The French wholesale electricity, natural gas and CO_2 markets in 2010-2011

October 2011

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Introduction

"*The Commission for Energy Regulation* [(CRE)] *monitors electricity and natural gas transactions carried out between suppliers, traders and producers, transactions carried out on the organised markets as well as cross-border trades. It monitors the consistency of the offers* […] *made by producers, traders and suppliers* […] *with their economic and technical constraints*" (Article L. 131-2 of the Energy Code).

CRE's mission of monitoring wholesale markets aims to ensure that wholesale market energy prices are consistent with the technical and economic fundamentals of these markets. In particular, CRE strives to verify that no market power is exercised in such a way that a participant abuses its situation to attain abnormal prices, notably with regard to its costs.

During 2010, the volumes traded on the **intermediated wholesale electricity markets** declined by 7% compared to 2009, mainly on the futures markets. The availability of production facilities, in particular nuclear plants, significantly increased and market volatility declined.

The average spot price of electricity increased by 10.4% in 2010 compared to 2009, to €47.5 /MWh. The average peak[1] price increased by 1.3% in 2010 to €59.0 /MWh. Prices for calendar products (Y+1) went from €51.7 /MWh on average in 2009 to €52.4 /MWh in 2010. These increases mainly reflect the resumption in consumption following the recovery in economic activity and the severe weather conditions in 2010.

Since the beginning of 2010, the recovery in availability of nuclear production facilities has contributed to improving the French electricity trade balance at the borders. The expansion of the trilateral coupling (France, Belgium, and the Netherlands) to Germany and, more recently, the German moratorium on nuclear production of electricity has had effects on the European wholesale electricity markets. French term contracts prices[2] are now below German prices.

The transparency of the market has increased, notably due to the publication of unplanned outages at production sites within 30 minutes since the end of 2010.

On the wholesale gas markets, volumes traded increased significantly in 2010 and in the first six months of 2011. This development extends the dynamic already observed in 2009. The context is still marked by a discrepancy between gas prices on the market and the price of long-term contracts indexed to oil.

With the resumption of demand, wholesale prices on the principal European markets were above the low points reached in 2010. The average spot price in the North zone was €17.6 /MWh in 2010, corresponding to a rise of 40% compared to 2009. This rise continued in 2011, with the spot price reaching levels close to €25 /MWh.

This fourth CRE report on performance of the French energy markets incorporates an **analysis of the CO_2 markets** for the first time**.** Since the entry into effect of the banking and financial regulation law in October 2010, CRE has been charged with "*monitor*[ing] *transactions carried out by suppliers, traders and producers of electricity and natural gas on greenhouse gas emission quotas* […] *and on the term contracts and financial instruments for which they constitute the underlying*"[3]. This monitoring, which is a transposition of the recommendations of the Prada report, is coordinated with the French financial regulator AMF (*Autorité des Marchés Financiers*), which monitors French spot and futures exchanges in CO_2. Cooperation between CRE and the AMF was formalised in a memorandum of understanding signed and made public in December 2010. As provided by the banking and financial regulation law, this agreement covers the electricity, gas and CO_2 markets and allows to implement a regulation adapted to both the financialisation of the energy markets and their specificities.

[1] Between 8 am and 8 pm
[2] Annual - Y+1
[3] Article L. 131-3 of the French Energy Code

Confidence in the European carbon market was affected at the beginning of 2010 by quota thefts recorded in some European countries. The European Commission has since acted to strengthen the security of the registries, one of the key links in the carbon market infrastructure. European carbon prices have varied in a volatile fashion in a context of an excess supply of quotas compared to actual emissions in both 2010 and 2009. The prospect of going to phase III in 2013, when quotas will become paid in large part - completely for the electricity sector – is supporting prices. Recently, prices have nevertheless fallen after the European Commission announced a planned directive on energy efficiency, in a context of growing uncertainty about economic activity. In total, the CO_2 quota price is now approaching €10 /t in October 2011, versus €14.3 /t on average for 2010.

The adoption of the REMIT[4] regulation by the European parliament in September 2011, then by the European Council in October 2011, paves the way for a harmonised framework for supervising the European energy markets. REMIT establishes a framework prohibiting market abuses in a way adapted to the electricity and gas markets, and takes account of the influence of the physical fundamentals of these markets. It entrusts ACER, the European regulator, with monitoring, in cooperation with national regulatory authorities (NRA). Investigations remain the responsibility of the NRA.

Harmonised monitoring of European energy markets will, as a consequence, necessitate coordinated implementation among the sectoral and financial regulators, ACER and the European Securities and Markets Authority. In fact, the REMIT regulation is coordinated with financial regulations, which are themselves currently under revision. Finally, a European system for monitoring the secondary carbon market is also expected.

The electricity and gas market monitoring mission carried out by CRE for five years and the framework established by the banking and financial regulation law constitute assets in efficient implementation at the national scale of the targeted monitoring architecture at the European level.

[4] Regulation for Energy Markets Integrity and Transparency

Overview

Electricity market

Electricity prices and trading

During 2010, the volumes traded on the intermediated wholesale electricity markets declined by 7% compared to 2009, to stand at 696 TWh.

This decline is mainly noted in the futures/forwards markets. It may be related to a lesser desire of the participants to manage their exposure to price risk or to make purchases on the market in a context of reduced volatility of electricity prices and an increased level of availability of production facilities. The decline in futures/forwards transactions was moreover especially marked in the case of transactions on the organised market, in connection with operational factors.

With regard to trade at borders, **French net exports recovered in 2010. The first months of 2011 confirm and amplify this trend.** Net exports in the first six months of 2011 nearly reached those for the entire year of 2010. This development can be set in a context of improved availability of nuclear facilities in both 2010 and 2011. All cross-border flows were consistent with the observed price differentials.

The average spot price of electricity rose by 10.4% in 2010 compared to 2009 (to €47.5 /MWh) in relation to the recovery of economic activity and severe winter weather conditions. The rise in average peak product price was less sizeable. These trends have continued through the beginning of 2011.

Generally, French spot prices have varied in a way consistent with the fundamentals of the electricity market.

Since the price peak of 12 January 2010 cited in the previous CRE monitoring report, EDF has confirmed the inclusion in its market offers of some load shedding volumes in a systematic way. CRE believes that these measures constitute a development favourable to the operation of the French wholesale market.

Other price peak episodes, of moderate extent, were also observed. These episodes undergo a systematic examination that has not revealed any anomalies.

The expansion of the trilateral coupling (TLC) to Germany, followed by the German moratorium on electricity production of nuclear origin, have had a significant impact on European prices since the end of the year. The coupling clearly improved the rate of convergence over time of prices between France and Germany. This rate of convergence has however diminished since the announcement of the moratorium, and French spot prices were below German spot prices by €1.8 /MWh on average over the first six months of 2011.

The inversion of the price gap between France and Germany is notable in the futures prices. Since the spring, France has been less expensive than Germany for yearly products, although a seasonal difference due to the temperature sensitivity of French demand persists between these two countries, as the variation in quarterly product prices attests.

Analysis and transparency of production

The year 2010 was marked by improvement in nuclear availability and thus a rise in nuclear production. This development continued into the beginning of 2011, with the rate of nuclear production reaching its highest levels in five years for similar periods, from January to the end of March and after the beginning of June.

Due to the rise in consumption and net exports, **production increased for all the generation technologies in 2010 with the exception of coal.** In 2010, hydro-storages followed their usual seasonal behaviour, but reached a low point at the end of the winter due to high use of hydroelectric facilities during this period. Consequently at the end of 2010 hydro-storages were close to their historic low. The particularly mild weather conditions of spring 2011 had the effect of amplifying this phenomenon, with hydroelectric stocks at their lowest in five years for a similar period throughout the first six months of 2011.

The marginality[5] of the various generation technology in 2010 was close to that reported in 2009, although a recovery in the marginality of nuclear generation, going from 8% in 2009 to 11% in 2010, is noted.

With regard to the use of EDF generation assets, **CRE is conducting specific follow-up of the gaps existing between spot market prices and the marginal costs of the EDF system** resulting from calculations by its daily optimisation models. This study deals with the hours for which EDF offers are assumed to determine the spot auction price.

On average, the price-cost gap was 3.2% over 2010. CRE considers that for this year the reported gap is at levels that do not constitute an abuse of dominant position.

Moreover, as cited in the previous monitoring report, the risk management policy followed by EDF in the framework of the “1% risk”[6] criterion was in particular examined by CRE. This led EDF to modify the methods of applying this management policy. Previously, to observe the 1% risk criterion, EDF Trading took account of a margin of uncertainty in the volumes available for sale to cover the hazards that might affect EDF’s supply and demand balance between auction and 4 pm. EDF has confirmed to CRE that since October 2010 this risk has been borne directly by EDF through application of the 1% risk criteria as of 11 am instead of 4 pm.

With regard to transparency of production data, the system established by the UFE and RTE was supplemented on several occasions in 2010 and 2011. Since 1 July 2010, predictions for short- and medium-term availability for each production unit of capacity greater than 100 MW have thus been published. In addition, since December 2010, unplanned outages for these units are published within 30 minutes.

Concerning delays for publication of unavailabilities, the French system provides for publication of these data one hour before closure of the spot exchange. As a result, significant modifications are published only in steps of 24 hours. At the European level, ERGEG recommends publication within a period of one hour. This is an important difference in approach and CRE consequently recommends that the transparency system be aligned with the standard proposed by ERGEG in this regard.

The difference between the projected availability of nuclear facilities on D-1 and the actual availability has been examined. This difference had already been cited in the previous monitoring report and CRE had indicated that it would be subject to regular monitoring and more precise analysis to explain its extent. EDF, the only operator of nuclear facilities, has since provided quantitative information explaining this difference, due to unplanned outages and delays in return to service following scheduled or unplanned outages.

Analysis of transactions

Analysis of the offers submitted by market participants on the EPEX Spot Auction platform for France shows that the level of offers on the spot market is correlated with the margin of the electrical system (differential between available production capacity and projected consumption).

There are few offers between €100 and €300 /MWh, these price ranges corresponding to peak and extreme peak production assets operating some hundreds of hours per year.

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[5] A generation technology is called marginal when its marginal production cost determines the market price; that is, in theory, when the highest-cost production unit in order to satisfy electricity demand belongs to this generation technology.

[6] Application of this criterion leads to implementation of measures to protect oneself against occurrence of a risk in 99% of cases.

As for cross-border trade, the individual transactions of participants were examined in order to identify nominations made contrary to price differentials. The case of import nominations over the Italian border was examined; issues of market design in Italy explain the observed proportion of these nominations. Such situations would be reduced by market coupling.

CO_2 market

Development of the institutional framework

Since the end of 2010, the Banking and Financial Regulation law has entrusted the French financial regulator, AMF (*Autorité des Marchés Financiers*), and CRE with a CO_2 market monitoring mission. The authority of AMF covers the organised spot and futures markets established in France. The authority of CRE covers CO_2 transactions carried out by participants in the electricity and gas wholesale markets.

To carry out its mission, CRE gives priority to a centralised transactional data collection approach, but the trading venues have not yet all adhered to this approach. Under these conditions, while awaiting the establishment of a European framework for carbon market supervision, CRE is envisaging establishment of bilateral data collection with the participants in the French electricity and gas wholesale markets within the scope of CRE monitoring.

The French CO_2 market monitoring system will take on its full significance once it is generalised to the European level. The CO_2 quota is handled on different markets in Europe, with market participants themselves acting in these different places, while CO_2 emitting industries manage their carbon constraints at the European level. A European system to regulate the secondary market is expected. While the inclusion of CO_2 as a wholesale energy product has been rejected in the regulation on energy market integrity and transparency (REMIT), inclusion in financial regulation is now envisaged[7].

The CO_2 markets will undergo a major development with the launch of phase III in 2013, in which part of the quotas will no longer be allocated free, but by auction. This system will involve notably the electricity production sector.

VAT fraud has already occurred in the CO_2 markets. They were the target of new attacks at the beginning of 2011, this time taking the form of quota thefts. These episodes highlighted the necessity of securing the quota processing system in a harmonised fashion in Europe. The European Commission has announced measures to this effect.

As indicated in the previous monitoring report, attention has been drawn to the risk of propagation of VAT fraud on the European electricity and gas markets. Measures to increase awareness and vigilance have been adopted by the parties involved (regulators, administrative and judiciary authorities, exchanges, network managers), at the national and European levels. Measures that participants and markets can take, as for example the so-called "*Know your Customer Check"* or KYC verifications, are crucial in this context.

The European CO_2 market and its fundamentals

The volumes traded on the CO_2 markets stabilised in 2010. The volumes traded on the spot markets decreased, with futures volumes having on the other hand made gains. These products are mainly traded on exchanges, the market share of these latter having increased during the past two years. Volumes traded through intermediaries in 2010 represent more than 3.5 times the volume of emissions allocated for the same year.

The variation in prices since 2005 has been marked by the successive effects of shocks on the supply-demand balance. During the first six months of 2011, the CO_2 market developed in a volatile fashion. An upward movement was observed following the German decision with regard to nuclear power

[7] http://ec.europa.eu/internal_market/securities/isd/mifid_en.htm Document 2011/0298 (COD)

production. The announcement of a proposed European directive on energy efficiency led on the other hand to a downward movement in prices.

The European CO_2 market has been characterised since 2009 by a supply exceeding demand with the exception of sites of combustion facilities, mainly electricity production facilities, at a deficit.

The quota surplus can be attributed in part to the consequences of the financial and economic crisis starting at the end of 2008. Comparing supply and demand and taking account of possibilities of accumulation, 185 Mt were accumulated at the end of 2010 on the supply side (for verified emissions of 1963 Mt in 2010). In contrast to what was observed at the end of phase I, the prospect of banking quotas for phase III constitutes a factor supporting prices.

Gas market

Gas prices and trading

During 2010, trading on the wholesale gas markets continued to develop. The gas supply on the world markets remains sizeable, due notably to the production of unconventional gas in the United States and the supply of substantial volumes of Liquefied Natural Gas (LNG).

Due to rising demand, wholesale prices on the principal European markets were above the low points reached in 2009, but remained low compared to the prices of long-term supply contracts indexed to oil products. The wholesale gas markets thus continued to be an attractive source of supply and an outlet for the volumes of surplus gas of some participants.

Consequently, the volumes delivered to the PEG hubs (*points d'échange de gaz*) increased by 59 TWh in 2010 to reach a level of 322 TWh, or over half of the physical removals made from the networks. This growth has been observed at the three French hubs but continues to be more modest in the South and Southwest.

The volumes traded on the intermediated wholesale markets increased by 65% in 2010 to reach a total of 246 TWh, a trend also followed by the number of transactions, and involving all maturities negotiated. These trends are confirmed in the first months of 2011, which show a stabilisation in the number of shippers after strong growth in 2010.

The transactions of one party, not a historic participant in the French market, were sizeable at the end of 2010 and beginning of 2011. This party informed CRE of a major development in its trading activities on the wholesale markets, both with a view to optimising its portfolio and with the aim of arbitrage. In the course of investigations conducted by CRE with regard to this party, no market manipulation was detected. CRE noted however points for improvement in terms of market risk management and record keeping according to the standard established by the third package. The party involved has informed CRE that it has strengthened its procedures for risk management and data retention since the period concerned. In addition, this episode involved discussions with the trading venue. CRE reminds, in this respect, the importance of monitoring activity conducted independently by the trading venues.

Wholesale gas prices increased during 2010. Less marked variations were seen in the first six months of 2011. Price variations in France and in Europe were similar, and there was convergence between the French PEG Nord, the Dutch TTF, and in particular the German NCG. In France, a better convergence of spot prices between PEG Nord and PEG Sud has been observed since the entry into service of the Fos Cavaou LNG terminal.

Use of infrastructures

Over the period covering 2010 and the first six months of 2011, a positive development in access to gas infrastructures has been reported, with a regular increase in the number of users of the gas transmission systems, notably due to access of industrial customers to PEG hubs and an increase in the number of customers at LNG terminals. On the other hand, due to the drop in recourse to storage compared to other sources of flexibility, the number of users of underground storage decreased.

In the coming years, the establishment of new mechanisms such as market coupling, the development of infrastructures (for example the project of doubling the Rhône pipeline or the construction of an LNG terminal in Dunkerque) and European harmonisation of the rules for access to transmission systems should allow market development to continue in France.

In the North zone, while entry capacity remains concentrated on a limited number of participants, the implementation of the commitments of GDF Suez has allowed the situation to improve. Thus, entry capacity is available upon reservation, notably at Taisnières H and Obergailbach. In addition, a certain number of projects (notably increased capacity at the Taisnières interconnection point, the Dunkerque LNG terminal, and the possibility of expanding regasification capacity at Montoir) could contribute to increasing the entry capacity in the North zone.

Access to infrastructures is improving in the South zone, in particular following commissioning of the Fos Cavaou LNG terminal. This has also led to a decrease in the level of use of the North-South link, with in particular, for the first time since its creation in 2009, firm capacities that were not reserved. This observation led to envisaging a market coupling mechanism between the North and South zones, which was launched in July 2011 with the aim of reconciling prices in these two zones. Finally, several development projects (notably establishment of new interconnection capacities between France and Spain, the possibility of an extension of operation of the Fos Tonkin terminal by 20 years beyond 2014 and the project to double the Rhône pipeline) should contribute to significantly improving supply conditions for the South of France.

Finally, CRE notes that there is no congestion between the South and Southwest zones; capacities are marketed in a coordinated way between the two operators and available upon reservation in the short- and long-term in both directions.

Supplying new entrants

In 2010, the supply structure for new entrants remained relatively stable compared to the preceding year with regard to purchases at PEG hubs. Increased recourse to PEG hubs has been reported over the first six months of 2011.

In the South zone, supply for new entrants has developed since 2011, with increased recourse to PEG hubs, the appearance of imports (LNG) and reduced supply from the North zone. Over the same period, a drop in recourse to imports was reported in the Southwest zone in favour of supply from the South zone, consistent with the increased liquidity of this zone.

An analysis of the opportunities for new entrants shows that their access to infrastructures is satisfactory. In general, they call on PEG hubs with a view to optimising their portfolios.

Section I: The wholesale electricity markets

1. Development of the main segments of the wholesale market

Activity on the wholesale electricity markets is mainly related to optimisation of the flexibility of their means of production by producers, trading transactions, cross-border trading and hedging of their projected consumption in order to satisfy customer needs by market participants.

In 2010, the availability of power plants recovered progressively and continuously starting from the second quarter due to the increased level of nuclear availability. This development contributed to a significant increase in volumes produced. These came to 549 TWh, or an increase of 30 TWh (+6%) compared to the volumes observed in 2009 (519 TWh).

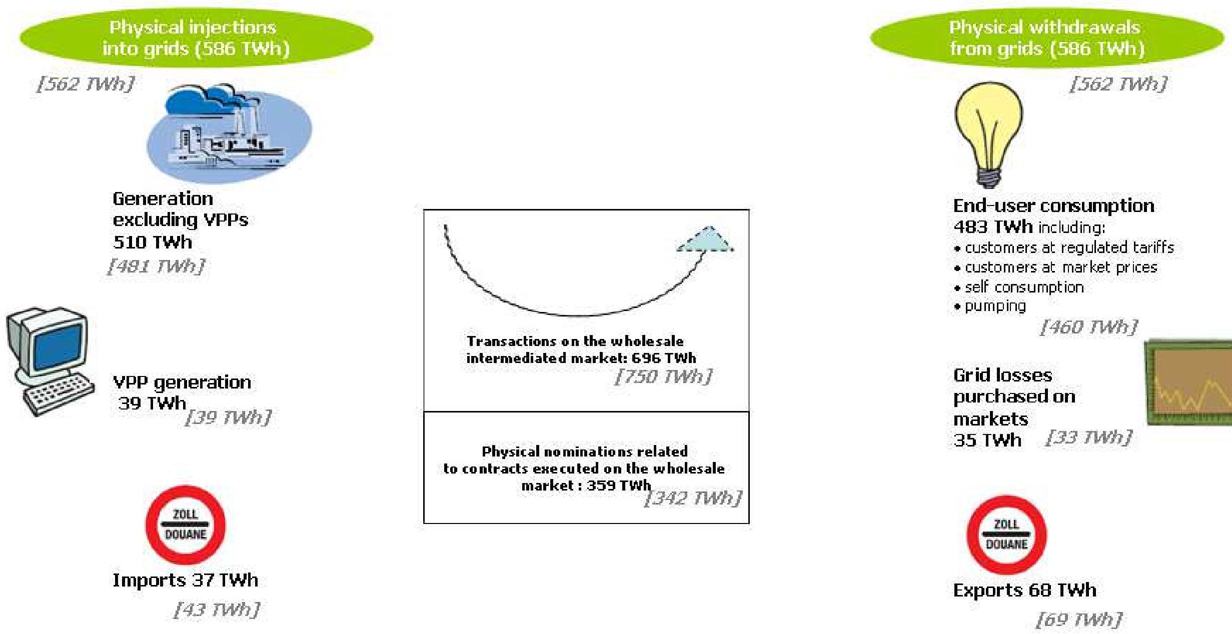
Economic activity as well as significant episodes of cold weather contributed to the annual growth in domestic electricity consumption. This reached 477 TWh (consumption of end customers excluding pumping consumption and losses of system operators), or an increase of 24 TWh compared to the volume consumed in 2009. This increased domestic consumption was more than compensated for by the rise in production, leading to a reduction in gross imports by 6 TWh. Moreover, a slight drop in gross exports was noted (by 1 TWh, or -1%) compared to the volume recorded the previous year.

In this context, trade on the intermediate wholesale electricity markets reached 696 TWh, a decrease of 7% compared to 2010. This drop involved in particular trade in futures/forwards products.

Physical deliveries between participants as a result of negotiated contracts on the wholesale markets (intermediate and bilateral), represented 359 TWh in the course of this year, or an increase of 17 TWh (+5%) compared to 2009.

Figure 1 shows a simplified view of these various flows for 2010 and 2009 (figures in brackets).

Figure 1: Energy flows between French wholesale electricity market upstream and downstream segments in 2010



Source: RTE – Analysis: CRE

1.1 Drop in volumes traded on the intermediated wholesale markets in 2010, mainly on the market of term contracts

Activity on the French intermediated wholesale market includes transactions concluded on the organised markets and on the intermediated OTC (brokerage platforms). This covers most of the activity on the French wholesale electricity market.

Down by 7% compared to 2009, the volumes traded on the wholesale market came to 696 TWh in 2010 (Table 1). In this same year, 127,041 transactions were concluded. Related to the macroeconomic data, electricity trading represented approximately 136% of French consumption in 2010, or a reduction of almost 19 points compared to 2009.

While the volumes traded on spot products (intraday, Day-ahead continuous and Day-ahead auction) increased (+4.8%), the futures/forwards market pulled down the volumes traded in 2010. Despite the slight increase in the number of transactions in this market segment in 2010 (Figure 2), the futures/forwards volumes traded declined by 8.3% compared to 2009. This downward trend continued in 2011 at a lower rate. Thus, the volumes traded in the first six months of 2011 (317 TWh) have declined by 3.2% compared to the first six months of 2010.

Table 1: Transactions

Volumes of transactions

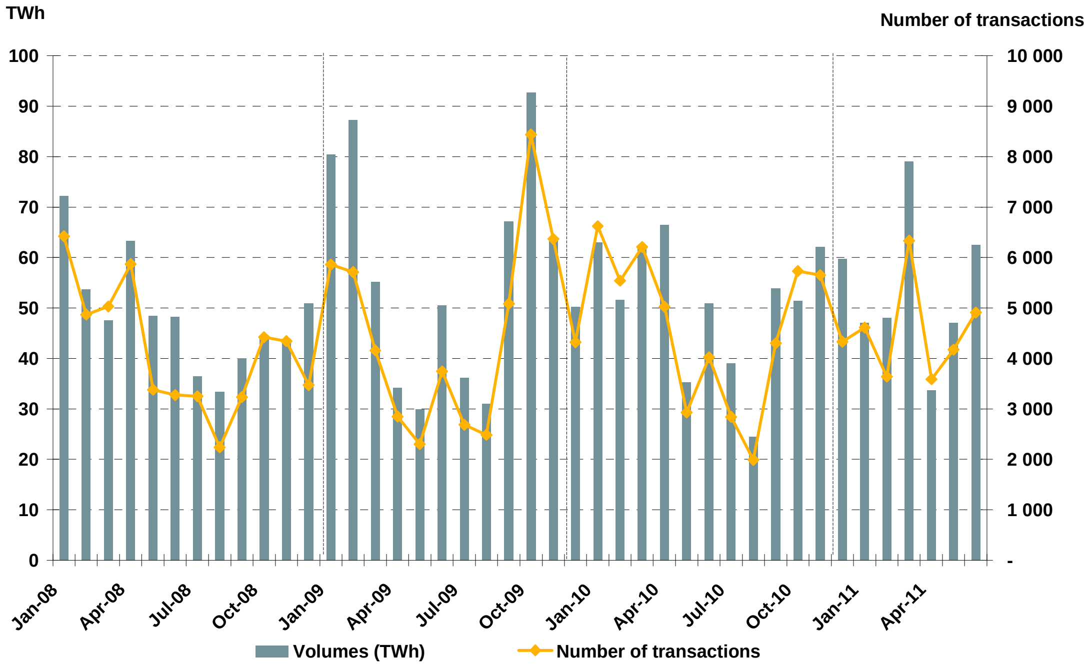
Volumes (TWh)	*2009*	*2010*	*H1 2010*	*H1 2011*
Intraday	1.1	1.0	0.6	0.4
Day-Ahead Continuous	17.9	20.2	10.2	10.1
Day-Ahead Auction	51.5	52.6	26.3	30.2
Futures/forwards market	678.8	622.1	328.0	317.4
Total	**749.2**	**695.9**	**365.0**	**358.2**

Number of transactions

Number of transactions	*2009*	*2010*	*H1 2010*	*H1 2011*
Intraday	**34,875**	**28,732**	**16,948**	**9,442**
Day-Ahead Continuous	**37,452**	**43,054**	**21,788**	**21,165**
Day-Ahead Auction	**n.a.**	**n.a.**	**n.a.**	**n.a.**
Futures/forwards market	**54,007**	**55,255**	**30,302**	**27,251**
Total	**126,334**	**127,041**	**69,038**	**57,858**

Sources: brokers, EPEX Spot France, EPD France – Analysis: CRE

Figure 2: Monthly changes in volumes and number of transactions on the intermediated futures/forwards market



Sources: brokers, EPD France; Analysis: CRE

Table 2 breaks down the quarterly changes in trading by type of product (monthly, quarterly, annual), comparing 2010 to 2009. The decline in volumes traded is significant for all quarters with the exception of the second quarter of 2010. This decline is reported mainly for Y+1 products, as well as monthly and Q+1 products.

The decline in futures/forwards volumes traded can be related to a decreased desire of participants to manage their exposure to price risk or to make purchases on the market in a context of reduced volatility in electricity prices and an increased level of availability of power plants.

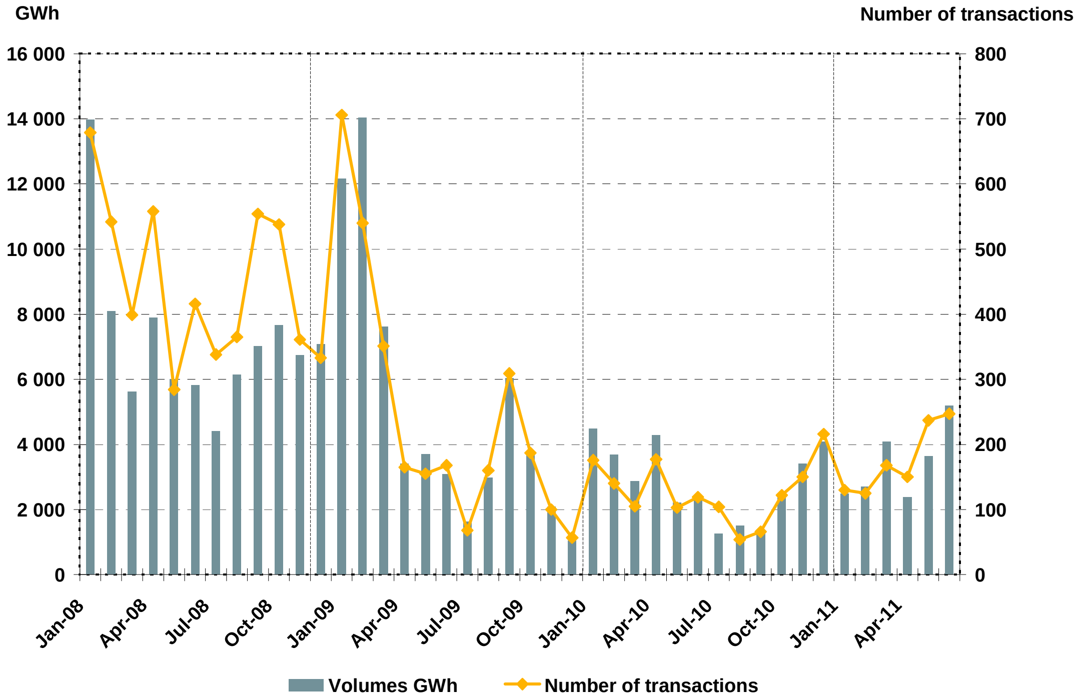
Table 2: Quarterly breakdown of volumes traded by products (in TWh, 2010 and 2009)

Maturity	*Q1 2010*	*Q1 2009*	*Q2 2010*	*Q2 2009*	*Q3 2010*	*Q3 2009*	*Q4 2010*	*Q4 2009*	*2010*	*2009*
M+1	23.6	19.3	15.4	19.8	13.9	17.3	16.5	37.2	69.5	93.6
M+2	7.5	7.5	4.0	4.0	6.2	6.4	5.3	12.0	23.0	29.9
M+3	1.4	3.4	2.6	3.8	3.1	2.8	3.2	1.7	10.3	11.6
Q+1	16.8	20.6	16.1	13.1	17.8	23.8	18.9	27.1	69.6	84.6
Q+2	15.6	16.7	12.8	8.5	5.4	11.7	8.2	6.0	41.9	42.9
Q+3	9.5	13.5	4.0	4.9	1.1	2.2	4.4	6.7	19.0	27.3
Q+4	5.1	8.3	1.6	0.6	1.2	2.3	6.1	11.1	13.9	22.3
Y+1	47.0	71.7	47.4	33.6	34.2	36.2	55.5	59.18	184.2	200.7
Y+2	14.8	18.4	27.3	8.4	15.2	12.2	20.1	14.86	77.4	53.8
Other	36.4	43.5	22.5	17.9	19.3	19.4	35.1	31.26	113.3	112.1
Total	**177.7**	**222.8**	**153.7**	**114.6**	**117.4**	**134.3**	**173.3**	**207.01**	**622.1**	**678.7**

Sources: brokers, EPD France; Analysis: CRE

The decline in futures/forwards transactions was moreover particularly marked in the case of trade on the organised market (Figure 3). This observation can be related to operational factors (in particular, trading interfaces) in 2009 and 2010. IT developments were implemented to handle these issues. EPD communicated detailed information to CRE on these operational factors.

Figure 3: Monthly changes in volumes and number of transactions on the organised futures market



Source: EEX Power French Derivatives

The number of balancing responsible entities active on the French market increased in 2010

The number of balancing responsible entities active on the French market increased in 2010. This increase is explained in particular by the rise in the number of European newcomers (Table 3).

Table 3: Balancing responsible entities active on the French market

Classification	*Number of active REs*				
	2007	*2008*	*2009*	*2010*	*H1 2011*
Integrated European producers	34	34	37	35	35
Financial traders	24	31	23	25	25
European newcomers	13	16	18	23	23
French producers	8	9	8	6	6
French newcomers	5	6	6	5	5
Industries	5	6	4	5	5
ELD[8]	5	4	4	4	4
Others	3	4	4	7	7
Total	**97**	**110**	**104**	**110**	**110**

Source: RTE – Analysis: CRE

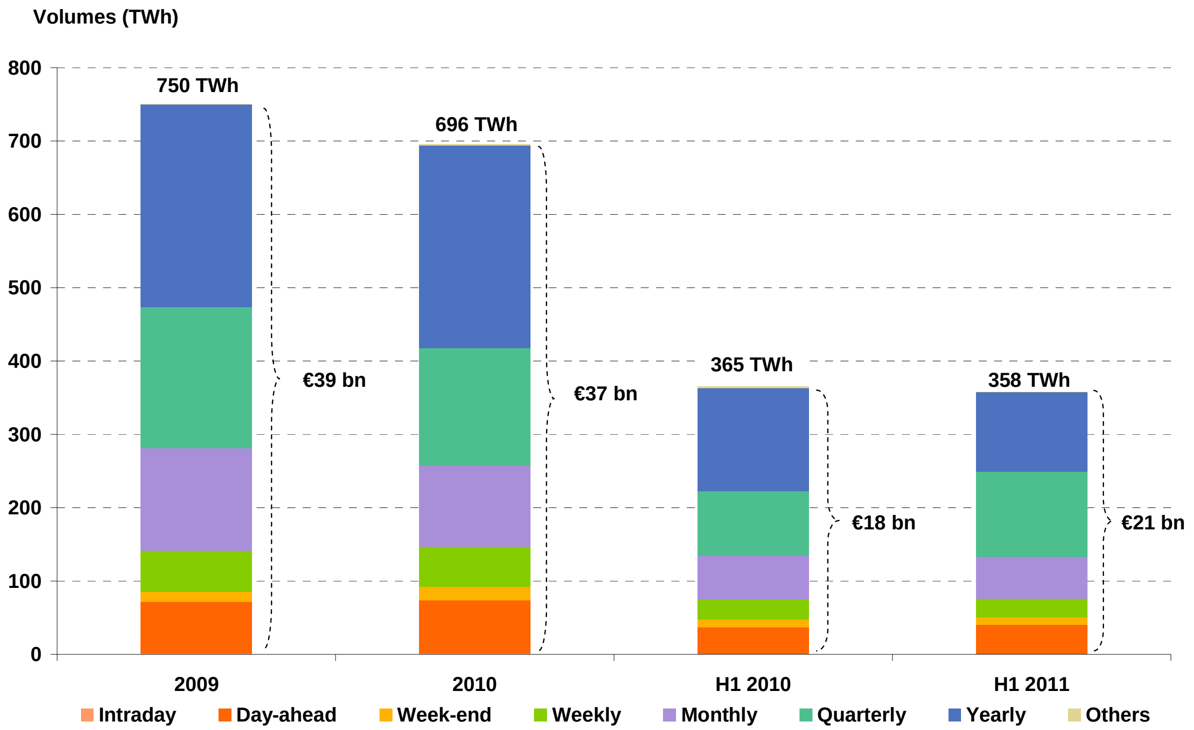
[8] Local Distribution Companies (Entreprises Locales de Distribution)

The size of the French wholesale electricity market reached €37 bn in 2010

Trade on the French electricity market has decreased from the previous year, going from 39 billion euro in 2009 to 37 billion euro the following year (Figure 4). This drop in value is explained mainly by a decrease of approximately 54 TWh in the overall volume in TWh traded.

While term contracts prices were stable or increased slightly (see paragraph 2.2) and spot prices headed upward (see paragraph 2.1), these trends did not compensate for the drop in volumes traded.

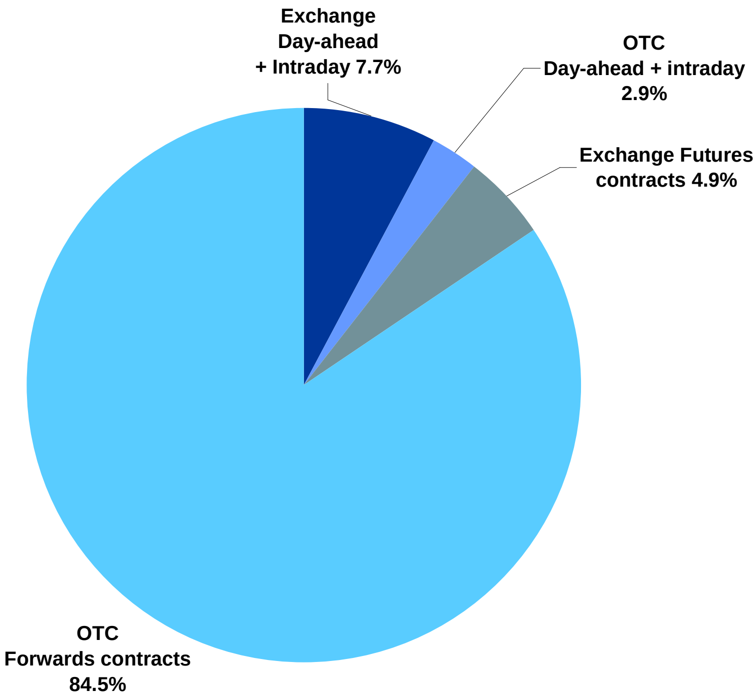
Figure 4: Volume and valuation of trade by product (in bn €)



Source: Brokers, EPEX Spot France, EPD France – Analysis: CRE

Because of their intrinsically higher volume, transactions of futures/forwards products represent 89% of the value of transactions made on the markets. Moreover, the majority of trades are made by mutual agreement; OTC trading platforms account for approximately 87% of the value traded on the market, with the remaining 13% traded on the organised markets (Figure 5).

Figure 5: Trade broken down by platform and by term (%) in 2010



Sources: Brokers, EPEX Spot France, EPD France – Analysis: CRE

1.2 Cross-border net volumes traded increase, due notably to improved nuclear availability

A recovery in net exports related mainly to the decline in volumes imported in 2010 due to better availability of nuclear power plants

Table 4 gives estimates of interconnection capacity (NTC – Net Trasfert Capacity) on the various borders in 2010. The interconnection capacities between France and the neighbouring countries represent approximately 13% of the installed generation capacities in France for export and 10% for import. This percentage complies with the criterion published in the conclusions of the European Council in Barcelona in March 2002 aiming to set the level of interconnection of countries at 10% of the installed capacity.

In 2010, volumes of electricity traded at the borders represented 65.8 TWh in exports and 36.7 TWh in imports (Table 5). The net export balance, 29.1 TWh, increased compared to 2009 (net exports of 24.6 TWh). This increase is mainly related to the substantial drop in volumes imported, from 43.4 TWh in 2009 to almost 36.7 TWh in 2010, combined with a slight decrease in volumes exported.

Table 4: Maximum import and export capacities between France and neighbouring countries in 2010 (in MW)

	Germany	*Belgium*	*Spain*	*Italy*	*United Kingdom*	*Switzer land*	*Total*
Import	4,300	2,000	1,500	995	2,000	1,900	12,695
In % of French installed capacity	3.5 %	1.6 %	1.2 %	0.8 %	1.6 %	1.5 %	10.3 %
Export	2,700	3,600	1,400	2,535	2,000	3,200	15,435
In % of French installed capacity	2.2 %	2.9 %	1.1 %	2.1 %	1.6 %	2.6 %	12.5 %

Source: RTE - Analysis: CRE

Table 5: Cross-border trade flows

in TWh	Germany			Belgium			Spain			Italy		
	Imp.	*Exp.*	*Net*	*Imp.*	*Exp.*	*Net*	*Imp.*	*Exp.*	*Net*	*Imp.*	*Exp.*	*Net*
2008	19.0	6.4	-12.6	1.9	10.9	9.0	3.0	5.8	2.8	1.8	19.6	17.8
2009	19.2	7.2	-12.0	5.8	3.0	-2.8	3.8	5.3	1.5	1.2	19.3	18.1
2010	16.0	9.2	-6.7	4.7	3.8	-0.9	3.5	1.9	-1.6	1.2	17.4	16.1
H1 2010	8.6	4.4	-4.2	2.7	1.7	-1.0	2.1	0.6	-1.5	0.3	9.2	8.9
H1 2011	4.5	5.6	1.0	0.6	4.6	4.0	1.8	1.3	-0.5	0.4	9.0	8.6

in TWh	United Kingdom			Switzerland			Total		
	Imp.	*Exp.*	*Net*	*Imp.*	*Exp.*	*Net*	*Imp.*	*Exp.*	*Net*
2008	1.4	12.7	11.3	7.7	26.1	18.4	34.7	81.4	46.7
2009	4.2	7.4	3.2	9.2	25.7	16.5	43.4	67.9	24.6
2010	5.4	8.3	2.9	5.8	25.1	19.3	36.7	65.8	29.1
H1 2010	3.2	3.1	-0.1	2.5	12.4	9.9	19.4	31.4	12.0
H1 2011	1.6	4.0	2.4	1.3	13 .9	12.6	10.2	38.3	28.2

Source: RTE - Analysis: CRE

The drop in imports is especially related to flows coming from Germany and Switzerland, imports from this latter country going from 9.2 TWh in 2009 to 5.8 TWh in 2010. For Germany, the downturn can be related to the structure of its production facilities, characterised by a strong component of coal-fired plants, for which fuel cost increased markedly in the course of 2010, and the better availability of French nuclear power plants. The drop in imports is also observed to a lesser degree with Belgium and Spain. For this latter country, exports went from 5.3 TWh in 2009 to 1.9 TWh in 2010, thus making France a net importer with regard to this country.

Net import balances have decreased compared to 2009 levels at the borders with Germany and Belgium. At the German border, the net import balance decreased by almost half, going from -12 TWh in 2009 to -6.7 TWh in 2010. This observation is consistent with the price spread between France and Germany. Net exports have increased compared to the 2009 level at the Swiss border.

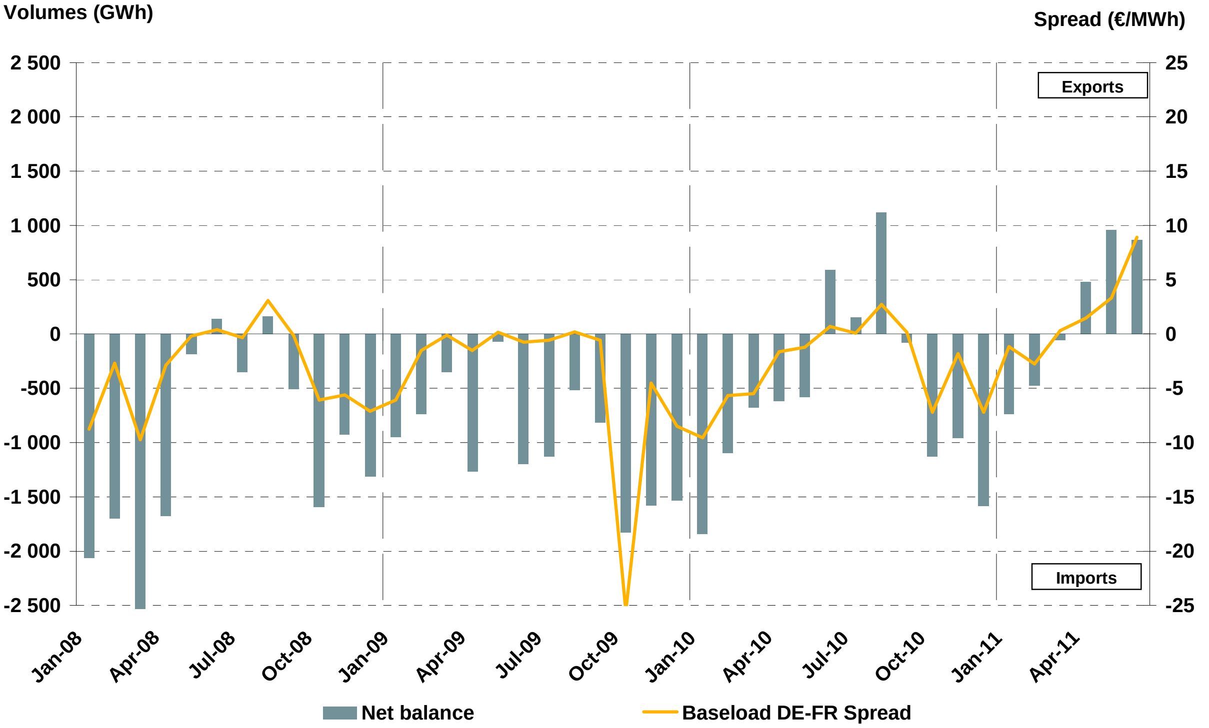
Data from the first months of 2011 compared to that for the same period in 2010 confirm this appreciable upward trend in the export balance, related to increased availability of nuclear power plants. In the case of Germany, Belgium and the United Kingdom, a net export balance has been observed in the first months of 2011, against a net import balance for the same period in 2010. In the case of Germany, this observation is also explained by the nuclear moratorium decided upon by the German government. Trade with Italy in fact represents the only notable exception: the net export balance decreased slightly by 0.3 TWh. Overall, the net export balance of 28.2 TWh in the first half of 2011 represents almost the entire export balance for 2010.

Cross-border flows consistent overall with price differentials between countries

A relation is expected between the price differential and the direction of trade at interconnections. Overall, trade balances observed at all the borders are consistent with the direction of average price differentials compared to France (day-ahead, base). Monthly changes in net trade balances at the borders are correlated with variations in price differentials, with this correlation being especially marked in the German and British cases (Figure 6). The overall consistency of cross-border flows with price differentials does not necessarily imply consistency of all the individual transactions. Analysis of the behaviour of the participants in their nominations at interconnections at the company scale is provided in section 4.2 of the report.

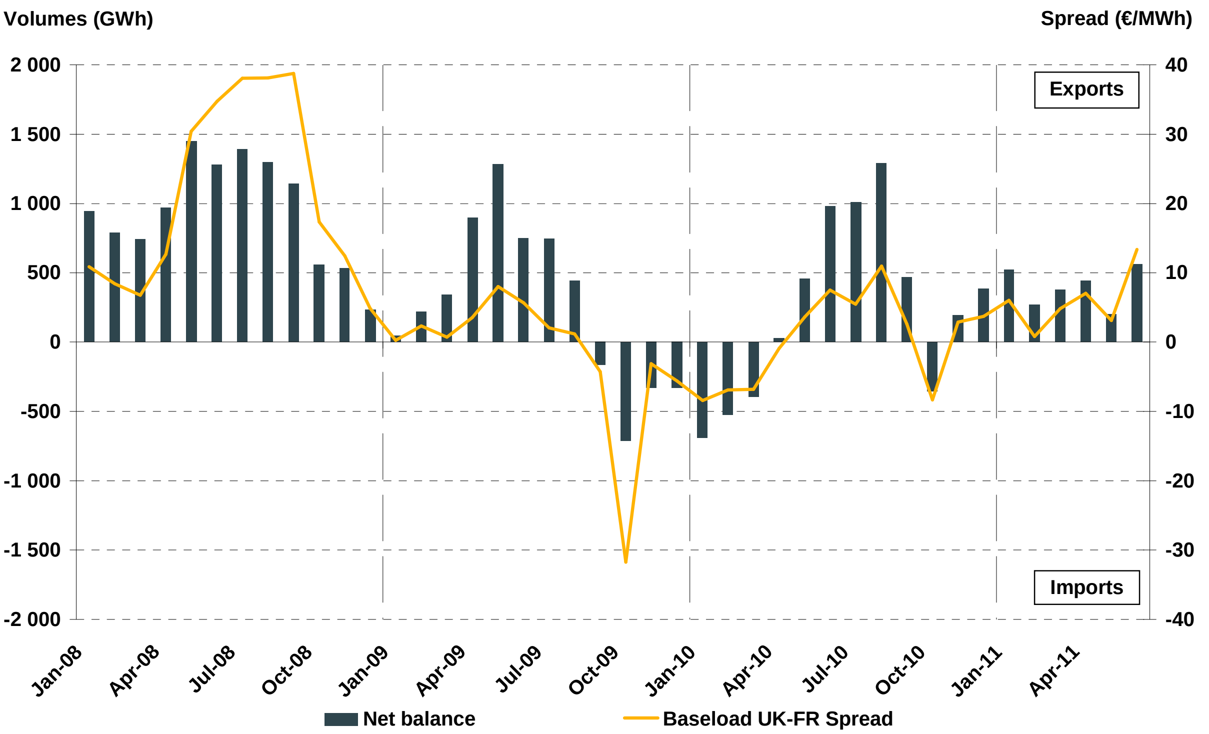
Figure 6: Net export balance and spread price with neighbouring countries

France – Germany



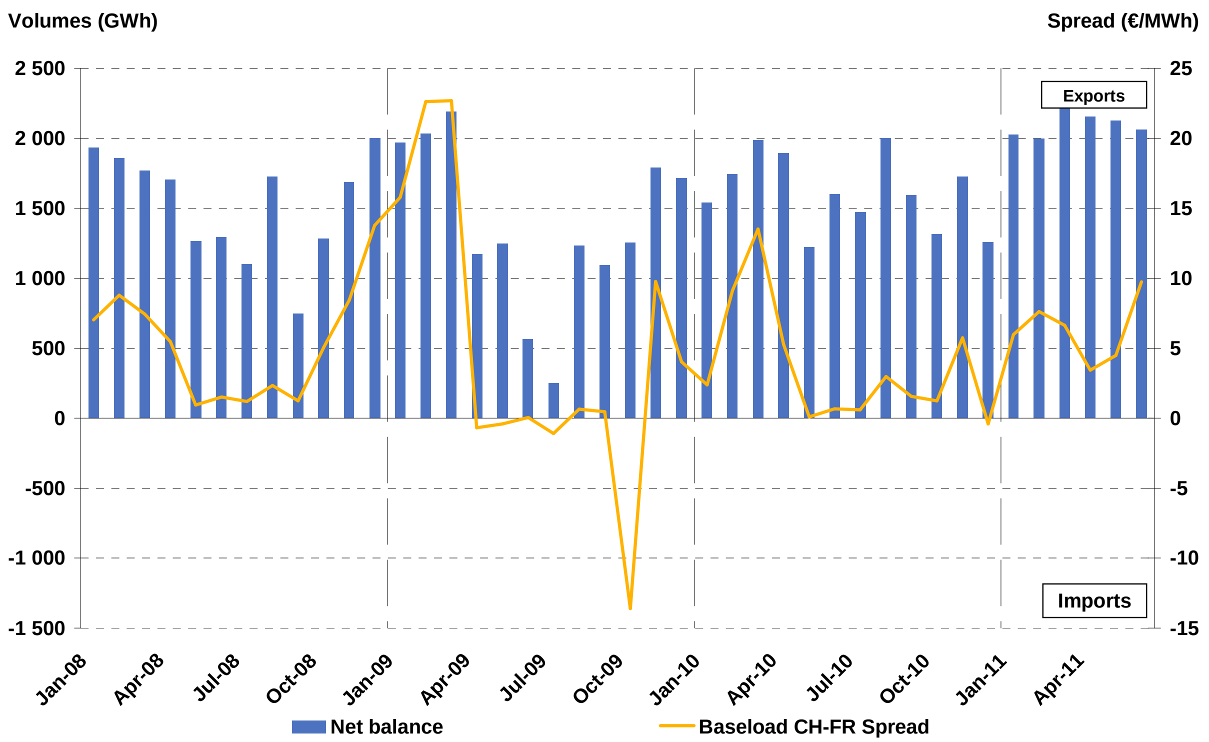
Sources: RTE, EPEX Spot; Analysis: CRE

France – United Kingdom



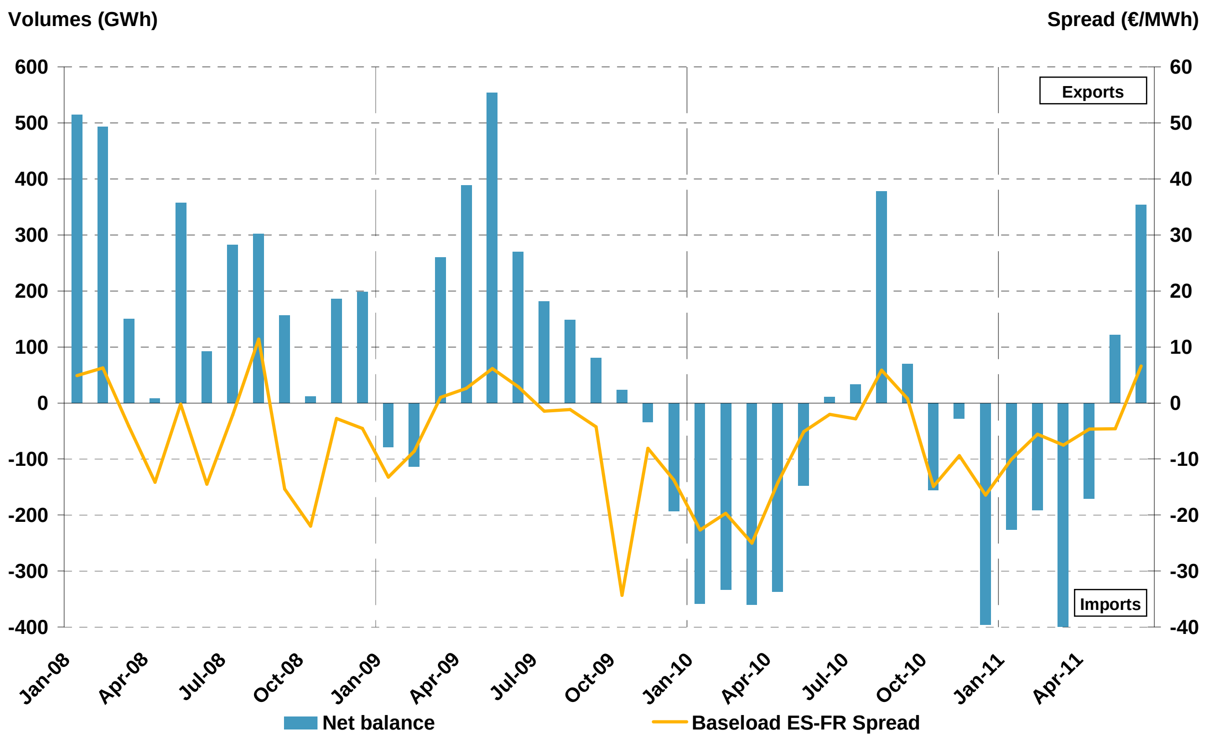
Sources: RTE, EPEX Spot; Analysis: CRE

France – Switzerland



Sources: RTE, EPEX Spot; Analysis: CRE

France – Spain



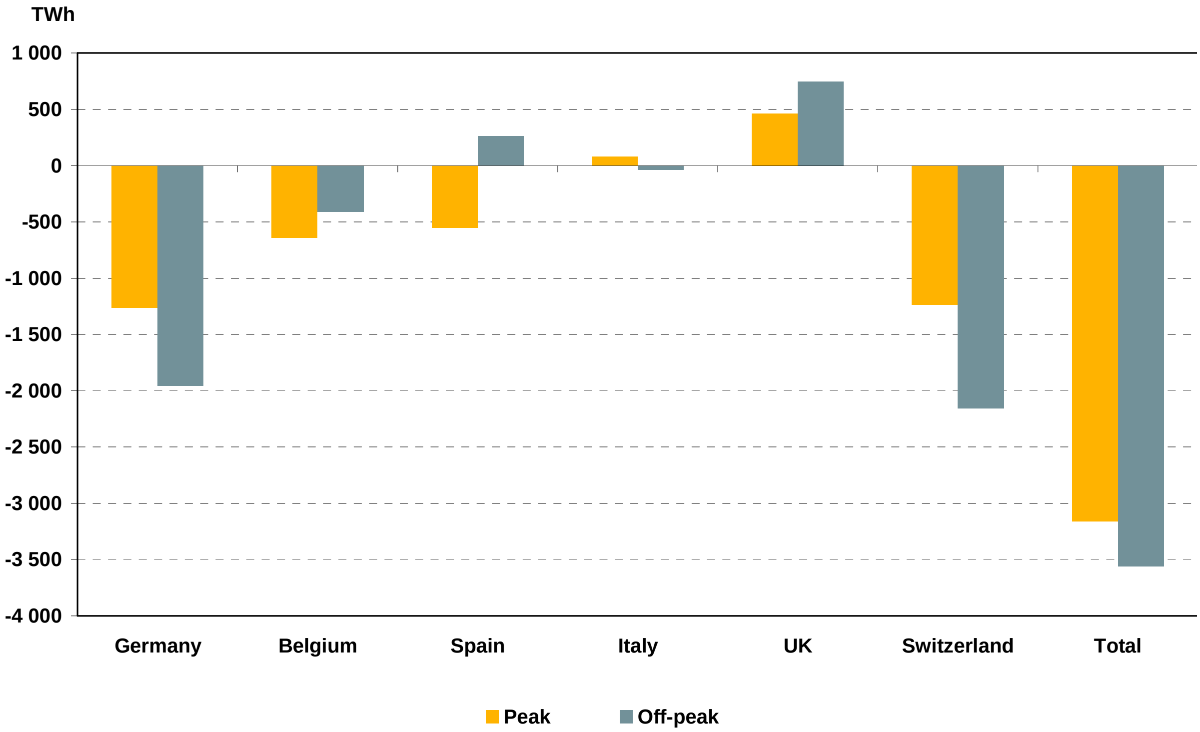
Sources: RTE, EPEX Spot; Analysis: CRE

Decreasing import needs in both peak and off-peak hours

Imports for 2010 declined by approximately 6.7 TWh compared to their 2009 level. This drop in imports was uniformly distributed between peak and off-peak hours; 53% of the drop in imports can be related to imports in off-peak hours (Figure 7).

