - PIRR	43.18	
GRTgaz - PITD	49.66	
Teréga - End consumer connected to the transmission network	28.91	50%
Teréga- PITD	52.23	

	Charge per station (€/station/year)
Delivery station	
GRTgaz	6,490.80
Teréga	3,197.33

	Charge per station (€/MWh injected)
Coefficient of the zone	
1	0
2	0.40
3	0.70

ANNEX 2: INDICATORS FOR MONITORING QUALITY OF SERVICE

In accordance with the principles defined in the "Regulatory framework" part of the present tariff decision, a mechanism to monitor service quality has been set up for both TSOs for key fields of their activity. This monitoring consists of indicators sent each month by the TSOs to CRE and published on their websites.

Some indicators that are particularly important for the proper functioning of the market are subject to a financial incentive system.

The following indicators are subject to a financial incentive:

- quality of quantities measured at PITDs and sent to the DSOs the day after to calculate provisional allocations;
- quality of the daily quantities telemetered at the delivery points of consumers connected to the transmission network and sent the following day;
- quality of intraday quantities telemetered at the delivery points of consumers connected to the transmission network and sent during the day;
- quality of overall day-ahead and within-day overall forecasts for end-of-day gas consumption.

The following indicators are monitored without being subject to a financial incentive:

- accuracy of the projected linepack indicator published by the TSOs on their public page;
- reduction of booked capacity;
- compliance with the annual maintenance programme published in October and February by the TSO;
- compliance with the probable values published in October and February by the TSO;
- provision of the most useful information to shippers;
- functioning of the single market zone;
- processing of claims;
- greenhouse gas emissions;
- greenhouse gas emissions in relation to the volume of gas transported;
- methane emissions in relation to the volume of gas transported.

The service quality regulation system may change during the ATRT7 tariff period. It may be subject to any audit deemed useful by CRE.

TSOs are authorised to write off one day per year to calculate the indicators, during the commissioning of a major version of an application contributing to the production of said indicators. They are required to communicate to market participants the tentative date for commissioning at least one month in advance, and then to confirm one week before the actual date of this commissioning.

1. TSO service quality monitoring indicators that give rise to financial incentives

a. Quality of quantities measured at PITDs and sent to the DSOs the day after to calculate provisional allocations

Calculation:	**Number of non-compliant(1) days per balancing zone and per month**
Scope:	- all shippers combined - all DSOs - per perimeter
Monitoring:	- frequency of calculation: monthly - frequency of reporting to CRE: monthly - frequency of publication: monthly - frequency of financial incentive calculation:
Objective:	**GRTgaz:** - basic objective: 1 non-compliant day per month - target objective: 0 non-compliant days per month **Teréga:** - basic objective: 1 non-compliant day per month - target objective: 0 non-compliant days per month

Incentives:	**GRTgaz:** - penalties / month: • €40 k for the 2nd non-compliant day; • €60 k per non-compliant day, as from the 3rd non-compliant day; - bonus / month: €50 k if the target objective is achieved; - cap: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by GRTgaz, is capped at +/- €600 k per year. **Teréga:** - penalties / month: • €40 k for the 2nd non-compliant day; • €60 k per non-compliant day, as from the 3rd non-compliant day; - bonuses / month: €25 k if the target objective is achieved; - cap: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by Teréga, is capped at +/- €300 k.
Implemen-tation date	- 1 April 2016

(1): For a given transmission balancing zone (ZET), day D of month M is non-compliant if the variation, in absolute terms, between the following values is strictly greater than 2%:

- *the provisional measurement of the quantity of gas delivered to all PITDs in the ZET on that day D and sent to the DSOs;*
- *The final measurement of quantity delivered to all PITDs of the ZET on that day D and sent to the DSO on the 20th of month M+1.*

b. Quality of daily quantities telemetered at the delivery points of consumers connected to the transmission network and sent the following day

Calculation:	- **Very good quality rate of information(4)** - **Good quality rate of information** - **Poor quality rate of information** (three values monitored for each TSO)
Scope:	- all shippers combined - all ZETs combined - all telemetered industrial delivery points - rounded off to one decimal place
Monitoring:	- frequency of calculation: monthly - frequency of reporting to CRE: monthly - frequency of publication: monthly - frequency of calculation of financial incentives: monthly
Incentives:	**GRTgaz:** The financial incentive relates to the monthly average of very good and poor quality rates of information. - penalties / month: €60 k per percent of poor quality information; - bonuses / month: €1 k per percent of very good quality information; - cap: the total annual amount, corresponding to the sum of penalties to be paid and the bonuses to be received by GRTgaz, is capped at €300 k for bonuses and €600 k per year for penalties. **Teréga:** The financial incentive relates to the monthly average of very good and poor quality rates of information. - penalties / month: €30 k per percent of poor quality information; - bonuses / month: €500 per percent of very good quality information; - cap: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by Teréga, is capped at €150 k per year for bonuses and €300 k for penalties.

