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Assessing the impact of wind power on day-ahead electricity prices in France

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Introduction

France has lagged behind many of its European neighbours notably Germany & Spain, in introducing wind power. At present, electricity in France is 75% nuclear, 13% hydro-power, 10% fossil-fuel thermal with only 2% from other renewable energy sources. Over the next 15 years, France plans to introduce wind power massively. In addition, other changes will affect the French power generation fleet: the nuclear plants built in the 1970s & 1980s are reaching their planned 40 year lifespan and will require more maintenance (some might be decommissioned); two new nuclear plants have been commissioned and several new gas powered turbines will be constructed to meet the demand in peak and semi-peak periods. The objective of this study is to evaluate the impact that these changes would have on day-ahead electricity prices in a statistical way, by simulating prices 24 hours per day on working days, over the next 10-15 years. By "statistical" we mean that the histograms of the simulated prices should be realistic; we are not attempting to predict prices on particular dates.

The impact of wind power on day-ahead electricity prices has attracted considerable attention in the literature since Jensen & Skytte (2003) pointed out that its introduction might lead to a drop in prices because its variable cost is much lower than conventional thermal power plants. Our study builds on empirical work by de Miera et al (2008), Weigt (2009), Sensfuss et al (2008) and Pfluger et al (2009). The first three studied the electricity markets in Germany and Spain which have a high penetration of wind power, compared to France where it is still very low. Consequently they evaluated its impact on prices over the past few years. In contrast we will focus on its impact in the future. Two common features of the four papers cited are that the demand was considered to be inelastic and that the electricity price is computed using the full merit order, implicitly assuming that all the electricity is traded through the bourse. Some of the differences between these four studies are due to the availability of information which varies from country to country and over time.

De Miera et al (2008) focused on the wholesale price of electricity in Spain. The authors identified two types of effects, firstly a direct effect where wind power displaces conventional thermal power in the merit order, thereby reducing the electricity price, and secondly an indirect effect due to the reduction in the CO_2 emitted. Several factors make it difficult to evaluate these effects: (1) the stochastic nature of wind generation which can vary rapidly over short periods of time, (2) structural relations (correlations) between wind power and hydro power and (3) the availability of information on plant availability, performance of thermal plants etc. They proposed two ways of empirically analysing the direct effect, firstly by using historical data and secondly by simulating the merit order (and hence the market price) without wind power and comparing it to market prices. The first study was only based on historical data over a 3-day period. The second approach consisted of simulating the merit order given the technical characteristics of the plants, over a 2.5 year period from 2005 until mid-2007. As a full simulation would have been beyond the scope of their study, they limited it in the following ways:

- The electricity demand was totally inelastic.
- The equipment availability was what had actually been observed.
- The dispatch of hydro plants followed what had been observed.
- Imports and exports were those actually observed.
- Restrictions on ramp up/down, and on the number of stops/starts per year were ignored.

The Spanish TSO, Red Eléctrica de Espana, provides information on the installed capacities of thermal plants, thermal production and wind production, and monthly figures on the availability of thermal power stations. Gas prices from the UK NBP market and CO_2 prices from EEX were used to estimate the generation costs of thermal plants. Electricity prices from the Spanish electricity bourse, OMEL, were compared to the average monthly prices simulated for the case without wind power. According to this analysis, wind power led to a reduction in wholesale electricity prices of about 7 €/MWh in 2005, 5 €/MWh in 2006 and 12 €/MWh in the first half of 2007. Even after taking account of the feed-in tariff support for wind power, this corresponds to substantial savings for Spain on its electricity bill.

Weigt (2009) analysed the extent to which wind energy could replace conventional thermal power in Germany using data on the hourly wind feed-in over the period from 2006 till mid-2008. His analysis indicated an overall load shift of about 4-5 GW, resulting in a reduction in peak hour prices of about 10 €/MWh in 2006, 17 €/MWh in 2007 and 19 €/MWh in the first half of 2008. This study was made possible by the fact that the four German TSOs started releasing the hourly wind feed-in data.

Sensfuss et al (2008) used an agent-based simulation approach to evaluate the impact of wind power on the merit order in the German market over the period 2001 - 2006; Pfluger et al (2009) used the same methodology to assess the impact of importing electricity from renewable sources into Southern Italy. Both papers used the PowerACE model. The merit order for dispatching power stations is based on their variable costs which depend primarily on fuel costs (Sensfuss & Genoese, 2006). In addition to modelling the spot market, the CO_2 market and the different reserves managed by the grid-operator, they incorporated "traders" designed to replicate strategies that are used in practice. Outages were simulated by randomly selecting the generator involved. In order to smooth out variations caused by these random outages, 50 simulations were run first with wind power and then without it, and then the resulting prices were averaged. According to their analysis, renewable electricity led to a drop in market prices in Germany of 7.8 €/MWh in 2006.

In a similar study on the Italian market, Pfluger et al (2009) compared the simulated prices with the real spot prices. The agreement is good during off-peak periods but the model seriously underestimates the real prices during peak periods and overestimates them in the early hours of the morning (1am -5am). This may be because they smoothed out the peaks and troughs by averaging 50 simulations. As Sensfuss et al (2008) noted, another reason is that most electricity is traded via bilateral contracts rather than through organised markets. This means that the supply curve is not the overall merit order. So one of the principal difficulties will be to find a way of simulating the supply curve without assuming that it is equivalent to the merit order and similarly without assuming the demand is inelastic. One of our objectives is to overcome one of the weaknesses of the existing methods by being able to generate realistic price peaks during peak hours.

Information available to public

As Weigt (2009) noted the availability of data is critical to empirical studies. In France, data comes from three sources: the grid operator, RTE, the day-ahead market run by EpexSpot (formerly Powernext) and the EDF. RTE provides the following information on its website:

1. The total consumption of electricity, 24 hours per day 365 days per year (since 1996),
2. The total production in France, 24 hours per day 365 days per year (since 1996),
3. The breakdown of the production, 24 hours per day 365 days per year according to the type of power plant (nuclear, hydropower, coal + gas, diesel + peaking plants) from November 2006 onward,
4. The breakdown of daily plant availability into the following categories (nuclear, coal, gas, diesel + peaking plants, run of river hydro-power, hydro-power from dams), since November 2006,
5. The availability of individual power plants, since 1 January 2010, and
6. The quantities exported/imported from each of six neighbouring countries (UK, Belgium, Germany, Switzerland, Italy, Spain), 24 hours per day 365 days per year, from 2002 onwards.

The fact that most of this data is only available from November 2007 onward made our study difficult because only two full years were available (Oct 2007-Sept 2008, & Oct 2008-Sept 2009). In addition the second year (2008-2009) was atypical because the consumption dropped sharply because of the economic crisis.

Since 2000 RTE has been required by law to produce long-term predictions on the equilibrium between supply and demand. To date four of these reports called *Bilan Prévisionnel* have been produced in 2003, 2005, 2007 and 2009. They give the expected number of hours per year when demand exceeds supply, for the next 10-15 years. To do this RTE has built up a set of 55 scenarios that are representative of the climatic conditions over the past 55 years. Knowing the structure of the power fleet they simulate the total consumption in France given the climatic conditions in each scenario and the merit order (taking account of random outages and also of the amount exported). Then RTE calculates the number of hours when the supply is not sufficient to meet the demand, and advises the government whether additional power plants are required and if so how many. RTE's mandate from the government does not extend to forecasting electricity prices.

