Deliberation

Deliberation of the French Energy Regulatory Commission of 12 December 2013 concerning decision on the tariffs for the use of a public electricity grid in the HVA or LV voltage range

Session participants: Philippe de Ladoucette, Chairman, Olivier Challan Belval, Hélène Gassin, Jean-Pierre Sotura and Michel Thiollière, commissioners.

Introduction

By the present deliberation, the French Energy Regulatory Commission (CRE) defines the methodology for determining the tariffs for the use of a public electricity grid in the HVA or LV voltage range and establishes the tariffs (termed “TURPE 4 HVA/LV”) set to apply as from 1 January 2014. They are designed to be applied for a period of around four years.

Context

The third set of tariffs for the use of public electricity grids, termed "TURPE 3", covering the period 2009-2013 entered into force on 1 Aug 2009, pursuant to the decision of 5 May 2009 approving the CRE tariff proposal of 26 February 2009.

By a decision of 28 November 2012 (n° 330548, 332639, 332643, *Société Direct Energie et Syndicat intercommunal de la périphérie de Paris pour l'électricité et les réseaux de communication*) the State Council invalidated TURPE 3 in so far as it sets the tariffs for the use of public distribution grids.

Given the retroactive nature of the cancellation and in accordance with this decision, by a deliberation of 29 March 2013, CRE proposed a new TURPE for the HVA and LV voltage range for the period from 1 August 2009 to 31 July 2013 to the Ministers of Economy and Energy. This tariff (termed "TURPE 3 HVA/LV Retroactive") was adopted by an explicit Ministerial decision on 24 May 2013 and published in the Journal officiel de la République française on 26 May 2013. It is based on the *ex post* coverage of all accounting expenses incurred by ERDF and the return on equity. Wishing to continue its work in developing a tariff methodology taking into account the reasons for the decision of the State Council and adapted for long term application, CRE decided to defer to 1 January 2014 the entry into force of the next tariff for use of public electricity distribution networks termed "TURPE 4 HVA/LV" and extend from 1 August to 31 December 2013 the approach proposed to the ministers in TURPE 3 HVA/LV Retroactive. This tariff fixed in accordance with Article L. 341-3 of the Energy Code was communicated to the ministers on 28 May 2013 and published in the Journal officiel de la République française in July 2013.

However, insofar as HVB tariffs were not affected by the State Council decision, the deliberation concerning decision on the tariffs for the use of a public electricity grid in the HVB voltage range (termed “TURPE 4 HVB”) was adopted according to the original work schedule on 3 April 2013 and published in the Journal officiel de la République française on 30 June 2013. These tariffs came into force on 1 Aug 2013.

Legal framework

The directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009, states in Article 37, that it is the responsibility of the regulatory authority to "*fix or approve, in accordance with transparent criteria, transport or distribution tariffs or their methods of calculation.*"

Articles L. 341-2, L. 341-3 and L. 341-4 of the French Energy Code define CRE's powers regarding the setting of TURPE.

Article L. 341-2 provides *that "the tariffs of use of the public electricity and public distribution grid are calculated in a transparent and non-discriminatory manner, to cover all costs incurred by the system operators to the extent that such costs correspond to those of an efficient system operator."*

Article L. 341-3 provides that:

"The methodologies used to establish tariffs for the use of public electricity transmission and distribution grids are set by the French Energy Regulatory Commission. […] *The Energy Regulatory Commission decides […] on the evolution of tariffs for the use of public electricity transmission and distribution grids* […]*. It may propose a multi-annual tariff framework together with appropriate short- or long-term incentives to encourage transmission and distribution grid operators to improve their performance particularly as regards the quality of the electricity, to encourage the integration of the domestic electricity market and security of supply and to find ways to improve productivity".*

The Energy Regulatory Commission takes into account the energy policy guidelines indicated by the administrative authority. It regularly informs the administrative authority during the tariff establishment phase. It consults energy market stakeholders as it sees fit.

The Energy Regulatory Commission transmits to the administrative authority, for publication in the Journal Official de la République Française, its reasoned decisions on changes in the level and structure of tariffs for the use of public electricity transmission and distribution grids, [...] on the date of entry into force of these tariffs."

Article L. 341-4 specifies that "the structure and level of the tariffs for the use of the public electricity transmission and distribution grids are set in such a way as to encourage clients to limit their consumption during periods in which consumption of all consumers is at its highest".

Since the entry into force of these provisions, CRE has sole authority to set the tariffs setting methodology. Accordingly, and pursuant to the provisions of Article L. 341-5 of the French Energy Code amended by Act No. 2013-619 of 16 July 2013 laying down various adjustment provisions to the law of the European Union in the field of sustainable development, the CRE, by a decision of 19 September 2013, proposed repeal of the provisions of Decree No. 2001-365 of 26 April 2001 relating to tariffs for use of public electricity transmission and distribution grids which governed these competences. The present deliberation should also take into account the reasons for the decision of 28 November 2012 of the Council of State (which are recalled in section A.2.3.3).

Finally, the adjusting of tariffs guarantees social and territorial cohesion by ensuring universal access to energy, in accordance with the energy policy objectives set forth in Article L. 100-1 of the energy code.

Tariff works

Since 2010, CRE has undertaken the preparation works of TURPE 4.

ERDF has formulated its final tariff request on 5 July 2013. This request was equivalent to a tariff increase of 8.9% on 1 January 2014 (assuming a constant tariff).

To develop the methodology for the establishment of the tariff, set the regulatory framework and the level and structure of the tariff, CRE drew on different studies assigned to external consultants:

- an international comparative study on incentive regulation mechanisms;
- a study on the costs structure of public electricity transmission and distribution grids;
- a study on the pricing methods for public electricity grids;
- a study on the weighted average cost of capital of electricity and natural gas infrastructures.

To this effect CRE organised five public consultations[1]:

- a first consultation in July 2010 which focused on the main features of the tariffs[2];
- a second in march 2012[3] which focused on the structure of tariffs;
- a third in June 2012[4] which focused on the regulatory framework;
- a fourth in November 2012[5] which covered the entire aspects of the tariff (level, tariff structure and framework);
- a fifth in July 2013[6] on the methodology for calculating ERDF capital charges and the resulting tariff level as well as the suppression of the medium- duration use option without time differentiation of LV ≤ 36 kVA tariffs.

On several occasions CRE gave audience to ERDF, its shareholder as well as all market stakeholders in July 2012, December 2012 and July 2013.

In addition, the Minister of Economy and Finances and the Minister of Ecology, Sustainable Development and Energy sent a letter of information to CRE, on 12 November 2013, stating that "*in view of the decision of the Council of State [...], and in order to implement a commonly accepted method of normative economic regulation [they are considering] presenting a bill shortly in Parliament.*" This letter can be consulted on the CRE website.

Finally, pursuant to the provisions of Article L. 341-3 of the French energy code, CRE took into account the energy policy guidelines transmitted by the Minister of Ecology, Sustainable development and Energy in a letter on 10 October 2012. These guidelines focus on the incentive tools for investment aimed at improvement of the security of supply, and the hourly/seasonal structure and the withdrawal tariffs. The guidelines can be consulted on CRE's website.

Main developments

Following the cancellation of the previous tariffs by the State Council, CRE has reviewed the methodology for calculating ERDF capital costs in order to take into account the specificities of the public distribution electricity concessions regime. The methodology for calculating capital charges adopted by CRE is exposed in section A.2.

The analysis of operating expenses and the new method for calculating capital charges led CRE to retain a 3.6%[7] increase on 1 January 2014 and an inflation-linked indexation from 1 August 2014 to 2017, not taking into account any difference between the forecasted and executed trajectories on items included in the scope of the income and expense adjustment account.

Moreover, CRE has renewed and reinforced the existing multiannual regulatory framework encouraging ERDF to improve cost control and the supply and the quality of service provided to users. In regard to the quality of supply, CRE has integrated an incentive regulatory mechanism to the penalties provision paid by

[1] The first four consultations focused on the overall tariffs of public electricity networks, which before the decision of the State Council of 28 November 2012 were intended to be a single tariff decision

[2] The consultation document and the summary of the responses of players are available at the following address: http://www.cre.fr/documents/consultations-publiques/consultation-publique-de-la-cre-sur-la-structure-des-tarifs-d-utilisation-des-reseaux-publics-d-electricite.

[3] The consultation document and the summary of the responses of players are available at the following address: http://www.cre.fr/documents/consultations-publiques/structure-des-tarifs-d-utilisation-des-reseaux-publics-de-transport-et-de-distribution-d-electricite.

[4] The consultation document and the summary of the responses of players are available at the following address: http://www.cre.fr/documents/consultations-publiques/cadre-de-regulation-des-tarifs-d-utilisation-des-reseaux-publics-d-electricite.

[5] The consultation document and the summary of the responses of players are available at the following address: http://www.cre.fr/documents/consultations-publiques/quatriemes-tarifs-d-utilisation-des-reseaux-publics-d-electricite.

[6] The consultation document is available at the following address: http://www.cre.fr/documents/consultations-publiques/quatriemes-tarifs-d-utilisation-des-reseaux-publics-de-distribution-d-electricite.

[7] The HVA/LV tariff represents approximately 45% of the electricity bill excluding tax residential consumers.

ERDF to clients cut off for over six hours. CRE introduced a monitoring of ERDF unit investment costs and "network quality and modernisation" investments as well as follow-up actions taken by ERDF to control the volume of losses.

CRE also attaches particular importance to the development of smart grids. Accordingly, in order to develop its philosophy it has launched a series of initiatives involving sector stakeholders. This decision is part of the process for the development of smart grids by introducing a regulatory framework favourable to research and development (R&D).

The development of *Linky* electricity smart meters, for which CRE proposed deployment in its July 7, 2011 deliberation, constitutes an essential element for the development of *Smart grids.* Expenses related to the deployment of smart meters have not been taken into account in the development of this tariff. As CRE has already indicated, in particular during the public consultation on 6 November 2012, the definition of the pricing framework for the *Linky* project will be the subject of an specific tariff decision (See. section D.3.6.3).

In relation to the tariff structure, this tariff decision removes the medium- duration use option without using time differentiation of LV ≤ 36 kVA tariffs in order to better address the concerns expressed in the letter to the Minister for Ecology, Sustainable Development and Energy of 10 October 2012 on guidelines for the energy policy.

The Higher Council of Energy consulted by CRE on the proposed tariff decision, delivered its opinion on 10 December 2013.

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Methodology for establishing tariffs

A. Methodological principles

1. Methodology for construction of tariffs

The construction of a new tariff can be divided into three parts: definition of the estimated tariff revenue and related regulatory framework and then construction of tariffs for each category of users.

On the one hand the regulatory framework aims to limit for certain predefined expense or income items the financial risk of the operator and/or user through clawback accounts, and on the other hand to encourage the operator to improve their performance notably by the continuity of supply, service quality and control of costs through the implementation of incentive mechanisms. The financial impact of these provisions is included either in the calculation for the forecasted tariff income or *ex post.*

The forecasted tariff income is broken down by the user in the form of tariffs. There are several tariff components meeting different purposes. However, those that constitute the bulk of operator sales are withdrawal tariffs. These are composed of different coefficients; all these coefficients are referred to as “tariff structure”.

Taking into account all of these components serves to establish tariffs at their date of entry into force and the way in which they change each year.

Definition of forecasted tariff income

CRE defines the operator’s estimated tariff income for the period considered based on a business plan[8] submitted by the operator.

This forecasted tariff income is composed of capital charges and net operating expenses as well as the impact of the clawback accounts.

$$RT_p = CNE_p + CC_p + A$$

Where:

- RT_p: Forecasted tariff income for the period;
- CNE_p: Forecasted net operating expenses for the period;
- CC_p: Forecasted capital charges for the period;
- A: Clearance of the clawback accounts for the period.

Given the specific accounting for concessions and ERDF balance, CRE has adopted the method of calculating capital charges as described in section A.2.

Net operating expenses include net running costs (mainly comprising external purchases, staff expenditure and taxes), purchases related to the electricity system and public transmission grid access expenses net of non-tariff-related income (mainly comprising income from annex services and connection contributions).

The level of operating expenses retained is determined based on all of the costs necessary for a system operator’s activity insofar as, pursuant to the law, these costs correspond to those of an efficient system operator. All of the forecasted data communicated by the operator is analysed thoroughly and corrected where necessary. In particular, with regard to net running costs, CRE endeavours to retain an operating expense trajectory integrating productivity efforts.

Regulatory framework

[8] In this case, the ERDF business plan was related to the years 2014 to 2017.

The operator's activity is regulated through different mechanisms constituting what is called the "regulatory framework".

First, the provisions of the regulatory framework enable the forecasted tariff income to be adjusted for inflation in order to protect the operator from inflation-related risks to which its expenses are exposed.

Second, for predefined items eligible for the expense and income clawback account (CRCP), the provisions of the regulatory framework make it possible to adjust, a posteriori, the tariff level to account for differences between forecasted and actual level of those items.

Lastly, in order to encourage the operator to efficiently manage the system, CRE has implemented incentive mechanisms. These provisions concern different fields of activity of the system operator: control of operating expenses, quality of service and supply to users, management of losses in the power system and the research and development activity. Some of these mechanisms are accompanied by financial incentives (in the form of positive or negative bonuses) which, according to the specific case, are added to or subtracted from the forecasted tariff income during the tariff period.

$$RT_N = RT'_p + E_{N-1} + I_{N-1}$$

Where:

- RT_N: Tariff income for the year N;
- RT'_p: Forecasted tariff income for the year N adjusted for actual inflation;
- E_{N-1}: Differences for the year N-1 charged to the CRCP balance;
- I_{N-1}: Incentives for the year N-1.

Tariff structure

The tariffs include a component function of the contract power and a component function of the energy injected or withdrawn. They are a function of the supply voltage and are defined for each connection point.

Withdrawal tariffs are constructed in such a way as to encourage each user to adopt a consumption behaviour that minimises long-term system costs. The methodology for constructing tariffs also takes into account the provisions of Article L. 341-4 of the Energy Code which stipulates that tariffs are set in order to encourage clients to limit their consumption during periods when consumption of all consumers is at its highest

In order to do so, and based on the forecasted flow distribution data and forecasted consumption data provided by the operator, the methodology for establishing withdrawal tariffs is based on an analysis of the distribution of system costs among the different hours of the year and allocates these costs to users based on their respective consumption characteristics.

2. Methodology for calculating capital charges

The decision of the Council of State on 28 November 2012 led CRE to review the methodology normally used by the CRE and other European regulators to determine the level of forecasted capital charges. This section describes all of the elements that have contributed to the work of the CRE in the development of a new methodology for calculating capital charges.

2.1. Main lessons from the study of European regulatory practices

To benefit from external thoughts, CRE reviewed regulatory systems implemented in other European countries. It has especially commissioned two studies, one on the international comparison of incentive regulation mechanisms and the other on the weighted average cost of capital for electricity and natural gas infrastructures that enabled it to have an overall overview of pricing approaches in different European countries. In March 2013 CRE also conducted an internal study on the ownership and financing of the activity of electricity distribution in which 16 European Regulators responded. CRE also relied on the study conducted in 2013 on the work of the Council of European Energy Regulators (CEER) on investment conditions in the transmission and distribution of electricity and natural gas in Europe[9]. All of this work has led to the following observations.

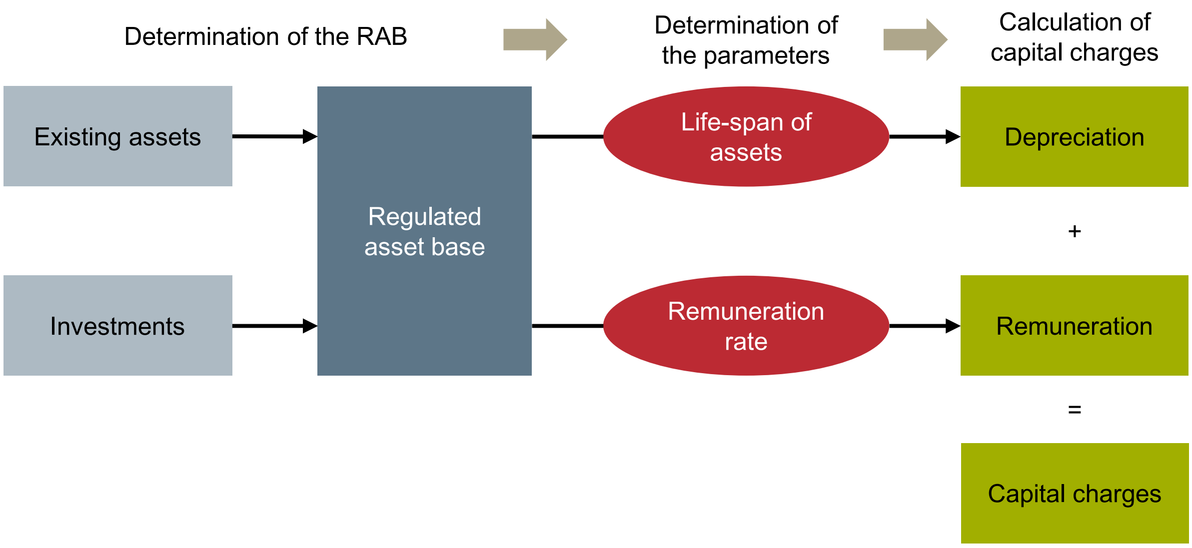
2.1.1. A remuneration based on the value of assets

Various studies show that almost all European regulators[10] now use a pricing approach based on the application of a rate of return to a regulatory asset base (RAB).

The choice of a method of remuneration based on the value of assets has the advantage of linking the level of remuneration to the value of assets put into service and therefore establishes a direct link between the remuneration of the system operator and the service provided to the user. Certainly, the main service offered by the network operator is to provide the user at the connection point and at any time, with a power level equal to the contracted power. The quality and continuity of this service provided, essentially depends on the amount and quality of the works that make up the network and accordingly the value of assets in service. This remuneration mode accordingly enables good alignment of the interests of users and the network operator.

Moreover, the generalisation of this remuneration method for regulators facilitates comparison exercises, accordingly, enabling reliance on the comparable method to define the appropriate level of remuneration of these monopolies.

Schema for determining capital charges in a classic "RAB x Rate" approach



2.1.2. Not owning the assets is not in itself an obstacle to a remuneration based on the value of assets

The review of the European regulatory framework displays a great diversity of situations with regard to the the distribution network operator’s shareholding, ownership of assets and funding.

[9] The public summary of this work can be consulted at the following address: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Cross-Sectoral/Tab/C13-EFB-09-03_Investment%20Conditions_memo.pdf.

[10] The survey conducted by the CEER on investment conditions (April 2013) indicates that the 20 responding countries use a RAB in the tariff calculation.

The above studies have identified two cases other than France where the assets, in whole or in part, are not the property of Distribution Network Operators (DNO), and are the subject of a concession regime:

- In Portugal, the assets are owned by the state or local authorities according to their voltage level. In the context of concession contracts, they are managed by DNOs who finance the entire investment;
- In Italy, assets are partly held by operators and partly by local authorities. DNOs exploit them through a concession contract and finance the majority of investments in the network.

In the case of Germany, assets are managed under concession contracts with local authorities, but are the property of DNOs or the Vertically Integrated Company (VIC) to which it belongs.

In the Czech Republic, local governments hold some of the assets and finance part of the investment. These assets are operated by the DNOs in the context of leases but are not included in the RAB.

Nevertheless, the work conducted by CRE did not reveal the existence of a similar mechanism to the French system with significant investment in project management of local government levels.

In all these countries, coverage of capital costs by the tariff for use of distribution networks is based on the application of a rate of return on capital to a RAB.

2.1.3. The method for calculating the RAB does not generally take into account the ownership of assets

In Italy and Portugal, assets under concession are included in the RAB.

In most European countries, investments financed by third parties, such as the connections are deducted from the RAB. However, in Italy and the Czech Republic, connection fees are included with a discount of 80 %.

2.1.4. A level of compensation based on a sample of comparable or economic theory

According to the CEER study, 18 regulators out of 20 use the methodology of weighted average cost of capital to determine the rate of remuneration. Almost all are based on parameters calculated normatively from a sample of listed comparables or by using economic theory. Only Germany and Latvia take into account the actual structure of the liabilities of DNOs (beyond a secured leverage ratio fixed at 60% in the case of Germany)

2.2. The public electricity distribution concession system and its effect on the ERDF balance

Since the Act dated 5 April 1884 on municipal organisation, municipalities are responsible for organising local public services, electricity distribution is an integral part of this. This law has since been amended several times and codified in the general code of local communities.

This role of licensing authority was confirmed by Article 6 of the Act dated 15 June 1906 on public electricity distribution, which made municipalities and joint municipal authorities, the first licensing authorities of public electricity distribution. This same law has also made the concession the main mode of public service management of electricity distribution.

Act No. 46-628 dated 8 April 1946 on the nationalisation of electricity and gas and Act No. 2000-108 dated 10 February 2000 on the modernisation and development of the public electricity service, have maintained this method of management of the public electricity distribution by the licensing authorities. These Acts have since been amended several times and codified in the Energy Code.

Article L. 111-52 provides that "*public electricity distribution system operators are, in their respective areas of exclusive service: the management company for public distribution from the separation between the activities of public distribution network management and the production or supply activities exercised by Electricité de France* [...]."

Article L. 322-1 of the same Code provides that "*the organising authorities of a public distribution network are defined in Article L. 2224-31 of the General Code of Territorial Units.* […] *the concession of the management of a public electricity distribution grid is granted by the organising authorities.*"

Article L. 322-2 provides that "*the manager of a public electricity distribution grid carries out its duties under the conditions laid down by specifications for concessions […].*"

Article L. 322-4 *provides that "subject to the provisions of Article L. 324-1, the works of public distribution networks [...] belong to local authorities or their designated groups in IV of Article L. 2224-31 of the General code of Territorial Units. However, the company managing the public distribution network, after legal separation imposed on Electricité de France by Article L. 111-57, is part owner of the transformer stations of high current to very high voltage or medium voltage that it operates."*

Article L. 322-6 provides that *"organising authorities for public distribution of electricity have the power to enforce all or part at their charge, orders of first establishment, extension, strengthening and development of distribution works. The provisions relating to the project management by these authorities are set out in Articles L. 3232-2 and L. 2224-31 of the General Code of Territorial Units.* "

The Organising Authorities of the public electricity grid (hereinafter termed "Licensors") are the owners of public distribution networks (excluding HVB/HVA transformer stations which are the property of ERDF) and grant their management to ERDF through concession contracts. The licensors also perform the project management of certain works on the networks (mainly on LV networks in rural areas), ERDF remains contracting authority of the majority of works (mainly on LV networks in urban areas and HVA networks).