Implementation date	- 1 April 2015

(4): Information is said to be of very good quality if the variation, in absolute terms, between the energy reading for day D sent on day D+1 and the final reading for day D sent in M+1 is strictly below 1%. If the difference is between 1% and 3% (or strictly higher than 3%), the value is of good quality (or poor quality).

c. Quality of intraday quantities telemetered at the delivery points of consumers connected to the transmission network and sent during the day

Calculation:	- **Very good quality rate of information**(1) - **Good quality rate of information** - **Poor quality rate of information** (three values monitored by GRTgaz and Teréga per hour)
Scope:	- calculation for each hour of the day - all shippers combined - all ZETs combined - all telemetered industrial delivery points - rounded off to the nearest percent
Monitoring:	- frequency of calculation: monthly - frequency of reporting to CRE: monthly - frequency of publication: monthly - frequency of calculation of financial incentives: monthly
Incentives:	The financial incentive related to the average monthly hourly average of very good and poor quality rates of information. **GRTgaz:** - penalties / month: €20 k per percent of poor quality information; - bonuses / month: €1 k per percent of very good quality information; - Cap: the total annual amount, corresponding to the sum, over all hour slots, of the penalties to be paid and bonuses to be received by GRTgaz, is capped at more or less €600 k per year. **Teréga:** - penalties / month: €10 k per percent of poor quality information; - bonuses / month: €500 per percent of very good quality information; - cap: the total annual amount, corresponding to the sum, over all hour slots, of the penalties to be paid and bonuses to be received by Teréga, is capped at more or less €300 k per year.
Implementation date	- 1 April 2014

(1): Information is said to be of very good quality if the variation, in absolute terms, between the energy reading in the timeslot for day D sent on day D and the final reading in the timeslot for day D sent in M+1 is strictly below 1%. If the difference is between 1% and 3% (or strictly higher than 3%), the value is of good quality (or poor quality). If the deviation is less than 100 kWh, the information is of very good quality.

d. Quality of day-ahead and within-day forecasts of overall end-of-gas-day consumption

Calculation:	- **Very good quality rate of information**(1) - **Good quality rate of information** - **Poor quality rate of information** (one rate per scope for the values published the day before and during the day, i.e. 3 values followed by GRTgaz and 3 values followed by Teréga)
Scope:	- all shippers combined - one value per scope - rounded off to one decimal place

Monitoring:	- frequency of calculation: monthly - frequency of reporting to CRE: monthly - frequency of publication: monthly - frequency of calculation of financial incentives: monthly
Incentives:	The financial incentive relates to the average of the very good quality and poor quality rates of information. **GRTgaz:** For the values published the day before (D-1) and during the day (D): - penalties: €80 per tenth of a percent of poor quality information; - bonuses: €20 per tenth of a percent of very good quality information; - cap: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by GRTgaz, is capped at around €600 k. **Teréga:** For the values published the day before (D-1) and during the day (D): - penalties: €40 per tenth of a percent of poor quality information; - bonuses: €10 per tenth of a percent of very good quality information; - cap: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by Teréga, is capped at around €300 k.
Implementation date:	- 1 April 2014

(1): For the forecast made the day before, information is said to be of very good, good, and poor quality if the variation, in absolute terms, between the following values is strictly less than 3%, between 3% and 6%, and strictly greater than 6% respectively:

- *the consumption forecast for day D published the day before at 5.00 p.m.;*
- *the final reading of the energy used on day D sent on the 20th of M+1.*

For the forecast made during the day, information is said to be of very good, good, and poor quality if the variation, in absolute terms, between the following values is strictly less than 3%, between 3% and 5%, and strictly greater than 5% respectively:

- *the consumption forecast for day D published on day D at 3.00 p.m.;*
- *the final reading of the energy used on day D sent on the 20th of M+1.*

The overall forecasts for end-of-gas-day consumption used to calculate the indicator concerning industrial clients, highly modulated sites and public distribution connected to the TSO's network.

