Deliberation

Proposal by the French Energy Regulatory Commission (CRE) dated 26 February 2009 on the tariffs for use of public electricity transmission and distribution grids

The following were present at the meeting: Philippe de LADOUCETTE, Chairman, Michel LAPEYRE, Vice-Chairman, Maurice MEDA, Vice-Chairman, Jean-Paul AGHETTI, Eric DYEVRE, Jean-Christophe LE DUIGOU and Emmanuel RODRIGUEZ, Commissioners.

Explanatory statement

I. Introduction

In compliance with the provisions of article 4 of the French amended Law No. 2000-108 dated 10 February 2000, the French Energy Regulatory Commission (CRE) proposes new tariffs to the Ministers in charge of the Economy and Energy for the use of public electricity grids (TURPE 3) to replace those in force (TURPE 2) approved by ministerial decision on 23 September 2005 and applied as from 1 January 2006.

In order to prepare this proposal, CRE launched an initial public consultation on the planned tariff rules in February 2008. At the end of August 2008, it launched a second consultation on its guidelines regarding tariff levels, changes in the regulatory framework and the average tariff scale. The contributions received enabled the Commission to bring together the reactions and suggestions of stakeholders (consumers, licensing authorities, suppliers, producers, system operators, trade unions). CRE also received a considerable number of letters from elected representatives, mainly concerning the issues of quality and the modernisation of public distribution grids.

On 31 October 2008, CRE submitted a tariff proposal for the use of public electricity transmission and distribution grids to the Ministers in charge of Energy and the Economy.

In view of the proposal's approval, the Ministers issued a decision dated 19 December 2008, requesting the two following points be dealt with in the proposal:

- the completion of mechanical consolidation of the public transmission network by 2017,
- time-of-day and seasonal adjustments to tariffs in order to encourage consumers to limit their consumption during peak demand periods.

In this proposal, as in the proposal issued on 31 October 2008, CRE has set two objectives:

- To give system operators the means to fulfil their public service duties as efficiently as possible.

  Public service is currently provided against a backdrop of considerable cost increases, due to several factors:

  - the necessity to improve quality in line with the observed increase in the average duration of power cuts on distribution grids. This situation requires significant investment,
  - transmission and distribution grid reinforcement and connection requirements resulting from the new electricity generation investment cycle,
  - the construction of new interconnection infrastructures to step up the integration of electricity markets in Europe,

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- distributors' commitment to modernising the grids licensed to them, with regard to metering systems in particular, to meet the challenges related to the opening of the markets, the development of decentralised generation and energy management.

In the medium term, these investment plans should benefit end users.

To rise up to these challenges, system operators require additional tariff-based resources.

- To ensure reasonable cost control so that excessive costs are not passed on to consumers.

  Article 4 of Regulation (EC) No. 1228/2003 provides that grid access tariffs "*reflect actual costs incurred insofar as they correspond to those of an efficient network operator*". Covering the actual costs incurred by system operators also involves encouraging efficient use of the tariff-based resources allocated to them.

In order to uphold competition between suppliers on the open market, the various regulated tariffs for the sale of electricity must take account of the changes to the related tariffs for the use of public grids so as to reflect costs as early as possible after the application of these tariffs for the use of public electricity grids, as required by law.

II. Main guidelines put forward by CRE

A. Factors determining tariff levels

The development and replacement of the networks to improve quality and foster the development of generation and interconnections

As regards the quality of distribution grids, ERDF has put forward two scenarios. CRE has selected the most ambitious scenario, including an additional 20% investment for service quality over the 2009-2012 period. By doing so, CRE confirms its desire to give distributors the means to improve quality.

Investments in distribution grids financed by ERDF total €11.9 billion between 2009 and 2012, i.e. 45% increase in the average annual amount compared to 2008. This figure includes €3.3 billion to improve service quality and €3.9 billion for connections.

Investments in the transmission network come to €4.7 billion between 2009 and 2012, i.e. a 36% increase in the average annual amount compared to 2008. These investments mainly concern the development of the bulk transmission grid and interconnections for €1.5 billion, the development of regional grids (€1.4 billion) and the replacement of the grid (€1.3 billion).

Revenues from interconnection management mechanisms not allocated *ex-ante* to the reduction of the TURPE (€202.9 million) are to be used to finance interconnection investments. This allocation, in compliance with Regulation (EC) No. 1228/2003, is aimed at covering the additional environmental expenditure related to these major projects.

The consolidation of electricity grid infrastructures

Following the severe storms in 1999, RTE was instructed by the government to set up a mechanical consolidation programme for the electricity transmission network representing €1.7 billion. The programme is due to be completed in 2017.

Given the importance of this consolidation for the safety of the electricity grid and security of supply, CRE has selected the overall consolidation budget representing €2.4 billion proposed by RTE. This 41% increase compared to the initial budget will be used in particular to consolidate infrastructures that were not planned in the initial programme.

This proposal contains the expenditure of this new budget planned for the 2009-2012 period with a view to completing the consolidation of the public transmission network in 2017.

A balanced rate of return on assets given the reduction in the risk profile of system operators

The methods required to calculate the regulated asset base (RAB) and the rate of return implemented as part of TURPE 2 have been retained. The rate of return of the asset base stands at 7.25%, nominal rate pre-tax. The range of values selected to set this rate, compared to the TURPE 2 values, take account of both the increase in financing costs and the significant reduction in system operators' risk profile.

CRE renews the recovery systems for expenses and revenues deemed difficult to forecast or to control (Expenses and Revenues Clawback Account or CRCP), deployed in the tariffs currently in application, but has extended the scope. In particular, the risk related to uncertainty concerning withdrawals is now included in the scope of the CRCP. This guaranteed tariff revenue for system operators, for volume, is justified due to the uncertainty surrounding withdrawal and injection levels and the number of connections, due to the development of energy management and decentralized generation initiatives.

Coverage of costs and the resulting tariff level

CRE has approved all investment figures requested by the operators and all operating costs that they have presented in order to support them, particularly as regards personnel costs.

It has also taken into account the increase in costs related to the compensation of line losses in relation to TURPE 2. The amount of these costs depends greatly on price levels on the electricity market. The sharp drop in these prices noted since the beginning of 2009 has significantly changed these cost estimates and as a result, the distribution tariff level. Conversely, as regards transmission, two effects offset each other. Firstly, as for distribution, the forecast purchase cost of losses is falling. Secondly, market price differentials between neighbouring countries currently lead to a reduction in the expected revenues related to interconnection management mechanisms.

The consequences of the latest market price trends on the purchase cost of losses does not question RTE's or ERDF's financial resources over the tariff period, as this item is eligible for the CRCP. Furthermore, it is beneficial to company competitiveness, consumer purchasing power and the opening of the market.

The CRCP balance estimated as at 31 December 2008 shows, for both RTE and ERDF, surplus earnings to be returned to users over the TURPE 3 application period, thus limiting the cost levels to be covered by the tariffs.

Consequently, this proposal, designed to enable system operators to cover their costs over a four-year period from 2009, provides for a 2% increase in the tariff for the use of the transmission network and 3% increase in the tariff for the use of distribution grids as of its application. From 2010 to 2012, the tariff scales will be modified according to the rate of inflation increased by 0.4% for the transmission grid and by 1.3% for the distribution grids (see section IV.A).

These changes in tariff will provide ERDF with cash flow that should cover its investments. Taking account of available cash flow, ERDF will not have to borrow funds, depending on the dividends policy rolled out by its shareholder.

The tariff alone is not sufficient to ensure all necessary investments. Changes in debt levels and dividend payments to the parent company decided by the shareholder may compete with the planned investments to improve grid quality. Giving the regulator the jurisdiction to approve the overall investment budget for distribution grids, in addition to the key role of licensing authorities and in cooperation with them, would have the advantage of ensuring that investments match requirements.

B. Regulatory principles

The foreseeable nature of the regulatory framework

As regards tariff structure, the framework in application is revised with a view to reinforcing time differentiation considerably. However, this revision requires in-depth studies to reconcile cost reflection objectives with limiting consumption during peak periods.

As a result, the extent of time-of-day adjustment will be initially reinforced solely for distribution tariffs. This provision is based on the observed increase of time differentiation of market prices in recent years and, therefore, of the purchase cost of losses. This modification will already incite more users to select a tariff with time differentiation, which will encourage consumption outside peak periods.

CRE will conduct in-depth studies of the structure of tariffs for the use of public transmission and distribution grids. The results of these studies could lead to a complete revision of the tariff calculation method.

As any far-reaching changes to the structure would have an impact on the financial balance of grid users, work on the tariff framework will be conducted in cooperation with all stakeholders concerned.

CRE aims to complete this work within a timeframe of two years. It plans to suggest to the Ministers that the tariff rules should be modified accordingly, without affecting the planned authorised revenue for RTE and ERDF.

As regards the tariff level, CRE proposes to retain the framework currently in application. In particular, the key principles for the calculation of the regulated asset base (RAB) have been retained. RAB is calculated based on the net book value of assets. In the case of ERDF, assets are incorporated into the RAB regardless of how they are financed, by the distributor or the franchiser.

However, a considerable proportion of system operators' costs concerns loss compensation. In light of this, stakeholders are considering the need to improve the loss purchase system. This is why CRE is creating a working group bringing together the various stakeholders. Its role will be to draw up diagnostics of the various possible changes. The conclusions of this group will be presented at the end of 2009.

Tariff visibility for operators: multiyear tariffs with a four-year term

The introduction of tariffs with a four-year term allows transmission and distribution grid operators to have greater visibility of changes in their revenues.

By extending the tariff period, system operators can also more easily complete the adaptations enabling them to control costs and improve quality, as the mechanisms introduced by this proposal should encourage them to.

Encouraging system operators to provide the best value-for-money service

CRE would like system operators to improve the technical and economic efficiency of their activity over the tariff period, while complying with the public service role entrusted to them, and has introduced incentives for cost control and quality improvement.

For this purpose, CRE has retained the levels of productivity gains on the operating costs within influence proposed by system operators. If, during the tariff period, a system operator makes additional gains, the extra productivity will be shared out between the system operator and consumers.

This proposal also provides for a specific system aimed at inciting system operators to control their costs related to loss compensation on the grids.

These provisions are coupled with a regulation framework inciting system operators to improve the quality provided to users, in terms of both quality of supply and quality of service. This quality incentive regulation framework will ensure in particular that system operators do not make productivity gains that are detrimental to the level of quality provided.

III. Tariff level

A. Operating costs

The operating costs to be covered by the tariffs have been calculated based on all operating costs required to manage the transmission and distribution grids. To determine the level of these costs, CRE referred to the following in particular:

- the data from the 2007 corporate financial statement of the operators,
- the forecast changes to costs provided by RTE and ERDF,
- the audit of ERDF's 2006 unbundled accounts and the 2007 opening balance sheet, conducted by an external firm,
- the audit of RTE's 2006 accounts conducted by CRE.

Operating costs have sharply increased compared to the forecasts used as the basis for determining TURPE 2 tariffs. One of the main factors explaining this increase, aside from inflation, is the increase in the purchase price of losses. The increase of these costs is also in line with operators' investment efforts. It may also reflect certain specific effects. This is for instance the case for ERDF's expenditure related to new regulatory provisions (removal of transformers containing PCB) or new costs related to the opening of the market.

In order to give operators the means to cover such expenditure and more generally fulfil their public service duties and to give them the resources to support their investment programmes, the exact requests made by system operators to cover all forecast costs relating to operations, maintenance, and the development and modernization of the grids have been approved by CRE.

Moreover, the forecast revenues received irrespective of the tariffs for the use of the grids are deducted from the operating costs to be covered by the tariffs.

1. Costs related to the compensation of energy losses

In accordance with the provisions of Directive 2003/54/EC dated 26 June 2003 and the French Law No. 2000-108 dated 10 February 2000, public transmission and distribution system operators purchase power required to compensate their energy losses according to non discriminatory and transparent competition procedures.

For RTE and ERDF, the forecast levels of energy losses in volume and the costs to compensate these losses that have been accepted to determine the tariff level are as follows:

Average TURPE 3	RTE	ERDF
Volume (TWh)	11.5	21.6
Cost (€M)	750	1,372

The volumes of energy losses have been deducted from the load curves planned by system operators for the 2009-2012 period. The level of costs related to the compensation of these losses for each tariff reference year has been estimated according to the corresponding annual volume of energy losses and the forward market prices observed.

2. Cost of system services

The tariff for the use of the public transmission grid covers costs related to (i) the constitution of primary and secondary reserves for active power-frequency control, (ii) the constitution of primary and secondary reserves for reactive power-voltage control, (iii) balancing for the settlement of system services, (iv) synchronous compensation.

The average provisional level of system services costs selected to determine the tariff level is €337.4 million per year.

Excluding point (iii), the cost of system services considered in this tariff proposal is based on the contracts for the participation in system services signed between RTE and producers for the 2008 to 2010 period. For the 2011 to 2012 period, the cost of system services presented by RTE will follow a similar trend.

The publication of French Order No. 2008-386 dated 23 April 2008 and its implementing decree dated 23 April 2008, defining the technical requirements for the design and operation of the connections of an electricity generation facility to the public electricity transmission grid, does not modify the terms of producers' participation to system services.

3. Costs of the balancing responsible entities system

All public grid users, whether or not they have exercised their eligibility, benefit from the balancing responsible entity system. Consequently, the corresponding costs have been included in the scope of costs covered by the tariffs for use of the public electricity grids, except for the share in these costs directly invoiced by RTE to users of this system who do not have connection points on public grids, such as market players exchanging blocks on the wholesale market.

4. Congestion costs

Congestion costs are included in the scope of costs covered by the tariffs for use of the public electricity grids and have been estimated from forecasts provided by RTE. They are made up of national and international congestion costs, the latter reflecting measures taken by the transmission system operator to ensure the actual availability of allocated interconnection capacities, in accordance with regulation (EC) No. 1228/2003.

5. Contribution to the Inter-TSO compensation mechanism

RTE's contribution to the European compensation mechanism between transmission system operators for international energy transits is included in the scope of costs covered by the tariffs and has been estimated based on forecasts provided by RTE.