These characteristics have accounting consequences as illustrated by the specific balance sheet items defined in the appendix to the ERDF 2012 financial statements.

Excerpts from the ERDF financial statements 2012

Assets owned by the group:

"*Most of the assets owned by the group consist of Delivery point sub-stations and works necessary for their operation (some regional dispatching infrastructure in particular).*"

<u>Concession fixed assets:</u>

"Under the law, ERDF is the sole concessionaire in charge of the bulk of public distribution networks in France, the licensor's are the local authorities (municipalities or municipality unions). The remaining (5% of delivery points) is served by non-nationalised distribution system operators (governed, SICAE …).

Registration of all concession assets are recorded as assets regardless of the contracting authority (works constructed or purchased by ERDF and works submitted by the licensor's) and the source of financing. The company:

- *operates the facilities at their own risk for the duration of the concession;*
- *bears the majority of both technical and economic risks and benefits for the lifetime of the network infrastructure."*

<u>Specific concession accounts:</u>

"*These liabilities are representative of the contractual rights and obligations of the concession specifications and are presented annually to the licensor's:*

- *depreciation on the portion of assets financed by the licensor, in respect of assets for which ERDF is the renewal contracting authority;*
- *the provision for renewal, based on the difference between the renewal value with identical capacity and functionality at the date of the financial statements and the original value, only for asset renewal before the end of the concession;*
- *non-depreciated concessionaire financing, valued at historical cost, contracts also provide that this funding be subject to a reassessment in the event of the concession expiry.*

During asset renewal, provision and depreciation of licensor financing for the replaced asset are net and post as existing assets, they are considered as the licensor's financing on the new asset. Any excess allowance is considered income.

During the concession term, the licensor's rights to renewed assets are consequently transformed as actual replacement of the asset, with no cash outflow to the benefit of the licensor, licensor's entitlement to existing assets.

Under these conditions, the licensor's rights to freely recover existing assets progressively rise while assets are renewed.

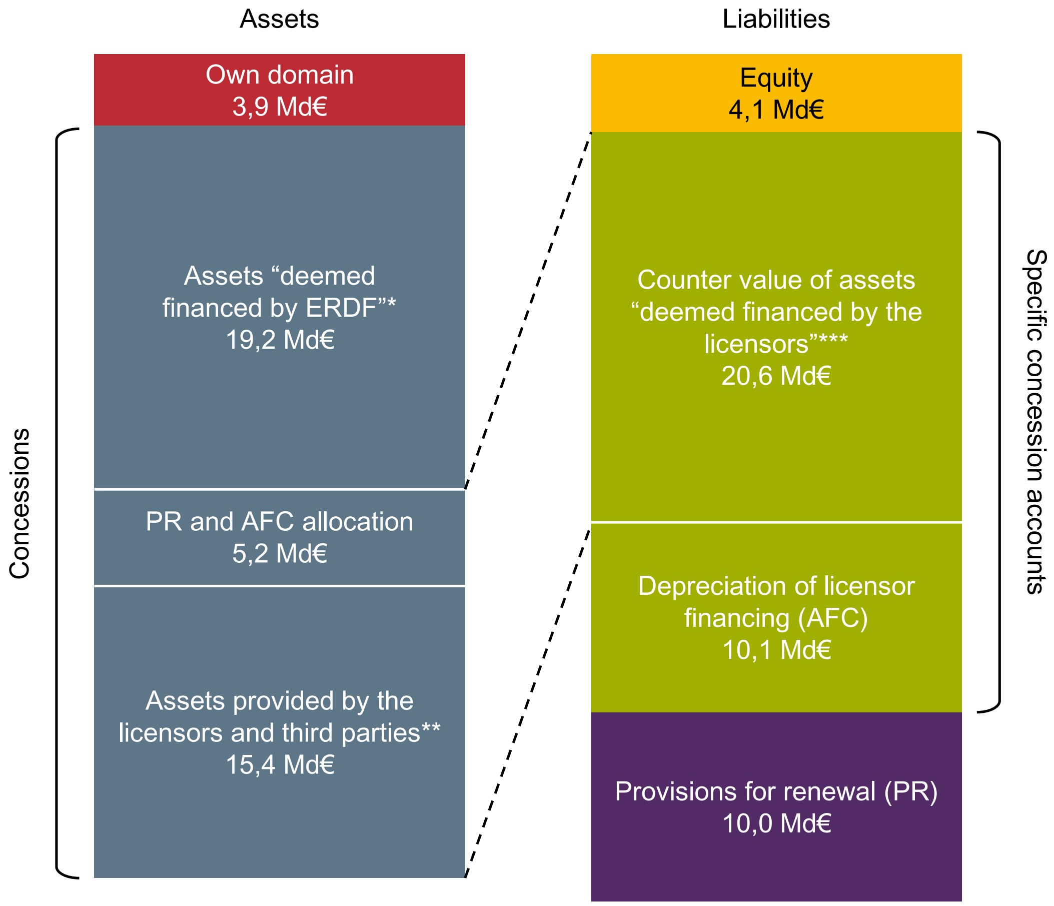
The specific concession liabilities accounts include the rights to existing assets and depreciation on the portion of assets financed by the licensor in respect of assets for renewal."

Provision for renewal:

"This provision, intended for the renewal of the works before the end of the concession, is based on the difference between the replacement value thereof with the same features and identical capacity and their original value. It is constituted for the lifetime of the structure and complements the industrial amortisation expense.

On 31 December of the financial year the replacement value is the subject of a revaluation on the basis of specific evidence to the profession derived from official publications. The impact of this amendment is spread over the remaining lifetime of the works concerned."

ERDF equity can therefore be summarised in the following manner (late 2012 amounts):



* Assets "deemed financed by ERDF" correspond to the non-depreciated licensor financing amount, as presented in the ERDF financial statements.

** This distinction between, on the one hand, the assets given by the licensor's and third parties, and on the other hand, allocations of provisions for renewal and depreciation of financing of licensor's is the result of a non-accounting analysis.

*** These are assets "deemed financed by the licensor's" as during renewal of assets, the provision and depreciation of the licensor's financing under the replaced assets are deemed as licensor financing on the new asset. This amount can also be qualified as the "licensor's rights on existing assets."

2.3. *Taking into account the specific characteristics of the concessions regime of public electricity distribution in the calculation of capital charges*

2.3.1. A tariff framework that encourages investment

The marginal rate of remuneration for new investments corresponds to the additional remuneration received for a new investment, divided by the value of this investment[11].

This marginal rate of return on new investments can be compared to the yield that could be obtained at an equivalent level of risk by affecting financial resources differently.

Accordingly, we can define the opportunity cost of capital as the rate below which an investor considers that they have no interest in committing resources to the concerned project.

Beyond the criteria of stability and clarity, it is appropriate that the remuneration of new investments cover the opportunity cost of the defined capital, otherwise the system operator could eventually be encouraged to invest at a lower level than the one ensuring the highest quality of service to users.

2.3.2. The capital asset pricing model

To determine the cost of capital, or minimum return expected by investors, European regulators are using the capital asset pricing model[12] (CAPM).

The CAPM establishes a relationship between the expected return of an asset (i.e. its capital cost) and a set of parameters:

- the degree of un-diversifiable risk of assets;
- the risk free rate

The CAPM is based on two principles:

- to hold risky assets, investors demand higher return than the return of the risk-free asset;
- investors are rational, they dilute the specific risk of their portfolio by diversifying it. The only risk therefore to which investors are remunerated is un-diversifiable risk, i.e. the risk of market fluctuations.

Before taking into account corporate tax (IS), the CAPM is written in the following manner:

Cost of capital = Risk free rate + Beta x Market premium

The risk free rate is the expected value of a risk-free asset return such as national sovereign bonds. The risk free rate compensates the investor for renouncing an immediate flow in favour of a future cash flow.

Beta is the sensitivity of the value of the assets of a given company compared to the fluctuations of the stock market. It is a measure of the un-diversifiable risk of the assets of the concerned company.

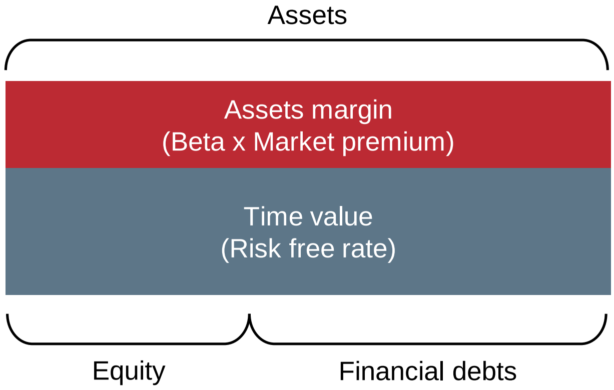
The market premium is the average return of the stock market relative to the risk free rate.

In pictorial terms we can consider that the first term (Risk free rate) is the time value and the second term (Beta x Market Prime) is the assets margin expected by the shareholders of the company concerned.

[11] Within the framework of classical approaches adopted by other European regulators the marginal rate of return on new investments is equal to the Weighted Average Cost of Capital (WACC).

[12] The capital asset pricing model (CAPM) is a theoretical model developed in particular by William Sharpe in the 1960s, based on the work of Harry Markowitz on portfolio theory which explains how rational investors use diversification to optimise their portfolio. This model is used to determine an appropriate rate of return for an asset given its sensitivity to un-diversifiable risk. It is used by financial analysts to determine the value of an asset, by regulators to remunerate regulated firms, by companies to assess the value of an investment opportunity,

The cost of capital can therefore be represented in the following manner (the full surface represents the return):



Before taking into account the Corporate Tax, the cost of capital can be written as follows:

$$\text{Cost of capital} = \text{Risk free rate} \times \left(\frac{\text{Equity}}{\text{Assets}} + \frac{\text{Financial debts}}{\text{Assets}} \right) + \text{Assets margin}$$

2.3.3. The need to take into account the reasons for the decision of the State Council of 28 November 2012

In its decision, the State Council considered that "in abstaining [...] to determine the weighted average cost of capital, to take into account the "specific concession accounts", which corresponds to licensors rights to freely recover the assets of the concession on termination of the contract, whose amount in the liabilities of the ERDF balance sheet, was € 26.3 billion at 31 December 2008, as well as the "provisions for renewal of fixed assets," which amounted to €10.6 billion, CRE and the ministers retained, as is apparent in the consultant's report of July 13, 2012, an erroneous legal method and thereby infringed the abovementioned provisions of the first paragraph of II of Article 4 of the Law of 10 February 2000 and Article 2 of the Decree of 26 April 2001." It is stated in the analysis in the Lebon tables that this legal error resides in "*the absence of any consideration for the calculation of the weighted average cost of capital of the company ERDF*" these two liabilities nevertheless represent significant amounts.

In order to comply with the grounds for the decision of the State Council, it is necessary while maintaining an approach based on the application of a rate of return to a RAB to take into account the particularities of the concessions regime.

2.3.4. Adaptation of the calculation of capital charges to the specific features of the concessions

a. Consideration of specific concession accounts and provisions for renewal

The specific concession accounts and provisions for renewal cover two categories of resources:

- on the one hand the resources provided by the licensors and third parties in the form of freely delivered works that represent a portion counter value of assets "deemed financed by the licensors;"
- on the other hand pre-financing corresponding to provisions for renewal and depreciation of the licensor's financing. Once these pre-financings have been allocated to replacement investments, the counter value of the corresponding assets is registered in the counter value of assets "deemed financed by licensors.

As noted by the public rapporteur, Frédéric Aladjidi, in his conclusions in the Decision of 28 November 2012:

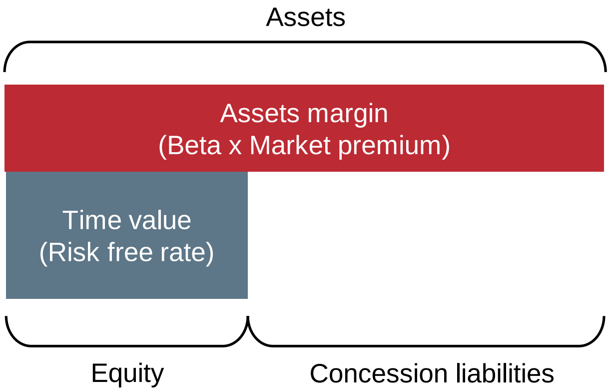
"*If we refine the analysis, as regards provisions for renewal [...] they do not appear to be regarded as equity capital, i.e. to use the definition given in the reference work "corporate Finance" P. Vernimmen* "capital brought by the investor or left by them in the company and which are at risk of industrial adventure, but, in return, which receive the profits" *but they seem assimilated to liabilities* [...]"

"The Court of auditors in the chapter of its annual report for 2004 on EDF specificities and their accounting procedure had raised the existing uncertainty on this point. But the EDF president stated that these provisions are "assimilated to (non-financial) liabilities in respect of local community licensor's," *solution taken up by the French National Accounting Council*."

This analysis can be extended to specific concession accounts.

The specific concession accounts and provisions for renewal may be regarded as non-financial liabilities, i.e., as debts that do not generate financial costs for ERDF.

These liabilities having no financial cost to ERDF, the cost of capital of the latter must be represented by the figure below (the Full Surface represents the remuneration):



b. Assets margin

Under the conditions of normal operation of the network, the tariff must provide ERDF with a "reasonable margin" to the extent that it operates the conceded network, including with regard to the works submitted by the licensor's, at their own risk as provided for in Article 1 of the concession specifications model:

"*The licensee is responsible for the operation of the service and manages it in accordance with these specifications. They operate at their own risk. Liability resulting from the existence of works and operation of the service conceded to them falls under their responsibility.*"

Under the CAPM framework, the "reasonable margin" (*i.e.* the assets margin) is given by the following formula:

Assets margin = Beta x Market premium

The fact that the ERDF enterprise value is not observable in a market does not preclude this value from existing and varying in a partly synchronous manner with the average market value of the shares. The concept of beta is also relevant in the context of unlisted assets. In this case, the value of beta may be estimated by referring to the beta of comparable listed companies.

c. Financial loans taken into account, where appropriate

Even if ERDF liabilities do not currently present a financial loan, it will not necessarily be so during the pricing period. If necessary, it is appropriate that the accompanying financial expenses be covered.

For this, two options were available to CRE, either the normative cover of financial fees by *ex-ante* fixing of a cost of debt or the explicit coverage of financial fees.

Insofar as the ERDF liabilities do not to date present a financial debt, CRE considers it preferable to retain the second option.

d. Coverage of depreciation charges and provisions for renewal

Article L. 341-2 of the energy code provides that tariffs notably cover "*costs resulting from the execution of missions and public service contracts."*

Moreover, consistent with the fact that the provisions for renewal and depreciation of the financing of licensors are deemed a resource without cost for ERDF (*see.* section A.2.3.4.a), all allocations to depreciation charges as well as allocations to provisions for renewal are covered by the tariffs. Accordingly to the same logic, covered allocations are also minus write-backs.

Before taking corporate tax into account, ERDF capital charges are given by the below formula:

$$\begin{aligned}\text{Capital charges} &= \text{Risk Free Rate} \times \text{Equity} + \text{Assets margin} \times \text{Assets} \\ &\quad + \text{Financial expenses} + \text{Net allocations}\end{aligned}$$

e. Consideration of corporate tax

After taking corporate tax into account, ERDF capital charges are given by the below formula:

$$\begin{aligned}\text{Capital charges} &= \frac{\text{Risk Free Rate}}{1 - \text{Corporate tax rate}} \times \text{Equity} + \frac{\text{Assets margin}}{1 - \text{Corporate tax rate}} \times \text{Assets} \\ &\quad + \text{Financial expenses} + \text{Net allocations}\end{aligned}$$

f. Regulated asset base

It is agreed that the amount of assets taken into account in this formula are representative of the service to users.

For this, the margin on assets applies to a RAB defined as the net book value of fixed assets at 1 January of the year (excluding financial assets and fixed assets under construction).

By simplifying, each year the RAB is increased by all investments on the networks and reduced by depreciations.

g. Regulated equity capital

As part of the above discussed formula for calculating capital costs, equity is subject to compensation at the risk free rate.

The amount of equity capital taken into account in the calculation of capital charges should be limited to equity used for the financing of assets included in the RAB. In the contrary case, the amount of equity bearing capital would not correspond to that of an efficient network operator. For this, CRE introduced the concept of regulated equity capital (CPR) to link the amount of equity capital paid to exclusive investments carried out by ERDF in the networks.

Regulated equity capital on 1 January 2014 is defined as the difference between the RAB and the sum of the specific concession accounts, provisions for renewals, investment grants and where appropriate, financial loans.

The regulated equity capital on 1 January of year *N+1* is defined as regulated equity capital on 1 January of year *N* increased, mainly, by ERDF investments put into service and reduced, primarily by net depreciation charges and provisions for renewal covered by the tariff as well as contributions by third parties received in the year.

h. Calculation formula

Finally ERDF capital charges are demonstrated by the following formula:

$$\text{Capital charges} = \frac{\text{Risk free rate}}{1 - \text{Corporate tax rate}} \times \text{CPR} + \frac{\text{Assets margin}}{1 - \text{Corporate tax rate}} \times \text{RAB} + \text{Financial expenses} + \text{Net allocations}$$

B. Date of entry into force of the tariffs

These tariffs are intended to apply with effect from 1 January 2014.

They are designed to be applied for a period of around four years.

C. Definition of estimated tariff income

1. Capital charges

1.1. Investment trajectory

CRE has accepted the investment trajectory proposed by ERDF on 26 June 2013 (in € million current and excluding investments related to the ERDF smart metering project):

Purpose	2014	2015	2016	2017
Connections and reinforcements	1,631	1,705	1,756	1,804
Regulations, safety of others and roads	408	418	417	417
Tools and operating resources	308	290	300	300
Quality and modernisation of network	942	965	993	1,026
Total	**3,289**	**3,378**	**3,466**	**3,547**

Compared to 2012, ERDF investments are oriented upwards (data excluding investments related to the ERDF smart metering project):

Purpose	2012 (in currents M€)	Average 2014-2017 (in currents M€)	Percentage increase
Connections and reinforcements	1,467	1,724	18 %
Regulations, safety of others and roads	399	415	4 %
Tools and operating resources	293	300	2 %
Quality and modernisation of network	875	982	12 %
Total	**3,034**	**3,420**	**13 %**

It is this forecasted trajectory of investments provided by ERDF, which is used to determine the level of the tariff.

Unlike electricity transmission, European law and French law have not entrusted CRE with the competence to assess the relevance of the investment trajectory submitted by the ERDF. “Departmental conferences”, introduced by Article 21 of Law n° 2010-1488 of 7 December 2010 on the 3rd paragraph of Article L. 2224-31 of the General Code of Territorial Units must develop provisional programs of all planned investment in public transmission grids. These conferences were organised in the majority of French “departments”. The consolidated findings of these conferences have to date, not been communicated to the CRE.

In any event, capital charges have been included in the CRCP scope. Accordingly, ERDF is guaranteed to recover the depreciation and return on capital associated with investments made. Consequently, it does not bear any financial risk even in the event that the investments exceed assumptions. Symmetrically, ERDF does not benefit from any under-investment relative to these assumptions.

ERDF stated in its request of 26 June 2013 that the trajectory investment "*could change depending on the one hand on policies adopted by the government (urban planning, energy transition ...), and on the other hand by compensation of the investment* [that CRE will have] *decided*".

CRE recalls that under Article L. 322-8 of the energy code, an electricity distribution system operator in their exclusive area, is notably in charge of:

- defining and implementing investment policies and the development of distribution networks in order to allow the connection of installations of consumers and producers as well as the interconnection with other networks;
- to ensure the design and construction of works as well as project management of works related to these networks, by annually reporting to the distribution network organising authority;
- to operate these networks and ensure their upkeep and maintenance.

Moreover, Article L. 121-1 of the Energy Code provides that the public electricity service must be managed "*in the best conditions of safety, quality, cost and economic, social and energy efficiency.*"

These obligations related to the fulfilment of the distribution system operator's public service mission are not subject to any condition. Consequently, CRE notes that the system operator cannot restrict the exercise of its mission as long as its costs are covered by the tariff, even though CRE looks closely at the incentivising features of the regulatory framework.

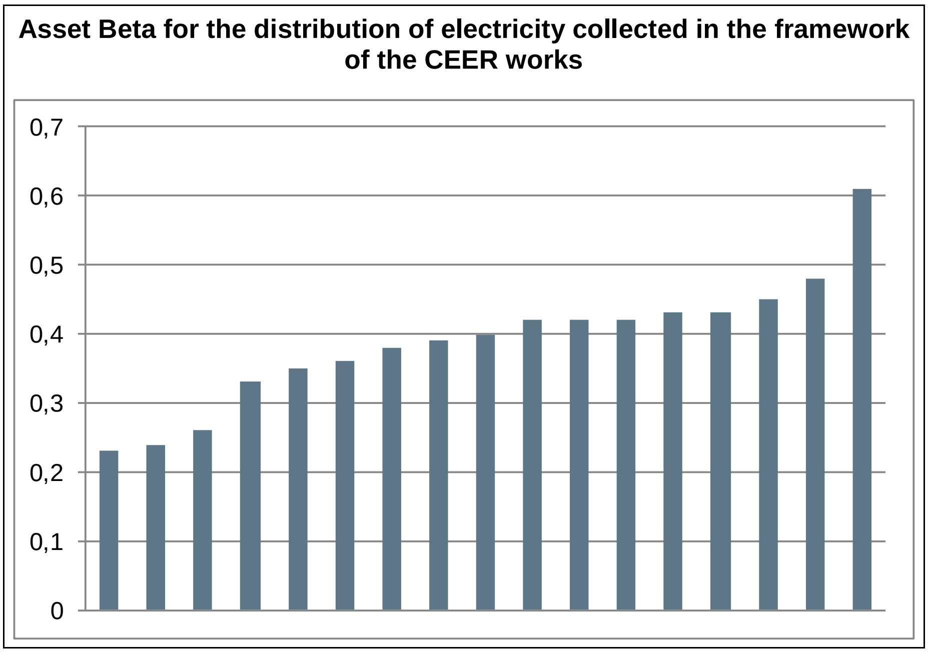
1.2. Setting of calculation of capital charges

As indicated in section A.2.3.4.h ERDF capital charges are given in the following formula:

$$\text{Capital charges} = \frac{\text{Risk free rate}}{1 - \text{Corporate tax rate}} \times CPR + \frac{\text{Assets margin}}{1 - \text{Corporate tax rate}} \times \text{RAB} \\ + \text{Financial expenses} + \text{Net Allocations}$$

CRE reviewed the beta and market premium parameters based on:

- the study carried out by an external consultant on the WACC for electricity and natural gas infrastructures. This study was conducted during the summer of 2011. The beta and market premium values recommended by this study are respectively, from 0.30 to 0.45 and from 3.8% to 5.2% for electricity distribution;
- In-house conducted works, in which information on the data used by other European regulators was updated. These data were notably collected in the particular context of the works of the Council of European Energy Regulators (CEER). The below graph shows the beta values for electricity distribution collected from other European regulators as part of CEER works.