2. Other indicators for monitoring TSO service quality

a. Accuracy of the projected linepack indicator published by the TSOs on their public page

The projected linepack indicator is an estimation by the TSOs of the gas level in each balancing zone at the end of the current gas day (5.00 a.m.). This indicator provides information about network tightness, in the same way as the imbalance indicator. The difference between the two indicators lies in the view of the system they provide: the first offers a projected view of the system for the current day, whereas the second gives a static view of a specific moment.

The projected linepack indicator affects TSO interventions in the markets and informs shippers about the availability of flexibility services based on linepack.

Calculation:	
Scope:	- One value per month and per balancing zone (one value for Teréga and one value for GRTgaz)
Monitoring:	- frequency of calculation: monthly - frequency of reporting to CRE: monthly - frequency of publication: monthly

Implementation date:	- 1 April 2016

(1): a component is considered non-compliant if the difference is both greater than 30 GWh and analysed as being abnormal.

b. Indicators related to maintenance programmes

Indicator name	Indicator calculation	Frequency of reporting to CRE and publication	Implementation date
Reduction of booked capacity	**Firm capacity made available during work / firm capacity booked** (one aggregate value per type of point(1) connected to the network of each TSO)	Annual	1 April 2016
Compliance with the annual maintenance programme published in October and February by the TSO	**Variation (in percentage) of the minimum capacity proposed in the maintenance programme published in October and February and the actual capacity made available at the end of the year** (one aggregate value per type of point(1) connected to the network of each TSO)		1 April 2020
Compliance with the probable values published in October and February by the TSO	**Variation (in percentage) of the capacity probably available in the maintenance programme published in October and February and the actual capacity made available at the end of the year** (one aggregate value per type of point(1) connected to the network of each TSO)		1 April 2020

(1): 3 categories of points are adopted:
- *the PIRs in the dominant direction;*
- *the entry at PITTMs;*
- *the entry and exit at PITS.*

The impact of maintenance performed at a superpoint will be passed on to the restricted points making up that superpoint, by application of the formula:

Firm capacity available PI_i = Firm capacity booked PI_i x (1-Firm rate of reduction superpoint)

where PI_i is a restricted point of the superpoint.

c. Monitoring of the provision of the most useful information to shippers on the TSOs websites

The information monitored by this indicator is as follows:

Information	Frequency of publication:	Frequency of verification	Quality threshold	Implementation date
Publication of notes and slips	Once per day at 1.00 p.m.	Once per day (publication or not of the information at 1.00 p.m.)	**Value followed: rate of availability before 1.00 p.m.**	**1 April 2020**

Publication of scheduling notices	Once per day at 4.00 p.m.	Once per day (publication or not of the information at 4.00 p.m.)	Value followed: rate of availability before 4.00 p.m.
Publication of intraday events	Once per hour with a one-hour time lag	Once per hour (publication or not of the information at T+1:15)	Value followed: rate of availability before T+1:15
Imbalance settlement price	Hourly, at each Powernext update	1 verification per hour(1)	Value followed: Monthly average of the overall availability rates for each price (average weighted price, marginal selling price, marginal purchase price)
Short-term capacity sales	Once per day	Once per day (publication or not of the information at T-20 to be offered for sale at T)	Value followed: rate of availability before T-20
Calls for locational spread	Once per day	Once per day at D+1	Value followed: rate of availability of the "Locational spread" page of GRTgaz and of Teréga (Tetra) at D+1
Vigilance information on network status	Once per hour with a one-hour time lag	Once per hour (publication or not of the information at T+1:15)	Value followed: rate of availability of the "Info vigilance" page of GRTgaz and of Teréga (Tetra) before T+1:15

The indicator is reported monthly to CRE, and is calculated as the average of all of these elements.

d. Monitoring of the quality of publications of the most useful information to shippers

Indicator name	Indicator calculation	Frequency of reporting to CRE and publication	Implementation date
Substitution of measurements by back-up data(1) for data at PITDs	Data announced as back-up by the TSOs (in GWh) / Back-up data actually sent by TSOs (in GWh) (one value monitored per TSO)	Monthly	1 April 2020