6. Personnel costs

Operators' proposals regarding personnel costs have been taken into account. The accepted estimates include:

- Operators' estimates in terms of changes in workforce and pay,
- The effects of the reform relating to the pension scheme for the electricity and gas industries provided for in French Order No. 2008-69 dated 22 January 2008 modifying the national status of personnel in these industries.

7. Costs related to the public transmission grid mechanical consolidation programme

The budget approved for the TURPE 3 application period enabling the mechanical consolidation programme to be completed in 2017 is valued at €186M per year on average. This budget will be monitored regularly by CRE.

8. Taxes and fees

This section is for the most part made up of:

- Local tax on businesses paid by the operators,
- Fees related to the fund for the amortization of rural electrification costs (FACE) and the electricity equalisation fund (FPE) for ERDF,
- Licence fees for ERDF,
- Pylon tax for RTE.

9. Central costs

Since becoming a subsidiary, RTE no longer pays group charges to EDF. After leaving EDF's cash pooling arrangement, RTE now manages its cash on a standalone basis independently from EDF and only pays EDF a sum limited to approximately €1 million per year over the 2009-2012 period, for the management of certain long-term debt items.

EDF plans to invoice ERDF for head office expenses over the 2009-2012 period. These expenses for services provided by the parent company to its subsidiary must be paid, however ERDF does not have the resources to cover these fees for the moment. Consequently, CRE has approved a sum of €70 million in its tariff proposal, excluding all EDF invoicing for communication and strategy and taking profit into consideration. This amount is a transitional aid for the TURPE 3 application period. ERDF must organise its own resources to carry out such services in the two years following the application of these tariffs, based on RTE's model. This budget is neither included in the cost items subject to productivity targets, nor in the items eligible for the CRCP account.

10. Operating cost levels

a) RTE

The levels of operating costs approved for RTE are as follows:

RTE – amounts in millions of €	**Average TURPE 3**
Gross operating costs	3 085
Operating income to be deducted	-102
Net operating costs	**2 983**

b) ERDF

The levels of operating costs approved for ERDF are as follows:

ERDF - amounts in millions of €	**Average TURPE 3**
Gross operating costs	9 482
Operating income to be deducted	-1 141
Net operating costs	**8 341**

B. Capital costs

Capital costs are made up of depreciations and financial return on fixed capital.

To calculate the capital costs to be covered by the tariffs, CRE has approved the provisional investment figures presented by the system operators. The rate of return of the regulated asset base is maintained at 7.25 %, nominal rate pre-tax.

1. Investment estimates

CRE has approved the investment estimates put forward by the operators. As regards ERDF's investments, CRE has selected, among the operators' proposals, the so-called targeted quality recovery scenario, which is the most conducive to improving quality. For RTE, CRE has included a considerable increase in investments on the transmission grid with a view to meeting the various requirements in terms of network renewal, connections and interconnection development.

The investment expenses approved are as follows:

Amounts in millions of €	**2009**	**2010**	**2011**	**2012**
RTE	1 040	1 112	1 192	1 360
ERDF share* ("targeted quality" estimate)	2 588	2 732	2 786	3 770

* Investments financed by ERDF (excluding third-party financing).

2. Regulated Asset Base (RAB)

The valuing principles for the regulated asset base approved for TURPE 2 have been renewed. The value of the RAB is calculated from the net book value of assets. The agreed asset incorporation date for the RAB is set at 1 January of the year following their commissioning. The RAB forecast for 2009 to 2012 is based on the pace of investments deployed over the period and is reduced by the depreciation expenses covered by the tariffs.

Moreover, the principle applied since TURPE 2 concerning fixed assets under the legal revaluation of 1976 has been retained. These assets are incorporated in the RAB at their acquisition cost (excluding revaluation). Working capital requirements (WCR) are excluded from the scope of assets retained for the RAB. Financial costs for current fixed assets are now only considered for coverage when the regulated activities in question finance investments with a long-term expenditure phase before commissioning. Consequently, no return is planned for ERDF. For RTE, the return for these assets is determined based on the generally approved method for capitalised interest costs, taking into account a rate of interest comparable to the cost of the debt.

The rate of return approved for RTE's current fixed assets is a nominal pre-tax rate of 4.8%, in line with the scope approved to calculate the weighted average cost of capital (see below).

a) RTE

In addition to the principles stated above, the RAB is reduced by investment subsidies and pre-recorded revenues from RTE's subsidiary @rteria, in accordance with the CRE deliberation dated 7 December 2006.

The provisional estimate approved for the RAB over the 2009-2012 period is as follows:

RTE – amounts in millions of €	**2009**	**2010**	**2011**	**2012**
RAB approved as at 01/01/N	**10 408**	**10 558**	**10 789**	**11 152**

b) ERDF

When determining TURPE 2, CRE applied the general principle that the value of assets to be considered for the RAB must be independent of their financing method, whether directly financed by the distributor or financed by the franchiser. It is, however, necessary to ensure that the system operator does not receive a double return related to these assets, hence the RAB calculation principles described in the TURPE 2 explanatory statement, namely:

- deduction of initial franchiser investments ("historic contributions"), as at 31 December 2004, from the net book value of fixed assets,
- assets employed as of 1 January 2005 are incorporated into the RAB in their full amount. In return, capital costs are reduced by the amount of third-party financing for the year.

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These principles have been retained for TURPE 3. This means that the depreciation of industrial assets to be covered by the tariffs must be reduced by the share of depreciation related to historic contributions. The corresponding annual amount for the TURPE 3 application period is estimated at €402 million on average for ERDF. The provisional level of capital costs takes this effect into account: the depreciation of industrial assets forecast by ERDF for the TURPE 3 application period is reduced by the depreciation expenses related to historic contributions. In return, the stock of the historic contributions deducted from the RAB decreases over time. This restatement is made from 1 January 2005 and also affects the CRCP financial statement for the TURPE 2 application period.

The provisional estimate for ERDF's RAB for the 2009 - 2012 period is as follows:

ERDF - amounts in millions of €	**2009**	**2010**	**2011**	**2012**
RAB approved as at 1 January	**28 450**	**29 973**	**31 558**	**33 124**

3. Rate of return on assets

The method adopted to evaluate the assets' rate of return is based on the weighted average cost of capital (WACC) for a normative financial structure. The operator's return should firstly finance the interest charges on its debt, and secondly provide a return on equity comparable with what investments elsewhere, with similar levels of risk, might bring.

The cost of capital is estimated using the Capital Asset Pricing Model (CAPM). As it does for each new tariff proposal, CRE has re-examined the various parameters used to calculate the WACC and the resulting range of values. It also bases its calculations on a study entrusted to an external consulting firm on the weighted average cost of capital for electricity and gas infrastructures. The purpose of this study was to present a benchmark analysis of the rates of regulators in Europe and to define a range of values for each of the elements that make up the WACC.

For this tariff proposal, CRE used the value of 7.25%, nominal rate pre-tax, using a range of values for each parameter included in the WACC formula. The estimates for each of these parameters appear in the table below. The main changes compared with the values used to set the TURPE 2 rates are:

- An increase in the cost of capital,
- Normative leverage in line with leverage observed for RTE and with European practices,
- A decrease in the asset beta, in line with the significant drop in operators' risk profile related to the extension of the CRCP's scope, which can be used in particular to protect operators from the risk of withdrawal fluctuation.

Nominal risk-free rate	4.20%
Debt spread	0.60%
Asset beta	0.33
Equity beta	0,66
Market premium	4.50%
Leverage (debt / debt + equity capital)	60.00%
Corporate income tax rate	34.43%
Cost of debt *	4.80%
Cost of equity *	10.92%
Nominal pre-tax WACC	7.25%

**nominal rate before corporate income tax*

4. Capital cost levels

The amounts of capital costs adopted for RTE and ERDF are as follows:

RTE – amounts in millions of €	**Average TURPE 3**
Return on employed assets	778
Return on current fixed assets	46
Depreciation covered by the tariff	599
Total capital costs	**1 423**

ERDF - amounts in millions of €	**Average TURPE 3**
Return on employed assets	2 231
Depreciation covered by the tariff	1 641
External contributions for the year	-607
Total capital costs	**3 265**

C. Recognition of the CRCP balance at the end of 2008

The CRCP balance at the end of 2008 is estimated at + €865.9 million for RTE and + €941.3 million for ERDF. Offsetting these amounts decreases the costs to be covered. In compliance with the TURPE 2 explanatory statement, these amounts include a rate of interest applied annually, at the end of the year, which is equal to the RAB basic rate of return, i.e.7.25%.

The balances calculated at the end of 2008 take into account:

- The outstanding CRCP balance for the TURPE 1 application period,
- The CRCP balance as at 31 December 2008 for the TURPE 2 application period,
- For RTE, revenues from auctions in 2005 on the France-Italy border, in accordance with the provisions of regulation (EC) No. 1228/2003,
- For ERDF, the approved adjustment related to historic contributions for the calculation of capital costs (see section III.B.2).

The CRCP balance at the end of 2008 is based on estimates for 2008. A secondary correction entry could be made according to the final values, as part of the annual CRCP offsetting mechanism (see section IV.E).

The CRCP balance at the end of 2008 is offset for a duration of five years, with constant annuity. These terms ultimately lead to amounts that are to be deducted from the costs to be covered by future tariffs of €212.6 million per annum for RTE and €231.1 million per annum for ERDF.

D. Costs for local distribution companies (entreprises locales de distribution - ELD)

CRE has estimated fixed costs for all ELDs based on the costs presented by ERDF and EDF Systèmes Electriques Insulaires (EDF SEI) on a pro rata basis of the energy they distribute.

Given the specific nature of the public distribution networks operated by the ELD or their clientele, the application of this proposal may lead to some ELDs recording shortfalls or surplus revenues that may require the adaptation of the current equalisation.

E. Revenues deductible from the costs to be covered

The forecasts for revenues received over and above the tariffs for the use of the grids are deducted from the forecast operating costs to be covered by the tariffs. For RTE, such revenues are mainly from interconnection auctions and for ERDF from additional services and connection contributions. The remainder of the item is made up of capitalised generation.

1. Revenues related to interconnection management mechanisms with neighbouring countries

Revenues related to interconnection management mechanisms with neighbouring countries are currently made up of revenues resulting from the interconnection capacity allocation mechanisms, known as auction revenues, and additional revenues related to the use of interconnection capacity such as revenues from contracts between transmission system operators (TSOs).

In accordance with article 6, point 6, section c) of Regulation (EC) No. 1228/2003, part of revenues from auctions may be allocated to decrease tariffs.

The forecast annual values of auction revenues allocated to decrease tariffs and revenues from contracts between transmission system operators are indicated in 2009 constant Euros in section IV.E.3.

2. Additional services

In addition to services covered by this tariff proposal, whose composition results mainly from franchise specifications and the payment of applicable board services, system operators propose additional services provided upon user request, or of their own doing. These additional services fall into two categories:

- Additional services provided under the monopoly of system operators: these services come under the provisions of section III of article 4 of the French amended law No. 2000-108 dated 10 February 2000 according to which CRE sends proposals justified by tariffs for additional services provided under the monopoly of system operators to the Ministers in charge of the Economy and Energy,
- Additional services provided by system operators according to competition principles: the prices of these services are freely determined by the system operators.

Forecast revenues from these services are deducted from the costs to be covered by the tariff for the use of public electricity grids up to the amounts stated in 2009 constant Euros in section IV.E.3.

These estimates are based on business forecasts provided by ERDF and the tariffs provided for in the CRE tariff proposal dated 30 October 2008 concerning additional services provided under the monopoly of system operators.

3. Connections

The billing system for operations of connection to public distribution grids has changed with the application of French law No. 2003-590 dated 2 July 2003 on urban planning and housing, to ensure compliance with law No. 2000-1208 dated 13 December 2000 on solidarity and urban renewal.

In application of these new provisions, each public distribution system operator draws up a price scale determining connection costs. Moreover, the terms for sharing this cost between applicants, local authorities in charge of urban planning and the tariffs for the use of public electricity grids have been specified. Therefore, public distribution system operators (by means of the tariffs for the use of public electricity grids) share the connection costs with the applicant in the proportion set by the tariff reduction rate for connections, and share extension costs with the local urban planning authority or the applicant (in particular if the applicant is a generator) in the proportion set by the tariff reduction rate for extensions.

Forecast revenues from connection operations are deducted from the costs to be covered by the tariffs for the use of public electricity grids up to the amounts stated in 2009 constant Euros in section IV.E.3.

These estimates take into account the new regulatory framework and the reduction rates defined by French Order dated 17 July 2008 (40% for the two aforementioned reduction rates).

However, given the new regulatory framework and the imprecision of the volumes of future connection requests, these revenues are included in the scope of the CRCP.

F. *Tariff revenues*

The level of costs to be recovered by the tariffs for each operator is as follows:

1. RTE

RTE – amounts in millions of €	**TURPE 3**
Net operating costs	2 983
Capital costs	1 423
CRCP	-213
CRFI	-5
Costs to be covered	**4 188**
Other tariff revenues / Compensation DPP extension	-25
Interconnection revenues deductible from tariff	-145
Tariff revenue	**4 019**

CRFI: *Compte Régulé de Financement des Interconnexions* (regulated account for the financing of interconnections) (see section V).

Other tariff revenues: net revenues from tariff components described in sections 4 and 9 to 13 of the tariff rules.

DPP: *Dépassements ponctuels programmés* (sporadic scheduled overshoots)

2. ERDF

ERDF - amounts in millions of €	**Average TURPE 3**
Net operating costs	8 341
Capital costs	3 265
CRCP	-231
Tariff revenue	**11 375**

3. Distribution tariff

The tariff for the use of public distribution grids in application in 2006 was determined on the basis of costs to be covered for ERD and local distribution companies (LDC). ERD's business scope covered non-interconnected electricity grids. Since ERDF became a subsidiary, these grids are operated by EDF SEI.

This tariff proposal is drawn up on the basis of costs to be covered for ERDF, EDF SEI and the LDCs.