To define the range of values to be used for the risk-free rate, the CRE in particular relies on the returns of French government bonds with long maturities.

The estimates retained by the CRE for each of these parameters is shown in the below table:

Risk-free rate (nominal)	4.0 %
Beta (1)	0.33
Market premium (2)	5.0 %
Margin on assets (after corporate tax) (= (1) x (2))	1.65 %
Corporate tax rate	34.43 %

1.3. Financial expenses

For the 2014-2017 period, ERDF does not intend to resort to loans to finance its investments (excluding exceptional investments such as the widespread deployment of smart meters, for instance).

Accordingly, the forecasted financial fees for the 2014-2017 period are equal to zero.

In any event, the differences in capital charges notably due to financial expenses different to the projection will be charged to the CRCP balance provided that such fees correspond to those of an efficient network operator.

1.4. Capital charges

In view of the above, the forecasted ERDF trajectory retained for capital charges is as follows:

In current M€	**2014**	**2015**	**2016**	**2017**
CPR	*3,818*	*4,608*	*5,395*	*6,413*
Return on CPR (before corporate tax)	233	281	329	391
RAB	*45,508*	*47,289*	*49,063*	*50,825*
Margin on assets (before corporate tax)	1,138	1,182	1,227	1,271
Net depreciation charges and provisions for renewal	2,327	2,416	2,496	2,578
Capital charges	**3,698**	**3,879**	**4,052**	**4,240**

2. Net operating expenses

Article L. 341-2 provides that "*the tariffs for using the public transmission network and public distribution networks shall be calculated in a transparent and non-discriminatory manner and shall cover all costs borne by the operators of these networks insofar as such costs correspond to those of an efficient network operator.* […]*".*

The operating expenses to be covered by the tariffs have been determined based on all operating costs required to run the public transmission system. To set the level of these expenses, CRE referred to the following in particular:

- the trajectory proposed by ERDF for 2014-2017;
- the data from ERDF's financial statements for the years 2009 to 2012 and the estimate for 2013;
- The feedback on TURPE 3 and the results from analyses conducted by CRE on ERDF's operating expenses for the years 2009 to 2017.

ERDF net operating expenses consist primarily of net ongoing expenses, expenses related to the electrical system and additional pricing products. However, access charges to the public transmission grid are not part of this scope. (*See.* section C.3).

The below table presents the trajectory of net operating expenses requested by ERDF on 26 June 2013 to which were included charges related to the financial incentive provided in section D.3.3.2:

In current M€	2014	2015	2016	2017
Net operating expenses	5 607	5 738	5 850	6 020
of which net ongoing expenses	*5 501*	*5 682*	*5 792*	*5 854*
including expenses related to the electricity system	*1 286*	*1 278*	*1 319*	*1 460*
- *of which non-tariff-related income*	*-1 180*	*-1 221*	*-1 261*	*-1 293*

Average net operating expenses for the tariff period 2014-2017 evolves by +3.1 % compared to average net operating expenses completed during the period 2009-2012. The average annual growth rate estimated between 2014 and 2017 is +2.4 %.

Net operating expenses have increased by +0.2 % between 2012 and the 2014 estimate. This low variation is mainly due to a sharp drop in expenses related to the electrical system -€322 million (-20%) and a moderate increase in non-tariff-related income products of +€106 million (+10%), offset by an increase of + €441 million in net operating expenses (+8.7 %).

2.1. Net ongoing expenses

Ongoing expenses are made up of other purchases and services (including concession fees), staff expenditure, taxes (which include contributions to rural electrification), other operating expenses and income after deduction of self production.

The main factors behind the increase in ERDF ongoing expenses are described in the following sections.

2.1.1. Other purchases and services

In current M€	2014	2015	2016	2017
Other purchases and services	3 148	3 274	3 344	3 384
of which concession fees	*316*	*325*	*342*	*352*

The main factors behind the increase in the "Other purchases and services" section are related to new expenses (*see.* sections a, b and c below) compared to the previous tariff period and the increase in operating assets which generate increased expenses.

a. Expenses related to regulatory changes

The anti-damages plan (or decree "DT/DICT") relating to the performance of work near certain underground, overhead or underwater transmission or distribution works, affects ERDF in a significant manner by strengthening network mapping obligations and imposing more stringent work treatment procedures. Based on initial experiments conducted by ERDF, forecast expenditure linked to the anti-damages plan amount to €78 million on average per year over the 2014-2017 period.

In its deliberation of 26 July 2012 concerning communication relating to the management of standard contract clients, CRE indicated that the payments made by ERDF to new suppliers for the management of end customers who have adopted a standard contract is liable to enter into the scope of costs covered by TURPE. This contract provides an obligation for ERDF to pay a fee for the management of the relationship with the end customer in order for him to access and use the public distribution system as long as the supplier does not benefit from sufficient economy of scales. The forecast for this kind of expenses amount to €11 million on average per year over the 2014-2017 period.

Expenses related to the implementation of the decree modifying the procedures for establishing projects and procedures for control of new and existing structures, as well as expenses related to the compliance of equipment containing traces of polychlorinated biphenyls (PCBs) have also been taken into account for an average of €18 million for 2014-2017.

b. Expenses related to preventive maintenance and quality improvement

The “Other purchases and services” section incorporates expenses resulting from ERDF improvement of service provided and the protection of property and persons, especially by developing preventive maintenance of its facilities (pruning programs on LV lines, checking land, *etc.*). Annual operating expenses under preventive maintenance planned by ERDF amount to €279 million on average per year over the 2014-2017 period. As for expenses relating to the improvement of service provided, they amount to €56 million per year on average for the period 2014-2017.

c. Expenses related to R&D and innovation linked to the development of *Smart grids*

The forecasted operating expenses related to R&D included in the trajectory are €56 million on average over the 2014-2017 period. The details of these expenses are described in section D.3.2.

2.1.2. Staff expenditure

In current M€	2014	2015	2016	2017
Staff expenditure	2,714	2,767	2,821	2,868

The personnel costs section is on average €2,792 million. ERDF has taken into account the requirements for renewal of skills, the strengthening the network, the new regulations and a policy to reintegrate some of its activities. The average annual growth rate estimated for the 2014-2017 period is 1.9 %.

The assumptions made by ERDF for the staff and remuneration increases have been retained in the net operating expenses trajectory for the period 2014-2017. In addition to the section C.2.1.5, CRE has analysed the productivity efforts proposed by ERDF for the period 2014-2017.

2.1.3. Taxes

In current M€	2014	2015	2016	2017
Taxes	732	754	773	784
of which contributions to rural electrification	*359*	*366*	*374*	*376*

On average, contributions to rural electrification represent 48% of the total "taxes" and increases by approximately 1.6% per year over the period. CRE has adopted the trajectory of expenses proposed by ERDF.

The other expenses are mainly made up of the local business tax (territorial economic contribution – *CET*), the IFER (flat-rate tax on network businesses) and taxes on wages. The annual growth rate of the section "taxes" excluding the impact related to contributions to rural electrification is 3% for the period 2014-2017.

2.1.4. Other income and operating expenses

In current M€	2014	2015	2016	2017
Other income and operating expenses	311	327	338	340

The section "Other operating expenses and income" consists primarily of expenses related to the net book value of scrapped fixed assets as well as expenses linked to the preferential tariff for employees.

Moreover, in the framework of the implementation of the dispute committee's settlement and sanctions decision of 22 October 2010 relating to the GRD-F contract, ERDF has also taken into account the coverage of supplier's credit losses on the delivery part. Forecast spending for this type of expense amount to €116 million on average per year over the 2014-2017 period.

2.1.5. Productivity objectives proposed by ERDF

Article L.341-3 of the Energy Code defines the incentive regulation principles to encourage operators to improve their performance, in particular by seeking productivity efforts.

CRE services have thoroughly analysed the operating expenses in order to identify potential productivity gains.

To apply this productivity objective, CRE first distinguished:

- (1) "New" expenses compared to those taken into account within the TURPE in force framework (mainly expenses related to new regulatory constraints, to improve preventive maintenance and quality, including additional staff encouraged by these new activities).
- (2) The specific expenses for which application of a productivity objective is not relevant. These items correspond mainly to tax expenses, other expenses and diverse income.

The analysis of these expenses is broken down in the relevant sections above (*see.* sections C.2.1.1 à C.2.1.4). ERDF other ongoing expenses are deemed to fall under an identical scope of activity (3) compared to the tariff period in force. This scope mainly comprises "Other purchases and services" expenses and "Staff expenditure". CRE considers that for the portion relating to this identical scope of activity, the trajectory for retained net ongoing expenses must incorporate productivity efforts.

The details for the calculation on a constant basis of activity used by CRE to conduct its analysis are presented below:

In current M€	2012	2014	2015	2016	2017
Total of net ongoing expenses	**5,060**	**5,501**	**5,682**	**5,792**	**5,854**
- New expenses (1)	**-331**	**-457**	**-493**	**-511**	**-525**
of which expenses linked to regulatory development - Section C.2.1.1.a	*-38*	*-90*	*-106*	*-108*	*-118*
of which maintenance preventive and quality improvement expenses- Section C.2.1.1.b	*-264*	*-317*	*-332*	*-343*	*-347*
of which R&D and innovation expenses - Section C.2.1.1.c	*-29*	*-50*	*-55*	*-60*	*-60*
- Other specific items (2)	**-1,105**	**-1,386**	**-1,442**	**-1,494**	**-1,498**
of which access charges - Section C.2.1.1	*-293*	*-316*	*-325*	*-342*	*-352*
of which taxes - Section C.2.1.3	*-701*	*-733*	*-754*	*-773*	*-784*
of which other income and operating expenses - Section C.2.1.4	*-86*	*-311*	*-327*	*-338*	*-340*
of which others	*-25*	*-26*	*-35*	*-41*	*-22*
Total expenses on a constant basis of activity (3)	**3,624**	**3,658**	**3,747**	**3,787**	**3,831**
other purchases and services (4)	*1,576*	*1,525*	*1,573*	*1,581*	*1,595*

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including staff expenditure (5)	*2 048*	*2 134*	*2 173*	*2 206*	*2 236*

* Net of capitalised production costs

The ERDF requested level on a constant basis of activity (3), i.e. adjusted of new expenses and other specified items, increase by +1.5% i.e. "inflation - 0.4%" per year on average.

This development is consistent between "Other purchases and services" (4) and "Staff expenses" (5) sections.

This trend follows:

- an observed increase of these expenses of +5.2% between 2011 and 2012;
- a growth trajectory of these expenses of +2.1% i.e. "inflation + 0.3%" per year on average on a constant basis over the 2011-2014 period.

CRE notes that the productivity target planned by the operator over the 2014-2017 period is more ambitious than the development observed in the 2011-2014 period. CRE has adopted the trajectory proposed by ERDF.

2.2. Expenses related to the electricity system

The expenses related to operation of the electricity system mainly cover the purchase of electrical losses in the grid.

In current M€	2014	2015	2016	2017
Purchase of losses	1,239	1,231	1,273	1,413
Others	47	47	47	47
Expenses related to the electricity system	**1,286**	**1,278**	**1,319**	**1,460**

The forecasted volume of energy loss and expenses related to the compensation of this loss taken into account by CRE for the 2014-2017 period is as follows:

	2014	2015	2016	2017
Volume (TWh)	24.59	24.97	25.31	25.62
Cost (M€ current)	1,239	1,231	1,273	1,413

Pursuant to Article L. 322-9 of the French energy code, ERDF freely negotiates contracts with producers and suppliers of its choice to cover losses, according to competitive, non-discriminatory and transparent procedures, such as public consultations or recourse to organised markets.

The setting up of regulated access to historical nuclear energy (ARENH) to compensate for losses introduced by Article L. 336-1 of the energy Code specified by the provisions of Decree n ° 2011-466 of 28 April 2011, provides ERDF with a new opportunity to purchase the energy needed to offset losses. This new system helps to reduce by approximately 19% the average unit cost of offsetting losses over the period 2014-2017.

The share of volumes purchased from ARENH represents a growing share of volume loss over the period 2014-2015, which explains the decrease in unit cost of purchasing losses during this period despite higher volumes of losses. This effect is offset for the years 2016 and 2017 by the establishment of a mechanism for capacity obligation and the forecasted increase in market prices.

After analysis, CRE uses the trajectory in cost of losses proposed by ERDF, presented as part of the CRE public consultation dated 9 July 2013. This trajectory takes into account:

- The downward revision of the trajectory increase in the price of ARENH and market price in relation to the trajectory of cost of losses presented as part of the public consultation of the CRE dated 6 November 2012;

- the order dated 19 November 2012 amending the Order of 25 November 2011 sets the timetable for the opening-up of rights of access to ARENH for losses;
- consideration of a projection of the cost of capacity which will be incurred by the providers for losses for the years 2016 and 2017 in accordance with Decree No. 2012-1405 of 14 December 2012.

2.3. Non-tariff-related income

The forecasts for income received independently of the system user tariffs are deducted from the forecasted operating income to be covered by the tariffs. For ERDF it is mainly revenue from additional services and connection contributions.

The forecasted trajectory of non-tariff-related income, connection contributions and revenue from additional services provided by ERDF are the following:

In current M€	2014	2015	2016	2017
Non-tariff related income	1,180	1,221	1,261	1,293
of which contributions connection	*609*	*640*	*672*	*697*
of which revenue from additional services	*206*	*213*	*219*	*226*

CRE believes these trajectories are consistent with the amounts reached in the previous tariff period as well as the number of connections planned by ERDF.

A new deliberation on the pricing of additional services is planned in 2014. Any change in rates of services that could result will be taken into account by the CRCP mechanism.

3. Access to the public transmission grid

The tariff for use of public distribution systems covers access of these network operators to the public transmission grid.

Based on the CRE deliberation dated 3 April 2013 deciding on the tariffs of use of a public electricity grid in the HVB voltage range, ERDF estimates the cost of accessing the public transmission grid to the following amounts:

In current M€	2014	2015	2016	2017
Cost of access to the public transmission grid	3,438	3,529	3,636	3,646

4. Balance of incentives at the end of 2012

The table below sets out the balance of financial incentives for the period of 1 August 2009 to 31 December 2012.

Incentive (in current M€) Penalty (+) / Bonus (-)	Aug – Dec. 2009	2010	2011	2012
Supply continuity	-18.6	25.5	-7.0	23.9
Quality of service	-0.1	-0.2	-0.3	-0.3
Total	**-18.7**	**25.3**	**-7.3**	**23.6**

After remuneration at 4.2% per year, the balance of incentives at the end of 2012 is € 22.3 million in favour of users.

The annuity enabling the clearance of the balance of the 2014-2017 period is €6 million in favour of grid users.

5. Pricing of expenses and forecasted tariff increases

The forecasted trajectory of pricing of net expenses is as follows:

In current M€	2014	2015	2016	2017

Capital charges	3,698	3,879	4,052	4,240
Net operating expenses excluding access to the public transmission grid	5,607	5,738	5,850	6,020
Access to the public transmission grid	3,438	3,529	3,636	3,646
Annuity of the incentives balance	-6	-6	-6	-6
Net expenses for pricing	**12,736**	**13,140**	**13,531**	**13,900**

Once integrated the EDF Insular Power Systems (EDF SEI) demand (€ 511 M of net annual expenses to be priced over the 2014-2017 period) taking into account inflation assumptions considered by ERDF in its business plan, the tariff should increase by 3.6% on 1 January 2014, excluding CRCP clearance of inflation at 1 August 2014 to 2017, in order to balance the net forecasted costs over the 2014-2017 period.

6. Local distribution companies and EDF SEI

Article L. 341-2 of the French Energy Code states that "*the tariffs for use of the public transmission grid and the public distribution system shall be calculated […] to cover all costs borne by the operators of these networks* […]."

CRE estimated all Local Distribution Company (LDC) costs at a flat rate from those incurred by ERDF and EDF SEI in proportion to the energy they distribute.

Given the peculiarities of public distribution systems operated by LDCs or their clientele the application of these tariffs can for certain LDCs, lead to potential shortfalls or excess revenue. In accordance with Article L. 121-29 of the Energy Code, these costs or excess revenues are to be distributed by the Equalisation electricity fund (FPE).

The base cost per unit of EDF SEI being greater than that of ERDF, its forecasted expenses will not be fully covered by the revenue it will receive directly. EDF SEI not benefiting from the FPE, the corresponding forecasted deviation should be offset by a repayment of ERDF to EDF SEI.

D. Regulatory framework

1. Annual tariff increase

From 2014, the tariffs will be mechanically adjusted on 1 August each year using the following percentage:

$$Z_N = IPC_N + K_N$$

Z_N: percentage of change, rounded off to the nearest tenth of a percent, in the tariff scale in application as from 1 August of the year N compared to that in application the previous month.

IPC_N: percentage of change between the average value of the consumer price index excluding tobacco over the calendar year N-1 and the average value of the same index over the calendar year N-2, as published by the French statistics agency INSEE (identifier: 000641194).

K_N: CRCP reconciliation factor for year N, calculated on the basis of the CRCP balance at 31 December of year N-1 and reconciliation's already conducted. The absolute value of the coefficient K_N is limited to 2%.

2. Expense and income clawback account

2.1. Principles

Given the period of the tariffs fixed at approximately four years, CRE has based the present tariff deliberation on estimates of short and medium-term trends in expenses and income.

For some categories of expense and income that are hard to predict or control, CRE has renewed the expense and income clawback account (CRCP) mechanism, set up under TURPE 2, to measure and offset, for previously identified items, the differences between forecasted and actual expenses and income on which the present tariffs are based, provided that these achievements correspond to an efficient network operator.

The CRCP is also the vehicle used for financial incentives resulting from the application of incentive regulatory mechanisms.

The contribution of CRCP reconciliation to the annual variation of the tariff scale is limited to +/- 2 %.

2.2. Scope

The expense and income items covered by the mechanism are as follows:

- the capital charges;
- the expenses related to compensation for electrical losses on the grids;
- the cost of access to the public transmission grid;
- the expenses linked to the net book value of scrapped fixed assets;
- income received for all tariff components according to the terms stated hereinafter;
- revenue from ancillary services (N.B: revenue from additional services created during the tariff period are excluded from the CRCP scope as long as the cost of providing these services was not taken into account in the development of tariffs);
- connection revenues;
- R&D operating expenses (according to the terms provided in section D.3.2.1);
- Financial incentives as well as compensation expenses linked to ceilings on total amounts of financial incentives related to the various incentive-based regulation mechanisms.

In addition, the results of audits conducted by CRE will be taken into account within the CRCP scope.

2.3. Operating rules

For each item deemed eligible for the CRCP, differences are calculated according to the rules stated below.

1. For each expense or revenue item considered, excluding income received for all pricing components, differences posted in the CRCP are calculated on the basis of a comparison between the reference value of estimated annual expenses or income and the actual amounts of these expenses or income for each year of the tariff period.

   As the tariff scale is indexed to the consumer price index (CPI) excluding tobacco, ERDF is hedged against the risk of inflation for all its expenses. However, changes in expense items covered by the CRCP mechanism, such as the compensation for energy losses on the grids or capital charges, are not necessarily related to CPI trends. To correct this, CRE has adapted the reference values used to calculate the CRCP balance.

   These reference values, required for calculation of the CRCP for year N, are therefore calculated on the basis of forecasted values in 2013 constant Euros and are re-evaluated annually according to the CPI evolution between year *N-1* and year 2012.

   The forecasted values in 2013 in constant Euros, for the various items of operating and capital charges, are set out below:

In M€$_{2013}$	**2014**	**2015**	**2016**	**2017**
Purchase of losses	-1,215	-1,183	-1,200	-1,307
Access to the public transmission system	-3,370	-3,392	-3,429	-3,371
Net book value of scrapped fixed assets	-65	-72	-73	-67
Operating expenses	**-4,650**	**-4,646**	**-4,703**	**-4,745**
Services income	202	204	207	209
Connected contributions	597	615	634	645
Operating income	**799**	**819**	**841**	**853**
Capital charges	**-3,625**	**-3,728**	**-3,822**	**-3,921**

2. As regards income received for all pricing components, the tariff income for the year N is compared to the forecasted tariff income adjusted for actual inflation and the CRCP amounts reconciled in year N. Accordingly, ERDF is hedged against the risk related to uncertainties in the forecasts for volumes transmitted.

In current M€	2014	2015	2016	2017
Forecasted tariff income	12,715	13,105	13,542	13,949

3. As regards expenses related to loss compensation, the difference in costs for year *N* between the forecasted value of the loss purchase cost and the costs actually borne by ERDF will be posted to the CRCP in full, excluding the following exceptions:
   - these costs do not cover any premiums paid by ERDF for an options ceiling price;
   - any excess costs resulting from the reconstitution of ERDF's portfolio will be offset via the CRCP: in full for force majeure events or supplier insolvency and 50% for events qualified as circumstances deemed as force majeure in contracts;
   - if the annual volume of imbalances attributed to ERDF's balancing scope (differences between the volume of losses actually recorded, following the process for calculating imbalances and the hourly estimate) is greater than 4% of the volume of recorded losses, an audit will be conducted by CRE to ensure that the causes of the increase in the volume of imbalances could not be controlled. If, following this audit, it is considered that the increase in the volume of imbalances could have been avoided, the difference in expenses related to loss compensation will only take into account the expenses up to the limit of 4% of the volume of recorded losses.
   - if the annual sum of the absolute values of the volumes of ERDF losses calculated during time reconciliation's is greater than 1 TWh, an audit will be conducted by the CRE to ensure the uncontrollable nature of the causes of the increase in the volume of losses. If, following this audit, the uncontrollable nature of the cause of the increase in the volume of ERDF loss is not proven, the gap in expenses related to losses will not take into account the time reconciliation costs to the limit of 1 TWh.
4. The financial incentives for each of the incentive-based mechanisms will be calculated as stated in the corresponding sections and posted each year to the CRCP balance. Where appropriate, the compensation of expenses related to ceilings on total amounts of financial incentives will also be charged annually to the CRCP balance.
5. In order to ensure the mechanism's financial neutrality, the discounted CRCP balance, for imbalances recorded over the period of application for the present tariffs, is calculated annually using an interest rate equivalent to the risk-free rate adopted within the framework of the present deliberation. (*See.* section C.1.2).
6. The CRCP balance calculated for calendar year *N* is reconciled in part or in full as of the following year. The impact of the annual reconciliation of the CRCP on the development of the tariff scale cannot be higher, in absolute value, than 2 %. Where relevant, the amounts not reconciled because of this limit are posted to the CRCP balance to be reconciled the following year.
7. ERDF will send the amounts required for the calculation of the CRCP of year *N* to CRE three months before the tariff change at the latest.