(1) Back-up data are sent by the TSOs when the data have not been forwarded by the DSOs

e. Monitoring of the processing of claims

Indicator name	Indicator calculation	Frequency of reporting to CRE and publication	Implementation date
Number of claims	Number of claims per year	Annual	1 April 2020

Processing time for claims	Average processing time (in days) for claims based on the level of complexity: - simple - complex - studies		1 April 2020

f. Monitoring of the functioning of the single market zone

Information	Frequency of publication	Frequency of verification	Quality threshold	Implementation date
Average end-of-day spread between the PEG and the TTF	Once per month	Once per month (publication or not of the information at D+10 of M+1)	Value followed: rate of availability before D+10 of month M+1	1 April 2020
Number of active participants at the PEG	Once per month	Once per month (publication or not of the information at D+10 of M+1)	Value followed: rate of availability before D+10 of month M+1	
Occurrence of bottlenecks in the network	Once per month	Once per month (publication or not of the information at D+10 of M+1)	Value followed: rate of availability before D+10 of month M+1	
Number of pooled restrictions	Once per month	Once per month (publication or not of the information at D+10 of M+1)	Value followed: rate of availability before D+10 of month M+1	
Total cost of locational spreads	Once per month	Once per month (publication or not of the information at D+10 of M+1)	Value followed: rate of availability before D+10 of month M+1	
Average cost of locational spreads	Once per month	Once per month (publication or not of the information at D+10 of M+1)	Value followed: rate of availability before D+10 of month M+1	
Impact of network maintenance in the event of a bottleneck(1)	Once per day the day after the bottleneck has appeared	Once per day (publication or not of the information at D+1)	Value followed: rate of availability before D+1	

(1): daily monitoring of the impact of network maintenance following the occurrence of a bottleneck in GWh/d broken down by limit and the side of application.

g. Environmental indicators

Indicator name	Indicator calculation	Frequency of reporting to CRE and publication	Implementation date
Greenhouse gas emissions	**Monthly greenhouse gas emissions (CO_2 equivalent)** (one value monitored per TSO)	Annual	1 January 2009
Greenhouse gas emissions in proportion to the volume of gas transported	**Monthly greenhouse gas emissions / monthly volume of gas transported** (one value monitored per TSO)		1 January 2009
Methane emissions in relation to the volume of gas transported	**Monthly methane emissions / monthly volume of gas transported** (one value monitored per TSO)		1 April 2020

ANNEX 3: EVOLUTION OF FIRM CAPACITY SUBSCRIPTIONS OVER THE ATRT7 PERIOD

The projections for the evolution of firm capacity booked at main network entry points are presented below:

Evolution of firm annual capacity booked (GWh/d)	2020	2021	2022	2023
PITTM Montoir	364	360	340	383
PITTM Fos	380	340	340	340
PITTM Dunkerque	250	250	250	250
PIR Taisnières B	[Confidential]	[Confiden-tial]	[Confidential]	[Confidential]
PIR Taisnières H	534	527	511	464
PIR Dunkerque	501	495	490	502
PIR Obergailbach	462	450	414	414
PIR Pirineos	177	177	177	80
PITS Atlantique	558	575	590	594
PITS Nord-Ouest	278	287	290	290
PITS Nord-Est	182	180	180	180
PITS Nord-B	230	224	224	224
PITS Sud-Est	597	626	635	635
PITS Sud-Ouest	556	556	556	556

The projections for the evolution of firm capacity booked at main network exit points are presented below:

Evolution of firm annual capacity booked (GWh/d)	2020	2021	2022	2023
PIR Oltingue	229	216	213	205

PIR Pirineos	148	148	148	112
PITS Atlantique	331	339	340	340
PITS Nord-Ouest	144	148	150	150
PITS Nord-Est	112	112	112	112
PITS Nord-B	103	100	100	100
PITS Sud-Est	99	94	95	95
PITS Sud-Ouest	300	300	300	300
Exit to the GRTgaz regional network	3,823	3,783	3,763	3,721
Exit to the Teréga regional network	322	319	317	315

