PÖYRY

WHOLESALE ELECTRICITY PRICE PROJECTIONS FOR FRANCE

An *ILEX Energy Report* to SNET

July 2009 edition

ILEX ENERGY REPORT

WHOLESALE ELECTRICITY PRICE PROJECTIONS FOR FRANCE

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EXECUTIVE SUMMARY

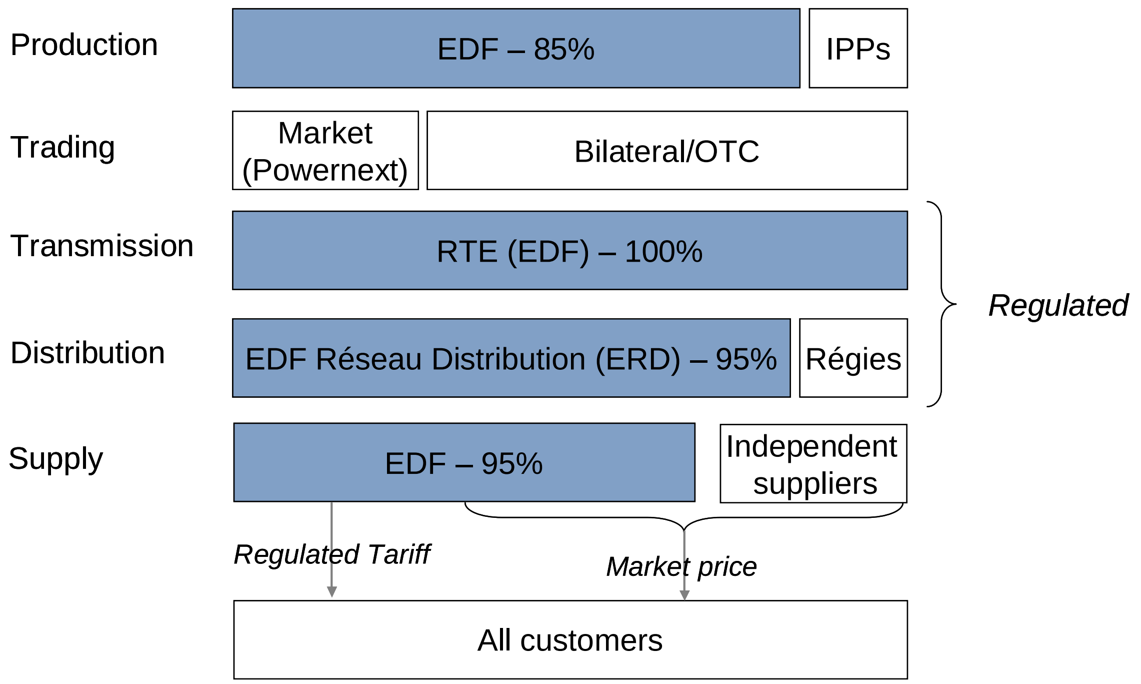
Pöyry Energy Consulting has been commissioned by SNET to provide an independent market report and analysis of the French market. We have used our *EurECa* model, which projects electricity generation and cross-border flows for twenty-five European countries, taking account of flows from a further six neighbouring countries to project wholesale electricity prices and spark-spreads for the period 2009–2030. The price projections in this report refer to the modelling that was undertaken by Pöyry Energy Consulting during July 2009.

Overview of the French electricity market

In 2008, electricity consumption in France was 494.5TWh, and peak demand reached 92.4GW. Domestic production was 549.1TWh and net exports were 46.6TWh. Nuclear contributed to 77.3% of the electricity produced in France, with the remainder of the generation mainly made-up of hydro (12.6%), thermal generation (9.8%) and wind (1%).

The French electricity market is dominated by the former monopoly EDF (Electricité de France) at all levels of the supply chain. Figure 1 shows the structure of the French electricity market together with EDF's share in the generation, transmission, distribution and supply sectors. The other major players in the generation market include GdF–Suez and E.ON France.

Figure 1 – French electricity market structure



The French transmission grid is operated, maintained and developed by Reseau Transport d'Electricite (RTE), a subsidiary fully owned by the EDF Group.

95% of the distribution network is operated maintained and developed by Electricité Réseau de Distribution France (ERDF), a subsidiary fully owned by the EDF Group. ERDF is engaged in a concession contract with French municipalities, which own the distribution assets.

The Commission de Régulation de l'Energie (CRE) has been the French energy regulator since its creation in March 2000. Its main mission is to oversee third party access (TPA) to the RTE grid and distribution networks and to determine tariffs for TPA. Its other responsibilities include protecting captive customers, investment planning for transmission and distribution (T&D), licensing new entrants and ensuring that public service obligations are respected.

In France, electricity is traded either over-the-counter through bilateral contracts or on the centralized Powernext market. Both spot (i.e. for the next day) and forwards (i.e. long-term contracts to be fulfilled at a future date in up to several years' time) are traded on Powernext. Around 80% of the volume actually delivered is traded over-the-counter, 15% on Powernext Day-ahead and 5% on Powernext Futures. Most spot products are traded through Powernext, whilst most baseload products are OTC transactions.