2.4. Treatment of the year 2013

As indicated in section E.1 of the deliberation of 29 March 2013 relating to the proposal concerning the tariffs for use of an HVA or LV voltage range public electricity system for the period of 1 August 2009 to 31 July 2013 and the deliberation of 28 May 2013 regarding the decision on the tariffs for use of an HVA or LV voltage range for the period from 1 August to 31 December 2013:

- the differences between, on the one hand, the net accounting expenses and tariff revenues and on the other hand, CRE estimates for the period from 1 January to 31 December 2013 shall be charged to the CRCP balance, provided that such expenses correspond to those of an efficient network operator;

- In order to ensure the financial neutrality of the mechanism, the updated CRCP balance for the differences observed in the period from 1 January to 31 December 2013 is calculated by using the nominal risk-free rate presented in section C.2 of the above deliberations (i.e. 4.2 %)

The calculated CRCP balance is accordingly cleared through tariff changes from 1 August 2014 within the limits of ± 2% impact on the tariff. Where relevant, the amounts remaining, because of this limit, will be posted to the CRCP balance to be cleared the following year.

3. Incentive regulation

3.1. Operating expenses

The trajectory of ERDF's net operating expenses is defined for the 2014-2017 period (*see.* section C.2). It includes a productivity objective related to net running expenses on the basis of an identical scope of activity compared to the previous tariff period.

The TURPE 3 regulatory framework made provisions for an asymmetrical system in which ERDF conserved 50% of the productivity gains in comparison to the set trajectory and conserves 100% of the productivity losses. For the TURPE 4 period, CRE adopted a symmetrical system in which ERDF conserves 100% of additional productivity gains and losses. Consequently CRE hopes to further encourage ERDF to control its costs.

3.2. Research and development

Currently, electrical networks are undergoing modernisation to address the development of renewable energy and new uses of electricity as well as issues of energy efficiency. New network technologies are being developed to move electrical networks in the direction of smart grids. CRE has wished to support this evolution for a long time.

To do this, it launched several initiatives: creation of a news website dedicated to *Smart Grids* and thematic forums,[13] the organisation of regional round tables on the governance of smart energy networks, technical workshops, etc. They enabled better knowledge of the expectations of the various stakeholders in relation to CRE. In the continuation of these initiatives and in the framework of the tasks assigned to it, namely to ensure the proper functioning and development of the electricity networks, CRE pays particular attention to the development of R&D activities dedicated to smart grids *via* the establishment of an adapted regulatory framework.

The present decision introduces a mechanism aimed at providing ERDF with the means to carry out the R&D and innovation projects required for the construction of the electricity systems of tomorrow by guaranteeing in particular the absence of tariff barriers to undertaking R&D projects or innovative investments. It also set up a follow-up mechanism aimed at giving electricity sector stakeholders greater visibility in the R&D projects carried out by ERDF in the innovation field.

3.2.1. Tariff treatment of R&D expenses

For the period from 2014 to 2017, ERDF presented the following R&D operating expenses trajectory broken down according to three themes:

In current M€	**2014**	**2015**	**2016**	**2017**	**Total**
Theme "improve the efficiency of distribution sector professions"	16	16	17	17	**66**
Theme "prepare the evolution of distribution professions"	15	16	19	19	**69**
The *Smart grid* demonstration program	19	23	24	24	**90**
R&D operating expenses	**50**	**55**	**60**	**60**	**225**

[13] To find out more about this approach and the CRE work program on the topic, visit the CRE website www.smartgrids-cre.fr.

NB: operating expenses related to the *Smart grid* demonstration program were not included in the R&D expenses provided by the CRE in its public consultation in November 2012.

CRE will review, at the end of the tariff period, the sums actually spent by ERDF and will return to users, via the CRCP mechanism, the difference between the forecasted and actual trajectory.

Any annual differences between the actual and forecasted trajectory will have to be justified by ERDF within the framework of the annual report sent to CRE.

Moreover, investment in R&D and innovation, particularly in the *Smart grids* field are entirely passed through, like other ERDF investment expenditure.

3.2.2. Develop the visibility of the ERDF innovation and R&D program

Within the framework of TURPE 4, CRE has introduced a follow-up of ERDF innovation projects. This follow-up will take the form of a report, sent by ERDF to CRE before the end of the first quarter of each calendar year, for the previous year notably including the following elements:

- a description of the projects carried out with the associated expenses and results obtained;
- a list of projects in progress and future projects with the expected outcomes;
- the expenses for the past year;
- the forecast expenses for each year up to the end of the tariff period;
- the number of full-time equivalents associated with R&D programs.
- the support and subsidies received.

In addition, every two years, CRE will publish a report on ERDF's innovation and R&D policy. This report will complete the communication tools already set up by CRE, in particular in the field of smart grids. It is aimed at giving stakeholders in the electricity sector visibility on the projects led by ERDF and financed by TURPE. The first report will cover the year 2014.

In order to give visibility to the stakeholders in the electricity sector for projects funded by TURPE scheduled for the 2014-2017 period, a description of ERDF *Smart grids* and R&D projects is provided in the appendix.

3.3. Quality of supply

3.3.1. Duration and annual average frequency of supply interruptions;

Article L. 341-3 of the French Energy Code states that CRE "*may propose […] appropriate short- or long-term incentives to encourage transmission and distribution network operators to improve their performance particularly as regards the quality of the electricity* […]."

To do so, CRE has renewed and reinforced the incentive mechanism for quality of supply implemented within the framework of previous tariffs.

In the framework of TURPE 3, supply interruptions for works were excluded from the scope of the incentive on the average annual duration to reflect the transformers disposal program containing traces of polychlorinated biphenyls (PCBs). This program being finalised, the incentive now takes into account the supply interruptions for works.

This change in scope led to a review of the average duration of reference interruptions. The average length of interruptions for work was16 minutes in 2012, the reference value for 2013 was 52 minutes, CRE set the reference value for 2014 to 68 minutes, then lowered this duration by 1 minute per year for compliance notably with the ERDF investment trajectory. The reference values are as follows:

2014	2015	2016	2017
68 minutes	67 minutes	66 minutes	65 minutes

Moreover, as it did for RTE, CRE updated the strength of the incentive and ceiling depending on the valuation of non-distributed energy emerging from the study conducted by RTE in 2011. The strength of the incentive was accordingly increased to €4.3 M/minute (against €4 M/minute under TURPE 3) and the floor/ceiling level was increased to € 54.2 M (against € 50M under TURPE 3).

Finally, CRE implemented monitoring of the annual frequency of interruptions.

The provisions of this section shall not preclude the transmittal by ERDF to CRE of other indicators that are not explicitly listed below. Moreover, these provisions do not prevent the transmission to the concerned stakeholders, in particular the users and licensing authorities' of indicators relating to the quality of public electricity distribution networks.

a. Parameters of the incentive scheme

The average duration of power cuts for the year *N* (DMC_N) is calculated using the following formula:

$$DMC_N = \frac{\sum_{Year\ N} Duration\ of\ BT\ installations\ powercuts}{Total\ number\ of BT\ installations\ as at\ 31\ December\ of\ year\ N}$$

DMC_N is determined excluding consecutive incidents to exceptional events (*see* definition below) and excluding causes related to the public transmission grid (or load shedding).

The level of financial incentive for year *N* is calculated using the below formula:

$$I_N = 4{,}3 \times \left(DMC_{N\ ref} - 34\right) \times \ln\left(\frac{DMC_N - 34}{DMC_{N\ ref} - 34}\right)$$

$DMC_{N\ ref}$: reference average duration of interruptions of year *N*, expressed in minutes. Its value is set to 68 minutes in 2014, 67 min in 2015, 66 min in 2016 and 65 min in 2017.

I_N: financial incentive for year *N* expressed in €M which may result in negative values. The absolute value of annual incentive I_N is limited to € 542 M.

The average duration of interruptions for the year *N* (FMC_N) is given using the following formula:

$$FMC_N = \frac{Number\ of\ BT\ installations\ powercuts}{Number\ of BT\ installations\ as at\ 31\ December\ of\ year\ N}$$

FMC_N is determined excluding consecutive incidents to exceptional events (*see.* definition below) and excluding causes related to the public transmission network (or load shedding).

b. Monitoring of quality of supply

Before the end of each calendar quarter, ERDF must provide CRE with the following information for the previous quarter:

- the sum of the durations of interruptions and the number of interruptions in consumer installations connected by LV in all cases;
- the sum of the duration of interruptions and the number of interruptions in consumer installations connected by LV for cases related to the public transmission grid (or load shedding);
- the sum of the duration of interruptions and the number of interruptions in consumer installations connected by LV excluding exceptional events and cases related to the public transmission grid (or load shedding);
- for each exceptional event: all factors justifying the exceptional nature of the event, the sum of the duration of interruptions and the number of interruptions in consumer installations connected by LV due to the event and any item to assess the speed and the adequacy of measures taken by ERDF to restore normal operating conditions;
- the sum of the duration of interruptions and the number of interruptions in consumer installations connected by LV consecutive to works related to the public transmission grid managed by ERDF;

Before the end of the first quarter of each year, ERDF must provide CRE with the following information for the previous year:

- the annual average duration of interruptions interruptions (for all reasons);
- the annual average duration of interruptions for reasons related to the public transmission grid; (load shedding);
- the annual average duration of interruptions excluding exceptional events and reasons related to the public transmission network (or load shedding);
- the annual average duration of interruptions consecutive to works on the public distribution network managed by ERDF;
- the total number of consumer installations connected by LV on 31 December.

c. Exceptional events

Under the incentive regulation for supply continuity, the following are considered to be exceptional events:

- destruction due to war, riots, looting, sabotage, attacks, criminal acts;
- damage caused by accidents and events that cannot be controlled, caused by third parties, such as fires, explosions and plane crashes;
- natural disasters defined by the amended French law No. 82-600 dated 13 July 1982 modified;
- sudden, unplanned and simultaneous unavailability of several production facilities connected to the public transmission grid, if unavailable power is greater than the provisions of the security regulations stipulated in Article 28 of the standard public electricity transmission grid franchise specifications (appended to French Order No. 2006-1731 dated 23 December 2006);
- disconnection of structures decided by public authorities on the grounds of public or police safety if this decision is not due to the actions or inaction of the public electricity system operator;
- atmospheric phenomena of an exceptional nature with regard to their impact on the grids, characterised by an annual probability of incidence of less than 5% for the given geographical area when at least 100,000 final users supplied by the public transmission and/or distribution grids go without electricity in one day and for the same reason.

3.3.2. Power interruption for a period exceeding 6 hours

Pursuant to Article L. 341-5 of the French Energy Code and considering its competence relating to the fixing of the methodology of tariffs as well as their development, CRE has proposed that the government repeal most of the provisions of Decree No. 2001-365 of 26 April 2001 relating to the tariffs of use of public electricity transmission and distribution grids. Article 6 of the Decree provides for a flat rate abatement mechanism of the fixed part of TURPE in the event of power interruption due to failure of public networks.

CRE, who wished to incorporate this mechanism in the context of this tariff, has questioned the relevance of this mechanism.

The device that CRE proposed provides a standard abatement of 2% of the fixed part of TURPE per period of power interruption of 6 hours when this interruption is due to a failure of the public grid.

As it had highlighted in October 2010 in its report on the quality of supply, CRE considers that this abatement is far too low especially in comparison to mechanisms conducted by our European neighbours.

Within the context of this tariff, CRE modified this mechanism providing for the payment by ERDF to users of a penalty of 20% of the fixed part of TURPE per period of 6 hours of power interruptions.

The mechanism that CRE proposed to repeal also provides an annual individual limit on the penalty to the amount of the fixed part of TURPE. The mechanism put in place by CRE removes this individual limit for users connected to the public distribution grid managed by ERDF.

The scope of failures in considered public distribution grids (all failures, including during exceptional events) and the automaticity of payment remain unchanged.

N.B: insofar as it is not possible to establish an incentive relating to RTE under this tariff, power interruptions of users connected to the public distribution grid managed by ERDF due to a failure of the public transmission grid does not give rise to the payment of a penalty.

However, this incentive should be neutral for ERDF and not be a reckless financial risk. Accordingly, these tariffs cover a penalty amount of €25 million per year (this amount is included in the post "Other operating income and expenses" presented in section C.2.1.4). In addition, the amounts paid by ERDF in excess of a limit of € 50 million per year will be offset by ERDF *via* the CRCP.

As a Local distribution Company, CRE considers modification of the mechanism of "2%/6 hours" as premature on their perimeter. Accordingly, it retains the mechanism set out in Article 6 of the aforementioned decree.

In the absence of abrogation of Article 6 of the above mentioned decree, the reduction in the decree and the device described below are cumulative.

The payment of this penalty or abatement does not deprive users of the right to seek the responsibility of their public network operator by common law.

a. ERDF

In the case of a power interruption greater than 6 hours due to a failure in the public networks it manages, ERDF will pay the users concerned a penalty equal to 20% of the annual fixed component of TURPE per 6 hour period. The annual fixed component taken into account is equal to the sum of the annual administrative management component, of the annual component count and the part proportional to the power subscribed from the annual component of withdrawals.

b. ELD and EDF SEI

In the case of a power interruption greater than 6 hours due to a failure in the public grids, the public network operator will pay the users concerned a penalty equal to 2% of the annual fixed parts of TURPE per 6 hour period. The annual fixed part taken into account is equal to the sum of the annual management component, of the annual component count and is proportional to the power subscribed from the annual component of withdrawals. However, the total penalties paid to a user during a calendar year may not exceed the annual fixed component.

In the case of a power supply interruption for a duration greater than 6 hours due to a failure caused by a public network located upstream of those managed by the public network operator, the public network operator pays the public network operator the penalties that the latter is required to pay pursuant to the preceding paragraph.

3.4. Quality of service

Article L. 341-3 of the French Energy Code states that CRE "*may propose […] appropriate short- or long-term incentives to encourage transmission and distribution network operators to improve their performances*".

To do this, CRE renewed and strengthened the incentive regulation mechanism of the quality of service.

Accordingly, the present decision introduces new financial incentives for ERDF and strengthens targets and amounts of existing incentives. In addition, it extends the incentive regulation mechanism of the quality of service to LDC of electricity of over 100,000 clients and EDF SEI.

The new financial incentives introduced for ERDF focus on the following indicators:

- the rate of commissioning (with displacement) on existing installations completed within the time frame requested;
- the rate of response to complaints within 15 days;
- the rate of semi-annual statements on the real index (reading or remote reading);

- The rate of compliance with the agreed date of provision of connection works.

For the LDCs with over 100,000 clients[14] and for EDF SEI, the two following financial incentives are introduced:

- payment of a penalty on user demand, in the case of scheduled appointments not respected by the distributor;
- payment of a penalty on user demand, in case of non-compliance with the deadline for sending a connection charges estimate.

Moreover, monitoring of the following indicators is introduced for these same LDCs and for EDF SEI:

- the number of complaints received by type and category of user;
- the rate of response to complaints within 30 days;
- rate of meters with at least one reading on actual index in the year;
    - rates of deadlines for submitting proposals of connection by user category.
- rate of compliance to the agreed date of commissioning of works by user category.

All indicated and monitored financial incentives are described in the appendix.

The provisions of this section shall not preclude the transmittal by the distribution network operators to CRE of other indicators that are not explicitly listed in the appendix. Moreover, these provisions do not prevent the transmission to market players of indicators relating to quality of service, particularly in the framework of the **Electricity Distribution Network Users Committee** (CURDE).

ERDF, ELDs of over 100,000 clients and EDF SEI must transmit to CRE quarterly results of indicators of quality of service and issue a publication via their website.

The CRE may conduct studies to assess user satisfaction in some fields relating to the relationship between the distributor and the end client.

The payment of penalties to users does not deprive them of the right to seek the responsibility of their public network operator according to common law.

3.5. Grid losses

In order to manage expenses to cover losses in the public transmission grid, an incentive regulation mechanism related to the purchase price of losses was introduced within the framework of TURPE 3. The mechanism for regulated access to historic nuclear power (ARENH) undermines the relevance of this incentive mechanism since, as from 2014, ERDF's energy purchases outside of this regulated mechanism will be highly limited. Accordingly, CRE has not renewed this mechanism in the context of TURPE 4.

In the period of application of TURPE 4, the purchase of energy required to compensate losses will represent almost 10% of the expenses to be covered by the tariff. In the interest of minimising public transmission grid operating costs, CRE consulted stakeholders on the relevance of inciting ERDF to control the volume of losses in the network they use.

The mechanism adopted within the framework of the present tariff provides for a monitoring of the actions undertaken by ERDF to contain the rate of losses in the grid it operates, without subjecting these actions to a financial incentive. In fact, to the extent that to date the influence of ERDF efforts on the loss rate achieved may not be precisely identified, the risk of defining a target trajectory for the reduction in volume of loss which is not relevant cannot be ruled out. Consequently, the implementation of a financial incentive to reduce the amount of electrical losses on distribution networks could involve significant financial risks for both network users and ERDF. This view is shared by the majority of stakeholders who have spoken on this subject in the context of public consultations conducted by the CRE to prepare this tariff.

[14] The LDCs concerned at this date are: ESR, Gérédis, SRD and URM.

The mechanism adopted is based on ERDF's annual report to CRE on the indicators involving both the means implemented by ERDF to reduce the amount of losses and the result of its actions:

- percentage of high-efficiency transformers in the transformers supplied during the year;
- percentage of high-efficiency transformers in the transformers in operation;
- number of cases handled in the framework of actions for detecting non-technical losses (including fraud);
- volume of "corrected" energy in GWh per year;
- rate of technical and non-technical losses on the transmission grids at the close of the time reconciliation process;
- "Accounting" loss rates on the networks operated by ERDF (the "accounting" rate loss notably takes into account the accounting records of periods of time reconciliation and financial flows occurring from M+1 to M+14).

Finally, in order to enable the implementation of a financial incentive to control the amount of losses for the next tariff period, CRE pays particular attention to the research and development program initiated by ERDF to ensure electricity balance. CRE develops monitoring of this work, which will ultimately improve the understanding of factors affecting the volume of losses on distribution networks. This monitoring is based on the ERDF transmission tariff in the early period of a works schedule relating to the reliability of the electricity balance and then an annual report on the actions undertaken by the network operator in the research program relating to the reliability of the electricity balance and their detailed results.

3.6. Investment under ERDF project management

3.6.1. Monitoring of unit costs of investment

From TURPE 2, capital costs were eligible to the CRCP mechanism. Accordingly, ERDF is guaranteed to recover the depreciation and return on investments carried out. It therefore does not bear any financial risk even in the event that the investments exceed assumptions. This regulatory framework is particularly favourable to investments in a context of rebound of investments (*See.* section C.1.1).

Article L. 341-3 of the energy code however provides *that "the tariffs of use of the public transmission grid and public distribution network are calculated […] in order to cover all costs incurred by the operators of these network to the extent that such costs correspond to those of an efficient network."*

If the CRE does not intend to challenge the inclusion of capital costs in the scope of CRCP, it must nevertheless ensure that this regulatory framework does not lead to a shift in investment costs.

In this perspective, in the framework of present tariffs, the CRE has set up monitoring of ERDF unit investment costs. This monitoring is detailed according to the following axes of analysis, among others:

- the voltage range (HVA or LV);
- the construction technique (overhead or underground);
- the geographical zone.

Before the end of 2014, ERDF will transmit to the CRE the list of relevant monitoring indicators, established in consultation with CRE. This list is accompanied by a history of values of these indicators for the widest possible period.

The indicators calculated for year *N* are transmitted by ERDF to the CRE at the latest before the end of the first half of year *N+1*.

3.6.2. Monitoring of "quality and network modernisation investments"

In addition to monitoring unit investment costs, CRE is setting up monitoring of "quality and network modernisation" investment programs.

This monitoring includes for each program the investments values, the nature of the network infrastructure encompassed and, where appropriate, the stock of existing infrastructure remaining to be processed.

Concerning year *N*, this information is transmitted by ERDF to the CRE at the latest before the end of the first half of year *N+1*. Where appropriate, this reporting is accompanied by any evidence to justify the differences between forecasted and actual values.

3.6.3. Smart meters

The development of smart electricity meters in France represents the emergence of the third generation of meters, after the electromechanical "blue" meters and electronic "blue" meters.

This new generation will bring five major advances:

- It will enable the piloting of consumer appliances through functionality defined in consultation with stakeholders gathered together by the CRE and public authorities from 2007 to 2011;
- It will simplify the daily life of consumers (remote reading and remote interventions);
- it will help them control their electricity expenditure by the transmission of more accurate and enriched information;
- It will enable electricity suppliers to propose tariffs tailored to specific needs;
- Finally, smart meters are an essential element in the development of smart grids.

The generalisation of these meters will contribute to the French program of energy transition.

This project requires a significant initial investment over six years and therefore specific financing modalities.

As it has repeatedly stated to ERDF, CRE confirms that given the exceptional nature of this project in its technical, industrial and financial dimensions, it is ready to favourably welcome the request to have an adapted regulatory framework, providing costs recovery smoothing, in order to coincide with the period of realization of the project's expected benefits.

The distribution systems operators in charge of the deployment would bear their share of the risks inherent to this project and its schedule.

The regulator would ensure the realisation of the expected performance of the network operator by appropriate regulation.

Consequently, the regulator would be willing to welcome a remuneration bonus for this project on the lifespan of meters.

In this perspective, this project would be dealt with in an *ad hoc* tariff deliberation.