The French electricity bourse, EpexSpot, runs daily auctions for electricity for the 24 1-hour time slices for delivery on the following day. On its website it provides the day-ahead price and volume resulting from the auction and also the aggregated offers to buy/sell electricity 24 hours per day 365 days per year (since Nov 2001).

Finally the average marginal costs of nuclear power and classical thermal power can be deduced from the strike prices of baseload and peakload VPP that are available on EDF's website. These were 9 € per MWh for nuclear power and 73 € per MWh for thermal power over the period from Oct 2007 to Sept 2008. The marginal cost of nuclear power varies little but that of thermal power tracks the fluctuations in fuel prices. These marginal costs are useful when splitting the aggregated offers to sell electricity on the bourse into three tranches according to their marginal cost.

Factors outside the scope of the study

Four other factors which will affect electricity prices in France in the future are

- the introduction of electric cars,
- the stochastic nature of wind availability
- the Central Western European market coupling which started in November 201O, links Germany, France, Belgium and the Netherlands, with further extensions to the Nordic market,
- a new law, called the *Loi Nome*, which will lead to major structural changes in France. The law was passed by parliament in November 2010 but the decrees to put it into effect had not been promulgated when this paper was written.

A companion paper (Armstrong, Iguer et al, 2011) assesses the impact of the introduction of electric vehicles on day-ahead prices in France.

Structure of the paper

This paper is structured as follows. The first step in this project was to study the behaviour of the electricity system during a typical price peak on Thursday 15 November 2007 in order to understand what caused the price spike on that day and why the price dropped back to normal levels on the next day. After analysing the electricity consumption in France, the electricity production (from the different types of power plants) and the exports & imports between France and neighbouring countries we studied the aggregated offers to buy and sell electricity on the day-ahead auction market which determine the market fixing. We concluded the standard approach in which price is computed by assuming that the demand is inelastic, and that the supply follows the overall merit order, is not appropriate for the French market. This analysis is given in the Appendix.

In Section 2 we present the scenarios for the supply and demand sides respectively. As this paper focuses on the impact of wind power on prices, twelve scenarios are presented for the future evolution of the French generation fleet, but only one scenario is considered for the demand. In Section 3 we describe our procedure for setting up realistic pairs of future supply and demand curves. The key point is to ensure that pairs of curves are matched, that is, that they correspond to a given set of weather conditions. So they are based on the aggregated offers to buy or to sell that are now available from the French bourse, Epexspot. To update them to future conditions, we have extended the methodology developed by the RTE in its multi-year generation adequacy reports (*Bilan Prévisionnel, 2006 & 2009*). In Section 4 we present the results obtained. The conclusions follow in Section 5.

Twelve scenarios for the generation fleet

In order to model the evolution of the aggregated curves of offers to sell electricity in the future we need to know how the current structure of the generation fleet in France is likely to evolve in the future. Twelve scenarios will be considered: two for wind power, three for nuclear (high, medium & low) and two for fossil fuel thermal power. As there is little perspective for an increase in hydro-power, only one scenario was considered. Random fluctuations are considered around all the scenarios. Having defined the total generation fleet, the next step is to simulate the capacity actually available at any time. We then focus on the demand side.

Wind-power & solar energy over the next 15 years

In an effort to achieve the European Unions 20/20/20 objective, the French government has decided to focus on wind-power and solar energy. Table 1 taken from the report of the COMOP parliamentary commission compares the situation in 2006 with its objectives for 2020. We consider two scenarios depending on the rate at which wind turbines are introduced. The first scenario (denoted by H) corresponds to a rapid increase with a capacity of 17 GW by 2020 and 25 GW by 2025; the second (denoted by L) is more modest: 10 GW in 2020 and 15 GW in 2025. One potential concern with wind power is that as extreme weather conditions in France are usually associated with anti-cyclones, less wind might be available precisely at the times when power is most required. In the 2006 *Bilan Prévisionnel*, RTE assumed that only 15% of the installed capacity would actually be available. After carrying out detailed studies of wind regimes, RTE concluded in 2009 that periods of extreme cold were not systematically correlated with lower than average wind availability over the whole of France and consequently raised the factor to 25%.

Table 1: French government's objectives for increasing electricity generated from wind-power.

	2006	2020	Obstacles to be surmounted
Wind Turbines (on shore)	1600 MW	19,000 MW	Acceptability Strengthen grid
Wind Turbines (off shore)	0	1400 MW	High cost Mastering technology

Nuclear power over the next 15 years

After the oil shocks in the mid-70s, the French government decided to replace the traditional fossil-fuel power stations by nuclear powered plants. A total of 58 reactors are currently in service:

- 34 reactors of 900 MW type were constructed between 1977 and 1987
- 20 reactors of the 1300 MW type were built between 1985 and 1993
- 4 reactors of the 1500 MW type were put into service between 1996 and 1999

In addition two new EPR reactors (1600 MW) are being built at Flamanville 3 and Penly, and should enter into service in 2012 and 2017 respectively.

The planned lifespan of the nuclear reactors built between 1977 and 1987 was initially 30 years, but has been extended to 40 years. Will it be extended to 50 years or will some be decommissioned? If their lifetime is extended, they will probably need longer maintenance periods. According to a press report[1], the availability factor for EDF's nuclear reactors dropped from 83.5% in 2005 to 79.2% in 2008 and in October 2009, 18 of its 58 reactors were out of action due to equipment failures (e.g. steam generators, alternators) or to planned shutdowns to load fuel.

Given the importance of nuclear power and the current uncertainties, three scenarios will be considered. In all three, the EPR starts production on schedule in 2012 and remains constant until the first generation nuclear plants undergo their fourth 10-yearly safety check in 2020. What happens from then on depends on (1) whether they are decommissioned or their life-time is extended by another decade and (2) how fast the new EPR reactors are constructed. In the first scenario which corresponds to the reference scenario in RTE's 2009 *Bilan Prévisionnel*, the new EPR just compensate for loss of production from the first generation reactors which are decommissioned. So the nuclear capacity remains constant at 65 GW. In the high nuclear scenario, the first generation reactors pass the safety tests and new EPR are constructed bringing the available nuclear capacity to 75 GW by 2025. In contrast to this, in the low scenario, 24 of the first generation are decommissioned and only 1 new EPR is built per year, resulting in 65 GW of capacity in 2025.

[1] http://www.leparisien.fr/flash-actualite-economie/electricite-la-production-des-reacteurs-nucleaires-francais-recule-en-2009-12-11-2009-708914.php]

Fossil-fuel power over the next 15 years

Fossil-fuel plants in France fall into two broad categories: old diesel or coal-fired power stations (typically more than 25 years old) or new combined cycle gas turbines (CCGT). The first category are being phased out because of environmental concerns. Since 2005, three new CCGT have been put into service mostly by new entrants to the electricity market:

- 790 MW by GDF Suez
- 412 MW by Poweo
- 860 MW by SNET

In addition to these plants which started production between September 2005 and January 2009, the government authorised the construction of another twenty CCGT each with a capacity of 400 MW or more. This indicates a strong potential for an increase in production over the next 10-15 years. Lastly, in 2009, decentralised plants accounted for 8.5 GW, but only 3.8 GW of this is linked into the grid. So these will have little effect on the electricity supply. We assume that the CCGT that have already been approved will start production by 2014. After that, in the low CCGT scenario, the capacity remains constant at about 11 GW whereas in the high scenario it increases by 900 MW per year reaching nearly 18 GW by 2025. Figure 1 illustrates the three scenarios for nuclear power (left), two scenarios for fossil fuel thermal power (centre) and two scenarios for wind power (right).