Wholesale electricity price projections

We have used our modelling expertise to create three scenarios that we feel cover a reasonable and internally consistent set of outcomes for wholesale prices within France, with the aim of examining the effect on prices of a number of key drivers:

- fuel prices (coal, oil and gas);
- gas market liberalisation;
- CO_2 prices;
- electricity demand;
- new power station construction and plant retirements; and
- costs and performance of new entrants.

These three scenarios can be summarised as follows and as in Table 1:

- **High.** The High price scenario examines the effect of high electricity demand and high fuel prices, driven primarily by crude oil prices returning to over $100/bbl in 2012 and remaining above this level, reaching $127/bbl in real terms in 2030. The high oil prices in turn drive gas prices up through indexation, at around €30/MWh in 2014 and up to around €40/MWh by 2030. We also assume that electricity demand growth will be relatively high leading to high levels of new thermal plant construction, and new nuclear reactors after 2020.
- **Central.** In the Central scenario, our Central oil price projection rises to $83/bbl by 2012 and remains in the $75–85/bbl range through to 2030. Gas prices remain stable at around €20/MWh for most of the period, indexed to our central oil price projections, as liberalisation throughout Europe either does not occur, or does not break the contractual linkages between oil and gas.
- **Low.** In the Low scenario, low demand for electricity is combined with a relatively high system margin and low fuel prices. We assume that gas prices break the link with oil, causing them to fall to the long-run marginal cost of gas supply. For all the modelled period the carbon price remains at a floor price (€10/tCO_2) that reflects our view of international carbon credit opportunity costs. Below this price, our modelled supply and utilisation of carbon credits from Joint Implementation and Clean

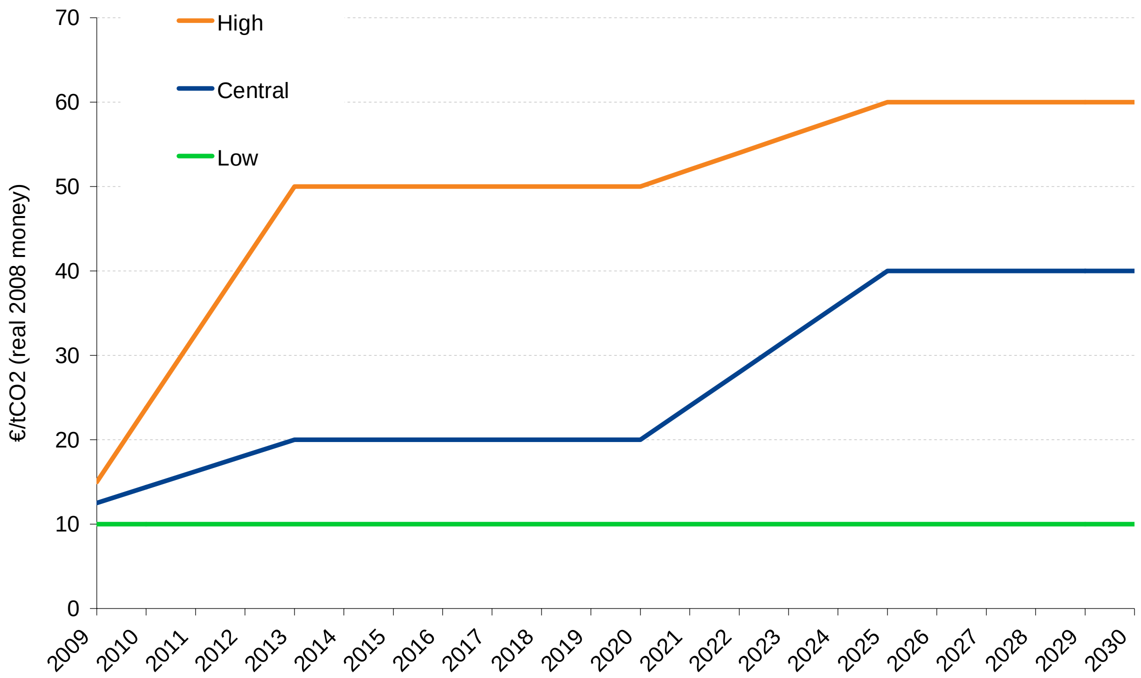
Development Mechanism projects is severely restricted, as they are assumed to flow to other parts of the world (e.g. Canada and Japan) than Europe. Low demand growth means low level of new thermal plants built under this scenario.

Table 1 – Summary of scenarios

	Fuel and carbon prices	Demand	New thermal build	Value of capacity
High	High	High	High	Increasing from high until 2015 and for the rest of modelled period.
Central	Central with oil-indexed gas prices	Central	Central	Slightly increasing to high from 2014 and for the rest of modelled period.
Low	Low	Low	Low	Slightly increasing to high from 2015 and for the rest of modelled period.