E. Tariff structure and rules applicable to users of the HVA and LV voltage range

Article L. 341-3 of the French Energy Code states that 3 "*The methodologies used to establish tariffs for the use of public electricity transmission and distribution grids are set by the French Energy Regulatory Commission*." It is completed by Article L. 341-2 of the same code which provides *that "the tariffs of use of the public electricity and public distribution grid are calculated in a transparent and non-discriminatory manner to cover all costs incurred by the operators of these networks to the extent that such costs correspond to those of an efficient network operator."* Lastly, Article L. 341-4 specifies that *"the structure and level of the tariffs for the use of the public electricity transmission and distribution grids are set in such a way as to encourage clients to limit their consumption during periods in which consumption of all consumers is at its highest."*

Within the framework of the legislative provisions quoted above, CRE carried out thorough work on the structure of grid infrastructure costs and the cost of losses, which represent the major portion of total expenses to be covered by the tariffs. The methodology used as well as the results of this work were presented to stakeholders within the framework of CRE's public consultations of 6 March 2012 and 6 November 2012, the summaries of which can be consulted on CRE's website.

The new methodology for constructing the tariffs takes into account the time difference of grid costs depending on the hours of the year and allocates to the different users these costs based on their consumption characteristics. Therefore, users with a high level of consumption during periods in which the consumption of all users is highest bear a major portion of the grid costs. They are therefore encouraged to defer their consumption during grid peak hours to hours during which the grid is least solicited, which will minimise expenses related to the use of public electricity grids in the long term.

This new tariff structure complies both with the principle of non-discrimination of tariffs specified in Article L. 341-2 of the Energy Code and the goal to control energy demands set forth in Article L. 341-4 of the same code.

Before describing in detail the methodology used to construct the present tariffs, CRE wishes to reiterate the general principles on which it based its decision in terms of tariff structure.

1. General principles

To make its tariff decision, CRE has retained the following general principles.

1.1. Tariffs independent of distance

In compliance with the provisions in Article 14, Paragraph 1, of (EC) Regulation No. 714/2009 of 13 July 2009, specifying that network access charges do not depend on the distance separating a producer and a consumer involved in a transaction, CRE has maintained the principle of "postage stamp" pricing, which consists in billing withdrawals at the same price regardless of the origin of the electricity consumed, and billing injections regardless of the destination of the electricity produced.

1.2. Tariff adjusting

Withdrawal rates on public distribution networks are identical across the country. They apply to all operators of public distribution networks, resulting in a geographical averaging of tariffs. Finally, the adjusting of tariffs guarantees social and territorial cohesion by ensuring universal access to energy, in accordance with the energy policy objectives set forth in article L. 100-1 of the energy code.

2. Methodology for constructing tariffs

The new tariff construction methodology is based on the following steps:

2.1. Tariffs based on hourly unit costs

The present tariffs, whether or not they propose different time categories, are defined on the basis of hourly unit costs for the use of the grids. Taking into account hourly unit costs in the tariff construction is carried out in two stages described below.

2.2. Distribution of costs over the different hours of the year

A same withdrawal volume does not result in the same grid costs according to the time of day during which this withdrawal occurs. Analysis of grid costs show that during the hours in which there is a considerable level of transmission in the grids, an incremental withdrawal generates higher incremental costs for losses and infrastructure development than during times when there are fewer loads in the grids.

Grid costs are therefore distributed over the different hours of the year. For each voltage range, unit costs for the use of the grid are calculated for each hour of the year. These hourly unit costs are calculated as the sum of the hourly unit cost of infrastructure and the hourly unit cost of losses. The hourly unit costs of infrastructure are calculated using the average incremental cost resulting from the load increase at each hour of the year. The hourly unit costs of losses are calculated using the electricity spot price profile on the French market, purged of multi-annual trends.

2.3. Allocation of hourly costs among users of the different voltage ranges proportionally to energy flows in the grids

On the basis of the matrix of forecast flows communicated by ERDF and RTE, it is observed that energy is injected mainly at very high voltage to be consumed mostly by users connected to downstream voltage ranges. The energy flows successively use portions of the grid at decreasing voltage levels. Therefore, the downstream grid users contribute, by the flow of energy they generate, a large portion of the costs borne by grid operators for the management of upstream grids. This is why the tariff income received from users covers not only the costs of the voltage range to which they are connected but also a portion of the costs of upstream voltage ranges.

The calculation of this contribution of withdrawals from a voltage range to the costs of upstream voltage ranges is based on the matrix of forecasted flows and the distribution of accounting costs by voltage range, also sent by ERDF and RTE to CRE.

The allocation of costs of one voltage range to downstream voltage ranges is on an hourly basis, the time differentiation of grid costs is passed on to all users.

Once this allocation of hourly costs is carried out among users of different voltage ranges, it is possible to deduct from it - for each voltage range - a global envelope of costs to be covered by all users of this voltage range. This global envelope is then distributed among the users of this voltage range depending on their consumption characteristics.

2.4. Tariffs based on the consumption characteristics of users

All users of the same voltage range do not use electricity in the same manner. Users' consumption characteristics are used to distribute the global envelope of costs allocated to the voltage range to which they are connected. The costs that each type of user generates within the same voltage range depend specifically on the rate of use of subscribed power (that can be referred to as duration of use) and the time distribution of withdrawals over the year.

The majority of users connected to public distribution systems do not yet have metering devices to accurately know their hourly consumption, the consumption characteristics of these users is determined from the usage profiles used in the context of the reconstitution of flow processes.

The rate of use of subscribed power serves to determine a variable component depending on the energy consumed and a fixed component depending on the power subscribed. While the subscribed power is a decisive variable for grid costs, it is not sufficient on its own to determine the costs generated by a user on the grids. It is also important to know the way in which this subscribed power is used: a customer that uses all of its power subscribed during the grids' peak hours generates more grid costs than a customer that uses only a portion of its subscribed power during those times.

The use of hourly grid costs enable the withdrawal profile of the different users to be taken into account in the grid costs allocation process. Consequently, for a same annual consumption volume, a user that consumes at times during which grid costs are high will contribute more to grid costs than a user that consumes at times during which grid costs are low.

For each voltage range, the global envelope of costs is therefore distributed among users connected to the same voltage range depending on the level of their subscribed power, the total volume of energy they withdraw over the year, and the distribution of their subscribed power and the volume of energy withdrawn over the different hours of the year.

The tariffs with time differentiation are defined by distributing costs among the different time categories. In particular, the "energy" component of each time category is designed to be proportional to the average unit cost for the given time category.

2.5. Form of tariff scales

CRE renews all previously existing distribution tariff options, with the exception of the medium-duration use without time differentiation offered to users connected to the LV ≤ 36 kVA voltage range, and bases the time differentiation of these tariffs on the time differentiation of network costs, thereby reconciling the principle of non-discrimination of tariffs listed in Article L. 341-2 of the Energy Code and the desire to control the energy demand in Article L. 341-4 of the same code.

Article L. 341-3 of the French Energy Code, provides that, in the context of its missions on tariffs of use of public electricity networks "*The Energy Regulatory Commission takes into account the energy policy guidelines indicated by the administrative authority*." CRE received the energy policy guidelines by letter dated 10 October 2012. These guidelines shall address the structure of the tariffs proposed to users connected to the LV ≤ 36 kVA voltage range, in the case of the currently hourly-seasonal distribution, the minister stated to committing *"to a structure directing users who have already chosen electric heating to variable tariffs during the day in order to smooth daily peaks."*

In order to better address the concerns expressed in the Minister's letter, while maintaining a satisfactory level of reflection of costs, the medium-duration use option without time differentiation offered to users connected to the LV ≤ 36 kVA voltage range shall be removed.

3. Tariff structure applicable to the use of the public electricity grid in the HVA or LV voltage range

The rules contain 14 sections. The first two define the concepts used and the tariff structure. Sections 3 to 12 describe the tariff components. Section 13 defines the indexation rules of pricing scales. Section14 specifies the transitional provisions applicable to the tariff option subscription and the removal of the average option usage without time differentiation of LV ≤ 36 kVA tariffs.

The rules defined under TURPE 3 are therefore for the most part renewed. However, given the feedback provided by the system operator and the contributions received during CRE's public consultation of 6 November 2012 and 9 July 2013, some provisions of the tariff rules have been modified or completed.

3.1. Definitions

The definitions of the terms "lines" and "user" are completed in order to clarify the terms of application of the present tariffs.

3.2. Tariff structure

Section 2 contains a description of the different categories of expenses to be covered by the present tariffs, the tariff structure established so as to reflect these different categories of expenses and the method for applying the various tariffs at each connection point.

3.3. Management

The terms for billing the administrative management component defined under TURPE 3 have been renewed, namely, explicit billing of management fees in the form of a fixed charge applied to all users (producers, consumers and system operators) depending on the voltage range of their connection.

In order to better reflect the system operator's costs, the annual management component is billed by connection point and by access contract.

Contract management costs are made up of costs related to grid user reception, management of user files, billing, debt recovery and outstanding amounts.

3.4. Metering

Pricing of the metering component applicable to users of medium and low-voltage networks depends on the ownership regime of the meter.

For users who own their metering system, the metering component covers costs:

- for checking that metering equipment is working correctly conducted on the initiative of the system operator;
- for reading or remote reading (including subscription and communication costs;
- for measuring, calculating and recording of metering data;
- for validating, correcting and provisioning validated metering data available.

Metering data is sent to the user or to a third party authorised by the user at a minimum frequency defined according to the subscribed voltage range and withdrawal power to which they have subscribed and/or the connection point's maximum injection power.

For users whose metering system is owned by the system operator or concessionary authorities, the metering component also covers the following costs:

- capital costs of metering devices after deduction of the share of connection contributions regarding metering devices;

- maintenance costs for metering equipment;
- renewal costs for metering equipment;
- where necessary, costs for metering equipment synchronisation.

However, this metering component does not include the cost to change metering systems at users' request or at the request of a third party authorised by the user, which is subject to specific billing under the tariff rules related to additional services provided under the monopoly of the system operator.

Specific tariff provisions are introduced to the metering component applied to users connected to the HVA voltage range and users connected to the LV voltage range having subscribed to a power greater than 120 kVA, in the case where the user, owner of a metering device not complying with the order of 4 January 2012 on metering devices, has refused its replacement.

3.5. Injection

Within the framework of strong development of distributed generation connected to the public electricity distribution grid, in 2011 CRE conducted a study on the costs and benefits generated by photovoltaic power plants on the distribution grids. This study, whose results were presented to stakeholders through the CRE public consultation of 6 March 2012, showed that in the current state of technology, the cost of reinforcing and maintaining the grid to be supported by ERDF could be valued at approximately € 402 million, in a photovoltaic production development scenario of around 6 GW by 2020.

Given the results of this study, CRE considered that a negative injection charge - i.e. which would reward producers connected to the public distribution grid - would not be justified. Information available today does not allow concluding in favour of an injection charge higher than zero. In fact one of the interesting properties of the injection charge is the possibility of introducing a price signal incentive for producers favouring the least expensive investment in grids.

However, the coordination problem between investment in generation capacity and distribution grids must be considered taking into account the inclusion of renewable energy production facilities in the regional patterns of climate, air and energy, which will result in regional patterns of connection to renewable energy networks. CRE considers feedback on regional patterns of grid connection to renewable energy necessary[15] before considering development of the injection tariff structure on public distribution systems.

The injection charge applied to users connected to the public distribution grid is therefore zero for the period covered by this tariff.

3.6. Withdrawal tariff on the HVA voltage range

Users connected to the HVA voltage range have the choice between three pricing options:

- option without time differentiation;
- option with time differentiation of five classes;
- option with time differentiation of eight classes.

Users opting for a tariff with time differentiation will have higher prices applied during peak winter hours, but may benefit from lower tariffs outside this period. The choice of pricing options and level of subscribed power is left to the network user or a third party authorised by them. Public distribution grid operators advise users or third parties authorised by them in choosing the option best suited to their needs.

The monthly subscribed power overrun components (CMDPS) are calculated so that users exceeding their subscribed power by 10% for 100 hours in the same time category will pay their bill as if they had subscribed 10% more power. The renewal of this calculation method maintains users' incentive to subscribe optimum power.

[15] Decree No. 2012-533 of 20 April 2012 relating to regional patterns of connection to renewable energy networks, provided by Article L. 321-7 of the energy code specifies the provisions governing the implementation of these regional patterns.

3.7. Withdrawal tariff on the LV voltage range

For all withdrawal tariffs in the LV voltage range the choice of one of the options depends on power requirements and usage rate of subscribed power. The choice of option pricing and levels of subscribed power is left to the network user or a third party authorised by them. Operators of public distribution networks advise users or third parties authorised on the choice of the option best suited to their needs.

3.7.1. LV > 36 kVA

Users connected to the LV voltage range and a subscribed power strictly greater than 36 kVA can choose between two time differentiation options:

- Medium-duration use option consisting of 4 time classes;
- Long-duration use option consisting of 5 temporal classes;

The choice between these options is carried out on the basis of the use of subscribed power supply rates.

The monthly subscribed power overrun components (CMDPS) are calculated so that users exceeding their subscribed power by 10% for 100 hours in the same time category will pay their bill as if they had subscribed 10% more power. The renewal of this calculation method enables the preservation of users' incentive to subscribe optimum power.

3.7.2. LV > 36 kVA

Users connected to the LV ≤ 36 kVA voltage range can choose between three options:

- Short-duration use;
- Medium-duration use with time differentiation;
- Long-duration use.

3.8. Complementary and back-up power

For complementary and back-up power lines, only the assigned parts are billed. This billing method takes into account the fact that, given the grid dimensioning rules of "*N-1*", it is not possible to distinguish surcharges related to complementary or back-up supply capacity.

A subscribed power overrun coefficient for back-up power, when this is connected to a voltage range that is different to that of the main supply, has been introduced. This provision guarantees that the incentive given to users to subscribe optimal power also applies when they subscribe to back-up power.

3.9. Tariff aggregation of connection points

The consolidation mechanism in application since 1 January 2006 has been renewed for the present tariff period.

3.10. Tariff provisions applicable to public distribution system operators

Public distribution system operators have specific characteristics defined by law and regulations. To include these specific characteristics in the tariffs applicable to the different voltage ranges, the following specific provisions have been maintained:

- transformer use is billed depending on the average direct loads of the transformer station;
- compensation for operating lines with the same voltage as the public grid upstream is determined based on the difference between tariffs in the delivery voltage range and in the upstream voltage range, decreased by the transformer use component and weighted by the parts of these lines operated by the various system operators;
- peak shaving of monthly bills for distributor power overruns is authorised in cases of extreme cold, under the same conditions as TURPE 3.

The definition of the terms l_1 and l_2, used to calculate compensation for operating lines at the same voltage as the public grid upstream are clarified.

3.11. Sporadic use

In order to take into account certain situations when network capacities can transmit power drawn for short periods without any adverse effects for other users, the system for billing scheduled temporary power overruns (DPP) as defined in TURPE 3 has been renewed. These overruns, which must have prior approval by the system operator, are billed at the average price of energy withdrawn by a user with a rate of use of 25 %.

DPP requests are conditioned by the completion of works on the electricity facilities of the requesting party.

The DPP mechanism is transitional so that public distribution system operators are not penalised.

3.12. Reactive power

The specific pricing system applied to reactive energy transit at public distribution grid points of connection to the public transmission grid has been renewed in order to stabilise the volume of HVA capacitors and therefore maintain reactive power capacity production in the public distribution grids.

A scale sets the penalties in the event of exceeding a "*phi tangent*" range contractually agreed by the parties with regard to the rules recorded in the reference technical documentation of the public transmission system operator.

Failing such agreement between the parties, the present tariff rules specify the method for determining the upper limit of the "*phi tangent*" range. This method is based on the use of historical values and provides for the introduction of a limit value.

This limit value is justified in particular by the rapid development of distributed generation and the trend towards natural increase of "*phi tangents*" in the public distribution grids, and avoids excessive differences in treatment between connection points.

3.13. Indexation of the pricing scale

All of the pricing scale coefficients, except the subscribed power weighting coefficient, coefficient *c* of the withdrawal component applicable to the HVA voltage range and the injection component, are indexed during annual tariff changes.

Round-off rules of tariff coefficients are specified.

3.14. Transitional provisions

To enable users to rapidly benefit from incentives from the new distribution tariff structure, as in TURPE3, CRE wishes to establish a transitional measure allowing users connected by HVA and LV - for six months from the date of entry into force of tariffs - to freely choose their tariff options without having to wait for the end of a period of 12 consecutive months from their previous tariff choice. This provision could result in a significant increase in tariff option change requests over a short period of time. Accordingly, certain distribution network operators could require several months to complete the changeover of all concerned users. As a result, the standard period of tariff change service may not be respected.

The removal of the medium-duration use option for users connected to the LV ≤ 36 kVA voltage range could cause congestion of the operators public distribution network information system, insofar as millions of users could be potentially concerned. To overcome this difficulty in operational implementation, these rules introducing transitional measures from 1 January 2014 to 31 July 2014, led to the calculation of the withdrawal component of users who subscribed to a medium-duration use rate before 1 January 2014 on the short-duration use rate of tariff coefficients. For the LV ≤ 36 kVA voltage range, users whose withdrawal component is established at July 31, 2014, based on the medium-duration use rate are deemed to have chosen the short-duration use rate from 1 August 2014.

F. Annexes

1. ERDF's R&D programme

Over the next tariff period, ERDF intends to carry out several innovative subjects to improve its operational efficiency and prepare the deployment of *Smart grids*.

These actions are a response to the challenges ERDF face today, like many distribution network operators throughout Europe:

- management of a large fleet of assets, consisting of ageing infrastructure and on which a large investment program is planned;
- scientific, technological, economic and societal challenges resulting from the increase in the number of stakeholders in the electrical system, the development of renewable energy, changing uses of electricity such as electric vehicles or modes of consumption (controlling demand, management of carbon footprint).

Main R&D projects and ERDF *Smart grids* pilot projects:

Theme "improve the efficiency of the distribution sector profession"

The work on this theme is aimed at improving performance in the management and operation of distribution networks (improved asset management, grid automation to optimise costs and quality and reliability of energy balance). To be noted among these projects are:

Conception of innovative components and optimisation of maintenance

ERDF has initiated significant investment programs to ensure quality of supply (cables, transformers, substation equipment). In parallel, to meet the challenges of ageing components, ERDF develops diagnostic methods and ageing models to optimise maintenance and renewal. The initial findings of the studies, supported by field and laboratory tests are expected in 2015.

Development of automation of the networks

It involves increasing the automation of networks and improving the functions of automatic disaster recovery (self-healing) to reduce downtime. Some functions may be implemented in the driving tools by the end of 2014, other functions will be gradually developed then tested by 2015/2016.

Reliability of the electricity report

As part of the reliability of the electricity report, ERDF has launched a research and development program. All the projects initiated aim to improve the understanding and quality of energy balance and seek to identify and model the various underlying influencing factors. By way of example, ERDF is working on a deconditioning method of losses. This work should help to isolate the overriding factor of the variation of loss represented by the climate and lead to a method of de-seasonally adjusting the loss rate experienced at the end of the time reconciliation process.

Theme "prepare the evolution of distribution businesses"

The work on this theme is aimed at enabling the distributor to facilitate changes in the electrical system: development of renewable energy, changing uses of electricity or consumption patterns. Among the projects noted are:

Integration of distributed generation (wind and photovoltaic) in the network

95 % of electricity generation means from renewable energy sources are connected to the distribution grid, however it was not originally designed to accommodate the production. The objective of R&D is to develop new network architecture and define solutions for the management of these new constraints (local automata and co-ordinated voltage control, for example) in order to control the quality of the electricity distributed. The field experiments in 2014 will validate the first solutions for integration in the tools of conduct in 2015, other functions will be gradually developed and tested by pilot projects in 2016/2017 (including associated equipment).

Electric vehicle recharging

This is to facilitate the development of electric vehicles, by connecting charging equipment to the power grid and by minimising their impact on the peak network load. Significant results, supported by pilot projectpilot projects are expected for the 2015/2017 period.

Preparation for the management of unstable networks

Electricity generation by wind generated and photovoltaic electricity plants being intermittent and low or non-controllable, the network should be tailored to ensure at each moment the balance between production and demand. This is to prepare future electrical systems, by integrating this intermittent generation and taking into account its technical constraints, by promoting the development of means of electricity storage by ensuring a perfect match between local requirements and the security of the national electricity grid and improving protection plans. The first results on local scheduled production and consumption are expected in 2014. More generally, the tools resulting from this program at different time horizons (planning, management planning, real-time) will be progressively developed during the 2017/2014 period and will be used by ERDF to meet the new requirements of players in the electricity distribution system.

Support for the smart Linky meter project and development of related services

The objective is to qualify materials for the *Linky* smart metering project and control the related computer systems, including those for the development of associated services (increased data volume to be processed, cyber-security, interoperability and standardisation). The meter programs will continue to contribute to the validation of the future Linky level (2014/2015). Those related to development of services associated with Linky will continue *at a minimum* up to 2017.

In addition, ERDF participates in European co-ordination and research projects for the preparation for the changing roles and professions of operators of distribution networks:

- Grid+: Support for the European Commission, within the framework of the initiative on the networks (EEGI: European Electricity Grid Initiative), for the development and update of road maps, the definition of performance indicators and the sharing of experience (www.gridplus.eu);
- Meter-On: European project led by the Association of European distributors EDSO for Smart Grids, aimed at comparing solutions for the deployment of advanced metering in Europe;
- EvolvDSO: European research project bringing together distribution network operators, transmission networks operators and universities, whose objective is to develop methods and tools to enable distributors to fulfil their new role as distribution systems operators in the context of distributed renewable generation growth.

The ERDF Smart grid pilot projects program

To go beyond the studies and research projects undertaken by ERDF, it is necessary to experiment with various objects *Smart grids* in real situations in a system approach. The objective of the ERDF *Smart grids* program is to integrate these results into an overall vision of the future network.

Moreover, beyond the conventional network components (electro-technical components and electrical distribution structures), new "active" components will develop: distributed generation means, storage means, dynamic and flexible loads among clients via clearing mechanisms (control of use, new price signals)or live loads on the network (electric vehicles). The behaviour laws of these objects and stakeholders are not purely deterministic and remain to be established through experiments. This is the challenge for pilot projectpilot projects and *Smart grids* pilot projects to measure the response of these objects and stakeholders in real conditions, *in situ*, in particular user acceptability of these new interactions with the network.

In order to answer these questions, a group of pilot projectpilot projects was developed. To date, ERDF is involved in four projects (see table below). These projects are carried out by consortia involving many partners. As part of its continued work on *Smart Grids* and more generally on future networks, ERDF is likely to be involved in new pilot projectprojects in France and in Europe.