Hydro-power

Four types of hydro-electric plants exist in France, each with different storage capacities:

- run of river (7.6 GW) with no possibility of storing water
- locks (4.3 GW) with limited possibilities for storing water (max 1 week)
- dams (9.3 GW) with a much larger storage capacity
- ponds with pumping facilities (4.2 GW). Water is released from the top pond into the lower one during peak hours then pumped back up at night.

The last two can provide power at short notice during peak periods when prices are high. Because of environment restrictions it is unlikely that additional hydro-facilities will be constructed in France in the future, so only one scenario will be considered.

Table 2 summarises the 12 scenarios that will be considered in the paper. We will focus on two of them: N°5 (when all three types of generators are at a maximum) and N°12 (when all the generators are at a minimum).

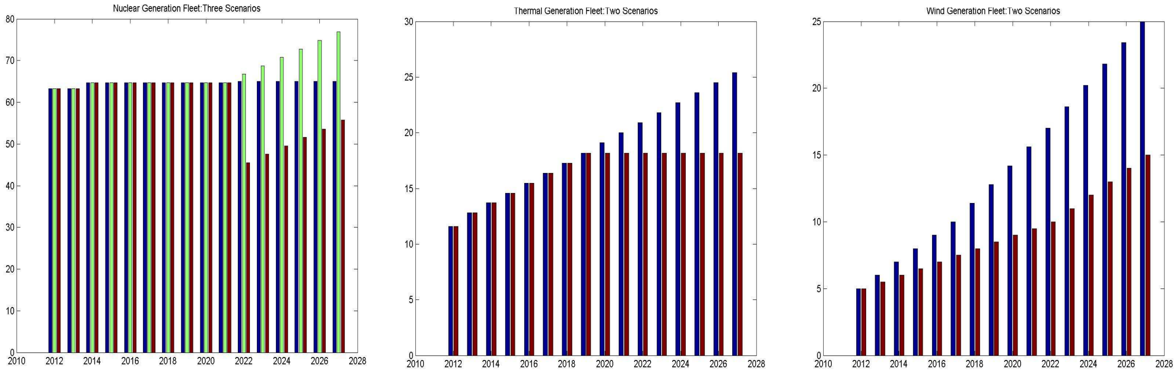

Figure 1: The production capacity available (in thousands of MWh) in the scenarios considered: (a) nuclear power scenarios (left), (b) fossil-fuel thermal (centre) & (c) wind power (right)

Table 2: Summary of twelve scenarios: Ref = Reference scenario, H = High, L = Low

	1	2	3	4	5	6	7	8	9	10	11	12
Nuclear	Ref	H	L	Ref	H	L	Ref	H	L	Ref	H	L
Wind	H	L	H	L	H	L	H	L	H	L	H	L
Thermal	H	H	H	H	H	H	L	L	L	L	L	L

One scenario for the demand side

As this paper focuses on the impact of wind power on prices, only one is considered for demand. As heating requirements in winter account for much of the electricity consumed by households, the demand is seasonal. To model this, we averaged the observed demand in three typical years: Oct 2005 - Sept 2006; Oct 2006 - Sept 2007 and Oct 2007 - Sept 2008, after rescaling them to take account of the annual increase from one year to another, and then smoothed it. This makes it possible to take account of factors such as

- Demand on Monday mornings is less than on other weekdays when thermal plants are being ramped up, and likewise on Friday afternoons.
- The demand is lower over the Christmas periods and during summer holidays.

Our approach

In the introduction we saw that the aggregated offers to sell electricity are not a scaled-down version of the full merit order, and that the demand on the bourse is not inelastic. In order to simulate day-ahead prices at future dates we need to be able to simulate realistic curves of the aggregated offers to buy and sell electricity, that is, matched pairs. The key point is how to link the overall supply and demand to the aggregated offers in the auction market. Figure 2 summarises our approach. On the supply side, for each of the twelve scenarios, we simulate the capacity that is actually available for each type of power plant (nuclear, fossil-fuel, hydro and wind power) for all 24 hours per day for all 260 week days per year.

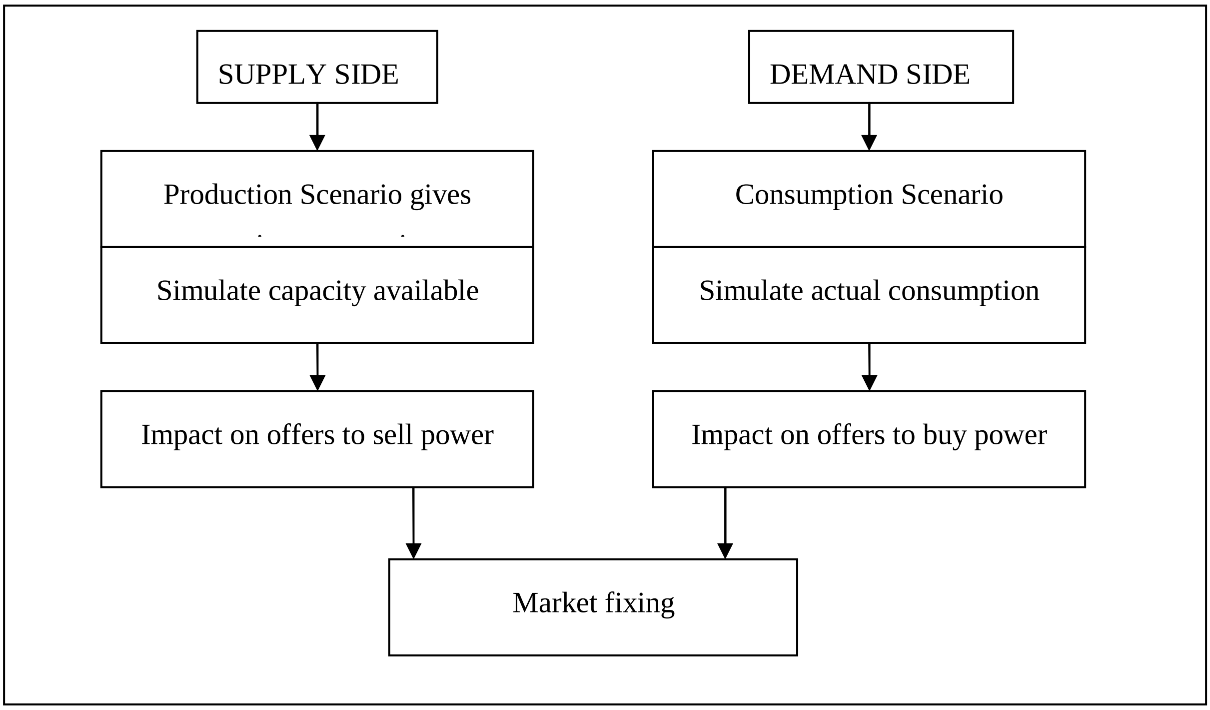

Figure 2: Diagram showing our approach

Supply side

We propose to do this in four steps for the supply side:

1. Select a typical reference year for which we have the aggregate offers, the total consumption and the actual production for each class of power plant. This gives us aggregated offers to sell electricity that are matched to actual production figures for each class of power plant. So whatever factors (weather etc) affected one, also influenced the others. We chose the 52-week period from Monday 1 October 2007 until

Friday 26 September 2008 as the reference year because information on the production per class only became available to the public from November 2006 onward. As the electricity consumption in France dropped because of the crisis starting in the fourth quarter of 2008, the following year is not typical.