We have considered scenarios with a value of carbon in the French market. We use a range of different carbon values owing to the uncertainty of the price of carbon allowances in the Emissions Trading Schemes. Our projections for the timeframe are presented in Table 2.

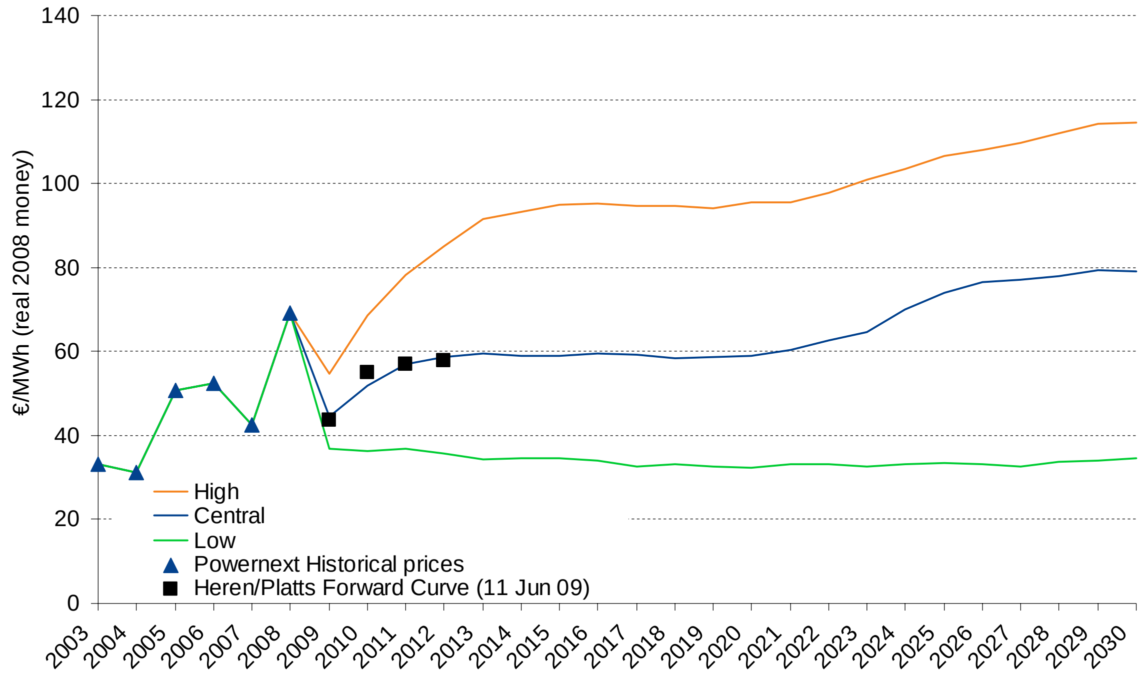
Table 2 – Pöyry assumptions for the value of carbon (€/tCO_2, real 2008 money)



Projections

The results of the three scenarios with a value of carbon are summarised in Figure 2 and Table 3.

Figure 2 – Wholesale electricity price projections for France – baseload (€/MWh, real 2008 money)



Source: Platts, Pöyry Energy Consulting analysis

High scenario

In our High scenario, the two most important drivers of high electricity prices are high demand and high fuel prices, with gas fired generation generally expensive relative to coal fired generation.

High oil prices and the continuation of oil-indexation across NWE cause the gas price to increase to around €30/MWh in 2014 and up to around €40/MWh by 2030. With ARA coal at around US$100/tonne and carbon prices rising to €50/tCO_2 for Phase II and €60/tCO_2 for Phase III and beyond, we project a rapid increase in high wholesale electricity prices from around €75/MWh in 2009 to €127/MWh in 2015. Until 2022, the wholesale price remains at around its 2015 level. In the outer years, wholesale electricity prices rise in line with increasing gas prices and growing demand, remaining at the top of our new entrant bands and reaching €146.8/MWh by 2030.

Central scenario

Our Central projection sees new entry commissioning from 2009 with the value of capacity high from 2014 onwards to support the new plants coming on. Wholesale electricity prices remain at around new entrant levels throughout with new entry coming on-line in all years.

Gas prices are projected to remain stable at around €20/MWh for most of the period, indexed to our central oil price projections, as liberalisation throughout Europe either does not occur, or does not break the contractual linkages between oil and gas. Overall, wholesale electricity prices remain at around €64/MWh for the majority of the modelled period. In the outer years, electricity prices start moving upwards in line with a rise in gas prices during this period.

Low scenario

The key drivers for the Low scenario are low demand and low fuel prices. The relatively high system margin leads to a low value of capacity in the beginning of the period. Wholesale electricity prices in this scenario remain under the new entry band for the entire period until 2030. Thus there is no conventional new entry in the Low scenario.