Project	Description
Grid4EU	The European Smart Grid project grouping six pilot projects in 6 European countries (www.grid4eu.eu)
Nice Grid	Integration of renewable energy sources, automation of networks, demand management and energy storage (www.nicegrid.fr)
Advanced	Study of the impact of active demand management and related services on distribution networks
Smart Community – Lyon Confluence	Management of electric vehicles, buildings and development of photovoltaic means
Smart Electric Lyon	Implementation of downstream meter solutions (www.smart-electric-lyon.fr)
Greenlys	Smart grid in urban areas, metering connecting inputs for the development and operation of networks (www.greenlys.fr)
Venteea	Integration of the high capacity production of renewable energy in a rural network
Postes Intelligents	Facilitate the interface between network transmission and distribution operators
Issy Grid	Energy optimisation on the scale of a neighbourhood
Houat and Hoëdic	Securing the electrical power supply of the islands by energetic optimised distribution
Smart Grid Vendée	Energy optimisation on the scale of a local authority
IGREENGRid	Insertion of renewable energies (www.igreengrid.com)
So Grid	Development of a CPL communication chain for controlling the distribution network (www.so-grid.com)

These pilot projectpilot projects are spread all over the French territory in order to test the various possible local contexts. This programme also has a European dimension. ERDF is the GRID4EU Coordinator, the large-scale European research and demonstration project of smart grid effect and participates in European projects such as IGREENGrid the massive integration of decentralised generation on distribution networks, active demand management.

In all, one hundred partners collaborate on these pilot projects. These partners come from the world of energy (suppliers, network operators ...), the electrical industry, the communication and information technologies domain, research laboratories and innovative start-ups, etc.

This project portfolio is constructed so as to handle all issues related to *Smart grids:*

The subjects studied in the pilot projects are numerous. They can be cited, but are not limited to:

- technical solutions to integrate renewable energies in the grid: state estimation, development of network observability solutions, new network automation functions, voltage regulation, storage and modulation of the production and consumption;
- active demand management: architecture and technical solution tests for coordination between the actors involved (subscribers, transmission and distribution network operators, "flexibility suppliers"), analysis of the acceptability of clients to these new stimuli, "modelling" of client behaviour, resource appraisal modulation of potential demand and impact of removals on the load curve, *etc.*;
- the capacity to optimise "real time" operation, taking into account the flexibilities present on the network (distributed generation, consumption, removals, etc..): rapid decision support algorithms, performance of measurement systems in the field and performance and communication systems;
- management planning: anticipation of potential constraints caused by variations in consumption and local production on the distribution network, identification then activation of the most efficient levers to overcome these constraints (changing patterns of conduct, setting the voltage, tariff signals, *etc.*);
- the impact of electric vehicle recharging on the distribution network: study and testing of smart charging of electric vehicles, integrating the needs of users and the network operator;
- the use of data collected (metering, network) to enrich studies, tools and methods for planning and network development: the capacity to handle large volumes of data ("big data" issues).

The first projects were launched in 2011. The entire program should run over the 2011-2017 period. The first experiments have started and the first results are expected in 2014.

2. Quality of service

2.1. ERDF

2.1.1. Financially incentivised indicators

a. Scheduled appointments not respected by the ERDF

Calculation	<u>*Number of scheduled appointments not kept by the DSO (Distribution Network Operator) and which gave rise to payment of a penalty by the DSO during the quarter, by user category*</u>
Scope	- All appointments scheduled therefore validated by the DSO - All appointments for procedure with DSO agent visit and requiring the presence of the user, not respected because of the DSO
Follow up	- Calculation frequency: Quarterly - Frequency of transmission to CRE: Quarterly - Calculation frequency: Quarterly
Objective	100 % of appointments not carried out: - Up to 31 December 2014: all appointments not carried out, reported by suppliers *via* EMS portal or by the users - from 1st January 2015: all appointments not kept automatically identified by the DSO
Incentives	- The amount of penalties identical to that invoiced by ERDF in case of non-execution of a scheduled action due to the user or supplier (absence from appointments, *etc.*) - Payment for the benefit of the end user *via* the supplier for single contract users or directly to the user in the case of users who entered into a direct access contract with the DSO
Date of commissioning	- Already implemented since 1st Aug 2009 - Commissioning on 1st January 2015 of the systematic payment of the penalty following automated detection of appointments not kept by the DSO.

b. The rate of commissioning with visit completed within the requested time frame

Calculation	<u>*Number of commissionings on existing system with visit concluded during the month M, carried out within the required time (if this delay is greater than the catalogue delay due to the user) or carried out in a deadline less or equal to the catalogue deadline (if the deadline requested by the user is less or equal to the catalogue deadline) / total number of commissionings closed within the SGE during the month M*</u>
Scope	- All commissionings with visit on existing installation concluded within the month, excluding express commissioning
Follow up	- Calculation frequency: Monthly - Frequency of transmission to CRE: Quarterly - Calculation frequency: Quarterly - Frequency of incentive of calculations: annual
Objective	From 1st January to 31 December 2014: - Base objective: 83 % - Target objective: 88 % From 1st January to 31 December 2015: - Base objective: 85 % - Target objective: 90 % From 1st January to 31 December 2016: - Base objective: 87 % - Target objective: 92 % From 1st January to 31 December 2017: - Base objective: 89 %

	- Target objective: 94 %
Incentives	- Penalty: 40 000 € per calendar year per tenth of a point below the basic objective - Bonus: 40 000 € per calendar year per tenth of a point below the target objective - CRCP payment
Date of implementation	1st January 2014

c. Electricity index rate reading and remote-reading every six months:

Calculation	*Number of meters read or remote-read during the month M/number of meters to be read every six months during the month M*
Scope	- All meters read or remote-read - Electricity meters only
Follow up	- Calculation frequency: Monthly - Frequency of transmission to CRE: Quarterly - Calculation frequency: Quarterly - Frequency of calculations of incentives: Annual
Objective	- Base objective: 94.8 % per calendar year - Target objective: 95.2 % per calendar year
Incentives	- Penalty: 40 000 € per calendar year per tenth of a point below the basic objective - Bonus: 40 000 € per calendar year per tenth of a point below the target objective - CRCP payment
Date of commissioning	1st January 2014

d. Transmission deadline to RTE of half-hourly measurement curves of each Balance Responsible Entity

Calculation	*Rate of compliance of deadline of sending to RTE of the Global Assessments Consumption Balance Responsible reported assets (including sites) on the ERDF network for week S-2 to week S*
Scope	The following measurement curves (MC): - cumulative MC of consumption from remote-read MC sites - cumulative MC of consumption from indexed sites (profiled) - cumulative MC of production from remote-read MC sites - cumulative MC of production from indexed sites (profiled)
Follow up	- Calculation frequency: quarterly - Frequency of transmission to the CR: quarterly - Calculation frequency: quarterly - Frequency of incentive calculation: Annual from the entry into force of tariffs
Objective	- Base objective: 96 % per calendar year - Target objective: 100 % per calendar year
Incentives	- Bonus: 50 000 € per calendar year if the performance is 100 % - Penalty: 5 000 € per calendar year per tenth of a point below the basic objective - CRCP payment
Date of commissioning	Commissioned since 1st Aug 2009

e. The rate of response to complaints within 15 calendar days;

Calculation	(N1 + N2) / D With: - N1: number of claims, excluding claims relating to the quality of supply, closed in the month M whose response time (closing date in SGE 'information hub') is less than or equal to 15 calendar days after the filing date in SGE - N2: number of claims relating to the quality of power supply closed in the month M for

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	which a letter of expectation or consistent response was sent on a date less than or equal to 15 calendar days after the filing date in SGE - D: number of claims closed in SGE during the month M
Scope	- All complaints sent directly by users or via suppliers whose response shall be conducted by the DSO, closed in SGE - All claim transmission media whether written or oral entered in SGE - All categories of users - Closed claim: claim for which a "consistent" response (no acknowledgement of receipt) was sent by the DSO
Follow up	- Calculation frequency: Monthly - Frequency of transmission to CRE: Quarterly - Calculation frequency: Quarterly - Frequency of calculation of incentives: annual
Objective	Base objective: - 85 % from 1st January 2014 to 31 December 2014 - 87 % from 1st January 2015 to 31 December 2015 - 90 % from 1st January 2016 to 31 December 2016 - 95 % from 1st January 2017
Incentives	- Penalty: 40 000 € per calendar year per tenth of a point below the basic objective - CRCP payment
Date of commissioning	1st January 2014

f. Number of claims processed within a deadline greater than 30 calendar days

Calculation	*<u>Number of claims closed in SGE (information hub) during the month and whose response time (closing date in SGE) is greater than or equal to 30 calendar days after the SGE filing date</u>*
Scope	- All complaints sent directly by users or via suppliers whose response shall be carried out by the DSO, closed in SGE - All claim transmission media whether written or oral entered in SGE - All categories of users - Closed claim: claim for which a "consistent" response (no acknowledgement of receipt) was sent by the DSO
Follow up	- Calculation frequency: Monthly - Frequency of transmission to CRE: Quarterly - Calculation frequency: Quarterly
Objective	100% of claims received directly from users or *via* the suppliers processed within 30 calendar days
Incentives	- Penalty: 30 € for each claim non-processed within 30 days - CRCP payment
Date of commissioning	1st January 2014

g. Number of penalties paid for sending outside the connection proposal deadline

Calculation	*<u>Number of penalties for connection proposals not submitted within the maximum deadline, resulting from the qualification of the application (in accordance with the procedures for processing connection requests) which gave rise to payment of a penalty during the quarter</u>*
Scope	- 100% of connection proposals not submitted within the deadline, by user claim - All the connections in injection and withdrawal
Follow up	- Calculation frequency: Quarterly - Frequency of transmission to CRE: Quarterly - Publication frequency: Quarterly

Incentives	- Penalties:
	  - 30 € for LV ≤ 36 kVA connections
	  - 100 € for LV ≤ 36 kVA connections and collective in LV
	  - 1,000 € for HVA connections
	- Payment: on request, to the connecting applicant, or the agent in the context of a specific representation mandate
	- The amounts and terms of penalty payments shall be visible and detailed in the connection procedures as well as in the contractual documents

Date of implementation	Already implemented since 1st Aug 2009

h. Number of penalties paid for the provision of connections not carried out on the date agreed with the user

Calculation	*Number of claims for connections not carried out on the date agreed with the user which gave rise to payment of a penalty during the quarter*
Scope	- 100% of connections not available on the date agreed with the user, by user claim - All connections on withdrawal or injection
Follow up	- Calculation frequency: Quarterly - Frequency of transmission to CRE: Quarterly - Calculation frequency: Quarterly

Incentives	- Penalties:
	  - 50 € for LV≤ 36 kVA connections
	  - 150 € for LV ≤ 36 kVA connections and LV collective
	  - 1 500 € for HVA connections
	- The amounts and terms of penalty payments shall be visible and detailed in the connection procedures as well as in the contractual documents
	- Payment: on claim, to the connection applicant, or agent under a specific representation mandate

Date of commissioning	1st January 2014

i. Supplier portal availability rate

Calculation	*Hours of availability (excluding planned downtime) during the week S / number of hours of SGE portal opening (opening hours are from 7am to 7 pm from Monday to Saturday except public holidays) during week S*
Scope	- SGE portal only, all features accessible from suppliers - Causes of downtime: everything preventing, hindering or slowing down in a significant manner - the use of the portal by suppliers, scheduled or not
Follow up	- Frequency of calculation: Daily - Frequency of transmission to the CRE: quarterly - Frequency of publication: quarterly - Frequency of the incentive calculation: daily and annual (from the coming - into force of tariffs)
Objective	- Base objective: 96 % per week - Target objective: 99 % per year
Incentives	- Penalty: 10 000 € per week below the base objective - Bonus: 40 000 € per calendar year per tenth of a point above the target objective
Date of commissioning	Already commissioned since 1st Aug 2009

2.1.2. *Indicators the object of a follow up*

a. Indicators relating to interventions

Label of the indicator	Calculation of the indicator	Calculation frequency	Date of commissioning
Rate of cancellations conducted in the deadlines requested by user category	Number of user initiative cancellations closed and carried out within the required time (if this deadline is greater than the catalogue deadline due to the user) or carried out in the catalogue deadline (if the deadline limit requested by the user is less or equal to the catalogue deadline) / total number of terminations closed during the month	Monthly	1st January 2014
Rate of cancellations in increments of deadline and by category of user	Number of cancellation incidents closed and carried out in the month in the predefined deadline / Number of cancellation incidents closed and carried out in the month	Monthly	Already implemented
Rate of commissioning conducted in the deadlines requested by category of users	Number of commissionings closed and carried out within the users requested deadline (if this deadline is greater than the catalogue deadline due to the user) or a catalogue deadline (if the deadline requested by the user is less or equal to the catalogue deadline) / Total number of commissioning cases closed and carried out during the month	Monthly	1st January 2014
Rate of commissioning by increments conducted in the deadlines and by category of users	Number of commissionings carried out on existing closed installations in the month and in the predefined deadline / Number of incidents of commissionings closed and carried out in the month	Monthly	Already implemented
Rate of supplier changes conducted in the deadlines requested by category of users	Number of supplier changes closed and carried out within the users requested deadline (if this deadline is greater than the catalogue deadline due to the user) or the catalogue deadline (if the deadline requested by the user is less or equal to the catalogue deadline) / Total number of supplier changes terminated and carried out during the month	Monthly	Already implemented
Rate of supplier changes	Number of supplier changes	Monthly	Already implemented

conducted in the increments of deadlines and by category of users	closed and carried out in the month in the predefined deadline limit / Number of supplier changes closed and carried out in the month		

b. Indicators relative to the relation with the users

Label of the indicator	Calculation of the indicator	Calculation frequency	Date of implementation
Number of complaints received by the DNO by type and user category;	Number of user complaints received by the DNO during the quarter for each of the following: - Reception - Quality of treatment of the service requested - Quality and continuity of supply - Works and connection - Reports and invoicing routing	Quarterly	Already implemented
Number of complaints received by the DNO directly from the users	Number of complaints sent directly by the users to the DNO during the quarter.	Quarterly	1st January 2014
Response rate to complaints within 15 calendar days by type and category of users	Number of complaints closed within the month for which the date of response (closing date in EMS) is less than or equal to 15 calendar days after the filing date in SGE / Number of complaints closed in the month	Monthly	1st January 2014
Response rate to complaints within 30 calendar days by type and category of users	Number of complaints closed within the month for which the date of response (closing date in SGE) is less than or equal to 30 calendar days after the filing date in SGE / Number of claims closed in the month	Monthly	Already implemented
Response rate to complaints within a deadline exceeding 60 calendar days by type and category of users	Number of complaints closed in the month in which the response date (closing date in SGE) is greater than 60 calendar days after the filing date in SGE / Number of complaints closed in the month	Monthly	1st January 2014
Rate of multiple complaints	Number of multiple complaints for the same connection point and the same type of complaint / total number of complaints	Monthly	1st January 2015

c. Indicators relating to the relationship with suppliers

Label of the indicator	Calculation of the indicator	Calculation frequency	Date of implementation
Rate of accessibility of the supplier-dedicated phone line	Number of calls answered (by an advisor) under "urgent business" of routing receptions	Quarterly	Already implemented

	during the quarter / Number of calls to be handled during the quarter under "urgent business" of routing receptions during the quarter		

d. Indicators relating to the reading and invoicing

Label of the indicator	**Calculation of the indicator**	**Calculation frequency**	**Date of implementation**
Rate of meters with at least one reading on actual index in the year for LV ≤ 36 kVA users	(Number of meters to be read - Number of meters with two absences or more at reading) / Number of meters to be read in the quarter	Quarterly	Already implemented
Rate of published monthly readings on actual index for LV ≤ 36 kVA and HVA users on a single contract	Number of LV ≤ 36 kVA and HVA withdrawal meter readings published on actual index during the month / Number of LV ≤ 36 kVA and HVA withdrawal meters to be read during the month	Monthly	Already implemented
Absence rates of 3 times and more of LV ≤ 36 kVA users at reading	Number of unread meters (3 times or more) due to the absence of the client /Number of meters to be read during the month	Quarterly	Already implemented
Rate of indexes corrected for LV ≤ 36 kVA users	Sum of "Asset Adjustment Bills" on the grounds of "Restatement of index" excluding source "Fraud" issued during the month / Total of monthly readings	Monthly	1 January 2014

e. Indicators relative to connectors

Label of the indicator	**Calculation of the indicator**	**Calculation frequency**	**Date of implementation**
Rate of Electricity Connection Receptions telephone accessibility	Number of calls taken during the quarter / Number of calls received during the quarter	Quarterly	Already implemented
Average time of submitting the connection proposal by user category	Amount of time for submission of connection proposal from the qualification of the request / Number of connection proposals issued during the quarter	Quarterly	Already implemented
Rate of connections completed per user category and per period of completion of the work	Rate of connections completed per user category and per deadline for completion of the step between the date of reception of the agreement on proposal for connection and the order of service of the	Quarterly	Already completed but adjustment of deadline increments

	municipality if any, and the actual date of availability for all cases in which the provision has occurred in the quarter		
Average time of completion of connection works by user category	Sum of connection works completion deadlines for all cases in which the provision has occurred in the quarter / total number of cases in which the provision occurred in the quarter	Quarterly	1 January 2014
Rate of proposals of connections submitted after the deadline per user category	Number of connection proposals not submitted within a maximum deadline resulting from qualification of the application (in accordance with the procedures for processing connection requests) / Number of connection proposals issued during the quarter	Quarterly	Already implemented
Rate of compliance of the agreed date of commissioning of works by category of users.	Number of connections provided at the date agreed with the user / Number of connections provided during the quarter	Quarterly	Already implemented
Number of compensations paid under the Decree No. 2012-38 of 10 January 2012 for electricity producing facilities from renewable energy power sources ≤ 3 kVA for the submission deadline of the connection agreement	Number of complaints for delays in submitting the connection agreement established by the decree that led to the payment of compensation in the quarter	Quarterly	1 January 2014
Number of compensations paid under the Decree No. 2012-38 of 10 January 2012 for electricity producing facilities from renewable energy power sources ≤ 3 kVA for the deadline for completion of the connection work	Number of complaints for delay in completion of the connection established by the decree that led to the payment of compensation in the quarter	Quarterly	1 January 2014

2.2. Local distribution companies of over 100 000 clients and EDF SEI

The methods for calculating the indicators can be adapted to the specificities of ELD (Local distribution companies) or EDF SEI.

2.2.1. Financially incentivised indicators

a. Scheduled appointments not respected by the DNO

Calculation	*Number of scheduled appointments not kept by the DNO and which gave rise to payment of a penalty by the DNO during the quarter, per user category*

Scope	- All appointments scheduled therefore validated by the DNO - All appointments for procedure with visit by a DNO agent and requiring the presence of the user, not respected because of the DNO
Follow up	Calculation frequency: Quarterly Frequency of transmission to CRE: Quarterly Calculation frequency: Quarterly
Objective	100% of missed appointments reported by users or suppliers
Incentives	The amount of penalties identical to those invoiced by DNOs in case of non-execution of a scheduled action due to the user or supplier (absence from appointments, etc.)
Date of commissioning	1st January 2014

b. Number of penalties paid for connection proposals submitted after the deadline

Calculation	*Number of penalties for connections not submitted within a maximum period resulting from qualification of the application (in accordance with the procedures for processing connection requests) which gave rise to payment of a penalty during the quarter*
Scope	100% of connection proposals not submitted within the deadlines, by user claim
Follow up	- Calculation frequency: Quarterly - Frequency of transmission to CRE: Quarterly - Calculation frequency: Quarterly

Incentives	- Penalty paid directly to clients on claims for each submission delay of the connection proposal not carried out, the amounts in this case are:
	  - 30 € for LV ≤ 36 kVA connections
	  - 100 € for LV ≤ 36 kVA connections and LV collective
	  - 1,000 € for HVA connections
	- Payment: to the connection applicant, or the agent under a specific representation mandate
	- The amounts and terms of penalty payments shall be visible and in a detailed manner in the connection procedures as well as in the contractual documents

Date of implementation	Implementation: 1st January 2014

2.2.2. Indicators that are monitored

Label of the indicator	Calculation of the indicator	Calculation frequency	Date of implementation
Number of complaints received by type and user category;	Number of user complaints received by the DNO during the quarter for each of the following types: - Reception - Quality of treatment of the service requested - Quality and continuity of supply - Works and connection - Reading and invoicing of routing	Quarterly	1 January 2014
The rate of response to	Number of complaints	Quarterly	1 January 2014

complaints within 30 days;	whose date of response is less than or equal to 30 calendar days after the date of receipt of the claim by the distributor / Number of complaints closed during the quarter		
Rates of meters with at least one reading on actual index in the year for LV ≤ 36 kVA consumers	(Number of meters to be read - Number of meters with two absences or more at reading) / Number of meters to be read in the quarter	Quarterly	1 January 2014
Rate of proposals of connections submitted after the deadline per user category	Number of connection proposals not sent within a maximum period resulting from the qualification of the application (in accordance with the procedures for processing connection requests) / Number of connection proposals issued during the quarter	Quarterly	1 January 2014
Rate of compliance of the agreed commissioning date of works per category of users.	Number of connections available by the date agreed with the user / Number of connections available during the quarter	Quarterly	1 January 2014

Tariff rules for the use of a medium or low -voltage public electricity grid

1. Definitions

For the application of these rules, the terms mentioned below have the following meanings

1.1. Absorption of reactive power

Transit of reactive electrical energy via the connection point used to serve the user of the public electricity grid.

1.2. Power supply

If users are connected to the public grid by several connection points, the main, complementary and back-up power sources should be identified in a contract with the operator of the public system to which they are connected.

1.2.1. Main power supply

A user's main power supply or supplies must ensure that the user is supplied with the withdrawal power to which they have subscribed and/or the maximum injection power agreed under normal operating conditions of the user's electrical equipment. Normal operating conditions are contractually agreed between the user and the public network operator to which they are connected, in compliance with quality commitments included in the corresponding access contract.

1.2.2. Back-up power supply

A user's power supply is a back-up power supply if it is a live circuit that is only used for the transfer of power between the public network and the installations of one or more users in the event of unavailability of all or part of their main and complementary power supplies.

The assigned part of a back-up power supply is the part of public grids which is only crossed by flows with as destination one or more connection points of one or more back-up power supplies of this user or another user.