2. Each of the twelve scenarios (Section 2) of future evolution of the generation fleet in France specifies the maximum capacity available for each class of generator. Using a procedure similar to that used by the RTE, we generate multiple realisations of the production for each class of power-plant (nuclear, thermal etc) 24 hours per day for 260 working days per year. Details are given in Armstrong et al (2011).
3. The aggregate offers to sell electricity into three tranches according to the marginal cost of production:
    a) low marginal cost which corresponds to nuclear power, run of river hydro and wind power
    b) mid range marginal costs which correspond to conventional thermal plants
    c) high marginal costs (or high opportunity costs) which correspond to peaking plants

The thresholds between the low and medium marginal cost tranches and between the medium and high tranches were set at 20 euros and 100 euros respectively, based on the strike prices of EDF's VPP.

Our basic assumption is that in the future the offers to sell electricity made by producers in each tranche will have the same shape as during the reference year. Figure 3 illustrates this concept. The solid black and red curves were the original aggregate offers to buy and to sell power respectively. Now suppose that in one simulation the production capacity available in the three tranches rises by 10%, 50% and 20% respectively compared to the reference year. Then we assume that the volumes offered in the first slice would also increase by 10%, giving the first segment of the dotted line. Similarly the volumes offered in the second tranche would rise by 50%. These are added to those in the first slice, and so on for the third tranche. The dotted line represents the new simulated aggregate offers to sell power.

Demand side

As this project focuses on the impact of wind power on the supply of electricity, a simplified scenario for the demand side was used for setting up the demand as outlined in Section 2. To compute the aggregate curve of offers to buy electricity in the future, we assume that the curves will increase in proportion to simulated consumption for France as a whole.

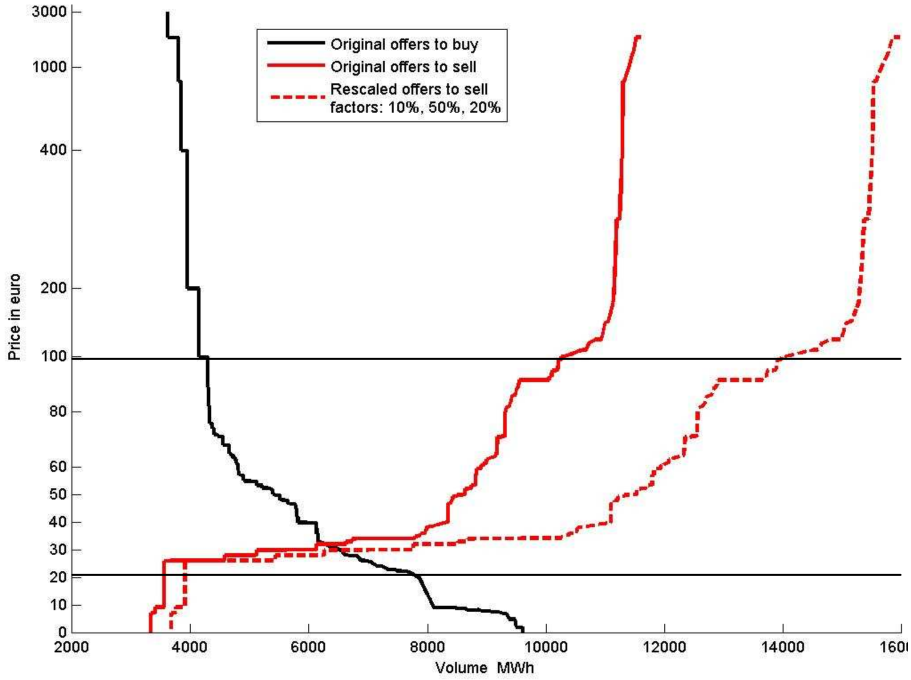

Figure 3: The solid curves represent the original curves of offers to buy electricity (black) and to sell it (red). The offers to sell power are split into three tranches to represent the low marginal cost producers (nuclear, run of river and wind power), intermediate costs (thermal plants) and finally high cost (peaking plants) and high opportunity costs (pumped dam power). The quantity offered in each tranche is rescaled to take account of the simulated production in that production class and the three parts are recombined.

Market fixing

Once the aggregate curves of offers to buy and to sell have been simulated, the intersection of the two curves gives the simulated day-ahead price and the corresponding volume.

of the two curves gives the simulated day-ahead price and the corresponding volume.

Results

Before analysing the results, we present the simulated prices in 2020 at two key times in the day: H5 (black) early in the morning when prices are lowest and H12 (red) which corresponds to the midday peak price, firstly for the scenarios HHH (Fig 4) and then for scenario LLL (Fig 5). As expected, the prices at H12 are consistently higher than those at H5. Moreover, price spikes tend to occur during peak hours, especially in the LLL scenario. This result contrasts with those obtained by Pfluger et al (2009) who did not succeed in generating high enough price spikes.

A total of 50 simulations of the day-ahead prices were generated 24 hours per day for the 260 weekdays in 2020. Their statistical properties were analysed. Figure 6 shows the average price at different times of day for the most favourable scenario (HHH), as a dotted line and for the least favourable one (LLL) as a solid line. At midday, the average price would be 35 euros higher under the least favourable scenarios for wind, nuclear and thermal power than when the three are high. In the early morning, the difference would still be about 10 euro.

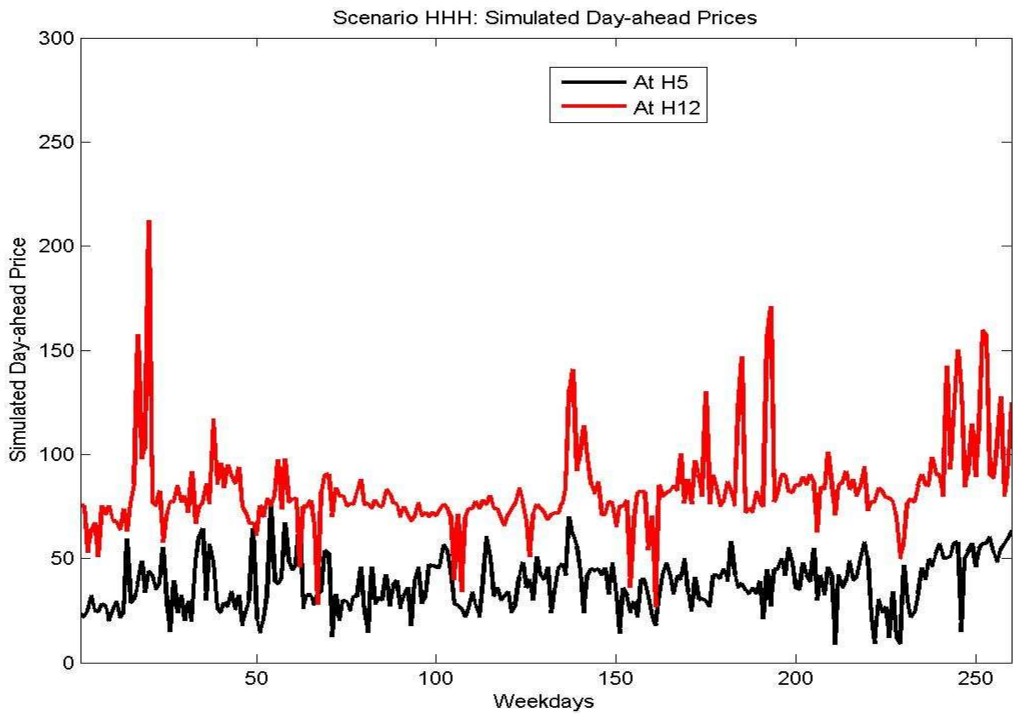

Figure 4: One set of simulated prices on weekdays in 2020 at H5 (black) and at H12 (red) for the most favourable scenario HHH