This decline is explained in particular by the drop in off-peak imports from Germany and Switzerland, due to a drop in the number of days during which the price differential in off-peak hours was favourable to imports.

Figure 7: Changes in cross-border imports between 2010 and 2009 (distribution between peak and off-peak hours)



Source: RTE; Analysis: CRE

1.3 The volume of losses bought by system operators has remained stable from one year to the next

Transmission and distribution systems generate energy losses. Consequently, system operators RTE and ERDF must buy a volume representing the amount of losses to transport electricity.

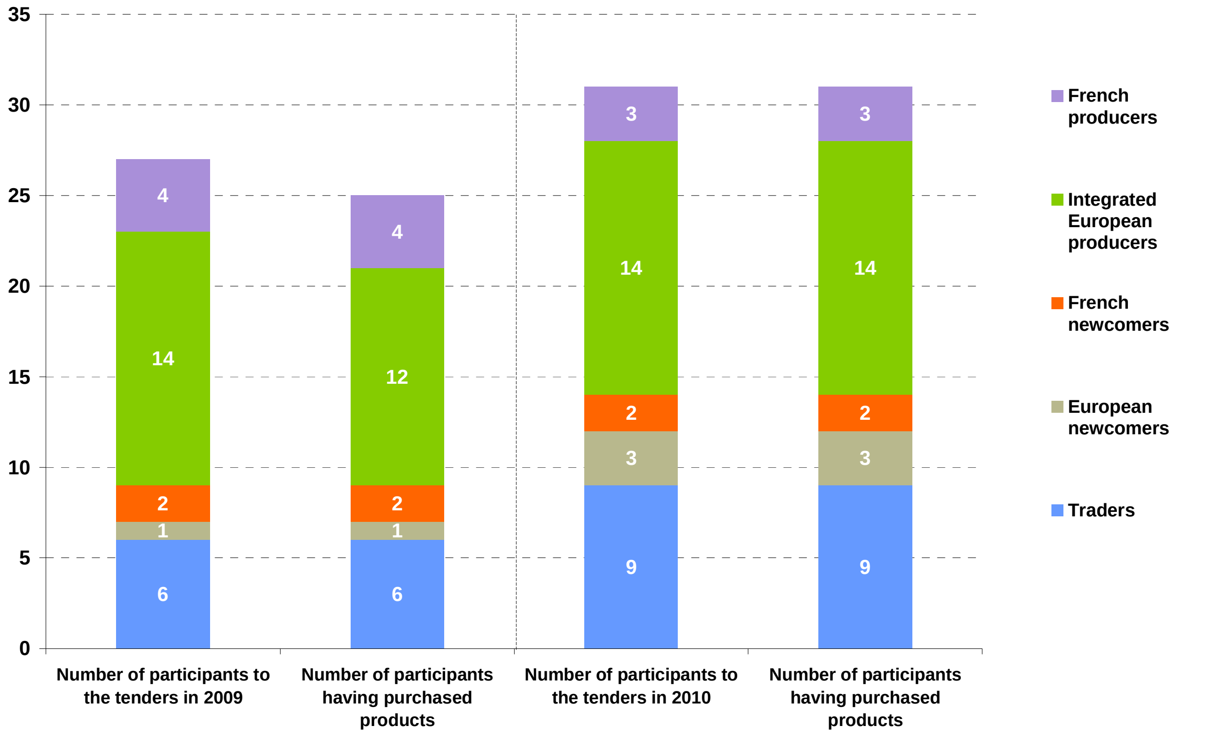
Purchases by the RTE and ERDF system operators necessary for compensation of their losses represented 33 TWh in 2010. This figure is constant compared to the 2009 level. In the first half of 2011, these purchases declined by 2.4 TWh compared to the same period in 2010.

Purchases of losses are made in consultations organised several times per month by the network managers. In 2010, 121 calls for tenders were organised by the two system operators; 85 were organised in the first half of 2011. For comparison, 105 calls for tenders were organised in 2009. Figure 8 shows the number of participants in these consultations.

During the calls for tenders in 2010 and the first half of 2011, system operators bought products covering various delivery horizons. Trades include monthly (from M+1 to M+22), quarterly (from Q+1 to Q+5), and annual (from Y+1 to Y+4) deliveries.

RTE and ERDF operate differently in covering their loss needs. ERDF buys all its needs in annual products, then trades products from one period to another to adjust its energy purchases to its load curve. RTE reconstitutes its curve starting with annual products, then quarterly and monthly. The two system operators activate options and premiums on D-2 to adjust their purchases to their needs. Since the beginning of 2009, RTE has also covered part of its needs on EPEX Spot in day-ahead, and on EPD since June 2010.

Figure 8: Number of participants in the tenders



Sources: RTE, ERDF; Analysis: CRE

1.4 The concentration on VPP ("virtual power plant") capacity auctions remains moderate, but is growing

Since 2001, EDF has offered access to 5,400 MW of production capacity located in France in quarterly auctions, 4,400 MW in the form of base products and 1,000 MW in the form of peak products. Base products, with a low strike price compared to the market price, are comparable to firm products. On the other hand, peak products, with a higher strike price, have a distinctly option-like nature.

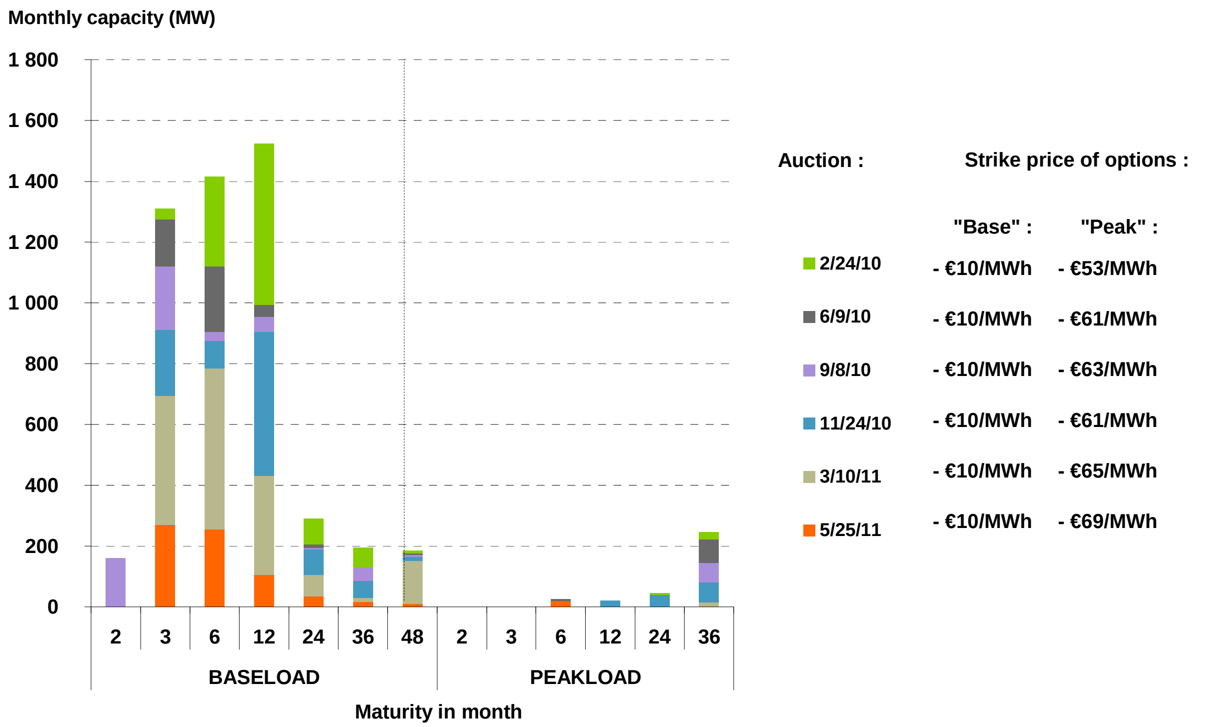
During these auctions, the products most purchased are, in order, base products with 12, 6, 3, and 24 months maturity. Figure 9 summarises the maturities of the products sold during the auctions of 2010 and the first half of 2011, and the strike prices of the option products purchased.

Analysis of the VPP capacities held for a given delivery month by each of the participants leads to the conclusion that this market is moderately concentrated (Figure 10). Thus, from January 2010 to June 2011 the market share of the dominant participant never exceeded 23% for the base product and 26% for the peak product. Moreover, the maximum monthly HHI indices recorded in this period were 1,465 for the peak product and 901 for the base product, demonstrating again that this market segment is acceptably open. These values are however higher than those of 2009.

Base products have a low strike price, €10/MWh at the auctions held in 2010 and the first half of 2011. Day-ahead prices in France were above €10/MWh during 99.4% of the hours in 2010 and the first half of 2011. Because of this, the option value of these products is rarely exercised and it is expected that they will be auctioned at a price very close to that of futures/forwards prices of corresponding maturities. Analysis of the diffrence between auction prices and market prices confirms this observation (Figure 11); the gap between the auction value and futures/forwards prices is on average only -0.004%, with a standard deviation of 1.3%.

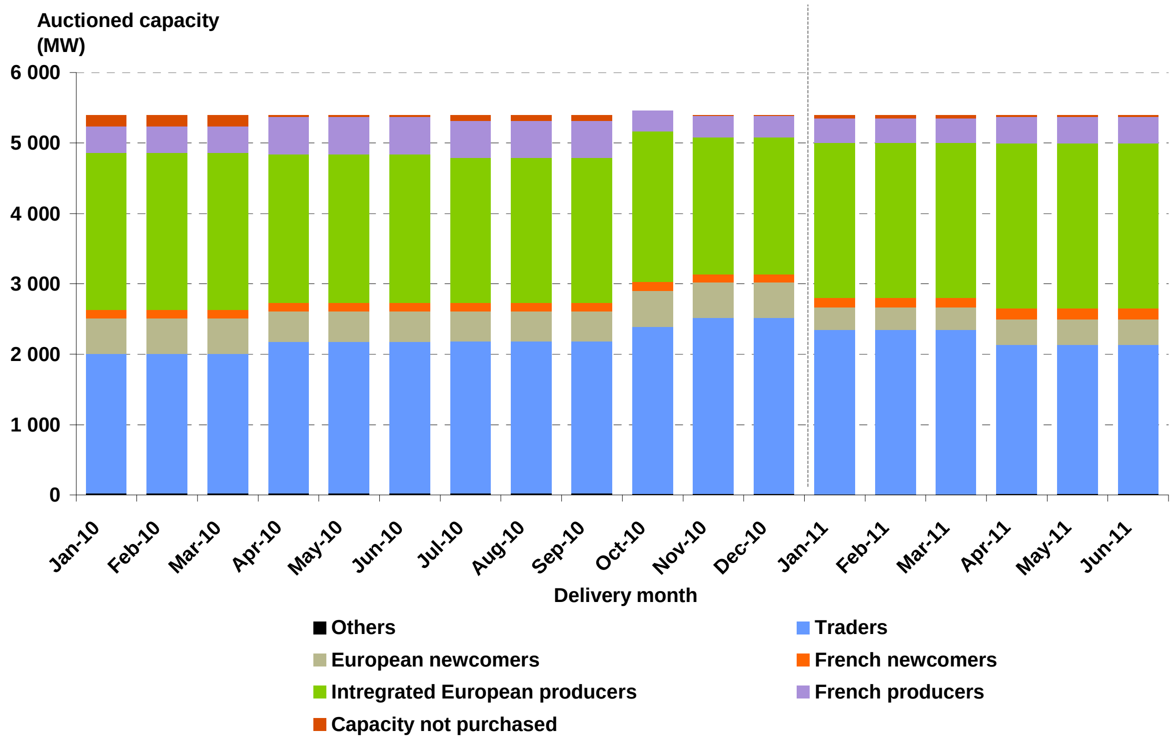
Peak products had a high strike price, between €53 and €63/MWh in the 2010 auctions and €65 and €69/MWh at the auctions for the first half of 2011. The value of these products was strongly linked to the level of and the anticipated volatility in day-ahead prices.

Figure 9: Maturity of the products sold at the auction



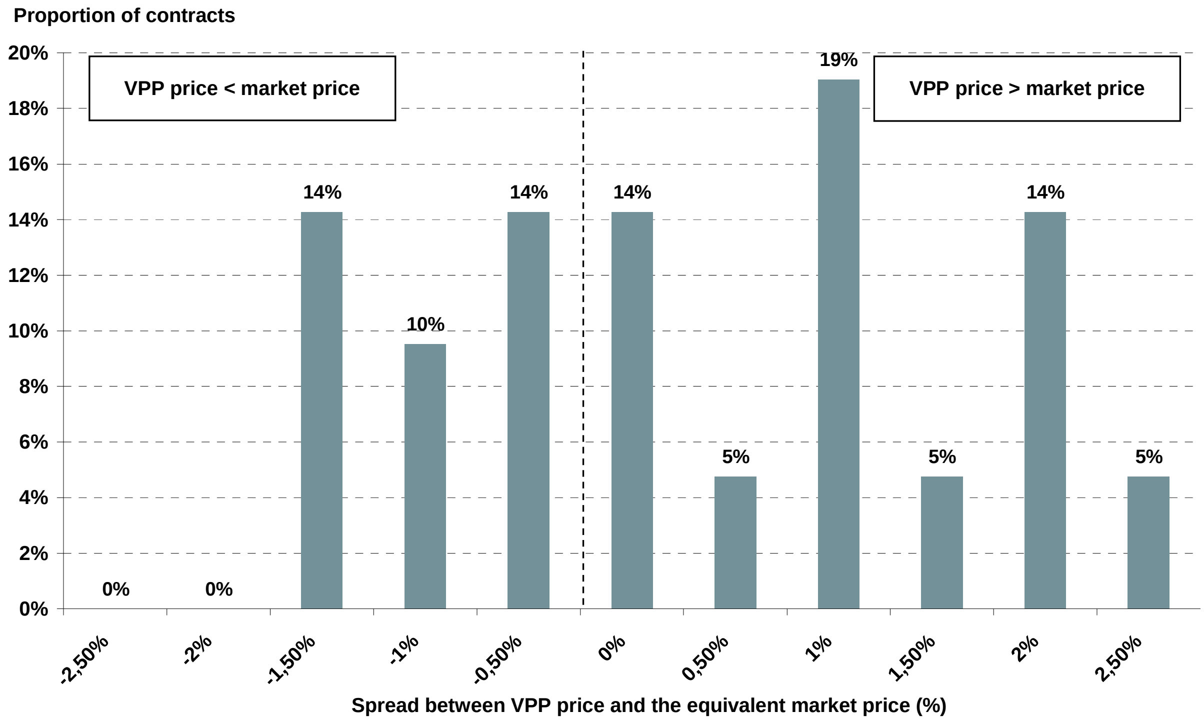
Source: EDF-Analysis CRE

Figure 10: Monthly capacities bought at the auction for delivery in 2010 and 1st half of 2011



Source: EDF; Analysis: CRE

Figure 11: Difference between the auction price of VPP base products and prices of equivalent products quoted on EPD France



Source: EDF, EPD; Analysis: CRE

2. Electricity prices

The variation in electricity prices on the spot market from January 2010 to June 2011 should be analysed in the context of the recovery in economic activity in 2010.

The substantial increase in energy demand and the increase in prices of comoditites are the determining factors in electricity prices over this period.

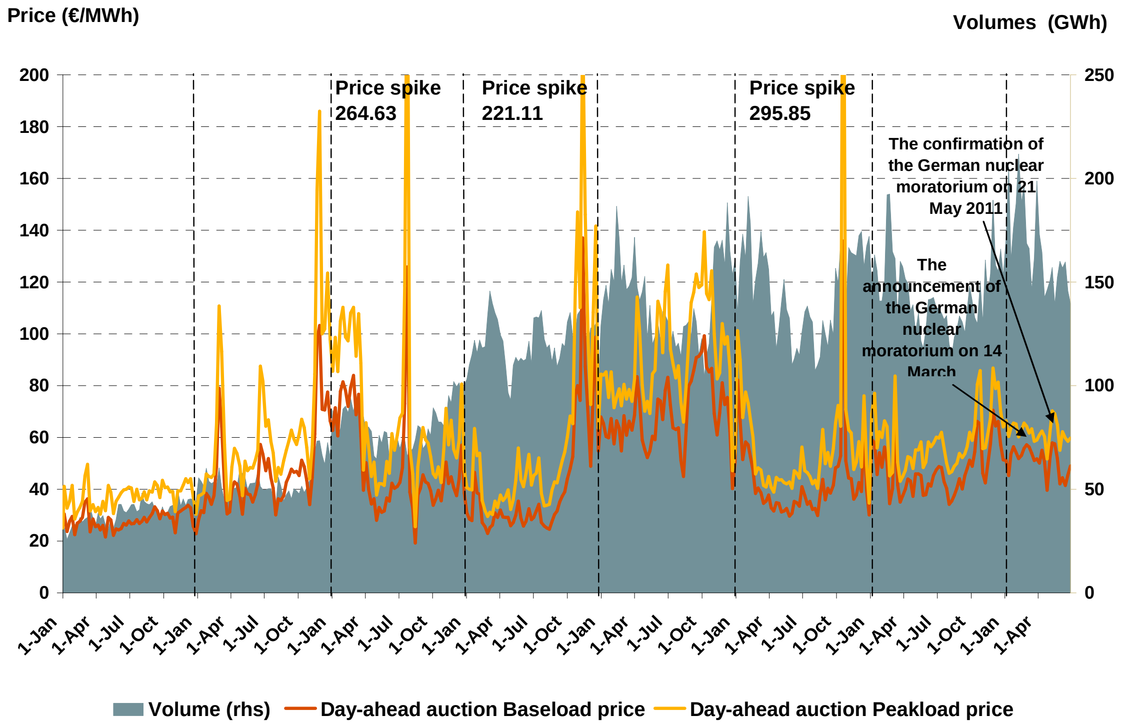
The electricity market was also affected by the consequences of the Fukushima nuclear accident. The German government decided on 14 March 2011 to suspend for three months the agreement extending the lifespan of nuclear power plants in Germany. The next day, the German Chancellor announced the shutdown of seven nuclear reactors (two of which were already undergoing maintenance), reducing the availability of German power plants by 5.3 GW. On 21 May 2011, the German government decided to make this decision definitive and to accompany it by a progressive shutdown in the activity of the other nuclear generating units by 2022. This decision had an impact on European energy prices, notably on electricity, both on the spot market and the market for term contracts.

2.1 French spot prices consistent with the fundamentals and price peaks more moderate than in the past

An average base electricity price of €47.5/MWh was recorded in 2010, almost €4.5/MWh more than in 2009 (€43.0/MWh). For peak prices the differences were less, with the average price per megawatt-hour at €59.0 against €58.2 in 2009.

In the first half of 2011, base and peak prices show an average of €51.0/MWh and €60.0/MWh respectively, levels comparable to the 2010 average.

Figure 12: Variation of spot prices in France (average weekly prices and volumes)

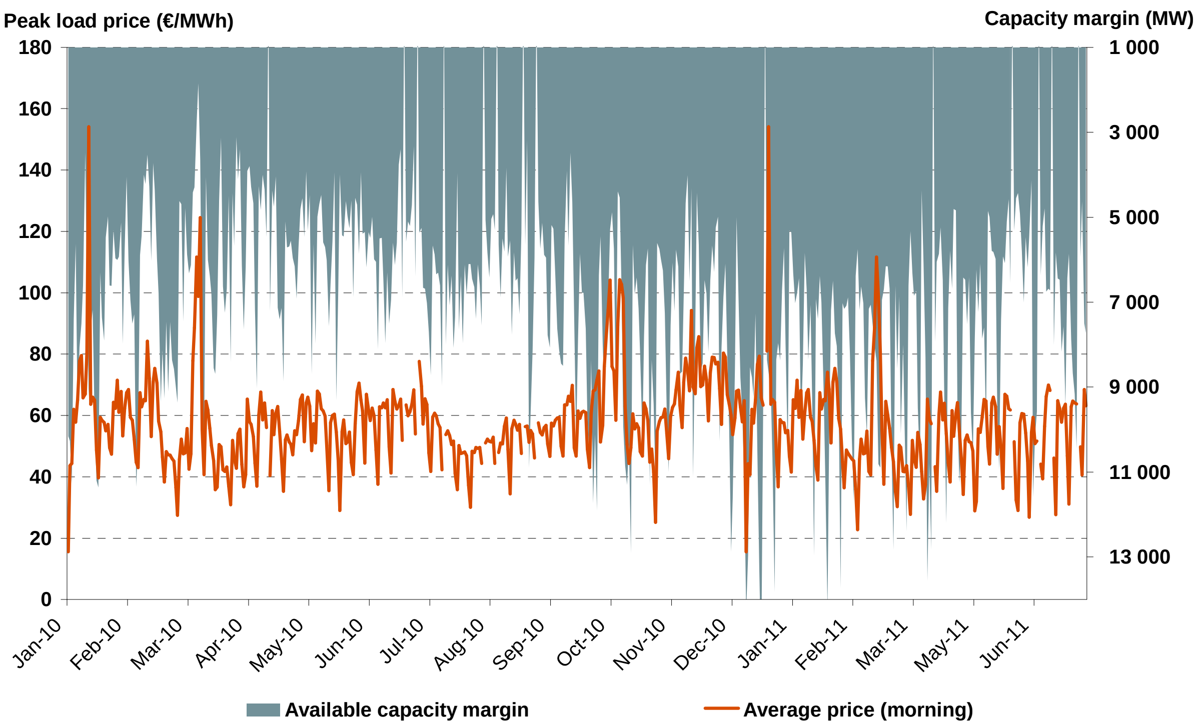


Source: EPEX Spot

The formation of hourly spot prices depends strongly on the margin of the system, that is, the differential between available generation capacity and load. It is observed that prices follow an upward trend when the margin is reduced, notably when it is below 10,000 MW; over 10% of the prices are then greater than or equal to €100/MWh. When the margin between available generation capacity and projected load is sizeable, only the less costly means of production are called upon, hence the marginal cost of the system and so the spot price are low. Conversely, in the event of strain on the power system, more costly peak generation capacity are called upon, which has an impact on the price resulting from the daily auction. In 2010 and the first half of 2011, the availability of nuclear power plants was constantly improving, thus allowing the available margins to be increased compared to 2009. Periods of strain on the network were thus much less frequent.

Each day, RTE publishes the margin level of the French power system for the morning and evening peak periods (hours of which vary from one day to the next). Comparison of these margins with the average spot price observed during these peak hours reveals the expected link between the level of strain on the French power system and prices set during the daily auction (Figure 13).

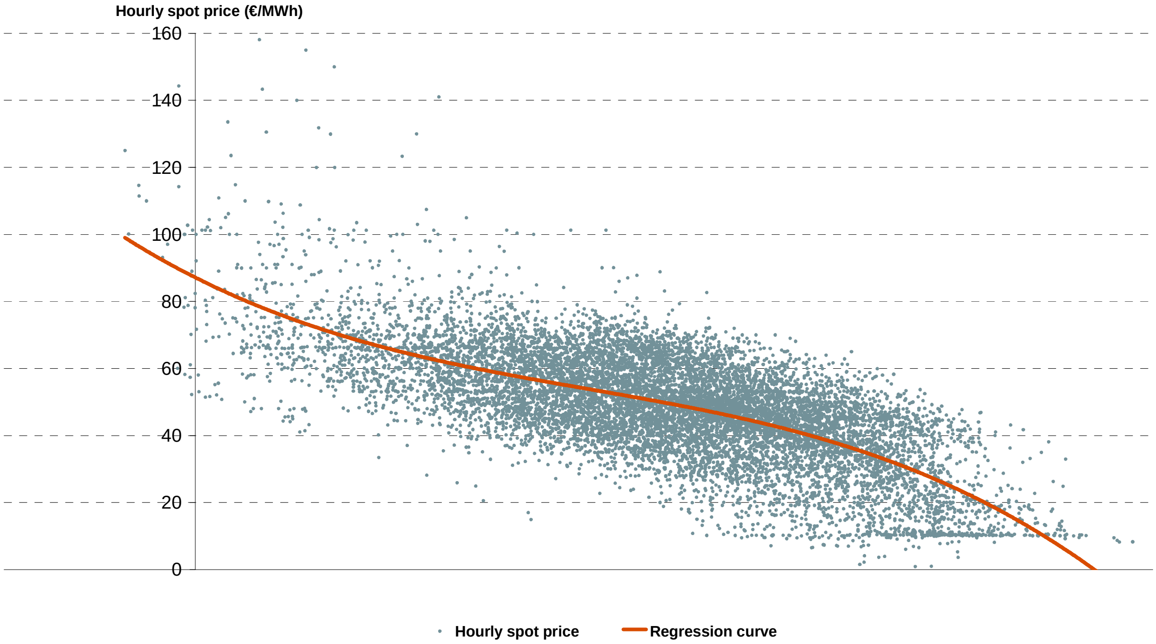
Figure 13: Spot price and RTE margin



Sources: RTE – EPEX Spot

Since July 2009, RTE has also published the availabilities observed (*a posteriori*) for generation units with power greater than 20 MW (RTE reference generation capacity) on its internet site. This new data allows the margin of the French power system, defined as the total observed availability of the RTE reference generation capacity minus the actual consumption for a given hour, to be calculated on an hourly grid, except for power plants with production of less than 20 MW. Unlike the peak margin previously calculated by RTE, this indicator does not take account of electricity traded at the borders, nor of a portion of the power plants. Thus only its variations are meaningful. A negative correlation with the spot price is expected. This is highlighted by Figure 14, where each point represents a system margin/spot price pair. Finally, as for the daily grid, hourly spot price fluctuations also follow for the most part those of the margin indicators (Figure 14). Thus, over the periods analysed (2010 and the first half of 2011) it is observed that when the hourly margin indicator increases (decreases), the corresponding spot price decreases (increases) in 85% of cases. In 2009, this level was 69%.

Figure 14: Hourly spot price and generation margin of the French power system



Sources: Producers – Analysis: CRE

Figure 15: Hourly spot price and generation margin of the French power system

Sources: Producers – Analysis: CRE

2010 was distinguished by relatively low spot price peaks

The price peak of 12 January 2010

During January 2010, an hourly price peak occurred for the 12 January fixing on EPEX Spot. This episode, cited in the previous CRE monitoring report, required a RFQ procedure to be triggered, resulting in prices of €196/MWh for hour 10 and €180/MWh for hour 11. Base and peak prices went to €86.6/MWh and €108.5/MWh) respectively.

This event led CRE to discuss with EDF the inclusion of load shedding in its market bids. EDF had indicated to CRE that part of its load shedding volumes, representing over 3000 MW, was already systematically offered to the market and had informed CRE that this practice was going to be extended to North peak day load shedding volumes (EJP, "*effacement jour de pointe*") and to some industrial load shedding volumes, as specified in the previous monitoring report.

EDF has since confirmed to CRE that EJP North load shedding is now systematically taken into account in its market bids. EDF has also justified the fact that other volumes corresponding to load shedding were not systematically taken into account. Some in fact had to remain available for possible activation by RTE. In the case of some industrial load shedding, EDF indicates that the heterogeneity in their activation methods does not allow them to be offered on the market under all circumstances.

CRE believes that these operational measures constitute a development favourable to the operation of the French wholesale electricity market and has noted the incorporation of these additional bids into the market.

The 12 March 2010 price peak reflects a strain on the supply-demand balance

On 12 March 2010, the hourly spot price at hour 9 reached a level of €240.7/MWh. The base price for the same day was €79.4/MWh. This price peak occurred in a context of high consumption related to particularly low temperatures for the season, at the time when consumption was highest for that day. The constraint on demand was combined with a supply shortage related to low availability of thermal power plants and unexpected unavailability of several power plants.

Price peaks of moderate amplitude in autumn 2010

During October 2010, several price peaks of moderate amplitude occurred during daytime, reaching €212/MWh:

on 21 October, hours 9 and 10 recorded prices of €155 and €130/MWh respectively,

on 25 October, hour 19 reached €150/MWh,

on 26 October, hours 8 and 9 exceeded €109/MWh while hour 19 reached €212/MWh,

on 27 October, hour 9 reached €120/MWh,

28 October, hour 9 reached €130/MWh.

These episodes and the associated transactional data are undergoing systematic examination to verify the consistency of such occurrences with the fundamentals of the French electrical system: consumption, generation availability of power plants and cross-border flows.

It turns out this period was characterised by a strained power system in the context of a strike and sizeable consumption. Bearing in mind the prices in bordering countries and the hours involved, the use of interconnections is deemed consistent and overall satisfactory. Moreover, analyses of the market shares and order books did not reveal any anomaly.

The most significant price peak occurred in December 2010 at an hour of sizeable consumption

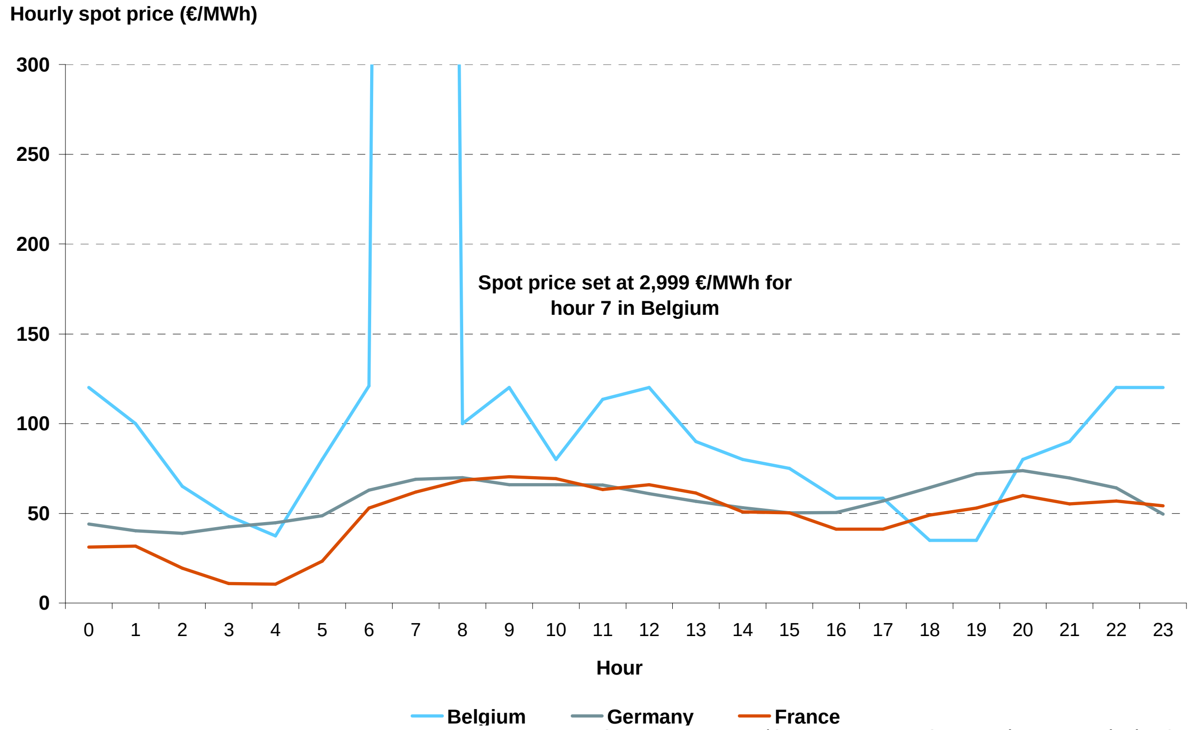
On 2 December 2010, hour 18 recorded a price of €252/MWh, the highest hourly price of the year. For hours 17 and 19, prices were €115/MWh and €106/MWh respectively. These prices occurring at peak hours characterise a strained system on days when consumption was sizeable. Thus, consumption on 2 December was 1,998 GWh, the eighth highest of the year. In hour 18, the power drawn approached 91 GW.

Finally, a price peak occurring in Belgium with no impact on French prices can be cited (Box 1).

Box 1: Decoupling of the markets of 27 March for the day of 28 March 2011

On Sunday 27 March, a technical incident related to the transition to daylight saving time led to a delay in publication of the auction results for the next day. Given the impossibility of publishing prices before the limiting time (14:00h), the decision was made to decouple the CWE markets. While this decoupling had no particular effect on German and French prices, the price on the Belgian market reached the ceiling of €2,999/MWh for hour 7. The price then returned to levels similar to those of the other markets: the base price for Monday 28 March in Belgium was set at €206/MWh.

Figure 16: Hourly spot prices for 28 March 2011



Sources: France /Germany EPEX Spot, Belpex – Analysis: CRE

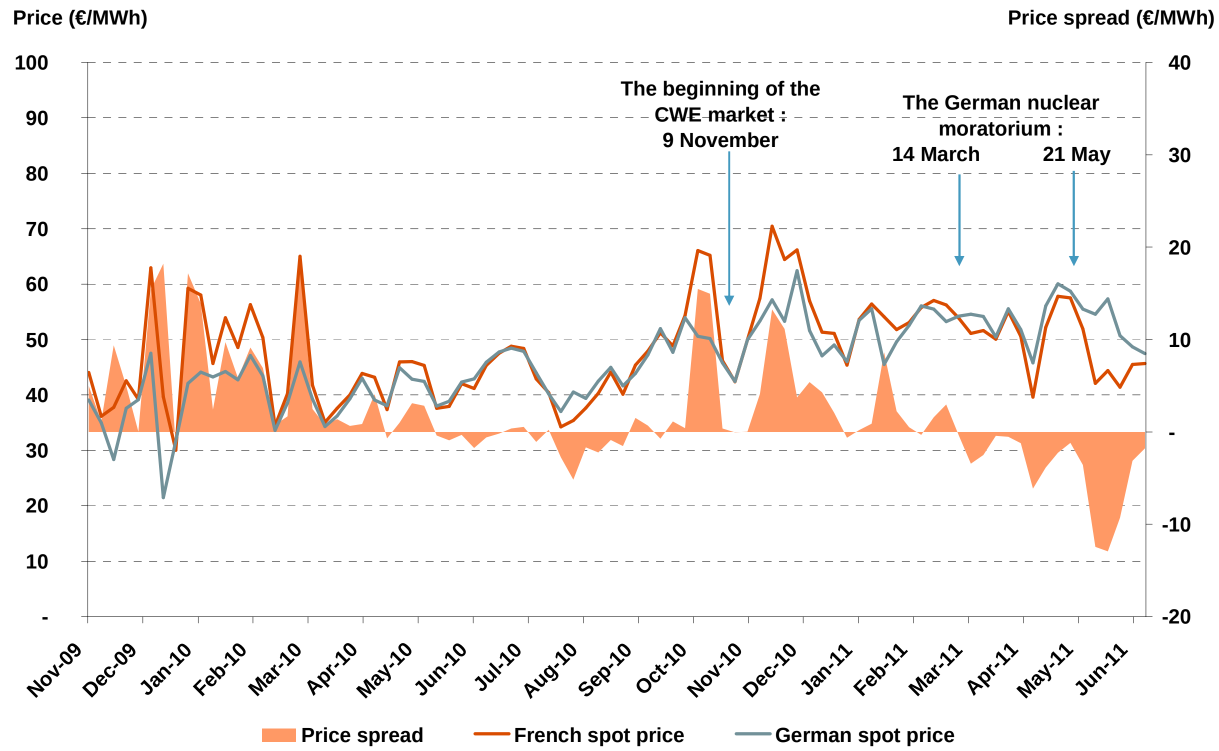
Market coupling and the German nuclear moratorium have affected the variation of French and German spot prices

The trilateral TLC (France – Belgium – Netherlands) coupling has existed since 21 November 2006 and was extended to Germany on 9 November 2010. The rate of convergence of hourly prices between France and Germany[9] has settled at 65% since coupling. Over the same period one year earlier (9 November 2009 – 30 June 2010), the convergence rate was only 1%. The convergence rate with Belgium was 86% in 2010 and exceeded 98% over the first half of 2011. Hourly convergence occurs only rarely (on the order of 1% of the time) for the other countries bordering France and not coupled with it (United Kingdom, Switzerland, Italy and Spain).

The announcement of the German nuclear moratorium on 14 March 2011 had an impact on the French and German spot markets. Starting from mid-March, the France-Germany spread of spot prices in fact changed sign, with the price of electricity in Germany becoming higher than in France. However, starting from confirmation of the moratorium on 21 May 2011 this spread took on sizeable values, testifying to an interconnection capacity between France and Germany that had become insufficient to make prices converge (Figure 17). In total, the French spot price was below the German spot price by €1.8/MWh on average over the first half of 2011, with a difference that exceeded €10/MWh in some weeks. In 2010, French spot prices were on average €3/MWh higher than the German spot price.

[9] defined as the percentage of hours for which the absolute price differential is less than € 0.05/MWh

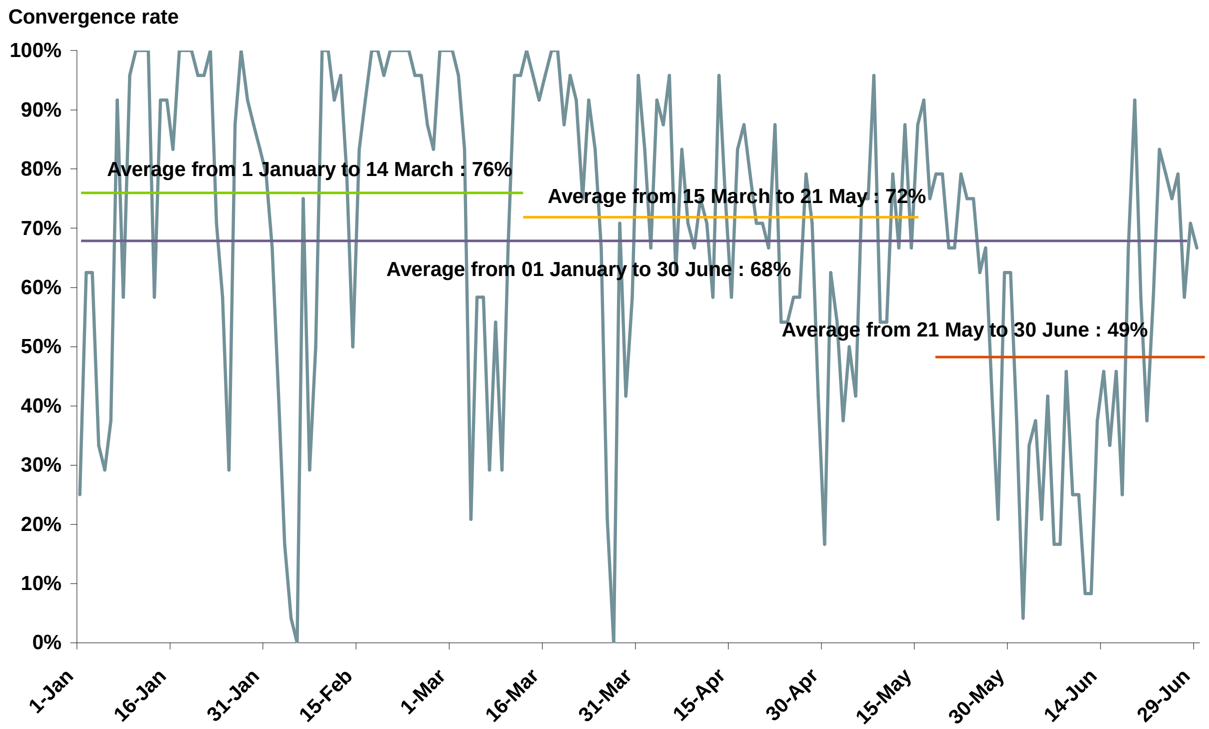
Figure 17: France – Germany spot price and price spread(weekly averages)



Source: EPEX Spot

The announcement of the German nuclear moratorium had a non-negligible effect with regard to convergence rate, as Figure 18 shows. Over the period preceding 14 March 2011, the convergence rate was set at almost 76%, versus 63% after this date. If confirmation of the moratorium on 21/05 is considered, the rate after this date deteriorated even further, falling to 49%. This decrease can be attributed to the very mild weather conditions in France, which led to very low spot prices in the off-peak hours, when the basic facilities were marginal and saturated French consumption and export capacities, while German spot prices at the same hours appeared to be set by conventional thermal power plants, at higher costs.

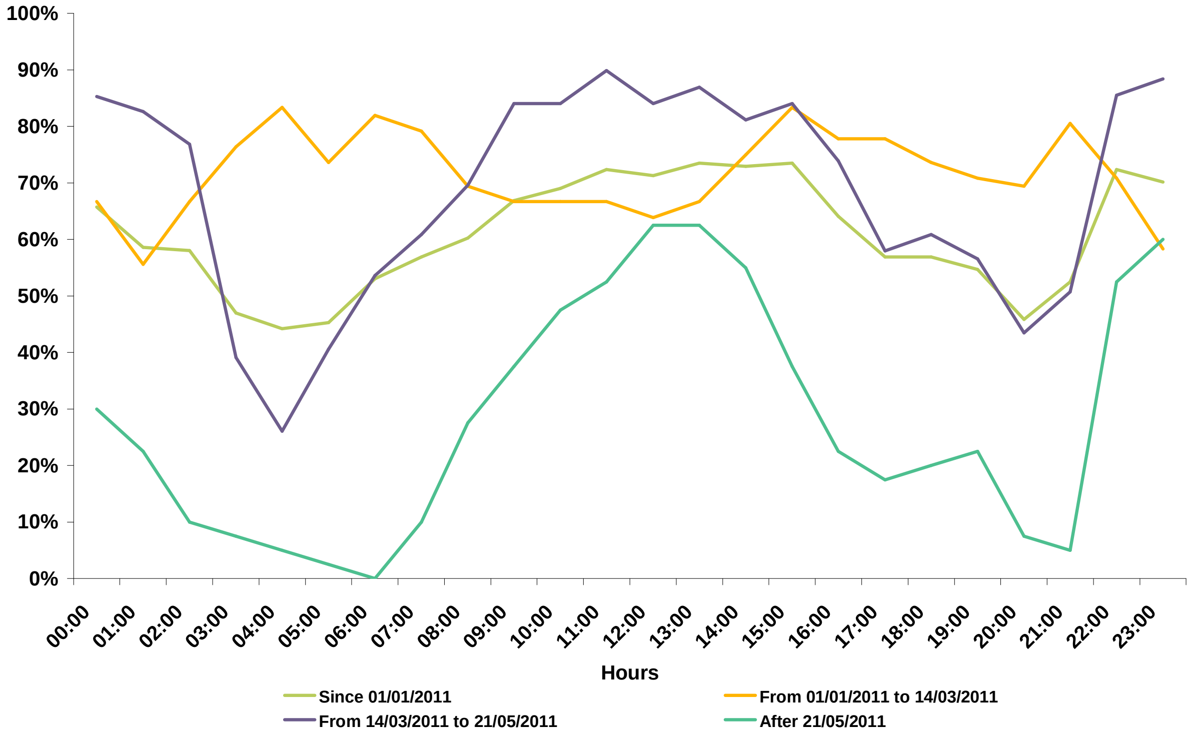
Figure 18: Daily rate of convergence of hourly prices, France-Germany



Source: EPEX spot

Figure 19 shows in fact that this loss of convergence was not uniform over a day; it occurred especially during the morning (before 10:00) and afternoon (between 15:00 and 21:00) hours. As the convergence rate curves for the periods from 14 March-21 May and after 21 May show, the midday (10:00 to 14:00) and end of day (22:00 to 24:00) hours maintained relatively good convergence rates compared to those of the first quarter of 2011. This phenomenon can be attributed to the differences in the German and French generation systems; the marginal generation units in these morning and afternoon hours were different, with French nuclear availability very good in the spring, while the nuclear moratorium in Germany removed more than 5 GW of German nuclear capacity from the bulk power system.

Figure 19: Average convergence rates per hour in the 1st half of 2011

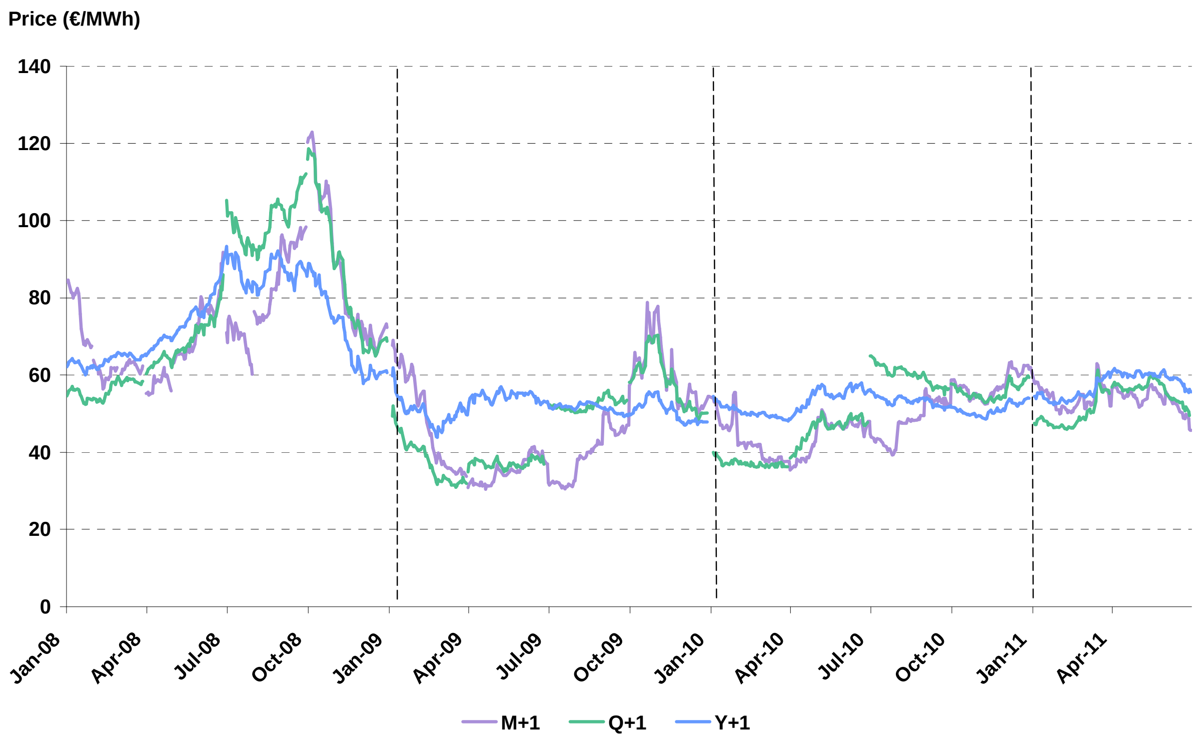


Source: EPEX spot

2.2 Prices of electricity term contracts increased less rapidly than those of fossil fuels in 2010

In 2010, the level of futures prices on the EEX Power Derivatives market changed little compared to 2009. Y+1 calendar products were stable throughout the year, with an average of € 52.4/MWh versus € 51.7/MWh in 2009. Monthly and quarterly futures (which show seasonal behaviour) were also more stable than in the preceding year. Like the Y+1 product, monthly M+1 and quarterly Q+1 products increased on average compared to 2009, settling respectively at €48.3/MWh (+€ 2.4/MWh) and €50.0/MWh (+€ 3.3/MWh).