Flows taken into account to establish the assigned part of back-up power supplies are those which are established under normal operating conditions in the event of unavailability of all or part of other power supplies for the user's electrical equipment agreed by contract with the public system operator to which they are connected given the typology of the public grid and whatever operations the operator may be carrying out on them.

1.2.3. Complementary power supply

A user's power sources which are neither main power supplies nor back-up power supplies are deemed to be the user's complementary power supplies.

The assigned part of a complementary power supply of a user is the part of the public grid which is only used by electricity flows originating from or with the destination of one or more connection points belonging to this user.

Flows incorporated to establish the assigned part of complementary power supplies are those which are established under normal operating conditions of the electrical equipment of the user agreed to by contract with the operator of the public grid to which they are connected, given the public grid topology and whatever operations their operator may be carrying out.

1.3. Cell

A cell is a set of electrical switch gears installed in an electrical substation and which consists of a main switching device (normally a circuit breaker), one or more isolating switches, voltage and current transformers and protection devices.

1.4. Time category

For any tariff for the use of public electricity grids, the time category is the set of hours in the year to which the same tariff coefficient is applied.

1.5. Grid access contract

A grid access contract is the contract referred to in Articles L. 111-91 to L. 111-95 of the French Energy Code, which defines the technical, legal, and financial terms for user access to a public transmission or distribution grid to withdraw and/or inject electrical power. It is signed with the public system operator either by the user or by the supplier on the user's behalf.

1.6. Measurement curve

A measurement curve is a set of average values stamped with the hour and date for a variable measured over consecutive integration periods of the same duration. The load curve is a curve measuring the active energy withdrawn

Integration periods are consecutive intervals of time of the same duration during which average values of an electrical variable varying over time are calculated. When the current rules state that the variables are calculated per integration period, the value of these variables is reduced for each integration period to their average value during this period.

1.7. Metering system

A metering system is composed of all the active and/or reactive energy meters at a given metering point, including cabinets, boxes and panels, as well as, if needs be, the following complementary items of equipment assigned to it: low-voltage and current transformers (CT), pricing signal receivers, synchronisation systems, devices for pricing conversion of metering data, communication interfaces for meter reading, control systems to limit demand, and test boxes.

A smart meter is a metering device connected to telecommunication networks which can be configured and read from remote information systems managed by the public network operator. The reading and flow control at the connection point of the installation are carried out in an automated manner.

1.8. Voltage range

The AC voltage ranges of public transmission and distribution grids are defined in the below table:

<table>
<tr><th>Connection voltage
(U_n)</th><th colspan="3">Voltage range</th></tr>
<tr><td>$U_n \leq 1$ kV</td><td colspan="2">Low-voltage (LV)</td><td>Low-voltage range</td></tr>
<tr><td>1 kV < $U_n \leq$ 40 kV</td><td>HVA 1</td><td rowspan="2">Medium-voltage range (HVA)</td><td rowspan="5">High-voltage range</td></tr>
<tr><td>40 kV < $U_n \leq$ 50 kV</td><td>HVA 2</td></tr>
<tr><td>50 kV < $U_n \leq$ 130 kV</td><td>HVB 1</td><td rowspan="3">High-voltage range (HVB)</td></tr>
<tr><td>130 kV < $U_n \leq$ 350 kV</td><td>HVB 2</td></tr>
<tr><td>350 kV < $U_n \leq$ 500 kV</td><td>HVB 3</td></tr>
</table>

The tariffs for the use of public electricity grids applicable to users connected to public grids in the HVA 2 voltage range are those of the HVB 1 voltage range. Within all these rules, the tariffs applicable to users connected to public grids in HVA 1 voltage range are labelled HVA voltage range tariffs.

1.9. Supply of reactive power

Transit of reactive electrical energy through the connection point for public electricity grid supply by the user.

1.10. Index

Energy index represent the time integration of the root mean square values of power, separately for each quadrant, from a selected time origin.

1.11. Active power injection

Transit of active electrical energy through the connection point for public electricity grid supply by the user.

1.12. Busbar

Three-phase set of three metallic bars or three conductors, each making up a set of points with equal voltage, common to each phase of a three-phase system. Buses are used to connect equipment together (devices, lines, wires). A busbar is not an electrical line (as defined below) for the purpose of these tariff rules.

1.13. Electrical line

An electrical line is composed of a circuit, a set of conductors and, if needs be, an overhead earth wire.

However, when a transformer and a busbar are situated within the same substation or within two adjoining substations, the circuit connecting the transformer to the busbar is not an electrical line for the purposes of the present tariff rules, but is an integral part of the transformers.

1.14. Transformers

Transformers are devices located at the interface between two different voltage ranges on public electricity grids.

1.15. Connection points

A user's connection point(s) on the public grid coincides with the ownership limit between the user's electrical equipment and the public grid electrical equipment, normally corresponding to the boundary of the electrical equipment, marked off by a disconnecting device. A disconnecting device is a device able to interrupt non-zero current flows between the two extremities of the device.

For the application of the current rules, for a user with several connection points on the public grid, it is considered that all or part of these points are mixed, if under normal operating conditions of the user's electrical equipment contractually agreed with the public system operators, they are connected by this user's electrical equipment to the connection voltage.

1.16. Profiling

System used by the public network operators to calculate the consumption or production, half-hour by half-hour of users for whom the recovery of flow is not carried out from a measurement curve with a view to identification of the differences responsible for their balance. This system is based on the determination, for categories of users, of their consumption or production form (profiles).

1.17. Active power (P)

Active power *P* refers to the average energy flow at a steady state at any point of the electricity grid.

1.18. Apparent power (S)

Apparent power *S* represents the amplitude of the signal of instantaneous power at any point of the electricity grid.

1.19. Reactive power (Q) and reactive energy

Reactive power *Q* is equal to active power multiplied by the *tg* φ ratio.

Reactive energy refers to all reactive power *Q* over a set period of time. Reactive energy is stored in the form of an electromagnetic field within electricity grids, but is not consumed by users.

1.20. Phi tangent (tg φ) ratio

The phi tangent (*tg* φ) ratio measures, at any point of the electricity grid, the phase displacement of voltage and intensity signals. The *tg* φ ratio is an important parameter for the operation and safety of the electricity grid.

1.21. Withdrawal of active power

Transit of active electrical energy through the connection point to supply the public electricity grid user.

1.22. User

A public transmission or distribution system user is any private individual or any legal entity, especially public system operators, directly supplying this public grid or directly served by this grid. Interconnection circuits are not considered as users under the present rules.

2. Structure of the tariffs for the use of public grids

The below tariffs are expressed without any deduction or taxes applicable to the use of public electricity grids including the pricing contribution mentioned in article 18-I of the amended law No. 2004-803 of 9 August 2004 on the public electricity and gas service and companies in the electricity and gas sectors.

Pursuant to Article L. 341-2 of the French Energy Code which states that "*the tariffs for using the public transmission network and the public distribution networks shall be calculated in a transparent and non-discriminatory manner and shall cover all costs borne by the operators of these networks insofar as such costs correspond to those of an efficient network operator*" the tariffs cover in particular:

- costs related to the constitution of operating reserves which consist of costs related to the acquisition by public system operators of ancillary services for voltage control and costs for constituting primary and secondary reserves for frequency control;
- costs related to operating the balance responsible entity system for electricity consumption and/or generation sites with a connection point on the public transmission and distribution grids;
- costs for metering, inspection, reading, validation and transmission of metering data;
- the share of costs of additional services provided under the monopoly of public system operators not covered by the tariffs for these services;
- the share of public electricity grid extension costs not covered by the contributions paid to public system operators when they are the contracting authority of the connection work.

An exception is also made for certain specifically identified services provided at a user's request or resulting from their own doing, which are billed separately, in particular in line with the terms laid out in the decision(s) approving the tariff proposal(s) regarding additional services provided under the monopoly of public electricity system operators in application, for the share of their costs that are not covered by the tariffs for the use of public electricity grids defined in sections 3 to 12 hereafter.

The grid access contract stipulates the user's connection point(s) on the public grid concerned and the tariff applied. For each connection point, it also specifies the connection voltage range, subscribed withdrawal power and the metering system deployed. Subscribed withdrawal power is defined at the beginning of a period of twelve consecutive months for this whole period. The network access contract describes conditions under which the subscribed withdrawal power capacity can be changed during this period.

At each connection point, the annual price paid for the use of a public electricity grid is the sum of the following items:

- the annual administrative management component(s) (CG) ;

- the annual metering component(s) (CC) ;
- the annual injection component(CI) ;
- the annual withdrawal component (CS) ;
- the monthly components for subscribed power overruns (CMDPS);
- the annual component for complementary and back-up power supplies (CACS);
- the component for tariff aggregation of connection points (CR);
- for public grid operators, the annual component for transformer use (CT), compensation for operating lines at the same voltage as upstream of the public grid and load peak shaving in extreme cold weather;
- the annual component for sporadic scheduled overruns (CDPP);
- the annual reactive energy component (CER).

These components are applied notwithstanding any provision to the contrary in specifications, franchise agreements and contracts, especially those concerning the billing of operating, maintenance and replacement costs.

Only the energy corresponding to physical flows measured at the connection point concerned is used to calculate annual injection and withdrawal components, measured per integration period by the contractually agreed metering system.

3. Annual administrative management component (CG)

The annual administrative management component in the grid access contract covers the costs of managing user files, physical and telephonic reception of clients, billing and debt recovery. Its amount depends on the conditions of establishment of this contract by the concerned public network operator either directly with a user of this network, or with the exclusive provider of the site of a user of the network under Article L. 111-92 of the energy code.

The annual management component of an access contract concluded by an exclusive supplier is also applicable to:

- consumers who have not exercised the right granted in Article L. 331-1 of the French Energy Code;
- users who benefit from a purchase price prior to the amended law No. 2000-108 of 10 February 2000.

The annual management component a_1 is determined for each connection point of one or more main power supplies and for each access contract, in line with table 1 below:

Table 1

a_1 (€/year)	Grid access contract signed by user	Grid access contract signed by supplier
HVA	723.24	69.84
LV > 36 kVA	348.84	55.92
LV ≤ 36 kVA	34.80	9.00

4. Annual metering component (CC)

The annual metering component covers the costs of metering, inspection, reading, transmission of metering data (submitted to the user or an authorised third party at minimum intervals defined in tables 2.1 and 2.2 below), and, if needs be, rental and maintenance costs and application of profiles to users fitted with meters without recording the measurement curve.

It is determined depending on the technical characteristics of metering systems and services requested by the users, in line with the tariffs below. Variables measured by the user's measuring and testing equipment must provide for calculation of annual components included in the tariff for the use of public grids.

The annual metering component is determined for each metering system and for each access contract according to tables 2.1 and 2.2 below, depending on the ownership of the metering system.

In the absence of metering systems, the public network grid operators may provide for transparent and non-discriminatory terms for estimating injected or withdrawn energy flows and subscribed power, according to the rules published in their technical reference documentation. In this case, the annual metering component equals € 1.20 / year.

4.1. Metering systems owned by the public electricity system operator or concessionary authorities

The annual metering component billed to users whose metering system belongs to the public system operator or concessionary authorities is defined in table 2.1 below, according to the voltage range, subscribed withdrawal power and/or maximum injection power, power control and variables measured (index or measurement curve).

Table 2.1

Voltage range	**Power (P)**	**Minimum transmission frequency**	**Power control**	**Values measured**	Annual metering component €/year
HVA	-	Monthly	Overrun	Measurement curve	1,222.32
				Index	519.36
LV	-	Monthly	Overrun	Measurement curve	1 222,32
	P > 36 kVA	Monthly	Overrun	Index	402.96
			Circuit-breaker		321.00
	18 kVA < P ≤ 36 kVA	Bi-annually	Circuit-breaker	Index	22.92
	P ≤ 18 kVA	Bi-annually	Circuit-breaker	Index	19.08
	P ≤ 36 kVA	Bi-monthly	Smart meter	Index	19.08

4.2. Metering systems owned by users

The annual metering component billed to users that own their metering system is defined in table 2.2 below, according to the voltage range, subscribed withdrawal power and/or maximum injection power, power control and variables measured (index or measurement curve).

However, for users connected to the HVA and the LV voltage range who have subscribed to a power greater than 120 kVA, in the case where the user owns a metering device not conform to the provisions of the decree of 4 January 2012 relating to metering devices refused its replacement, the annual metering component billed to the user is defined in Table 2.1 of Section 4.1 above, according to the voltage range, subscribed withdrawal power and/or maximum injection power, power control and variables measured (index or measurement curve).

Table 2.2

Voltage range	**Power (P)**	**Minimum transmission frequency**	**Power control**	**Values measured**	Annual metering component €/year
HVA	-	Monthly	Overrun	Measurement curve	572.52
				Index	157.08
LV	-	Monthly	Overrun	Measurement curve	572.52
	P > 36 kVA	Monthly	Overrun	Index	143.76

			Circuit-breaker		150.00
	18 kVA < P ≤ 36 kVA	Bi-annually	Circuit-breaker	Index	9.12
	P ≤ 18 kVA	Bi-annually	Circuit-breaker	Index	9.12

5. Annual injection component (CI);

The annual injection component is determined at each connection point, depending on the active energy injected on the public grid, according to table 3 below:

Table 3

Voltage range	c€/MWh
HVA	0
LV	0

6. Annual withdrawal components (CS) and monthly components for subscribed power overruns (CMDPS) in the HVA voltage range

For the establishment of their annual withdrawals component in the HVA voltage range, users choose for each connection point and for an entire period of 12 consecutive months except transitional provision contained in section 14, one of the three following tariffs:

- optional tariff without time differentiation;
- optional tariff with time differentiation of 5 classes;
- optional tariff with time differentiation of 8 classes;

6.1. Optional tariff without time differentiation;

Users choose a subscribed power, $P_{Subscribed}$ in multiples of 1 kW for each of their connection points in the HVA voltage range for which they have chosen this tariff.

At each connection point, the annual withdrawal component is determined according to the following formula:

$$CS = a_2.P_{Subscribed} + b.\tau^c.P_{Subscribed} + \sum_{12\ months} CMDPS$$

The rate of use τ is calculated based on active energy withdrawn over the period of 12 months $E_{withdrawn}$ in kWh, of the subscribed power $P_{Subsribed}$ in kW and duration of the considered year *D* in hours according to the following formula:

$$\tau = \frac{E_{withdrawn}}{D.P_{Subscribed}}$$

The coefficients a*2*, *b* and *c* used are those in table 4 below

Table 4

Voltage range	a_2 (€/kW/year)	b (€/kW/year)	c
HVA	21.72	87.19	0.690

6.2. Optional tariffs with time differentiation;

For each of their connection points in the HVA voltage range, users choose, for each of the *n* time categories it is made up of, subscribed power *Pi* in multiples of 1 kW, where *i* designates the time category. Whatever the value of *i*, subscribed power must be such that $P_{i+1} \geq P_i$.

At each connection point, the annual withdrawal component is determined according to the following formula:

$$CS = a_2.P_{Subscribed\ weighted} + \sum_{i=1}^{n} d_i.E_i + \sum_{12\ months} CMDPS$$

E_i designates active energy withdrawn during the i^{th} time category, expressed in kWh.

$P_{subscribed\ weighted}$ designates the weighted subscribed power calculated according to the following formula:

$$P_{Subscribed\ weighted} = k_1.P_1 + \sum_{i=2}^{n} k_i.(P_i - P_{i-1})$$

6.2.1. HVA tariff with time differentiation of 5 classes;

For the HVA tariff with time differentiation of 5 classes (n = 5), the coefficients a_2, d_i and k_i used are those of tables 5.1 and 5.2 below:

Table 5.1

a_2 (€/kW/year)	9.36

Table 5.2

	On-peak hours (i = 1)	**Mid-peak hours in Winter (i = 2)**	**Off-peak hours in Winter (i = 3)**	**Mid-peak hours in Summer (i = 4)**	**Off-peak hours in Summer (i = 5)**
Energy weighting coefficient **(c€/kWh)**	d_1 = 3.02	d_2 = 2.59	d_3 = 1.55	d_4 = 1.32	d_5 = 0.88
Power weighting coefficient	k_1 = 100 %	k_2 = 92 %	k_3 = 55 %	k_4 = 40 %	k_5 = 12 %

The time classes are set locally by the operator of the public network based on the operating conditions of public networks. They are available to any person on request and are posted on the public grid operator's website or failing this, by any other appropriate means. Winter is from November to March. Summer is from April to October. On-peak hours are set from December to February inclusive, at 2 hours in the morning in the range of 8:00 a.m. to 12:00 and 2 hours in the evening in the range from 5:00 p.m. to 9:00 p.m... Sundays are fully off-peak hours. The other days comprise 8 off-peak hours to be fixed in the range of 9:30 p.m. to 7:30 a.m.

6.2.2. Optional HVA tariff with time differentiation of 8 classes;

For the HVA tariff with time differentiation of 8 classes (n = 8), the coefficients a_2, d_i and k_i used are those of tables 6.1 and 6.2 below:

Table 6.1

a_2 (€/kW/year)	9.36

Table 6.2

	On-peak hours (i = 1)	Mid-peak hours in Winter (i = 2)	Mid-peak hours March and November (i = 3)	Off-peak hours in Winter (i = 4)	Off-peak hours March and November (i = 5)	Mid-peak hours in Summer (i = 6)	Off-peak hours in Summer (i = 7)	July-Aug (i = 8)
Energy weighting coefficient **(c€/kWh)**	d_1 = 3.04	d_2 = 2.76	d_3 = 2.28	d_4 = 1.60	d_5 = 1.24	d_6 = 1.38	d_7 = 0.87	d_8 = 1.09
Power weighting coefficient	k_1 = 100 %	k_2 = 93 %	k_3 = 72 %	k_4 = 56 %	k_5 = 46 %	k_6 = 40 %	k_7 = 21 %	k_8 = 10 %

The temporal classes are set locally by the operator of the public network based on the operating conditions of public networks. They are available to any person on request and are posted on the public grid operator's website or failing this, by any other appropriate means. Winter is December, January and February. Summer is April, May, June, September and October. On-peak hours are set, from December to February inclusive, for 2 hours in the morning in the range of 8:00 a.m. to 12:00 and 2 hours in the evening in the range from 5:00 p.m. to 9:00 p.m. Sundays, Saturdays and public holidays are deemed as off-peak hours. The other days comprise 6 hours off-peak to be fixed in the range of 9:30 p.m. to 7:30 a.m. The months of July and Aug constitute a unique time category.

6.3. Monthly components for subscribed power overruns (CMDPS)

6.3.1. HVA tariff with meters measuring overruns per integration period of 10 minutes

For users to which a tariff without time differentiation is applied, with a connection point equipped with a meter measuring active power overruns compared to the subscribed power by integration period of 10 minutes, the monthly overruns components of subscribed power concerning this point are established each month according to the following modalities:

$$\mathrm{CMDPS} = 0{,}08.a_2.\sqrt{\sum\left(\Delta P^2\right)}$$

For users to which a tariff with time differentiation is applied, with a connection point equipped with a meter measuring active power overruns compared to the subscribed power by integration period of 10 minutes, the monthly overruns components of subscribed power concerning this point are established each month according to the following modalities:

$$CMDPS = \sum_{i \text{ categories of the month}} 0{,}15.k_i.a_2.\sqrt{\sum\left(\Delta P^2\right)}$$

Power overruns compared to subscribed power ΔP are calculated per integration period of 10 minutes. The coefficients a_2 and k_i used are those of sections 6.1 and 6.2 according to the chosen option

6.3.2. HVA tariff with meter with maximum power indicator

For users to which a tariff without time differentiation is applied, with a connection point equipped with a maximum power metering indicator or with power recording, the monthly overrun components of the subscribed power relating to this point are established each month from ΔP_{max}, difference between the maximum power reached during the month and the subscribed power, according to the following modalities:

$$\mathrm{CMDPS} = 0{,}7.a_2.\Delta P_{max}$$

For users to which a tariff with time differentiation is applied, with a connection point equipped with a maximum power metering indicator or with power recording, the monthly overflow components of the subscribed power relating to this point are established each month from $\Delta P_{(max)i}$, differences, for each time class, between the maximum power reached during the month during the considered time class and the subscribed power during the considered time class, according to the following modalities:

$$CMDPS = \sum_{i\ categories\ of\ the month} 1{,}6.k_i.a_2.\Delta P_{(\max)i}$$

The coefficients a_2 and k_i used are those of sections 6.1 and 6.2 according to the chosen option

7. Annual withdrawal components (CS) and monthly components for subscribed power overruns (CMDPS) in the LV voltage range

7.1. Annual withdrawal components and monthly components for subscribed power overruns in LV voltage range greater than 36 kVA

For the establishment of their annual withdrawals component in the LV voltage range, greater than 36 kVA, users choose for the entire period of 12 consecutive months except transitional provision contained in section 14, one of two tariffs with the following time differentiation: medium and long term-use

For each of the time classes defined in Section 7.1.1 and section 7.1.2, and for each of their points of connection in the LV voltage range greater than 36 kVA, users select, in multiples of 1 kVA, an apparent subscribed power S_i where i designates the time class.

When the control of overruns is carried out on the active subscribed power, it is equal to the apparent subscribed power multiplied by 0.93.

When the control overruns of the subscribed power is provided by a circuit breaker at the interface with the public grid, the subscribed power is equal to the power control of the monitoring equipment that controls the circuit breaker.

Whatever the value of i, the subscribed power must be such that $S_{i+1} \geq S_i$. At each connection point, the annual withdrawal component is determined according to the following formula:

$$CS = a_2.S_{Subscribed\ weighted} + \sum_{i=1}^{n} d_i.E_i + \sum_{12\ months} CMDPS$$

E_i designates active energy withdrawn during the i^{th} time category, expressed in kWh.