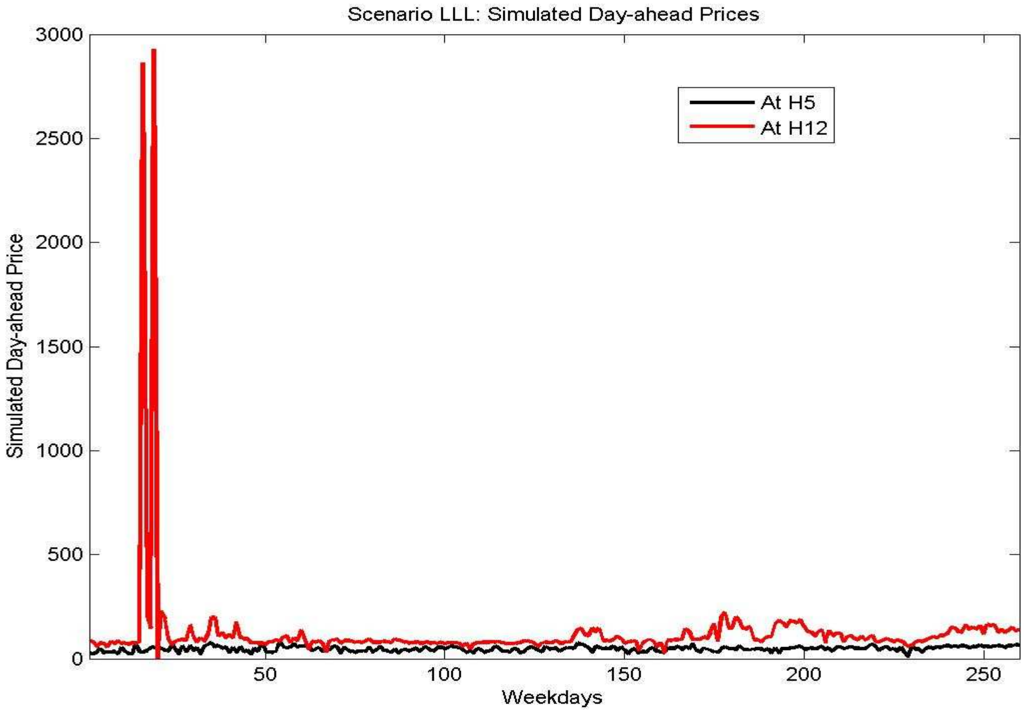

Figure 5: One set of simulated prices on weekdays in 2020 at H5 (black) and at H12 (red) for the most favourable scenario LLL

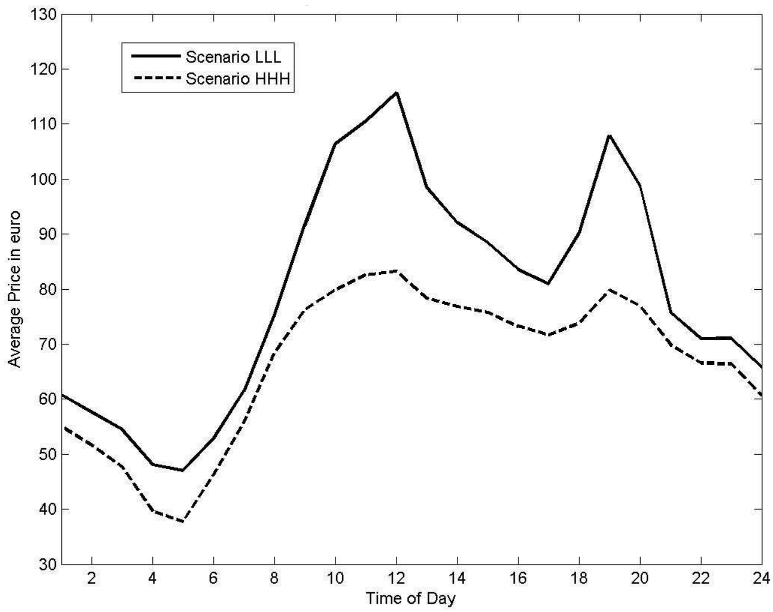

Figure 6: Average prices at different times of the day on weekdays in 2020 at H12 for the least favourable scenario LLL (solid line) and the most favourable scenario HHH (dotted line)

Conclusions

The primary objective in this research project was to develop a method for simulating day-ahead prices on the French market without assuming that the demand was inelastic or that the offers to sell power were a scaled down version of the full merit order. Work by Pfluger et al (2009) had showed that using the full merit order did not produce the price peaks seen in real data in Italy. So our second objective was to generate realistic spikes Our method for simulating day-ahead prices extends the method developed by the French grid operator, RTE, for predicting whether there will be sufficient generation capacity in the future. It uses three types of data which are available hourly 365 days per year: (1) the aggregated offers to buy and sell electricity in France, (2) the total consumption and (3) the actual production for each class of power plant, during the period from Oct 2007 until 2008 . As this data is available at exactly the same times, whatever factors (weather, outages, strikes etc) affected one, also influenced the others. This is important from a statistical point of view because we can filter these factors out when testing whether differences between the prices are significant.

Although a total of twelve scenarios were developed (three for nuclear, two for wind power and two for thermal plants) only the least favourable (denoted by LLL) and the most favourable (denoted by HHH) were analysed in this paper, as these two cover the range of possibilities. A total of 50 simulations of day-ahead prices in 2020 were generated 24 hours per day for the 260 weekdays. The results show that our method generates realistic price spikes. As expected, the spikes occur more frequently in the LLL scenario and are higher than in the HHH scenario. See Figs 4 & 5. Secondly the average price at each hour of the day is higher in the LLL scenario than in the HHH scenario (Fig 6). The difference is about 35 euros per MWh at the midday peak (H12) compared to about 10 euro at H5 in the early morning.

Further work is still required but the initial results are quite promising. Several factors were not considered in this paper: the coupling of the French and Germany markets, the stochasticity in the wind power, the introduction of electric vehicles and finally a new law called the Loi Nome. A companion paper to this (Armstrong, Iguer et al, 2011) analyses the impact of the EVs on day-ahead prices. In the near future we plan to compare the effect of the stochastic wind power, as the grid operator, RTE, started publishing observed values for wind availability in January 2011.