Figure 20: Prices of futures - France



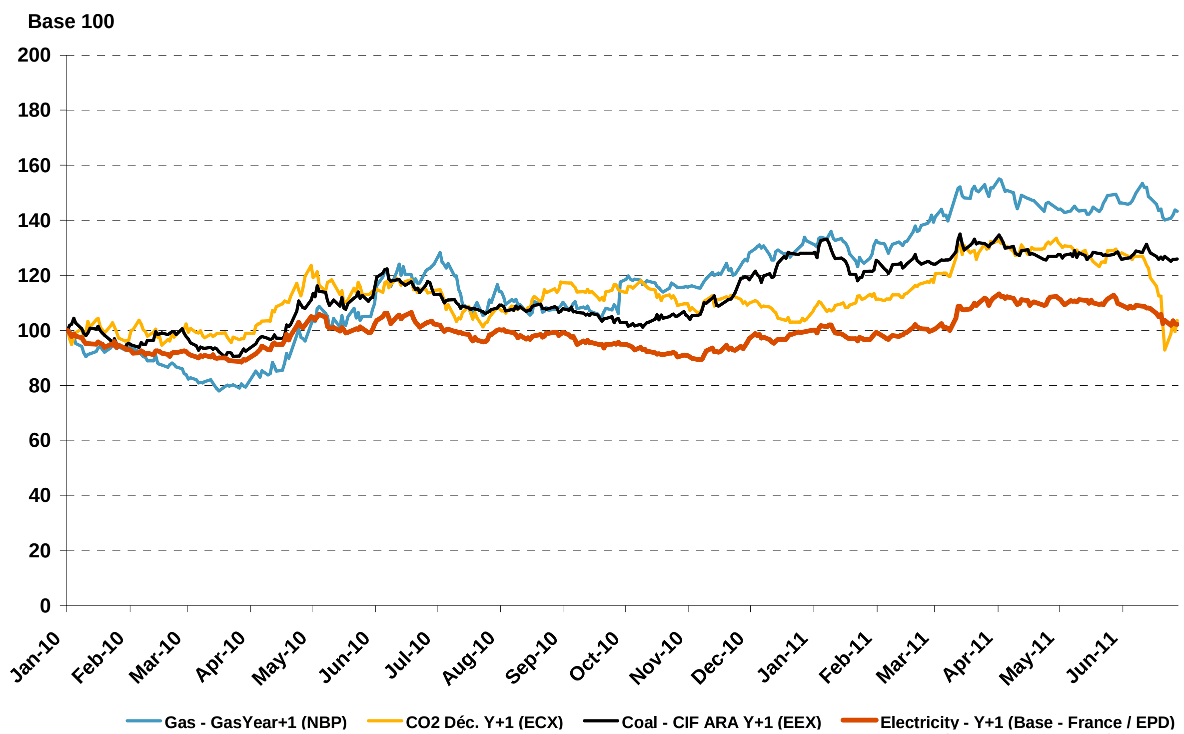
Source: EEX Power Derivatives

Over the first half of 2011, these resources increased; the average quotation of the Y+1 product was € 57.3/MWh, and those of the M+1 and Q+1 seasonal products were set at € 53.9/MWh and € 52.7/MWh respectively.

Comparison of the price variation in the Y+1 electricity product and fossil fuel prices (Figure 21) shows that the price of electricity remained more stable than those of fuels, and in particular of gas and coal.

Figure 21: Fuel and electricity prices

Base 100 January 2010

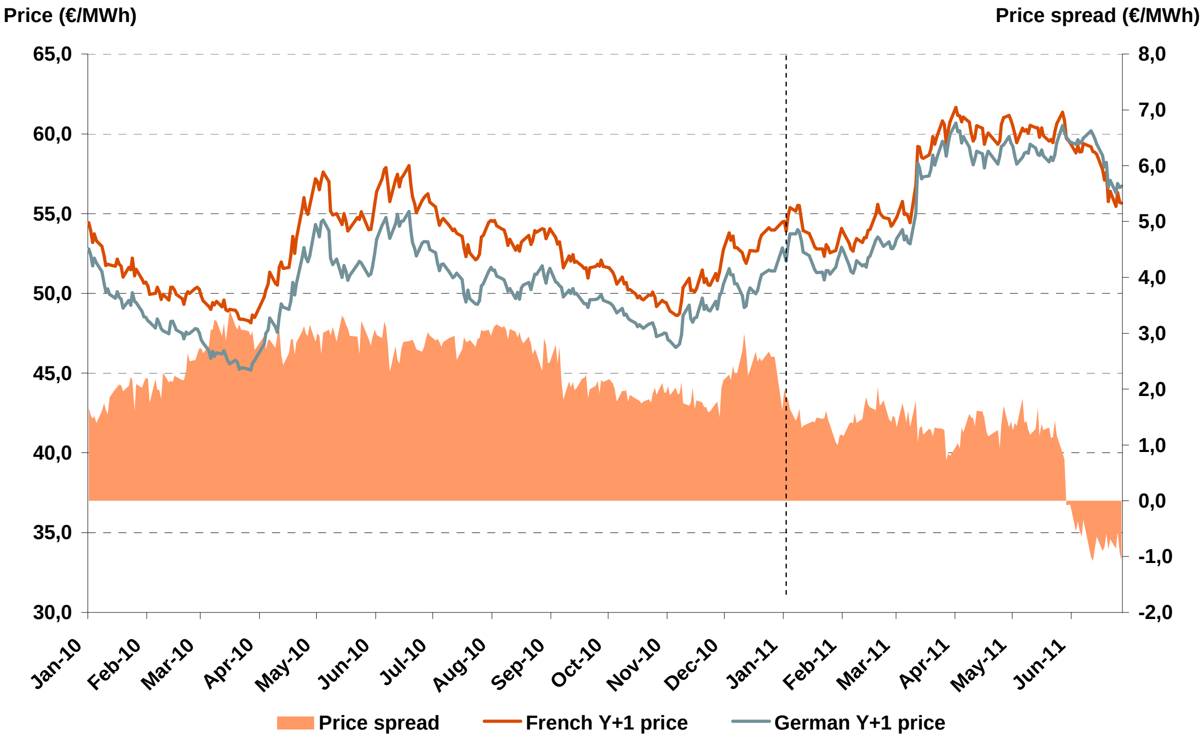


Sources: EPD, ECX, Heren

Inversion of the one-year price spread between France and Germany since the announcement of the nuclear moratorium

The reduction in the spread between France and Germany at the start of the first half of 2011 (Figure 22) can be related to expectations with regard to the recent French and German spot market coupling. Its inversion at the beginning of June (France less expensive) signals however a structural modification and can be attributed to the German nuclear moratorium. Figure 22 shows the marked increase in the price of base Y+1 futures in mid-March in France and Germany, as well as the inversion of the spread between these products at the beginning of June 2011 following the confirmation on 21 May 2011 of the progressive shutdown of nuclear plants in Germany by 2022.

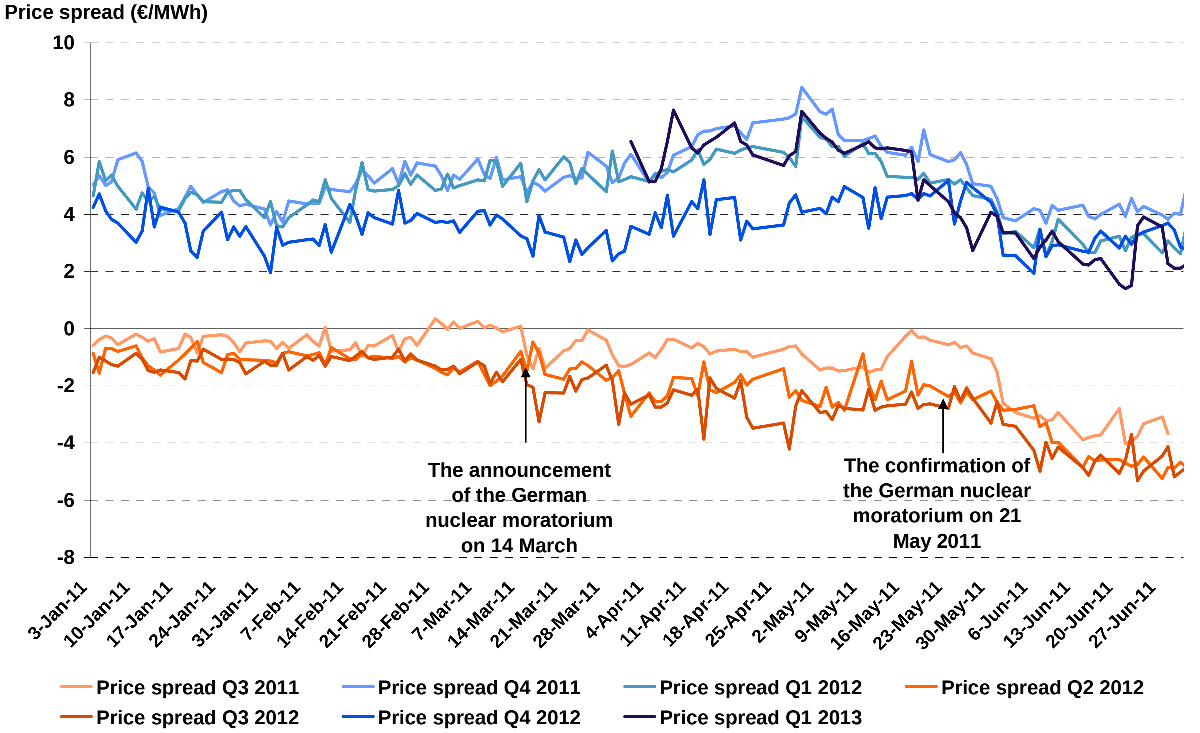
Figure 22: Y+1 price and France - Germany price spread



Source: EEX Power Derivatives

The effects of the moratorium on futures prices can also be perceived on quarterly products, with the latter also taking account of the temperature sensitivity of French electricity consumption. Thus, Figure 23 shows that the price spreads of Q1 and Q4 quarterly products (winter quarters) are usually positive (France more expensive), while those of Q2 and Q3 quarterly products (summer quarters) are usually negative (France less expensive). The variation in spreads since the beginning of 2011 has been marked by the announcement and confirmation of the German nuclear moratorium. Over the first half of 2011, price spreads for Q4 and Q1 products, when France is more expensive, lost between 0.5 and €3.4/MWh on average after 21 May 2011. Likewise over the first half of 2011, price differentials for Q2 and Q3 products, when France is less expensive, show decreasing gaps between €2 and €3.4/MWh on average recorded for periods before and after 21 May. These variations also highlight an increase in German prices compared to French prices.

Figure 23: France – Germany price spread in quarterly futures

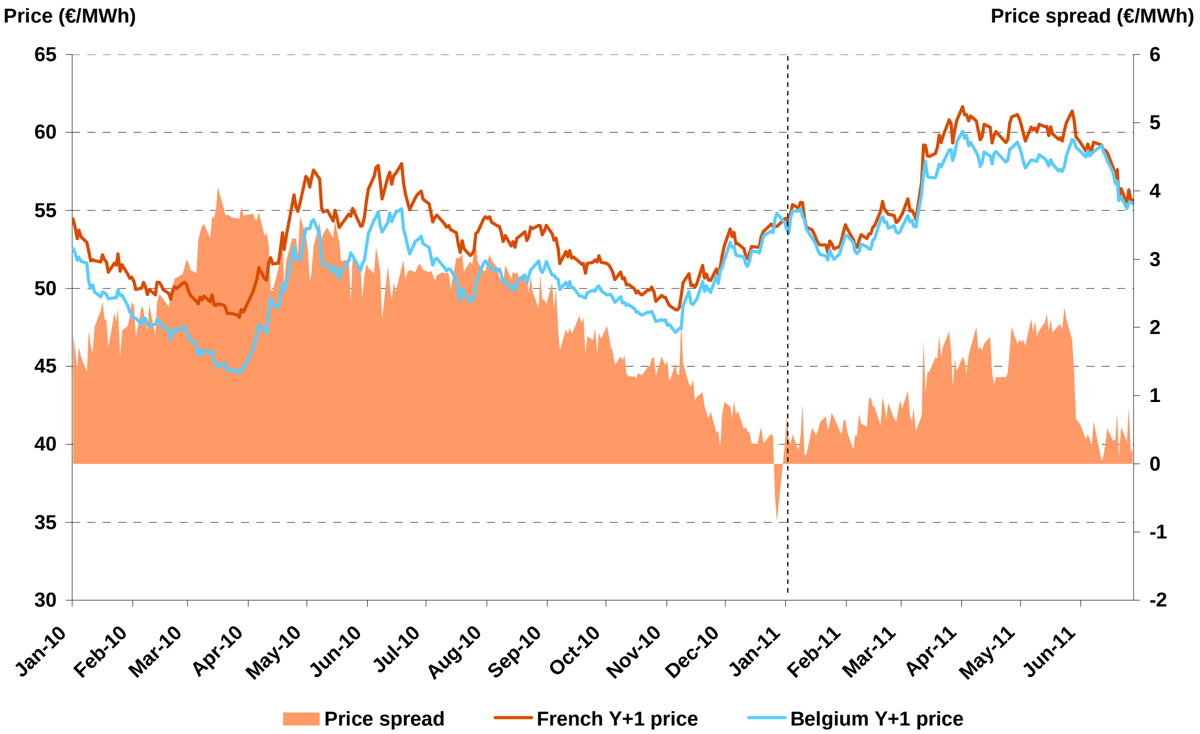


Source: EEX Power Derivatives

Despite the market coupling in place between France, Belgium and the Netherlands for several years, spreads in futures prices remain

The spread between Y+1 base calendar products in France and Belgium (Figure 24) was high throughout 2010, with a notable drop in the last two months; while the Y+1 calendar product in France had been quoted at between €2 and €3/MWh more than its equivalent in Belgium, the price difference went below €1/MWh. This price difference continued to vary over low values in the beginning of 2011 before rising again starting in March. This rise was however very brief, with the spread returning to a very low level as of the end of May 2011.

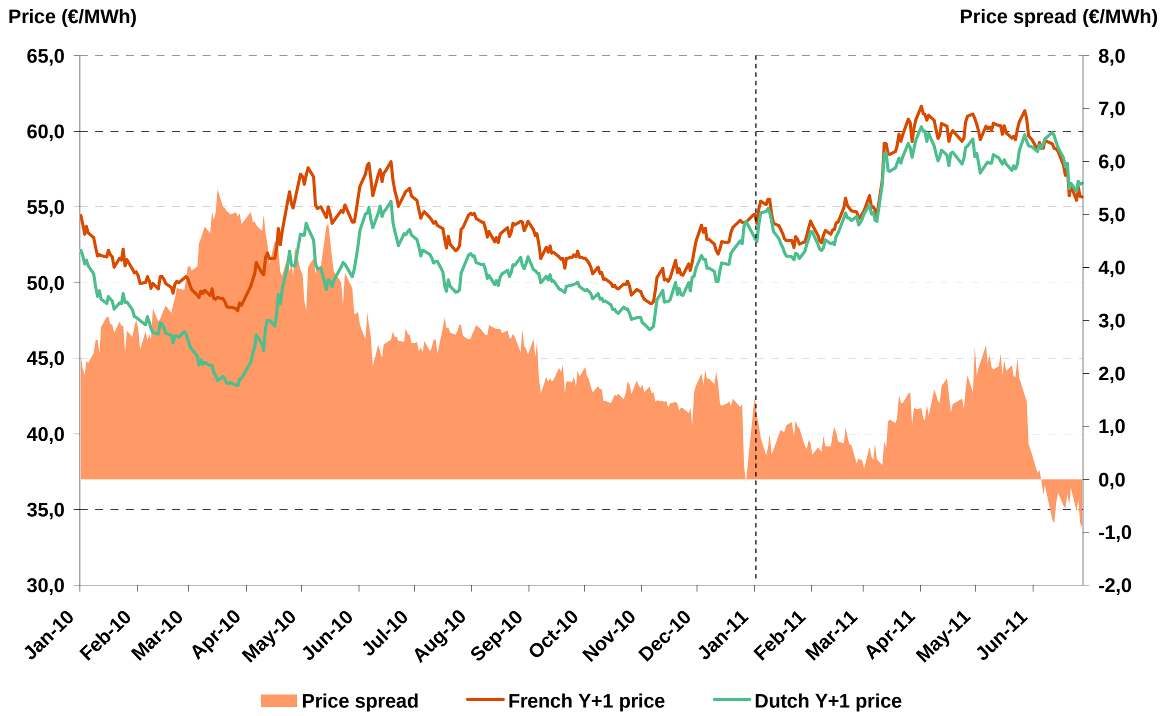
Figure 24: Y+1 price and France - Belgium price spread



Sources: EEX Power Derivatives, APX-ENDEX

For France and the Netherlands, as for Belgium, a drop can be observed in the price differential between Y+1 calendar products (Figure 25), but also an inversion of the spread, as with Germany, where the French futures became less expensive starting from the end of May/beginning of June 2011.

Figure 25: Y+1 price and France – the Netherlands price spread

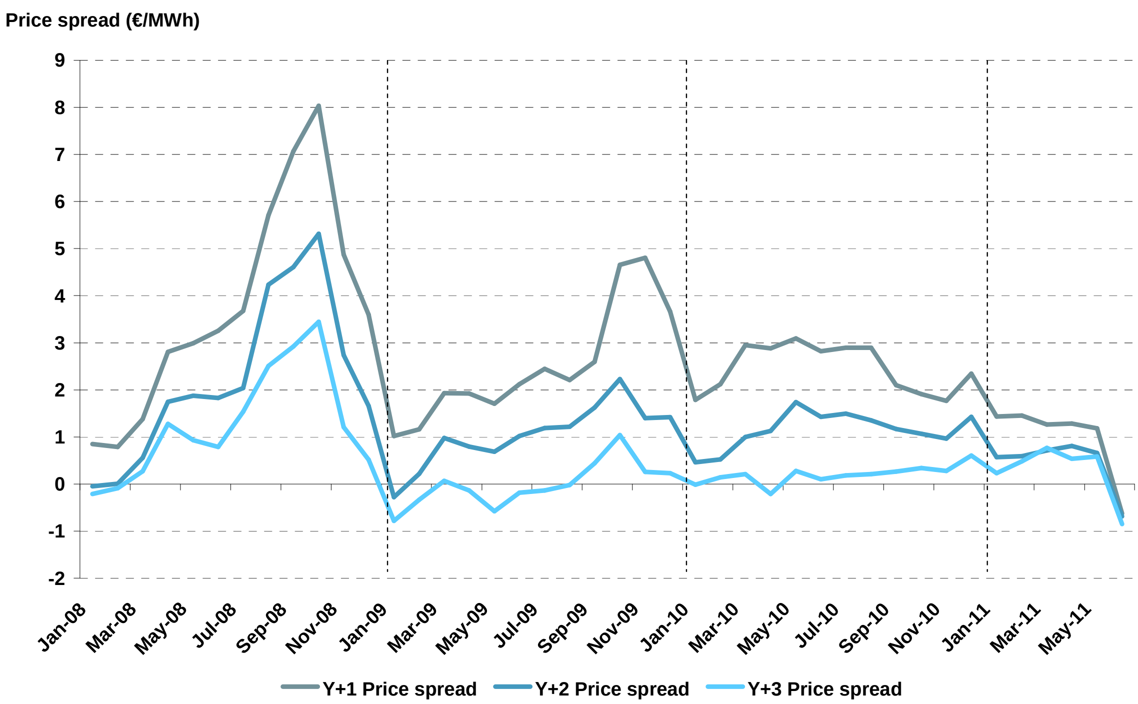


Sources: EEX Power Derivatives, APX-ENDEX

Decrease in spreads between products with maturity

Study of base Y+1 base calendar products reveals that the France-Germany spread (Figure 26) increases the nearer the product maturity. A slight reduction in spreads at the end of 2010 (probably related to spot market coupling) is noted, as well as an inversion in June 2011, a consequence of the confirmation of the German nuclear moratorium.

Figure 26: France – Germany price spread in calendar products (monthly averages)

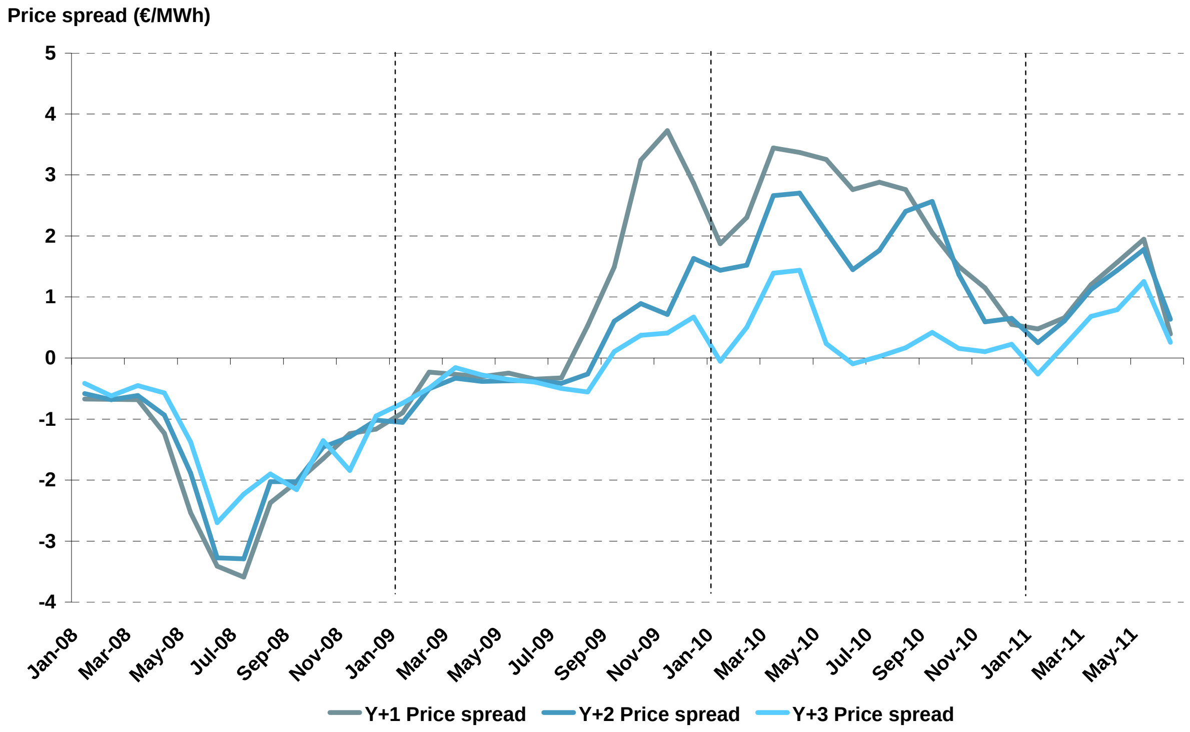


Source: EEX Power Derivatives

Likewise, for Belgium (Figure 27) and the Netherlands (Figure 28) it is observed that the closer the maturity, the larger the spread (in absolute value) tends to be.

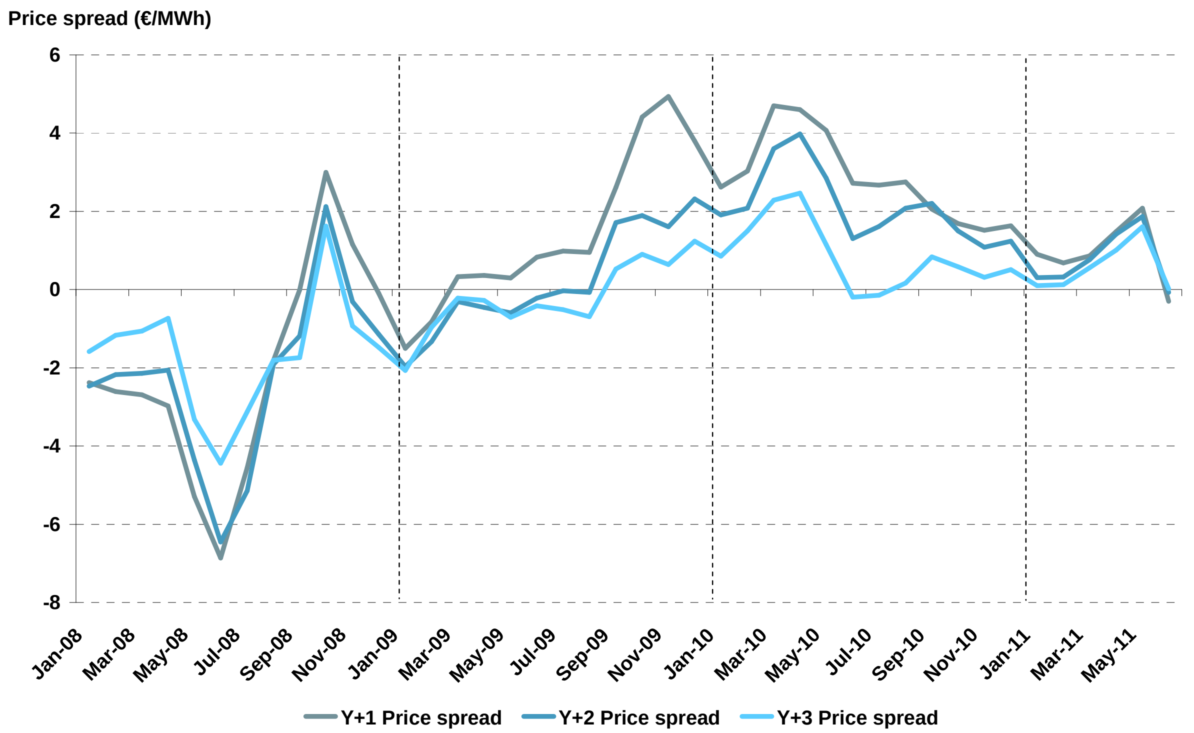
The presence of a spread to the disadvantage of France with regard to these markets with which there is coupling may reflect the presence of a risk premium. In fact, prices on the French spot market are more volatile, due in part to greater temperature sensitivity in consumption and lower liquidity.

Figure 27: France – Belgium price spread in calendar products (monthly averages)



Sources: EEX Power Derivatives, APX-ENDEX

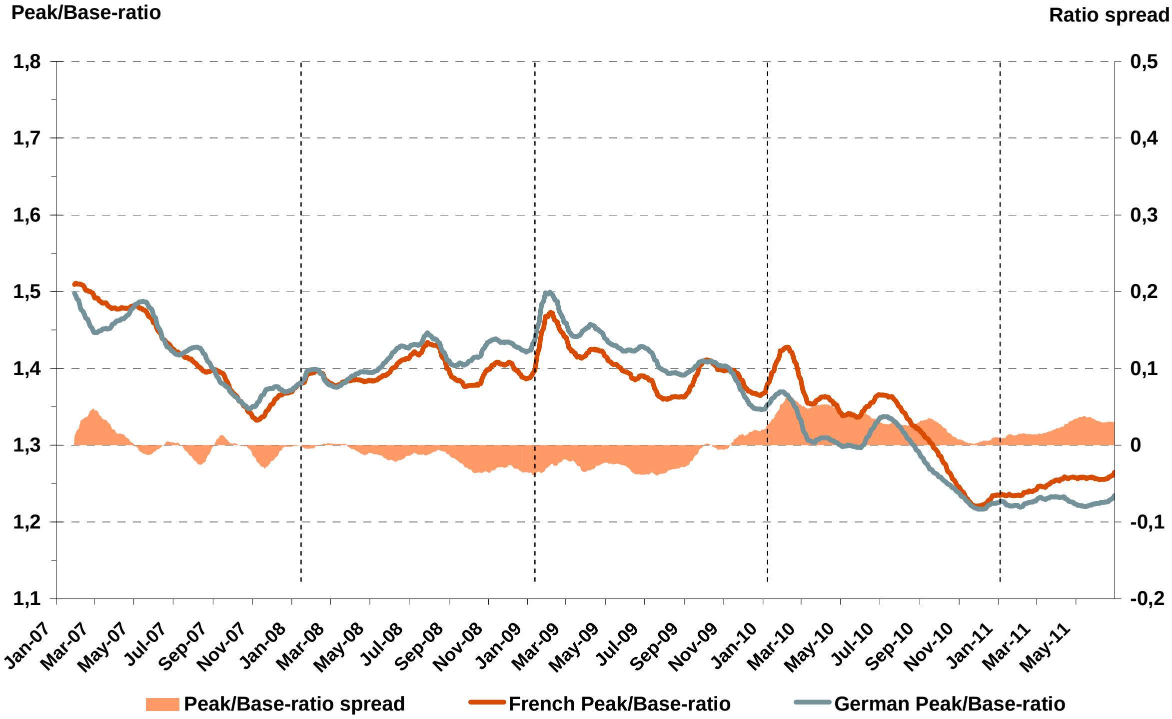
Figure 28: France – the Netherlands price spread in calendar products (monthly averages)



Sources: EEX Power Derivatives, APX-ENDEX

Finally, the recovery of the ratio between prices of Y+1 peak and base calendar products since the end of 2010 can be noted in France and in Germany after a downward trend of several years (Figure 30). The downward trend of the French peak/base ratio in the wake of the German ratio is in general attributed by market observers to the growing share of photovoltaic generation in the German production mix.

Figure 29: Variation of the peak/base ratios of Y+1 calendar products in France and in Germany and spread (moving averages over 20 days)



Source: EEX Power Derivatives

3. Analysis of electricity production and transparency of production data

According to RTE, as of 1 January 2011 the installed generation capacity in France was 123.5 GW, a rise of 3.1 GW over the past year. Figure 30 gives the distribution of this total capacity as a function of the various types of generation technologies, and its variation.The increase in capacity connected to the transmission system (1.43 GW) is due mainly to the connection of two combined cycle gas turbines and two combustion turbines plants. The distribution network has undergone sustained growth in the renewable generation capacities connected, with over 600 MW added in photovoltaic and 950 MW in wind power.

If only the reference facilities connected to the transmission system are considered, the installed capacity totals 105 GW, 63.1 GW of them for nuclear power plants alone, which thus represent 60.1% of these facilities. Hydroelectric power constitutes 23.1%, including a small majority of generation units of “lake” type, managed as a function of the hydro-storage available in barrier lakes, and the remainder made up of so-called “run-of-river” plants, the production of which depends on water availability. The rest of the capacities consist mainly of thermal combustion power plants, which are still dominated by fuel oil and coal generation (6.9% and 6.6% respectively), even though gas power plants (3.2%) have undergone extensive development, with 900 MW installed in 2010 and as much planned for 2011.

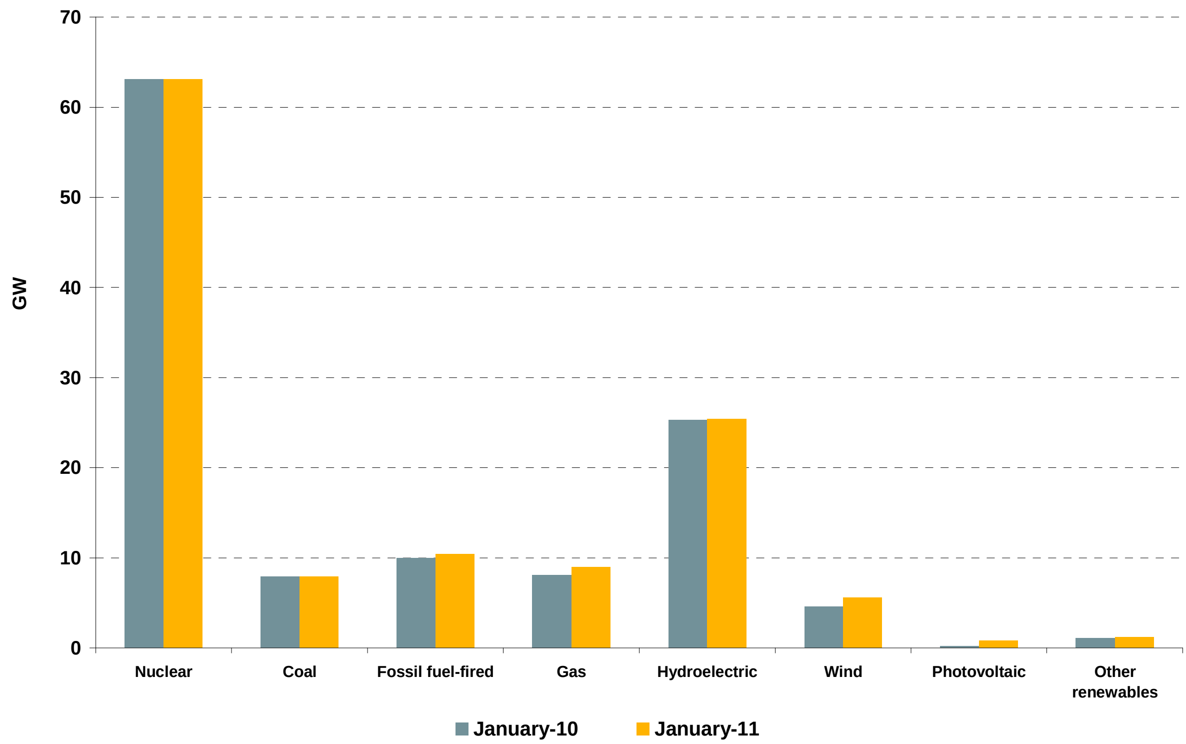
The installed generation capacity operated by the EDF group totals over 95 GW, approximately 91% of the reference facilities. The principal competitors of the historic French producer on the electricity production market are:

GDF SUEZ which, through CNR, SHEM, its generation assets and the aforementioned holdings in nuclear power plants, holds 5.5% of the total capacity of the reference ;

E.On France (SNET, E.On group), which holds 3% of the installed capacity.

These three producers operate over 99% of the capacity of the reference generation capacity in total.

Figure 30: French electricity generation facilities (levels of the various generation technologies)



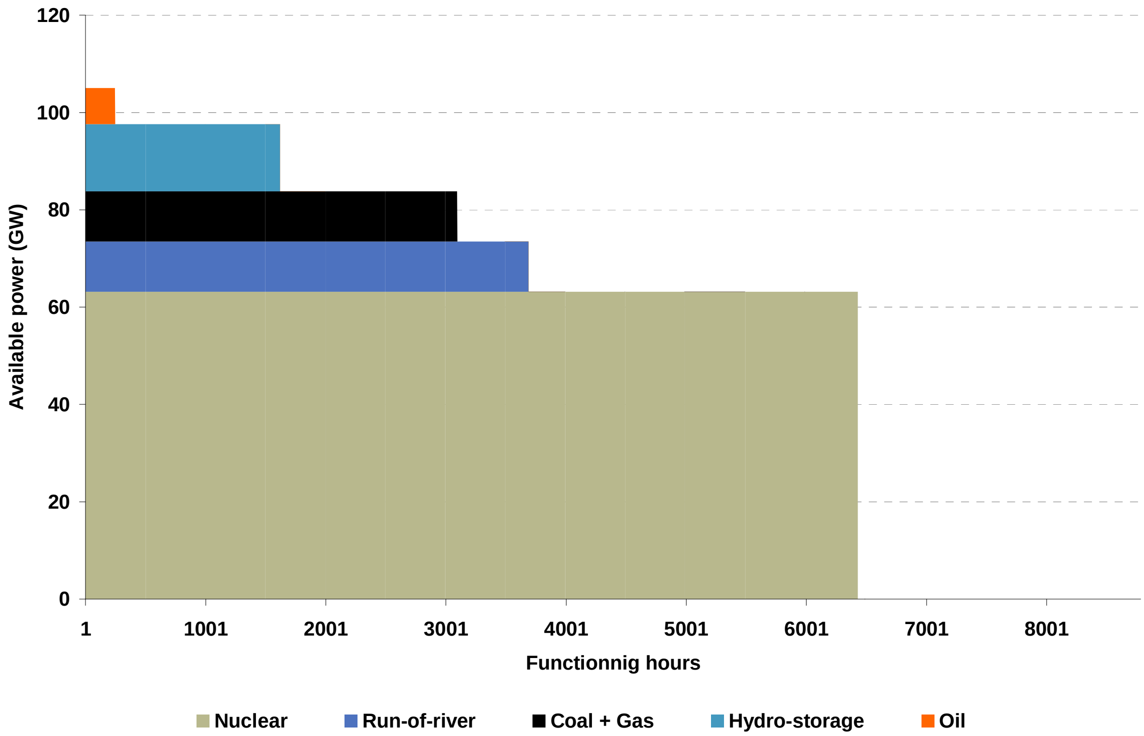
Source: RTE

3.1 *The utilisation rates of the various generation technologies reflect the relative levels of marginal production cost*

The ratio between total energy production and installed capacity allows the rates of utilisation of each type of generation technologies to be determined. These rates, converted to the equivalent utilisation period, are shown in Figure 31 below. These equivalent periods thus reflect both the availability and the utilisation (base or peak) of the various generation technologies. The highest utilisation period in 2010 is observed to be that of nuclear power plants, with 73% of the time versus 70% in 2009 due to increased availability. Conversely, fuel oil power plants, which constitute peak production, are only used 3% of the time.

The highest equivalent utilisation periods thus correspond to the generation technologies with lowest marginal cost, with the exception of “inevitable” and “unfirm” production such as hydroelectric run-of-river or wind power.

Figure 31: Utilisation period of the various genearion technologies in 2010



Source: RTE - Analysis: CRE

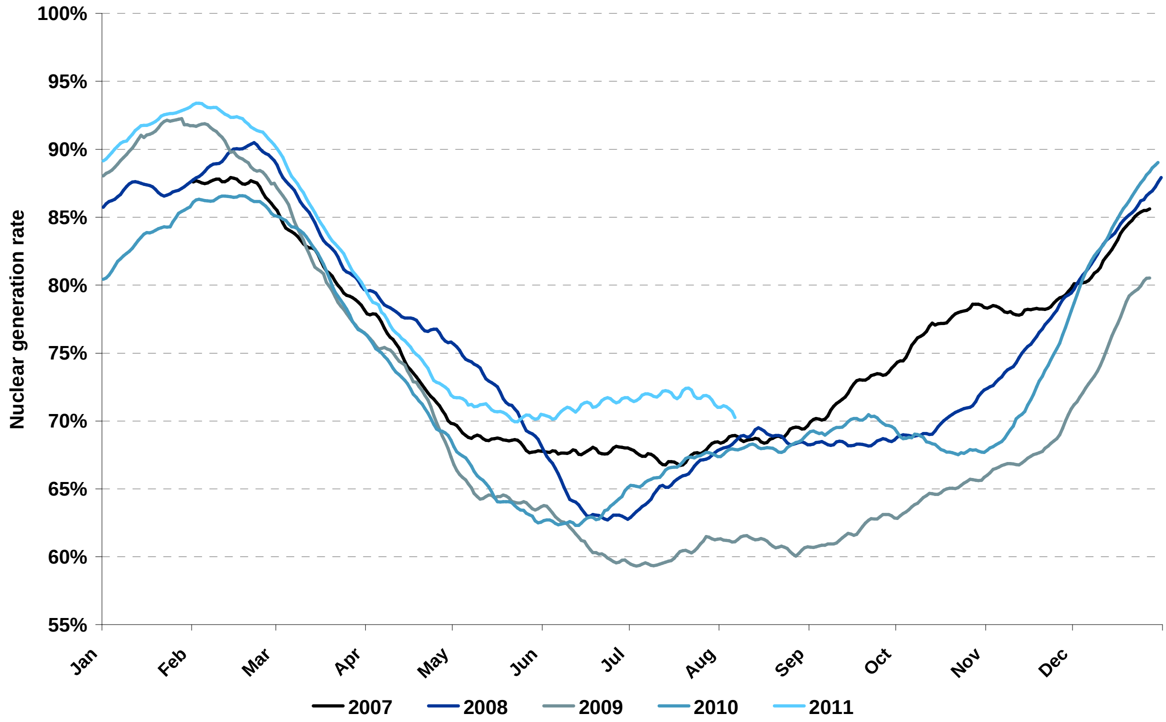
2010 was distinguished by a distinct improvement in availability of nuclear power plants

After the very sizeable downturn in the nuclear production rate reported in the second half of 2009, which strongly affected the French electricity export balance, the performance of EDF nuclear power plants began to climb starting from mid-2010. Availability of the power plants increased sharply as of this date, despite a relapse in October 2010, to reach historically high values at the end of the year as well as the beginning of 2011, when a brief period of 100% availability was even recorded.

In 2010 the nuclear generation rate was 73.6%, an advance compared to the 70.5% of 2009 but still below the rates recorded in 2007 and 2008 (almost 76%). Total nuclear energy production came to 408 TWh, up by 5% relative to the previous year.

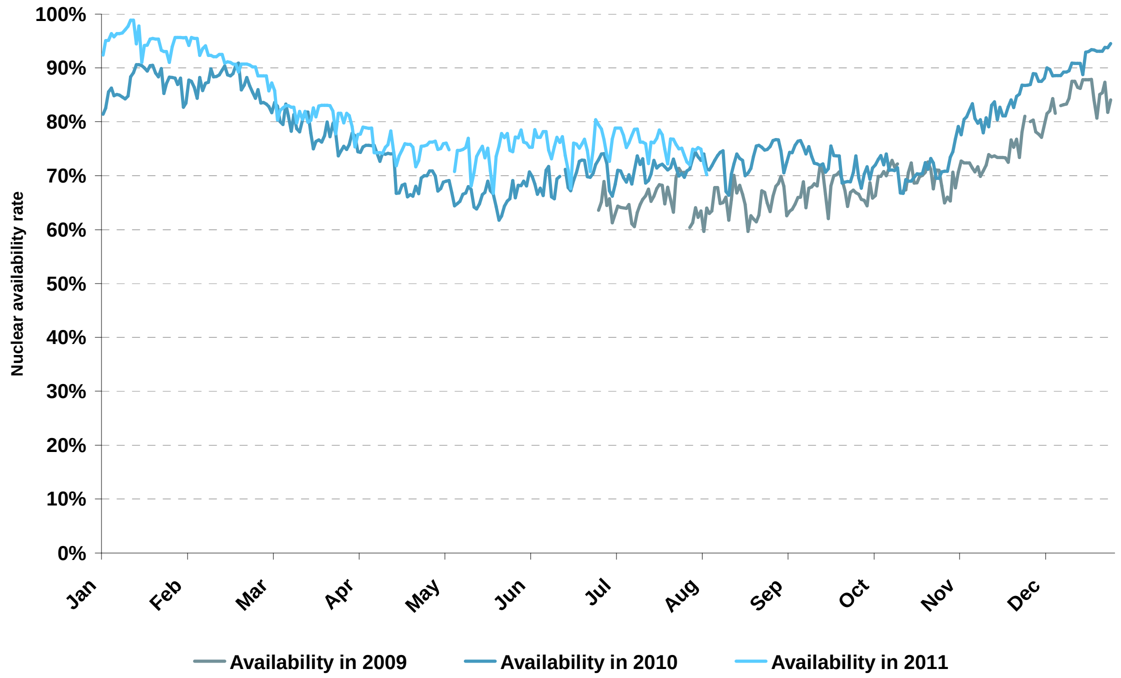
The improvement in availability of nuclear power plants led to a marked improvement in the export balance, which recovered starting from May 2010 to attain summer values close to those observed in 2008 (Figure 34).

Figure 32: Nuclear generation rate 2009-2011 (Actual nuclear generation/installed nuclear capacity - moving average over 30 days)



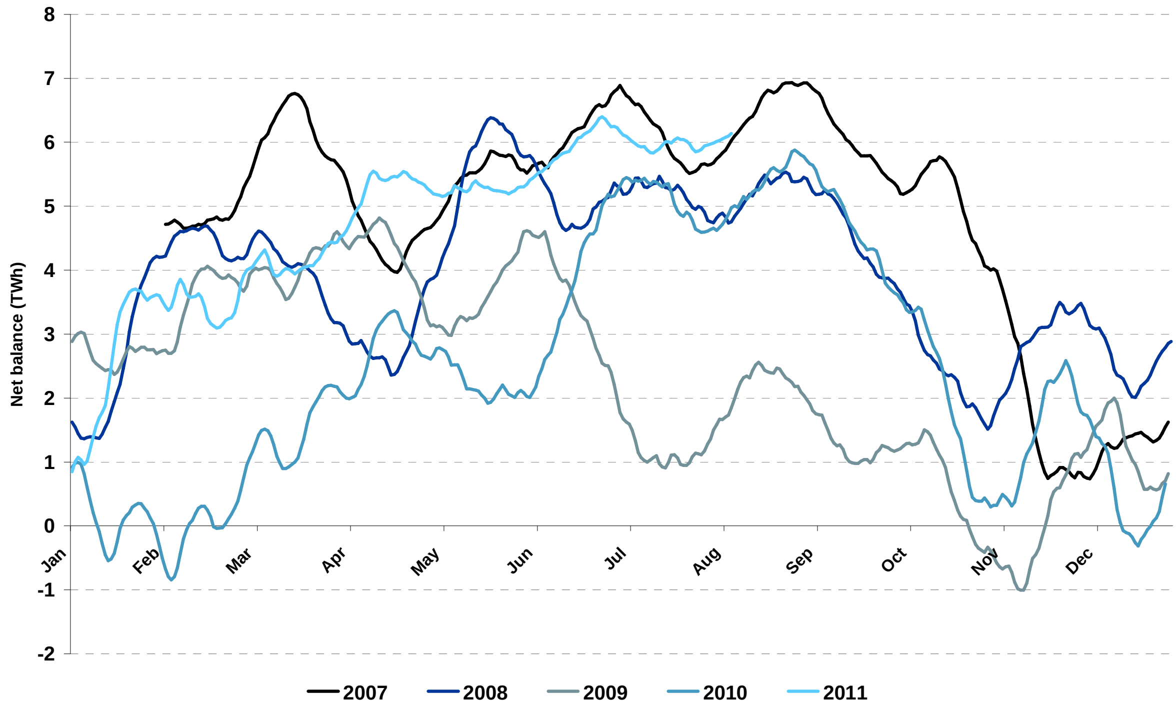
Source: RTE - Analysis: CRE

Figure 33: Level of nuclear availability 2009-2010 (Available nuclear capacity/installed nuclear capacity)



Source: RTE - Analysis: CRE

Figure 34: Monthly export balance 2007-2010 (Moving average over 30 days)



Source: RTE - Analysis: CRE

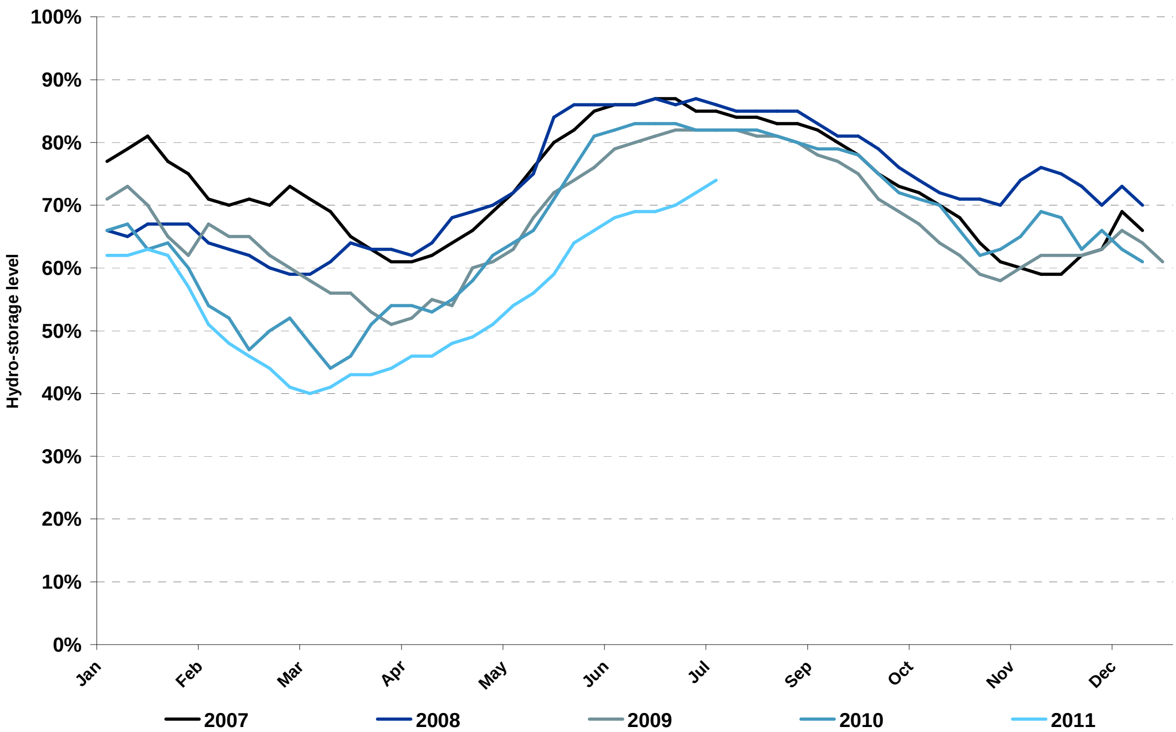
All generation technologies increased production with the exception of those for coal-fired power plants

As in the previous year, hydro-storage fell sharply during the first months of the year, reaching a minimum of 43% in March 2010. This especially low value compared to levels reported in previous years testifies to high utilisation of these reserves during winter 2009-2010 and low water availability since then. Reserves were subsequently reconstituted but remained below the values normally recorded all year, as in 2009.

In 2010, total hydroelectric generation came to 68 TWh, a rise of almost 10% compared to 2009. Production also grew for other facilities (see Table 6) and a strong increase in wind and photovoltaic production, explained by the development of the respective generation technologies, is noted in particular.

Production from convential thermal power plants grew by 8% between 2009 and 2010 to reach approximately 60 TWh. Within this group, coal-fired power plants are the only ones to have experienced a decrease in production, with only 19 TWh produced in 2010, a drop of 7.6% compared to the previous year.

Figure 35: Hydro-storage



Source: RTE - Analysis: CRE

Table 6: Electricity production for the various types of facilities

Facilities	Total energy produced (TWh)	Variation 2010/2009	Production level (% of the installed capacity)
Nuclear	407.9	4.6%	74%
Coal	19.1	-7.6%	28%
Fuel oil	7.9	2.7%	9%
Gas	30	24.7%	42%
Hydroelectric	68	9.9%	31%
Wind	9.6	22.2%	24%
Photovoltaic	0.6	281.6%	34%

Source: RTE

3.2 In 2010, the marginal facilities were the same overall as in 2009

A generation technology is called marginal when its marginal production cost determines the market price, that is, in theory, when the highest production cost unit in order to satisfy electricity demand belongs to this type of technology.

Analysis of marginality consists in practice of identifying, for each hour of the day, the type of generation technology to which the price set by the market corresponded; that is, searching for the operating power plant for which the marginal production cost was closest to the market price.

The analysis presented here uses both a price criterion and a power criterion in order to determine the unit and thus the marginal facility at a given time:

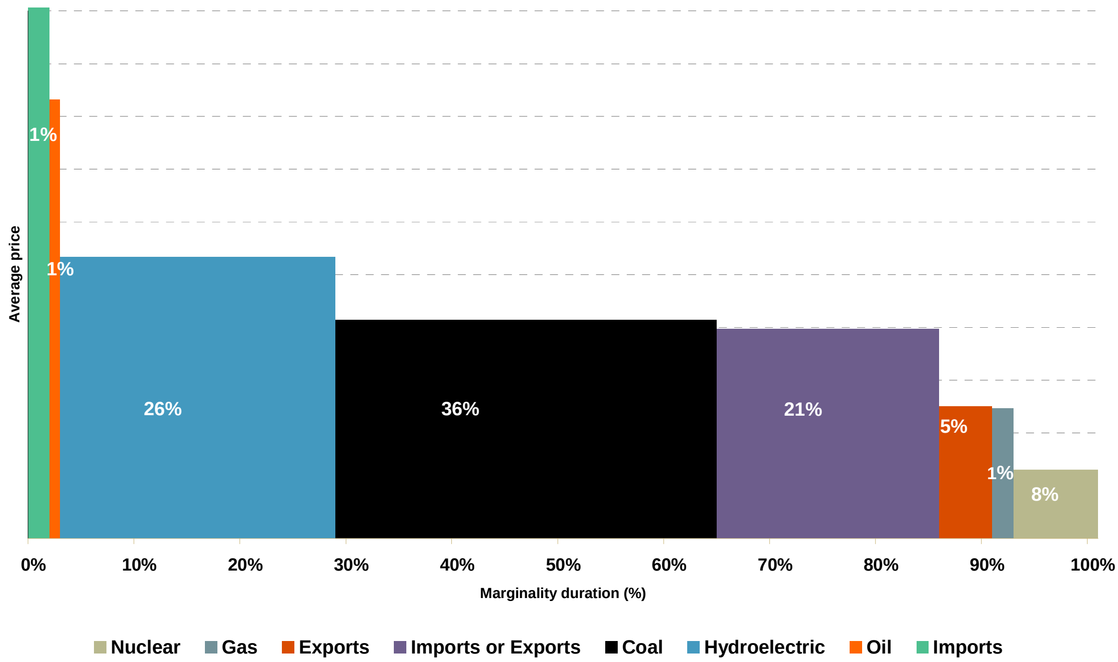
the price criterion selects power plants for which the difference between market price and production cost is less than €5/MWh;

the power criterion leads to consideration only of units with production lying between 15% and 85% of the theoretical maximum generation capacity.

Among all the units fulfilling these two criteria, the one considered marginal is then the one for which production cost is closest to the market price. If however no unit fulfils them, it is then assumed that price levels are explained by supply and demand from outside the country, and the borders are considered marginal.