$S_{subscribed\ weighted}$ designates weighted subscribed power calculated according to the following formula:

$$S_{Subscribed\ weighted} = k_1.S_1 + \sum_{i=2}^{n} k_i.(S_i - S_{i-1})$$

7.1.1. LV ≤ 36 kVA long-duration use tariff

For the LV > 36 kVA long-duration use tariff with 5 time classes (n = 5), two apparent subscribed powers may be applied to a same user. The coefficients a_2, k_i and d_i used are those of table 7.1 and 7.2 below:

Table 7.1

a_2 (€/kW/year)	21.12

Table 7.2

	On-peak hours (i = 1)	**Mid-peak hours in Winter (i = 2)**	**Off-peak hours in Winter (i = 3)**	**Mid-peak hours in Summer (i = 4)**	**Off-peak hours in Summer (i = 5)**
Energy weighting coefficient **(c€/kWh)**	d_1 = 3.62	d_2 = 3.62	d_3 = 2.50	d_4 = 1.94	d_5 = 1.49
Power weighting coefficient	k_1 = 100 %	k_2 = 95 %	k_3 = 49 %	k_4 = 31 %	k_5 = 8 %

The time classes are set locally by the operator of the public network based on the operating conditions of public networks. They are available to any person on request and posted on the public grid operator's website or failing this, by any other appropriate means. Winter is from November to March. Summer is from April to October. On-peak hours are set, from December to February inclusive for 2 hours in the morning in the range of 8:00 a.m. to 12:00 and 2 hours in the evening in the range from 5:00 p.m. to 9:00 p.m. Every day comprises 8 consecutive off-peak hours or is split into two periods in the ranges of 12 to 4 p.m. and 9:30 p.m. to 7:30 am.

7.1.2. LV > 36 kVA medium-duration use tariff

For the LV > 36 kVA medium-duration use range tariff with 4 time classes (n = 4), the apparent subscribed power must be such that $S_1 = S_2 = S_3 = S_4$. The coefficients a_2 and d_i used are those of table 8.1 and 8.2 below:

Table 8.1

a_2 (€/kW/year)	12.00

Table 8.2

	Mid-peak hours in Winter (i = 1)	**Off-peak hours in Winter (i = 2)**	**Mid-peak hours in Summer (i = 3)**	**Off-peak hours in Summer (i = 4)**
Energy weighting coefficient **(c€/kWh)**	d_1 = 4.27	d_2 = 3.11	d_3 = 2.21	d_4 = 1.64

The time classes are set locally by the operator of the public network based on the operating conditions of public networks. They are available to any person on request and are posted on the public grid operator's website or failing this, by any other appropriate means. Winter is from November to March. Summer is from April to October. Every day comprises 8 consecutive off-peak hours or is split into two periods in the ranges of 12 to 4 p.m. and 9:30 p.m. to 7:30 am.

7.1.3. Monthly components for subscribed power overruns (CMDPS)

LV > 36 kVA tariff with overrun meters
of active power

For LV users greater than 36 kVA who have chosen the long-duration use tariff, with a connection point equipped with a meter measuring active power overruns compared to the active subscribed power by integration period of 10 minutes, the monthly subscribed power overflow components relating to this point are established each month for each time class of the month in question, according to the following modalities:

$$CMDPS = \sum_{i\ categories\ of\ the month} 0{,}15.k_i.a_2.\sqrt{\sum\left(\Delta P^2\right)}$$

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Power overruns in relation to the subscribed power ΔP are calculated per integration period of 10 minutes. The coefficients a_2 and k_i used are those of section 7.1.1.

For LV users greater than 36 kVA who have chosen the medium-duration use tariff, with a connection point equipped with a meter measuring active power overruns compared to the subscribed power by integration period of 10 minutes, the monthly subscribed power overflow components relating to this point are established each month for each time class of the month in question, according to the following modalities:

$$\text{CMDPS} = 0{,}15.a_2.\sqrt{\sum\left(\Delta P^2\right)}$$

Power overruns ΔP, compared to subscribed power at time of the overrun are calculated per 10 minute integration period. The coefficient a_2 used is that of section 7.1.2.

LV > 36 kVA tariff with overrun meter
of apparent power

For LV users greater than 36 kVA with a connection point equipped with meters measuring overruns, Δ*S*, between the apparent power observed every minute in rolling root mean square and the subscribed power, the subscribed monthly apparent power overrun components relative to this point are established each month, for each time class of the considered month on the base of the overrun delay *h* (in hours), and according to the below formula:

$$\text{CMDPS} = 11{,}11.h$$

7.2. Annual withdrawal component in LV voltage range up to and including 36 kVA

For the establishment of their annual withdrawals component in the LV voltage range up to and including 36 kVA, for an entire period of 12 consecutive months except transitional provision contained in section 14, users choose one of the three following tariffs:

- short-duration use;
- medium-duration use with time differentiation;
- long-duration use.

For the tariff of their choice, they define a subscribed power, $P_{Subscribed}$, by multiples of 1 kVA.

When the control of overruns of the subscribed power is provided by a circuit breaker at the interface to the public network, the subscribed power is equal to the control power of the monitoring equipment controlling the circuit breaker.

At each point of connection to the LV voltage range up to and including the subscribed 36 kVA power, the annual withdrawal component is established according to the following formula:

$$CS = a_2.P_{Subscribed} + \sum_{i=1}^{n} d_i.E_i$$

E_i designates the energy withdrawn during the i[th] time class expressed in kWh and $P_{Subscribed}$ designates the subscribed power equal to the control power of the monitoring equipment that controls the circuit breaker.

7.2.1. LV ≤ 36 kVA short-duration use tariff

For the short-duration use tariff, n = 1 and the coefficients a_2 and d_1 used are those of table 9 below:

Table 9

Subscribed power (P)	**a_2 (€/kVA/year)**	**d_1 (c€/kWh)**
P > 9 kVA	3.60	3.50
9 kVA < P 18 kVA	6.48	3.24

18 kVA < P	12.96	2.60

7.2.2. LV ≤ 36 kVA medium-duration use tariff with time differentiation

For the medium-duration use tariff with time differentiation (n = 2) and the coefficients a_2, d_i and d_2 used are those of table 10 below:

Table 10

Subscribed power (P)	**a_2 (€/kW/year)**	**d_1 Peak hours (c€/kWh)**	**d_2 Off-peak hours (c€/kWh)**
P > 9 kVA	4.32	3.94	2.44
9 kVA < P 18 kVA	7.32	3.53	2.19
18 kVA < P	14.04	2.96	1.84

The time classes are set locally by the public network operator based on the public network operating conditions. They are available to any person on request and are posted on the public grid operator's website or failing this, by any other appropriate means. The peak hours are 8 in number per day, are possibly non-contiguous and must be fixed within the ranges from 12 pm to 5 pm and from 8 pm to 8 am.

7.2.3. LV ≤ 36 kVA long-duration use tariff

For application of the long-duration tariff use, in the absence of metering systems, public system operators can provide transparent and non-discriminatory methods for estimating these withdrawal flows and subscribed powers.

The subscription pace of the power is 0.1 kVA, n = 1 and the coefficients a_2 and d_1 used are those of table 11 below:

Table 11

	a_2 (€/kW/year)	**d_1 (c€/kWh)**
Long-duration use.	57.24	1.35

8. The annual component for complementary and back-up power supplies (CACS);

The complementary and back-up power supplies established on user request are billed according to the methods described below. The annual component for complementary and back-up power supplies (CACS) is equal to the sum of these components.

8.1. Complementary power supply

The parts dedicated to a user's complementary power supply are subject to a charge for the electrical equipment of which they are composed. This charge is based on the length of these assigned parts according to the following scale:

Table 12

Voltage range	**Cells (€/cell/year)**	**Lines (€/kW/year)**
HVA	3,145.50	Overhead lines: 858.05 Underground lines: 1,287.08

8.2. Back-up power supply

The parts dedicated to a user's back-up power supply are subject to a charge for the electrical equipment of which they are composed. This charge is based on the length of these assigned parts according to the tariff scale in table 12 above. The power subscribed for back-up power supplies is less than or equal to the power subscribed for main power supplies.

If a back-up power supply is shared among several users, the bill for the parts assigned to back-up power supplies and crossed by flows to several users' connection points is shared among these users at the pro rata of the power which they have subscribed on this back-up power supply.

If the back-up power supply is in the same voltage range as the main power supply and, at the request of the user, it is connected to a public grid transformer different from that used for their main power supply, billing of the parts assigned to back-up power supplies is equal to the sum of the component resulting from application of the tariff scale in table 12 above and the component determined in line with the tariff scale in table 13 below, corresponding to the pricing of the transformation power reservation:

Table 13

Power supply voltage range	€/kW/year or €/kVA/year
HVA	6.14
LV	6.39

If the back-up power supply is in a different voltage range to that of the main power supply, annual billing of back-up power supplies is equal to the sum of the component resulting from the application of the tariff scale in table 12 above and the component determined according to the tariff scale in table 14 below, corresponding to pricing of the public electricity grid providing back-up in a lower voltage range.

If the back-up power supply, which is in a voltage range different to that of the main power supply, is equipped with a meter measuring active power overruns compared to back-up supply power subscribed per integration period of 10 minutes, the monthly subscribed power overrun component for back-up supply is set each month according to the below method:

$$\text{CMDPS} = \alpha . \sqrt{\sum \left(\Delta P^2 \right)}$$

Table 14

Main supply voltage range	Main supply voltage range	Fixed RATE(€/kW/year)	Power share (c€/kWh)	α (c€/kW)
HVB 2	HVA	7.96	1.71	63.94
HVB 1	HVA	2.77	1.71	22.69
HVA	LV	-	-	-

9. Component for tariff aggregation of connection points (CR)

A user connected to a public network by several connection points on the same public network in the same HVA voltage range and equipped with meters with measurement curves for each of these points can, if they so wish, benefit from tariff aggregation of all or part of these points for the application of the tariffs described in sections 5 and 6, through payment of an aggregation component. In this case, the annual injection component (CI), annual withdrawal component (CS), monthly components for subscribed power overruns (CMDPS), annual component for sporadic scheduled overruns (CDPP) and annual reactive energy component (CER) are defined based on the sum of the physical flows measured at the connection points concerned. The possibility of tariff aggregation for connection points on the same public grid is limited to the scope of the same distribution franchise for public distribution system operators and to the same site for other users.

The aggregation of connection point reactive energy flows is only possible in cases where these connection points meet the conditions stated in the electricity system operator's reference technical documentation.

The aggregation component (CR) is determined according to the length of the existing public electricity grid for this physical aggregation, independently of operating conditions, and on the transit capacity available on the grid for this aggregation. The amount of this component is calculated according to the following formula,

$P_{Subscribed\ aggregated}$, the subscribed power for all tariff consolidated points and l, the shortest total length of the electrical equipment on the public grid considered for physical aggregation.

$$CR = l.k.P_{Subscribed\ aggregated}$$

Coefficient k is defined in table 15 below:

Table 15

Voltage range	k (€/kW/year)
HVA	Overhead lines: 0.48 Underground lines: 0.69

10. Specific provisions for annual withdrawal components (CS) of public distribution system operators

For connection points connected to the HVA voltage range, specific provisions relating to annual components of public network distribution operator's withdrawals are provided in Section 9 of tariffs for use of a public electricity network in the HVB voltage range. In this context, the transitional provisions in Section 13.1 of tariffs for use of a public electricity network in the HVB voltage range are applicable to the calculation of the annual component of withdrawals applicable to the HVB 1 voltage range.

10.1. Annual component for transformer use (CT)

A public distribution system operator that operates one or more overhead or underground lines downstream of their connection point, in the same voltage range as that downstream of the transformer to which they are directly connected, without an intermediate line upstream of the connection point, can benefit upon request from the annual withdrawal component (CS) applicable to the voltage range just above that applicable to the connection point. The operator must in this case pay an annual component for transformer use, reflecting the costs of transformers and cells. This component is calculated according to the following formula, depending on subscribed power $P_{Subscribed}$.

$$CT = k.P_{Subscribed}$$

The coefficient k used is that defined in table16 below:

Table 16

Voltage range Connection points	Voltage range of the applied pricing	k (€/kW/year)
LV	HVA	7.96

This arrangement can be combined with that of tariff aggregation according to the methods in section 9. In this case, the tariff scale in the voltage range above each connection point is applied first followed by the tariff aggregation mentioned above.

10.2. Compensation for operating lines at the same voltage as the upstream public grid

A public distribution system operator that operates lines downstream of their connection point, in the same voltage range as the lines upstream of this connection point, benefits from this compensation if the pricing applicable to the considered connection point is that of the voltage range of this point.

In this case, the annual withdrawal component (CS) for this connection point is calculated according to the following formula, with:

- l_1, the total length of the line(s) operated in voltage range N by the public distribution system operator;
- l_2, the total length of the line(s) operated in voltage range N by the public distribution system operator to which they are connected and which is absolutely necessary for linking their connection point to this

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operator's voltage transformer(s) required to guarantee the subscribed power in normal operating conditions defined in the reference technical documentation of the public system operator upstream;

- $CT_{N/N+1}$ is the annual component for transformer use between the voltage ranges of *N+1* and *N* defined in section 10.1.

$$CS = \frac{I_2}{I_1 + I_2} CS_N + \frac{I_1}{I_1 + I_2}\left(CS_{N+1} + CT_{N/N+1}\right)$$

10.3. Peak shaving in extreme cold weather

Public distribution system operators can benefit from peak shaving of their power overruns from the public system operator upstream to which they are connected in the event of severe cold spells. This provision is applied in compliance with transparent and non-discriminatory methods.

11. Annual component for sporadic scheduled overruns (CDPP);

For sporadic overruns scheduled for work during the period from 1 May to the 31 October and notified to the public system operator in advance, a user, not exclusively supplied by or using one or more back-up power supplies, whose connection point is equipped with a meter with measurement curve and connected to the HVA voltage range, can request the application of a specific tariff scale for the calculation of their component for subscribed power overruns related to this connection point.

In this case, during the period when this price scale is applied, the subscribed power overruns are subject to the following billing method which replaces the billing for subscribed power overruns defined in section 6.3.

$$CDPP = k.\sum \Delta P$$

Power overruns compared to subscribed power ΔP are calculated per integration period of 10 minutes. The *k* coefficient is defined by table 17 below:

Table 17

Voltage range	k (c€/kW)
HVA	0.374

In support of their request for the application of a specific tariff scale for the calculation of their component for subscribed power overruns, users provide all elements that justify the actual nature of the work to be conducted on their electricity facilities. When such a request comes from a public distribution system operator and is the result of the request of a user connected to this grid, the public distribution system operator passes the aforementioned elements to the upstream public system operator, and provides the user's maximum power request which will be subtracted from the public distribution system operator's overruns and billed according to the provisions applicable to sporadic scheduled overruns.

The application of this provision is limited for each connection point to a maximum of once per calendar year, for use over a maximum of 14 continuous days. For the breakdown of the number of applications of this provision per connection point, the applications carried out upon the request of the public distribution system operators are not taken into account when they are the result of a request from a user connected to their network. Days which have not been used cannot be carried over.

The public system operator, or where necessary the upstream public system operator, can refuse or suspend application of this provision to a user, due to operating constraints foreseen on their public grid. This refusal or suspension has to be justified and notified to CRE at the same time.

12. Annual reactive energy component (CER).

In the absence of metering systems recording physical flows of reactive energy, public system operators can provide transparent and non-discriminatory methods for estimating these flows in their reference technical documentation.

The provisions in sections 12.1 and 12.2 do not apply to connection points located at the interface between two public electricity grids.

12.1. Withdrawal flows

If physical flows of active energy at a connection point are withdrawal flows, public system operators provide reactive energy free of charge:

- up to the value of the *tg* φ_{max} ratio defined in table 18 below, from 1 November to 31 March, from 6:00 a.m. to 10:00 p.m. Monday to Saturday;
- as an exception, for connection points where the user has opted for a tariff with time differentiation, not exceeding the *tg* φ_{max} ratio defined in table 18 below, during on-peak winter hours and mid-peak winter hours; as well as the peak hours of November and march of options with 8 time classes;
- without limitation outside these periods.

During the periods subject to limitation, reactive energy absorbed in the HVA and LV voltage range greater than 36 kVA beyond the value of the tg φmax ratio are billed in line with table 18 below:

Table 18

Voltage range	*tg* φ_{max} ratio	c€/kvar.hr
HVA	0.4	1.83
LV > 36 kVA	0.4	1.92

12.2. Injection flows

When physical active energy flows at a connection point are injection flows, and the facility is not subject to voltage control, the user commits on the one hand, to not absorb reactive power in the LV voltage range and on the other hand, to supply or absorb in the HVA voltage range a quantity of reactive power determined by the public network operator and fixed in relation to the power delivered to the public network operator, according to the rules published in the reference technical documentation of the public network operator.

In the LV voltage range for installations with a power supply greater than 36 kVA, the reactive power consumed is billed according to table 19 below.

In the HVA voltage range, the reactive energy supplied or absorbed beyond the *tg* φ_{max} ratio or below the ratio *tg* φ_{min} is billed according to table 19 below.

However, below a low monthly production threshold, the reactive power consumed or supplied below the *tg* φ_{min} ratio or above a monthly threshold is billed according to table 19 below.

The distribution system operator sets the low production threshold and monthly reactive energy threshold. They determine the *tg* φ_{max} and *tg* φ_{min} values of the thresholds of the *tg* φ ratio per time range.

Table 19

Voltage range	c€/kvar.hr
HVA	1.83
LV > 36 kVA	1.92

If physical flows of active energy at a connection point are injection flows and the facility is subject to voltage control and the user does not benefit from a contract as provided by article L. 321-11 of the French Energy Code, the user undertakes to maintain the voltage of the facility's connection point within a range determined by the public system operator and set according to the rules published in the reference technical documentation of the public system operator to which the user is connected.

Should the voltage exceed the agreed range, the user is billed according to table 20 below for the difference between the reactive energy that the facility has actually provided or absorbed and the reactive energy that it should have provided or absorbed to maintain the voltage within the range agreed in the operating contract, up to the operating capacities defined by diagrams [U, Q] of the connection contract. These elements are determined according to the rules published in the reference technical documentation of the public distribution system operator.

Table 20

Voltage range	c€/kvar.hr
HVA	1.83

12.3. Specific provisions for the annual reactive energy component between two public electricity system operators

At each shared connection point, the public system operators agree, by contract, on the quantity of reactive energy that they exchange, determined according to active energy transits, in compliance with the rules published in the reference technical documentation of the injecting system operator

The reactive energy provided above the tg φmax ratio or absorbed below the tg φmin ratio is billed per connection point according to table 21 below.

The tg φmax and tg φmin values of the tg φ ratio thresholds per connection point are agreed upon by contract per time slot between public system operators. The contractual term $tg\ \varphi_{max}$ is less than 0.4 and by default takes into account, the historic values of the ratio *tg* φ found.

Table 21

Voltage range	c€/kvar.hr
HVA	1.83

The tg φmax and tg φmin values of the tg φ ratio thresholds per connection point are agreed upon by contract per time slot between public system operators.

Failing agreement, the contractual term tg φmax is equal to the “historical value” defined as the maximum value of monthly tg φ observed at the connection point during winter in 2006 to 2009, without exceeding 0.4. If, at the date of entry into force of the present tariff rules, the value of this contractual tg φmax term is higher than the “historical value”, the contractual tg φmax term is gradually decreased up to this through annual drops of 0.05. These annual drops cease to apply once the contractual tg φmax term is lower than or equal to 0.2.

Within a period of one year following the entry into force of the present tariff rules, system operators adapt their reference technical documentation to specify the principles setting the terms for changing this contractual value, taking into account, on the one hand, reasonable possibilities of the public distribution system operator to control the reactive energy withdrawn by its grid, and on the other hand, voltage constraints identified, at a horizon of 5 to 10 years, by injecting system operator.

By way of exception, two public system operators may conclude agreements based on fixed reactive power thresholds expressed in MVAR per connection point. The applicable reference technical documentation specifies the terms for determining these thresholds and verifying compliance with these thresholds at sufficiently representative intervals These terms take into account the type of voltage constraints, identified at a horizon of 5 to 10 years, as well as the reasonable possibilities of the public distribution system operator to control the reactive energy supplied or withdrawn by its network.

13. Indexation of the tariff scale

Each year *N* as from 2014, the level of components defined by tables 1 to 2.2 and 4 to 21 above are automatically adjusted on 1 Aug of year *N*, with the exception of the power weighting coefficients of withdrawal components and coefficient *c* of table 4, 5.2, 6.2 and 7.2.

The tariff scale in application as of 1 Aug of year *N* is obtained by adjusting the tariff scale in application the previous month in line with changes in the consumer price index excluding tobacco and a reconciliation factor for the expense and income clawback account (CRCP).

The tariff scale is automatically adjusted in line with the following percentage:

$$Z_N = IPC_N + K_N$$

Z_N: percentage of change, rounded off to the nearest tenth of a percent, in the tariff scale in application as from 1 August of the year N compared to that in application the previous month.

IPC_N: percentage of change between the average value of the consumer price index excluding tobacco over the calendar year N-1 and the average value of the same index over the calendar year N-2, as published by the French statistics agency INSEE (identifier: 000641194).

K_N: CRCP reconciliation factor for year N, calculated on the basis of the CRCP balance as at 31 December of year N-1 and reconciliation's already conducted. The absolute value of the coefficient K_N is limited to 2 %.

Rounding off rules are as follows for the adjustment of tariff scales:

- the coefficients of fixed components of the annual withdrawal components and the annual administrative management and metering components are rounded off to the nearest Euro cent dividable by the nearest 12;
- the other coefficients subject to adjustment are rounded off to the nearest hundredth of the unit in which they are expressed.

14. Transitional provisions applicable to the implementation of the present tariffs rules

For the first six months of application of these tariff rules, for each connection point, users (or third parties authorised by them) choose their tariff option without having to comply with 12 consecutive month periods since their previous tariff option choice. This provision does not apply to the subscription of power withdrawal. This provision can only be activated once and is effective as of date of completion.

From 1 January 2014 to 31 July 2014 and for the LV voltage range up to and including the subscribed power of 36 kVA, the users' withdrawal component, having chosen before 1 January 2014 the medium-duration use tariff is determined using the following formula:

$$CS = a_2 . P_{Subscribed} + \sum_{i=1}^{n} d_i . E_i$$

E_i designates active energy withdrawn during the i^{th} time category, expressed in kWh and $P_{Subscribed}$ designates the subscribed power equal to the control power of the monitoring equipment which controls the circuit breaker.

For the medium-duration use tariff, n = 1 and the coefficients a_2 and d_i used are those of table 22 below:

Table 22

Subscribed power (P)	a_2 (€/kW/year)	d_1 (c€/kWh)
P > 9 kVA	3.60	3.50
9 kVA < P 18 kVA	6.48	3.24
18 kVA < P	12.96	2.60

For the LV voltage range up to and including the subscribed power of 36 kVA, users whose withdrawal component determined on July 31, 2014 and based on the medium-duration use rate are deemed to have chosen the short-duration use rate from 1 August 2014.

Paris, 12 December 2013

For the French Energy Regulatory Commission,

The President,

Philippe de LADOUCETTE