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Appendix: Understanding how price spikes occur

The work by Pfluger et al (2009) on the Italian electric system showed that the classic merit-order approach failed to generate the high prices observed during peak hours. To understand what is happening, we studied the price spike that occurred on Thursday 15 November 2007. Figure A-1 presents the day-ahead prices during the hour from 11.00 to 11.50 am (H12 for short) throughout the month of November. On Tuesday 13 and Wednesday 14 prices were above normal (123 € & 148 €/MWh), on Thursday they reached 500 €/MWh only to drop again on Friday to 175 €/MWh. In France, price peaks are usually triggered by production incidents or by unusually cold weather. During the week 12-16 November both occurred. On Wednesday 14, the production from nuclear power plants dropped by 18% due to industrial action[2] and on Thursday 15, a cold snap hit the country. Figure A-2 shows the minimum temperatures (°C) recorded in Paris and Lyon. As French homes use electric heating, this led to a sharp increase in demand. The solid line in Fig A-3 shows the production from nuclear power plants during the week 12-16 November. Note the sharp drop on Wednesday. For comparison purposes the production during the preceding week 5-9 November is shown as a dotted line. Increased production of hydro electricity partly compensated for the lost nuclear production (Fig A-4) but the total production in France (Fig A-5) was still down compared to other days. The consumption in France on Wednesday (Fig A-6) was also below that on other days. EDF, offers a preferential tariffs to domestic and industrial clients who agree to reduce their consumption on request. Judging by the drop in consumption EDF apparently exercised its rights on Wednesday 14.

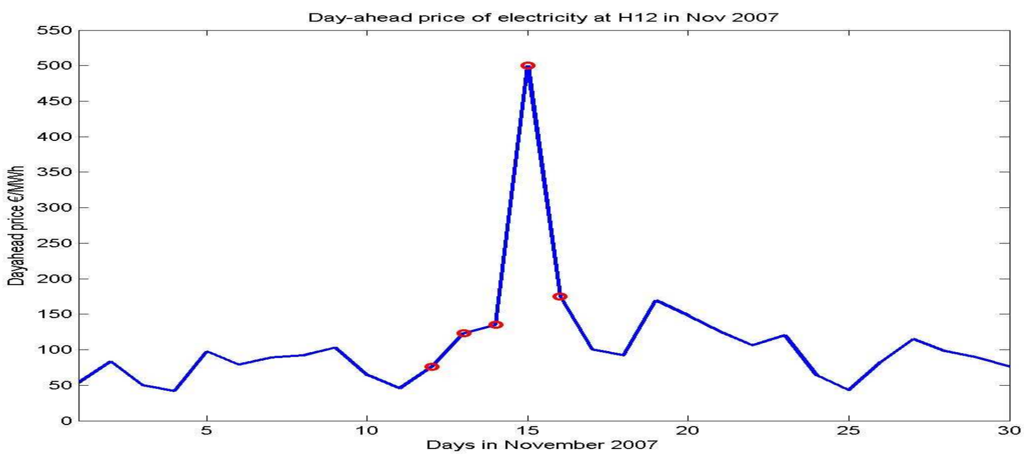

Figure A-1: Day-ahead prices at 12H during November 2007. The 5 days from Monday 12 to Friday 16 April 2007 are circled in red.

[2] According to the French newspaper, Le Figaro, dated 9 November 2007, the five unions working in the energy sector called for a strike on Wednesday 14 November in opposition to reforms in retirement conditions for public servants brought in by the Sarkosy government.

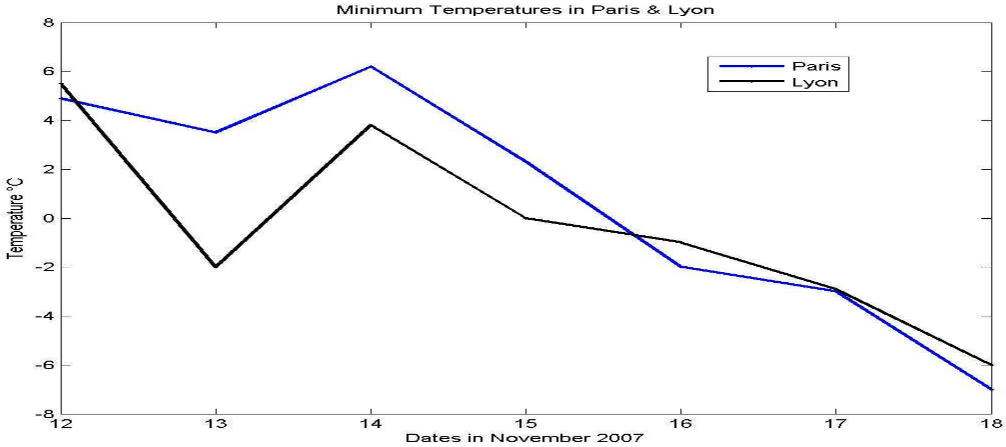

Figure A-2: Minimum temperatures recorded in Paris (blue) & Lyon (black)

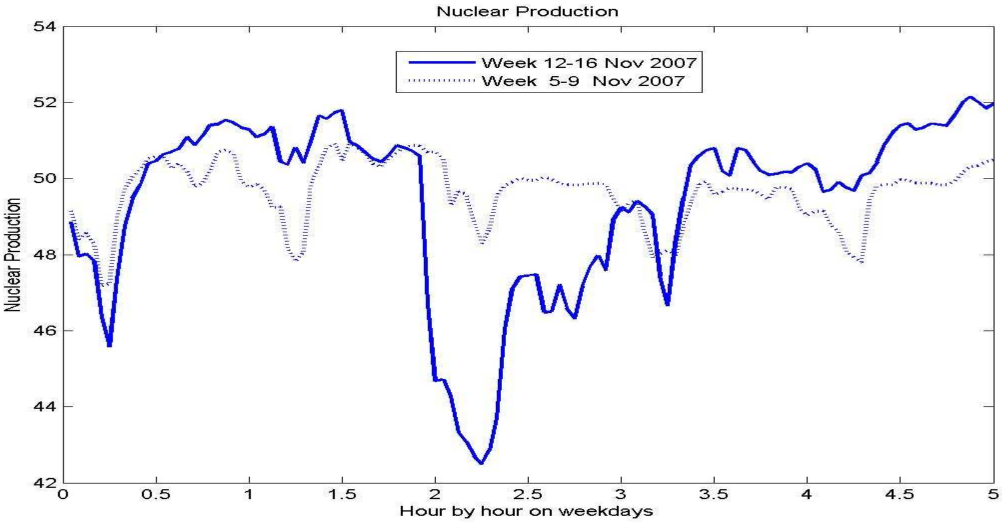

Figure A-3: The hourly production from nuclear plants during weekdays 5-9 (dotted line) & 12-16 (solid line) November 2007. Note the 18% drop in production on Wednesday 14

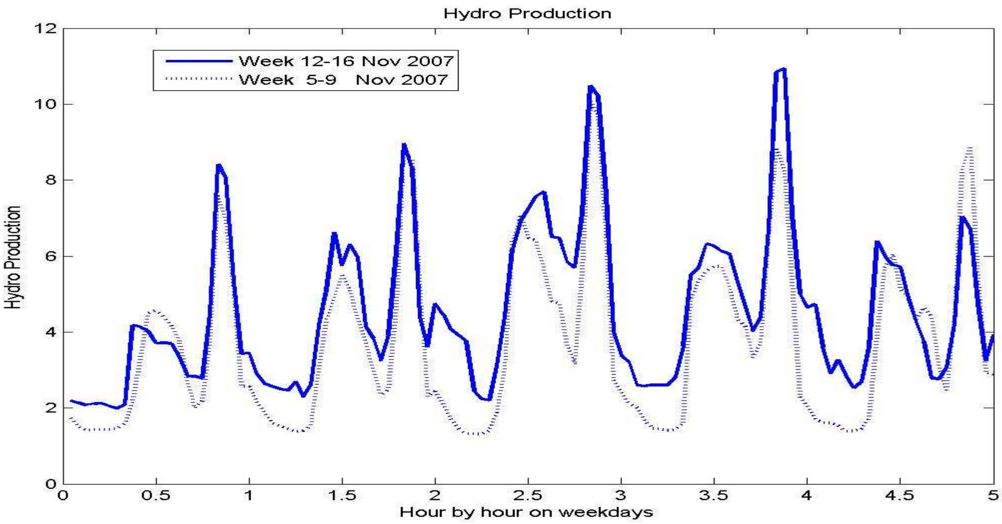

Figure A-4: The hourly production of hydro-electricity during weekdays 5-9 (dotted line) & 12-16 (solid line) November 2007. Note the increase in hydro production on Wednesday 14