The average unit tariff revenue for the 2009-2012 period for the distribution grids, including charges for the use of the transmission network, comes to 32.6€/MWH.

The distributor EDF SEI has a greater basic unit cost than ERDF that will not be covered in total by the revenues it will receive directly. The difference will be compensated by transfer to EDF SEI.

IV. Regulatory framework

This tariff proposal sets out incentive-based multiyear tariffs. The tariff period covers four years and incentives to control costs and improve quality have been set up.

A. Annual tariff trends

The average increase is spread evenly over the period according to an estimate determined on the basis of forecast trends in harmonised index of consumer prices (HICP) reduced by a change factor for system operators' costs, X.

This cost change factor takes into account the productivity gains proposed by RTE and ERDF over their scope of controllable costs and the impact of tariff changes on suppliers and consumers. The adopted cost change factor is – 0.4% for RTE and – 1.3% for ERDF.

These elements are used to define the initial level of the tariff scale for 2009. The initial tariff scale will subsequently change according to the index of consumer prices and factor X.

The first tariff change for 2009 involves an average 2% increase for the tariff for the use of the public transmission grid and an average 3% increase for the tariff for the use of the public distribution grids.

As of 2010, tariff levels will automatically be adjusted on the same date as the first change in 2009, by applying to the tariff scale in force the following percentage change, for year N:

For HVB ranges: $Z_N = IPCH_N - X + K_N$

Z_N: percentage of change of the tariff scale in application as of the first day of month *M* (where *M* is the month of the entry into force of the tariffs) of year *N* compared to that in application the previous month.

$IPCH_N$: percentage of change between the average value of the harmonised index of consumer prices - France 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.

X: cost change factor equal to – 0.4%.

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

For HVA and LV ranges: $Z'_N = IPCH_N - X' + K'_N$

Z'_N: percentage of change of the tariff scale in application as of the first day of month *M* of year *N* compared to that in application the previous month.

X': cost change factor equal to – 1.3%.

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

B. Cost control incentives

This tariff proposition includes incentives to control operating costs for RTE and ERDF deemed controllable.

The reference basis to measure RTE productivity can be broken down as follows:

RTE – amounts in millions of €	**2009**
Net operating costs	**2 918**
Costs related to loss compensation	-820
International congestion costs	-6
Net book value of decommissioned fixed assets	-29
Net outsourced costs related to interconnection management fees	-2
TSO revenues	19
Purchases related to the electricity system (excluding congestion and losses)	-378
Consolidation expenses	-140
Tax	-433
Other net operating revenues	41
Basis of controllable costs	**1 170**

The following changes (in 2009 constant Euros) are applicable for the 2009-2012 period:

RTE - amounts in millions of €	**2009**	**2010**	**2011**	**2012**
Basis of controllable costs	**1 170**	**1 161**	**1 151**	**1 151**

The reference basis to measure ERDF productivity can be broken down as follows:

ERDF - amounts in millions of €	**2009**
Net operating costs	**8 233**
Charges for the use of the transmission network	-2 936
Costs related to loss compensation	-1 455
Net book value of decommissioned fixed assets	-40
Connection contributions	623
Revenues from additional services	177
Tax	-679
Central costs	-70
Other net operating revenues	164
Basis of controllable costs	**4 017**

The following changes (in 2009 constant Euros) are applicable for the 2009-2012 period:

ERDF - amounts in millions of €	**2009**	**2010**	**2011**	**2012**
Basis of controllable costs	**4 017**	**3 935**	**3 871**	**3 894**

If the amount of controllable operating costs actually generated for year N is lower than the amount stated above, revalued against HICP trends adopted for the calculation of tariffs for year N and prior years, 50% of the difference will be deducted from the estimate of costs to be recovered. For 2009, the reference basis will be determined on a pro rata basis as of the date of entry into force of the tariffs.

The cost control incentive calculated annually and discounted at an annual rate of 4.2% attributed to the CRCP balance at the end of the tariff period.

C. Incentive-based regulation of costs related to loss compensation

RTE and ERDF purchase three types of products to compensate their energy losses: forward products, hourly-based products (options and forfeit penalty) and imbalances (residual losses compensated with the balancing mechanism). To compensate losses, the products are stacked with different timeframes:

- Forward products: the system operator makes a long-term forecast of losses, more than three years in advance. This forecast may be refined almost up to real time. The system operator enters into forward product contracts to cover this forecast. The contracts are broken down into annual, quarterly and monthly blocks, setting apart baseload hours (24h/24h) and peakload hours (8am-8pm Monday to Friday). Monthly forecast requirements in baseload and peak energy are covered by stacking annual (2 products), quarterly (8 products) and monthly (24 products) blocks, or by exchanging energy blocks to follow the long-term forecast curve as closely as possible, i.e. a total of 34 different forward products each year (and combinations of these products for exchanges). The organised market for forward products in France is Powernext® Futures,
- Hourly-based products: these products cover forecasts refined to hourly periods. Hourly product contracts almost up to real time are known as spot products. The organised market for spot products in France is Powernext® Day-Ahead,
- Imbalances: imbalances with losses recorded for half-hourly periods in the system operator's scope of balancing (residual losses) are valued at prices determined by the balancing mechanism.

In order to incite ERDF and RTE to limit costs related to loss compensation and to ensure that their purchasing policy is efficient, CRE has set up an incentive-based mechanism concerning transactions of forward products in proportion to the volumes declared to CRE by RTE and ERDF, according to the terms described below.

This mechanism is made up of three parameters:

- System operator *performance* (see performance calculation section below),
- A *bonus* or penalty *(*according to whether performance is positive or negative) equal to 50% of the system operator's *performance,*
- A limit applied to protect users from excessive cost increases due to the system operator's counter-performance (negative *performance*).

1. Calculation of the system operator's annual performance

The system operator's performance is calculated annually as the difference between the reference cost and the actual cost.

Performance is positive when the actual cost is lower than the reference cost. Performance is negative (counter-performance) when the actual cost is greater than the reference cost.

Performance = reference cost – actual cost

a) Reference cost

The reference cost for year N calculated in N+1, reflects the purchasing conditions of a reference system operator. It is determined from average Futures listings and the energy volumes declared by the system operator for each forward product required to cover the forecast requirements for year N, excluding volumes formalised by contract before the tariff application date.

Transactions of forward products due to be delivered after 2012, formalised by contract during the TURPE 3 application period, will be regulated according to the rules in force at the time of contract.

Before 28 December each year, RTE and ERDF declare to CRE, by registered letter with acknowledgement of receipt or any other method that certifies this declaration to CRE, the energy volumes needed to cover the forecast annual requirements, per type of forward product. These energy volumes may be negative to enable system operators to conduct purchasing policies including exchanges of energy blocks between months or quarters.

These declarations may be modified for each forward product until the day before the first day that the product is listed on Powernext® Futures, according to the same notification terms as annual declarations.

In the 15 days following the publication of this tariff proposal in the French *Journal Officiel* (official bulletin), an initial declaration must be sent to CRE stating the energy volumes still to be purchased from the date of application of the tariffs for all products being listed on this date.

The average Futures listing for each product declared is calculated on the basis of the mathematical non-weighted average of *Daily Settlement Prices* recorded *ex-post* on Powernext® Futures between the date of application of the tariffs and the close of the product's listing period for a standard purchase and on the shared listing period for two exchanged products after the date of application of the tariffs for a block exchange.

Each year, the reference cost is calculated as the total of declared energy volumes, valued by the average Futures listing of the various forward products.

$$\text{Reference cost} = \sum_{X} \left[\text{voldéclaré}_X \times \text{cotFmoy}_X \right]$$

voldéclaré$_X$: energy volume declared corresponding to product *X*

cotFmoy$_X$: average Futures listing of product *X*

b) Actual cost

The portfolio of monthly forecast energy volumes is put together using the portfolio of declared energy volumes, separating off-peak and peak hours. The portfolio of monthly forecast energy volumes consequently includes 24 monthly values.

CRE will check that the monthly forecast energy volumes declared correspond to the monthly energy volumes contractualised, with all differences valued at *spot prices*.

Each year, the actual cost is calculated as follows:

- The total of contractualised forward product costs,
- Restated with the imbalances between monthly forecast energy volumes and monthly energy volumes contractualised via forward product transactions, valued by the average *Day-Ahead listing.*

The actual cost is estimated by CRE on the basis of data provided monthly by the system operator and only considers product transactions made by the system operator after the tariffs' application date.

The average Day-Ahead listing is the mathematical non-weighted average of listings recorded on Powernext® Day-Ahead over all hours purchased compared to the monthly forecast energy volume.

If, for one of the 24 items in the portfolio, the monthly energy volume contractualised via forward product transactions made by the system operator from the tariff application date is lower than the monthly forecast energy volume, the cost of the contractualised monthly energy volume transaction is increased by the difference in volume valued at the average *Day-Ahead* listing.

If, for one of the 24 items in the portfolio, the monthly energy volume contractualised via forward product transactions made by the system operator from the tariff application date is greater than the monthly forecast energy volume, the cost of the contractualised monthly energy volume transaction is decreased by the difference in volume valued at the average *Day-Ahead* listing.

$$\text{Actual cost} = \sum_X \left[\text{volconst}_X \times \text{prixconst}_X\right] - \sum_h \left[\left(\text{volhconst}_h - \text{volhprev}_h\right) \times \cot\text{DAmoy}\right]$$

volconst$_X$: volume of product *X* recorded for forward product transactions made by the system operator from the tariff application date

prixconst$_X$: average price recorded from the tariff application date for product *X* transactions.

volhconst$_h$: energy volume for hourly periods contractualised via forward product transactions made by the system operator from the tariff application date

volhprev$_h$: forecast energy volume for hourly periods

cotDAmoy: average *Day-Ahead* listing

2. Procedure for sharing out the system operator's annual performance

In the event of positive performance, the system operator receives a bonus, equal to 50% of performance.

In the event of negative performance (counter-performance), the system operator receives a penalty, equal to at least 50% of performance. The remainder of the negative performance is borne by users, up to a ceiling of €20 million for RTE and €40 million for ERDF.

The bonus/penalty for year N related to the incentive-based regulation for loss compensation will be calculated at the end of the first half of each year N+1.

3. Impact of exceptional circumstances on the incentive-based regulation of loss compensation

If market conditions or a major change in system operators' scope clearly change the principles of the incentive-based regulation described in this proposal, changes to the performance calculation may be proposed.

In the event of a supplier failing to supply, the actual cost used to calculate performance includes all transactions in the system operator's portfolio that have been contractualised. Only new transactions related to the reconstitution of the portfolio will be excluded from the system operator's performance calculation.

D. Incentive-based quality regulation

The quality provided by system operators is one factor given in return for the tariffs paid by users. In order to provide users with the best economically justified level of quality, improvement incentives must be applied, as for cost control. The incentive-based quality regulation also aims to prevent false productivity gains being reached through drops in the quality of supply or service.

This scheme is designed to apply to RTE and ERDF.

The indicators provided to CRE by RTE and ERDF are included in RTE's and ERDF's operational process steering over the second half of 2009. These processes, and the RTE and ERDF steering system, will be subject to certification audits conducted by external bodies, in compliance with ISO 9001 requirements.

Moreover, the quality monitoring systems used by RTE and ERDF and the data provided by RTE and ERDF may be subject to any audit considered useful by CRE.

1. Incentive-based supply continuity regulation

CRE has set up a mechanism to encourage supply continuity. For its first implementation, only the "average power cut duration" indicator will be subject to a financial incentive. Depending on feedback, CRE may extend the scope of the technical criteria subject to incentives in the next tariff proposal, in order to cover other aspects of supply quality.

The provisions of this section do not prevent RTE or ERDF from providing CRE with other quality indicators concerning the public electricity grid, in particular those in the ERDF or RTE activity reports. In addition, these provisions do not prevent ERDF or RTE from sending quality indicators concerning the public electricity grid to other stakeholders, in particular users and licensing authorities.

a) RTE

Parameters of the incentive scheme

For RTE, the average power cut duration for year *N* (DMC_N), in minutes, is calculated by using the following formula:

$$DMC_N = \frac{\text{Total END for year N x 60}}{\text{PMDA (excl. losses) for year N-1}}$$

END: undistributed energy, in MWH. Non distributed energy is determined excluding incidents following exceptional events (see definition below). The calculation of non distributed energy includes load shedding for reasons related to the public transmission grid.

PMDA: average annual distributed power, in MW. *PMDA* is obtained by dividing the value of energy (excluding losses) distributed in the year by 8,760 hours (or 8,784 hours if year *N-1* is a leap year).

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

$$I_N = -9.6 \times DMC_{réf} \times \ln\left(\frac{DMC_N}{DMC_{réf}}\right)$$

$DMC_{réf}$: reference average power cut duration, in minutes. This value is set at 2 min 24 s for the entire duration of the tariff period.

I_N: financial incentive for year *N*, in M€, which may result in negative values. The absolute value of annual incentive I_N is limited to €20M.

Monitoring supply continuity

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

- Energy not distributed (for all reasons),
- Energy not distributed excluding exceptional events,
- For each exceptional event: all factors justifying the exceptional nature of the event, the energy not distributed during the event and all factors demonstrating how quickly RTE took measures to restore normal operating conditions and how relevant these measures are,
- Energy not distributed during load shedding,
- Energy not distributed during load shedding due to the public transmission grid.

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

- The average annual power cut duration (for all reasons),
- The average annual power cut duration excluding exceptional events,
- The average annual power cut duration following load shedding,

- The average annual power cut duration following load shedding due to the public transmission grid.

b) ERDF

Parameters of the incentive scheme

For ERDF, the average power cut duration for year *N* (DMC_N) is calculated by using the following formula:

$$DMC_N = \frac{\sum_{Year\ N} Powercut\ durations\ for\ LV\ customers}{Total\ number\ of\ LV\ customers\ as\ at\ 1^{st}\ January\ of\ year\ N}$$

DMC_N is determined excluding incidents resulting from exceptional events (see definition below) and excluding reasons related to the public transmission grid (or load shedding). Power cuts following work on the public grid operated by ERDF are also excluded, due to the programme for the removal of transformers containing PCB which, if considered, would lead to a temporary increase in the average power cut duration the extent of which ERDF claims it is unable to measure at present. In order to avoid abuse, ERDF must provide CRE with the average annual power cut duration following work on the public distribution grid operated by ERDF, with the details of impact related to the programme for the removal of transformers containing PCB.