ANNEX 4: INFORMATION TO BE PUBLISHED WITHIN THE FRAMEWORK OF THE TARIFF NETWORK CODE

Article	Information to be published	Publication
29(a) 29(b)	a) for standard capacity products for firm capacity: i. the reserve prices applicable until at least the end of the gas year after the annual yearly capacity auction; ii. the multipliers and seasonal factors applied to reserve prices for non-yearly standard capacity products; iii. the justification of the national regulatory authority for the level of multipliers; iv. where seasonal factors are applied, the justification for their application; b) for standard capacity products for interruptible capacity: i. the reserve prices applicable until at least the end of the gas year after the annual yearly capacity auction; ii. an assessment of the probability of interruption including: 1. the list of all types of standard capacity products for interruptible capacity offered including the respective probability of interruption and the level of discount applied; 2. the explanation of how the probability of interruption is calculated for each type of product referred to in point 1); 3. the historical or forecasted data, or both, used for the estimation of the probability of interruption referred to in point 2).	a) for standard capacity products for firm capacity: i. the tariffs are indicated in section 5.2.2 ii. the applicable multipliers are indicated in section 5.2.4 iii. the justification is indicated in section 5.2.2 iv. N/A b) for standard capacity products for interruptible capacity: i. Standard capacity products for interruptible capacity and the level of discount applicable are indicated in section 5.2.2 ii. the details of the calculations of the probabilities of interruption, explained in section 4.2.3, are published by the TSOs: • GRTgaz • Teréga
30(1)(a)	Information on parameters used in the applied reference price methodology that are related to the technical characteristics of the transmission system, such as: i. technical capacity at entry and exit points and associated assumptions; ii. forecasted contracted capacity at entry and exit points and associated assumptions; iii. the structural representation of the transmission network with an appropriate level of detail; v. additional technical information about the transmission network, such as the length and the diameter of pipelines and the power of compressor stations;	• The distances taken into account are indicated in Annex 6. • The evolution of capacity booked at entry and exit points is indicated in Annex 3. • The technical capacity data and all technical information are published on the websites of the TSOs based on ENTSOG's model. o GRTgaz o Teréga • The structural representation of the transmission network

<table>
<tr><td></td><td></td><td>is published on the TSOs' websites:
o GRTgaz
o Teréga</td></tr>
<tr><td>30(1)(b)</td><td>i. the allowed or target revenue, or both, of the transmission system operator;
ii. the information related to changes in the revenue referred to in point i) from one year to the next year;
iii. the following parameters:
a. types of assets included in the regulated asset base and their aggregated value;
b. the cost of capital and its calculation methodology;
c. capital expenditures, including:
i. methodologies to determine the initial value of the assets;
ii. methodologies to re-evaluate the assets;
iii. explanations of the evolution of the value of the assets;
iv. depreciation periods and amounts per asset type;
d. operational expenditures;
e. incentive mechanisms and efficiency targets;
f. inflation indices;
iv. the transmission services revenue;
a. the entry-exit split;
b. the intra-system/cross-system split.
v. the information related to the reconciliation of the regulatory account (the actually obtained revenue, the under- or over-recovery of the allowed revenue and the part thereof attributed to the CRCP, and the reconciliation period)
vi. the intended use of the auction premium;</td><td>• The information related to capital expenditures, operating expenses and allowed revenue is indicated in section 3.1.
• The information related to incentive mechanisms, the functioning of the CRCP, is indicated in section 2.3.
• the entry-exit split between transmission services revenue is 34% (entries)/66%(exits), and is described in section 4.2.1
• the split in transmission services revenue between transit and domestic consumption is roughly 24% for transit and 76% for domestic consumption.
• The information related to the intended use of the auction premium is indicated in section 5.1.3.</td></tr>
<tr><td>30(1)(c)</td><td>i. where applied, non-transmission tariffs for non-transmission services
ii. the reference prices and other prices applicable at points other than those referred to in Article 29.</td><td>The tariffs for non-transmission services and all the prices applicable at the different points are indicated in part 5.</td></tr>
<tr><td>30(2)</td><td>• explanations of the differences in the levels of tariffs between two tariff periods
• a simplified tariff model</td><td>• The differences between the levels of tariffs between 2019 and the tariffs over the ATRT7 period are indicated in section 4.2.1. The explanations of these differences are developed in part 3.</td></tr>
</table>

		• The simplified model is published on CRE's website.