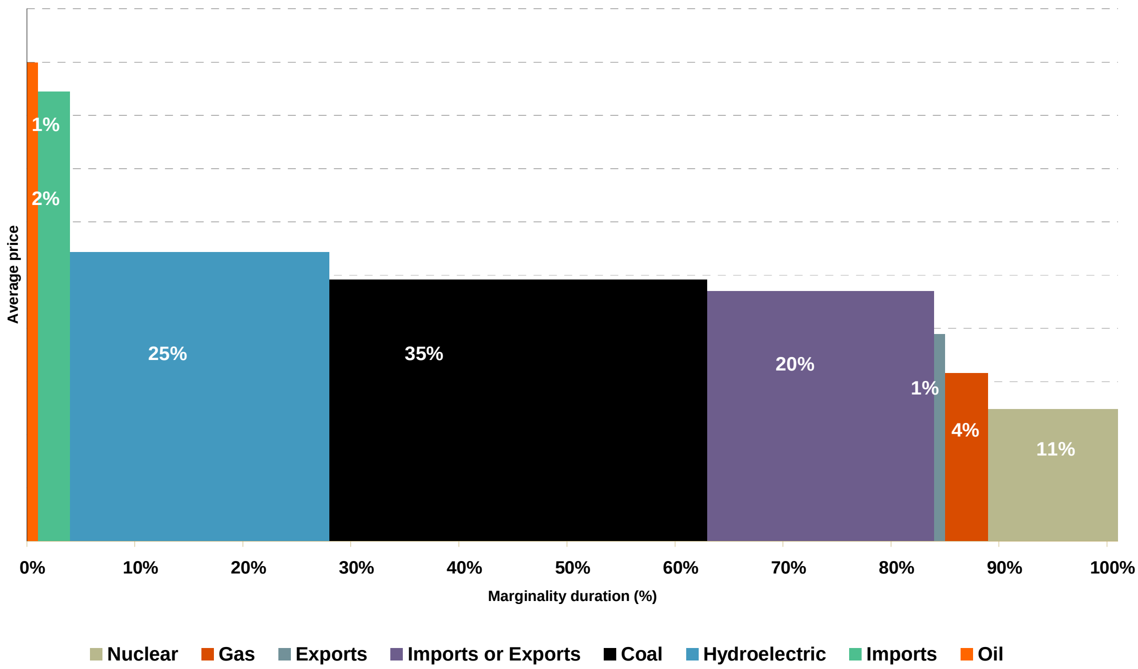
The results of these estimates for 2009 and 2010 are summarised in the figures below. It should be pointed out however that these results are highly dependent on the computational method and the thresholds used. However, they allow facilities to be ranked as a function of their period of marginality in a quite stable way.

Figure 36: Period of marginality of the various generation technologies in 2009



Source: CRE

Figure 37: Period of marginality of the various generation technologies in 2010



Source: CRE

In 2010 there was:

- an increase in the period of marginality of nuclear power plants from 8% to 11%;
- a slight decrease in the marginality of coal-fired power plants and stability of the borders.

Overall in 2010, market prices could not be explained by the marginal cost of any production unit (to the threshold of €5/MWh) in 27% of cases, a figure identical to that for 2009. In these cases, as previously specified, the borders are assumed to determine the French market price.

3.3 The transparency of production data continued to improve in 2010

UFE continues to develop its transparency system, with publication of unscheduled shutdowns in particular

Since November 2006, the Union Française de l'Électricité (French Electricity Industry Association) has participated in the transparency of the electricity market by publishing a portion of the data on electricity generation in France in partnership with RTE. This system, based on collection of this information from members of UFE, covers almost 90% of French production and involves all generating units with nominal capacity greater than 20 MW.

CRE had asked UFE to improve the transparency of production data, essential for proper operation of the wholesale electricity markets[10]. This transparency is vital for all market participants, in particular so that they can assess the variation of the electricity supply/demand balance.

UFE has since improved its system:

- Since 1 July 2010, projections of short- and medium-term availability for every generating unit of capacity greater than 100 MW are published on the RTE internet site.
- In addition, this system was supplemented in December 2010 by publication of unscheduled shutdowns of these units within a period of 30 minutes, along with its causes and the estimated date of resumption of service the morning after the shutdown at the latest.

New developments have moreover been announced by RTE and UFE for 2011, involving publication of projected generation of French wind turbine power units as well as publication of actual recorded production for generating units of more than 100 MW, within one hour and by unit.

It should also be noted that EDF improved the method of calculating dates for return of nuclear generating units to the network in July 2011. While up to now, the dates displayed for return to operation for generating units shut down have been dates "at the earliest" corresponding to a minimum technically feasible period, return dates now incorporate time margins in line with delays recorded based on experience.

CRE believes that all these developments fulfil an expectation of market participants.

An improving level of data transmission

The transparency system cannot be effective unless it is based on systematic transmission of the data to be published. In this regard, the level of transmission recorded in the case of availability projections is better, although it can still be improved. In 2010, 89.6% of the information necessary in establishing projections of availability by generation power plant was transmitted on average, versus only 80.2% in 2009. If this level of transmission is weighted by the installed capacity taken into consideration for each of the projections, an increased level of 94% in 2010, versus 92% the previous year, is also obtained.

[10] See in particular CRE deliberation of 20 November 2009

Table 7: Projected availabilities of the various types of generation technologies

Facility / Data	Coal	Hydroelectric, run-of-river	Fuel oil	Gas	Nuclear	Hydroelectric, lake
Level of exhaustive projections	87.6%	91.0%	96.1%	76.2%	96.1%	92.4%
Average statistical deviation at 7 days	439 MW	-4 MW	208 MW	96 MW	1929 MW	84 MW
(D-7) average statistical deviation in % of facilities	6.4%	0.0%	2.8%	2.9%	3.1%	0.6%
(D-7) average statistical deviation -2008-	4.6%	-3.0%	3.9%	0.1%	2.7%	0.6%

Analysis: CRE, based on information collected and transmitted by RTE

**The level of exhaustive projections is the ratio of the number of exhaustive projections received and the total number of projections expected for daily (D-1 to D-7) and weekly (W-1 to W-12) projections. A projection is considered exhaustive when all the participants involved with this type of production facility have provided a projection for the date and maturity considered.*

The projected availability of thermal and nuclear generating units is still overestimated

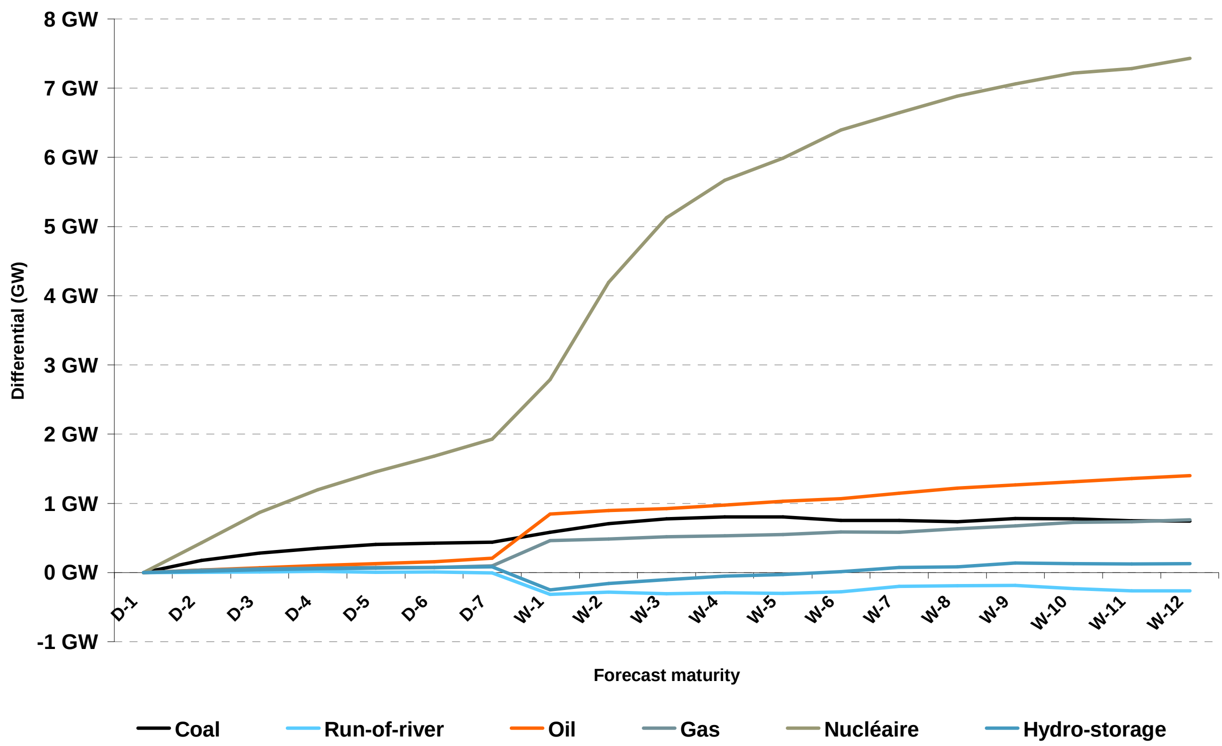
The deviation between the projected availabilities announced at various terms and the actual value is measured in order to measure the quality of the published specifications for the various facilities.

Analysis of these deviations reveals a statistical bias in the projected availabilities of the various generation technologies. In 2010, this bias was positive for all the thermal generation units and particularly significant (relative to the installed generation capacity) for fuel oil and coal generation units, for which it grew relative to the previous year. In the nuclear case, the "projection error" at 7 days was 1.7 GW on average, a value also slightly above that of 2009.

It should be noted however that this statistical overestimate of the projections is a consequence of the methodology used, which leads producers to declare the generation capacities that they estimate to be available in the future without taking account statistically of the inevitable unscheduled incidents randomly affecting generating units.

Figure 38 shows the recorded average deviations between published projections of availability and the D-1 projection, the last known projection for terms of less than12 weeks.

Figure 38: Average deviation between projections of availability and the (D-1) last projection[11]



Source: RTE; Analysis: CRE

The dispersion of the projections around their average appears, as in the previous year, to be low for nuclear and hydroelectric lake facilities, with an average standard deviation of the projection bias representing respectively 2.9% and 3.4% of the installed facilities over the period, but high for coal, fuel oil and gas facilities (8.5%, 13.6% and 13.6%). These results should however be compared in perspective with the different number of units constituting each of these generation technologies.

Actual availability is statistically below projections published on D-1 for nuclear facilities

If the projected availabilities announced on D-1 are now compared to those actually observed on day D, a statistical overestimate of the projections again appears, representing 1,048 MW on average over 2010.

Table 8: Average deviations between D-1 projected and actual availabilities

Coal	Hydroelectric, run-of-river	Fuel oil	Gas	Nuclear	Hydroelectric, lake	Total
274 MW	24 MW	136 MW	-152 MW	716 MW	50 MW	1,048 MW

Source: RTE; Analysis: CRE

Nuclear power plants alone explain a large part of the recorded statistical deviation, with a deviation of 716 MW on average. This deviation had already been cited in the previous monitoring report and CRE had indicated that it would undergo regular follow-up and a more precise analysis to explain its extent.

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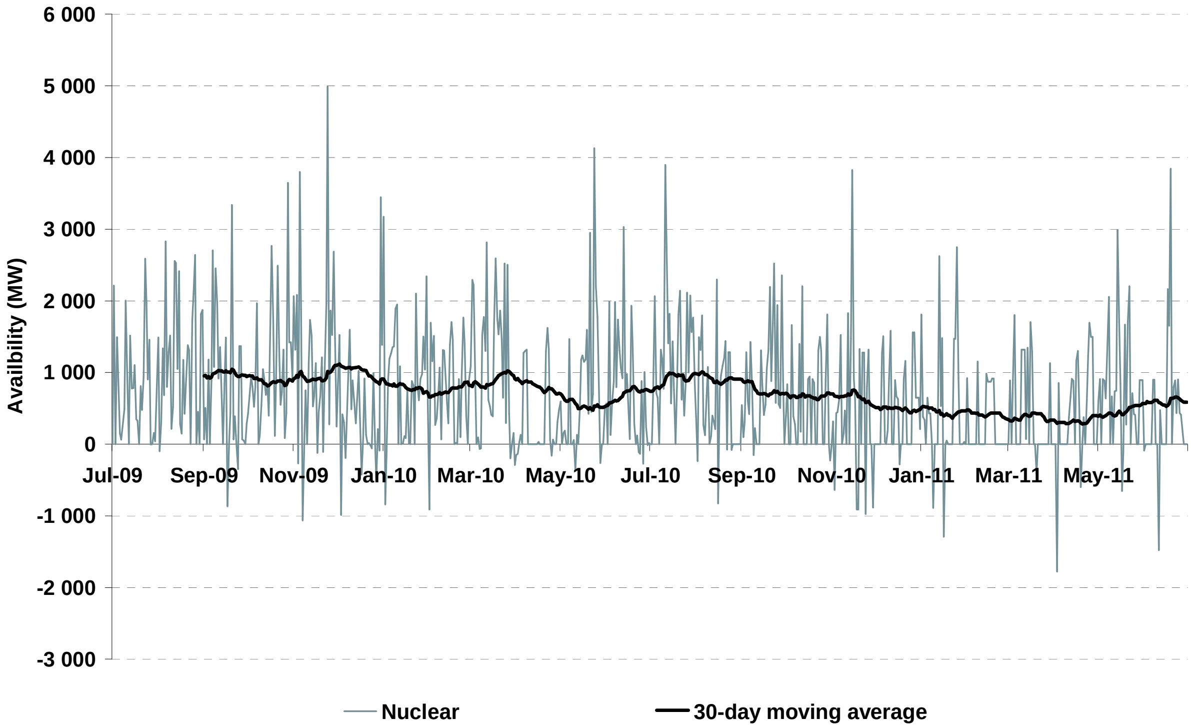
[11] The growth in the deviation of the projection with its maturity results from the rules defined by producers as to transmission of availability projections. The "transparency" specifications of UFE, in II.e., indicate that "*the projected available power published on a given date takes into account only unavailability that is certain to occur; it does not incorporate any evaluation of the risk of unscheduled unavailability*". This precise definition thus excludes any evaluation of the inability of a facility to maintain its availability or to become available again.

EDF, the sole operator of nuclear power plants, has since supplied the quantitative information explaining this deviation, due to:

unscheduled shutdowns;

postponements of return to operation following scheduled or unscheduled shutdowns.

Figure 39: Average deviation between (D-1) projection and actual nuclear availability



Source: RTE - Analysis: CRE

In addition, the deviation between actual nuclear availability and the (D-1) projection has tended to decrease in absolute value since 2009.

Prediction of unavailability: a key item on which the system would benefit from compliance with the ERGEG recommendation

The information currently published by RTE and UFE on availability involves the so-called reference facilities, that is, all generating units of capacity greater than 20 MW, for which hourly counting information is accessible on D+1 for D, under reasonably acceptable economic conditions, located in the territory of Metropolitan France and belonging to certain types of generation technologies (nuclear, coal, gas, fuel oil/peak, lake hydroelectric/run-of-river and pumped-storage hydroelectric) and participating producers[12].

A projected value of available aggregate peak load by type of facility for all the generating units, broken down by unit for generating units of nominal capacity greater than or equal to 100 MW, is published, the peak being defined by UFE as "the daily maximum in electricity consumption. The hour at which it occurs can vary according to seasonal load curves. In general, it occurs at 19:00 in winter and 13:00 in summer"[13]. These data are published each day for D+1 to D+7, **one hour before closure of the spot exchange**. **As a result, publication of significant changes occurs only in steps of 24 hours.**

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[12] EDF, GDFSuez, E.ON and Poweo Groups. The transparency initiative as such covers over 90% of the French production facilities connected to the public transport network.

[13] Publication of information on production - Specifications book of the UFE initiative

The European Commission believes that "the present framework for publication of fundamental data at the European level does not provide a level of detail sufficient for market participants to be able develop a consistent and precise vision of the fundamentals of the electricity market in the European Union. […] To remedy this situation, the Commission asked ERGEG in January 2010 to prepare draft guidelines"[14]. From 22 July to 16 September 2011, the European Commission submitted to public consultation a draft of ERGEG[15] guidelines on transparency of fundamental data, dated December 2010.

This provides the following requirements with regard to availability:

- publication of projections for installed total generation capacity for all existing generating units of more than 1 MW installed capacity, for three years and by type of technology (nuclear, lignite, coal, coke, gas, fuel oil, waste, peat, hydroelectric reservoir, hydroelectric run-of-river, stations for energy transfer by pumping, tidal energy, wind power, solar, other renewable) and publication of projections of available capacity for each planned or existing generating unit of more than 100 MW over 3 years;
- publication of projections of scheduled unavailability of generating units if they lead to a change in available capacity greater than or equal to 100 MW. In particular, the name of the generating unit, the group, the installed capacity, the facility, the estimated dates and times, the reason for unavailability and the available generating capacity must be published, on condition that this unavailability lasts at least one hour. All information of this type must be published and, as necessary, updated within a period of one hour after the decision for shutdown or a modification thereof is made.

These differences become all the more important as the REMIT regulation should make the requirements of the appendix to regulation EC No. 714/2009 a reference with regard to publication of privileged information, removing, in the event of observance, the classification of insider trading for a market intervention.

As cited above, transparency of production data has progressed greatly over the past several years in France. This is the case notably on the key point of publication of unscheduled shutdowns. Moreover, the level of coverage of facilities by the French transparency system (over 90%) is among the highest in Europe.

On the specific point of deadlines for publication for projections of unavailability, the difference in approach with the ERGEG recommendation is significant, especially for the spot markets.

CRE consequently recommends that the transparency system conform with the standard proposed by ERGEG with regard to projected availability, which would in particular facilitate implementation of the REMIT regulation.

3.4 The audit of EDF valuation methods shows that in 2010 market offers were consistent overall with the marginal costs of EDF

As indicated in previous editions of the monitoring report, CRE conducts special follow-up of the difference between spot market prices and marginal costs of EDF facilities resulting from the daily calculations of its optimisation models.

This study involves the hours for which EDF offers are assumed to determine the auction price. On average, the price - costs difference was 3.2% in 2010. Overall, CRE believes that, for this year, the gap between prices and marginal costs was at levels that do not constitute an abuse of dominant position.

[14] Text accompanying the public consultation launched by the European Commission on 22 July 2011

[15] http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_CONSULT/CLOSED%20PUBLIC%20CONSULTATIONS/ELECTRICITY/Comitology%20Guideline%20Electricity%20Transparency/CD/E10-ENM-27-03_FEDT_7-Dec-2010.pdf

In addition, as mentioned in the previous monitoring report, CRE examined in particular the risk management policy followed by EDF in the framework of the “1% risk” criterion. This led EDF to change the methods of applying this management policy.

Previously, to fulfil the 1% risk criterion, EDF Trading took into account a margin of uncertainty on the volumes for sale to cover hazards likely to affect the supply-demand balance of EDF between the fixing of the exchange and 16:00. EDF has confirmed to CRE that since October 2010 this risk has been borne directly by EDF through application of the 1% risk criteria requirements as of 11:00 instead of 16:00.

4. Analysis of transactions

4.1 *The offer on the spot market reflects the state of the electrical system*

This section analyses the offers submitted by the various market participants on the EPEX Spot *Auction platform for France.*

The level of the offer on the spot market is correlated with the system margin, and few offers lie between €100 and €300/MWh

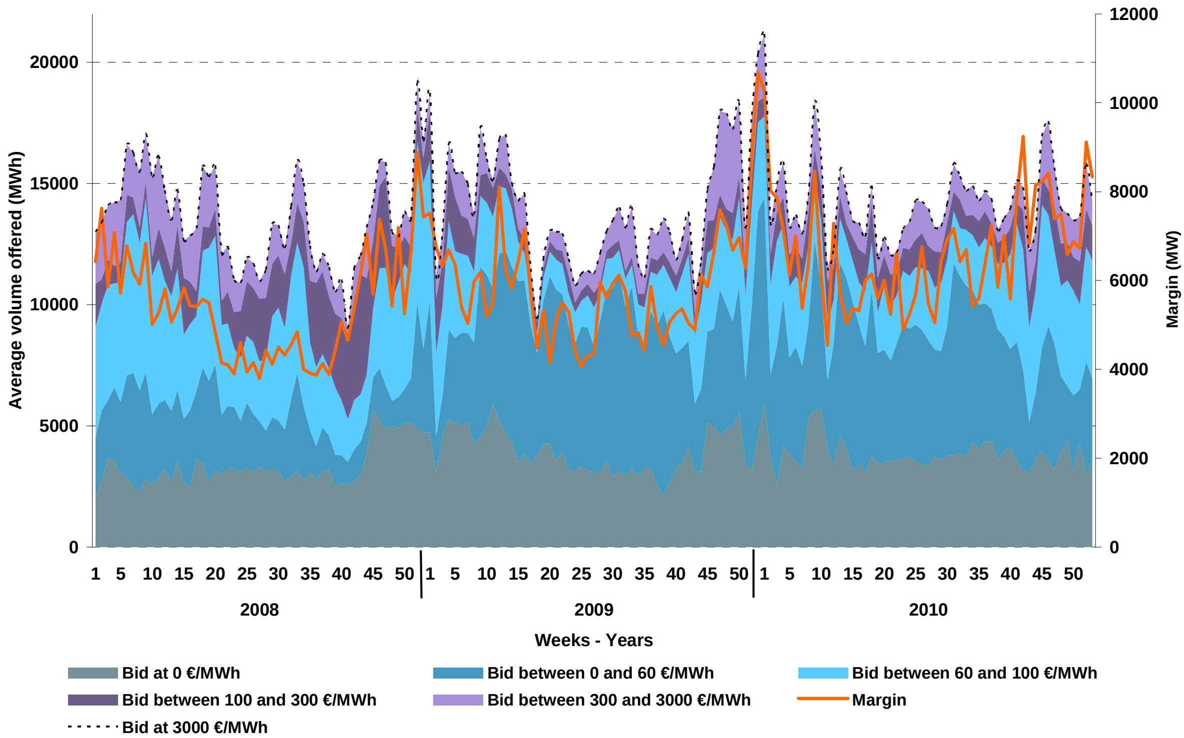
Figure 40 compares the ask order books (volumes offered at various prices) and the margin indicator, that is, the excess available capacity that reflects the state of strain on the French power system.

In 2010, hourly offers at any price (for €0/MWh) were on average 3,830 MWh, a decrease of 90 MWh compared to 2009. On average, 35% of volumes were offered at price levels between €0 and €60/MWh, with an average volume offered of approximately 5,026 MWh.

At the end of 2008 a significant anomaly in the offer between €0 and €60/MWh, reflecting the drop in fuel prices, was observed. During 2010, the proportion of offers between €0 and €60/MWh was observed to decrease over the course of the year, thus following a trend opposite to that of fuel prices.

The average volume of the hourly offer between €60/MWh and €100/MWh was 3,026 MWh, up by 26% compared to 2009. Beyond €100/MWh, the average volume of the hourly offer increased by 272 MWh. The narrow price ranges between €100/MWh and €300/MWh and between €300/MWh and €3,000/MWh are due to the fact that these price ranges correspond to offers of peak and extreme peak generating technologies with an operating period of several hundred hours per year. Overall, a clear correlation exists between the margin indicator and the total volume offered on EPEX Spot.

Figure 40: Aggregate –bid and margin indicator - 2010



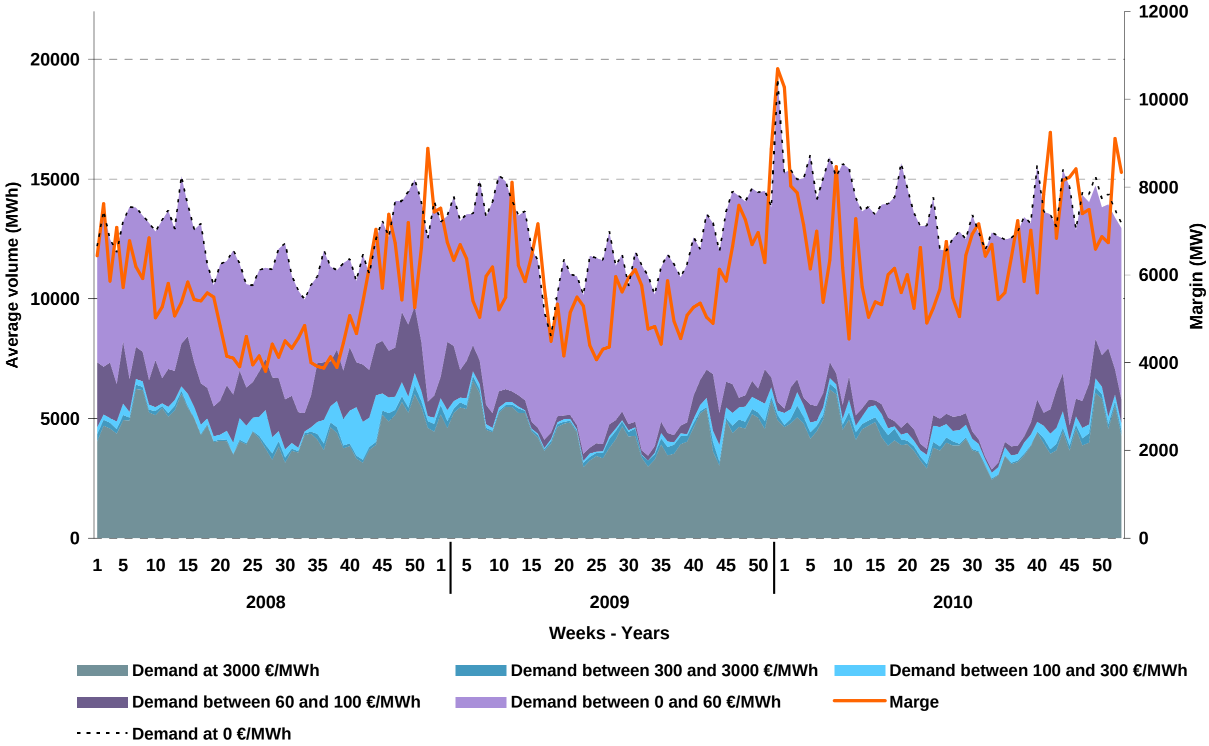
Source: EPEX - Analysis: CRE

Most of the demand lies below €100/MWh

Sixty-six percent of the aggregate demand is characterised by a willingness-to-pay lying between €0 and €100/MWh (Figure 41). The average hourly volume demanded for a willingness to pay between €100/MWh and €300/MWh is relatively low (approximately 395 MWh).

The average volume of hourly offers for the demand at any price was 4,163 MWh in 2010, a drop of 319 MWh compared to 2009.

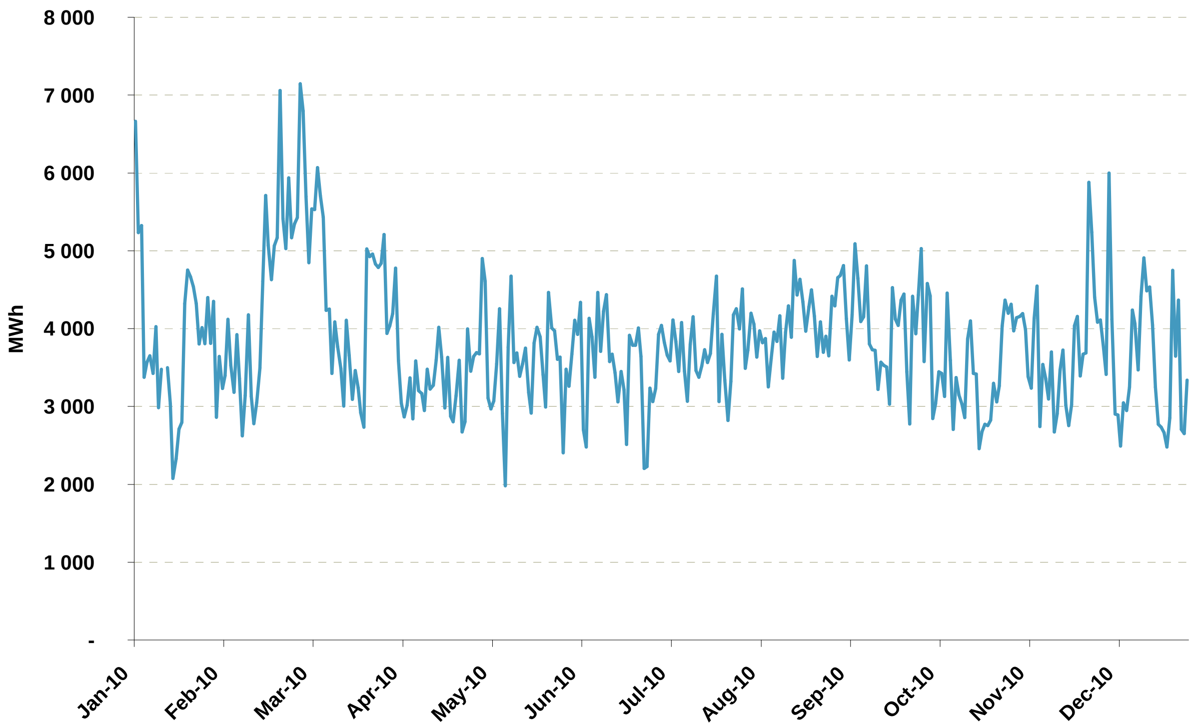
Figure 41: Aggregate demand and margin indicator - 2010



Source: EPEX - Analysis: CRE

Figure 42 shows the variation of the offer at any price after the price peak of 12 January 2010.

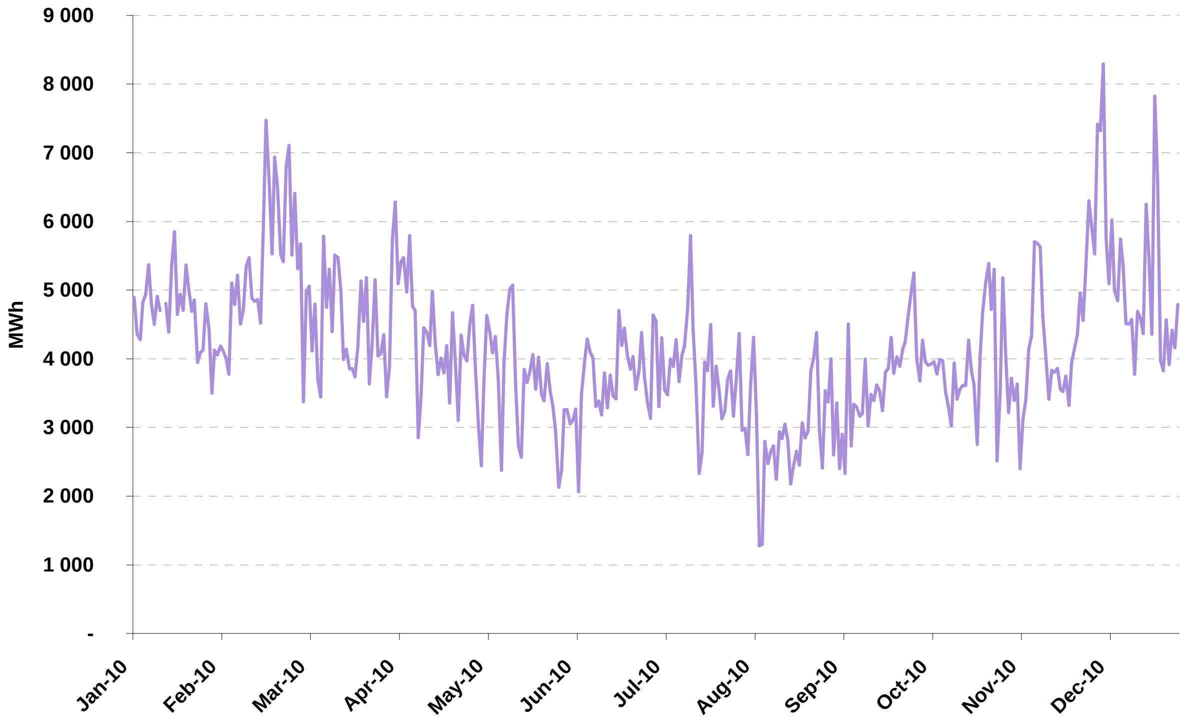
Figure 42: Offer at any price



Source: EPEX - Analysis: CRE

The variation of the demand at any price (€3,000/MWh) is shown in Figure 43.

Figure 43: Demand at any price



Source: EPEX - Analysis: CRE

4.2 Nominations of daily capacities in opposition to hourly prices tended to decrease between 2009 and 2010

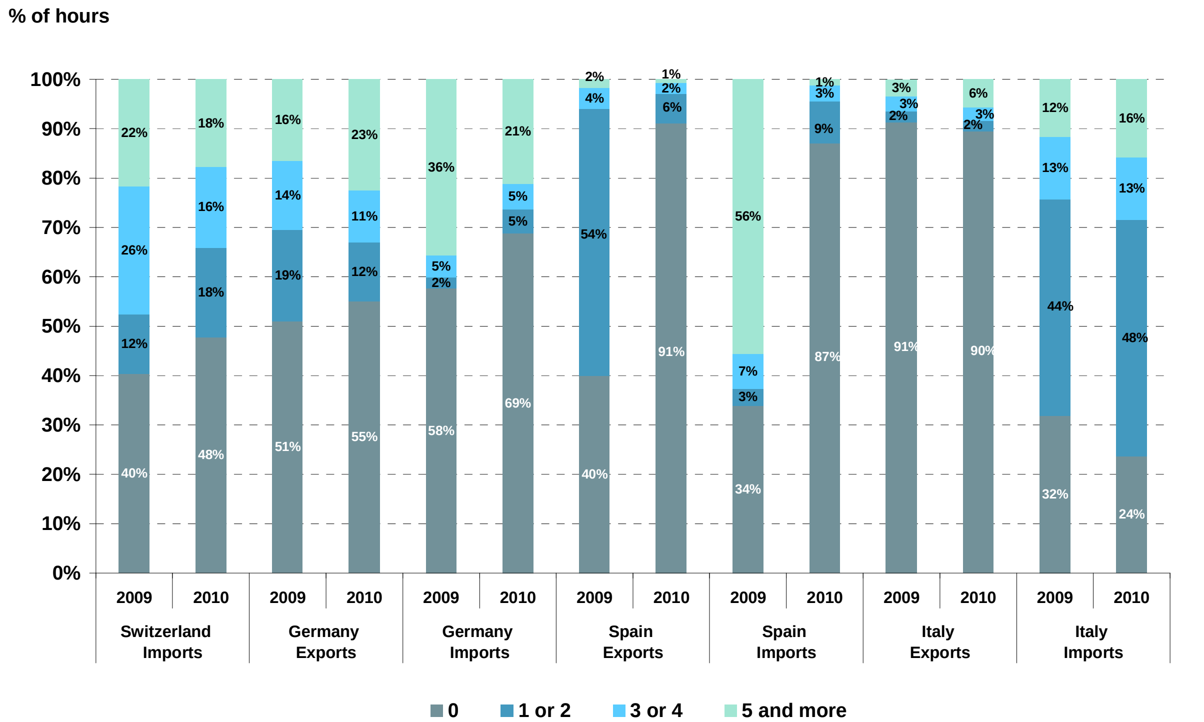
A nomination of energy in opposition occurs when a participant imports or exports energy in the opposite sense to the price differential between the two countries by nominating a daily interconnection capacity, that is, being aware of the reference spot price.

For example, the participant imports using a daily interconnection capacity while the day-ahead price is lower in France.

An analysis was conducted starting from the hourly price differentials and the block prices (peak and off-peak), using exchange price references.

Figure 44 shows the daily nominations in hours in opposition to hourly spot prices between 2009 and 2010. It shows that the number of participants nominating in opposition decreased with respect to all countries, notably Spain, where the proportion of hours without nomination in opposition borders on 90% in 2010, versus 37% in 2009. Only import nominations on the Italian border were less consistent with the exchange price differentials in 2010. The explanation given by both market participants and regulators points to issues of market design in Italy. Establishment of market coupling could resolve this problem.

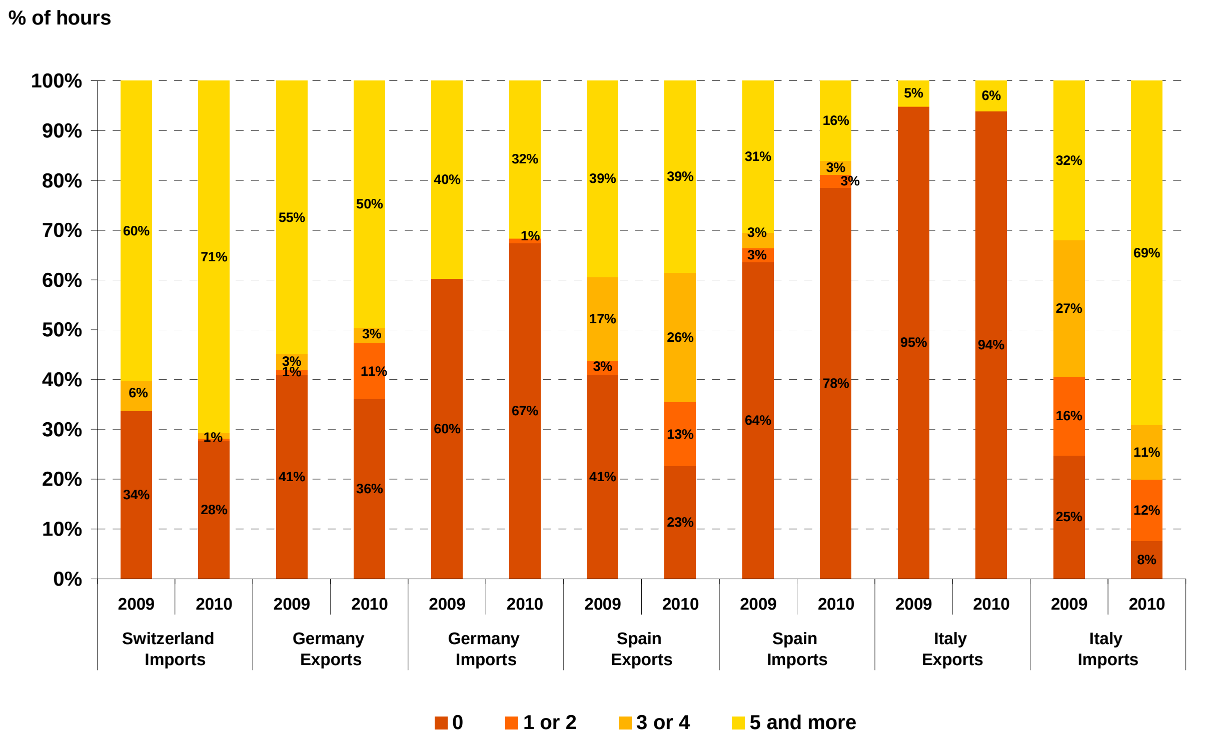
Figure 44: Proportion of hours during which nominations in opposition to hourly prices occurred and number of participants who nominated in opposition in 2009 and in 2010



Sources: EPEX Spot, IPEX, OMEL, RTE - Analysis: CRE

Figure 45 shows the daily nominations in hours in opposition to peak and off-peak block prices. As it involves averages of hourly prices, comparison with hourly nominations of daily capacity seems less logical. However, it must be taken into consideration that some participants could nominate over several hours in a row, and thus not take hourly prices into account one by one, but their average over the hours nominated. Thus, nominations considered in opposition with regard to hourly prices could be justified if compared to block prices. However, if analysis by blocks is compared to analysis by hour, a tendency toward a greater number of hours with nomination in opposition with regard to block prices than with regard to spot prices is noted.

Figure 45: Proportion of hours during which nominations in opposition occurred compared to peak and off-peak block prices and number of participants who nominated in opposition in 2009 and in 2010



Sources: EPEX Spot, IPEX, OMEL, RTE - Analysis: CRE

Section II: CO_2 Markets

1. CO2 Markets: evolution of the institutional framework and future prospects

1.1 Since the end of 2010, CRE has been monitoring the carbon transactions made by participants in the French electricity and gas markets

In spring 2010, the Prada Commission[16], charged with making recommendations regarding the regulation of carbon markets, recommended that harmonized monitoring of the European CO_2 market be implemented based on three pillars:

- give financial regulators authority on the CO_2 markets in all member states and expand the authority of energy regulators to the analysis of the fundamentals and interactions between the CO_2 market and energy markets;
- organise the cooperation of financial regulators and energy regulators;
- give authority to the European Securities and Markets Authority to oversee the entire system, in connection with ACER while ensuring the consistency of this system with the monitoring architecture to be proposed for the gas and electricity markets.

Prior to the establishment of such a supervisory architecture in Europe, the Prada Commission recommended, at a national level and as of 2010, to give authority to the AMF on the CO_2 spot market in France, to organise the cooperation with CRE and to expand the authority of CRE to the analysis of interactions between energy markets and the CO_2 markets.

The recommendations of the Prada Commission were transposed in the French Financial and Banking Regulation law (LRBF) adopted 22 October 2010. The LRBF:

- authorises the negotiation of allowances on a regulated market;
- gives authority to the AMF on the CO_2 spot market;
- extends the mission of CRE to the analysis of the coherence between energy market fundamentals and transactions on the CO_2 market. Article 131-3 of the energy code now provides that CRE, in this capacity, monitors transactions made by the participants in the French gas and electricity markets[17], in order to analyse the coherence of these transactions with their economic, technical and regulatory constraints;
- establishes the principle of broadened cooperation between the AMF and CRE[18]. This cooperation was formalized in an agreement signed between both institutions and published 10 December 2010.

While the scope of supervision of the AMF is in practice the Bluenext platform (which became a regulated market in March 2011), regardless of the quality of the stakeholder, the scope of CRE

[16] http://www.economie.gouv.fr/services/rap10/100419rap-prada.pdf

[17] *"As part of the exercise of its duties, the French Energy Regulatory Commission monitors transactions carried out by suppliers, traders and producers of electricity and natural gas on greenhouse gas emission allowances as defined in Article L. 229-15 of the Environmental Code, and on other units mentioned in Chapter IX of Title II of Book II of the Environmental Code [EUAs, CERs, ERUs], as well as contracts and financial futures instruments which they underlie, in order to analyse the coherence of these transactions with the economic, technical and regulatory constraints of the activity of these suppliers, traders and producers of electricity and natural gas.*"

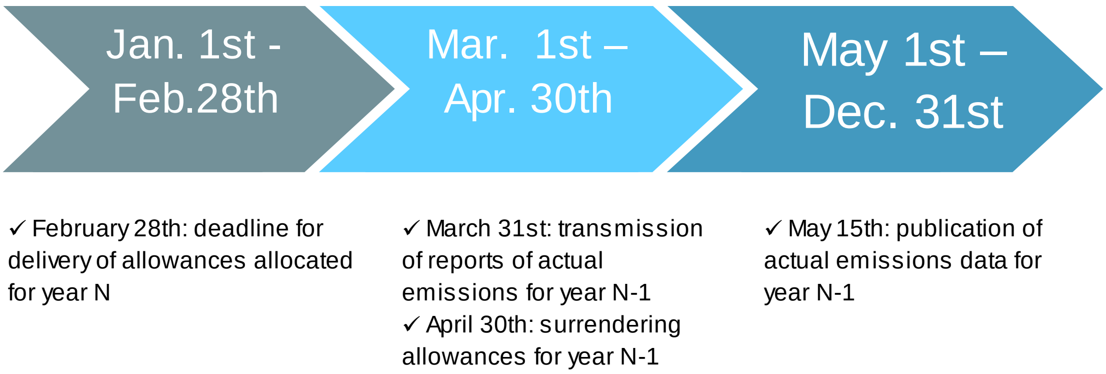
[18] *"The French Energy Regulatory Commission and the Financial Markets Authority cooperate with each other. They shall provide each other with the necessary information to accomplish their missions "(Article 3 of the LRBF*).

supervision covers transactions made by active players on the French electricity and natural gas markets (suppliers, traders, producers), regardless of where the transactions are carried out and their modality (exchange, broker, bilateral).

The transactions covered by the scope of CRE supervision include:

- the European allowances (EUA): the emission permits are distributed annually to industrial sites participating in the European Union Emission Trading Scheme (EU ETS[19]). An allowance corresponds to the emission of one ton of CO_2. The allocation method is described for each country in a National Allocation Plan (NAP), approved by the European Commission. The companies involved can then exchange the emission allowances. At period end, the subjected sites must surrender those allowances to match their actual emissions (**Erreur ! Source du renvoi introuvable.**);
- Certified Emission Reduction units (CER) from projects implemented under the Clean Development Mechanism (CDM): CDM allows credit, in the form of CERs, to be assigned to emission reductions achieved through projects carried out in developing countries. Credits represent the emissions savings from the project compared to a baseline scenario and are validated by an independent auditor. They may be returned at period end in substitution to some EUAs up to a certain percentage (13.5% maximum in France);
- the Emission Reduction Units (ERUs) from joint implementation (JI) projects: the JI mechanism works the same way as the CDM one, except that JI projects are carried out in industrialised countries. In the same way as CERs, ERUs can be returned in exchange of some EUAs at the end of the period.

Figure 46: Schedule of compliance for the players on the European Union Emission Trading Scheme (EU ETS)



Source: European Commission

CO_2 markets have experienced VAT fraud in the past. As mentioned in the previous monitoring report, attention was paid to the risk of VAT fraud spread in the European gas and electricity markets. Awareness and vigilance measures have been adopted by stakeholders (regulators, administrative and legal authorities, stock exchanges, network operators), both at national and European levels. Measures which the participants and the marketplaces can adopt, such as audits called "*Know Your Customer Check* or KYC" are crucial in this context.

CRE, for its part, sent a questionnaire, late 2010, to all the players registered as balance responsible entities or shippers on the French gas and electricity markets, in order to make them aware of this risk. The questionnaire also intended to identify balancing perimeter lending operations to third parties. Based on the statements of the players, it confirms the absence of such transactions for the vast majority of market participants. A small number of positive responses have been documented by the concerned participants and often involve intra-group transactions. This helped to ensure that the lending of balancing perimeter was on limited volumes.

[19] The scope of the EU ETS corresponds to EU27 countries, plus Norway, Iceland and Liechtenstein

1.2 CRE favours a centralized reporting of transactional data, but all the market venues have not yet adhered to this approach

In terms of market participants, the monitoring scope of CRE covers transactions made by French gas and electricity market players. These transactions can be performed on stock exchanges and over-the-counter (OTC), either intermediated through brokers or non-intermediated OTC.

The main stock exchanges are Bluenext in Paris, the European Climate Exchange in London (ECX) and the European Energy Exchange in Leipzig (EEX). Transactions on intermediated OTC are mainly concluded through brokers of the London Energy Brokers' Association.

As was done for the gas and electricity, and for sake of systematic reporting, CRE prefers an approach where collection of transactional data is centralized. Such an approach can be completed, if necessary, by bilateral requests made to the participants, in particular in the event of an audit or investigation. At the time of writing this report, the Bluenext and EEX stock exchanges regularly send CRE transactional data falling within its scope. In the case of Bluenext, the data within the scope of CRE is provided by the AMF. This approach illustrates a practical aspect of CRE-AMF cooperation and avoids Bluenext having to carry out double reporting.

Other marketplaces are not yet involved in such an approach. Some of them have mentioned the European feature of the CO_2 allowance (in contrast to a volume of gas or electricity delivered to a balancing area in France) as a factor making it challenging to implement reporting adapted to the scope of CRE.

Under these conditions, and pending the establishment of a European monitoring framework for carbon markets, CRE plans to set up a bilateral collection of data from the participants in the French wholesale gas and electricity markets.

1.3 Monitoring of the CO2 market will become fully meaningful once extended to Europe

As indicated by CRE in its monitoring report published in October 2010, "the provisions [from the LRBF] will take on their full meaning when they are extended to all European countries, as the underlying markets (electricity, gas, emission allowances) are themselves traded at a European level."

Indeed, in the case of CO_2 allowances:

- in general, the players intervene on the various marketplaces;
- concerned entities manage their carbon constraints at a European level. In particular, this is the case for energy companies that are also often present on several national energy markets;
- the CO_2 allowance is treated on different marketplaces in Europe.

Thus with the current national monitoring system, CRE and the AMF cover a limited scope at the European level: a player on a European carbon market outside Bluenext, who is not a participant in the French wholesale gas and electricity market does not belong either to the supervision field of the AMF, or to that of CRE.

Outlook on European legislation

In December 2010, the European Commission issued a communication for the improvement of CO_2[20] market supervision in line with the review of other texts of European regulations, in particular on financial regulation. Options given for a regulation of the secondary market are:

[20] Communication from the European Commission to improve the supervisory framework of the European market for emission allowances. This documents recalls that there is no European legislation to regulate a comprehensive scope of the carbon market, and that a legislative proposal could be made based on the results of a consultation with the players in question on the issue during the first half of 2011

- the creation of a specific regulatory framework for the carbon market;
- the inclusion of the European carbon market in the framework of financial regulation;
- the inclusion of the European carbon market in the framework of regulation on energy markets (REMIT[21]): this option was excluded *in fine* and the final text does not qualify the CO_2 allowance as a "wholesale energy product". Note however that REMIT plans to give ACER access to carbon transactional data collected by the authority which will be responsible for CO_2 market monitoring.

As part of the revision of financial regulation, the European Commission has recently taken a stance for the qualification of the CO_2 allowance as a financial instrument[22].

Securing the chain of processing allowances illustrates the importance of a harmonized approach at European level

Beyond regulation considerations, the allowances market must also be protected in terms of market infrastructure. It took all its relevance, following the detection of security problems for recent records (see **Erreur ! Source du renvoi introuvable.**). Following an initial set of security enhancements, a new set of rules was presented to the European Parliament and the European Council in June 2011[23].

Box 2: January 2011 – All transactions suspended on the CO_2 spot market

Suspension of all spot transactions

Following repeated attacks against national registries in some countries during the week starting Jan. 17, the European Commission ordered the suspension of trading with these registries as of January 19. [24] Spot trading on the exchanges was also suspended following this decision, including the suspension of Bluenext trading, which reopened on 4 March 2011 along with the French registry. In May 2011, Bluenext launched the "Safe Harbour" system which guarantees the authenticity of allowances traded on the platform by going back to their original issuer. These events show the importance of improved security of the system infrastructures in place, and that in order to achieve a minimum security level throughout the European Union.

Security of national registries

Like the banks that allow the amounts belonging to account holders to be kept track of, national registries provide traceability of European allowances for market players. The spokeswoman for the Climate Commissioner, Connie Hedegaard, referred to fraudsters "who have access to the company's account (on national registries), steal emission allowances and resell them on the spot markets." Approximately 3.5 million tonnes of CO_2 (45 to 50 million Euros) were reportedly stolen and resold.

In terms of regulation, the safety features required for national registries are contained in Regulation (EC) No 2216/2004 and subsequent amendments; the most recent is Regulation (EU) No. 920/2010 dated October 2010.

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http://ec.europa.eu/clima/news/docs/communication_en.pdf

[21] Regulation of the European Parliament and Council on the Integrity and Transparency of energy markets http://register.consilium.europa.eu/pdf/en/11/pe00/pe00034.en11.pdf

[22]http://ec.europa.eu/internal_market/securities/isd/mifid_fr.htm Document 2011/0298 (COD)

[23] The proposed measures mainly consist in the introduction of a 24 hour turnaround time for the execution of cash transactions, new account categories, lists of trusted accounts and double-checking routines, as well as the ability for authorities to freeze allowances and accounts and to delay the execution of a transaction and setting up a mask for the serial numbers of the allowances. http://ec.europa.eu/clima/news/articles/news_2011061702_en.htm

[24] European Commission, 19 January 2011. http://ec.europa.eu/clima/news/articles/news_2011011901_en.htm

1.4 Phase III (2013-2020) will result in significant changes of scope for the CO_2 market

The third phase of the trading system, which will start in 2013 with the objective of achieving a 20% reduction in greenhouse gas emissions compared to 1990, will bring a number of changes to the EU "Cap and Trade" system:

- progressively, emission allowances will not be allocated for free to industrials, but will be auctioned up to nearly 50% of them (up to 100% for the electric companies);
- as of 2013, the allowances which are not allocated free of charge will be auctioned on one or more platforms, causing a primary CO_2 market to emerge. A regulatory framework has been established by the Commission as per the Regulation of November 12, 2010. The auction platforms shall, in particular, be regulated markets in the sense of financial regulation;
- a global emissions cap shall be set at the European level (roughly 1,900 Mt), annually reducing the total level of allowable emissions by 1.74%;
- a protective mechanism initially makes provision for energy-intensive consumer sectors that are unable to pass on costs to their customers or are open to international competition ("carbon leakage"), and they will continue to receive their allowances for free;
- anticipated phase III allowance auctions should be held in 2012 for a volume of 120 million tonnes, thus ensuring a smooth transition between Phase II and Phase III;
- in addition to the aviation sector in 2012, new emitting industries, as well as carbon capture and storage facilities will be included in the trading scheme.