In the Low scenario, gas prices are fully de-index from oil by 2014 and fall to low levels, under €10/MWh in real terms. This decline in gas prices, combined with coal prices remaining under $50/tonne from 2017 and gradually decreasing to $41/tonne by 2030, ensures that the wholesale electricity prices are below €35/MWh from 2013 onwards.

Table 3 – Wholesale electricity price projections for France – baseload
(€/MWh, real 2008 money)

€/MWh	High	Central	Low
2009	54.7	44.6	36.9
2010	68.5	51.8	36.3
2011	78.1	56.9	37.0
2012	85.2	58.6	35.8
2013	91.6	59.4	34.4
2014	93.4	59.0	34.5
2015	95.0	59.0	34.6
2016	95.1	59.4	33.9
2017	94.8	59.1	32.7
2018	94.6	58.4	33.1
2019	94.0	58.7	32.5
2020	95.6	58.9	32.2
2021	95.6	60.5	33.2
2022	97.7	62.7	33.1
2023	101.0	64.5	32.7
2024	103.4	70.1	33.1
2025	106.6	73.9	33.4
2026	107.9	76.4	33.2
2027	109.6	77.2	32.6
2028	111.9	77.8	33.6
2029	114.2	79.2	33.9
2030	114.5	79.1	34.5

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1. INTRODUCTION

1.1 Content of this report

This independent report presents Pöyry's analysis of the wholesale prices for the French electricity market. The projections cover the period 2009–2030, based on our detailed modelling of the fundamentals of supply and demand in France. We have combined input assumptions to create three detailed and internally consistent market scenarios for our price projections. The price projections in this report refer to the modelling that was undertaken by Pöyry Energy Consulting during July 2009.

The remainder of this report is structured as follows:

- Chapter 2 describes the main characteristics of the French electricity market;
- Chapter 3 presents the French policy for supporting the uptake of renewable generation technologies;
- Chapter 4 describes and presents the inputs to our wholesale electricity price projections, which also includes setting out our gas price projections;
- Chapter 5 explains how we combine our input assumptions to develop our price projection scenarios and presents our final wholesale electricity price projections;
- Annex A explains how our European electricity market model, EurECa, operates;
- Annex B provides two worked examples for calculating the potential value of a renewable wind development in France; and
- Annex C present the range of available Ilex Energy Reports.

1.2 Pöyry Energy Consulting

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1.3 Conventions

All monetary values quoted in this report are in Euros in **real 2008** prices, unless otherwise stated. Annual data relates to calendar years running from 1 January to 31 December, unless explicitly defined otherwise.

1.3.1 Sources

Where tables, figures and charts are not specifically sourced they should be attributed to Pöyry Energy Consulting.

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2. BACKGROUND TO THE FRENCH ELECTRICITY MARKET

In this chapter we provide a background to the French electricity market covering the following key topics:

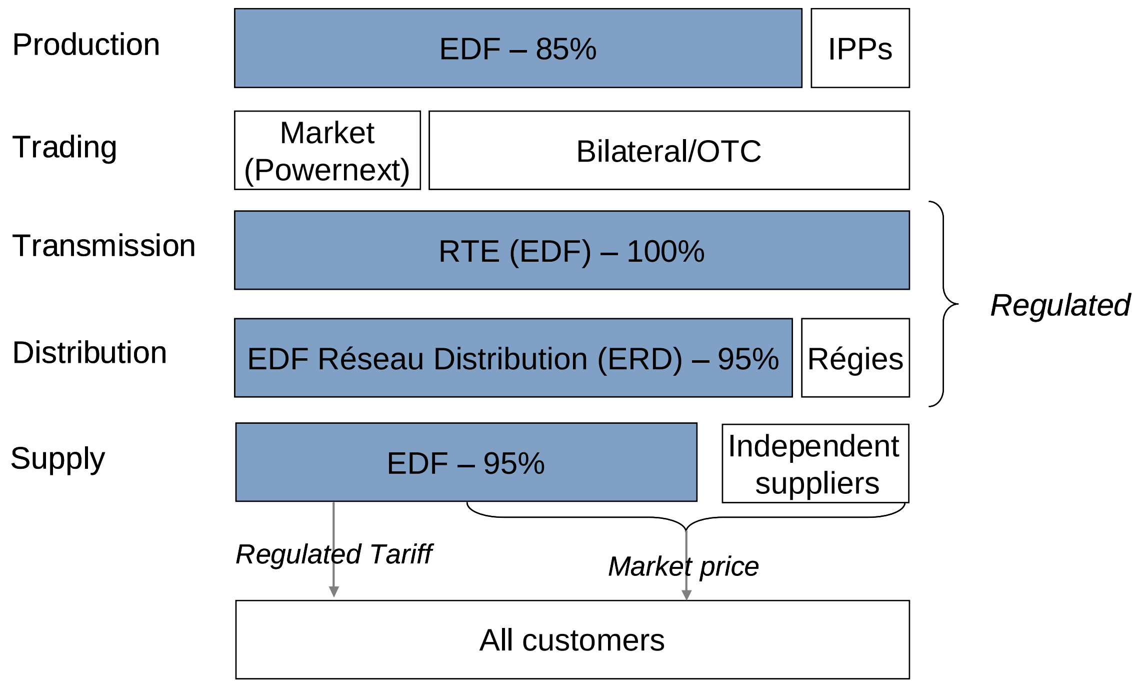
- market structure;
- the major players in the electricity generation, transmission and supply sectors;
- physical characteristics of the French market, including total capacity and demand levels;
- the different trading arrangements used to sell and purchase power;
- economic regulation, environmental regulation and recent developments in European regulation; and
- a description of how France has implemented the European Union Emissions Trading Scheme into national policy. In chapter 3 we describe the French policy for supporting the growth in renewable electricity generation.