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

$$I_N = -4 \times (DMC_{N\,réf} - 28) \times \ln\left(\frac{DMC_N - 28}{DMC_{N\,réf} - 28}\right)$$

$DMC_{N\,réf}$: reference average power cut duration for year *N*, in minutes. This value is set at 55 min in 2009 and 2010, 54 min in 2011 and 52 min in 2012.

I_N: financial incentive for year *N*, in M€, which may result in negative values. The absolute value of annual incentive I_N is limited to €50M.

Monitoring supply continuity

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

- The average power cut duration (for all reasons),
- The average power cut duration for all reasons related to the public transmission grid (or load shedding),
- The average power cut duration excluding exceptional events and reasons related to the public transmission grid (or load shedding),
- For each exceptional event: all factors justifying the ‘exceptional event’ classification, the average power cut duration due to the event and all factors demonstrating how quickly ERDF took measures to restore normal operating conditions and how relevant these measures are;
- Work on the public distribution grid operated by ERDF (with the details of impact related to the programme for the removal of transformers containing PCB).

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

- The average annual power cut duration (for all reasons),
- The average annual power cut duration for all reasons related to the public transmission grid (or load shedding),

- The average annual power cut duration excluding exceptional events and reasons related to the public transmission grid (or load shedding),
- The average annual power cut duration following work on the public distribution grid operated by ERDF (with the details of impact related to the programme for the removal of transformers containing PCB).

c) *Exceptional events*

The following are considered to be exceptional events under the incentive-based supply continuity regulation:

- 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 French amended law No. 82-600 dated 13 July 1982,
- Sudden, unplanned and simultaneous unavailability of several generation 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.

2. Incentive-based service quality regulation

The service quality regulation mechanism can be broken down into two types of indicators:

- Indicators monitored by CRE that are subject to a financial incentive or penalty if previously defined objectives are not reached or exceeded. These financial incentives come in the form of either a bonus or a penalty allocated to the CRCP account, or financial compensation paid directly by ERDF to users (or third parties authorised by said users) that so request,
- Indicators that are simply monitored by CRE.

These indicators are provided to CRE by ERDF and are published. The terms for publication, in particular on the ERDF website, are proposed to CRE by ERDF three months after the tariff application date at the latest.

The provisions of this section do not prevent ERDF from providing CRE with other service quality indicators, in particular as part of the ERDF activity report or as part of the monitoring of retail markets. Furthermore, these provisions do not prevent ERDF from providing service quality indicators to market players, in particular suppliers and licensing authorities, especially as part of the *Comité des Utilisateurs de Réseau de Distribution Electrique* (electricity distribution grid users committee - CURDE) or contractual relations with ERDF.

a) *ERDF service quality monitoring indicators covered by the financial incentive*

The following five indicators are covered by the financial incentive:

- The number of complaints for scheduled appointments not kept by ERDF,
- The complaints response rate within 30 days,
- The number of connection proposals not sent within the set timeframe,
- The time needed to send the half-hourly measurement curves for each balancing responsible entity to RTE,

- The availability rate of the “Supplier” portal.

The details of these indicators and the related financial incentives are specified in the appendix (section VII).

The total amount of bonuses/penalties that ERDF may pay or receive as part of the incentive-based service quality regulation is limited to a ceiling of €20M/year in absolute value.

b) Other ERDF service quality monitoring indicators

ERDF service quality monitoring includes:

- three indicators concerning call-outs/work,
- two indicators concerning user relations,
- two indicators concerning supplier relations,
- four indicators concerning metering and billing,
- four indicators concerning connections.

The details of these indicators are specified in the appendix (section VII).

On the basis of feedback, CRE may modify the list or the definition of ERDF service quality monitoring indicators during the tariff period.

E. CRCP - Expenses and Revenues Clawback Account

1. Principles

Given the four-year term of the application period of the proposed tariffs, CRE has based this tariff proposal on estimates of short- and medium-term trends affecting expenses and revenues. It is difficult for public system operators to forecast or control some categories of expenses and revenues.

If the tariffs for the use of public electricity grids could not be adjusted in accordance with these expenses or revenues, system operators would be exposed to a financial risk or conversely could benefit from external factors which would be likely to increase their profitability. It is therefore legitimate, either to compensate system operators for their deficits, via a tariff adjustment, or to retrocede the excess revenues to users.

To do so, CRE has renewed the Expenses and Revenues Clawback Account mechanism (CRCP), set up as part of TURPE 2, to measure and compensate discrepancies between actual and forecast expenses and revenues for previously identified items on which the tariff proposal is based.

This account is an extra-accounting trustee account holding surplus earnings and, where necessary, shortfalls for public system operators. It is offset annually by decreases or increases in the tariff scale. The contribution of CRCP offsetting to the annual variation of the tariff scale is limited to approximately 2%.

2. Scope

For this tariff proposal, the expense and revenue items covered by the mechanism are as follows:

- Costs related to loss compensation on the grids,
- Grid access costs paid by ERDF to RTE,
- Some costs related to interconnection management, namely international congestion costs and net outsourced costs related to interconnection capacity allocation management fees, provided they can be audited,
- Capital costs,
- The net book value of decommissioned fixed assets (stranded costs),
- The extra insurance premium underwritten by ERDF against storms in the event of a major climatic risk,

- Revenues received for all pricing components according to the terms stated hereinafter (section IV.E.3 of point 2 below),
- Revenues related to transmission grid interconnection congestion management mechanisms with neighbouring countries. These revenues are free of all compensation paid by RTE in the event of a reduction in interconnection capacity,
- Revenues related to contracts between TSOs,
- Revenues received for connection operations,
- Revenues received for the provision of additional services,
- The difference between planned and actual annuities resulting from the application of the CRFI mechanism, described in section V,
- Financial incentives related to the various incentive-based regulation mechanisms.

As regards the local tax on businesses (*taxe professionnelle*), in the event of legislative modifications affecting the adopted estimates, the differences resulting from such modifications would be considered in the CRCP.

In the event of RTE having to pay additional rent to the French national railway company SNCF for the use of electricity transmission structures operated by RTE over the 2002-2008 period following a final judgment from the Administrative Court after RTE has used all avenues for appeal, these costs would be considered in the CRCP.

In addition, the results of audits conducted by CRE will be considered in the CRCP.

3. Operating rules

For each item considered for the CRCP, discrepancies are calculated according to the rules stated below.

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

   As the tariff scale is indexed to the consumer price index, system operators are covered from the risk of inflation for all their expenses. Yet changes in expense items covered by the CRCP mechanism, such as the compensation of energy losses on the public electricity grid or capital costs, are not necessarily related to HICP trends. To correct this, CRE has adapted the reference values used to calculate the CRCP.

   These reference values, required for the calculation of the CRCP for year N, are therefore calculated on the basis of provisional values in 2009 constant Euros and are revalued annually according to the HICP adopted for the calculation of the tariff scale of year N and previous years.

   The provisional values, in 2009 constant Euros, for the various items of operating and capital costs, are displayed in the table below:

   For RTE:

RTE – amounts in millions of €	2009	2010	2011	2012
Costs related to loss compensation	820	713	703	675
International congestion costs	6	5	5	5
Net book value of decommissioned fixed assets	29	37	33	28
Net outsourced costs related to interconnection management fees	2	2	2	2
Operating costs	**857**	**757**	**743**	**709**
Net auction revenues of paid compensation in cases of capacity reduction	215	195	172	179
TSO revenues	19	17	16	16
Operating revenues	**234**	**212**	**188**	**194**
Capital costs	**1 351**	**1 362**	**1 384**	**1 416**
CRFI annuities	**0**	**1**	**5**	**12**

For ERDF:

ERDF - amounts in millions of €	2009	2010	2011	2012
Charges for the use of the transmission network	2 936	2 984	3 027	3 077
Costs related to loss compensation	1 455	1 326	1 315	1 230
Net book value of demolished fixed assets	40	39	38	38
Operating costs	**4 431**	**4 349**	**4 380**	**4 345**
Connection contributions	623	617	621	625
Revenues from additional services	177	179	181	183
Operating revenues	**800**	**796**	**802**	**808**
Capital costs	**2 963**	**3 082**	**3 204**	**3 396**

2. As regards revenues received for all pricing components, surplus earnings or shortfalls for year N will be valued on the basis of the tariff turnover generated, forecast energy volumes, power subscriptions and the number of connection points used to draw up the pricing components and the tariffs of the corresponding year. Operators are therefore covered for the risk related to the uncertainty of forecast quantities used to draw up the tariffs.

   The aggregated provisional values of subscribed power and withdrawn energy volumes used are as follows:

		2009	2010	2011	2012
Energy (TWH)	**HVB**	459.14	463.67	465.76	469.63
	HVA	123.08	124.56	125.90	128.13
	LV	222.79	225.59	228.42	231.05
Power (GW)	**HVB**	94.87	95.79	96.35	97.15
	HVA	59.14	59.79	60.45	61.07
	LV	363.86	368.34	372.89	377.22

3. As regards expenses related to loss compensation, the difference in costs for year N between the reference value of the loss purchase cost and the costs actually borne by the system operator will be posted to the CRCP in full, excluding the following exceptions:
   - These costs do not cover any premiums paid by the system operator for an options ceiling price,
   - Any excess costs resulting from the reconstitution of the system operator's portfolio will be offset via the CRCP: in full for *force majeure* events or supplier insolvency and 50% for events qualified as circumstances considered as *force majeure* in contracts,

- If the annual volume of imbalances attributed to the system operator's balancing scope (differences between the volume of losses actually recorded, following the process to calculate imbalances in *M+x* and the hourly estimate) is greater than 4% for ERDF and 8% for RTE 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 costs related to loss compensation will only take into account the costs to purchase half-hourly products up to the limit of 4% for ERDF and 8% for RTE of the volume of recorded losses,
- If the annual sum of absolute values of ERDF's loss volumes calculated during temporal reconciliations is greater than 1 TWH, 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 costs related to losses will only take into account temporal reconciliation costs up 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.

   In order to spread the impact of the incentive-based regulation related to loss compensation, supply continuity and service quality over time, the total amount of financial incentives is allocated to the CRCP at the end of the tariff period. These amounts are calculated annually and discounted at a rate equivalent to a risk-free rate according to the same calculation terms as the CRCP items (described in the following point).
5. In order to ensure the mechanism's financial neutrality, the discounted CRCP balance, for imbalances recorded over the TURPE 3 application period, is calculated annually according to a rate of interest equivalent to the risk-free rate adopted as part of this tariff proposal. This rate is 4.2% for the TURPE 3 application period.
6. The CRCP balance calculated for calendar year N is offset in part or in full as of the following year. The annual offsetting of the balance cannot have an impact on the tariff scale greater than approximately 2%.
7. System operators will send the amounts required for the calculation of the CRCP of year N to CRE two months before the tariff change at the latest.

4. Provisions for 2009

From 1 January 2009 to the tariff application date, the CRCP scope and operating rules will continue to apply as defined in TURPE 2. The reference values taken into account are calculated on a pro rata basis of the values used for TURPE 2.

From the tariff application date to 31 December 2009, the CRCP scope and operating rules will apply as defined in TURPE 3. The provisional values taken into account will be calculated on a pro rata basis of the values above for 2009.

V. Interconnections financed by auction revenues

A. Financing of interconnections by auction revenues

Article 6, point 6 of Regulation (EC) No. 1228/2003 states that any revenues resulting from the allocation of interconnections shall be used for one or more of the following purposes:

- guaranteeing the actual availability of the allocated capacity,
- network investments maintaining or increasing interconnection capacities,
- as an income to be deducted from costs to be covered by network tariffs.

In accordance with this regulation, this tariff proposal is based on the considerable allocation of provisional revenues to the financing of network investments to increase interconnection capacities.

The total amount of auction revenues allocated to interconnection financing is €202.9 million. The balance of the revenues is allocated to decreasing the tariffs.

If over the entire tariff period, the total amount of interconnection investments financed by auction revenues is lower than €202.9 million, the remaining balance at the end of the tariff period will be allocated to decreasing the tariffs.

B. Interconnections financed by auction revenues

The interconnection investments made by RTE financed by auction revenues are accounted for in the operator's industrial assets. Consequently, they appear in RTE's regulated asset base. These investments lead to capital costs during their lifespan.

In order to avoid a double return on assets, the costs to be covered by the tariff are reduced by the capital costs corresponding to the forecast investments financed by auction revenues adopted by CRE. For this purpose, a specific regulatory account has been created, the *Compte Régulé de Financement des Interconnexions* (regulated account for the financing of interconnections - CRFI). This account corresponds to the forecast investments financed by auction revenues presented above. These investments incur capital costs that must be deducted from the tariff (CRFI annuity).

Capital costs are determined according to the following terms:

- Pre-tax rate of return of 7.25%,
- Depreciation on the basis of a normative duration of 40 years.

M€	Average TURPE 3
CRFI annuity	5

Each year, actual interconnection investments financed by auction revenues are compared to the adopted forecast. Any differences will be attributed to the CRFI and their impact on capital costs to be restated is corrected via the CRCP.

VI. Tariff structure

A. General tariff principles and structure

As a basis for its tariff proposal, CRE has retained the following general principles, used for the tariffs in force.

1. Tariffs independent of distance

In compliance with provisions in article 4, paragraph 1 of Regulation (EC) 1228/2003 dated 26 June 2003, which mainly states that grid access charges do not depend on the distance separating a generator and consumer involved in a transaction, CRE has maintained the tariff principle known as "postage stamp".

2. Identical tariffs throughout the territory

For the bulk transmission grid, neither current public transmission grid congestion characteristics nor the public system operator's investment plans justify differentiation of tariffs according to geographical zones. The existing very high voltage grid can transit the power generated through various generation facilities whatever the generation plan adopted. The tariffs are therefore identical throughout the territory.