ANNEX 5: COMPARISON WITH THE CAPACITY WEIGHTED DISTANCE METHOD OF THE TARIFF NETWORK CODE

Article 8 of the Tariff network code provides a detailed description of a method for calculating reference prices at entry and exit points based on the contracted capacity, the distance covered by the gas as weighting factors, and clusters of entry and exit points in the relevant flow scenarios (capacity weighted distance reference price methodology (CWD)).

The code specifies that the method for calculating reference prices adopted by each regulatory will be compared with this CWD method. CRE presents the tariffs that would result from the strict application of this method:

€/MWh/d/year	CWD Entries	CWD Exits
PIR Virtualys	164.05	
PIR Taisnières B	164.05	
PIR Dunkerque	164.05	
PIR Obergailbach	164.05	
PIR Oltingue	164.05	397.38
PIR Pirineos	164.05	559.04
PITTM Dunkerque	141.65	
PITTM Montoir	141.65	
PITTM Fos	141.65	
Regional network exit		59.40
PITS	5.40	23.67

The parameters of the capacity-weighted distance reference price methodology are close to those of CRE's method, the main difference being the use of a 50/50 ratio for splitting revenue between entries and exits. CRE considers that the application of a 50/50 split is not suitable to the specific configuration of the French network (see section 4.2.1.2).

In addition, the CWD method aims, in spirit, to result in homogenous unit costs (€/MWh/d/year/km) for the different users of the gas transmission network. However, its concrete application, once a same entry point can supply several exit pints, does not necessarily lead to this result. Here, the France-Switzerland unit cost totals €0.74/MWh/d/year/km compared to €0.67/MWh/d/year/km for France-Spain, and €0.62/MWh/d/year/km for the supply of domestic clients.

ANNEX 6: LIST OF FLOW SCENARIOS

Annexes published on CRE's website[60]

ANNEX 7: LIST OF REGIONAL TARIFF LEVELS (NTR) PER SITE

Annexes published on CRE's website for GRTgaz[61] and Teréga[62].

[60] List of flow scenarios
[61] List of GRTgaz's NTRs
[62] List of Teréga's NTRs

ANNEX 8: REFERENCES FOR THE ANNUAL UPDATE OF THE TARIFF FOR THE USE OF GRTGAZ'S AND TERÉGA'S NATURAL GAS TRANSMISSION NETWORKS

1) Capital expenses

For the years 2020 to 2023, the reference capital expenses taken into account for updating the tariff as at 1 April of each year are those defined in the following table:

Target normative CAPEX, in current €M	2020	2021	2022	2023
GRTgaz	974,7	996.4	1,017.3	1,009.3
Teréga	166,9	171.2	176.9	179.7

2) Operating expenses

For the years 2020 to 2023, the net reference operating expenses taken into account for updating the tariff as at 1 April of each year are those defined in the following table:

Target net OPEX, in current €M	2020	2021	2022	2023
GRTgaz	794,4	804.1	817.8	832.6
Teréga	82,4	83.4	84.5	85.9

For the years 2021 to 2023, the amount taken into account for updating the tariff as at 1 April of year Y is equal to the reference value for year Y:

- divided by forecast inflation between year 2019 and year Y;

	2020	2021	2022	2023
Forecast inflation between year 2019 and year Y	1,5 %	3,12 %	4,88 %	6,76 %

- multiplied, for the years 2022 and 2023, by the inflation realized between the year 2019 and the year Y-2. Actual inflation is defined as the change in the average value of the consumer price index excluding tobacco, as calculated by INSEE for all households throughout France (INSEE reference 1763852), recorded in year Y-2, compared to the average value of the same index recorded in calendar year 2019;
- multiplied by the inflation realized between year Y-2 and year Y-1, or if not available, its best estimate, defined as the change in the average value of the consumer price index excluding tobacco, as calculated by INSEE for all households in France (INSEE reference number 1763852);
- multiplied by the forecast inflation for year Y taken into account in the budget bill for year Y.

3) Inter-operator flows

- **Payment by Teréga to GRTgaz for the income received at the PIR Pirineos exit point**

Within the framework of the annual update of the ATRT7 tariff, the amount paid back by Teréga to GRTgaz for income received at the PIR Pirineos is updated.

It corresponds to a unit level, set at €121.6/MWh/d/year as at 1 April 2020 and adjusted each year for inflation, applied to updated subscriptions of capacity at the PIR Pirineos exit point.