Moreover, in March 2011, the British government has also initiated the establishment of a "floor price" of carbon for British electricity producers as of April 2013 (see **Erreur ! Source du renvoi introuvable.**).

Table 9: Main differences between phase II and phase III

	Phase II (2008 - 2012)	*Phase III (2013 - 2020)*
Installations concerned	12,000	More than 12,000
Countries concerned	27 member countries of the European Union, Lichtenstein, Norway and Iceland.	As in Phase II. Switzerland could participate as of 2013.
Sectors concerned	Electrical power, iron, steel, cement and lime, oil refineries, glass, ceramics, pulp and paper. Civil aviation should be involved as of 2012.	As in Phase II, plus the ferrous and non-ferrous metals, aluminium, nitric acid, glycolic acid, ammonia, soda dust, hydrogen, petrochemicals
Greenhouse gas concerned	CO_2	CO_2, N_2O, PFC
Method for allocating	National Allocation Plans	Allocation across the European Union
Allocation for free	96% allocated for free, 4% auctioned	0% (may be exceptions) for the production of electricity. Decreasing rate from 80% to 30% for other sectors from 2013 to 2020. In total, for 2013, about 50% of allowances will be allocated free of charge.
Allowance transfer between phases	An unlimited amount of allowances can be transferred in phase III	Unlimited transfer to the following years, however, no borrowing after 2020.
Use of CERs	1.4 thousand million tons	1.6 thousand million tons
Other	Non-discharge penalty of €100/t if the allowance is not surrendered on time.	Same penalty as for Phase II, adjusted for inflation.

Source: Directorate General for Energy and Climate

Box 3: The White paper of the United Kingdom Government "*for secure, affordable and low-carbon electricity*"

In July 2011 the Secretary of State for Energy and Climate Change for the Government of the United Kingdom presented a White Paper to the British Parliament, "*for secure, affordable and low-carbon electricity*". This paper, reporting a threat to the security of electricity supply, the need to decarbonise power generation, as well as prospects for increased demand in electricity and electricity prices, outlines guidelines for the electricity sector on the other side of the Channel. In particular, these comprise in:

- the establishment, as of 2014, of feed-in tariffs for electricity produced from renewable energy sources. It would be a fixed feed-in tariff with contract for difference between a reference price if the energy was sold on the markets (on the *day-ahead* market in the case of fatal production and on the futures market for facilities that can operate in baseload) and a strike price determined by auction or tender;
- the definition of a floor price for CO_2 allowances for the electricity sector, as of 2013. It would be implemented by the removal of the tax on fossil fuels exemption available to electricity producers.. The amount of this tax for electricity producers would depend, on one hand, on the market prices of the allowances and on the target floor price target, and on the other hand, on the carbon content of the fossil fuel in question. The target floor price for a tonne of CO_2 would increase from £15.7/t (€18.1/t) in 2013 to £30/t (€34.5/t) in 2020 and then to £70/t (€80.6/t) in constant currencies in 2030;
- setting an annual limit of 450g[25] of CO_2 per kWh for new fossil fuel power stations . This level could change over time without being applicable retroactively;
- the establishment of a capacity mechanism, either in the form of a strategic reserve, or by implementing a capacity market for all providers wiiling to offer capacity (generation but also storage and demand-side response). This mechanism could be in place in 2015.

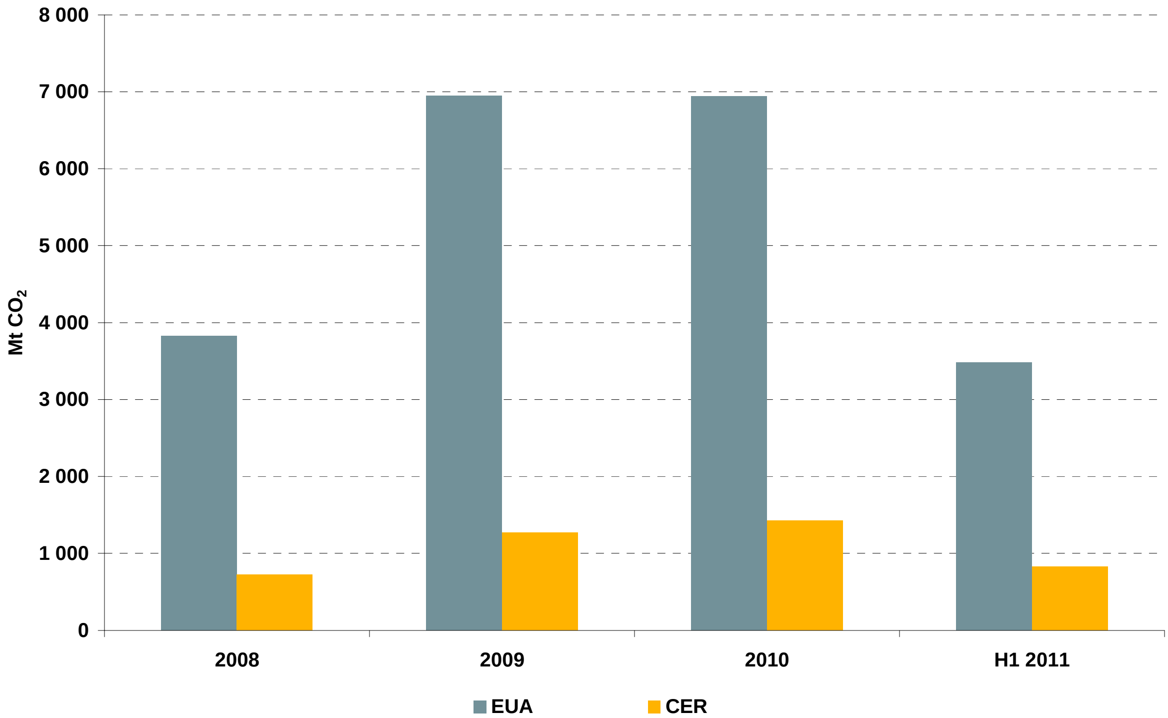
[25] Emission factors identified by CRE to build **Erreur ! Source du renvoi introuvable.** are respectively 960 and 411 g of CO_2 per kWh for a coal plant and gas plant

2. Volumes traded on the CO_2 market

In this section, the characteristics of transactions carried out on the European market, i.e. all of the EU ETS, are analyzed. The figures presented in this section entirely cover the transactions concluded within the global European scope via organized markets and within the intermediated OTC: this scope represents the bulk of trading on the secondary allowances market. The corresponding data has been made public.

2.1 The trading volumes have stabilized in 2010 versus 2009

Figure 47: Annual EUA and CER volumes since 2008



Sources: Bluenext, ECX, EEX, LEBA

As shown in **Erreur ! Source du renvoi introuvable.**, the total volumes traded in 2010 have stabilized in relation to 2009, after the sharp rise in the previous year: a total of 8,366 Mt were traded, against 8,215 million tonnes of CO_2 (Mt) in 2009, an increase of only 2%.

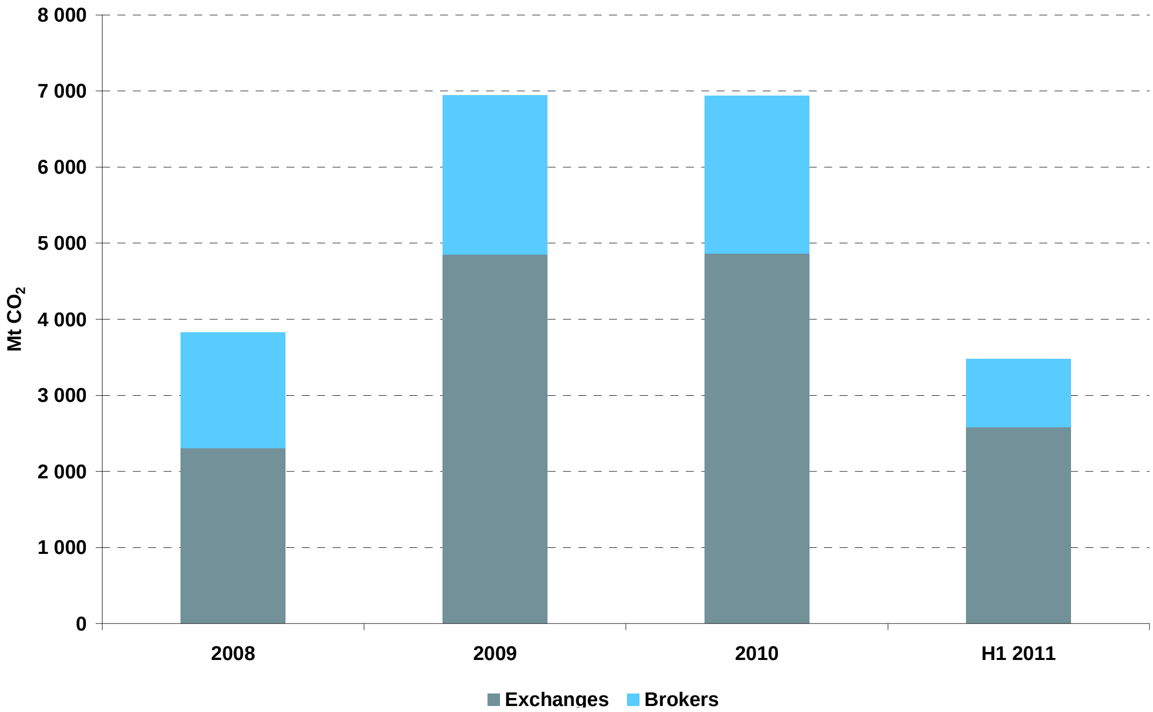
For 2010, a total of 6,941 Mt equivalent of EUA were traded on the secondary market, slightly less than in 2009, when the total transactions amounted to 6,946 Mt. These exchanges accounted for 101.7 thousand million Euros in 2010 against 92.7 thousand million Euros in 2009. This increase of almost 10% was due to higher prices in 2010 than in 2009. The ratio of number of allowances traded on the secondary market over the number of allowances distributed on the primary market (allowances allocated free of charge and allowances auctioned, i.e. roughly 2,100 Mt) is 334% over 2010.

In the market for CERs, trade volumes were 1,425 Mt, i.e. an increase of over 12% in relation to a total of 1,270 Mt in 2009. The corresponding value is estimated at roughly 17.5 thousand million Euros in 2010, versus 15.0 thousand million Euros in 2009.

Finally, in the ERU market 3.3 Mt of units were traded in 2010: this figure is very small compared to the total transactions of EUA and CER because the ERU only became available for purchase as of November 2010, with a reduced level of supply and very low liquidity. The amount of trade in Euros on the ERU market was 55.7 million Euros.

2.2 Ramp-up of trading on organised markets since 2009

Figure 48: Annual EUA volumes

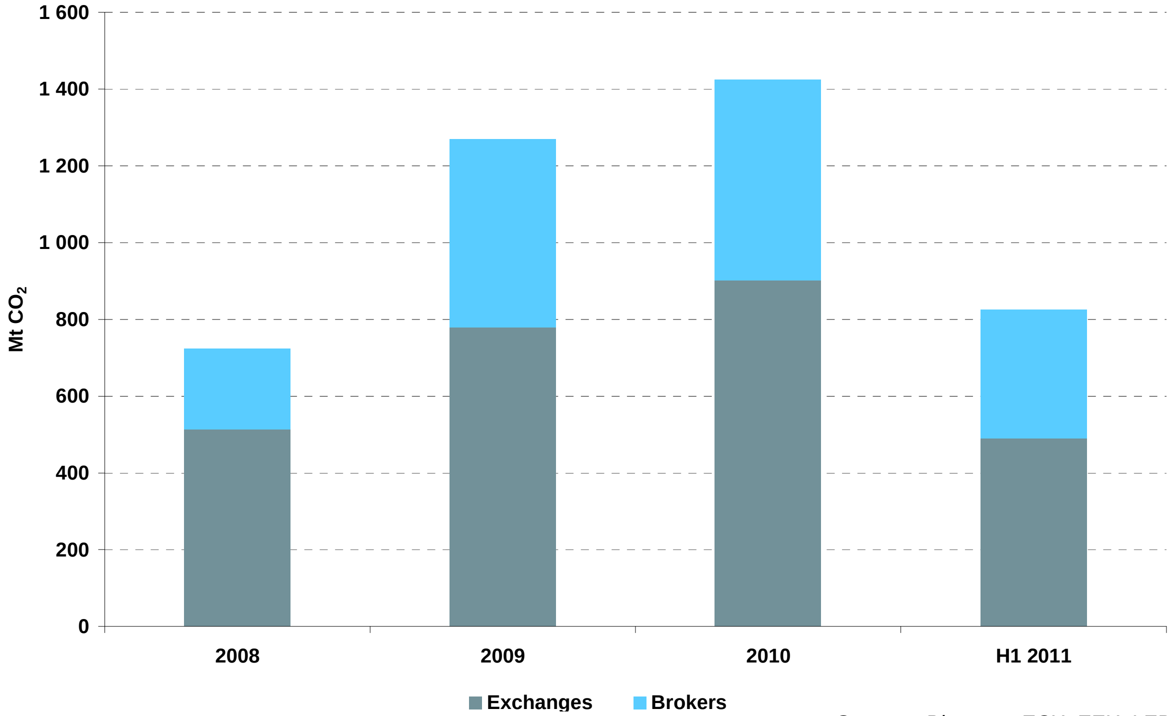


Sources: BLUENEXT, ECX, EEX, LEBA

Erreur ! Source du renvoi introuvable. shows that the overall stabilization of the level of trade observed in 2010 on the European carbon market follows the rise of the volumes traded on the stock exchanges as of 2009. Thus, the increase in volume observed as of 2008 was mainly driven by the organized markets, whose share in trading has increased from 60% in 2008 to 70% in 2009 and 2010 on the EUA market.

Thus, the EUA volumes traded on the ECX platform (which represented over 50% of total trade in 2008) increased by 124% between 2008 and 2010, against a 36% increase on the intermediated OTC. In 2010, on this same market, 64% of the trade was carried out on the ECX platform, which accounted for more than 90% of the transactions on the organised markets.

Figure 49: Annual CER volumes

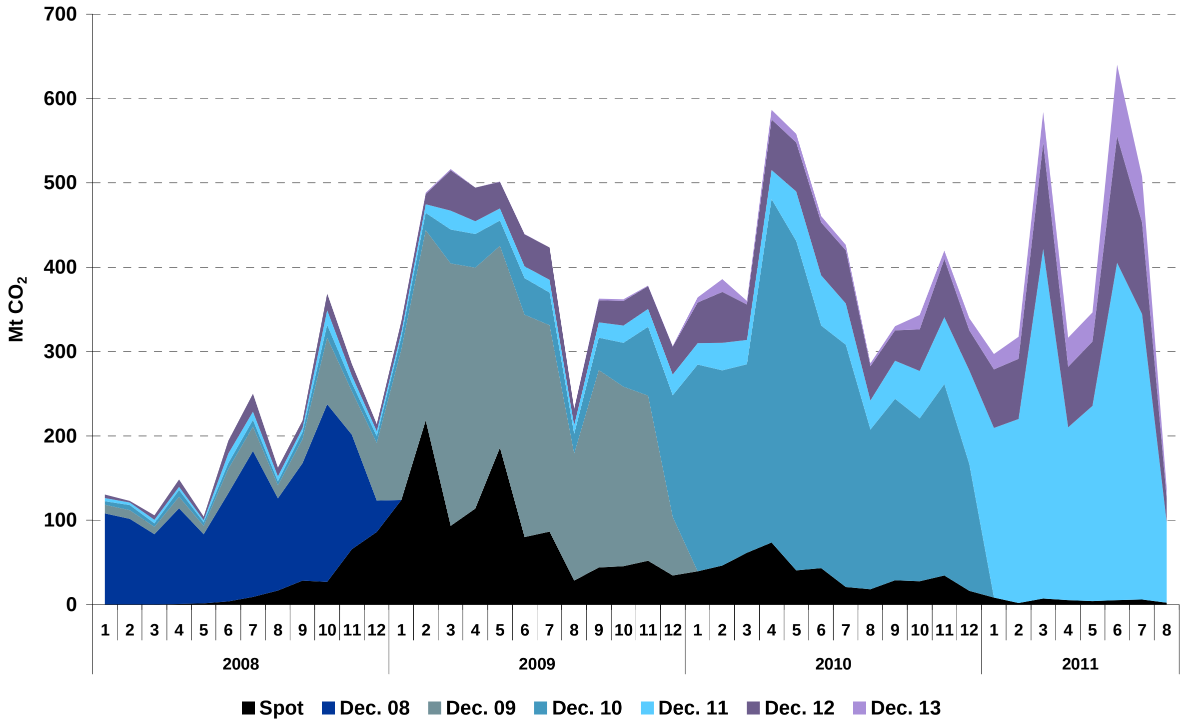


Sources: Bluenext, ECX, EEX, LEBA

The increase in the market size of the CERs (**Erreur ! Source du renvoi introuvable.**) was rather supported by the OTC platforms: in 2008, they accounted for less than 30% of trade. Their share increased to almost 40% in 2010. This development is the result of growth in trade of CERs in intermediated OTC of 149% between 2008 and 2010, against a 76% increase on the organized markets.

2.3 Increase in term contracts trading as of 2009

Figure 50: Evolution of trade by maturity in the market for EUA



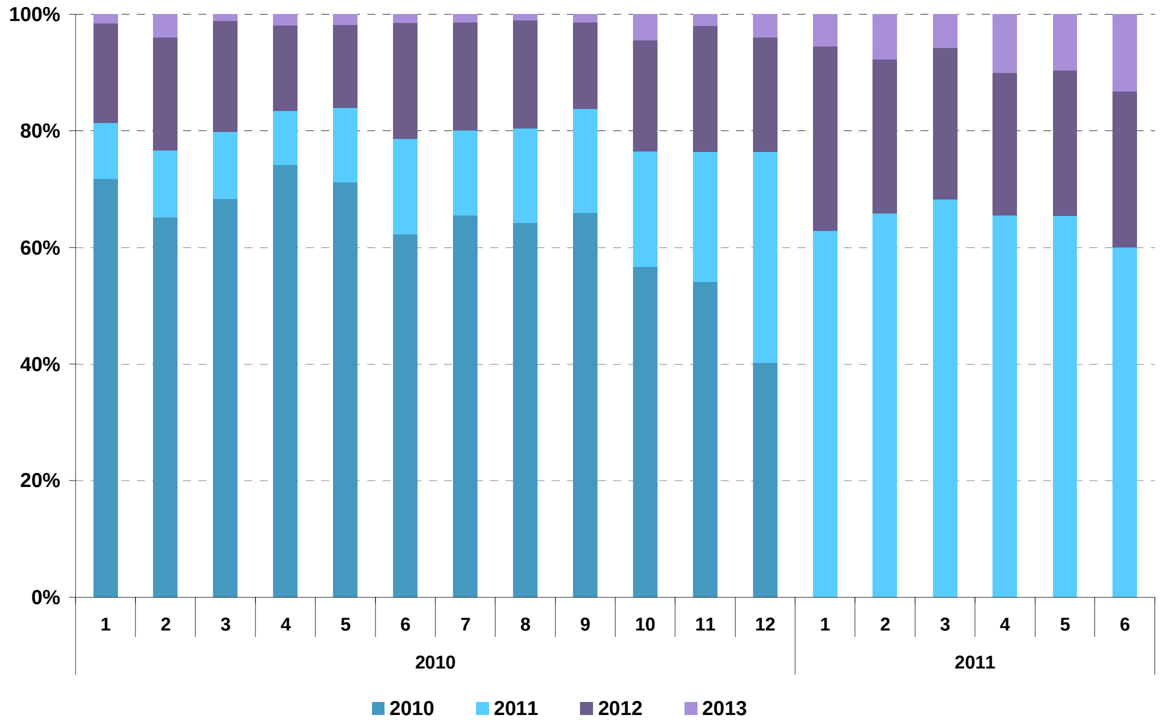
Sources: Bluenext, ECX, EEX

In 2010, 91% of total transactions on the exchanges involved term contracts for the EUA market, of which almost all were performed on ECX. In 2009, the figure was 77%, which shows a significant increase in term contracts in the market for EUA. In the CER market, the corresponding figure was unchanged between 2009 and 2010 and is 90%.

According to **Erreur ! Source du renvoi introuvable.**, for a given year, the contracts traded are mostly on deliveries for the end of the current year: this means that the players essentially protect themselves one year in advance for their actual emissions since the surplus allowances can be traded for the following exercised years, and the possible defaults can be acquired on the spot market prior to allowance restitution in early April.

This analysis is detailed in **Erreur ! Source du renvoi introuvable.**, which shows the distribution by maturity of the EUA futures in 2010 and the first half of 2011 to be delivered in December and traded on ECX. The data shows some seasonality as the share of these contracts is highest early in the year with more than 70% of the volume for January, then gradually decreases as the deadline for delivery approaches: thus, contracts for delivery in December 2010 only represent 40% of the trading in December 2010.

Figure 51: EUA volumes by maturity on the ECX platform



Source: ECX

2.4 Participants in the CO_2 markets

A classification of participants in the CO_2 markets can be made from public lists of members of Bluenext, ECX and EEX platforms, as presented in **Erreur ! Source du renvoi introuvable.**.

Table 10: Classification of participants in the CO_2 market.

	CRE Scope	*Outside of CRE scope*	*Total*
Electricity generators in France	6	0	6
Electricity generators in Europe	31	42	73
Other physical energy companies (gas, oil, etc.)	13	10	23
Consulting or trading firms specializing in energy or CO_2	12	44	56
Financial institutions	28	104	132
Others, including other emitting entities	2	18	20
Total	92	218	310

Sources: Bluenext, ECX, EEX, RTE, DGEC, CRE analysis

From this analysis, it is apparent that:

- the largest share of CO_2 market participants consists of non-specialized financial institutions that can intervene in arbitrations for their own account or for third parties;
- many European generators are directly involved in the carbon market;
- companies that specialize in consulting or trading in the energy and carbon markets and carbon have developed;
- companies included within the supervisory scope of CRE are mainly physical European energy companies, and to a lesser extent non-specialized financial institutions, acting either on their own account or for third parties, both on the French energy markets and on the CO_2 market;
- emitting entites outside the electricity sector are relatively few to intervene in the CO_2 markets.

It would be worth complementing this evaluation of the number of participants by an analysis of the contribution of each of these categories to the liquidity of the CO_2 market. Such an analysis may be conducted only when the reporting mechanisms between CRE and the market players which are being put in place are finalized (see section **Erreur ! Source du renvoi introuvable.**).

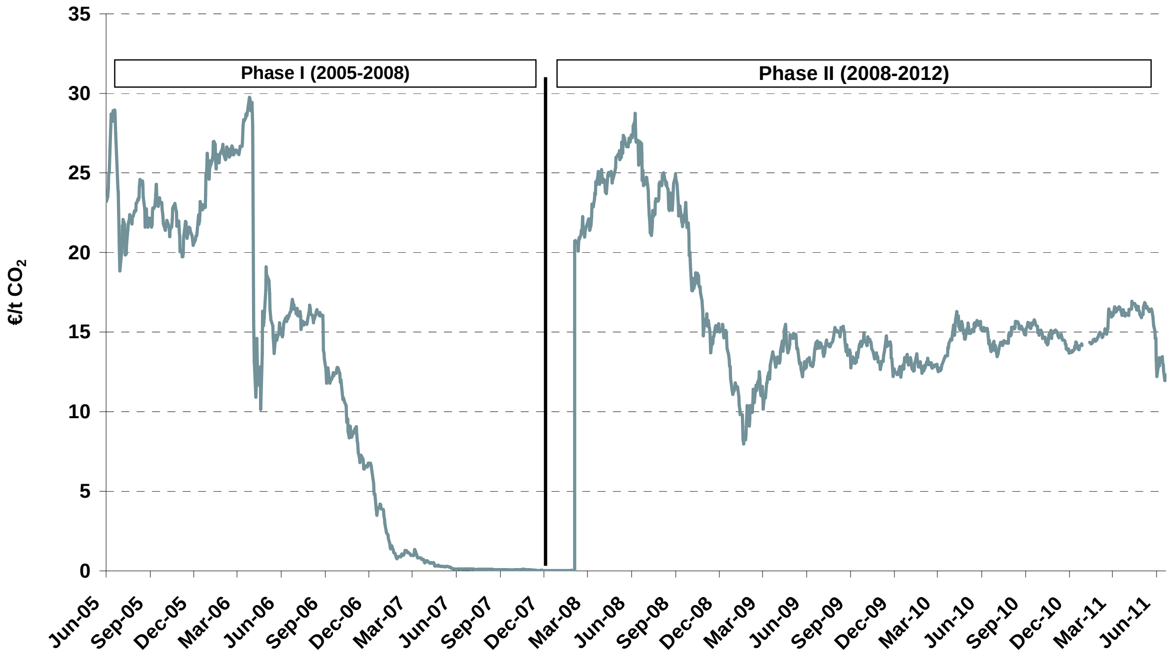
3. CO_2 prices in Europe

3.1 The price trend is characterized by the effects of successive shocks on the supply and demand balance since 2005

The carbon price on the spot market has experienced several important movements since 2005, in general due to shocks due to the perception by the market of the supply / demand balance (**Erreur ! Source du renvoi introuvable.**):

- at the end of phase I (from 2005 to 2008), the price converged to 0 because the volumes of allowances offered were oversized in relation to actual emissions, and because the allowances could not be used in view of compliance in phase II;
- in 2008, the economic crisis caused a slowdown in industrial production, causing a decline in demand for allowances, with a fall in prices to a level that has remained relatively stable at around €14/t as of the second quarter of 2009;
- more recently, the price of the allowance has evolved in a volatile fashion, including, in particular, i) an upward trend following the announcement of the moratorium on nuclear power in Germany in March 2011, and ii) a sharp decline in late June, linked to an increased perception by the market of the risk of oversupply, following the publication of a draft directive on energy efficiency[26].

Figure 52: Evolution of the spot price since 2005



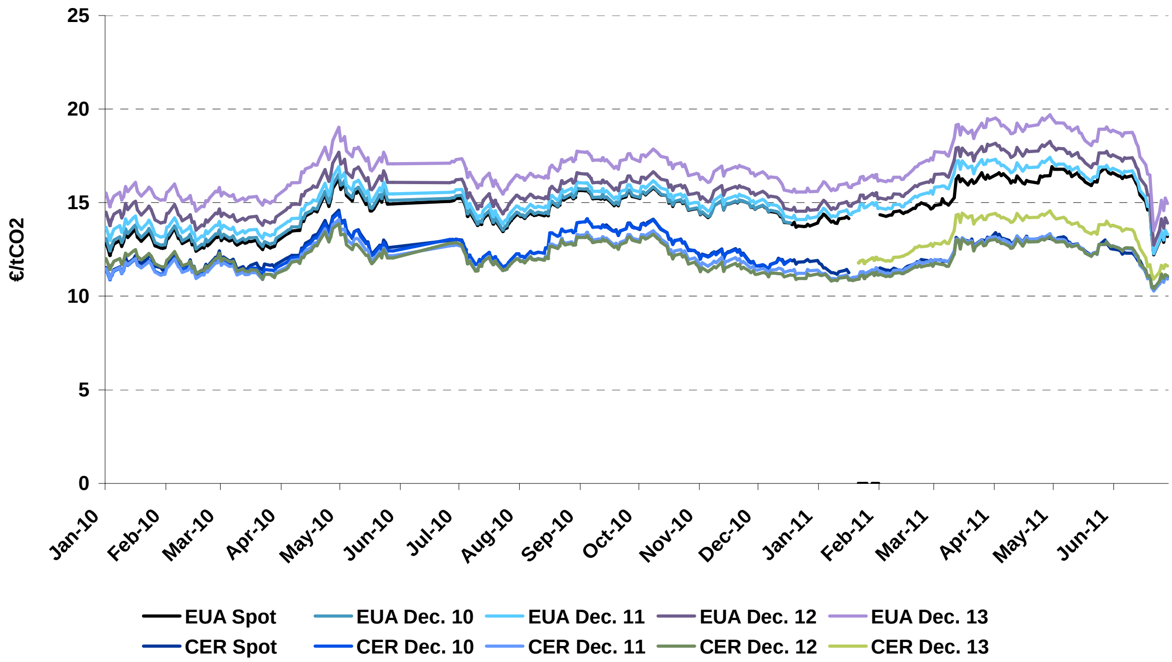
Sources: Bluenext

[26] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2011:0370:FIN:EN:PDF

From 1 January 2010 to 30 June 2011, the price of the allowance on the European spot market ranged from €12.17/t to €16.93/t for an average price of €14.69/t (**Erreur ! Source du renvoi introuvable.**). These minimum and maximum values correspond to the two previously mentioned announcements.

The price of the CER units is largely indexed to the prices of the EUA since CER and EUA can be surrendered interchangeably for compliance, within the ceiling for CER units. Therefore, the price of the CER has followed a trend similar to that of the EUA, and was also marked by the two successive shocks described above. On the spot market, the price varied between €10.45/t and €14.59/t, with an average of €12.43/t.

Figure 53: Evolution of prices since 2010



Sources: Bluenext, ECX

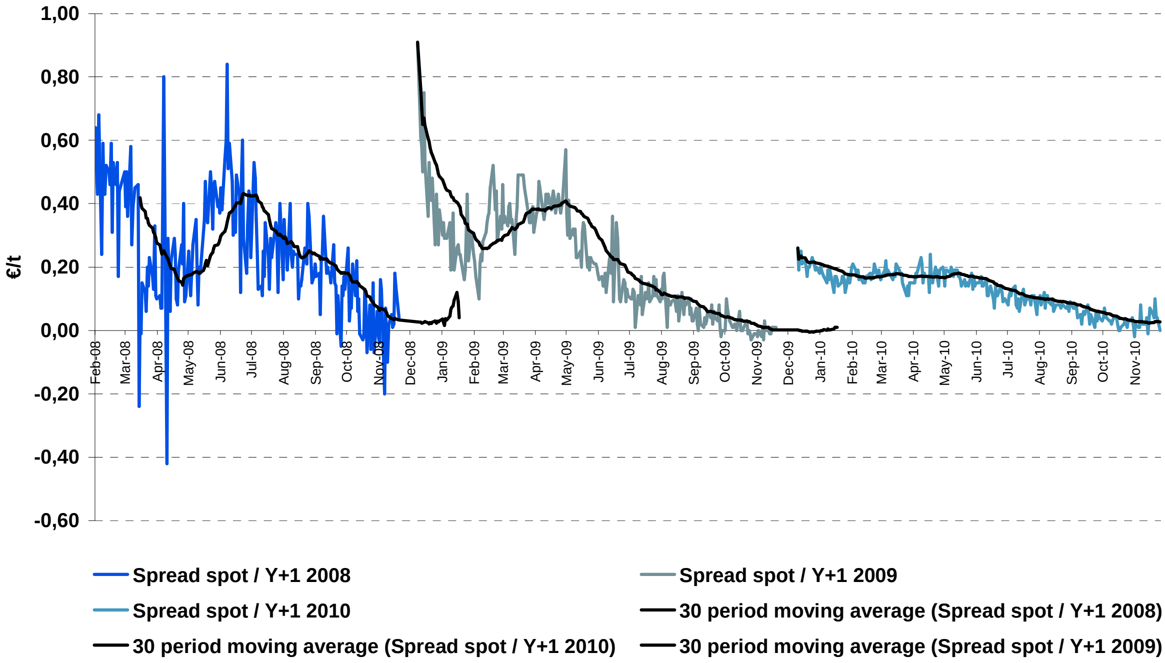
In 2010, the EUA futures contracts for December 2010 delivery were traded on average on the EUA market at € 14.52/t (€ 0.13/t higher than the average spot price over the same period). In comparison, over the same period, transactions on the Dec2011 contracts were carried out at an average of € 14.86/t (for an average premium of € 0.47/t compared to the spot price).

Finally, after the two price shocks that occurred in March and June 2011, the future Dec2010 prices were affected by relative price movements similar to those found on the spot market, namely:

- +11% between 1 March and 31 March in the upward trend over March for both the EUA market and the CER market;
- -19% between 1 June and 30 June on the downward trend in June for the EUA market and -13% in the CER market.

3.2 *In 2010 term contract prices better anticipated December spot prices*

Figure 54: EUAs – Spread between spot prices and December prices



Sources: Bluenext, ECX

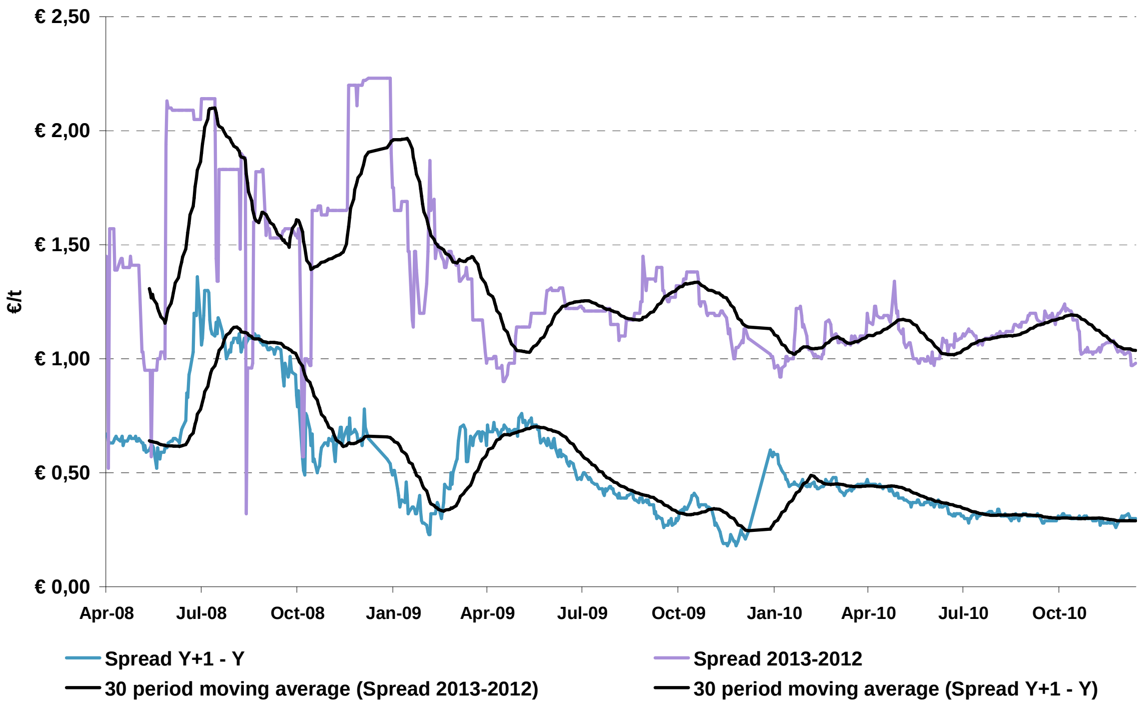
The only products with high levels of liquidity in the European allowances market are products for delivery in December for a given year and for a time horizon of several years (in the logic of price formation on supply / demand balance anticipation over a period of compliance). Products for delivery in December 2020 are already available, but they represent very few transactions: in 2010 the most traded products are for delivery in December 2010, December 2011, December 2012 and December 2013.

Futures EUA products for delivery in December are formally identical to those traded in the spot market in December. This can be seen through the convergence of prices of contracts for delivery in December in the final months of the year, as shown in **Erreur ! Source du renvoi introuvable.**.

The convergence is faster over the years between 2008 and 2010, resulting in an average difference between spot prices and prices for term contracts which is much lower in 2010 (€ 0.12/t) than in 2009 (€ 0.20/t) and 2008 (€ 0.24/t), probably because of lower transactional costs in 2010.

3.3 *The price spreads between different maturities reflect the storable feature of CO2 allowances*

Figure 55: EUA - Price spread between Y+1 - Y products and between 2013 - 2012 products since 2008



Source: ECX

Between 2008 and 2010, the price spread between Y and Y+1 products is generally less than € 1/t for the products within a phase or trading period, which is consistent with the similar nature of the products concerned, in particular through the ability to borrow allowances from one year to the next. However, the price spread between 2012 and 2013 products is greater than €1/t (see **Erreur ! Source du renvoi introuvable.**): this difference highlights the fact that in this case we are dealing with two different products, since the rules of the allowances trading system prohibit borrowing from one period to the next (**Erreur ! Source du renvoi introuvable.**).

For the period shown, the Y+1 - Y spread is € 0.54/t on average, i.e. € 0.74/t below the average 2013-2012 spread of € 1.28/t. After the price shock of June 2011, the price movement was such that the 2013 - 2012 spread decreased significantly more than the Y+1 - Y spread (-20% for the 2013 - 2012 spread, against -11% for the Y+1 – Y spread). This comparison suggests that the market perceived a change in the supply / demand balance in the sense of a long-term over-allocation, i.e. beyond the second period.

Box 4: Banking and borrowing rules

CO_2 allowances are annually delivered (i.e. transferred by the holder of the relevant register of the account of the State concerned, to the deposit account of the operator of the installation concerned) following the National Allocation Plan of the allowances for the period, before February 28 of each year (**Erreur ! Source du renvoi introuvable.**).

Before April 30, operators of installations involved must return a volume of allowances equal to its verified emissions for the previous year. During a given phase, allowances which are returned can be any allowances previously delivered during the same phase. It is therefore possible, within a phase, to "borrow" an allowance delivered for the year following the compliance period in question.

Thus, in April 2009, it was possible to use an allowance delivered in February 2009 for 2008 compliance. However, in April 2009, it was not possible to use an allowance delivered in February 2010 for 2008 compliance.

Borrowing is not possible between phases. This allows emissions during a phase to be capped while allowing flexibility between the different compliance periods during the same phase.

Surrendered allowances are subsequently cancelled. Any non-cancelled allowance can be used later for purposes of compliance (called banking). This rule applies within the same phase (e.g.: in April 2010, use for 2009 compliance of an allowance delivered in February 2008).

The allowances of Phase I were not bankable until Phase II (which, because of the over supply in phase I drove the price to drop to 0 at the end of Phase I - see section **Erreur ! Source du renvoi introuvable.**), but the allowances of Phase II are bankable until Phase III.

4. Fundamentals of the European CO2 market

CO_2 prices are formed on the basis of the supply / demand balance of the allowances market, as perceived by market players:

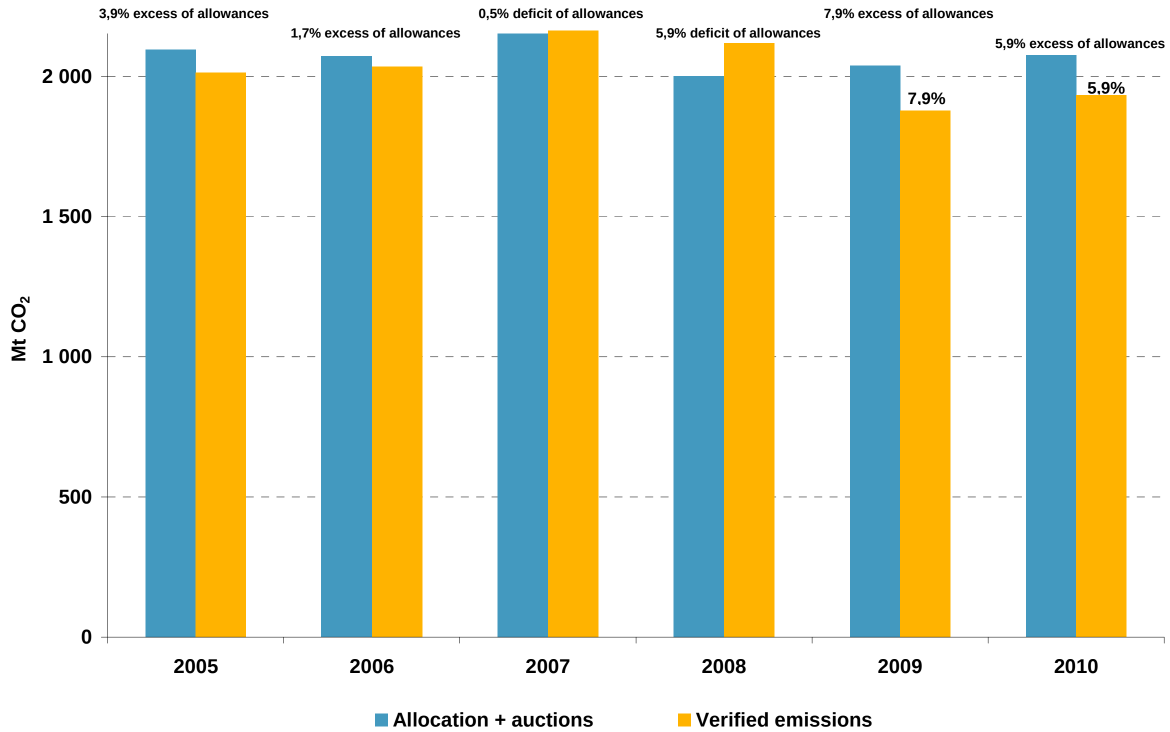
- In the case of the EUA, the supply is the amount of allowances delivered in the primary market within the context of free allocation and auction. In the case of CER and ERU units, the offer is based on the execution of emission reduction projects and the validation of new projects. While all EUAs marketed by the Member States are intended to be used by sites located in the European perimeter within the context of their compliance with the Allowances Directive, CER are released on a global scale: therefore, they can be purchased outside the European perimeter (for example through voluntary compensation);
- Demand depends on the actual verified emissions by industrial sites subjected to compliance. Therefore, they depend on the level of activity, particularly on the level of power generation. In this regard, the fundamentals of CO_2 prices share common characteristics with those of electricity prices, in particular with an at least indirect influence of the price of fossil fuels.

4.1 A supply which exceeds demand across all sectors except energy companies which are net buyers of allowances

The supply of allowances exceeds demand since 2009

Actual emissions of installations subject to allowances are published once a year in April. Actual emissions can be compared with allocated emissions in order to show the net balance of facilities participating in the system within the European perimeter (**Erreur ! Source du renvoi introuvable.**).

Figure 56: Supply and demand of allowances since 2005



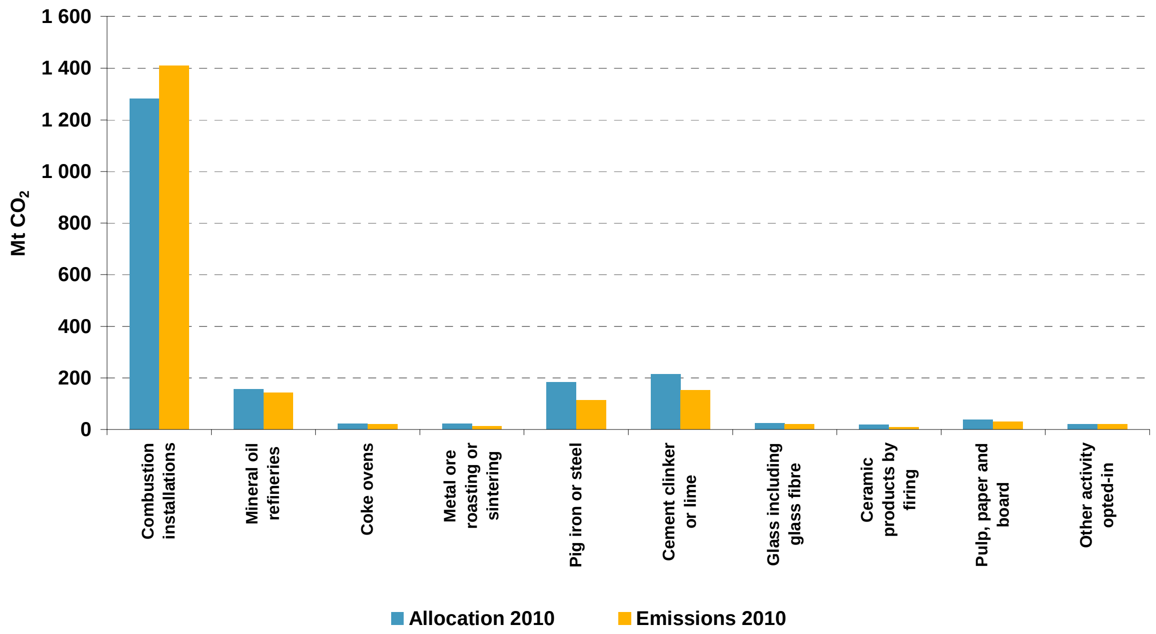
Source: CITL

For the past two years, the supply of allowances exceeds demand across all sectors. On average, the total supply of allowances in Phase I was 2,107 Mt per year, versus 2,035 Mt per year in Phase II until 2010, i.e. a reduction of 3.4%. However, this decrease is less than the drop in the level of verified emissions (an average of 2,071 in Phase 1 as compared to 1,977 Mt in phase 2, i.e. -4.6%).

Only one sector has a deficit in allowances

For 2010, analysis per sector shows that only the combustion sites, mainly power generation plants, are in deficit with regards to allowances (**Erreur ! Source du renvoi introuvable.**).

Figure 57: Allowances and actual emissions by type of site in 2010

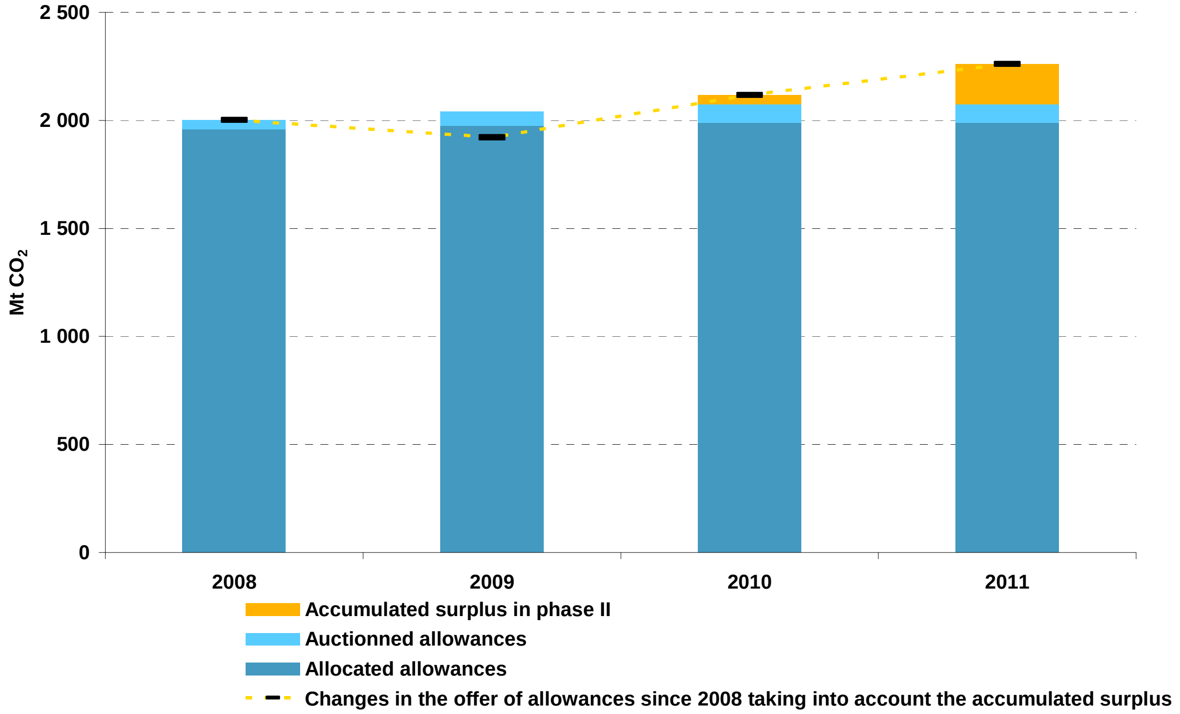


Source: CITL

The allowance price is mainly supported by the possibility of banking for Phase III

In this configuration, where supply exceeds demand, there is a surplus of allowances: through the banking principle (**Erreur ! Source du renvoi introuvable.**), this surplus is accumulated as there is no ceiling adjustment. As shown on **Erreur ! Source du renvoi introuvable.**, this accumulation of allowances can be likened to an increase in the actual supply of allowances when taking into account the transfer of successive surpluses (assuming a 2011 level of supply equivalent to that of 2010).

Figure 58: Accumulation of an allowance surplus in Phase II



Source: CITL, European Commission (assuming a 2011 level of supply equivalent to that of 2010)

At the end of 2010, 185 Mt had been cumulated: in addition, this figure only reflects the cumulative difference between distributed allowances and actual emissions, without taking into account the fact that some of the emission rights were restored in the form of Kyoto units, which means that the EUAs surplus at the end of 2010 is even higher.

Under these conditions, the possibility of banking allowances from Phase II for use in Phase III (**Erreur ! Source du renvoi introuvable.**) is the main factor to prevent a price collapse by the end of 2012. For the record, this lack of banking possibility from Phase I to Phase II explains the convergence of the price toward 0 in phase I.

4.2 Correlation between CO_2 and electricity prices

The energy and carbon markets are strongly interconnected:

- At the forefront of subjected industry players are the electricity generators which are strong emitters of CO_2. In the EU, they represent almost a third of CO_2 emissions and nearly 50% of total allocated emission allowances (**Erreur ! Source du renvoi introuvable.**: in 2010, combustion installations, essentially electricity generation facilities, account for 64% of the allocation of allowances and 73% of the verified emissions). This leads to a strong correlation between the determinants of CO_2 and those of energy markets. There are obvious common trends between the price of the CO_2 and the price of other fossil fuels and electricity (**Erreur ! Source du renvoi introuvable.**: from 2008 to 2010, the correlation between allowance prices and German electricity prices was higher than 90%);
- The price of emission allowances is based on prices of the other energy commodities. Thus, the key market drivers that determine the fluctuations of the price of allowances are linked to the demand for allowances (temperature and rainfall, energy prices, level of production, new technology) and also to the regulated supply of allowances. The relative equilibrium of coal and gas prices affects the price of allowances: since production of electricity by coal plants emits more CO_2, an increase in gas prices encourages electricity generation by coal operated power plants, thus inducing an increase in the demand for allowances.

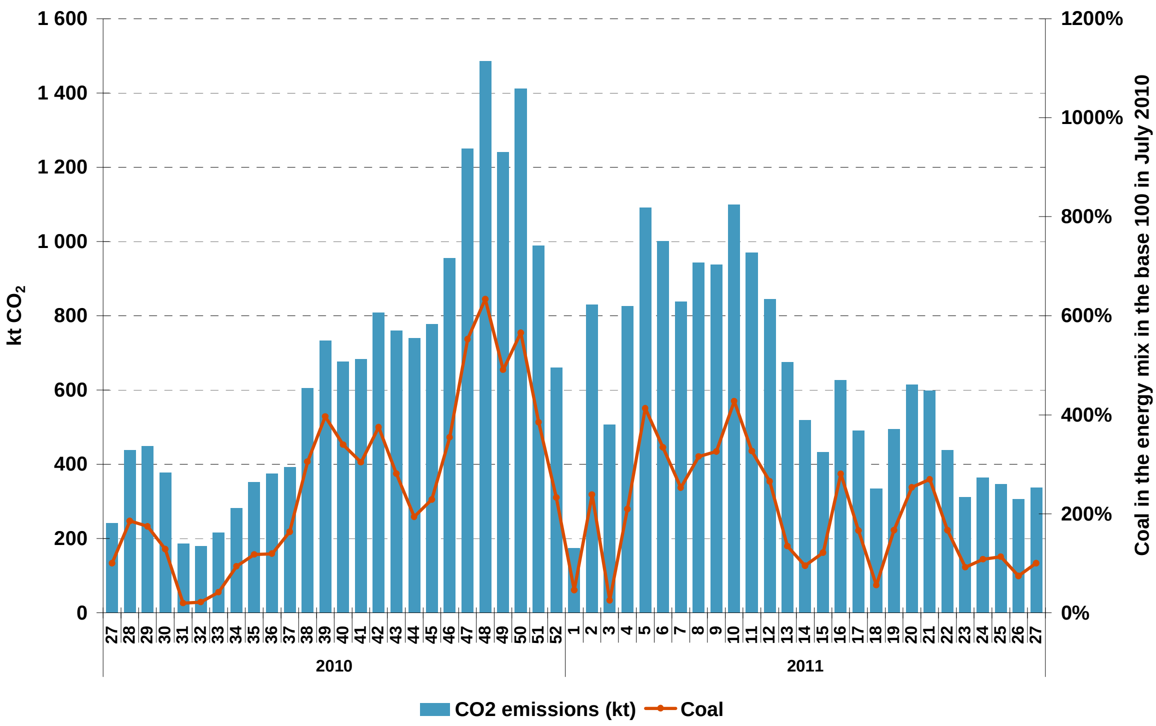
Figure 59: Electricity prices and CO_2 prices

Sources: EEX, ECX

4.3 The evolution of market prices is favourable to the coal-fired generation

Emissions from electricity generation plants are related, in particular, to the presence of coal in the energy mix. Thus, a greater involvement of thermal power plants means higher emission levels (**Erreur ! Source du renvoi introuvable.**).