For public distribution grids, the proposed tariff is also identical throughout the territory and is applied to all public distribution system operators, resulting in geographical equalisation of tariffs in compliance with the principle of equality provided for in article 1 of the amended law No. 2000-108 dated 10 February 2000.

3. Injection stamp

Concerning this point, article 4 of French Order No. 2001-365 dated 26 April 2001 stipulates that "tariffs should take into account measures adopted within the framework of the European Union to standardise pricing applicable to international energy exchanges and to facilitate international electricity exchanges". Work carried out under the auspices of the European Commission recommends progressive standardisation of injection stamps in Europe, and proposes to limit their average level to 0.5 €/MWH. These standardisation criteria have been fulfilled in the proposed tariffs.

4. Tariffs based on operator accounting costs

Article 2 of the French Order No. 2001-365 dated 26 April 2001 stipulates that tariffs are to be calculated "based on all costs of these grids, as resulting from analysis of technical costs [and] operator general accounting". CRE has therefore adopted a method for tariff construction which is based on using operator accounting costs.

Public system operators divide their accounting costs into voltage ranges. Once the total cost to be paid by all users of a voltage level has been determined, the cost is then distributed among these users.

5. Allocation of costs among users at the pro rata of energy flows produced on the grids

Energy is mainly injected at very high voltage to be consumed for the most part by distribution grid users. This is why energy successively uses portions of the grid at decreasing voltage levels. Grid users therefore contribute, through the energy flows produced for them, to a very large majority of the costs borne by operators to manage grids upstream. Thus, tariff revenues received from a user not only cover the costs of the user's connection voltage range but also part of the costs of upstream voltage ranges.

6. Withdrawal tariffs based on subscribed power and energy withdrawn

Withdrawal tariffs depend on the connection voltage range, subscribed power and energy withdrawn.

The tariff revenues received from users of the same voltage level must cover the cost of losses and system services generated by these users, and part of the fixed grid costs, for upstream voltage levels and connections.

7. Portfolio effect of power transited on the transmission and distribution grids

The probability that all users withdraw all subscribed power at the same time is especially low since users withdraw energy for a short duration over the year. A user with a short duration of use will contribute to dimensioning the grids to a lesser extent, and as a result should pay a lower contribution to finance fixed costs.

This is calculated by portfolio effect coefficients that reflect the proportion of subscribed power consumed on average, per connection point, during the most loaded hours for the upstream grid.

This portfolio effect is even more significant if the grid used by power flows is highly meshed. This explains that the portfolio effect is differentiated according to voltage level. The higher the number of lines provided by the grid for power transit, the higher the portfolio effect. At the highest voltage levels (HVB), grids are made up of complex mesh networks, while the lowest voltage levels (HVA and LV) are structured around dead end circuits.

8. Allocation of costs among users of the same voltage range

Once the total cost to be covered by tariff revenues from all users of the same voltage range is determined, this cost must be spread among the users of this voltage range, according to different criteria for each type of cost.

The cost of losses depends directly on withdrawal volumes. As a result, this cost is spread among users of the same voltage range according to the quantity of energy they withdraw.

As the HVB3 network has the most complex mesh, withdrawals on downstream grids have a high portfolio effect with the HVB3 voltage range. Therefore, HVB3 costs do not depend on the power subscribed by users of downstream grids, but on the quantity of energy they withdraw. This is why the proportion of HVB3 costs borne by users of lower voltage ranges is distributed according to the quantity of energy withdrawn.

The other costs are distributed according to the level of subscribed power and energy withdrawn by each user.

9. Structure of tariff options

In compliance with both the non-discrimination principle of tariffs stipulated in article 4-II of the French law dated 10 February 2000 and the drive to control energy demands stipulated in point IV of the same article, CRE has renewed time differentiation of tariffs already in place for distribution by stepping up:

- The degree of time modulation by increasing the ratio between the variable proportion of peak hours and of off-peak hours and the winter/summer ratio,
- The appeal of time differentiated tariffs compared to tariffs without differentiation.

These modifications are based on an objective criterion, namely the increase of time and seasonal differentiation of market prices and therefore the purchase cost of losses, observed over the last few years.

As regards the transmission tariff, CRE believes that since there is currently no time differentiation for the HVB tariff and in consideration of elements currently at its disposal, it is not possible, at short notice, to make far-reaching modifications to the tariff structure or to create new time differentiated tariffs abruptly.

B. Content of and main changes in tariff rules for the use of public electricity grids

The tariff rules contain 15 sections. The first two define the notions used and the structure of tariffs. Sections 3 to 13 describe tariff components.

The rules defined as part of TURPE 2 have been renewed for the most part.

However, in light of the feedback given by system operators and contributions received during public consultations, some provisions of the tariff rules have been modified or added to.

1. Definitions

The list of definitions has been added to in order to specify the conditions of application of the tariffs for the use of public electricity grids.

2. Structure of tariffs for the use of public grids

Section 2 contains a description of the various categories of costs covered by the tariffs for the use of public electricity grids, the tariff structure determined so as to reflect these various categories of costs and the way of applying the various tariffs to each connection point.

The terms of calculation of the tariffs for the points connected to the grid for a duration of less than one year are also specified.

3. Administrative management component

The system implemented during the previous tariff proposal is renewed, namely the express billing of management costs in the form of a fixed charge applicable to all users (producers, consumers and system operators) according to their connection voltage range. This system differentiates users with a grid access contract distinct from the supply contract and those with a single contract with their supplier. For the latter, the management costs borne by distribution system operators are reduced as a large proportion of system operator file management activities is conducted by suppliers who pass the cost on to their customers within a competitive context.

In order to better reflect the costs incurred by system operators, the annual administrative management component is billed per connection point and per access contract.

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

The analysis of system operator accounts shows that the level of the administrative management component applicable to the HVB voltage range is constant in comparison with TURPE 2, but that this component must be revalued for lower voltage ranges.

4. Metering

Previous provisions to enable users to freely choose their metering systems and thus to benefit from offers of supply appropriate to their consumption have been renewed.

All users are billed a metering component depending on the services opted for (meter with index or measurement curve, power control, etc).

This component does not depend on the model of meter installed, or on the reading mode (physical meter reading, remote meter reading through switched telephone network, powerline communication, GSM, etc), insofar as these characteristics come under public grid operators' technical and managerial options and have no impact on accuracy of metering data.

However, in order to simplify the previously implemented provisions, CRE proposes identical pricing for single and multi-index meters and a clarification of pricing of the metering component according to meter ownership.

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

- Checks that metering equipment is working correctly conducted on the initiative of public system operators,
- Reading or remote reading (including subscription and communication costs),
- Measurement, calculation and recording of metering data,
- Validation, correction and provision of validated metering data,
- Where necessary, profiling, for users who do not have meters that record measurement curves.

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

For users whose metering device is owned by public system operators or authorities organising public electricity distribution, the new metering component also covers the following costs:

- Capital costs of metering devices after deduction of the share of connection contributions regarding metering devices,
- Metering equipment maintenance costs,
- Metering equipment renewal costs,
- Where necessary, metering equipment synchronisation costs.

This metering component does not include the cost to change metering devices carried out upon the request of the user or the user's agent, which is subject to specific billing as part of the tariff rules concerning additional services provided under the monopoly of public electricity system operators.

In application of French Order No. 2007-1280 dated 28 August 2007 on the composition of connection and extension structures of connections to public electricity grids, the costs for initial on-site installation and sealing are now billed as part of the contribution paid to the contracting authority of the connection work.

The analysis of system operator accounts shows that the level of the metering component applicable to the HVB voltage range is constant in comparison with the previous tariff rules, but that this component must be revalued for lower voltage ranges.

In order to better reflect the costs undertaken by system operators, the annual metering component is billed per connection point and per access contract.

In order to improve electricity market operating conditions, particularly to the advantage of consumers, and to reduce the costs of system operators, it is necessary to propose advanced metering devices to users as soon as possible. This is why, in its Communication dated 6 June 2007 concerning changes to low-power low-voltage electricity metering (≤ 36 kVA), CRE accepted the principle of a pilot project conducted by ERDF on the large-scale deployment of advanced metering systems. In support of this experiment, the metering component applicable to users with advanced meters is identical to that applied to other users.

5. Injection stamp

As France is a net exporter of electricity, the net contribution made by RTE to the European compensation mechanism between transmission grids for transits is positive. French grid users must not bear the cost of this contribution, for which exporters are responsible. The injection stamp paid by generators located on French territory therefore covers the cost of this contribution.

Generators must also bear, in due proportion, the increase in public transmission system operator costs over the tariff period.

Consequently, the injection stamp is set at 19 €c/MWH over the entire tariff period.

6. HVB withdrawal stamp

The HVB withdrawal tariff depends on subscribed power $P_{Subscribed}$ in kW and the rate of use of subscribed power. The pricing formula proposed for the annual withdrawal component, similar to that in force since 1 November 2002, is as follows:

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

The rate of use is given by the following formula, where D = the number of hours in the year:

$$\tau = \frac{E_{Withdrawn}}{D \cdot P_{Subscribed}}$$

The charge $a_2.P_{Subscribed}$ represents the amount for power reservation. It reflects the public system operator's cost of providing subscribed power at the connection point at any time of the year.

The charge $b.\tau^c.P_{Subscribed}$ represents the share in the bill depending on the energy withdrawn. This pricing formula results from the relative reduction in grid costs generated by users depending on the duration of their use.

As for the tariffs for the use of public electricity grids currently in force, monthly components for power overshoots (CMDPS) are calculated so that users exceeding 10% of their subscribed power for 100 hours in the same month pay the same bill than they would have if subscribing to power 10% higher. Through the renewal of this calculation method, the optimum subscribed power for each user remains unchanged following the transition from TURPE 2 to TURPE 3.

7. HVA withdrawal tariffs

Users connected to the HVA voltage range can choose from three pricing options:

- Option without time differentiation with the same structure as for the HVB voltage range,
- Option with time differentiation in five classes,
- Option with time differentiation in eight classes.

Users opting for tariffs with time differentiation pay high prices during winter full-rate hours but can benefit from lower tariffs outside this period. Grid users or their authorised third parties are free to choose the pricing option and levels of subscribed power. Public distribution system operators advise users or their authorised third parties to enable them to choose the option best suited to their needs.

8. LV withdrawal tariffs

a) LV > 36 kVA

Users connected to the LV range with subscribed power strictly above 36 kVA can choose from two options with time differentiation based on the rate of use of subscribed power.

b) LV ≤ 36 kVA

Users connected to the LV range with subscribed power less than or equal to 36 kVA can choose from four options: short-term utilisation, medium-term utilisation, medium-term utilisation with time differentiation and long-term utilisation.

For all withdrawal tariffs in the LV range, the choice of one of the options depends on needs for power and the rate of use of subscribed power. Grid users or their authorised third parties are free to choose the pricing option and levels of subscribed power. Public distribution system operators advise users or their authorised third parties to enable them to choose the option best suited to their needs.

9. Complementary and back-up power supplies

The level of the annual component for complementary and back-up power supplies is calculated based on average direct costs of lines. In the same way as for consolidations, these levels provide users with financial incentive to invest in their own equipment, in line with the cost of public structures.

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

10. Tariff aggregation of connection points

The level of the aggregation component is calculated based on the average direct costs of lines for physical consolidation. This method of calculation provides users with financial incentive to invest in their own equipment to manage the portfolio effect of their uses, in line with the cost of public structures fulfilling the same function for them.

11. Pricing provisions applicable to public distribution grids

Public distribution system operators have specificities which have been partly defined by the amended law No. 2000-108 dated 10 February 2000 and by article 5-II of French Order No. 2001-365 dated 26 April 2001. In order to incorporate these specificities in the tariffs applicable to the different voltage ranges, the following specific systems have been maintained:

- Transformer utilisation is invoiced depending on the average direct loads of the transformer station,
- Compensation for operating lines at the same voltage as the public grid upstream is determined based on the difference between tariffs in the delivery voltage range and in the voltage range directly below, decreased by the transformer utilisation component and weighted by the parts of these lines operated by the various system operators,
- Peak shaving of monthly bills for distributor power overshoots is authorised in cases of extreme cold, under the same conditions as for TURPE 2.

12. Sporadic utilisation

In order to take into account certain situations when grid capacities can transport power drawn for short periods without any adverse effects for other users, the system for invoicing sporadic scheduled power overshoots (DPP) implemented by TURPE 2 has been renewed. These overshoots, which must have prior approval from the public system operator, are invoiced at the average price of energy withdrawn by a user with a rate of use of 25%.

In order to improve this system, the DPP application period is extended from 1 May to 31 October and the maintenance periods are partly outside the DPP application period in force for TURPE 2.

In return, DPP requests are conditioned by the completion of work on the electricity facilities of the requesting party.

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

13. Billing of reactive energy

The reactive energy pricing system for withdrawal flows is renewed.

a) On keeping compensation devices installed on the public electricity distribution grid

Based on the observation that deploying high voltage reactive power compensation devices corresponds to an economic and technical optimum, to counter the scheduled removal of part of the reactive power compensation devices installed on public distribution grids, and to maintain an average "*phi tangent*" ratio between 0.16 and 0.185 at public distribution grid points of connection to the public transmission grid, specific pricing is applied to reactive power transits at these connection points.

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. In particular, these rules may provide for a gradual decrease in the upper threshold of the "*phi tangent*" ratio of the current obligation of 0.4 to the target value of 0.2 through annual reductions of 0.05 as from 2010.
The values of the thresholds used for the application of the tariff rules take into account, by default, the traditional "*phi tangent*" ratio threshold values, presented in the reference technical documentation of system operators.

b) On the operating capacities of generation facilities with low power control

To support the development of decentralised generation while ensuring the security of the electricity system, the reactive power transit pricing system for injection flows has been completed.