- **Inter-TSO payment relating to the annual national update of main network tariff charges**

Within the framework of the annual update of the ATRT7 tariff, a $k_{national}$ coefficient is calculated, to define the annual change in the main network tariffs (see section 2.2.3 and 2.2.5 of the deliberation). It leads to an opposing difference in income between GRTgaz and Teréga. This difference is paid back between the TSOs.

4) Annual difference between projected income and target allowed revenue

A smoothing system taking into account the annual difference between projected income and the target allowed revenue, whose value discounted at the 1.7% risk-free rate is zero over the ATRT7 tarif period, is added to operators' allowed revenue based on the following trajectory:

Annual difference, in current €M	2020	2021	2022	2023
GRTgaz	43,9	1,0	-22,6	-22,2
Teréga	11,8	4,6	-1,3	-15,8

5) Calculation and reconciliation of the CRCP balance

The overall balance of the CRCP is equal to the amount to be paid into or deducted from the CRCP for the year passed and the previous year, to which is added the balance of the CRCP not reconciled over former years.

The amount to be paid into or deducted from the CRCP is calculated by CRE, for each year passed, based on the difference, for each item concerned, between the actual amounts and reference amounts defined below. All or part of the difference is paid into the CRCP; the portion is determined based on the coverage rate specified by the present deliberation.

GRTgaz, in current €M	Rate	2020	2021	2022	2023
Transmission revenue “100 CRCP”	100%	1408,4	1409,7	1430,5	1437,1
“Upstream” transmission revenue	100%	-	370,5	362,3	362,9
	80%	386,1	Updated each year in compliance with section 2.3.3		
Income from CCGT and CT connections	100%	5,4	2,9	0,0	0,0
Income from biomethane unit connections	100%	2,8	6,4	6,4	7,4
Income from NGV station unit connections	100%	0,0	0,0	0,0	0,0
Income from services for third parties related to major land-use planning projects(excluding third party participation in connections)	100%	25,4	27,0	26,6	27,4
capital gain on assets disposal (building or land)	80%	0,0	0,0	0,0	0,0
Income from penalties received from clients exceeding capacity	100%	1,5	2,0	2,0	2,0
Normative "network" capital expenses	100%	885,3	894,7	905,3	901,2
Reference for the calculation of differences in Normative capital expenses "non-networks" due to inflation.	100%	89,4	101,8	112,0	108,1
Engine power expenses and difference between income and expenses related to CO_2 quotas	100%	-	99,5	91,2	91,0
	80%	95,7	Updated each year in compliance with section 2.3.3		
Consumables expenses	100%	-	5,0	4,9	4,7

	80%	5,1	Updated each year in compliance with section 2.3.3		
Costs for the H-L conversion service	100%	66,2	66,3	65,9	65,5
Costs and income generated by congestion management mechanisms	100%	4,4	4,4	4,4	4,4
Any costs related to, where applicable, remuneration of the consumers connected to the transmission network that have signed an interruptibility contract on the basis of Article L. 431-6-2 of the energy code	100%	0,0	0,0	0,0	0,0
Costs of studies for large abandoned projects previously approved by CRE or other stranded costs addressed on a case-by-case basis for which CRE approved coverage	100%	0,0	0,0	0,0	0,0
Expenses and income related to the contract between GRTgaz and Teréga (expense)	100%	34,9	35,4	36,0	36,7
Inter-operator payment between GRTgaz and Teréga (income)	100%	19,6	19,8	20,1	20,2
Expenses and income associated with contracts with other regulated operators (in particular, storage operators)	100%	37,8	32,7	32,5	33,1
Payment made by DSOs to TSOs for the portion of the biomethane injection charge collected from producers connected to the distribution network aimed at covering the OPEX associated with TSO backhaul (income)	100%	0,0	0,0	0,0	0,0
Inter-operator flow between GRTgaz and Teréga related to the change in the $k_{national}$ factor	100%	0,0	0,0	0,0	0,0
Bonuses and penalties resulting from the incentive regulation mechanisms	100%	0,0	0,0	0,0	0,0
R&D expenses	100% of costs not used at the end of the period	26,0	27,5	29,4	30,6

In addition, with regard to net operating expenses, for the years 2020 to 2023, the amount taken into account in the calculation of the CRCP balance takes into account the difference between forecast and actual inflation.