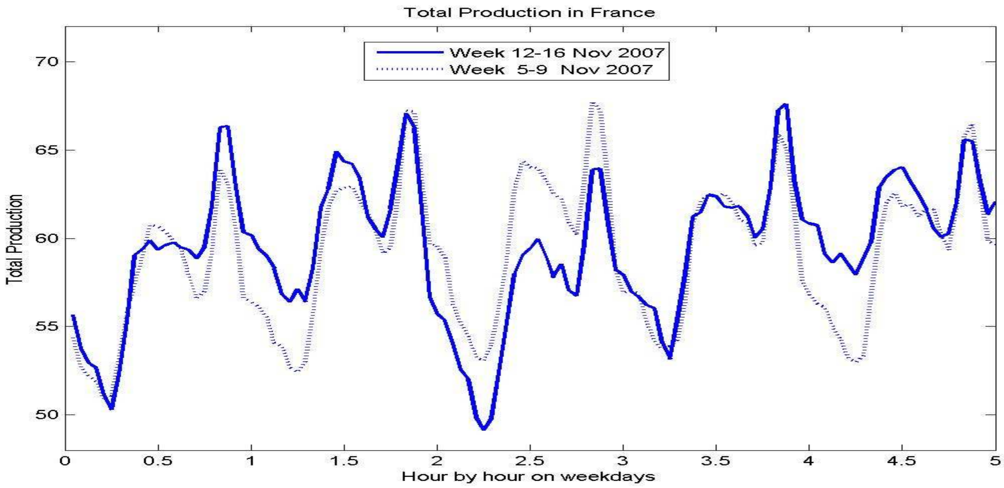

Figure A-5: The total hourly production in France during weekdays 5-9 (dotted line) & 12-16 (solid line) November 2007. Note that the total production on Wednesday 14 was below that of the previous week

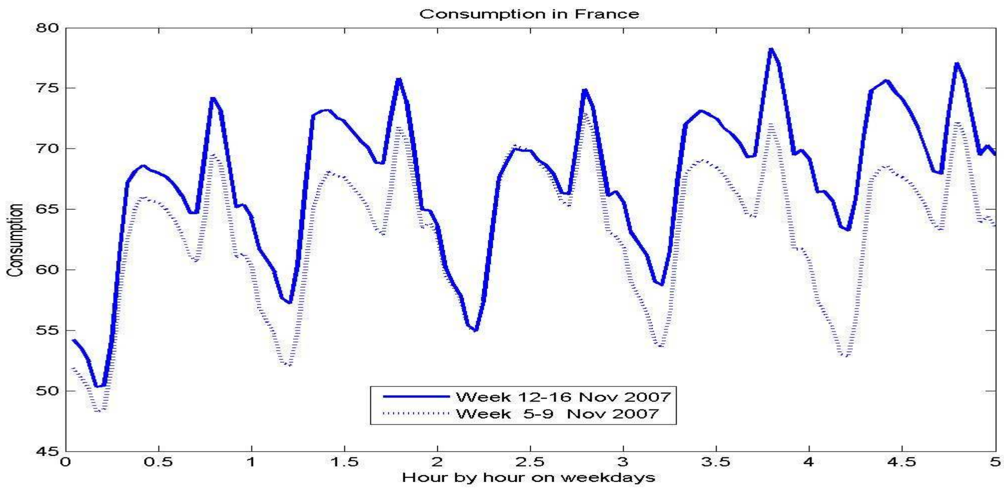

Figure A-6: The total hourly consumption in France during weekdays 5-9 (dotted line) & 12-16 (solid line) November 2007. Note that production on Wednesday 14 equalled that of the previous week

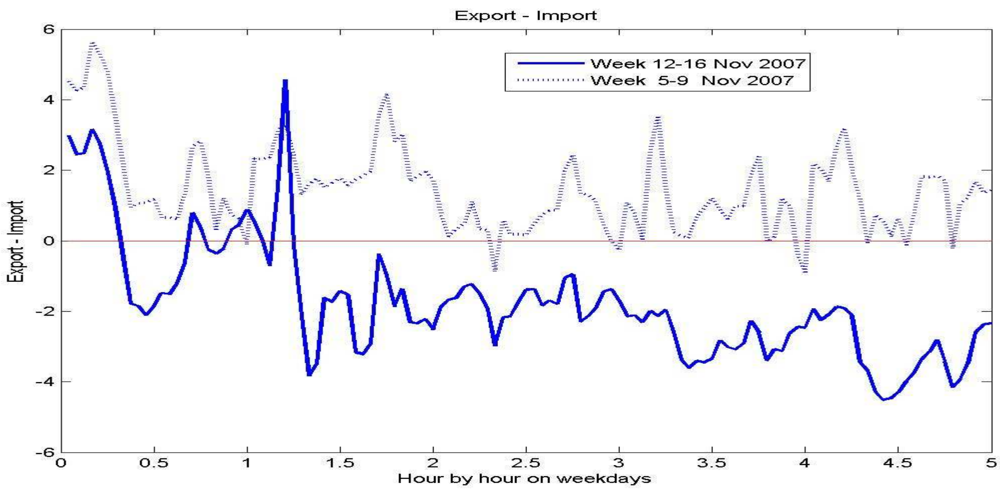

Figure A-7: The net quantity exported from / imported into France during weekdays 5-9 (dotted line) & 12-16 (solid line) November 2007. From Tuesday of the second week France became a net importer whereas France normally exports power

In general France exports power from its nuclear plants during off-peak periods but tends to import it during peak periods. The dotted line in Fig A-7 shows that France became a net importer (solid line) on Tuesday 13, after having been a net exporter the previous week. Some countries like Switzerland which had been a net importer at H12 even on Thursday 15 switched to become net exporters on Friday 16. We interpret this as meaning that the high prices on the French day-ahead market had encouraged Swiss producers to export to France on the following day.

Impact on the aggregated offers to buy & sell electricity

The next step is to see how the situation for France as a whole affected the aggregated offers to buy and sell electricity on the bourse. Figure A-8 presents these curves for H12 for four consecutive days, Tuesday 13 (top left), Wednesday 14 (top right), Thursday 15 (lower left) and Friday 16 (lower right). In each case the black increasing curve represents the offers to sell power and the red circle indicates the market fixing. Note that (1) the demand on the bourse is not inelastic even in periods of stress and (2) the shapes of the curves changed rapidly from one day to the next.