The previous tariff rules characterised the ranges of supply or absorption of reactive power transit not subject to pricing thanks to two "*phi tangent*" ratio thresholds. However, this proved to be insufficient given the operating capacities of low power facilities. The ranges not invoiced at low power have therefore been extended.

c) For generation facilities with voltage control and without system services participation contracts

The creation of wind power development zones abolished the 12 MW threshold previously limiting decentralised generation facility power. Decentralised high-power generation is therefore set to develop, spurred on by wind power generation. As a result, more stringent restrictions on high voltage are beginning to be seen at these facilities' connection points for which an increase in "*phi tangent*" values for reactive power absorption is insufficient.

As these facilities are not intended to enter into a system services participation contract with the public transmission system operator, the tariff rules provide for penalty levels applicable to a facility taking part in voltage control upon the request of system operators, in addition to the existing provisions.

d) On changes to metering periods

The periods subject to tariffs have been modified in line with the programmability of A5 type metering devices.

e) On the tariff aggregation of connection points

The current aggregation terms favour an imbalance of compensation devices and prevent distribution system operators from controlling reactive power transits from generation facilities consolidated with other facilities.

Under these circumstances, the tariff rules provide that the consolidation of connection points for the purpose of billing the annual reactive power component is only possible under the conditions set by system operators in their reference technical documentation.

14. Indexation of the pricing scale

Section 14 defines the pricing scale indexation terms.

15. Transitional provision concerning the implementation of this tariff proposal

In order to enable users to rapidly take advantage of the incentives created by increasing the time and seasonal differentiation of tariffs, CRE has introduced a transitional six-month measure, with effect as of the date the tariffs enter into force, under which it is not necessary to wait for the anniversary date of the last pricing option decision to change option.

In return, this provision should lead to a significant increase in requests to change option over a short period. Some distribution system operators may require several months to conduct the changes for all users concerned. Subsequently, the standard timeframe to conduct changes of transport tariff options set out in the CRE proposal dated 30 October 2008, on additional services provided under the monopoly of system operators, may not be complied with.

VII. Appendices

A. ERDF service quality monitoring indicators covered by the financial incentive

1. Number of complaints for scheduled appointments not kept by ERDF

Indicator:	*Number of complaints for scheduled appointments not kept by ERDF leading to the payment of financial compensation (with breakdown of user categories)*
Monitoring:	Calculated: quarterly Transmitted to CRE: quarterly Published: quarterly
Target:	100% of appointments not kept due to ERDF and reported by users or third parties authorised by these users are subject to financial compensation
Incentive:	Financial compensation paid by ERDF: amounts identical to those billed by ERDF in the event of a scheduled call-out not respected by the user or a third party authorised by the user (absent during call-out, etc.), for each appointment not kept Payment: directly to users submitting a request (or to third parties authorised by these users if the request was made by these third parties)

2. The complaints response rate within 30 days

Indicator:	Number of user complaints processed within 30 calendar days / total number of complaints (excluding complaints requesting compensation related to quality on public grids)
Monitoring:	Calculated: quarterly Transmitted to CRE: quarterly Published: quarterly Incentive calculated: annually (as of the tariff application date)
Target:	Basic target: 95% of user complaints (either received directly or via third parties authorised by these users) processed within 30 calendar days (excluding complaints requesting compensation related to quality on public grids)
Incentive:	Penalty: €100,000 for each whole point below the basic target Payment: to the CRCP

NB: Complaints requesting compensation related to quality on public grids have been excluded from this indicator upon ERDF request. The relevance of this exclusion will be reassessed for the next tariff proposal.

3. Number of connection proposals not sent within the set timeframe

This indicator and the related financial compensation only concern connections for which ERDF manages the entire contract.

Indicator:	Number of connection proposals not sent within the maximum timeframe resulting from the qualification of the request, in compliance with the ERDF billing scale for connection operations to the public electricity distribution grid (with breakdown of connection categories)
Monitoring:	Calculated: quarterly Transmitted to CRE: quarterly Published: quarterly
Target:	100% of exceeded timeframes to send connection proposals reported by persons requesting the connection or by an authorised third party are subject to financial compensation
Incentive:	Financial compensation paid by ERDF: - €30 for individual connection requests for LV ≤ 36 kVA - €100 for individual connection requests for LV > 36 kVA and collective connection requests for LV - €1000 for HVA connection requests Payment: to the person requesting the connection (or to third parties authorised by these persons if the request was made by these third parties)

4. The time to send the half-hourly measurement curves for each balancing responsible entity to RTE

Indicator:	Rate of compliance with the timeframe to send RTE the overall consumption assessments for balancing responsible entities declared active (with sites) on the ERDF network for week W-2 each W and the following measurement curves (MC): - Aggregated MC for consumption on sites with remote measurement curve reading - Aggregated MC for consumption on sites with indexes (profiled) - Aggregated MC for generation on sites with remote measurement curve reading - Aggregated MC for generation on sites with indexes (profiled)
Monitoring:	Calculated: quarterly Transmitted to CRE: quarterly Published: quarterly Incentive calculated: annually (as of the tariff application date)
Target:	Basic target: 90% Main target: 96%
Incentive:	Penalty: €50,000 for each whole point below the basic target Bonus: €50,000 for each whole point above the main target Payment: to the CRCP

5. The availability rate of the "Supplier" portal

Indicator:	Number of hours of availability (excluding scheduled unavailability) / number of opening hours of the exchange management system portal (opening hours are from 7am to 7pm Monday to Saturday excluding public holidays)
Monitoring:	Calculated: weekly Transmitted to CRE: quarterly Published: quarterly Incentive calculated: weekly and annually (as of the tariff application date)
Target:	Basic target: 96% per week Main target: 99% per year
Incentive:	Penalty: €10,000 per week below the basic target Bonus: €100,000 per year above the main target Payment: to the CRCP

B. Other ERDF service quality monitoring indicators

1. Indicators concerning call-outs/work

Description of the indicator	Calculation of the indicator	Transmitted to CRE
Timeframe for start-ups on existing facilities	Rate of start-ups on existing facilities conducted by timeframe bracket and consumer category	Monthly
Timeframe for termination	Rate of terminations conducted by timeframe bracket and consumer category	Monthly
Timeframe to change supplier	Rate of changes of supplier made by timeframe bracket and consumer category	Monthly

NB: ERDF's current information systems (IS) do not enable the operator to produce indicators concerning additional services for all consumer categories. These indicators are calculated based only on consumers managed by the IS set up for the opening of the markets. This will continue until the ERDF and EDF IS are completely separate.

2. Indicators concerning user relations

Description of the indicator	Calculation of the indicator	Transmitted to CRE
Total number of user complaints	Number of user complaints (received directly or via a third party authorised by the user) by type and user category	Quarterly
Rate of response to user complaints within 30 days (breakdown per type and per user category)	Number of user complaints processed within 30 days / total number of complaints, by type and user category (this indicator is calculated excluding complaints requesting compensation related to quality on public grids)	Quarterly

3. Indicators concerning supplier relations

Description of the indicator	Calculation of the indicator	Transmitted to CRE
Number of supplier complaints	Total number of supplier complaints by type	Quarterly
Accessibility rate of the specific supplier hotline	Number of calls taken on the “urgent business” line of transport receptions / Number of calls to be taken	Quarterly

4. Indicators concerning metering and billing

Description of the indicator	Calculation of the indicator	Transmitted to CRE
Rate of meters with at least one real index reading in the year for LV ≤ 36 kVA consumers	Number of meters with at least one real index reading in the year / number of meters to be read	Quarterly
Rate of monthly readings published based on real indices for LV > 36 kVA and HVA single contract consumers	Number of readings published based on real indices / number of readings published	Monthly
Publication rate of readings and bills by Exchange Management System, for LV > 36 kVA and HVA single contract consumers within the timeframe	Amount of reading and billing data published within the timeframe / amount of reading and billing data expected	Monthly
Absence rate during readings of 3 or more times for LV ≤ 36 kVA consumers	Number of customers absent 3 or more times during readings / number of meters to be read	Quarterly

5. Indicators concerning connections

These indicators only concern connections for which ERDF manages the entire contract.

Description of the indicator	Calculation of the indicator	Transmitted to CRE
Accessibility rate of the Electricity Connection Hotline	Number of telephone calls taken / number of calls received	Quarterly
Timeframe to send a	Timeframe to send a technical and financial	Quarterly

technical and financial connection proposal	connection proposal as of qualification of the request (with breakdown per connection category).	
Rate of compliance with the agreed operation start-up date for connection structures	Number of connections of which operations started within the timeframe agreed upon receipt of the technical and financial connection proposal (and where necessary instruction memorandum of the competent authority for town planning) / Number of connections put into operation (with breakdown per connection category)	Quarterly
Timeframe for connection work	Timeframe between the date of receipt of the approval of the technical and financial connection proposal (and where necessary instruction memorandum of the competent authority for town planning) and the actual date of operation start-up (with breakdown per connection category): - Average timeframe for individual connections LV ≤ 36 kVA without extension - Rate of connections by timeframe bracket for the other cases (with breakdown per connection category)	Quarterly

VIII. Definitions

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

A. Absorption of reactive power

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

B. Power supply

If a user is connected to the public grid(s) by several power supplies, the main, complementary and back-up power sources should be designated in a contract with the operator(s) of the public grid(s) to which they are connected.

1. Main power supply/supplies

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 to under normal operating conditions of the user's electrical equipment. Normal operating conditions are contractually agreed between the user and the operator(s) of the public grid(s) to which they are connected, in compliance with quality commitments contained in the corresponding access contract.

2. Back-up power supply

A user's power supply is a back-up power supply if it is a live circuit but only used for the transfer of power between the public grid and facilities 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 the destination of one or more connection points to 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 of the electrical equipment of the user(s) agreed to by contract with the operator of the public grid(s) to which they are connected, given the public grid topology and whatever operations their operators may be carrying out.

3. Complementary power supply

A user's power sources which are neither main power supplies nor back-up power supplies are considered as this user's complementary power supplies.
The assigned part of a complementary power supply is the part of the public grids which is only crossed by 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(s) of the public grid(s) to which they are connected, given the public grid topology and whatever operations their operators may be carrying out.

C. Cell

A cell is a set of electrical switchgears 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.

D. Time class

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

E. Grid access contract

The grid access contract is the contract governed by article 23 of the amended law No. 2000-108 dated 10 February 2000 which defines the technical, legal and financial terms for user access to a public transmission or distribution grid for withdrawal and/or injection of electrical power. It is concluded with the public system operator either by the user or by the supplier on their behalf.

F. 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. If 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.

G. 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.

An advanced meter is a metering device connected to telecommunication networks that can be remotely configured and consulted using the public system operator’s information system. Readings are made and flows are controlled at the facility’s connection point automatically.

H. Voltage range

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

<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 (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 and very high voltage (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>

Tariffs applicable to users connected to public HVA 2 grids are those of the HVB 1 voltage range. According to the set of current rules, tariffs applicable to users connected to public HVA 1 grids are called HVA voltage range tariffs.

I. Reactive power supply

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

J. Index

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

K. Active power injection

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

L. 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.

M. Electrical line

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

N. Transformer

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

O. Connection points

A user's connection point(s) on the public grid coincide(s) 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 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 HVB and HVA grids, 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 operator(s), they are connected by this user's electrical equipment to the connection voltage.

P. Profiling

System used by public grid operators to calculate, on a half-hourly basis, consumption or generation of users for whom settlement is not based on a measurement curve in order to determine imbalances of their balancing responsible entities. This system is based on determining the form of their consumption or generation (load profiles) for categories of users.

Q. Active power (P)

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

R. Apparent power (S)

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

S. Reactive power (Q) and reactive energy

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

Reactive energy refers to the reactive power *Q* integrant 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.

*T. 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.

U. Withdrawal of active power

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

V. 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.

IX. Pricing scale for the use of public grids

The tariffs below 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 law dated 9 August 2004.

In compliance with article 4-II of the amended law dated 10 February 2000 which requires coverage of "all costs borne by operators of these grids, including costs resulting from fulfilling public service assignments and contracts", and with article 2 of amended Order No. 2001-365 dated 26 April 2001, in particular, they cover:

- Costs related to the constitution of operating reserves which consists of costs related to the acquisition by public system operators of system services for voltage control and costs for constituting primary and secondary reserves for frequency control,
- Costs related to operating the balancing 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, profiling 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 of these services,
- The share of public electricity grid start-up and 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 on a user's request or resulting from his/her own doing, which are invoiced 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 13 hereafter. The same applies to the use of interconnections with transmission grids in neighbouring countries which can be invoiced according to the results of market mechanisms set up in application of regulation (EC) No. 1228/2003 dated 26 June 2003.

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, withdrawal subscribed power subscribed by the user and the metering system deployed. Withdrawal subscribed power is defined at the beginning of a period of 12 consecutive months for the whole period. The grid access contract governs the terms for modifying withdrawal power subscribed 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),

- Monthly components for subscribed power overshoots (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 utilisation (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 overshoots (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 renewal 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.

When a user is connected to the public electricity grid for less than one year, the set proportion of the tariffs for the use of public electricity grids defined in sections 3 to 13 hereafter is calculated on a monthly pro rata basis. The invoiced amount may not be less than 1/12th of the set proportion in question.

X. 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 customers, invoicing and debt recovery. For HVA and low voltage ranges, the amount depends on the contract terms laid down by the public system operator concerned, either directly with a user of this grid, or with the exclusive supplier to the grid user's site in application of article 23 of the amended law No. 2000-108 dated 10 February 2000.

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

- Consumers who have not exercised the right granted under section I of article 22 of amended law No. 2000-108 dated 10 February 2000,
- Users who benefit from a purchase price prior to the amended law No. 2000-108 dated 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 concluded by user	Grid access contract concluded by supplier
HVB	7,700.00	7,700.00
HVA	640.92	61.80
LV > 36 kVA	309.12	49.56
LV ≤ 36 kVA	30.84	8.04

XI. Annual metering component (CC)

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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, the costs related to the rental, maintenance and application of load profiles to users equipped with meters that do not record measurement curves. It is determined depending on technical characteristics of metering systems and services requested by the users in line with the tariffs stated 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, public system operators can apply transparent and non-discriminatory methods for estimating energy flows injected or withdrawn and subscribed power, according to the rules stipulated in their reference technical documentation. In this case, the annual metering component is 1.20 €/year.