2.1 Current Industry Structure

2.1.1 Overview of the French Electricity market

The French electricity market is dominated by the former monopoly EDF (Electricité de France) at all levels of the supply chain. Figure 3 shows the structure of the French electricity market along with EDF's share in the generation, transmission, distribution and supply sectors. These areas are described in detail in the following sections.

Figure 3 – French electricity market structure



2.1.2 Liberalisation and market opening

The French Government implemented the EU Electricity Directive[1] through the Electricity Law in 2000[2]. The main provisions of the Electricity Law are:

- the establishment of an independent regulatory commission, the Commission de Régulation de l'Energie (CRE);
- Third Party Access (TPA) to transmission and distribution networks for eligible customers;
- TPA tariffs set by the French Ministry of the Economy, Finance and Industry (MINEFI) in consultation with CRE;
- generators, including foreign companies, allowed to build new generation plants subject to government authorisations;
- MINEFI issues calls for tender based on periodic reviews of capacity requirements; and
- MINEFI oversees the long term planning and investment in the transmission grid (RTE).

Liberalisation has been completed in several phases, as regards to 'eligible' customers who can choose their own supplier:

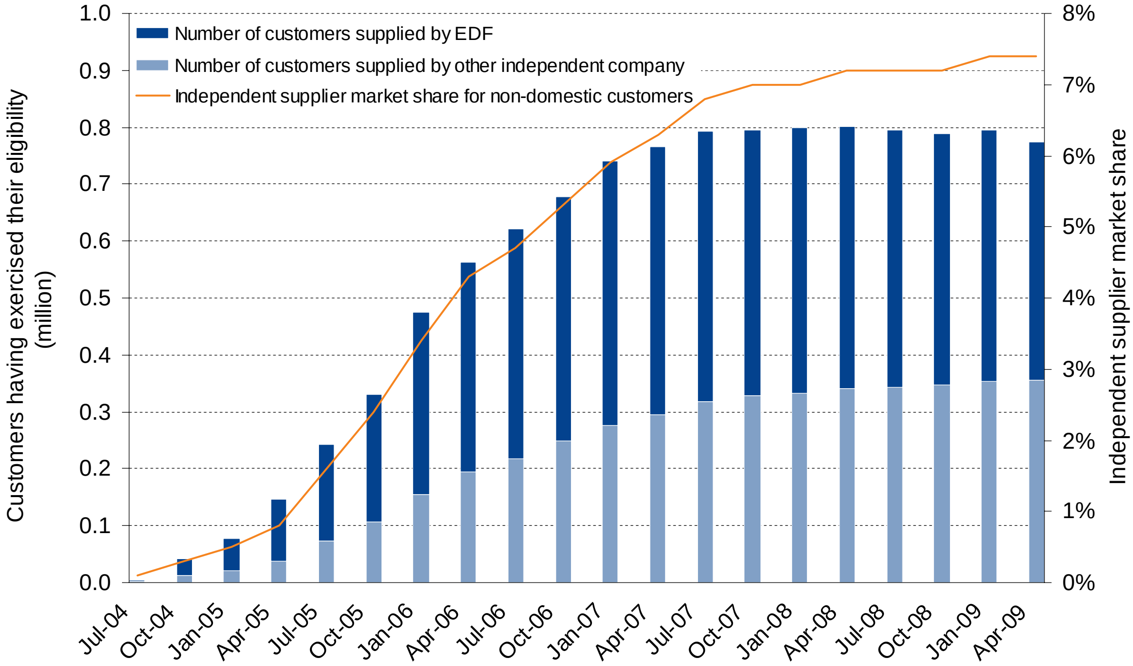
- June 2000, any site consuming more than 16GWh of electricity annually;
- February 2003, any site consuming more than 7GWh;
- July 2004, any non-domestic consumer, consuming approximately 295TWh p.a.; and
- July 2007, any domestic consumer, consuming approximately 135TWh per annum.

Eligible customers have not necessarily exercised their eligibility. For those customers who have not, the tariff they are charged is still regulated. For those customers that have exercised their eligibility, they either have not changed suppliers so far and do not pay regulated tariffs; or they have switched suppliers. Figure 4 shows the switching rate in the French market for non-domestic customers.