Figure 60: Emissions of the French production plants

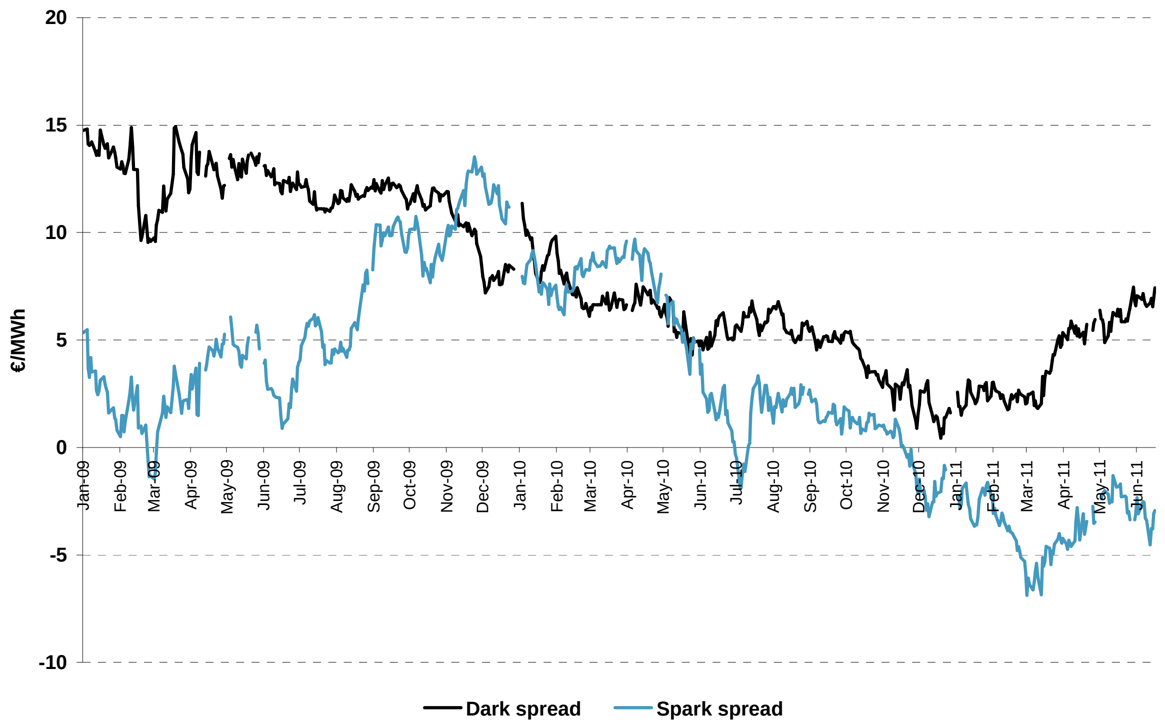


Source: RTE

As such, German nuclear moratorium led to higher CO_2 prices to the extent that the market anticipated an at least partial switch over from nuclear power generation to coal-based electricity generation.

The *clean dark spreads* and *clean spark spreads* represent the theoretical short-term profits of the respective owners of coal and gas plants (**Erreur ! Source du renvoi introuvable.**). A sustained drop of one of these values compared to the other reflects the loss of competitiveness of one of the production sectors: thus, as of May 2010, the gas industry is less competitive than the coal industry, despite the comparative advantage of the gas sector in terms of emissions.

Figure 61: *Clean dark & spark spreads*



Sources: EEX, ECX, Argus (prices Y +1)

Table 11: Formula for calculating *clean dark & spark spreads*

Clean Dark Spread (€/MWh) = p_E – (p_C + p_{CO2})	*Clean Spark Spread (€/MWh) = p_E – (p_G + p_{CO2})*
p_E price Y+1 Germany base (€/MWh) p_C price Y+1 coal (€/MWh)[27] p_{CO2} price Y+1 CO_2 (€/MWh)[28]	p_E price Y+1 Germany base (€/MWh) p_G price Y+1 gas (€/MWh) **Erreur ! Signet non défini.** p_{CO2} price Y+1 CO_2 (€/MWh) **Erreur ! Signet non défini.**

[27] Based on an assumption of a calorific power value of 8.14 MWh / t for coal, and a yield of 35% for coal plants and 49% for gas plants. It should be noted, on the one hand, that these yields correspond to new reference installations and therefore can be different to the yields of existing installations, and, on the other hand, that other costs, in particular transport costs, are not taken into account.

[28] Based on an assumed emission factor of 0.96 t CO_2 / MWh for coal plants and 0.41 t CO_2 / MWh for gas plants

Section III: Wholesale gas markets

1. The development of gas trading

During 2010, trading on wholesale gas markets continued to grow. Gas supply remains high on world markets, particularly due to the production of unconventional gas in the United States and the arrival of substantial volumes of liquefied natural gas (LNG).

The recessionary context of 2009 had the effect of pulling gas demand down. The result of an abundant supply and weak demand was then a historically low level of prices on the wholesale markets in Europe. In particular, these prices had proved much lower than those of long-term supply contracts indexed to oil products[29]. Many European suppliers had then entered in a renegotiation phase of those contracts with manufacturers of gas producing countries in order to obtain conditions which were closer to those of the short-term markets, for example by introducing market indexing.

Due to increasing demand, driven by the gradual economic recovery observed in 2010, wholesale prices in the leading European trading venues had started to increase from the low points reached in 2009 but remained down compared to long-term supply contract prices indexed to oil products.

The gas wholesale markets therefore continued to be an attractive source of supply for importers, suppliers and consumers and to represent an outlet for non-purchased gas volumes within the context of flexibility clauses in long-term contracts for producers.

It is difficult to predict the extent and duration of the disconnection between oil prices and the gas market price. Market observers believe that this gap could continue at least in the short term.

The total gas flows in France (Figure 62) reflect these contextual elements. In 2010, 637 TWh of gas were physically delivered to all French gas networks, an increase of 38 TWh (+6%) compared to the volumes delivered in 2009. This increase is related to the net rebound in consumption of end consumers (539 TWh, i.e. an increase of 50 TWh or 10% compared to 2009), mitigated by a decline in exports (91 TWh, i.e. a decrease of 13 TWh or 12% compared to 2009). What's more, in 2010 consumption also exceeded the levels recorded in 2008 (509 TWh).

Despite their slight decline, imports remain above consumption. They have indeed represented 596 TWh in 2010 as compared to 603 TWh in 2009. The decline which began in 2009 continues and imports have regained their 2007 level. Physical movements associated with the storage and destocking have allowed the steady inflow of imports to be balanced with the seasonal consumption needs which are concentrated in winter. Destocking operations were higher in 2010 than in 2009, contrary to the storage operations, which is consistent with an increase in demand and lower imports. Net stored volumes were negative in 2010 (-34 TWh), contrary to 2009 (13 TWh) and 2008 (6 TWh).

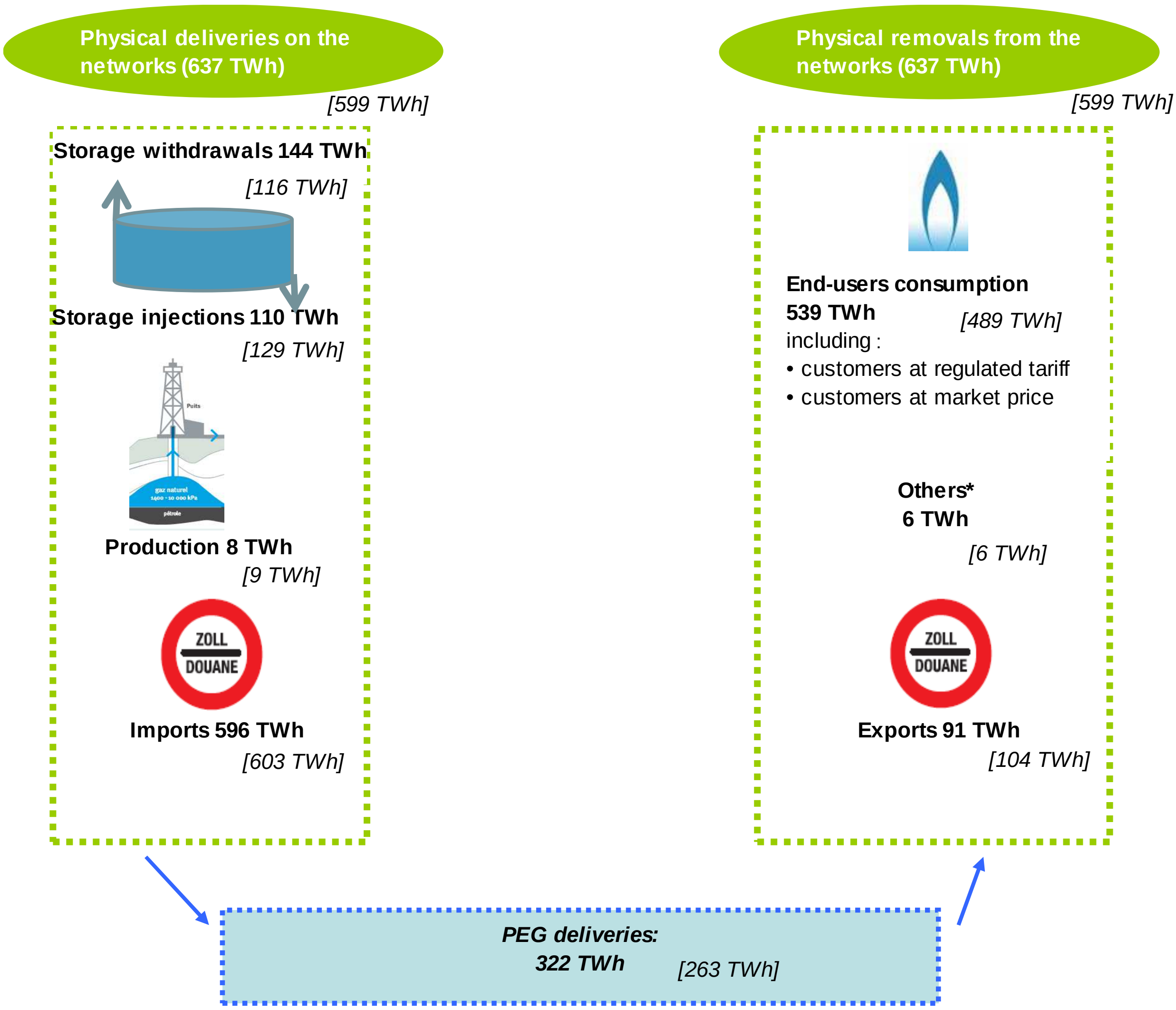
Deliveries and the physical removals of quantities of gas at the Gas Exchange Points (PEG hubs) materialize the trading carried out on the wholesale markets. Deliveries to the PEG hubs increased by over 22% compared to 2009, reaching 322 TWh in 2010. This increase, which was more important than that of the consumption, is the net reflection of the increase in trade on wholesale markets.

The energy wholesale markets evolved during the 1st half of 2011 in a context marked by:

- geopolitical tensions;
- natural events in Japan and their impacts on the Japanese nuclear generation and the expectations of evolution in demand for LNG;
- the decisions of the German government regarding electronuclear power generation in March and May 2011, which might have fuelled anticipated gas import increases in Germany.

[29] See the report of CRE on the supply costs of GDF Suez: http://www.cre.fr/documents/publications/rapports-thematiques/rapport-sur-les-couts-d-approvisionnement-de-gdf-suez/rapport-sur-les-couts-d-approvisionnement-de-gdf-suez-mission-d-expertise-de-la-cre.

Figure 62: Supply and opportunities of the French gas market - 2010 [2009]



** the 'Others' item corresponds to the gas consumed by the TSOs and DSOs to ensure network functionning (own consumption, metering errors, losses…)*

Source: GRTgaz, TIGF - Analysis: CRE

1.1. Strong growth in shipments during 2010, especially at the PEG Nord

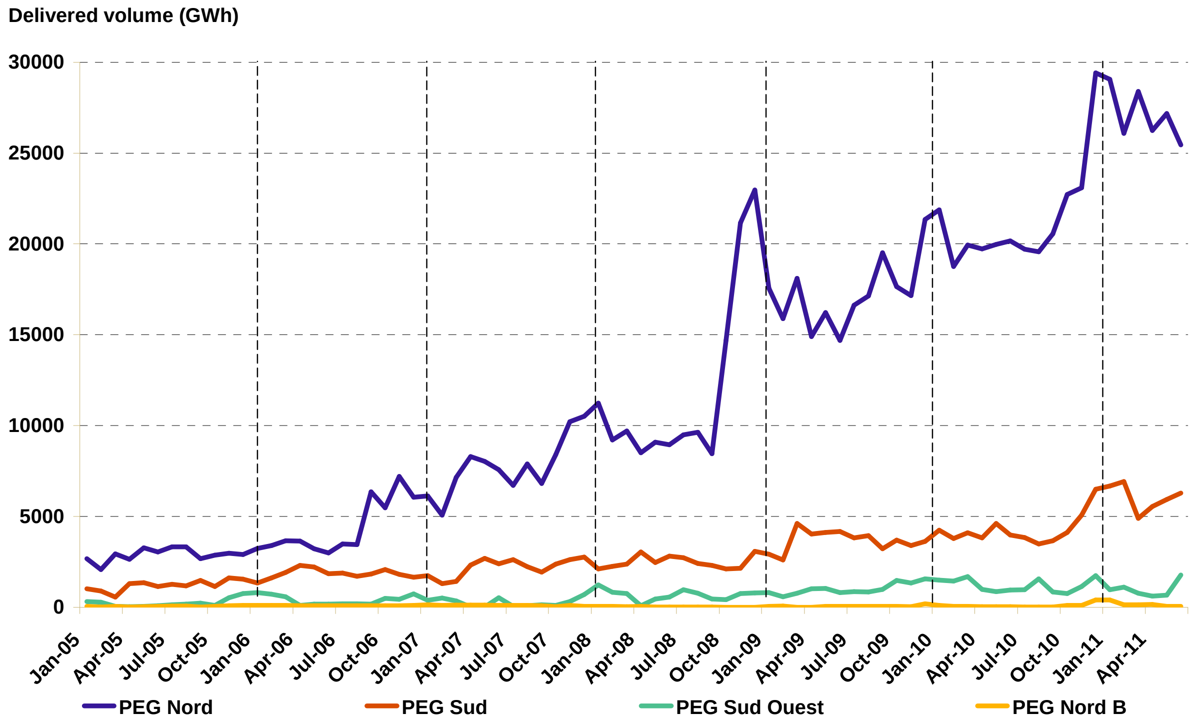
Deliveries to the Gas Exchange Points (PEG) represent the sum of net shipper appointments to the various French PEG (PEG Nord, Nord-B, Sud and Sud-Ouest). These deliveries are based on trading between the different players of wholesale markets and provide evidence of the use of the wholesale market, whether purely bilateral or intermediated (Powernext Gas Exchange since November 2008 or broker platforms). These deliveries include purchases or sales made by network managers made to cover their balancing needs.

Deliveries at a given time reflect all transactions on the spot or term contracts markets and delivered during this period. This volume does not represent the volume of transactions between the players on that date, because a volume of gas for a specified period may be negotiated between two or more players, but upon delivery only one net delivery will result from these exchanges.

2010 was characterized by delivery levels to the PEG higher than in 2009 (+ 59TWh). After high levels in December 2009 and January 2010, the volumes delivered to the PEG hubs evolved on constant levels (roughly 20 GWh per month in the PEG Nord and about 4 GWh per month in the PEG Sud) before a sharp increase at the end of the year (close to 30 TWh per month in the PEG Nord and 7 TWh per month in the PEG Sud). This increase appears to be an underlying trend of the market. During the 1st half of 2011 the average monthly delivery volume was 34.2 TWh as compared to 25.4 during the 1st half of 2010.

Delivered volume growth was observed in the three French areas (North, South and Southwest) but continues to be smaller in the South and Southwest areas. It does not seem that the commissioning of the methane terminal at Fos-Cavaou in April 2010 has had a particular impact on the volume of deliveries in the PEG Sud, since the use of the North-South link was impacted (see Figure 74).

Figure 63: Deliveries to PEG hubs (monthly data)



Sources: GRTgaz, TIGF - Analysis: CRE

Stabilization of the number of shippers in the 1st half of 2011 after a sharp rise in 2010

Table 12: Number of active shippers in removal and / or delivery at the PEG hubs

	2009	*2010*	*H1 2011*
Total number of active shippers	50	70	70
Of which financial traders	8	9	9

Source: GRTgaz, TIGF - Analysis: CRE

Throughout 2010, 70 shippers were active on at least one PEG in France. This number has risen sharply over the previous year (+20). Among the new arrivals, there are three suppliers of end customers and 14 shippers acting for their own needs (infrastructure managers and industrials). Moreover, among the active shippers to the PEG, there are a total of nine players backed by known players in the financial sector.

After this sharp increase, the number of shippers stabilized in the 1st half of 2011 as compared to 2010 (see Table 12).

1.2. Gas trading on the intermediated market continues to grow in 2010

Activity on the French intermediated wholesale market groups together the transactions concluded on the organised market (Powernext) and on the intermediated OTC market (brokers).

During 2010 the traded volumes in these markets have marked a progression of 65% in relation to 2009 levels, a total of 246 TWh as compared to 149 TWh (Table 13). This volume represents 36,921 transactions concluded in 2010, up sharply from the 2009 level (22,429) (Table 13).

This upward trend is observed on all maturities traded. The volumes traded on *Day-Ahead* products were up 88% from 2009 levels. On the term contracts, the increase was lower (+49% in 2010 compared to 2009).

Data from the first months of 2011, as compared with 2010, confirm the increase in trade. Thus, in the first half of 2011, the growing trend of the trading volumes continues, totalling a volume of 208 TWh during this period (Table 13 and Figure 64). Seasonal products trading accounted for almost 75 TWh in the first half of 2011, slightly higher than the volume traded on these products over the whole of 2010 (68 TWh), up (44%) compared to the 1st half of 2010. Over the same period, trading in monthly products doubled, accompanied by an increase in the average size of the monthly traded products (33.4 against 24.2 GWh). In general, the average volume traded per transaction is increasing steadily since 2008 and reached 9 GWh per transaction in the 1st half of 2011.

Structural factors cited above continue to be a driving force behind this increased liquidity of wholesale markets (trade-offs between supply through contracts indexed to oil products and cheaper purchasing markets, deferred non-removed amounts on such contracts for resale on wholesale markets), even if the activity of a player on Powernext Gas Futures should be noted (see Box 5).

A seasonal factor related to the allocation of storage capacity has also contributed to the growth observed on the term contracts during the first months of 2011. These allocations made in late February for the April 2011 to March 2012 period give players the necessary visibility for distant horizon operations.

Table 13: Transactions on the intermediated spot and term contracts market

a. Trading volume

Volume (TWh)	*2009*	*2010*	*H1 2010*	*H1 2011*
Spot market	38	80	33	56
Day-ahead products	21	39	18	27
Futures/forwards Market	111	165	89	152
Monthly products	44	57	21	45
Seasonal products	47	68	52	75
Total intermediated market	**149**	**246**	**122**	**208**

Source: Brokers, Powernext - Analysis: CRE

b. Number of transactions

Number of transactions	*2009*	*2010*	*H1 2010*	*H1 2011*
Spot market	20,291	34,230	15,915	21,173
Day-ahead products	14,692	23,264	11,225	13,845
Futures/forwards Market	2,138	2,691	1,213	2,039
Monthly products	1,608	2,067	859	1,353
Seasonal products	298	340	251	435
Total intermediated market	**22,429**	**36,921**	**17,128**	**23,212**

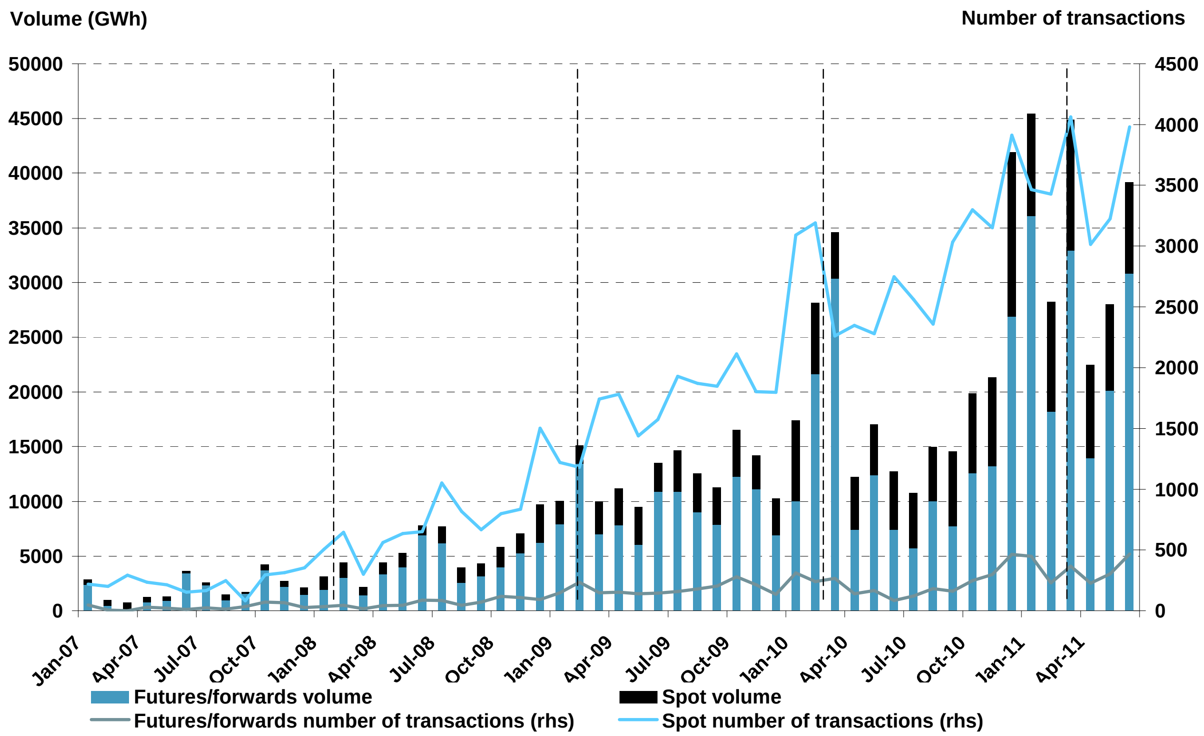
Source: Brokers, Powernext - Analysis: CRE

c. Average size of transactions

Average volume (GWh) per transaction	*2009*	*2010*	*H1 2010*	*H1 2011*
Spot market	1.9	2.3	2.1	2.7
Day-ahead products	1.4	1.7	1.6	1.9
Futures/forwards Market	51.9	61.5	73.5	74.6
Monthly products	27.3	27.8	24.2	33.4
Seasonal products	158.4	199.5	206.9	171.3
Total intermediated market	**6.6**	**6.7**	**7.1**	**9.0**

Source: Brokers, Powernext - Analysis: CRE

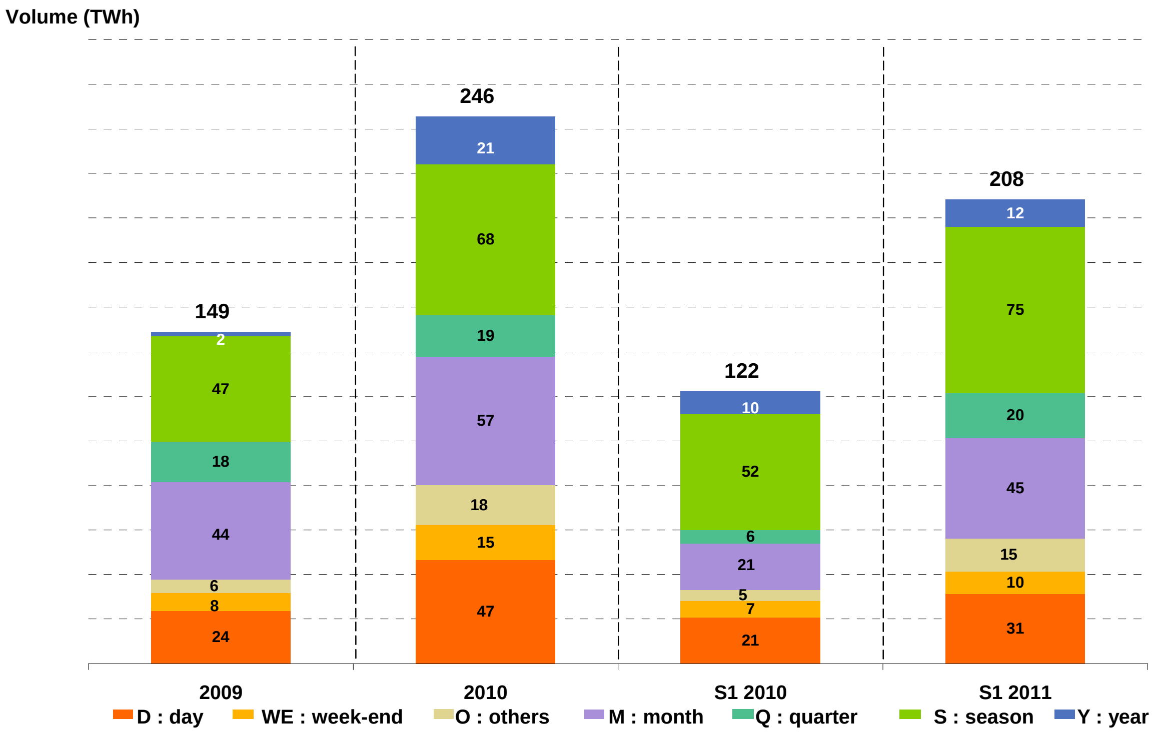
Figure 64: Evolution of trading volumes and number of transactions (Spot and term contracts market)



Source: Brokers, Powernext - Analysis: CRE

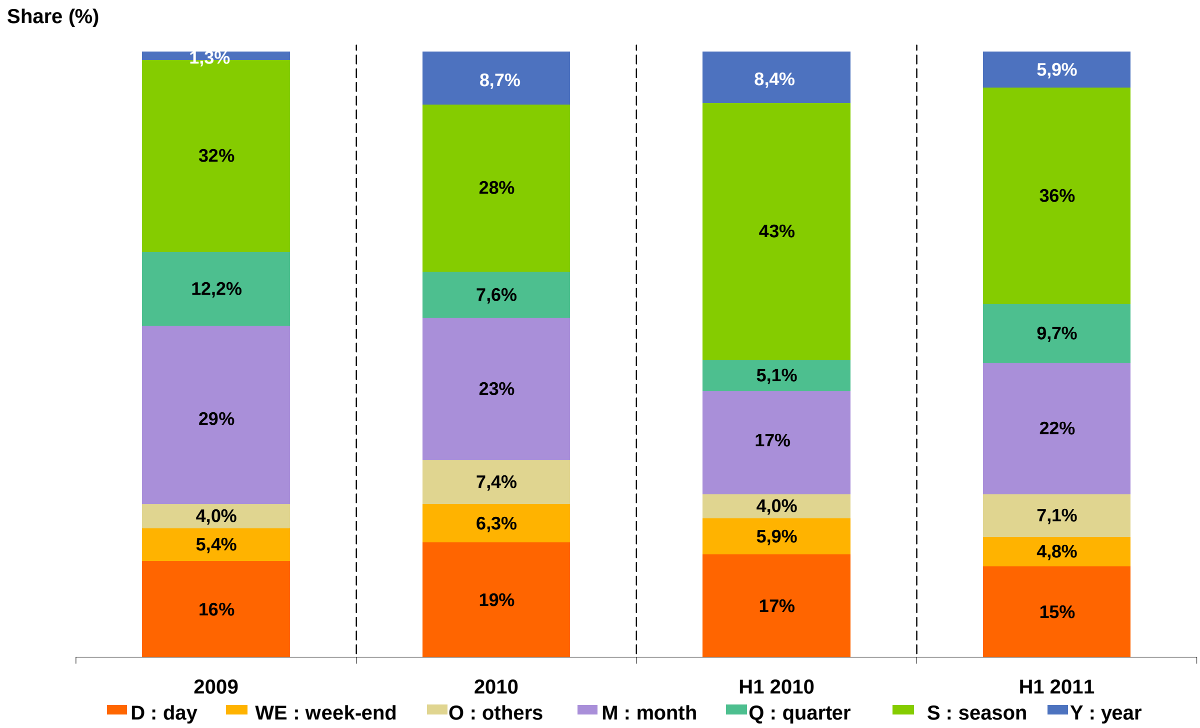
Figure 65: Distribution of trading volumes by product

a. By TWh



Source: Brokers, Powernext - Analysis: CRE

b. By Percentage -

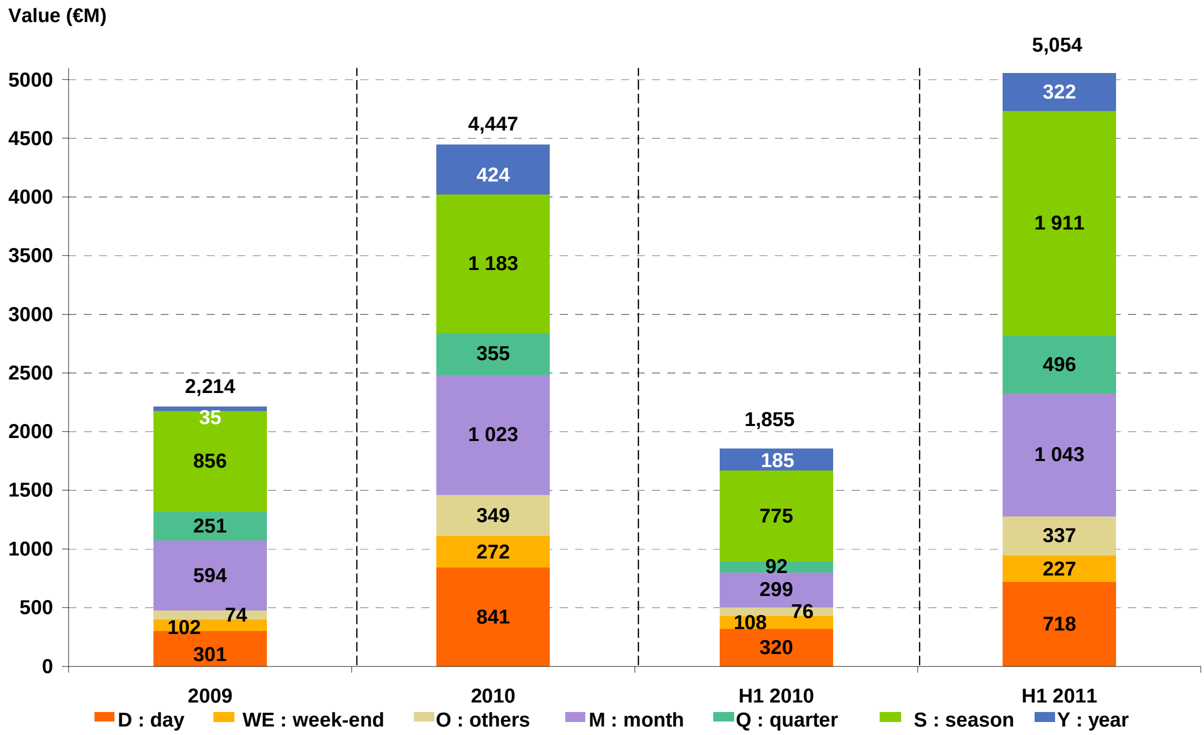


Source: Brokers, Powernext - Analysis: CRE

The size of the wholesale gas market in France amounted to 4.4 billion Euros in 2010.

The valuation of trading carried out in the market reached 4.4 billion Euros in 2010, double the value compared to the valuation of 2009. The increase in securities traded exceeds the growth of trading volumes due to rising gas prices over the period considered. This value effect lasted during the first months of 2011. The gas wholesale market exceeded 5 billion Euros in value in the first half of 2011.

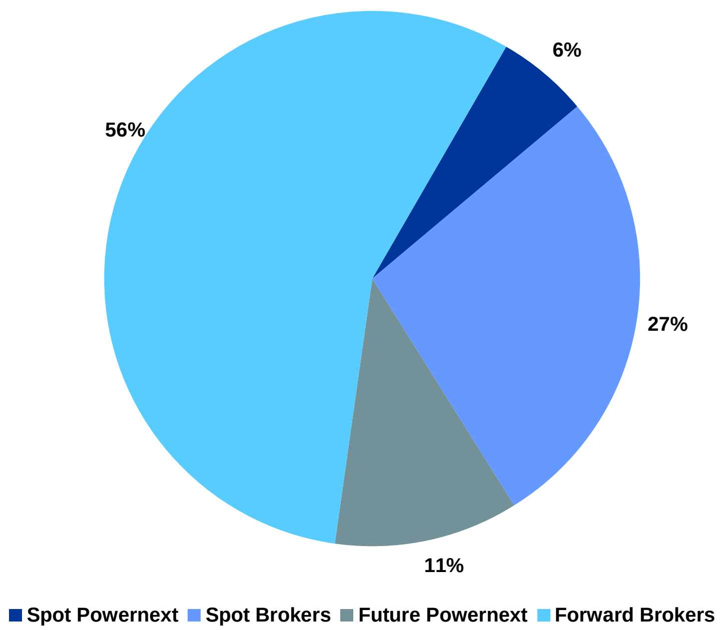
Figure 66: Valuation of trading volume (in €M)



Source: Brokers, Powernext - Analysis: CRE

83% of trading volumes in 2010 were on broker platforms, the remaining 17% were traded on organized markets (Figure 67), the latter continuing to gain market share.

Figure 67: Distribution of spot and term contracts volumes traded at PEG hubs and type of intermediation (2010)



Source: Brokers, Powernext - Analysis: CRE

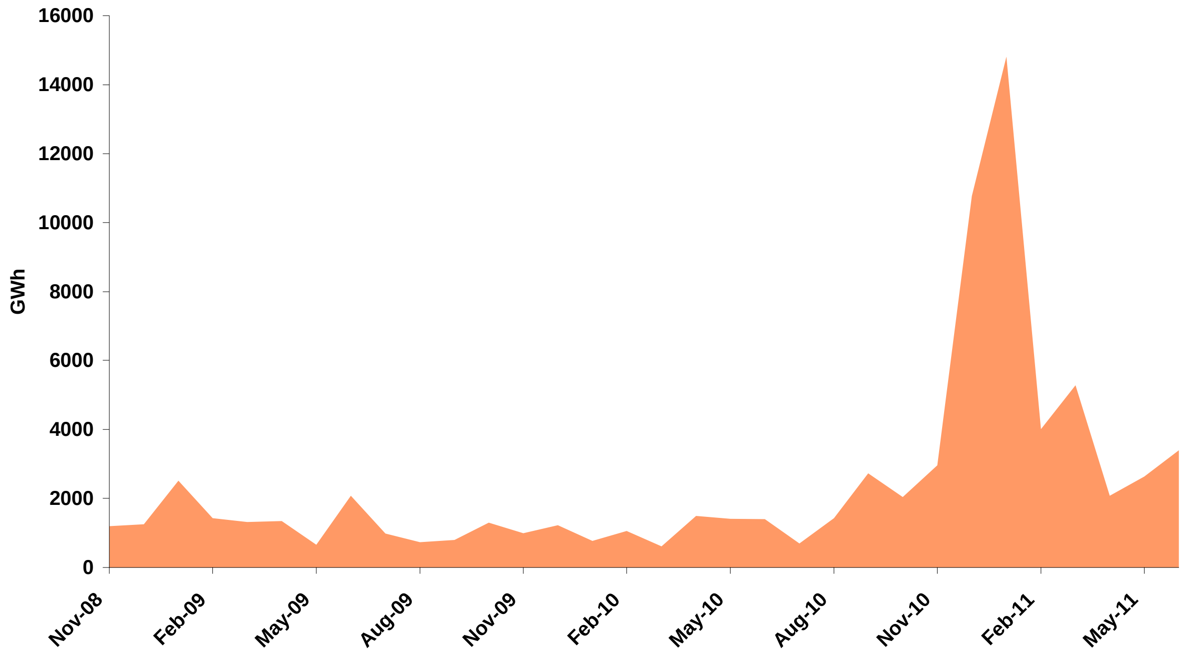
Box 5: Activity on Powernext Gas Futures in late 2010 and early 2011

Activity on Powernext Gas Futures was particularly intense in late 2010 and early 2011. Trading volumes were strongly related to operations by one player who is not a historical player in the French market. It has informed CRE of a major development of its trading activities on the wholesale markets, both in a logic of optimization of its portfolio and with the purpose of arbitrage. This player also took the opportunity of economic conditions deemed to be favourable early in 2011 to intervene on large volumes on the gas exchange.

During investigations conducted by CRE on this player, no market manipulation or attempted market manipulation was detected. However, CRE noted points for improvement in terms of market risk management and record keeping according to the standard expected by the third package. The player in question informed CRE that it had reinforced its risk management and record keeping procedures as of the period in question.

Also, this episode was the subject of discussions with the trading venue. As such, CRE reminds the importance of a monitoring activity conducted independently by the trading venues.

Figure 68: Evolution of monthly volumes traded on Powernext Gas Futures



Source: Powernext - Analysis: CRE

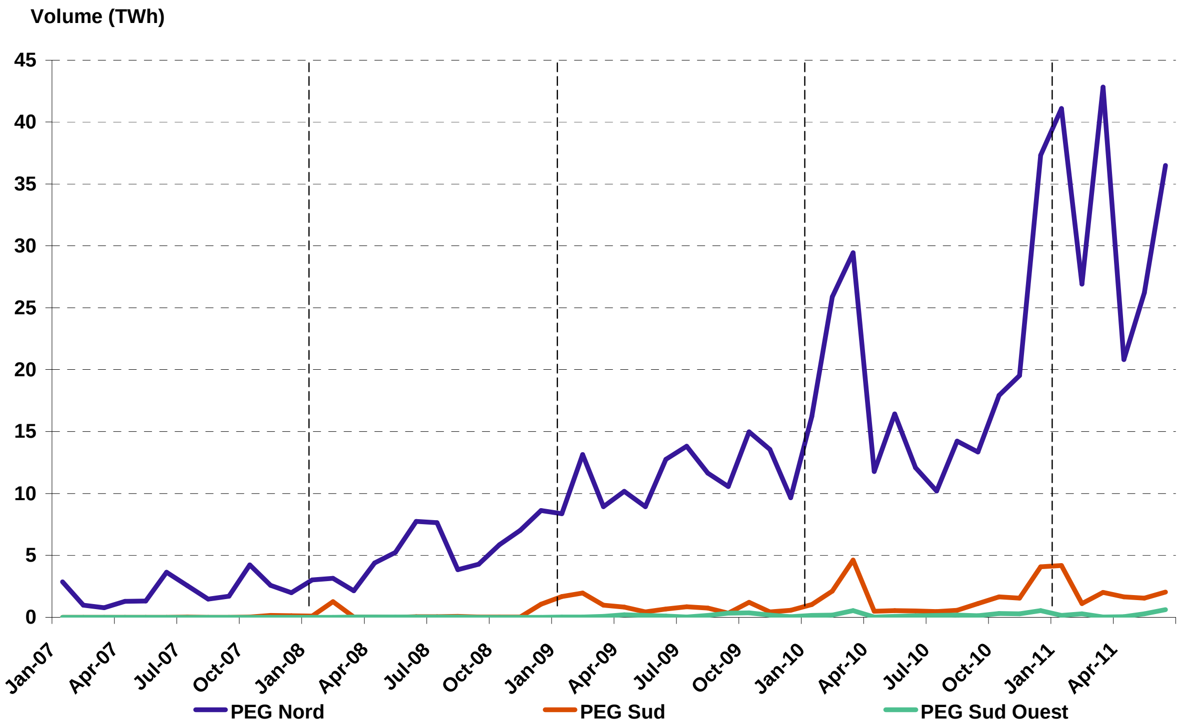
The North zone is the area where trading is most highly developed

Following the example of deliveries at the PEG, the distribution of trading volumes in the three areas shows the predominance of trade in the PEG Nord. It concentrates roughly 91% of volumes traded in 2010.

The volumes traded in the South Zone, which concentrates 26% of domestic consumption, also increased during 2010 (18.6 TWh in 2010, against 10.6 TWh in 2009). The effects over time of the introduction of *spread* products on July 1st 2011 (see Box 7) on Powernext Gas Spot should be monitored.

Liquidity in the Southwest Zone (TIGF) remains low, with a trading volume of 2.6 TWh, while it cooncentrates roughly 6% of national consumption.

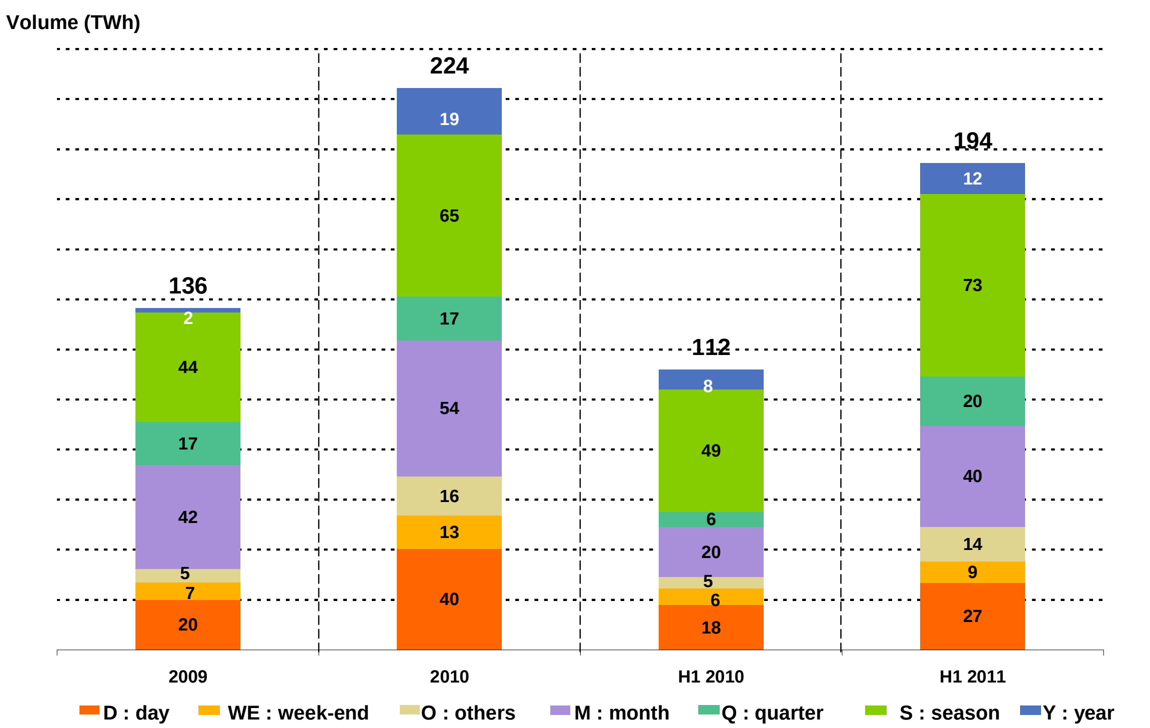
Figure 69: Trading volume by PEG (monthly data)



Source: Brokers, Powernext - Analysis: CRE

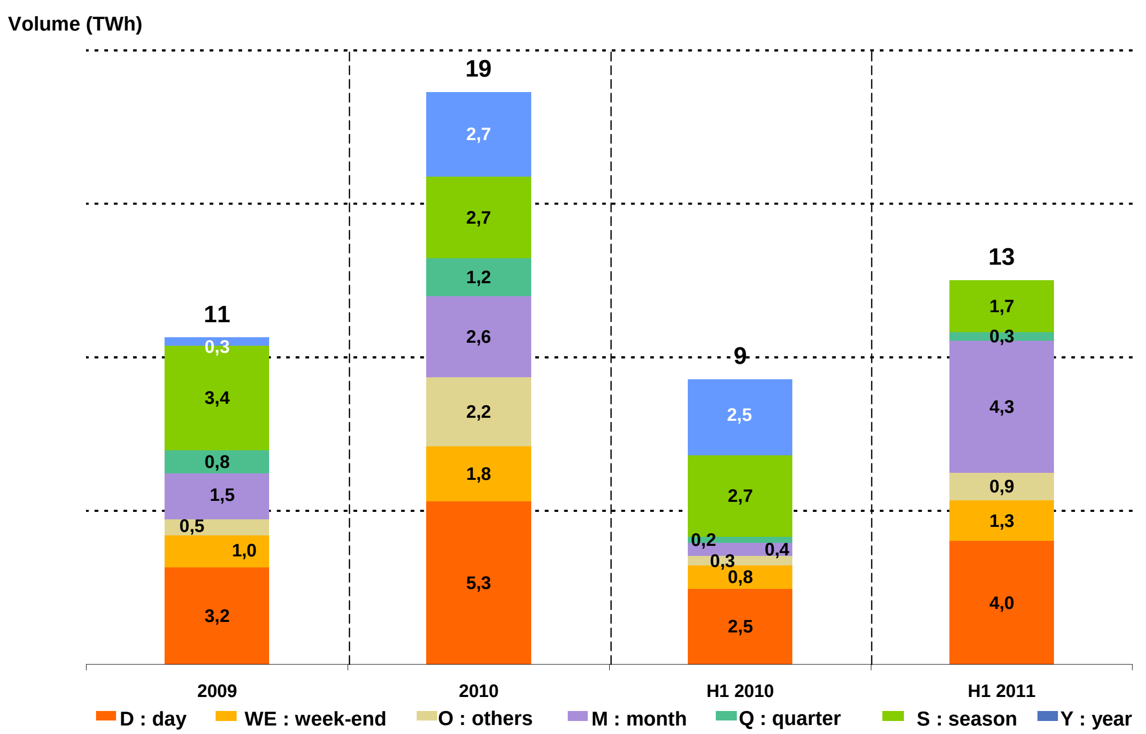
Figure 70: Distribution of trading volume by product and PEG

a. PEG Nord



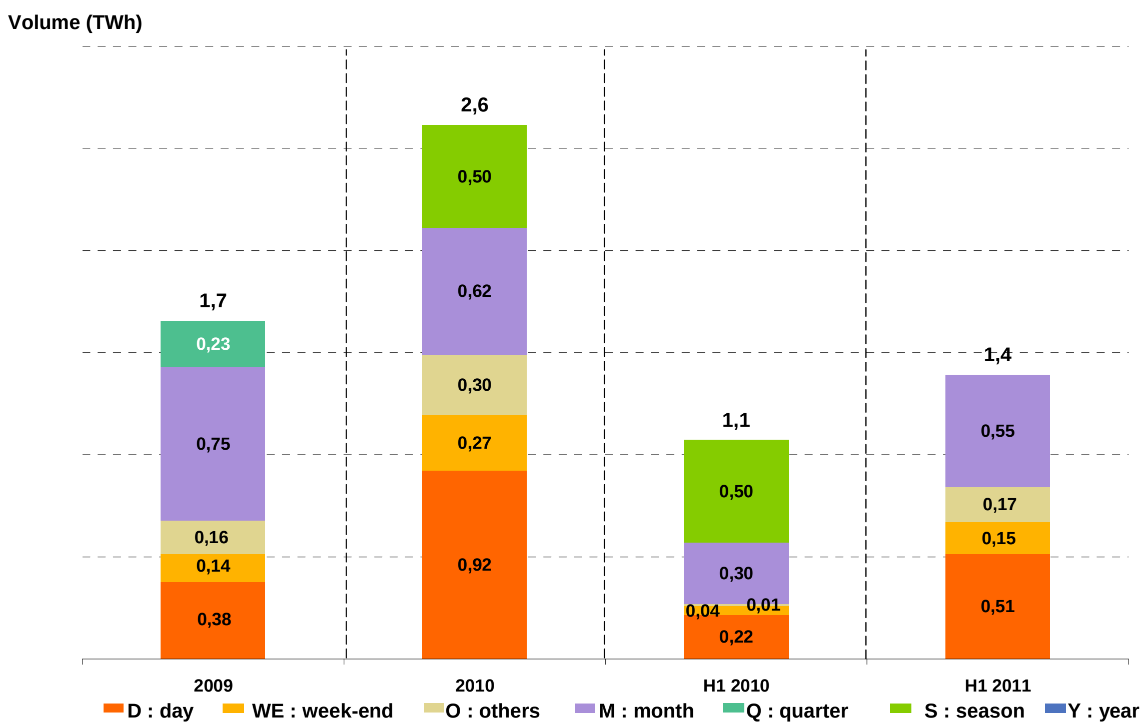
Source: Brokers, Powernext - Analysis: CRE

b. PEG Sud



Source: Brokers, Powernext - Analysis: CRE

c. PEG Sud Ouest



Source: Brokers, Powernext - Analysis: CRE

An increasingly liquid PEG Nord because of a large number of active buyers; the other two zones remain concentrated

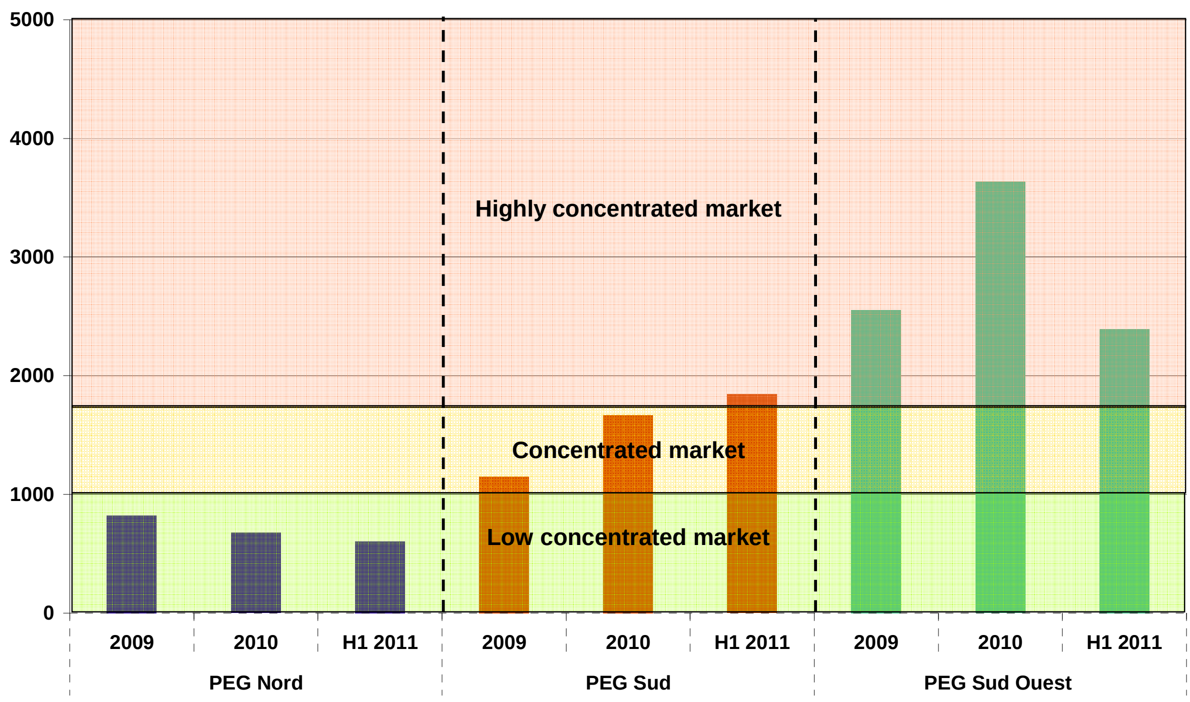
Figure 71 illustrates the degree of concentration of the North, South and Southwest zones. The North zone, both for the purchase and sale of any product, corresponds to HHI indexes which are representative of low market concentration. This finding is also reflected through the evolution of the market shares. The combined market share of the three biggest players in the PEG Nord declined steadily since 2009 and seems to be stabilized, in terms of collections and deliveries as well as in terms of transactions (Figure 72). In the first half of 2011, the three largest players accounted for roughly 30% of the market share for collections - deliveries and 40% for purchases - sales.

In contrast, the Southwest zone remained highly concentrated. Throughout 2010 and in the first half of 2011 there has even been an increase in some HHI indexes in this area. These movements are linked to interventions of some players who, because of the low liquidity of the market in this area can take significant market shares with modest volumes in absolute terms. Therefore, the analysis of changes in HHI indexes in the Southwest area lead, first of all, to take note, once again, of its low liquidity.