A. Metering systems belonging to public system operators or authorities organising public electricity distribution

The annual metering component billed to users whose metering system belongs to public system operators or authorities organising public electricity distribution 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	Variables measured	Annual metering component €/year
HVB	-	Weekly	Overshoot	Measurement curve	2,662.32
HVA	-	Monthly	Overshoot	Measurement curve	1,083.24
				Index	460.44
LV	-	Monthly	Overshoot	Measurement curve	1,083.24
	P > 36 kVA	Monthly	Overshoot	Index	357.12
			Circuit breaker		284.40
	18 kVA < P ≤ 36 kVA	6-monthly	Circuit breaker	Index	20.28
	P ≤ 18 kVA	6-monthly	Circuit breaker	Index	16.80
	P ≤ 36 kVA	Every 2 months	Advanced metering system	Index	16.80

B. Metering systems belonging to users

The annual metering component billed to users who 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).

Table 2.2

Voltage range	Power (P)	Minimum transmission frequency	Power control	Variables measured	Annual metering component €/year
HVB	-	Weekly	Overshoot	Measurement curve	477.96
HVA	-	Monthly	Overshoot	Measurement curve	507.36
				Index	139.32
LV	-	Monthly	Overshoot	Measurement curve	507.36
	P > 36 kVA	Monthly	Overshoot	Index	127.44
			Circuit breaker		132.96
	18 kVA < P ≤ 36 kVA	6-monthly	Circuit breaker	Index	8.16
	P ≤ 18 kVA	6-monthly	Circuit breaker	Index	8.16

XII. 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
HVB 3	19
HVB 2	19
HVB 1	0
HVA	0
LV	0

XIII. Annual withdrawal components (CS) and monthly components for subscribed power overshoots (CMDPS) in HVB voltage ranges

A. Annual withdrawal component (CS)

Users choose a subscribed power, $P_{Subscribed}$, in multiples of 1 kW for each of their connection points in HVB voltage ranges. 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 consecutive months under consideration $E_{withdrawn}$ in kWh, the subscribed power $P_{Subscribed}$ in kW and duration D in hours of the year considered according to the following formula:

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

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
HVB 3	5.55	15.35	0.932
HVB 2	10.20	23.86	0.717
HVB 1	13.55	49.10	0.777

B. Monthly components for subscribed power overshoots (CMDPS)

Components for subscribed power overshoots are determined each month according to the following methods:

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

Power overshoots of subscribed power ΔP are calculated per integration period of 10 minutes and the factor applicable is defined in table 5 below:

Table 5

Voltage range	α (€/kW)
HVB 3	0.25
HVB 2	0.59
HVB 1	0.79

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

In order to determine their annual withdrawal component in the HVA voltage range, users choose one of the following three tariffs for each connection point and for a complete period of 12 consecutive months, excluding the transitional provision laid out in section 15:

- Optional tariff without time differentiation,
- Optional tariff with time differentiation in 5 classes,
- Optional tariff with time differentiation in 8 classes.

A. Optional tariff without time differentiation

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

At each of these connection points, 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 12-month period under consideration $E_{withdrawn}$ in kWh, the subscribed power $P_{Subscribed}$ in kW and duration D in hours of the year considered according to the following formula:

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

Coefficients a_2, b and c used are those in table 6 below:

Table 6

Voltage range	a_2 (€/kW/year)	b (€/kW/year)	c
HVA	20.03	77.12	0.800

B. Optional tariffs with time differentiation

For each of their connection points in the HVA voltage range for which they have chosen such a tariff and for each of the n time classes it is made up of, users choose subscribed power P_i in multiples of 1 kW, where i designates the time class. Whatever the value of i, subscribed power must be such that $P_{i+1} \geq P_i$.

At each of these connection points, 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 class, expressed in kWh

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

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

1. Optional HVA tariff with time differentiation in 5 classes

For the HVA tariff with 5 time classes (n = 5), coefficients a_2, d_i and k_i used are those in tables 7.1 and 7.2 below:

Table 7.1

a_2 (€/kW/year)	11.88

Table 7.2

	Peak hours (i = 1)	**Winter full-rate hours (i = 2)**	**Winter off-peak hours (i = 3)**	**Summer full-rate hours (i = 4)**	**Summer off-peak hours (i = 5)**
Energy weighting coefficient (c€/kWh)	d_1 = 6.60	d_2 = 2.78	d_3 = 1.48	d_4 = 0.88	d_5 = 0.68
Power weighting coefficient	k_1 = 100%	k_2 = 88%	k_3 = 62%	k_4 = 52%	k_5 = 42%

Time classes are set locally by the public system operator according to the operating conditions of the public grids. They are notified to anybody upon request and published on the public system operator's website or in the absence of such a site, through any other appropriate means. Winter is considered as being from November to March and summer from April to October. Peak hours are set from December to February inclusive, at two hours within the range of 8-12 in the morning and 2 hours in the evening within the range of 5-9. Sundays are fully considered as off-peak hours and the other days are composed of 8 off-peak hours to be determined within the range of 9.30 pm to 7.30 am.

2. Optional HVA tariff with time differentiation in 8 classes

For the HVA tariff with 8 time classes (n = 8), coefficients a_2, d_i and k_i used are those in tables 8.1 and 8.2 below:

Table 8.1

a_2 (€/kW/year)	11.88

Table 8.2

	Peak hours (i = 1)	Winter full-rate hours (i = 2)	Full-rate hours in March and November (i = 3)	Winter off-peak hours (i = 4)	Off-peak hours in March and November (i = 5)	Summer full-rate hours (i = 6)	Summer off-peak hours (i = 7)	July-August (i = 8)
Energy weighting coefficient (c€/kWh)	d_1 = 6.80	d_2 = 3.25	d_3 = 2.27	d_4 = 1.78	d_5 = 1.43	d_6 = 0.94	d_7 = 0.73	d_8 = 0.62
Power weighting coefficient	k_1 = 100%	k_2 = 89%	k_3 = 75%	k_4 = 66%	k_5 = 56%	k_6 = 36%	k_7 = 24%	k_8 = 17%

Time classes are set locally by the public system operator according to the operating conditions of the public grids. They are notified to anybody upon request and published on the public system operator's website or in the absence of such a site, through any other appropriate means. Winter covers the months of December, January and February and summer is composed of April, May, June, September and October. Peak hours are set from December to February inclusive, at two hours within the range of 8-12 in the morning and 2 hours in the evening within the range of 5-9. Saturdays, Sundays and public holidays are fully considered as off-peak hours and the other days are composed of 6 off-peak hours to be determined within the range of 11.30 pm to 7.30 am.

C. Monthly component for subscribed power overshoots (CMDPS)

1. HVA tariff with meters measuring overshoots per integration period of 10 minutes

For users, to whom a tariff without time differentiation is applied, and whose connection point is equipped with a meter measuring active power overshoots against subscribed power per integration period of 10 minutes, monthly components for exceeding subscribed power related to this point are defined each month based on the following method:

$$CMDPS = 0.08.a_2.\sqrt{\sum\left(\Delta P^2\right)}$$

For users, to whom a tariff with time differentiation is applied, and whose connection point is equipped with a meter measuring active power overshoots against subscribed power per integration period of 10 minutes, monthly components for exceeding subscribed power related to this point are defined every month for each time class of the month under consideration, based on the following method:

$$CMDPS = \sum_{i\,classes\ of\ the\,month} 0.15.k_i.a_2.\sqrt{\sum\left(\Delta P^2\right)}$$

Power overshoots of subscribed power ΔP are calculated per integration period of 10 minutes. Coefficients a_2 and k_i used are those in 7.1 and 7.2, depending on the option selected.

2. HVA tariffs with meter indicating maximum power

For users, to whom a tariff without time differentiation is applied, and whose connection point is equipped with a meter indicating maximum power and with power recorder, monthly components for overshooting subscribed power related to this point are defined every month based on ΔP_{max}, the difference between maximum power reached during the month and subscribed power, according to the following method:

$$CMDPS = 0.7.a_2.\Delta P_{\max}$$

For users, to whom a tariff with time differentiation is applied, and whose connection point is equipped with a meter indicating maximum power and with power recorder, monthly components for overshooting subscribed power related to this point are defined every month based on $\Delta P_{(max)i}$, the differences for each time class between maximum power reached during the time class under consideration and subscribed power during the time class considered according to the following method:

$$CMDPS = \sum_{i\,classes\ of\ the\ month} 1.6.k_i.a_2.\Delta P_{(\max)i}$$

Coefficients a_2 and k_i used are those in sections 7.1 and 7.2, depending on the option selected.

XV. Annual withdrawal components (CS) and monthly components for subscribed power overshoots (CMDPS) in the LV range

A. Annual withdrawal components and monthly components for subscribed power overshoots in the LV range above 36 kVA

In order to determine their annual withdrawal component in the LV range strictly above 36 kVA, users choose, for the entire period of 12 consecutive months, excluding the transitional provision laid out in section XXII, one of the two following tariffs with time differentiation: medium-term and long-term utilisation.

For each of the time classes defined in sections 8.1.1 and 8.1.2, and for each connection point in the LV range strictly above 36 kVA, users choose, in multiples of 1 kVA, apparent subscribed power S_i where i designates the time class.

When overshoots are checked against subscribed active power, the latter is equal to apparent subscribed power multiplied by 0.93.

When overshoots of apparent subscribed power are checked by a circuit breaker at the interconnection with the public grid, apparent subscribed power is equal to the control power of the surveillance equipment commanding the circuit breaker.

In addition, whatever the value of i, apparent 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 power withdrawn during the i^th^ time class, expressed in kWh.

$S_{Subscribed\ weighted}$ designates weighted apparent subscribed power, calculated in line with the following formula:

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

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1. *Tariffs for long-term utilisation of LV > 36 kVA*

For the tariff for long-term utilisation of LV > 36 kVA in 5 time classes (n = 5), a maximum of two apparent subscribed powers can be applied to the same user. Coefficients a_2, k_i and d_i used are those in tables 9.1 and 9.2 below:

Table 9.1

a_2 (€/kVA/year)	21.00

Table 9.2

	Peak hours (i = 1)	Winter full-rate hours (i = 2)	Winter off-peak hours (i = 3)	Summer full-rate hours (i = 4)	Summer off-peak hours (i = 5)
Energy weighting coefficient (c€/kWh)	d_1 = 3.42	d_2 = 3.42	d_3 = 2.36	d_4 = 1.19	d_5 = 1.01
Power weighting coefficient	k_1 = 100%	k_2 = 71%	k_3 = 61%	k_4 = 50%	k_5 = 50%

Time classes are set locally by the public system operator according to the operating conditions of the public grids. They are notified to anybody upon request and published on the public system operator's website or in the absence of such a site, through any other appropriate means. Winter is considered as being from November to March and summer from April to October. Peak hours are set from December to February inclusive, at two hours within the range of 8-12 in the morning and 2 hours in the evening within the range of 5-9. All days have 8 off-peak hours, either consecutive or broken up into two periods, within the range of 12pm to 4pm and 9.30 pm to 7.30 am.

2. *Tariffs for medium-term utilisation of LV > 36 kVA*

For the tariff for medium-term utilisation of LV > 36 kVA in 4 time classes (n = 4), apparent subscribed power must be such that $S_1 = S_2 = S_3 = S_4$. Coefficients a_2 and d_i used are those in tables 10.1 and 10.2 below:

Table 10.1

a_2 (€/kVA/year)	12.24

Table 10.2

	Winter full-rate hours (i = 1)	Winter off-peak hours (i = 2)	Summer full-rate hours (i = 3)	Summer off-peak hours (i = 4)
Energy weighting coefficient (c€/kWh)	d_1 = 4.26	d_2 = 2.89	d_3 = 1.18	d_4 = 1.01

Time classes are set locally by the public system operator according to the operating conditions of the public grids. They are notified to anybody upon request and published on the public system operator's website or in the absence of such a site, through any other appropriate means. Winter is considered as being from November to March and summer from April to October. All days have 8 off-peak hours, either consecutive or broken up into two periods, within the range of 12pm to 4pm and 9.30 pm to 7.30 am.

3. *Monthly component for subscribed power overshoots (CMDPS)*

Tariff for LV > 36 kVA with meter
measuring active power overshoots

For users of LV above 36 kVA who have chosen the tariff for long-term utilisation and whose connection point is equipped with a meter measuring active power overshoots against subscribed active power per integration period of 10 minutes, monthly components for subscribed power overshoots related to this point are defined every month for each time class in the month considered, based on the following method:

$$CMDPS = \sum_{i\,classes\ of\ the\ month} 0.15.k_i.a_2.\sqrt{\sum\left(\Delta P^2\right)}$$

Power overshoots of subscribed power ΔP are calculated per integration period of 10 minutes. Coefficients a_2 and k_i used are those in section 8.1.1.

For users of LV above 36 kVA who have chosen the tariff for medium-term utilisation and whose connection point is equipped with a meter measuring active power overshoots against subscribed power per integration period of 10 minutes, monthly components for subscribed power overshoots related to this point are defined every month for each time class in the month considered, based on the following method:

$$CMDPS = 0.15.a_2.\sqrt{\sum\left(\Delta P^2\right)}$$

Power overshoots, ΔP, compared to subscribed power at the time of the overshoot are calculated per integration period of 10 minutes. Coefficient a_2 used is that in section 8.1.2.

Tariff for LV > 36 kVA with meter
measuring apparent power overshoots

For users of LV above 36 kVA whose connection point is equipped with meters measuring overshoots, ΔS, between apparent power observed every minute as a sliding average of the root-sum square and subscribed power, monthly components for overshooting subscribed apparent power related to this point are determined every month for each time class in the month under consideration, based on overshoot duration h (in hours) and according to the following formula:

$$CMDPS = 11.11.h$$

B. *Annual withdrawal component in the low voltage range up to 36 kVA inclusive*

In order to determine their annual withdrawal component in the LV range up to subscribed power of 36 kVA inclusive, users choose, for an entire period of 12 consecutive months, excluding the transitional provision laid out in section XXII, one of the following four tariffs:

- Short-term utilisation,
- Medium-term utilisation,
- Medium-term utilisation with time differentiation,
- Long-term utilisation.