This amount is equal to the reference value for year Y:

- divided by the forecast inflation between the year 2019 and the year Y;

	2020	2021	2022	2023
Forecast inflation between year 2019 and year Y	1,5 %	3,12 %	4,88 %	6,76 %

- multiplied by the actual inflation recorded between the year 2019 and the year Y. Actual inflation is defined as the change in the average value of the consumer price index excluding tobacco, as calculated by the French national statistics office INSEE, for all households in the whole of France (INSEE reference 1763852), recorded for calendar year Y, compared to the average value of the same index recorded in calendar year 2019.

Teréga, in current €M	Rate	2020	2021	2022	2023
Transmission revenue "100 CRCP"	100%	174,2	174,2	174,5	173,4
"Upstream" transmission revenue	100%	-	103,6	104,9	95,6
	80%	105,6	Updated each year in compliance with section 2.3.3		
Income from CCGT and CT connections	100%	0,0	0,0	0,0	0,0
Income from biomethane unit connections	100%	0,5	0,5	0,5	0,5
Income from NGV station unit connections	100%	0,0	0,0	0,0	0,0
Income from services for third parties related to major land-use planning projects	100%	0,0	0,0	0,0	0,0
capital gain on assets disposal (building or land)	80%	0,0	0,0	0,0	0,0
Income from penalties received from clients exceeding capacity	100%	0,3	0,4	0,4	0,4
Normative "network" capital expenses	100%	146,0	148,8	153,1	155,9
Reference for the calculation of differences in Normative capital expenses "non-networks" due to inflation.	100%	20,8	22,5	23,8	23,8
Differences with the TOTEX experiment reference trajectory	50%	23,8	22,3	21,6	21,6
Engine power expenses and difference between income and expenses related to CO_2 quotas	100%	-	8,0	8,1	8,1
	80%	8,0	Updated each year in compliance with section 2.3.3		
Consumables expenses	100%	-	0,2	0,2	0,2
	80%	0,2	Updated each year in compliance with section 2.3.3		
Costs and income generated by congestion management mechanisms	100%	0,6	0,6	0,6	0,6
Any costs related to, where applicable, remuneration of the consumers connected to the transmission network that have signed an interruptibility contract on the basis of Article L. 431-6-2 of the energy code	100%	0,0	0,0	0,0	0,0
Costs of studies for large abandoned projects previously approved by CRE or other stranded costs addressed on a case-by-case basis for which CRE approved coverage	100%	0,0	0,0	0,0	0,0
Expenses and income related to the contract between GRTgaz and Teréga (income)	100%	34,9	35,4	36,0	36,7
Inter-operator payment between GRTgaz and Teréga (expense)	100%	19,6	19,8	20,1	20,2
Expenses and income associated with contracts with other regulated operators (in particular, storage operators)	100%	6,6	6,7	6,9	7,0
Payment made by DSOs to TSOs for the portion of the biomethane injection charge collected from producers connected to the distribution network aimed at covering the OPEX associated with TSO backhaul (income)	100%	0,0	0,0	0,0	0,0

Inter-operator flow between GRTgaz and Teréga related to the change in the knational factor	100%	0,0	0,0	0,0	0,0
Bonuses and penalties resulting from the incentive regulation mechanisms	100%	0,0	0,0	0,0	0,0
R&D expenses	100% of costs not used at the end of the period	2,5	2,6	2,6	2,7

In addition, with regard to net operating expenses, for the years 2020 to 2023, the amount taken into account in the calculation of the CRCP balance takes into account the difference between forecast and actual inflation.

This amount is equal to the reference value for year Y:

- divided by the forecast inflation between the year 2019 and the year Y;

	2020	2021	2022	2023
Forecast inflation between year 2019 and year Y	1,5 %	3,12 %	4,88 %	6,76 %

- multiplied by the actual inflation recorded between the year 2019 and the year Y. Actual inflation is defined as the change in the average value of the consumer price index excluding tobacco, as calculated by the French national statistics office INSEE, for all households in the whole of France (INSEE reference 1763852), recorded for calendar year Y, compared to the average value of the same index recorded in calendar year 2019.

6) Storage tariff

The update of the storage tariff is performed based on the conditions specified in the ATRT7 tariff according to the allowed income for Storengy, Teréga and Géométhane, and target auction income.