The South zone, meanwhile, has a configuration where the HHI indexes increase in sales, but decrease for purchases. The sale concentration is confirmed by observing the market share of the three biggest players for sales (Figure 72). Consistently, the market share of the three biggest players in the delivery to the PEG increases. The decrease in HHI indexes for purchases comes from a similar phenomenon (see Figure 72). These developments are to be connected to the commissioning of the methane terminal at Fos Cavaou.

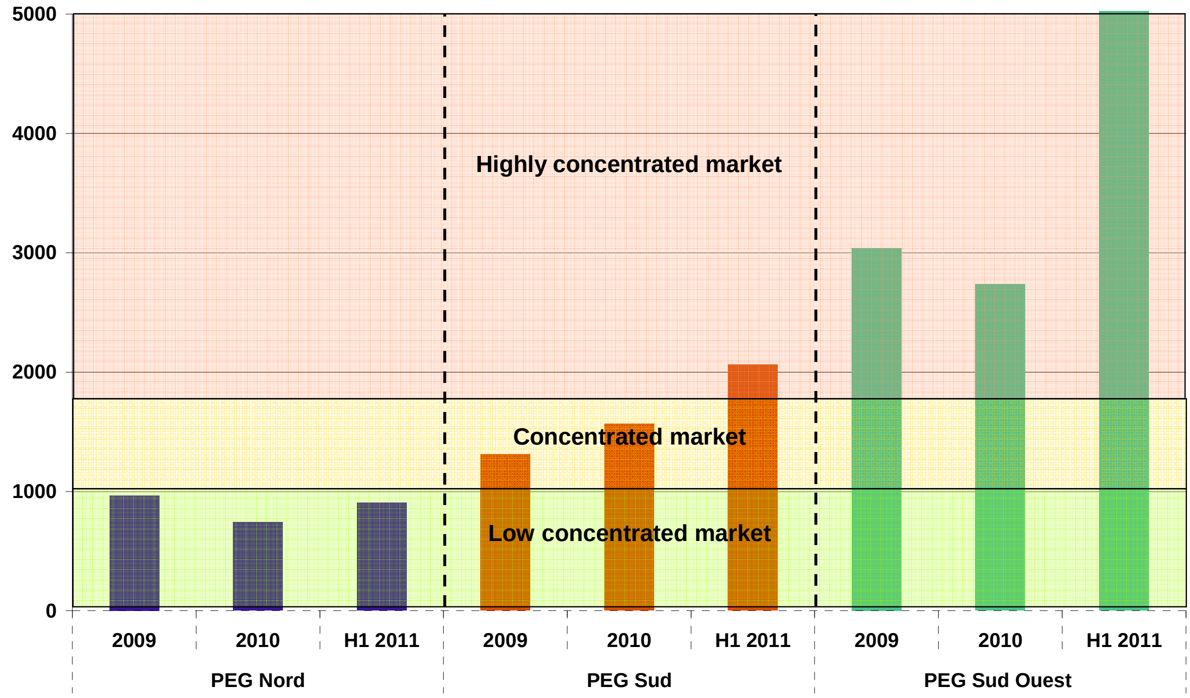
Figure 71: HHI index in the different markets, 2010 and H1 2011, by PEG

a. For sale on the spot market



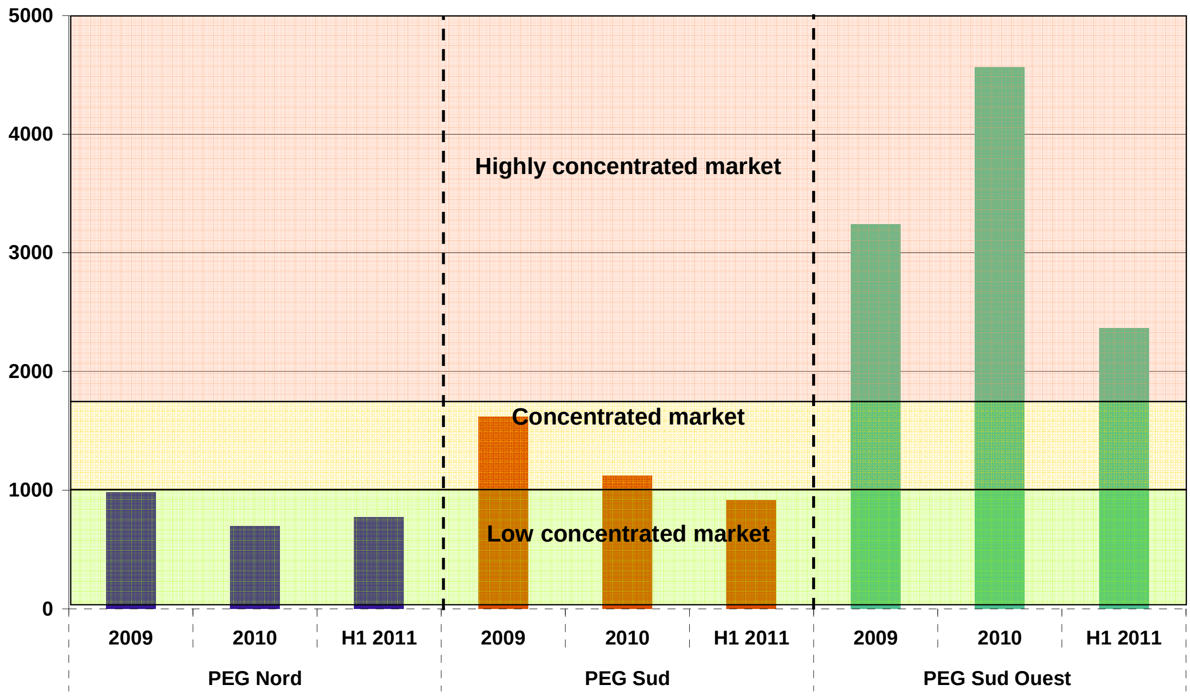
Source: Brokers, Powernext - Analysis: CRE

b. For sale on the term contracts market



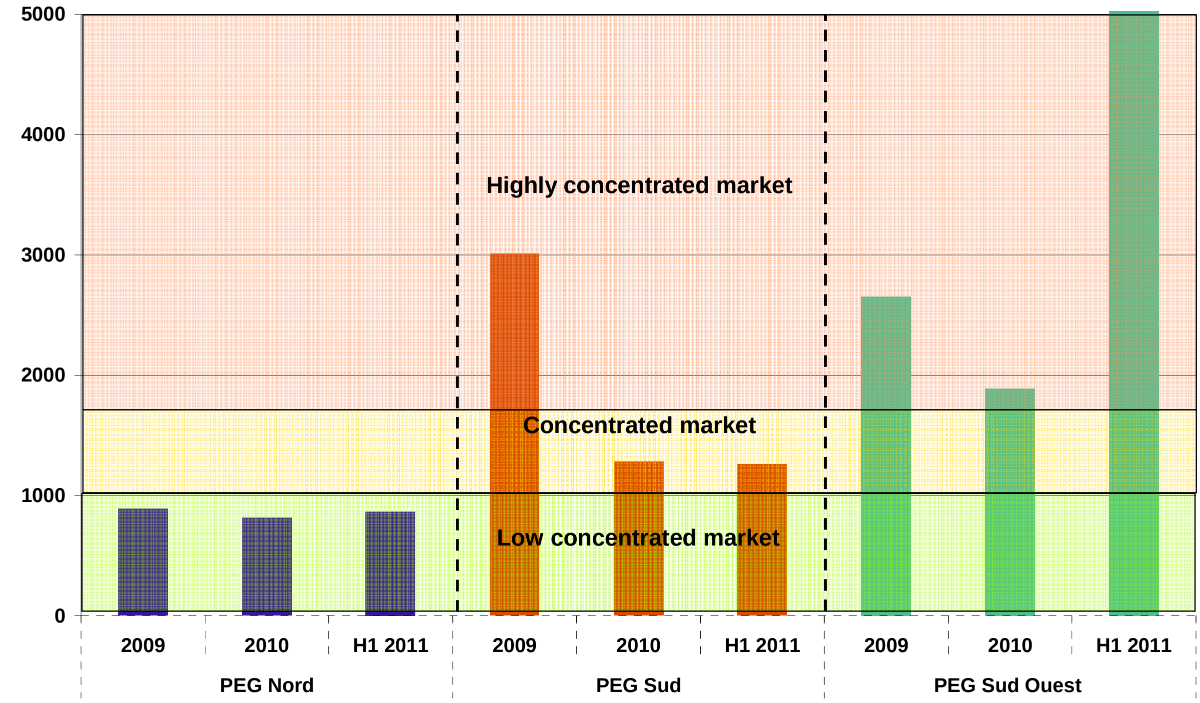
Source: Brokers, Powernext - Analysis: CRE

c. For purchase on the spot market



Source: Brokers, Powernext - Analysis: CRE

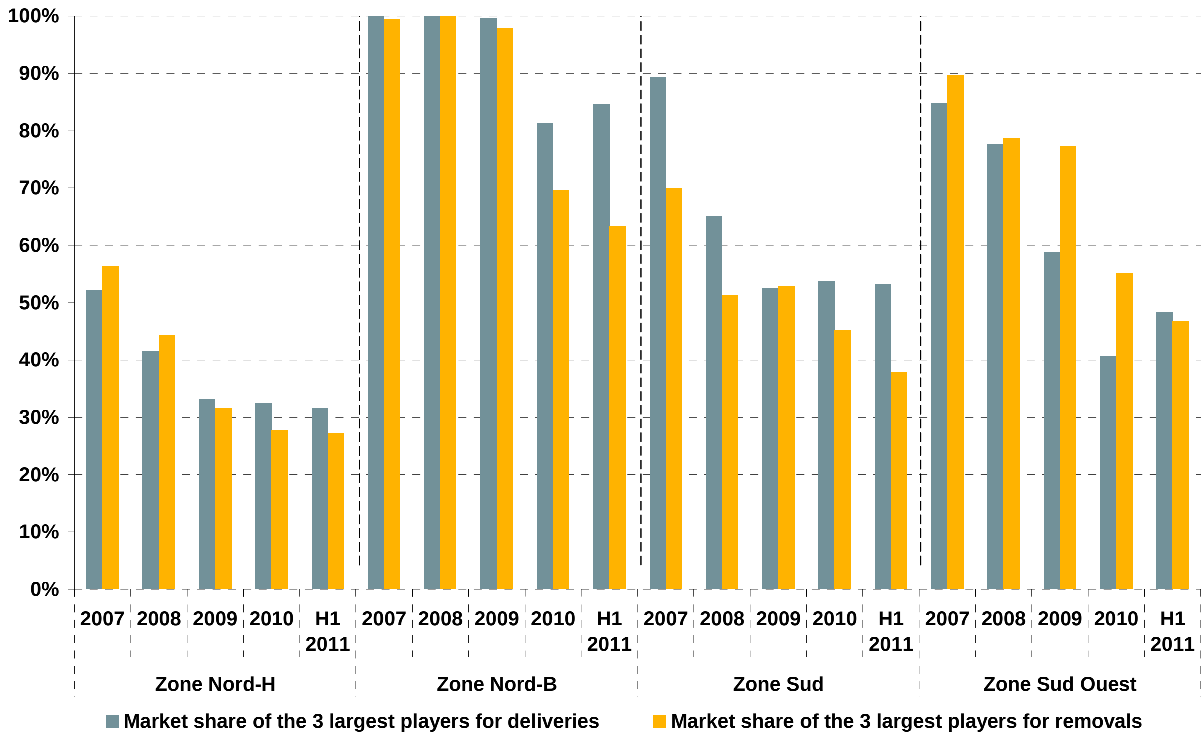
d. For purchase on the term contracts market



Source: Brokers, Powernext - Analysis: CRE

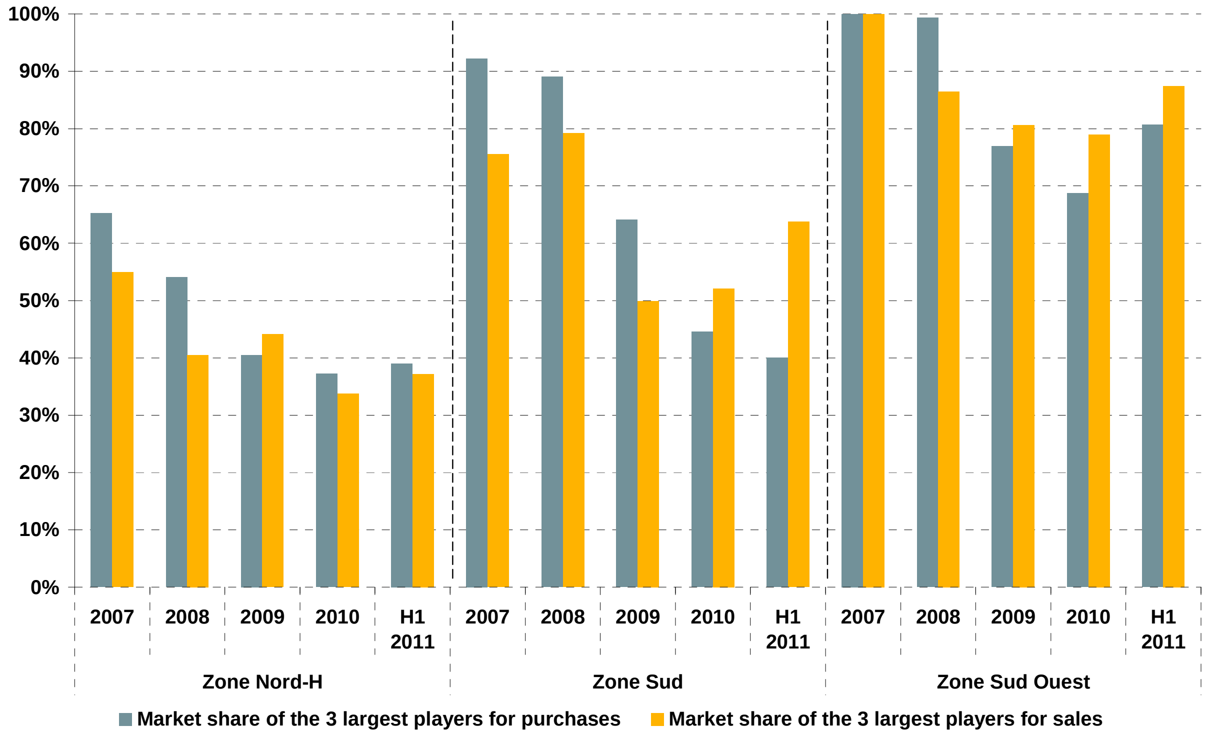
Figure 72: Combined market share of the three biggest players by PEG

a. Removals and deliveries to PEG hubs



Source: GRTgaz, TIGF - Analysis: CRE

b. For purchase and for sale



Source: Brokers, Powernext - Analysis: CRE

2. Gas prices

Gas prices in Europe experienced a largely upward trend during 2010 and the first half of 2011, after seeing a sharp fall in 2009. The lack of correlation between wholesale market prices and long-term contract prices indexed to oil, which saw light in 2009, continued throughout 2010 and into 2011. The extent of this disparity was variable: after reaching its peak in the first quarter of 2010, it decreased initially at the end of 2010. It then increased again in the first half of 2011, but did not reach the maximum levels seen previously.

The changes in gas prices observed since the beginning of 2010 can be linked to various factors that have had an impact on gas demand, in a context that remains oriented towards a structural surplus of capacity associated with the arrival of American unconventional gases and additional liquefaction capacity:

- the recovery of economic activity in relation to 2009 levels;
- the economic factor associated with the climate;
- in the first half of 2011, the market’s anticipation of renewed demand after Fukushima, and the volatility associated with geopolitical events.

2.1. Wholesale gas prices firm up in France during 2010 and stabilise in the first half of 2011

The day-ahead prices for the PEG Nord increased noticeably during the course of 2010, averaging €17.6/MWh compared with €12.6/MWh in 2009 (see Figure 73), for the reasons mentioned above.

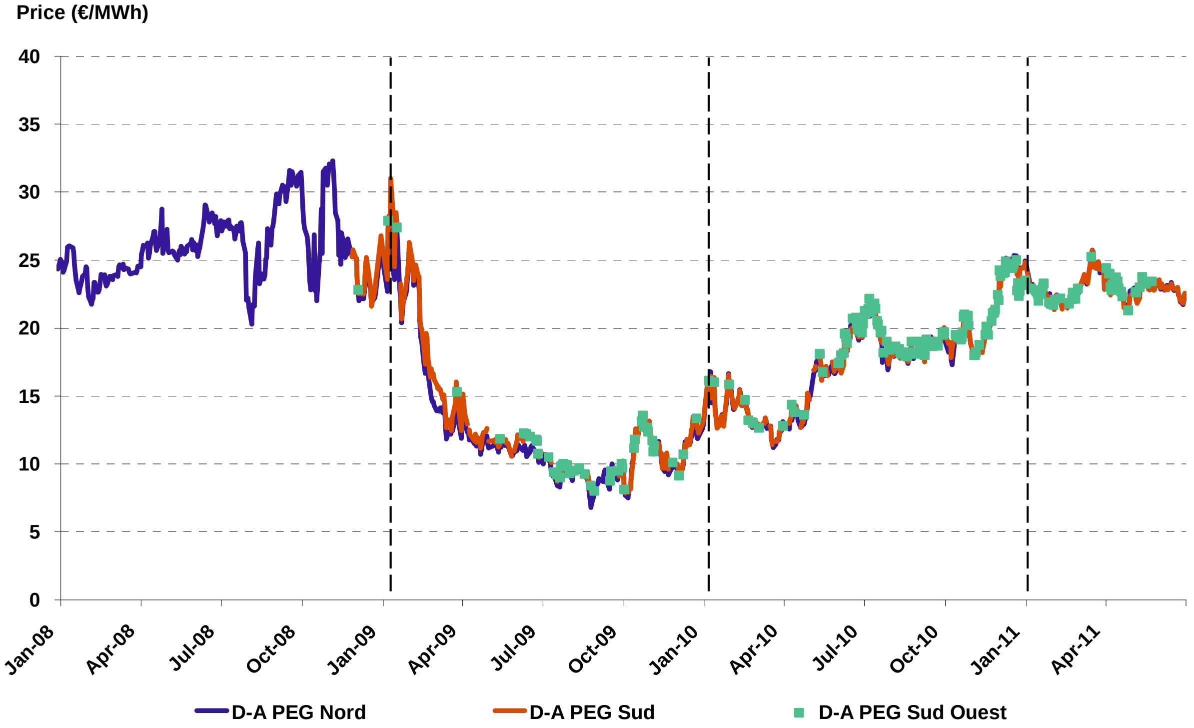
A largely upward trend was observed in 2010, with peaks of volatility mainly attributable to the climatic events of that year. In the first half of 2011, the day-ahead prices for the PEG Nord saw an increase of almost 51% compared with the first half of 2010, and an average of €22.9/MWh compared with €15.16/MWh during the same period the previous year, reaching levels comparable to those at the end of 2010. The volatility of spot prices during this period can be associated with the climatic events and the international context.

The term prices were sustained for the same reasons as the spot market prices, and also as a result of the rise in oil and petroleum products prices (see Figure 73). The M+1 product increased by 39% in 2010, showing an average price of €17.3/MWh compared with €12.4/MWh in 2009. For the Season product segment, the average price listed was €18.4/MWh in 2010 compared with €16.7/MWh in the previous year, representing an increase of 10%. The rise in these prices was more evident at the beginning of the gas year, due to the high demand on the S+1 inherent to arbitrage by the players involved.

In the first half of 2011, the M+1 and S+1 products reached €23.0/MWh and €25.2/MWh respectively, compared with €15.1/MWh and €16.2/MWh during the same period in 2010.

Figure 73: Price changes on the French market (based on daily values)

a. Day-ahead price



Sources: Argus, Heren, Powernext – Analysis: CRE

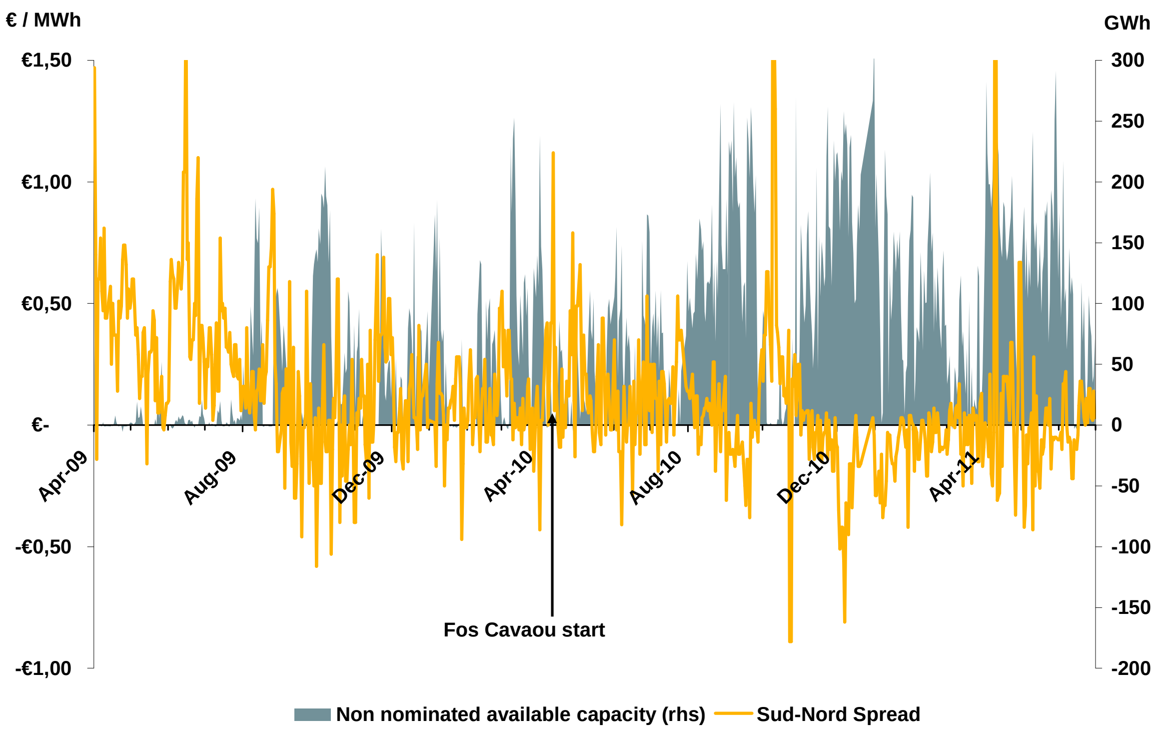
b. Term prices for the PEG Nord

Sources: Argus, Heren, Powernext – Analysis: CRE

2.2. Better spot price convergence between PEG Nord and PEG Sud since the Fos Cavaou LNG terminal began operation

The convergence of spot prices between the PEG Nord and PEG Sud entered a new phase during the course of 2010. After the Fos Cavaou LNG terminal went into operation, use of the North to South link was seen to decrease (see Figure 74) and better convergence was observed between North-South prices. The average South-North spread on the market was €0.04/MWh between 1 April 2010 and 30 June 2011, compared with €0.2/MWh between 1 April 2009 and 31 March 2010 (see Figure 74), which was confirmed by the OTC price index analysis. However, the prices for the PEG Nord and PEG Sud were not systematically the same when the capacity between the zones was not completely used. Situations of this kind should be resolved by implementing a market coupling mechanism (see Box 7).

Figure 74: PEG Nord - PEG Sud spread and unused North to South capacity



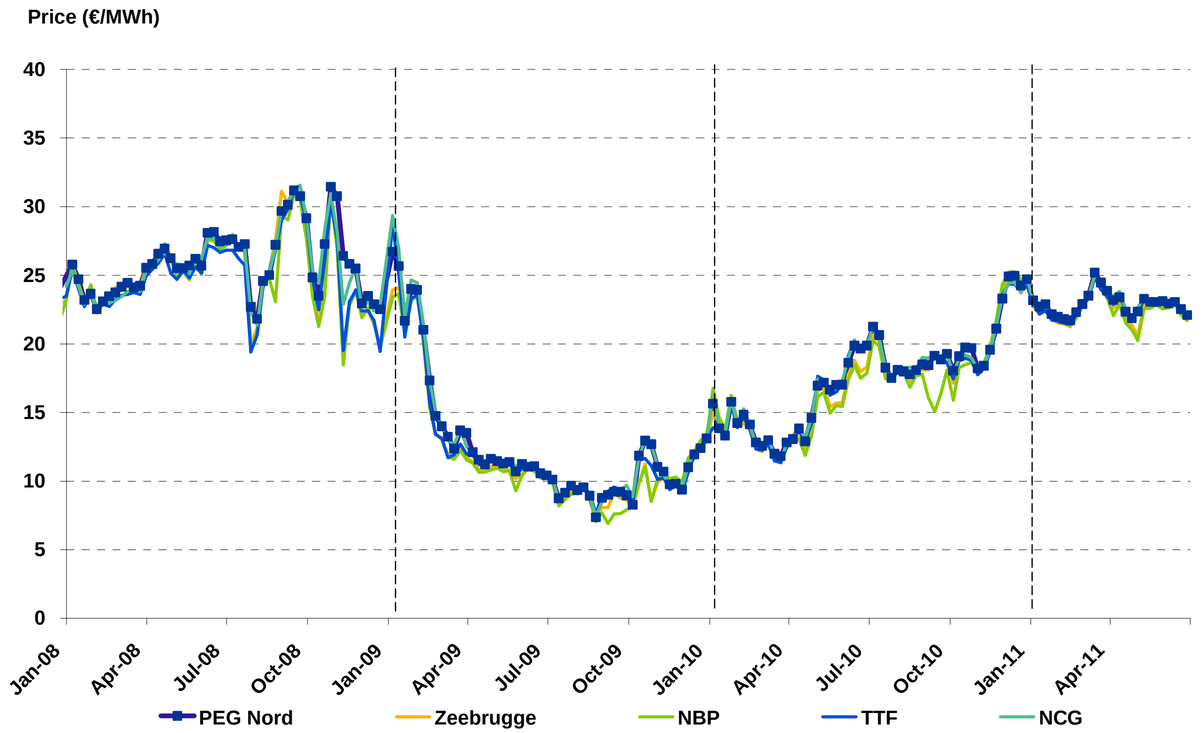
Sources: GRTgaz, Powernext – Analysis: CRE

2.3. Significant price rises on the European spot and term contracts markets with strong price convergence between France's PEG Nord, Germany's NCG and the Netherlands' TTF hubs

Similar price changes were seen across the European marketplaces (see Figure 75), all of which were influenced by the supply and demand factors mentioned previously.

Prices on the NBP dropped significantly during the third quarter due to the Interconnector closing down for maintenance. The brief stop on exports to the continent (via Belgium) therefore created an excess supply available to the UK during a period when market demand was relatively stable.

Figure 75: Day-ahead prices for France – Europe (weekly averages)

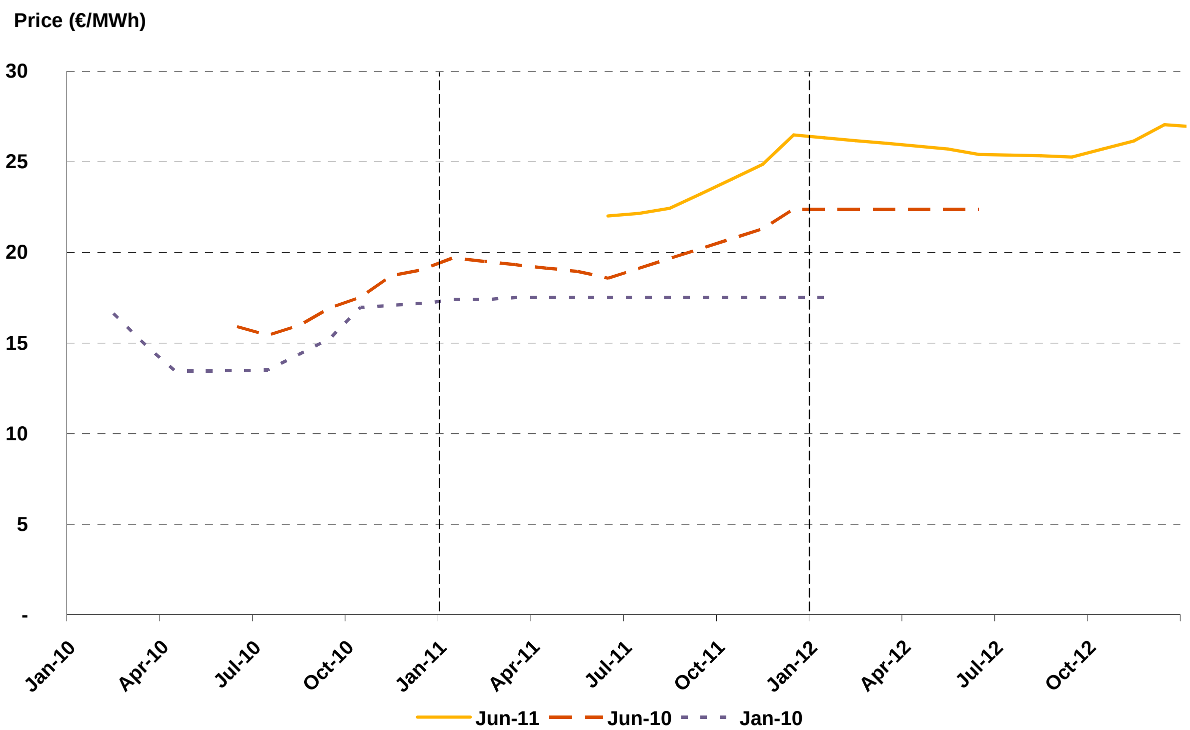


Sources: Argus, Heren, Powernext - Analysis: CRE

In line with the spot market, prices on the term contracts markets saw an upward trend during 2010 and the first half of 2011.

The term prices curve (see Figure 76) illustrates high price levels ahead for all term contracts products, and for the longest time scales.

Figure 76: Term prices curve for Zeebrugge

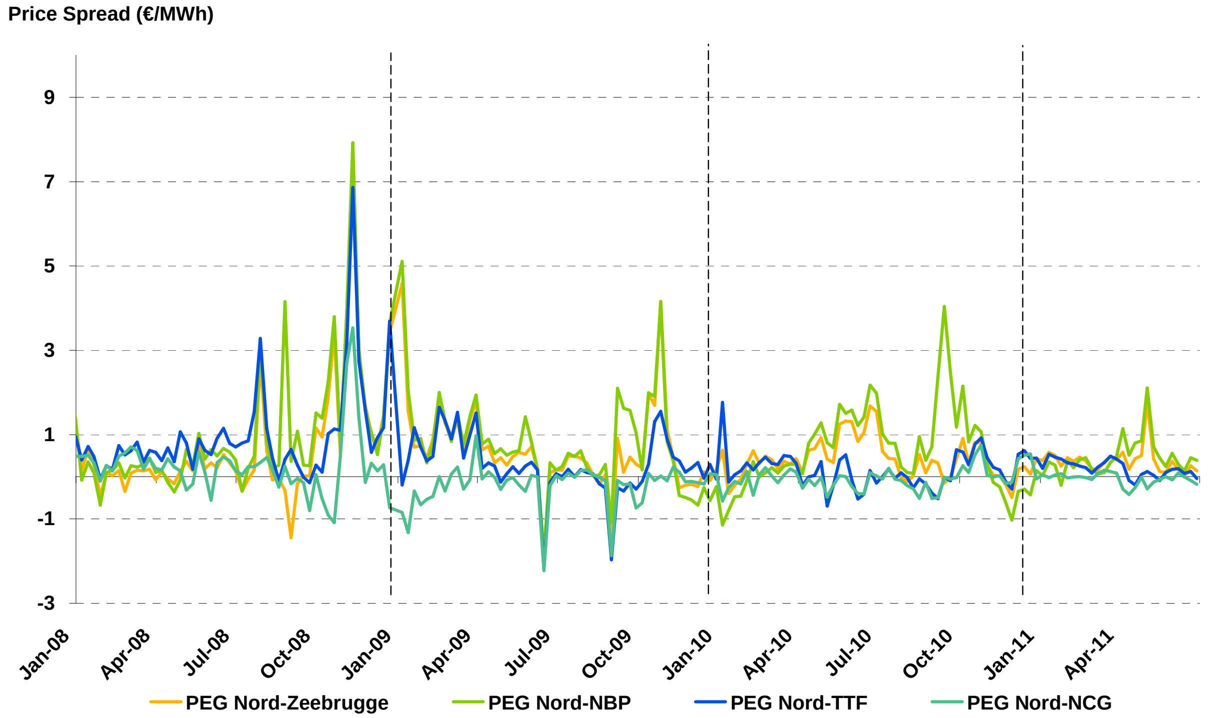


Sources: Argus, Heren, Powernext - Analysis: CRE

The day-ahead price spreads in 2010 were narrower than in the previous year (see Figure 77 and Table 14). The greatest price difference was between the PEG Nord and the NBP (€0.63/MWh), while the spread between PEG Nord and NCG prices was negligible (-€0.04/MWh). In 2010, the PEG Nord's day-ahead prices also came considerably close to the TTF's prices, and this trend persisted during the first half of 2011.

On the term contracts market, in 2010 the spread between PEG Nord and NBP prices grew wider than in 2009, but this divergence tended to narrow during the first half of 2011. The spread between French and Belgian market prices remained stable between 2009 and 2010 and decreased in the first half of 2011 (see Table 14). As in the case of the day-ahead prices in 2010, the convergence of term prices between the PEG Nord and other European hubs was more significant with NCG prices than with TTF prices. In the first half of 2011, the price spreads between the French, German and Dutch markets narrowed.

Figure 77: Day-ahead price spreads for France – Europe (weekly averages)



Sources: Argus, Heren, Powernext - Analysis: CRE

Table 14: Spreads

a. On spot prices (day-ahead)

Average spread in €/MWh	*2008*	*2009*	*2010*	*H1 2011*
Zeebrugge (B)	0.69	0.58	0.42	0.38
NBP (GB)	0.95	0.71	0.63	0.43
TTF (NL)	0.93	0.28	0.17	0.21
NCG (Ger)	0.27	-0.19	-0.04	-0.04

b. On term prices (month-ahead)

Average spread in €/MWh	*2008*	*2009*	*2010*	*H1 2011*
Zeebrugge (B)	0.20	0.49	0.48	0.29
NBP (GB)	0.44	0.52	0.70	0.42
TTF (NL)	0.72	0.31	0.14	0.13
NCG (Ger)	0.20	-0.15	-0.09	-0.02

Note: average daily spread (PEG Nord price – foreign price)

Sources: Argus, Heren, Powernext - Analysis: CRE

2.4. Gas market prices and long-term contract prices still fail to reconnect but differences are less pronounced than in 2009

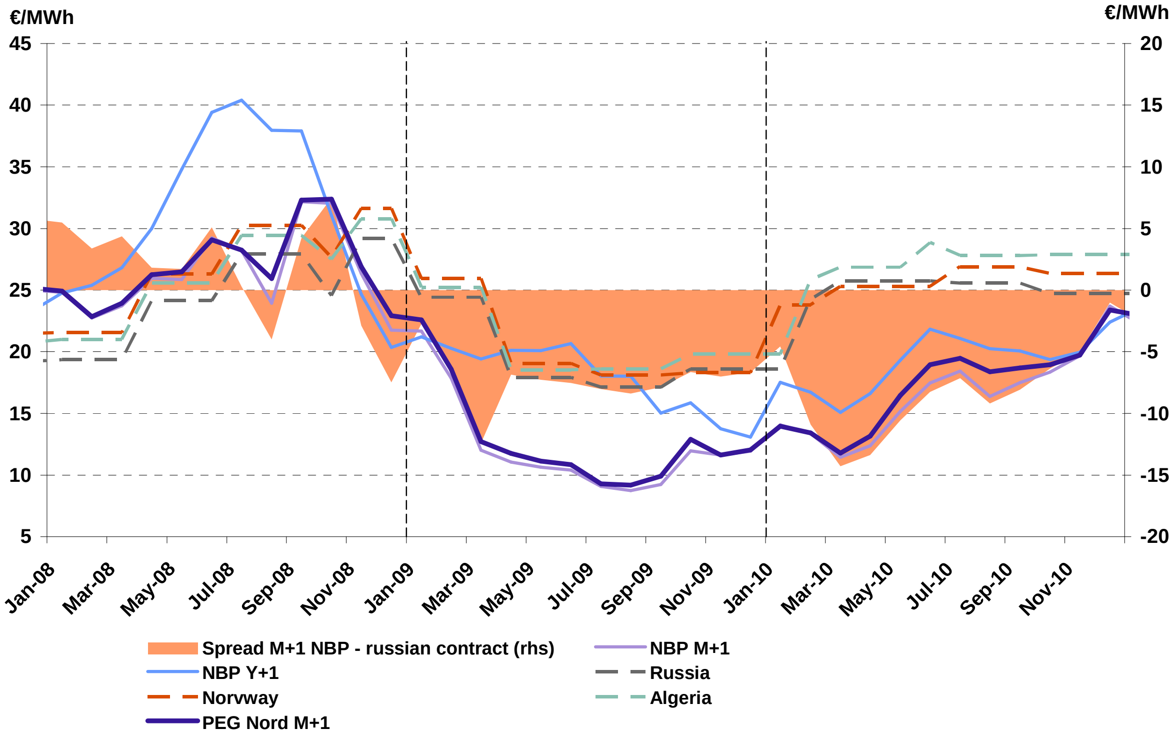
During 2010, gas wholesale market prices remained lower than long-term procurement contract prices indexed to oil and petroleum products, given the large quantity of gas (see Figure 78). However, the difference between gas market prices and long-term prices indexed to oil reduced significantly in July and December 2010, and in March 2011, due to the rise in gas prices on the term contracts markets.

The spread widened again at the end of the first half of 2011, due to the high increase in oil prices and, at the same time, a fall in the term prices on the gas markets.

The lack of correlation between market gas prices and contract gas prices indexed to the price of oil created a misunderstanding among consumers, which fed the debate on greater market indexing. CRE has submitted a report to the Energy Minister on this matter.

Figure 78: Gas prices (market indexes and prices of oil and its derivatives)

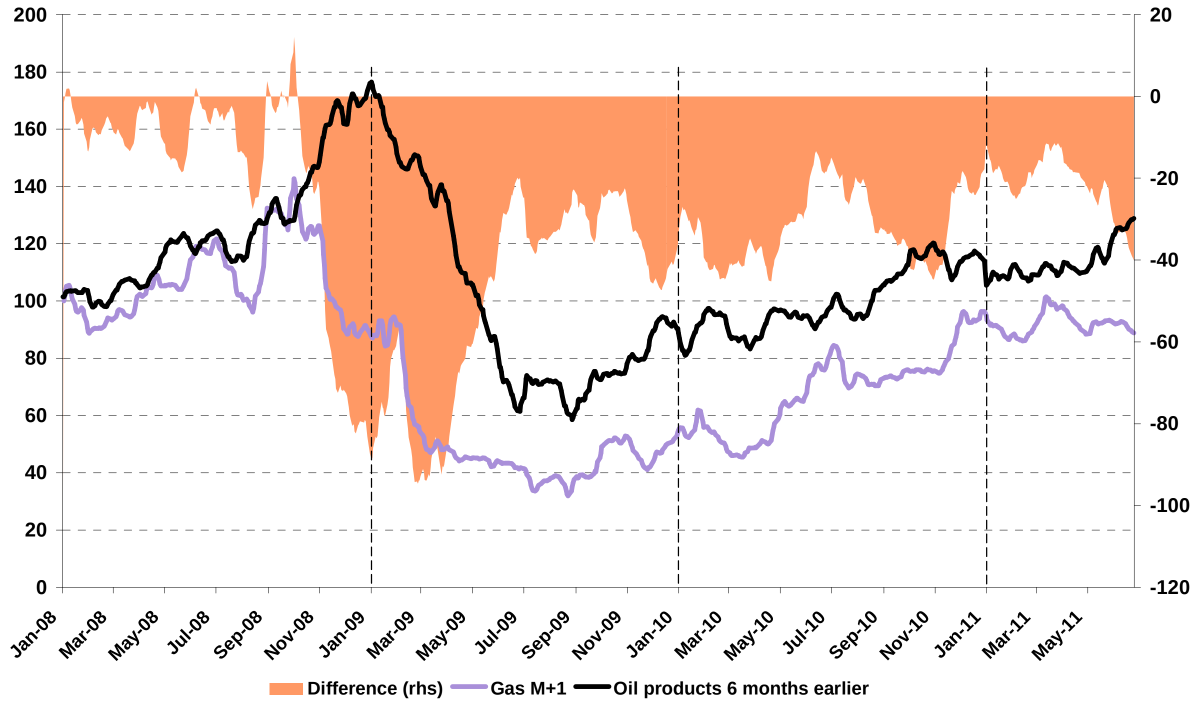
a. Compared with a reference index[30]



Source: Heren - Analysis: CRE

[30] This index ceased publication in January 2011.

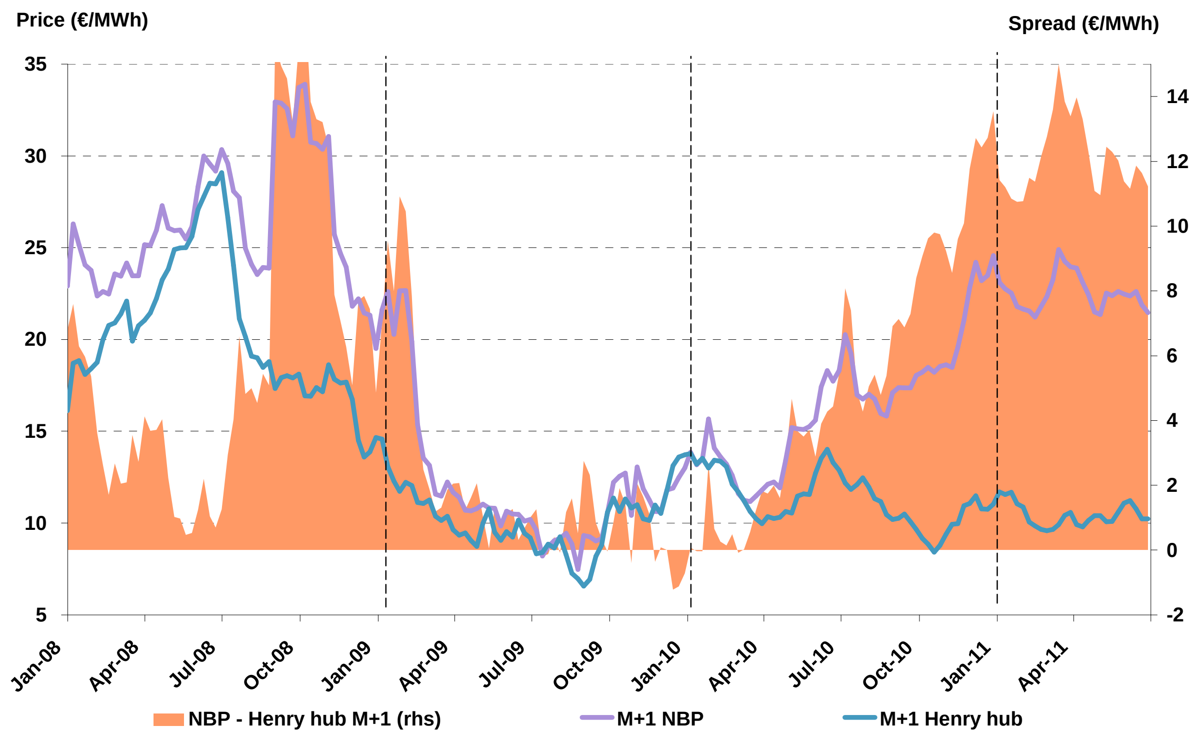
b. Compared with a composite index of petroleum product prices 6 months earlier



Sources: Heren, Bloomberg - Analysis: CRE

The development of American unconventional gas production has allowed Henry Hub prices to fall significantly and their fluctuation to stabilise, while European regional market prices did nothing but rise in 2010 and during the first half of 2011. Price differences between the NBP and the Henry Hub gradually increased, reaching €13.55/MWh in December 2010 and €15/MWh in March 2011 (see Figure 79).

Figure 79: M+1 prices in the United Kingdom and the United States



Sources: Heren, Bloomberg - Analysis: CRE

Brent prices increased significantly during 2010 by an average of 36% (€60.6/barrel) compared with 2009 (€44.5/barrel), due to rising consumption in both OECD member countries and emerging countries (essentially in South America and Asia). At the end of 2010, the depreciation of the dollar in relation to the euro withstood the price increase, which accelerated following the emergence of geopolitical tensions in North Africa and the Middle East from January 2011. As a large number of gas-producing countries are in this part of the world, the spectre of a reduced supply led to a significant increase in prices, which peaked at €87.82/barrel in April 2011.

Figure 80: Changes in Brent prices

Source: Bloomberg - Analysis: CRE

The level of volatility calculated from the gas market and petroleum product prices is shown in Table 15 and Figure 81.

Table 15: Annual volatility of market and petroleum product prices (based on daily values)

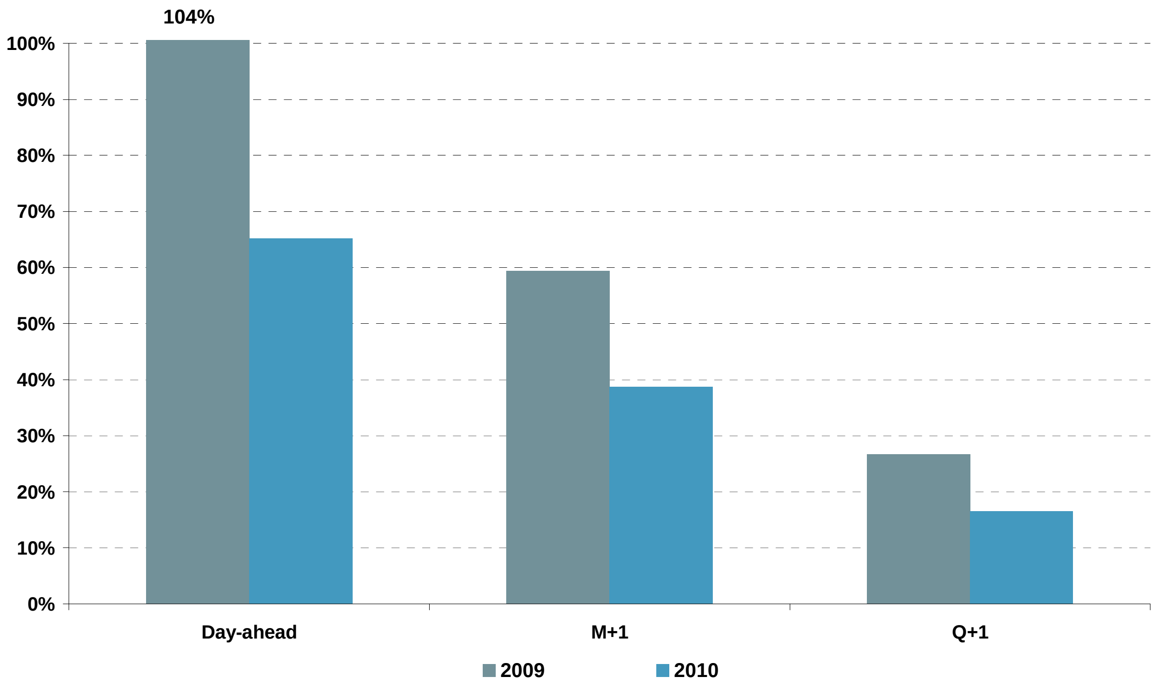
	Gas market prices				Petroleum product prices		
	PEG Nord	NBP	Zeebrugge	TTF	Brent	FOD	FOL
2008	64%	105%	96%	77%	52%	37%	65%
2009	81%	125%	101%	95%	41%	46%	52%
2010	56%	80%	76%	64%	24%	26%	26%
2011 YTD	34%	38%	38%	34%	25%	22%	23%
2008-2011	64%	98%	86%	75%	39%	35%	47%

Note: day-ahead PEG Nord, NBP, Zeebrugge, TTF - Brent, FOD and FOL in Euros

Sources: Argus, Heren, Bloomberg, DGEC - Analysis: CRE

The expected link between volatility and maturity is illustrated in Figure 81.

Figure 81: Annualised volatility history between 2009 and 2010



Source: Heren - Analysis: CRE

3. Gas infrastructures

During the period spanning 2010 and the first half of 2011, access to the gas infrastructures was seen to increase as the number of transmission network users steadily grew (see Table 16). This was particularly due to improved access to the PEG hubs for industrial customers, who have been able to purchase gas on the wholesale markets on their own behalf since 2009.

In terms of access to the three LNG terminals, the number of customers significantly increased due to the gradual commissioning of the Fos Cavaou terminal during the course of 2010. It should also be noted that the number of continuous service customers, unloading at least 10 ships per year at a terminal, is increasing. The number of continuous service shippers stands at five in 2011, compared with only one in 2010. This can be explained by the application of the commitments made by GDF Suez to the European Commission, which allowed capacity release at the Fos Cavaou and Montoir de Bretagne LNG terminals.

With regard to underground storage facilities, a reduction in the number of users was observed on 1 July 2011 compared with July 2010. This can be explained by a fall in the use of storage compared with the other sources of flexibility available to shippers. The weakness of the winter/summer price spreads on the wholesale markets largely explains the lower appeal of storage facilities. This trend is illustrated by the falling levels of stored gas in the last two years (see Figure 82).

More generally, improved access to the gas infrastructures contributes highly to the gradual development of competition and liquidity on the wholesale markets in France.

Table 16: Number of users with reserved infrastructure capacity

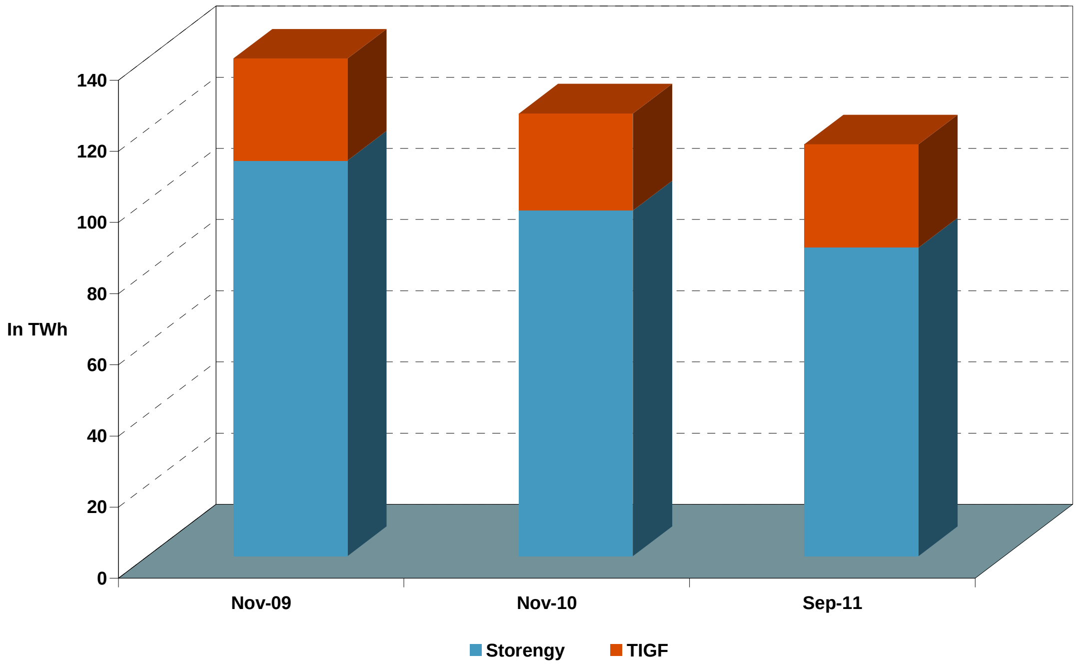
	1 Jan 2009	*1 Jan 2010*	*1 Jan 2011*	*1 July 2011*
GRTgaz	50	57	76	83
TIGF (transmission system)	19	19	23	23

	1 April 2009	*1 April 2010*	*1 July 2011*
Storengy	23	30	24
TIGF (storage)	8	10	11

	2009	*2010*	*2011*
Montoir terminal	5	6	5
Fos Tonkin terminal	2	2	2
Fos Cavaou terminal	-	2	3

Sources: GRTgaz, TIGF, Storengy, Elengy

Figure 82: Levels of stored gas in France



Sources: TIGF, Storengy

During the next few years, several factors should enable the continuing development of markets in France:

- **Introduction of new mechanisms:** since late 2010, work has been carried out on a market coupling mechanism under the Concertation Gaz consultation system. The aim of this mechanism is to improve access conditions and the operation of the gas market in the South zone before the GRTgaz network's North and South zones are merged, a project that could be implemented by 2015. Experiments with this mechanism began on 1 July 2011 and will continue until 31 March 2012. Initial feedback on the mechanism is expected in autumn 2011.