1 'Common rules for an internal market in electricity'. Electricity Directive 96/92/EC.

2 Law nº 2000-108, 10 February 2000.

Figure 4 – Non-domestic customers switching to market based tariffs



Source: CRE

In 2005, a significant number of industrial customers switched to non-regulated contracts linked to market prices supplied both by EDF and other independent suppliers. In 2006, market prices increased significantly whilst regulated tariffs remained linked largely to the cost of nuclear and therefore remained fairly stable. This caused a lack of competitiveness for those customers exposed to the market price, especially large intensive energy users.

In response to this, the French government introduced a law in December 2006[3] which set up a transitional two-year period during which industrial sites that had exercised their eligibility could take advantage of an intermediate tariff. The tariff, known as ‘tarif de retour’, or TaRTAM, was calculated as a fixed 10 to 23 per cent increase on the regulated tariff, depending on the consumption characteristics of the customer[4]. The impact of this law was minor in terms of the number of client switching back to the regulated tariff: only 3,600 clients decided to take advantage of this offer. The law, however, may have had a much greater impact on how market prices are perceived, in the sense that they have been associated with a permanent option, with a significant price risk.

Liberalisation has been coolly received by residential customers so far. Poweo, one of the new entrants in the French market, had acquired only 3,717 customers by the end of 2007 rather than the 100,000 initially expected[5]. These results were attributed to several factors, including the influential consumer association ‘UFC – Que Choisir’ appeal to French customers to stay with regulated tariffs, which would not rise above inflation

3 Law 2006-1537, 7 December 2006, article 15.

4 Decree of the 3 January 2007.

5 Poweo, Annual results 2009.

before 2010. Despite this modest start, Poweo had 106,200 customers in 2008[6] and claimed over 320,000 customers at the end of 2008. Overall, at the end of March 2009, a total of 884,000 households (out of 29.7 million) had switched to non-regulated tariffs, of which 9,000 had remained with their historical supplier[7].

On 21 January 2008 the French Government implemented the right of 'reversibility' between regulated and non-regulated tariffs for electricity to all households, which will apply until July 2010[8]. This right enables customers to switch back to EDF at the 'regulated tariff'. The policy for after 2010 is not clear yet, and it will be a major bone of contention in the coming years between the European Commission (which would like full undistorted competition in electricity markets) and the French government (which would like to protect French customers from higher market prices).

2.1.3 How to increase competition in the French electricity market: main conclusions from the 'Champsaur report'

As mentioned above the 'reversibility' right enables customers to switch back to EDF at the 'regulated tariff'. It was implemented to help large consumers, who had switched to market contracts, because market prices were much higher than regulated tariffs. However there is doubt that this can be a long-lasting solution, especially as it is incompatible with EU regulations.

In November 2008, the French government established the 'Commission Champsaur' to look at ways to improve competition in the French electricity market. The 'Champsaur report' – released in April 2009 – suggested a complex system, aimed at providing all suppliers with access to low cost baseload nuclear electricity in order to boost competition and terminate the TaRTAM:

- 'The current market situation is neither economically satisfactory in the short-term, nor sustainable in the long-term.'
- 'Market prices in France do not reflect the competitive advantages of the generation mix.'

The latter refers to the very competitive nuclear and hydraulic electricity generation, which accounts for 90 % of the total production. Today, the higher costs of gas- or coal-fired power plants, which are dominant in neighbouring countries, set the French market prices.

Peak electricity is a market where competition can be enforced at the French and/or European levels. Competition for baseload production is rather difficult in Europe because of the past differences in national policies, which created generation mix with different production costs.

Two policies could allow to pass-through the benefits of the competitive French generation mix to the customers:

- Taxing EDF windfall profits derived from its low cost nuclear electricity generation, and distributing the revenues to the customers;

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6 Platts, Power in Europe.

7 'Observatoire des marches de l'électricité et du gaz – premier trimestre'. CRE, Juin 2009.

8 CRE, Rapport d'activité, juin 2008.

- Providing a regulated access to (nuclear) baseload production at identical costs for all suppliers. Each supplier (incumbent or newcomer) would have access to a share of baseload electricity proportional to its clients' portfolio. Price would be based on long-term marginal cost (allowing for the renewal of these means of generation).