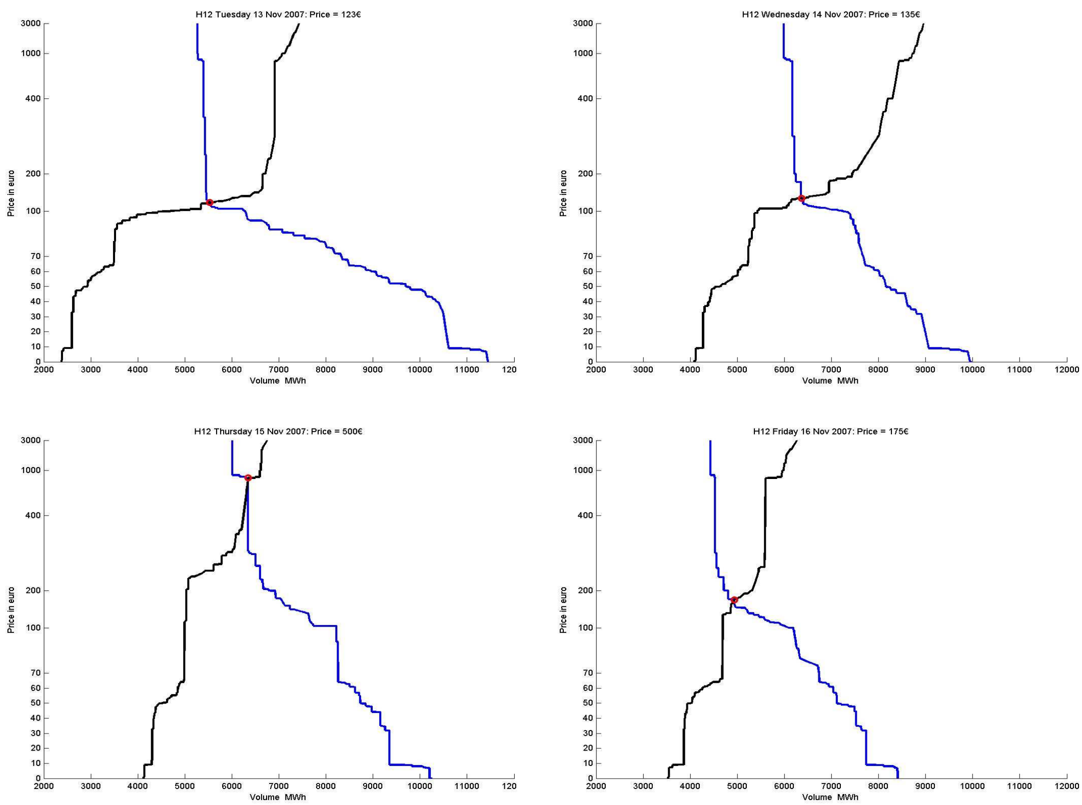

Figure A-8: The aggregated offers to buy electricity (blue) and to sell it (black) with the market fixing shown in red, for Tuesday 13 Nov (top left), Wednesday (top right), Thursday (bottom left) and Friday (bottom left). The day-ahead prices were 123 €, 135 €, 500 € and 178 € respectively

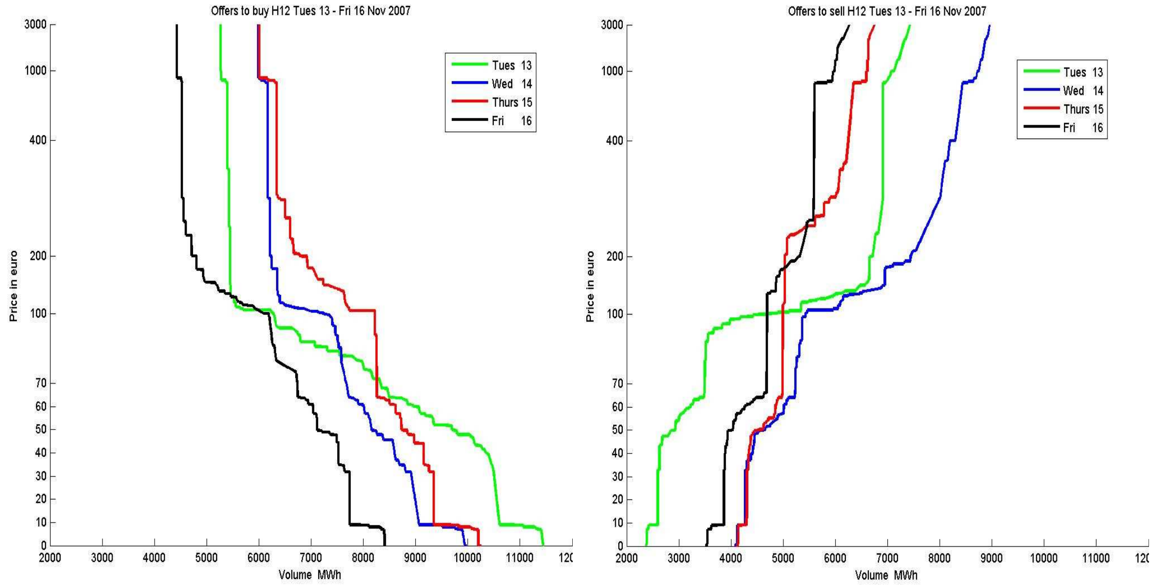

Figure A-9: The aggregated offers to buy electricity (left) and to sell it (right) for Tuesday 13 Nov (green), Wednesday (blue), Thursday (red) and Friday (black). The day-ahead prices were 123 €, 135 €, 500 € and 178 € respectively

Plotting the offers to sell power for these 4 days (Fig A-9) shows the marked changes from one day to the next. Do these sudden changes reflect changes in the overall merit order? By consulting the RTE website, we found that except for Wed 14, the total production capacity available was similar from one day to another so the full merit order would have been very similar for three of the four days. Despite that, the aggregate offers to sell electricity are quite different. In the next paragraph we propose an explanation.

Figure A-9 presents the aggregated offers to buy electricity on left and those to sell it on right on same four consecutive days as in Fig A-8: Tuesday 13 (green), Wednesday 14 (blue), Thursday 15 (red) and Friday 16 Nov). The demand for electricity on Wednesday and Thursday was much higher than on Tuesday, but on Friday 16 it was lower which is rather surprising as it was the coldest working day that week. On the supply side, more electricity (> 8000 MWh at the market maximum price of 3000 euro) was offered for sale on the bourse on Wednesday than the other days, despite the production incident with the nuclear power plants. This is probably because offers for Wednesday had to be submitted to EpexSpot by 11am on the previous day when nuclear production was normal (solid line, Fig A-3). The offers to sell on Thursday would have been submitted before 11am Wednesday when nuclear production was way below normal and when producers were expecting the cold front to arrive. This probably explains why so little was on offer (about 6000MWh at the market maximum price of 3000 euro). The approaching cold front probably explains the tight supply on Friday, but it is rather surprising to see how low the offers to buy were for Friday, especially given the temperature.

Looking at these curves, we note that

- The demand on the bourse is only inelastic at very high prices. At ordinary prices (below 150 euros) the demand varies with the price.
- The offers to buy and to sell change dramatically from one day to another.
- Except for Wednesday 14 when a production incident reduced the nuclear power, the same power plants were available, so the overall merit would be the same and yet the offers to sell on the bourse are not the same. So the offers to sell are not a scaled down version of the full merit order.

We therefore conclude that the standard approach in which price is computed by assuming that the demand is inelastic, and that the supply follows the overall merit order, is not appropriate for the French market.