- **Development of infrastructures:** investment decisions essential to the development of the French gas market were taken in 2011. On 19 April 2011, CRE approved GRTgaz's €484m ERIDAN project to loop the Rhône pipeline, which will improve access to the South zone by 2015-16. This investment is essential to the prospect of merging the North and South zones on the GRTgaz network and creating a north-south corridor, linking the south of France and the Iberian Peninsula to north-west Europe.

Furthermore, on 27 June 2011, EDF and its partners Total and Fluxys took the decision to build a new LNG terminal at Dunkirk, with a regasification capacity of 13 bcm per year. This is expected to start operation in late 2015. CRE has authorised investments in pipelines to transport the imported gas from Dunkirk across the country and to strengthen the core network. The total investment will be close to €1.2bn[31], almost equivalent to the cost of the terminal. Connecting this terminal to GRTgaz's transmission network could also create firm physical capacity for transporting gas from France to Belgium by establishing a new interconnection point at Veurne. Moreover, the sponsors of the project "Fos Faster", who are planning to build a new LNG terminal in the district of Fos sur Mer, took the decision to pursue their project in mid-2011 following the public debate at the end of 2010.

With regard to the terminals already in operation, in 2011 Elengy launched a call to tender to extend the life of the Fos Tonkin terminal, and is planning to launch a second call to increase the regasification capacity at the Montoir de Bretagne terminal.

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[31] The investment budget for connecting the Dunkirk terminal is currently undergoing a detailed audit.

Finally, a new consultative committee, bringing shippers and terminal operators together, was set up following deliberations by CRE on 15 March 2011, with the aim of improving access conditions at the regulated LNG terminals (see Box 6).

- **Standardisation of rules for accessing the transmission networks:** the third Gas Directive adopted in 2009 includes long-term plans to standardise the rules for accessing the gas transmission networks at European level. These new rules are being defined through a new preparation process, involving the new Agency for the Cooperation of Energy Regulators (ACER), the gas infrastructure operators and the European Commission. Several areas will be standardised gradually in this way, including the rules for allocating capacity or balancing.

Box 6: LNG consultative committee

Creation of an LNG consultative committee for the regulated LNG terminals

On the strength of the positive feedback on the Concertation Gaz system, which was created in September 2008 to enable consultation on transmission network access, and following discussions on 15 March 2011, CRE asked Elengy and STMFC to establish a similar mechanism in the domain of liquefied natural gas. With a view to increasing the number of shippers at the three regulated terminals in France, this consultative committee intends to bring shippers and infrastructure operators together, with the aim of adapting and changing the conditions for accessing these infrastructures.

The first meeting of the plenary committee, responsible for steering the project and defining the work programme, was held in May 2011. The first working groups were organised in June 2011 and have been meeting on a monthly basis since September 2011.

In the short term, the committee’s work programme is planning to improve the transmission sharing rules for shippers benefiting from continuous operation. In the medium term, the committee will assess whether or not it is appropriate to change the services (continuous, uniform or spot) offered by the regulated terminals, in accordance with the tariff decree of 20 October 2009.

3.1. Satisfactory use of the infrastructures in the North zone

Entry capacity in the North zone continues to be held by a limited number of players, but the application of the commitments made by GDF SUEZ has enabled the situation to improve. Entry capacity is available for reservation by third parties, particularly at Taisnières H (interconnection with Belgium) and Obergailbach (interconnection with Germany).

The entry capacity in the North zone continues to be held by a limited number of players. However, the release of French entry capacity by GDF Suez from 2010, under the group's commitments to the European Commission, has enabled the situation to improve considerably. New shippers have reserved long-term entry capacity mainly in the North zone, at Obergailbach, Taisnières H and the Montoir de Bretagne LNG terminal. As a result, the HHI index on capacity ownership at the main land entry points in the North zone was seen to fall between the first half of 2010 and the first half of 2011 (see Figure 83).

Thus in March 2010, 80 GWh per day of long-term firm entry capacity at the Obergailbach entry point, and 10GWh per day at Taisnières H, were marketed for use from 1 October 2010. This capacity was offered along with upstream capacity to guarantee a link with adjacent marketplaces (the NCG in Germany or the NBP in the UK) or to use routes for procuring gas from Russia under long-term contracts.

Although not all of the released capacity has been issued for long-term use at the land entry points, a large part has found a buyer (see the 2009-2010 Market Monitoring Report, Box 3, Page 83).

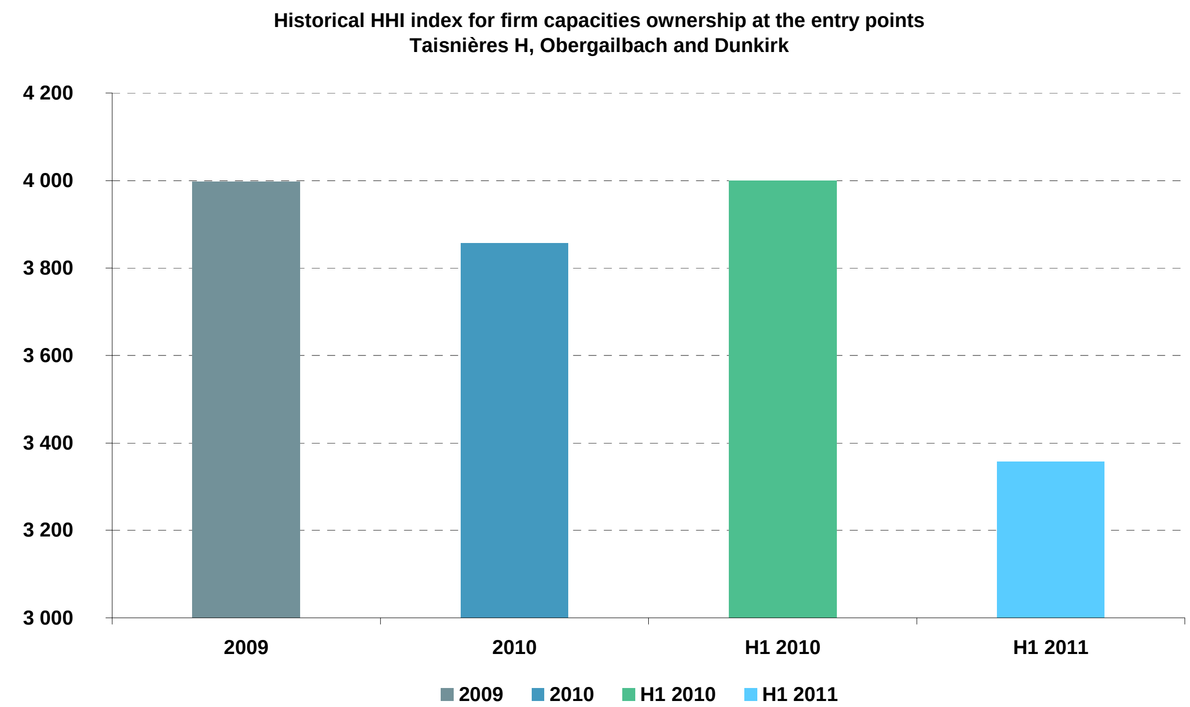
It should be noted that a firm capacity of more than 100 GWh per day is still available at the Taisnières H entry point until December 2013, after which 50 GWh per day of additional capacity will be introduced as a result of the Belgium-France Open Season, which ended in 2008. At the Obergailbach entry point, not all of the capacity released under the agreements has been reserved. To date, more than 150 GWh per day of firm capacity remain available in the short and long term.

All of the firm capacity at the Dunkirk entry point has been reserved, as a result of which 15 GWh per day of additional firm capacity at short notice (of a period not exceeding one year) have been marketed for use from 1 October 2011. Some of this additional capacity remains available. The "capacity release" mechanism used for long-term capacity allows shippers to gain access to capacity when they need it.

At the Montoir de Bretagne LNG terminal, two batches of 1 bcm per year for up to 25 years were offered from 1 October 2010 and 1 October 2011 respectively. By the end of the marketing process, one batch of 1 bcm per year was allocated (see the 2009-2010 Market Monitoring Report, Box 3, Page 83). The unallocated quantities were offered again for reservation on a "first come, first served" basis, and some were reserved by new shippers.

It should also be noted that there was an increase in the number of "uniform" and "spot" type unloading operations at the Montoir de Bretagne terminal in 2010 compared with 2009. Four "spot" type unloading operations were registered in 2010, compared with none in 2009. However, the number of "uniform" unloading operations remained stable at 10, the same figure as in 2009. This reflects the growing appeal of the PEG Nord, in a context where LNG prices were lower than long-term supply contract prices.

Figure 83: Capacity ownership at the North zone's entry points



Source: GRTgaz

Planned infrastructure development in the North zone

A certain number of projects are helping to increase entry capacity in GRTgaz's North zone:

- Following the Belgium-France Open Season, which ended in 2008, capacity at the Taisnières interconnection point will increase by 50 GWh per day in December 2013.
- With regard to the import of liquefied natural gas, on 27 June 2011, EDF and its partners Total and Fluxys took the decision to build a new LNG terminal at Dunkirk, with a regasification capacity of 13 bcm per year. This is expected to start operation in late 2015.

  During discussions on 12 July 2011, CRE established the conditions for connecting this new terminal to GRTgaz's transmission network, subject to confirmation following an audit of the technical and financial information provided by GRTgaz. The investments to be made will particularly involve the major Arc de Dierrey core network reinforcement project in the north-east of France.
- In April 2011, Elengy announced a future market consultation on the possibility of increasing the regasification capacity at its Montoir de Bretagne terminal to 12.5 or 16.5 bcm per year.

– Furthermore, to enable better integration between the Belgian and French markets, an Open Season for capacity from France to Belgium was launched by GRTgaz and Fluxys (non-binding phase from May to August 2010). It suggested the creation of a new interconnection point that would allow physical flows of gas from France to Belgium, as only virtual counter flows at Taisnières are currently possible. This new interconnection point would also enable physical flows from Belgium, particularly in the event of a supply shortage, and would therefore help to bolster supply security. The binding phase for this call to tender is anticipated in late 2011 or early 2012.

3.2. Improved access to infrastructures in the south of France

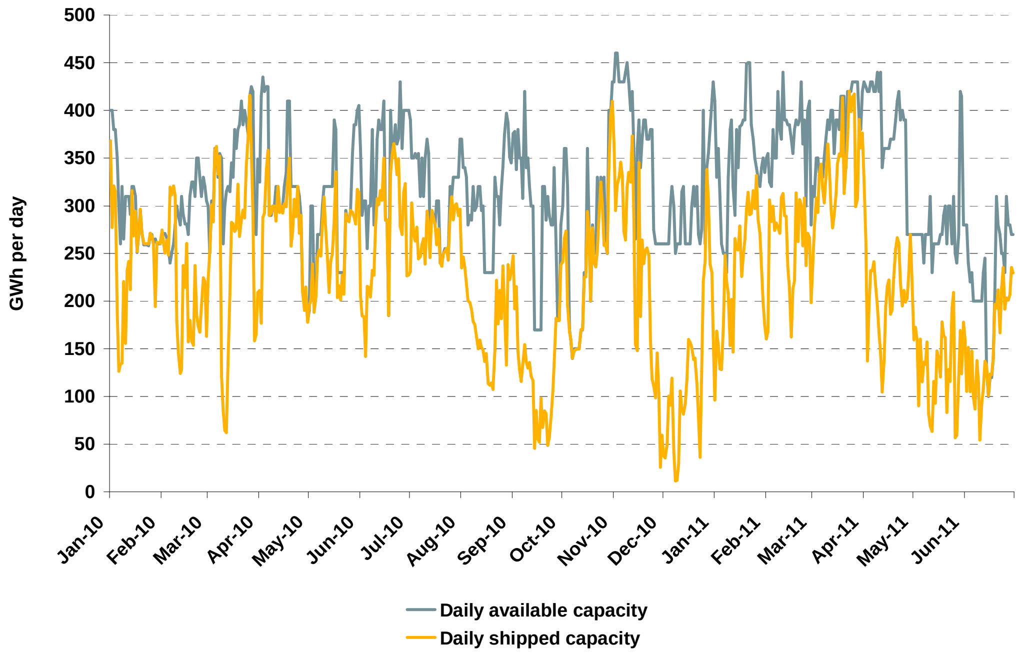
The new Fos Cavaou terminal facilitates access to the south of France

Access to the south of France was marked in 2010 by the gradual commissioning of the Fos Cavaou terminal. A first stage began on 1 April 2010, when the terminal went into commercial operation with prefectural authorisation for reduced emission (approximately 30% of its capacity); this will be followed by a second stage allowing emission at full capacity on 1 November 2010.

The arrival of large quantities of gas in the south of France via the Fos Cavaou terminal led to a significant reduction in the use of capacity on the interconnection between GRTgaz's North and South zones, which had previously been the main supply source for the south of France. The usage rate fell from 81% in the first half of 2010 to 66% in the first half of 2011 (see Figure 84). Thus for the first time since the creation of the North-South link in 2009, some of the firm capacity from 1 April 2011 in the North-South direction was not reserved by shippers.

In addition, two batches of 1 bcm per year were offered from 1 January 2011 at the Fos Cavaou terminal under the commitments made by GDF Suez. After this capacity was marketed in 2010, one batch was reserved, therefore increasing the number of terminal users and shippers likely to supply gas to the south of France.

Figure 84: Use of the North-South link



Source: GRTgaz

Experiments with a market coupling mechanism: an intermediate stage before merging GRTgaz's North and South zones

Some of the unsold firm capacity (10 GWh per day) at GRTgaz's North-South link, for use from 1 April 2011, has been used to conduct an experiment with a market coupling mechanism between GRTgaz's PEG Nord and PEG Sud.

The aim of this mechanism is to bring the market prices closer together and increase liquidity on Powernext Gas Spot for the PEG Sud, which was lower than that for the PEG Nord (see paragraph 2.2). This experiment promotes the gradual convergence of the wholesale markets under the prospect of a future merger of these zones, which could take place by 2015 (see Box 7).

Box 7: Market coupling

An experiment has been launched with a market coupling mechanism between GRTgaz's North and South zones.

With the short-term aim of improving access conditions and gas market operation in GRTgaz's South zone, following discussions on 19 April 2011, CRE approved GRTgaz's proposal to experiment with a market coupling mechanism between the North and South zones of its network.

This experiment, initially expected to take place between July 2011 and March 2012, should optimise the use of North/South capacity based on market conditions, and increase liquidity at the North and South Gas Exchange Points (PEG Nord and PEG Sud) by partially linking up their order books (i.e. all purchase and sales orders). It should also strengthen price convergence between the PEG Nord and PEG Sud where possible or, in the event of a bottleneck, reveal the market value of the interconnection capacity.

In concrete terms, 10 GWh per day of firm transmission capacity on the North/South link, which had remained unsold after the various marketing campaigns, were allocated by GRTgaz to the coupling mechanism in both the North to South and South to North directions. This mechanism is based on a "PEG Sud – PEG Nord spread" type product, corresponding to a gas "swap" between the two hubs (gas is purchased in one zone and the same volume is sold in the other zone). GRTgaz intervenes on the Powernext Gas Spot Exchange in response to the requests made on the PEG Sud – PEG Nord spread product, enabling North-South link capacity to be allocated implicitly (with transactions covering the gas and the capacity at the same time). Initial results from the experiment reveal a significant reduction in the spread price between GRTgaz's North and South zones and increased liquidity in the South zone. Demand is predominantly for capacity in the North to South direction, and the allocation of 10 GWh per day to the coupling mechanism seems sufficient.

This experiment is part of the work in progress at European level on the target market model for gas, and promotes the gradual convergence of the wholesale markets for GRTgaz's North and South zones, under the prospect of a future merger of these zones, which could take place by 2015. In order to sustain the market coupling mechanism beyond 31 March 2012, a volume of 10 GWh per day of firm capacity for use from 1 April 2012 has not been sold, so that it can be allocated to the mechanism. In addition, all or part of the unsold capacity at the link between GRTgaz's two zones after the standard marketing process could be added to the 10 GWh per day already reserved for the period commencing 1 April 2012. Initial feedback expected in the autumn, together with work carried out under the gas consultation system, will finally help to set the level of capacity dedicated to the market coupling mechanism.

Planned infrastructure development in the south of France

Several development projects should help to improve the supply conditions in the south of France considerably:

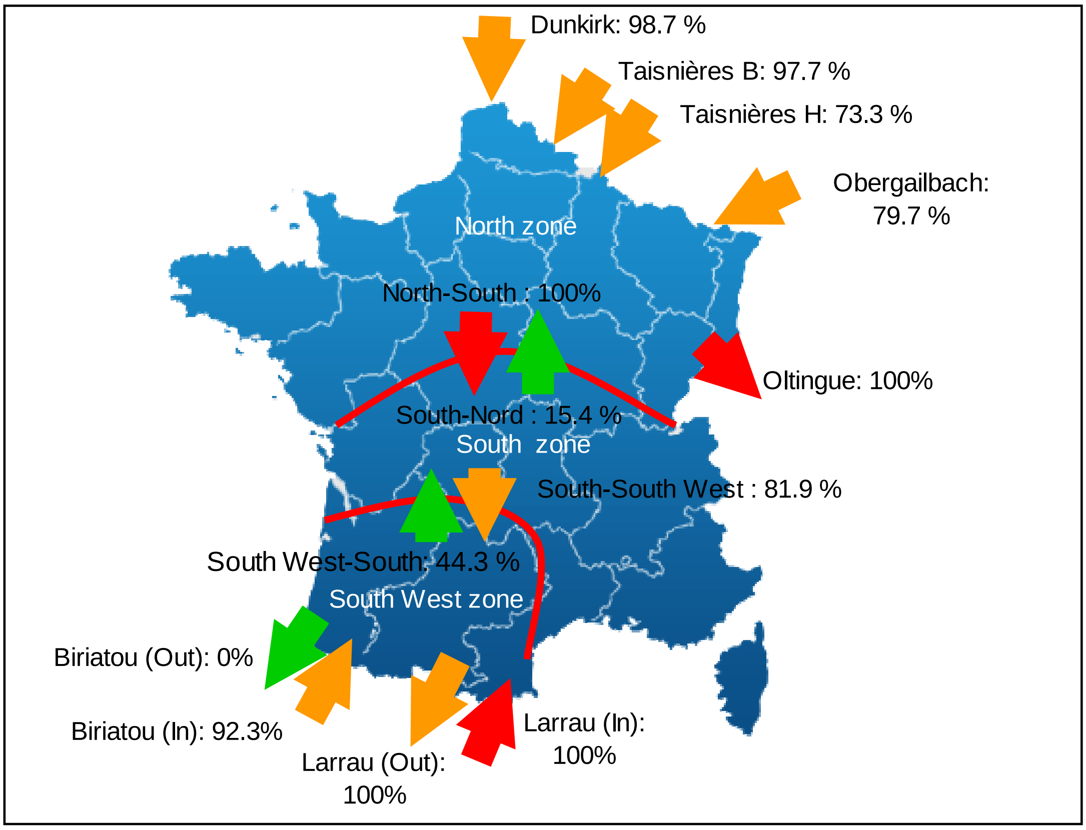
- The introduction of new interconnection capacity between Spain and France from 2013 and 2015, based on decisions following the two Open Seasons in 2009 and 2010, should enable gas to be transported to France from the Iberian Peninsula (Algerian gas or Spanish LNG). In summary, the entry capacity at Larrau will increase by 5.5 bcm per year in 2013, and at Biriatou by 2 bcm per year in 2015.
- Furthermore, in 2011 Elengy launched a call to tender with the aim of extending the operation of the Fos Tonkin terminal by 20 years beyond 2014. Elengy is considering various investment scenarios, which may involve providing up to 7 bcm per year of regasification capacity, depending on the needs expressed by the shippers. The binding phase is anticipated in autumn 2011.
- Finally, on 19 April 2011, CRE approved the investment proposed by GRTgaz under the ERIDAN project to doubling the Rhône pipeline. This will improve access to the South zone by 2015-16 through the creation of 120 GWh per day of entry capacity.

No physical congestion between the South and South-West zones

Although the supply to the south of France needs to see further improvements, the link between the South and South-West hubs is not restricted. It should be noted that the capacities are grouped together at this link and are sold in the form of trading desk sales coordinated between the two operators. Capacity at this link is available for reservation in the short and long term and in both directions.

Figure 85: Transmission capacity reservation

Subscribed firm capacity in relation to marketable capacity (June to December 2011)



Sources: GRTgaz, TIGF

4. Supplies and outlets of new entrants

4.1. A stable supply model for new entrants[32], with increased recourse to purchases at the Gas Exchange Points (PEG) in the first half of 2011

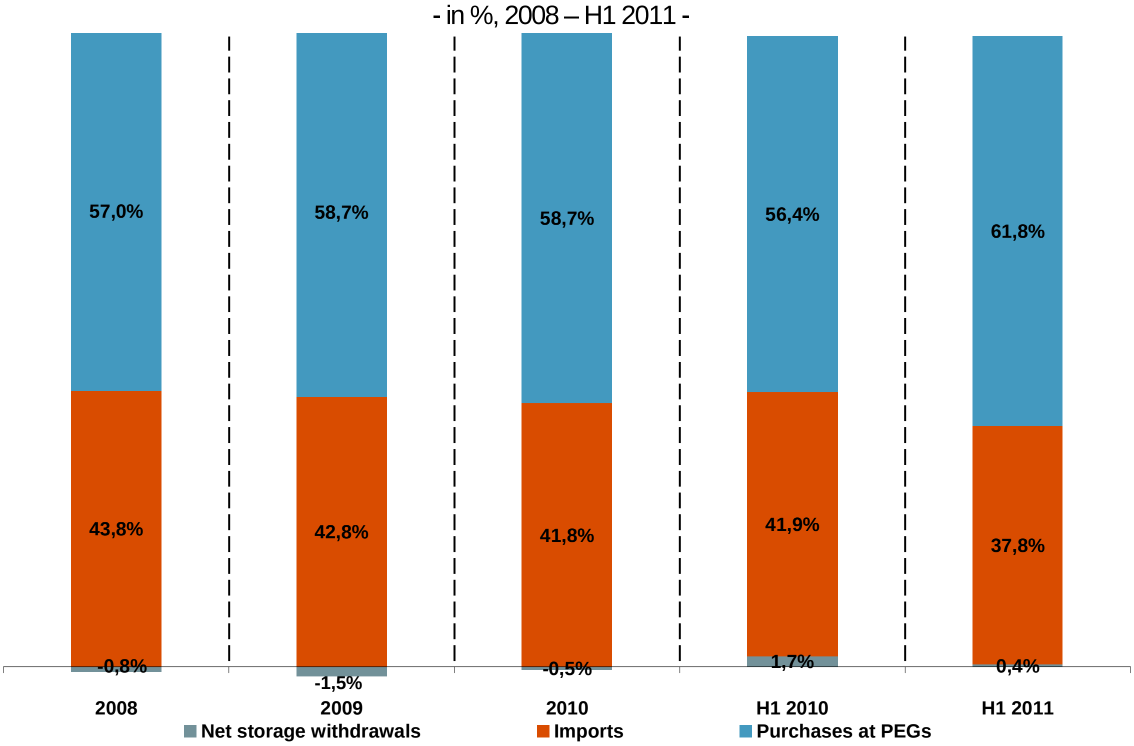
In 2010, the supply structure remained relatively stable compared with the previous year, in terms of purchases at the PEG hubs, while seeing a slight fall in imports (-1%) and less use of stored supplies.

However, the supply configuration changed in favour of purchases at the PEG hubs during the first half of 2011. These transactions increased by more than 5% compared with the first half of 2010, while imports decreased by almost 4%. It should be noted that since the Fos Cavaou terminal went into operation in April 2010, LNG imports for new entrants across all the terminals increased significantly during the first half of 2011, rising from 6% of the total of their supplies in the first half of 2010 to 11%. At the same time, imports via pipelines saw a slight fall as a consequence.

Compared with the traditional suppliers, the new entrants make more use of the PEG hubs to purchase their supplies. This particularly holds true for new entrants supplying end customers.

Figure 86: Supplies for new entrants in France by source

- in %, 2008 – H1 2011 -



Sources: GRTgaz, TIGF - Analysis: CRE

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32 Alternative suppliers or new entrants include all shippers that are not incumbent suppliers in France.

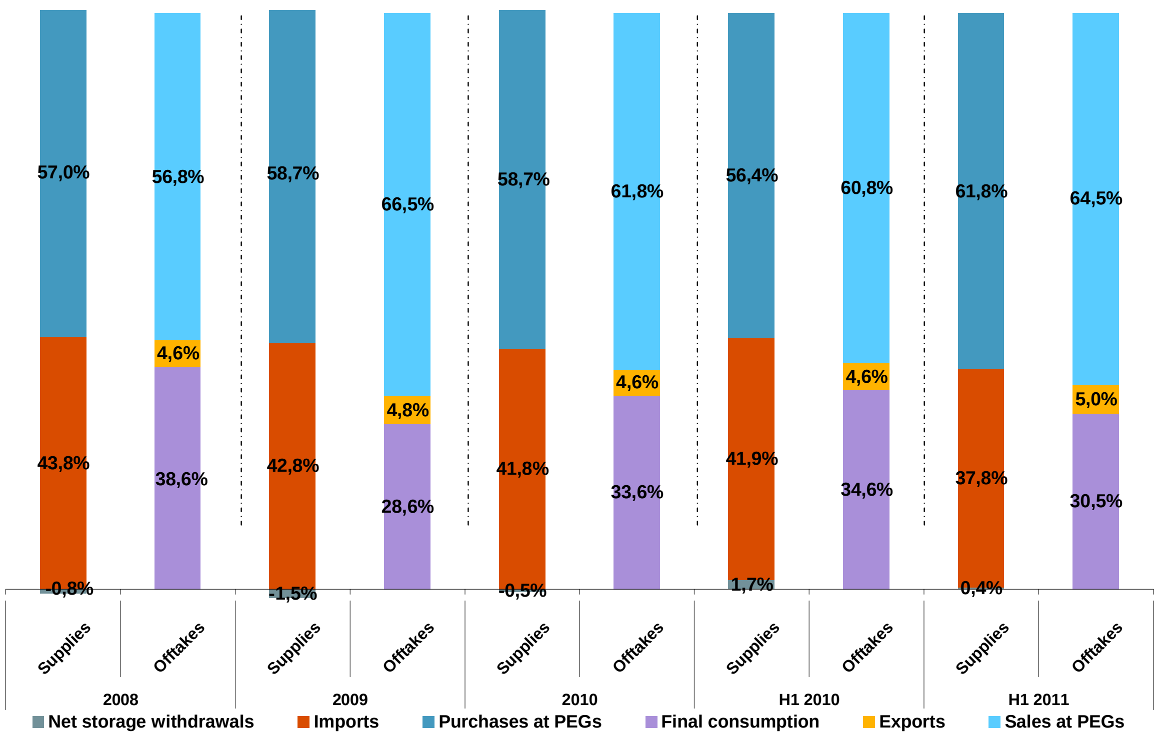
New entrants use PEG purchases and imports to supply their customers and optimise their portfolios

Although the proportion of imports fell slightly between 2008 and 2010 (as it did between the first half of 2010 and the same period in 2011), the imported volume completely covered the final consumption of the alternative suppliers' customers. This illustrates the favourable conditions under which new entrants are able to access the gas infrastructures. Furthermore, they generally turn to the PEG hubs to optimise their portfolios, while accessing the infrastructures to obtain supplies in volume (see Figure 87). In 2010, the volumes bought and sold by purely financial players[33] at the PEG represented around 30% of the total volume, equal to slightly less than half of the purchases or sales. This type of player therefore makes an appreciable contribution to liquidity at the PEG. Exports were divided between the North and South-West zones and represented between 5% and 8% of the new entrants' outlets during 2009 and 2010. The South-West zone saw a greater number of exports due to the fact that it has two exit points (Larrau and Biratou) compared with only one (Oltingue) in the North zone.

Most of the alternative suppliers' outlets are therefore represented by sales at the PEG and end-customer consumption, but in reverse proportions to those of the traditional operators, who deliver the majority of their volume to end customers. This statement can only be qualified if we remove the contribution to the volumes sold at the PEG by the new entrants who do not supply gas to end consumers.

Figure 87: Supplies and outlets for new entrants in France

- in %, 2008 – H1 2011 –



Sources: GRTgaz, TIGF - Analysis: CRE

[33] Shippers who did not supply any gas to end customers.

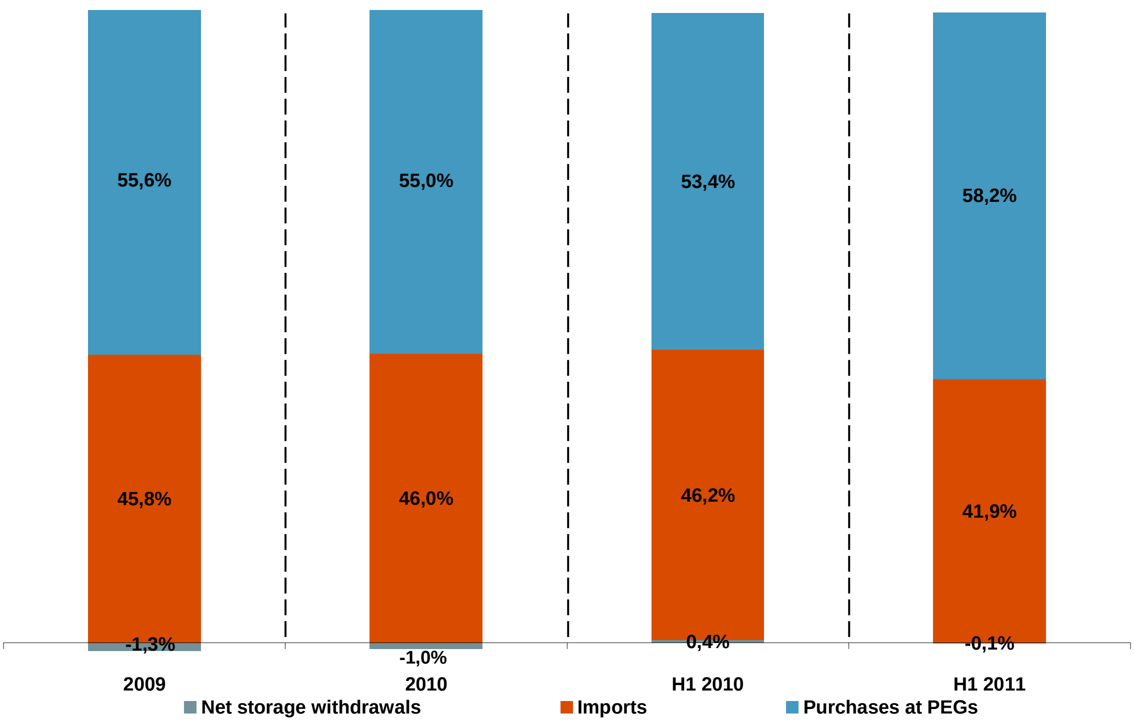
4.2. North zone supply structure in line with the national model

Since the North zone was established as a result of the merger of three of GRTgaz's balancing zones on 1 January 2009, new entrants have had increased access (without tariff barriers) to a greater number of entry points (Montoir, Dunkirk, Taisnières and Obergailbach). As a consequence, liquidity at the PEG Nord appreciated due to the increased number of players and traded volumes (+ 64%) between 2009 and 2010.

The distribution of supplies in the North zone was almost identical between 2009 and 2010. However, in the first half of 2011, the increase in purchases at the PEG Nord and the fall in imports saw a similar pattern to that observed nationally during the same period (see Figure 88). Purchases at the PEG Nord represented 55% in 2010 compared with 55.6% in 2009, and increased by almost 5% in relative value during the first half of 2011 in comparison with the same period in 2010. Imports remained stable in 2010 and saw a 4% decrease in the first half of 2011. The use of stored supplies fell to -0.1% in the first half of 2011 compared with 0.4% during the same period in 2010.

Figure 88: Supplies for new entrants in the North zone by source [34]

- in %, 2009 – H1 2011 –



Sources: GRTgaz, TIGF - Analysis: CRE

4.3. Imports emerge as a supply method in the South zone

The supply structure for new entrants changed markedly in 2010 compared with the previous year, as purchases at the PEG Sud increased by 8% in 2010 and by 14% in the first half of 2011. During the course of 2010, imports (of LNG only) represented a modest 1% of supplies, whereas in the first half of 2011 they amounted to almost 8%.

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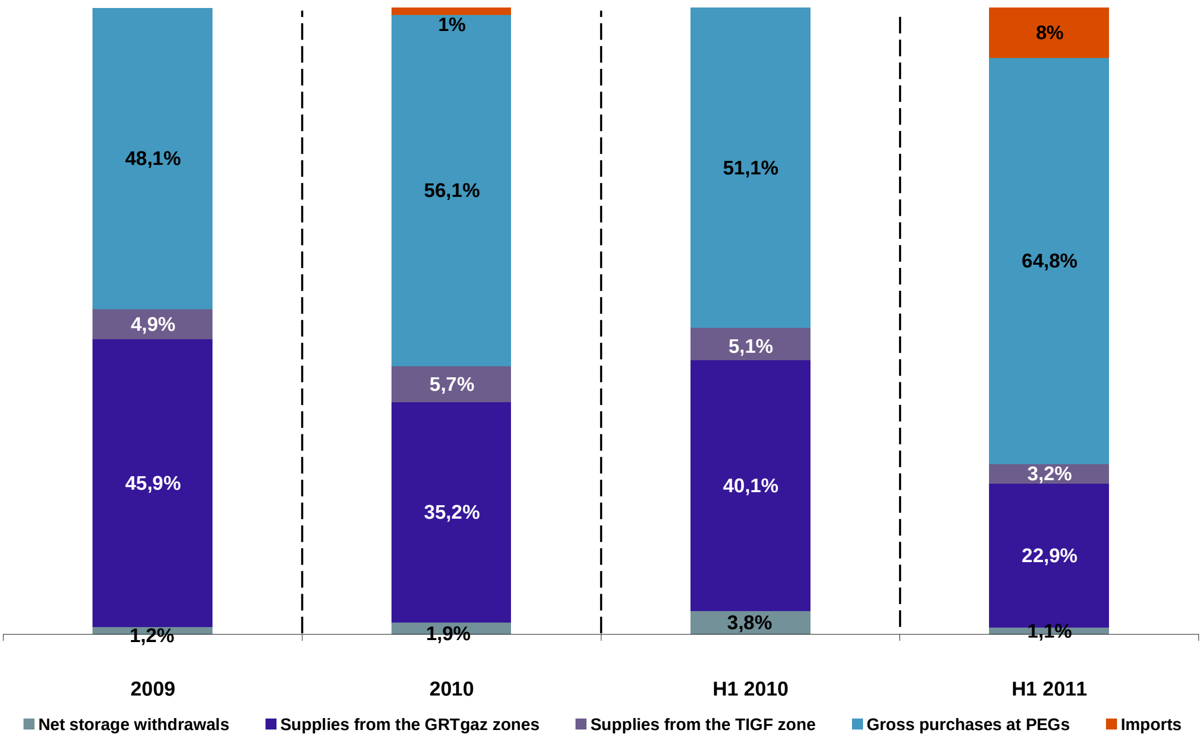
[34] The South/North link is not taken into account as imports from the South zone remain marginal.

Supplies from the North zone gradually fell in 2010 and during the first half of 2011, by -11% and -17% respectively. Supplies from the South-West zone, along with the use of stored gas, slightly increased between 2009 and 2010 but decreased by -2% and -3% respectively during the first half of 2011.

Supplies in the South zone for new entrants were mainly destined for consumption by end customers and for resale at the PEG.

Figure 89: Supplies for new entrants in the South zone by source

- in %, 2009 – H1 2011 –



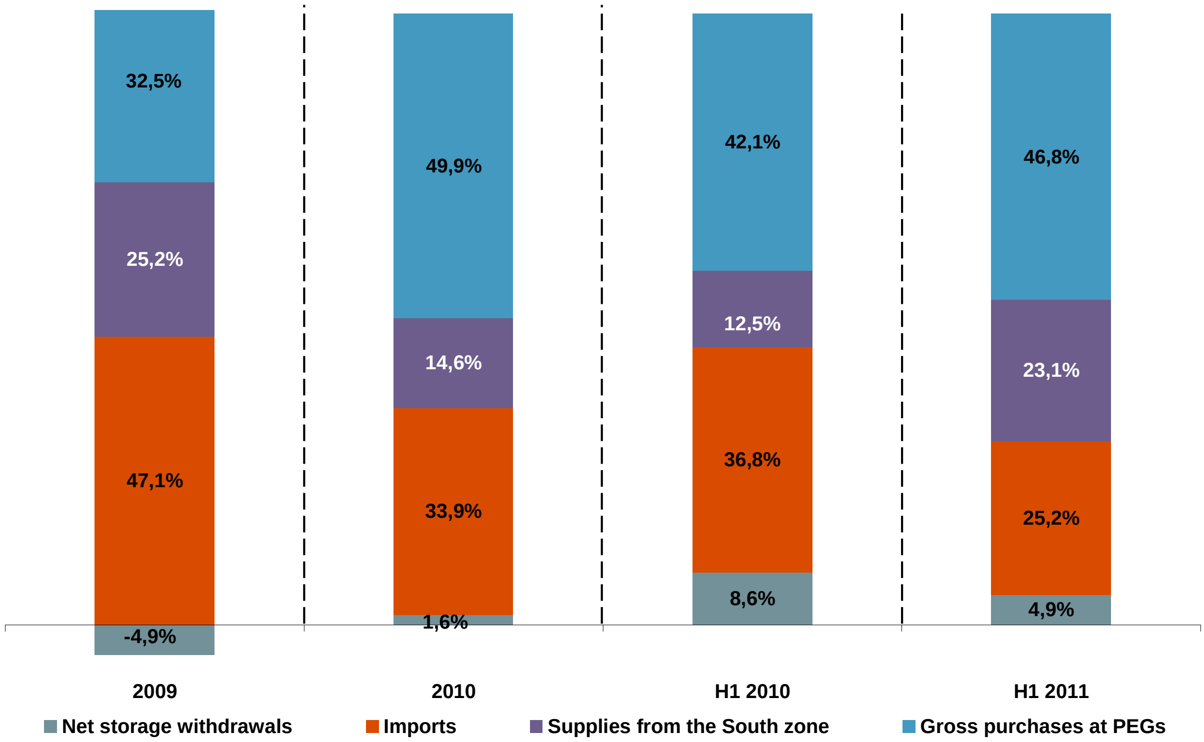
Sources: GRTgaz, TIGF - Analysis: CRE

4.4. PEG purchases represented half of all supplies in the South-West zone in 2010

In 2010, supplies for new entrants in the South-West zone mainly centred on purchases at the PEG Sud Ouest (amounting to 50%), while in 2009, more than 70% came from imports from the South zone. PEG Sud Ouest purchases increased by 17% in 2010 and by 5% during the first half of 2011, thus offsetting the fall in supplies from the South zone and imports from Larrau and Biriatou, which saw a decrease of 13% and 12% in 2010 and during the first half of 2011 respectively. After falling in 2010 (in comparison with 2009), supplies from the South zone increased again by +11% during the first half of 2011. Less use was made of storages supplies during the first half of 2011 compared with the previous year.

Figure 90: Supplies for new entrants in the South-West zone by source

- in %, 2009 – H1 2011 -



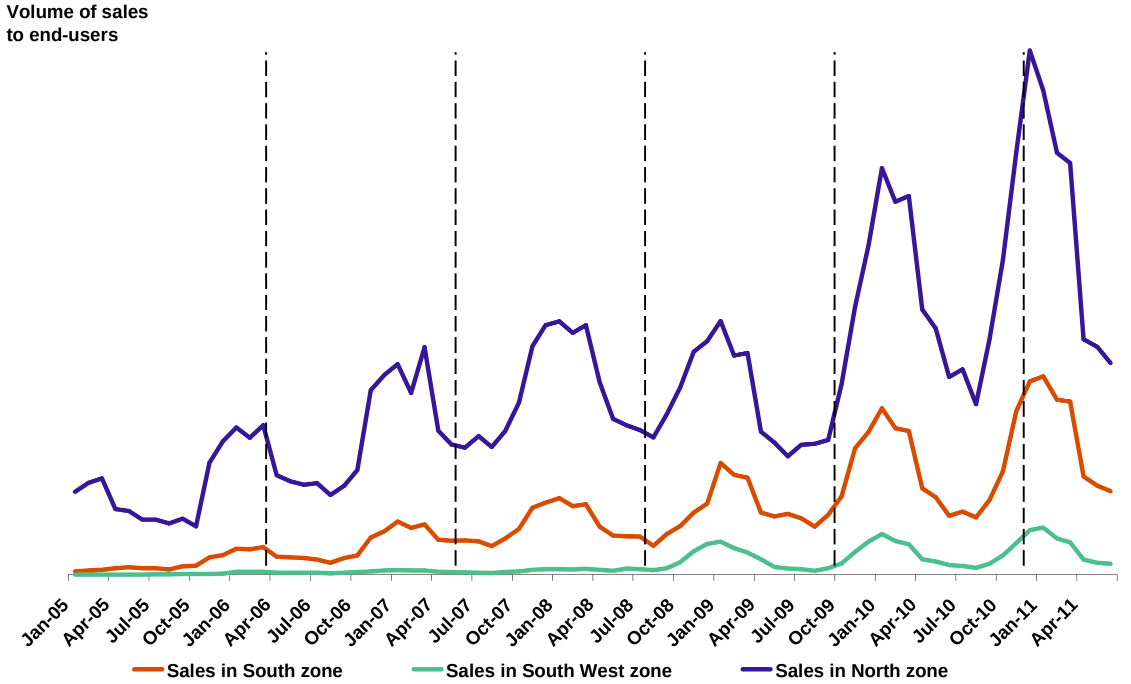
Sources: GRTgaz, TIGF - Analysis: CRE

4.5. The change in the supply structure had a positive impact on alternative supplier sales

Activity of new entrants has changed continuously since 2009, but not without disparities between the different zones.

Figure 91: Monthly sales by alternative suppliers to end customers across the three zones

(2005 – H1 2011)



Sources: GRTgaz, TIGF

Appendices

Glossary

Electricity

Main power exchanges in Europe (organised markets):

APX: Amsterdam Power Exchange spot market, mandatory for Dutch imports and exports, held by the APX-ENDEX group (www.apx.nl).

Belpex: Belgium Power Exchange spot market, held by the APX-ENDEX group (http://www.belpex.be/).

ENDEX: Dutch futures market, held by the APX-ENDEX group (www.apxendex.com).

EPD: EEX Power Derivatives, French and German futures markets, held by EEX and Powernext.

EPEX Spot France: non-mandatory French spot market, held by EEX and Powernext (www.epexspot.eu).

EPEX Spot Germany: non-mandatory German spot market, held by EEX and Powernext (www.epexspot.eu).

NordPool: non-mandatory Scandinavian market (www.nordpool.no).

Omel: quasi-mandatory Spanish pool (www.omel.es).

Wholesale products:

Base: 24 hours a day, 7 days a week.

Day-ahead: contract signed on one day for delivery the next day.

Future or Forward: standard contract signed for the delivery of a given quantity at a given price according to a defined schedule, requiring payment of a premium and a security deposit. The proposed schedule varies according to the organised market (weekly, monthly, quarterly, half-yearly or yearly). The schedule Y+1 corresponds to the calendar year following the current year.

Peak (continental Europe): from 8am to 8pm, Monday to Friday.

Wholesale market segments:

Wholesale purchases and sales (OTC) : Declaration of block exchanges (i.e. day-ahead nominations to RTE) which are not concluded at the Powernext platform.

End consumption: sales to sites as a balancing entity or in the form of blocks.

Imports and exports:

http://clients.rte-france.com/lang/fr/clients_traders_fournisseurs/vie/bilan_annu.jsp

Sales to network operators to compensate for their losses:

http://clients.rte-france.com/lang/fr/clients_traders_fournisseurs/vie/vie_perte_RPT.jsp

http://www.erdfdistribution.fr/electricite-reseau-distribution-france/fournisseurs-d-electricite/compensation-des-pertes-130105.html

VPP: Virtual Power Plant or capacity auctions organised by EDF following a decision by the European Commission (see Case DG COMP/M.1853 - EDF/ENBW).

(**http://encherescapacites.edf.com/accueil-com-fr/encheres-de-capacite/presentation-114005.html**)

VPP base: products reflecting a power plant operating in base mode. The principle is that bidders pay a fixed premium (in €/MW) every month to reserve available capacity, and submit a capacity usage schedule to EDF on a regular basis. They then pay a striking price for each MWh withdrawn, which is close to the marginal cost for EDF's nuclear power plants. The pricing structure therefore takes the form of "fixed cost + variable cost".

VPP peak: products reflecting a power plant operating in peak mode. The principle is the same as for VPP base products, but the price paid for each MWh withdrawn is an estimate of the marginal cost for EDF's power plants operating in peak mode. Given this high variable cost, the fixed premium paid by the bidders is lower than for the VPP base products.

Wholesale purchases and sales (OTC): notifications of exchanges of blocks, i.e. nominated quantities, to RTE on a given day for the following day, excluding transactions on Powernext.

Other terms:

Electricity system margin: difference between the available generation capacity and the estimated consumption.

CO_2

Banking: option for registrants to use an allowance delivered at the beginning of a previous compliance period in order to meet compliance requirements.

Bluenext: carbon market based in Paris (www.bluenext.eu).

Borrowing: the borrowing of an allowance for compliance purposes, giving registrants the option to use an allowance granted at the beginning of the following compliance period (allowances for Year N are entered on the registers before 28 February, while on 30 April in Year N, allowances must be returned in respect of emissions for Year N-1).

Carbon dioxide (CO_2): main greenhouse gas, produced primarily from the combustion of fossil energies.

CDM: Clean Development Mechanism. This is one of the flexibility mechanisms under the Kyoto Protocol, which enables developed countries to finance emissions reduction or greenhouse gas sequestration projects in developing countries and to claim Certified Emissions Reduction units (CERs), which they can accrue to fulfil their own emissions reduction obligations. CDM projects aim to encourage the transfer of environmentally-friendly technologies and to promote sustainable development in developing countries.

CERs: Certified Emissions Reduction units from projects deployed under the Clean Development Mechanism (CDM). Some countries and companies make use of credits from CDM projects and joint application projects to comply with their Kyoto objectives.

CITL: Community Independent Transaction Log, a reporting platform managed by the European Commission, which incorporates the information submitted by the national registers on a daily basis.

Climate and energy package: set of European legal texts relating to energy and climate change, adopted at the end of 2008.

ECX: carbon market based in London (www.theice.com).

Emissions allowance (or emissions permit): unit of account under the EU Emission Trading Scheme. The allowance is a quantity of GHG emissions (expressed in tonnes of CO_2 equivalent) that cannot be exceeded over a given period, which is granted to a country or an economic agent by an administrative authority (intergovernmental organisation or government agency).

Emissions permit: see Emissions allowance.

ERUs: Emissions Reduction Units, carbon credits generated by Joint Implementation (JI) projects, in accordance with the rules defined by the Kyoto Protocol. Companies falling within the scope of the European Union Emission Trading Scheme (EUETS) can use these credits to meet their greenhouse gas emission reduction obligations.

EUA: EU emission Allowance, which authorises the holder to emit the equivalent of one tonne of carbon dioxide in greenhouse gases.

EU-ETS: the European Union Emission Trading Scheme is an EU mechanism that aims to reduce the global emission of CO_2 and achieve the European Union's objectives under the Kyoto Protocol. It is the largest greenhouse gas emission trading scheme in the world.

GHG: greenhouse gas. Gas contributing to the greenhouse effect (see Greenhouse effect). Not all GHGs make the same contribution to the greenhouse effect. In order to compare the different greenhouse gas emissions, their effects are expressed in terms of tonnes of carbon dioxide.

Greenhouse effect: effect causing a natural process, which maintains the lower atmosphere at an average temperature of 15℃. It is linked to the pr esence of certain gases in the atmosphere, such as carbon dioxide and methane, which trap the radiation emitted by the Earth and reflect some of it in the direction of the sun. As the quantity of greenhouse gases produced by humans is too high, temperatures are increasing significantly.

Kyoto Protocol: international treaty aiming to reduce greenhouse gas emissions. The Protocol sets out detailed commitments for the industrialised countries concerned, for reducing or limiting greenhouse gas (GHG) emissions during the first, so-called commitment period, i.e. 2008-2012 (-5.2% in relation to 1990). To achieve this, these countries are obliged to define policies and national measures to fight climate change.

Gas

Backhaul capacity: capacity on the main network enabling the shipper to make nominations in the opposite direction to the dominant direction of flow when the gas can only flow in one direction. It can only be used on a given day if the overall flow resulting from all of the shippers' nominations is in the dominant direction of flow.

Day-ahead product: contract signed on one day for delivery the following day.

DFO: 0.1% domestic fuel oil.

ERGEG (European Regulators' Group for Electricity and Gas): established by the European Commission under the Directives of 2003, the purpose of the ERGEG is to advise and assist the Commission in consolidating the domestic energy market, by helping to fully implement the European directives and regulations and to prepare future legislation in the areas of gas and electricity. The ERGEG comprises the European Commission and the independent regulators in the European Union's 27 member states. The member states of the European Economic Area, together with the candidate countries for EU membership, are also invited as observers. In order to meet its objectives, which are also the subject of a public work programme, the ERGEG has a comparable structure to that of the Council of European Energy Regulators (CEER). The ERGEG also widely consults the players in the energy sector on matters on which it is asked to put forward opinions. These opinions also involve the European Commission, which may then impose applicable restrictions through the Community's committee procedure.

Flexibility clause: provision set out in long-term import contracts giving the purchaser the option to reduce or increase the volumes withdrawn, within the limits of a pre-defined range.

Forward product: contract signed for the delivery of a given quantity at a given price according to a defined schedule.

Future product: a forward contract negotiated on an exchange (organised market). The proposed schedules vary according to the organised market (weekly, monthly, quarterly, half-yearly or yearly). The schedule Y+1 corresponds to the calendar year following the current year (delivery from 1 January to 31 December).

Gas exchange point (PEG): virtual point on the French gas transmission network at which shippers can trade volumes of gas. There is one PEG in each of the balancing zones on the French network.

Gas release: obligation on the part of a supplier to release a share of his gas resources to other suppliers for a given period. The general purpose of this operation is to allow competition to develop, by offering alternative suppliers the option to secure supplies without having to negotiate by private agreement with the traditional supplier.

Gas wholesale market coupling: mechanism based on one or more stock markets for comparing the supply and demand on the coupled markets and allocating concurrently and implicitly the interconnection capacities between the balancing zones (North and South in this instance). This mechanism would see benefits from some of the advantages of a merger between the balancing zones, without a need to invest heavily in infrastructures. The market coupling between GRTgaz's North and South zones respects the specific nature of the gas market: day-ahead market prices for gas are determined continuously (each transaction is made at a specific price) rather than by fixing, as is the case for electricity (a single auction is operated by the market to determine the price for each hour of the following day).

Herfindahl-Hirschmann Index (HHI): this is equal to the sum of the squares of the market shares of the companies, and is a measure of market concentration. The more concentrated the market, the higher the HHI index will be. Generally speaking, a market is considered to have a low concentration ratio if its HHI is below 1,000, and a high concentration ratio if its HHI is above 1,800.

HFO: heavy fuel oil with low sulphur content.

Intra-daily: market for contracts finalised on a given day for delivery on the same day or on the following day, if the transaction occurs after the main period of activity on the day-ahead market.

NBP (National Balancing Point): gas hub in the United Kingdom. Due to the large volumes traded on this notional hub, the prices used serve as an important reference for gas wholesale trading in Europe.

Net-back: mechanism for establishing the prices of long-term gas purchasing contracts, based on a logic of pricing natural gas in relation to the energies competing with it, and taking account of the cost of transporting the gas from the producer country to the consumer country.

Nomination: quantity of energy, expressed in kWh (GCV 25℃), notified by the shipper to the transport network operator each day the shipper asks the network operator to withdraw, transport or deliver energy. By extension, the verb "nominate" defines the action of notifying the transport network operator of a nomination.

Short term: the short-term market comprises the Day-ahead, Weekend, Weekly and Other products.

Spot: short-term market, including operations for delivery within a short time scale. The spot market covers intra-daily and day-ahead products.

Take-or-pay: clause in a gas or electricity supply contract, in which the seller guarantees the availability of the gas or electricity to the purchaser, who in return guarantees to pay for a minimum amount of energy, whether delivery is taken or not.

Uniform service: a cargo of LNG is regasified with constant emission over 30 days.

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CO_2

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