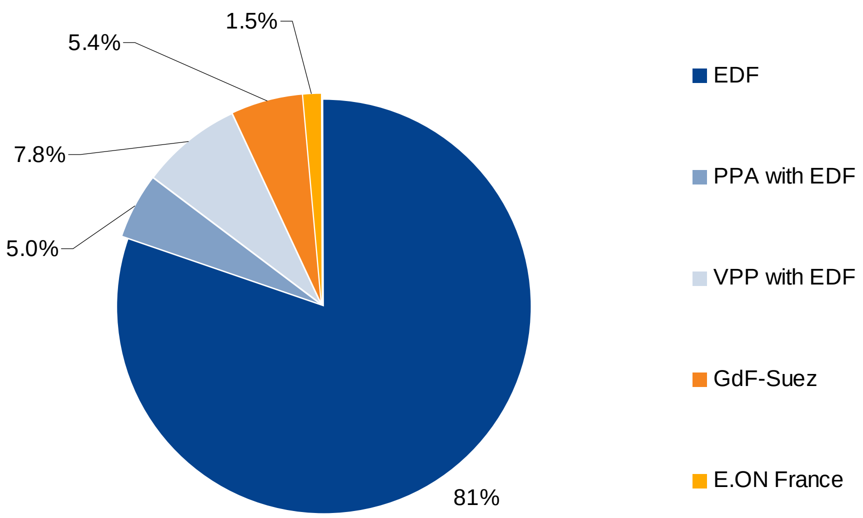
The authors of the report favour the second option and ask for an 'account unbundling' of EDF, whereby EDF's nuclear power plants would be separated from the other means of generation. In such framework, the authors recommend that regulated tariffs be terminated for large consumers. The low procurement cost would give all suppliers, including the newcomers, the opportunity to become competitive.

2.2 Structure of Generation, Supply and Transmission

2.2.1 Generation companies

Electricité de France (EDF) is owned by the French state at 85%. The former fully state-owned monopoly still dominates the French electricity market at every stage of the supply chain. In 2008, EDF produced around 441TWh, which accounts for 81% of France's total generation. 5% of its generation is through compulsory Power Purchase Agreements (PPA)[9].

Figure 5 – Generation market share in 2008



Source: CRE

2.2.1.1 Electricité de France (EDF)

EDF is Europe's largest power utility and became a publicly-traded company – 'Société anonyme' – in 2004. 12.7% of EDF shares were sold on the Paris stock market in a move that reportedly valued EDF at €55bn. and by November 2007, this figure had risen to €153bn.

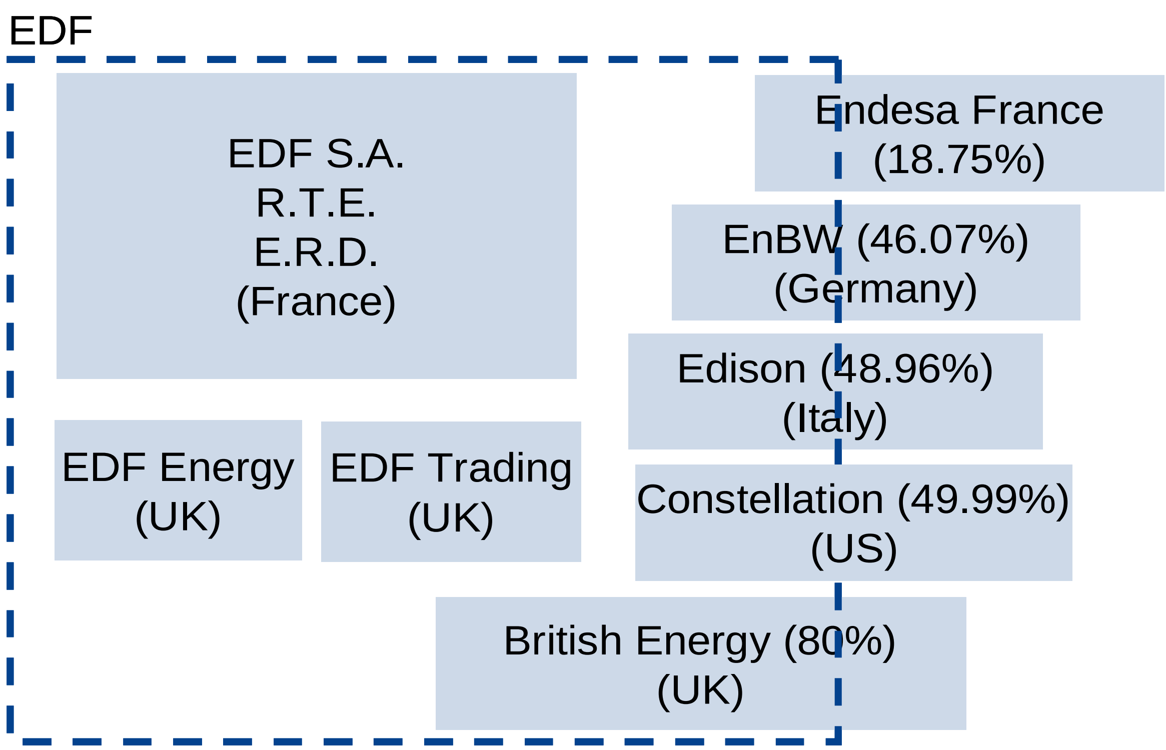
9 EDF, Annual Report 2008.

At around the same time, the French government sold 2.47% of its shares in EDF for which it received €3.7bn, thus bringing down the State's stake to around 84.8%. Under current law, the French government is allowed to reduce its stake down to 70%[10].