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

When overshoots of subscribed power are controlled by a circuit breaker at the interconnection with the public grid, subscribed power is equal to the control power of the surveillance equipment commanding the circuit breaker.

For each connection point in the LV range up to subscribed power of 36 kVA inclusive, the annual withdrawal component is determined in line with the following formula:

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

E_i designates energy withdrawn during the i^{th} time class, expressed in kWh and $P_{Subscribed}$ designates subscribed power equal to the control power of surveillance equipment commanding the circuit breaker.

1. *Tariff for short-term utilisation of LV≤ 36 kVA*

For the tariff for short-term utilisation, n = 1 and coefficients a_2 and d_1 used are those in table 11 below:

Table 11

Subscribed power (P)	a_2 (€/kVA/year)	d_1 (c€/kWh)
P ≤ 9 kVA	3.12	3.15
9 kVA < P ≤ 18 kVA	5.64	2.98
18 kVA < P	11.40	2.65

2. *Tariff for medium-term utilisation of LV ≤ 36 kVA*

For the tariff for medium-term utilisation, n = 1 and coefficients a_2 and d_1 used are those in table 12 below:

Table 12

Subscribed power (P)	a_2 (€/kVA/year)	d_1 (c€/kWh)
P ≤ 9 kVA	4.44	2.97
9 kVA < P ≤ 18 kVA	8.28	2.71
18 kVA < P	18.24	2.13

3. *Tariff for medium-term utilisation of LV ≤ 36 kVA with time differentiation*

For the tariff for medium-term utilisation with time differentiation, n = 2 and coefficients a_2, d_1 and d_2 used are those in table 13 below:

Table 13

Subscribed power (P)	a_2 (€/kVA/year)	d_1 Full-rate hours (c€/kWh)	d_2 Off-peak hours (c€/kWh)
P ≤ 9 kVA	4.44	3.33	2.07
9 kVA < P ≤ 18 kVA	8.28	2.98	1.85
18 kVA < P	18.24	2.31	1. 44

Time classes are set locally by the public system operator according to the operating conditions of the public grids. They are notified to anybody upon request and published on the public system operator's website or in the absence of such a site, through any other appropriate means. There are 8 off-peak hours per day which can be non-consecutive, and these must be fixed in the ranges of 12-5 pm and 8 pm to 8 am.

4. *Tariff for long-term utilisation of LV ≤ 36 kVA*

For the application of the tariff for long-term utilisation, in the absence of metering systems, public system operators can apply transparent and non-discriminatory methods for estimating energy flows withdrawn and subscribed power.

Power is subscribed in multiples of 0.1 kVA, n = 1 and coefficients a_2 and d_1 used are those in table 14 below:

Table 14

	a_2 (€/kVA/year)	d_1 (c€/kWh)
Long-term utilisation	51.60	1.02

XVI. Annual component for complementary and back-up power supplies (CACS)

Complementary and back-up power supplies established upon the request of users are invoiced 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.

A. Complementary power supplies

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

Table 15

Voltage range	Cell (€/cell/year)	Lines (€/km/year)
HVB 3	91,999	8,718
HVB 2	55,483	Overhead lines: 5,558 Underground lines: 27,789
HVB 1	28,819	Overhead lines: 3,298 Underground lines: 6,596
HVA	3,050	Overhead lines: 832 Underground lines: 1,248

B. Back-up power supplies

The parts dedicated to a user's back-up power supplies are subject to a charge for the electrical equipment which they are composed of. This charge is based on the length of these assigned parts according to the price scale in table 15 above. 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 invoice 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 to this back-up power supply.

If the back-up power supply is in the same voltage range as the main power supply and, on request from the user, it is connected to a public grid transformer different from that used for their main power supply, invoicing of the parts assigned to back-up power supplies is equal to the sum of the component resulting from application of the price scale in table 15 above and the component determined in line with the price scale in table 16 below, corresponding to pricing of transformation power reservation:

Table 16

Power supply voltage range	€/kW/year or €/kVA/year
HVB 2	1.34
HVB 1	2.56
HVA	5.95
LV	6.20

If the back-up power supply is in a voltage range different from that of the main power supply, annual invoicing of back-up power supplies is equal to the sum of the component resulting from the application of the price scale in table 15 above and the component determined according to the price scale in table 17 below, corresponding to pricing of the public electricity grid providing back-up in a lower voltage range.

Table 17

Main power supply voltage range	Back-up power supply voltage range	Fixed rate (€/kW/year)	Power share (c€/kWh)
HVB 3	HVB 2	6.39	0.65
	HVB 1	4.69	1.12
HVB 2	HVB 1	1.37	1.12
	HVA	7.72	1.66
HVB 1	HVA	2.69	1.66
HVA	LV	-	-

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

A user connected to a public grid at several connection points on the same public grid in the same HVB or 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 tariffs as described in sections 5, 6 and 7, through payment of an aggregation component. In this case, the annual injection component (CI), annual withdrawal component (CS), monthly components for subscribed power overshoots (CMDPS), annual component for sporadic scheduled overshoots (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 reference technical documentation of public system operators.

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, depending on $P_{Subscribed\ aggregated}$, 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 by table 18 below:

Table 18

Voltage range	k (€/kW/km/year)
HVB 3	0.05
HVB 2	Overhead lines: 0.13 Underground lines: 0.50
HVB 1	Overhead lines: 0.66 Underground lines: 1.16
HVA	Overhead lines: 0.47 Underground lines: 0.67

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

A. Annual component for transformer utilisation (CT)

A public distribution system operator who 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 of the connection point. The operator must in this case pay an annual component for transformer utilisation, reflecting the costs of transformers and cells. This component is calculated according to the following formula, depending on subscribed power $P_{Subscribed}$.

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

Coefficient *k* used is that defined in table 19 below:

Table 19

Connection point voltage range	Voltage range of the pricing applied	k (€/kW/year)
HVB 2	HVB 3	1.56
HVB 1	HVB 2	3.36
HVA	HVB 1	5.95
LV	HVA	7.72

This arrangement can be combined with that of tariff aggregation according to the methods in section 10. In this case, the price scale in the voltage range above each connection point is firstly applied and then the tariff aggregation mentioned above.

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

A public distribution system operator who 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 connection point considered 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, length of the grid operated in voltage range *N* by the public distribution system operator,
- l_2, the shortest length of the grid operated in voltage range *N* by the public distribution system operator to which they are connected and which links their connection point to this operator's voltage transformer,
- $CT_{N/N+1}$, annual component for transformer utilisation between the voltage ranges of *N+1* and *N* defined in section 11.1.

$$CS = \frac{l_2}{l_1 + l_2} CS_N + \frac{l_1}{l_1 + l_2}\left(CS_{N+1} + CT_{N/N+1}\right)$$

C. Peak shaving in extreme cold weather

Public distribution system operators can benefit from peak shaving of their power overshoots 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.

XIX. Annual component for sporadic scheduled overshoots (CDPP)

For sporadic overshoots scheduled for work during the period from 1 May to 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 either the HVB or HVA ranges, can request the application of a specific price scale for the calculation of their component for subscribed power overshoots related to this connection point.

In this case, during the period when this price scale is applied, subscribed power overshoots are subject to the following invoicing which replaces the invoicing for subscribed power overshoots defined in sections 6.2 and 7.3.

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

Power overshoots of subscribed power ΔP are calculated per integration period of 10 minutes. Factor *k* applicable is defined in table 20 below:

Table 20

Voltage range	k (c€/kW)
HVB 3	0.077
HVB 2	0.152
HVB 1	0.241
HVA	0.363

In support of their request for the application of a specific price scale for the calculation of their component for subscribed power overshoots, 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 overshoots and invoiced according to the provisions applicable to sporadic scheduled overshoots.

The application of this provision is limited for each connection point to a maximum of once a 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 made upon the request of 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.

XX. 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 13.1 and 13.2 do not apply to connection points located at the interconnection between two public electricity grids.

A. 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 $tg\ \varphi_{max}$ ratio defined in table 21 below, from 1st November to 31st March, from 6am to 10pm Monday to Saturday,
- As an exception, for connection points where the user has opted for a tariff with time differentiation, not exceeding the $tg\ \varphi_{max}$ ratio defined in table 21 below, during winter peak hours and full-rate hours as well as during full-rate hours in November and March for options with 8 time classes,
- Without limitation outside these periods.

During these periods subject to limitation, reactive energy absorbed in the HVB, HVA and LV ranges above 36 kVA, beyond the value of the $tg\ \varphi_{max}$ ratio is invoiced in line with table 21 below:

Table 21

Voltage range	$tg\ \varphi_{max}$ ratio	c€/kvar.h
HVB 3	0.4	1.30
HVB 2	0.4	1.39
HVB 1	0.4	1.55
HVA	0.4	1.77
LV > 36 kVA	0.4	1.86

B. Injection flows

If physical active energy flows at a connection point are injection flows, and that the facility is not subject to voltage control, the user is committed to not absorbing reactive power in the LV range and to providing or absorbing, in the HVA voltage range, a quantity of reactive power determined by the public system operator and set depending on active power delivered to the public system operator, according to the rules published in the reference technical documentation of the public distribution system operator.

In the LV range, for facilities with power above 36 kVA, absorbed reactive energy is invoiced according to table 22 below.

In the HVA voltage range, reactive energy provided or absorbed above the $tg\ \varphi_{max}$ ratio or below the $tg\ \varphi_{min}$ ratio is invoiced according to table 22 below.

However, below a low monthly generation level, reactive energy provided or absorbed below the $tg\ \varphi_{min}$ ratio or above a threshold of monthly reactive energy is invoiced according to table 22 below.

The public distribution system operator sets the low generation level and the threshold of monthly reactive energy, as well as the $tg\ \varphi_{max}$ and $tg\ \varphi_{min}$ values of the $tg\ \varphi$ ratio thresholds per time slot.

Table 22

Voltage range	c€/kvar.h
HVA	1.77
LV > 36 kVA	1.86

When the voltage of a facility is controlled, and the user does not benefit from a contract as provided by article 15-III of the French amended law No. 2000-108 dated 10 February 2000, 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 invoiced according to table 23 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 23

Voltage range	c€/kvar.h
HVB 3	1.30
HVB 2	1.39
HVB 1	1.55
HVA	1.77

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

At each connection point shared, the public system operators agree, by contract, the quantity of reactive energy they exchange, determined according to transits of active energy, in compliance with the rules published in the reference technical documentation of the public transmission system operator or, in this operator's absence among the contracting parties, the injecting system operator.

The reactive energy provided above the $tg\ \varphi_{max}$ ratio or absorbed below the $tg\ \varphi_{min}$ ratio is invoiced per connection point according to table 24 below.

The $tg\ \varphi_{max}$ and $tg\ \varphi_{min}$ values of the $tg\ \varphi$ ratio thresholds per connection point are agreed upon by contract per time slot between public system operators. The contractual $tg\ \varphi_{max}$ value is lower than 0.4 and, by default, considers the past values of the $tg\ \varphi$ ratio observed.

Table 24

Voltage range	c€/kvar.h
HVB 3	1.30
HVB 2	1.39
HVB 1	1.55
HVA	1.77

XXI. Indexation of the pricing scale

M, the anniversary month of the application date of these tariff rules.

Each year *N* as from 2010, the level of the following components is automatically adjusted on the first day of month *M*:

- The annual administrative management component applicable to the HVA and LV voltage ranges (coefficient a_1),
- The annual metering component applicable to the HVA and LV voltage ranges,
- The annual withdrawal component applicable to all voltage ranges (adjustment of coefficients a_2, b and d_i only),
- The monthly subscribed power overshoot components applicable to the HVB voltage range (coefficient α, the coefficients applicable to the other voltage ranges are automatically adjusted due to the adjustment of coefficients a_2).

The pricing scale in application as of the first day of month *M* of year *N* is obtained by adjusting the pricing scale in application the previous month in line with changes in the harmonised index of consumer prices, a cost change factor and an offsetting factor of the Expenses and Revenues Clawback Account (CRCP).

A. HVB voltage range

For the HVB voltage range, the pricing scale is automatically adjusted in line with the following percentage:

$$Z_N = IPCH_N - X + K_N$$

Z_N: percentage of change of the pricing scale in application as of the first day of month *M* of year *N* compared to that in application the previous month.

$IPCH_N$: percentage of change between the average value of the harmonised index of consumer prices - France 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) (id. code: 000671193).

X: cost change factor equal to – 0.4%.

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

B. HVA and LV voltage ranges

For the HVA and LV voltage ranges, the pricing scale is automatically adjusted in line with the following percentage:

$$Z'_N = IPCH_N - X' + K'_N$$

Z'_N: percentage of change of the price structure in application as of the first day of month *M* of year *N* compared to that in application the previous month.

$IPCH_N$: percentage of change between the average value of the harmonised index of consumer prices - France 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) (id. code: 000671193).

X': cost change factor equal to – 1.3%.

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

C. Rounding rules

Rounding rules are as follows for the adjustment of pricing scales:

- For the HVB and HVA voltage ranges, the coefficients of set and variable parts of the annual withdrawal components without time differentiation are rounded to the nearest euro cent,
- The other coefficients of the variable parts of the annual withdrawal components are rounded to the nearest euro cent hundredth,
- For the HVB voltage range, the coefficients of the monthly subscribed power overshoot components are rounded to the nearest euro cent,
- The other coefficients of the set parts of the annual withdrawal components and the annual administrative management and metering components are rounded to the nearest value divisible by 12.

XXII. Transitional provision concerning the implementation of these tariff rules

For the first six months of application of these tariff rules and for the HVA and LV voltage ranges, users (or authorised third parties) can select their tariff option for each connection point without having to comply with the periods of 12 consecutive months since selecting their previous tariff option. This provision does not apply to the subscription of withdrawal power.

Executed in Paris, 26 February 2009

On behalf of the Energy Regulatory Commission (CRE),

The Chairman,

Philippe de LADOUCETTE