EDF Group is a major player in the markets of France, the United Kingdom, Germany and Italy, as illustrated in Figure 6, and is also involved in power generation in other European countries and the rest of the world, including Asia and the United States. EDF has recently focused its activities in Europe by selling its shares in Latin America, but is still looking for opportunities for power generation in China, the United States, UK and South Africa. EDF is also diversifying its portfolio by investing in renewable energy and in the gas market. In 2008 net sales were €64.3bn (€38.1bn for France), with 38.5 million customers (27.9 million in France)[11].

Following the acquisition of British Energy by EDF in January 2009, EDF and Centrica set up a joint venture (80/20) to build four new EPR nuclear power stations in the UK. Within this agreement, EDF and Centrica will share the electricity production of BE according to scale of the stake of the company in the joint venture (i.e. 80% for EDF and 20% for Centrica). In addition EDF is committed to provide Centrica with 18TWh of electricity at market price for a period of 5 years starting in 2011. EDF also acquired 51% of Centrica share in SPE for €1.3bn. As Centrica will pay EDF €1.2bn for a 20% stake in British Energy, the whole transaction is really similar to an asset swaps between the two companies. The implementation is expected for the end of 2009.

Figure 6 – Main EDF ownership in North West Europe



Source: EDF, Pöyry Energy Consulting

10 'La vente de titres EDF rapporte bien moins que prévu à l'Etat'. Les Echos, 4 December 2007.

11 EDF, Annual Report 2008.

EDF owns around 159GW[12] of capacity in the world (98.4GW in France), including 58 nuclear reactors accounting for 65.8GW, and a 1650MW EPR under construction in Flamanville scheduled to come online in 2012. Over the period 2008–2010, EDF is investing €35bn, including €20bn in France, in generation, transmission and distribution. EDF is continuing its programme to build additional capacity. 6GW are due to come online by 2012, of which 4GW will be fossil-fuelled thermal capacity to be used for times of high demand and peaking periods.

In 2008, over 190MW of additional wind power capacity was brought online in France, including major fields such as Chemin d'Ablis (52MW in the Eure-et-Loir department) and Salles-Curan (87MW in the Aveyron department). The French utility is increasing its investments in solar power generation in 2009. As of 30 June 2009, 116MW are in construction and 27.6MW are already online in the world, with respectively 71.2MW and 7.4MW in France.

On 29 January 2009, the construction of a second EPR nuclear unit (1650MW) in France – in Penly – was announced. The construction should start in 2012 and completion is scheduled for 2017.

2.2.1.2 Gaz de France – SUEZ

Resulting from the merger of Gaz de France (GDF) and Suez on 22 July 2008, GDF Suez was created. The French state still holds a 35.6% share of the capital in the company in order to protect national interests.

GDF Suez is investing €30bn over the period 2008–2010. The target is to increase its installed capacity to 100GW worldwide and to 10GW in France. In 2008, the company generated 277TWh[13] and its installed capacity in France was 6.4GW. Wind energy is its fastest growing renewable source of power generation which accounted for 383MW in 2008 and 400MW are currently under construction.

GDF Suez seeks to invest in nuclear power generation. Currently, the company holds 1.1GW of installed capacity in the French plants Chooz and Tricastin, operated by EDF. It holds a 33.33% stake in the second EPR project in Penly and is competing with EDF for a third EPR project. However, the French government announced in June 2009 that alternatives to this project will be found and that there will not be a third EPR in France before 2020.

Since December 2003, GDF Suez has held 49.5% of the Compagnie Nationale du Rhone (CNR). 30% is owned by Caisse des Dépôts et Consignations (CDC), and a number of local authorities make up the remainder[14]. CNR owns about 3GW of hydro capacity from installations along the river Rhône, whose generation level is fairly unpredictable, but it has an average annual generation of approximately 16TWh.

In July 2009, E.ON and GDF-Suez received a fine of €553 million each for breaking European Union antitrust rules by colluding on sales of natural gas in national markets since 1975. On 31 July 2009, both companies finalised a swap generation capacity agreement in Europe. GDF-Suez will acquire 860MW in conventional power plants and 132MW in hydro from E.ON. In addition, GDF-Suez will acquire electricity generated out

12 This does take into account of the on-going acquisition of British Energy (10.6GW).

13 GDF Suez Business and Sustainable Development Report, 2008.

14 CNR website.

of a capacity of 700 MW in form of drawing rights from E.ON nuclear power plants in Germany. As a counterpart, E.ON will acquire 941MW in conventional power plants (the 556MW Langerlo coal and biomass plant and the 385MW Vilvoorde gas-fired plant) from GDF-Suez. In addition, E.ON will acquire electricity generated out of a capacity of 770 MW in form of drawing rights from GDF-Suez nuclear power plants with delivery points in Belgium and the Netherlands.

2.2.1.3 E.ON France (formerly SNET)

E.ON France is the third largest power company in France (on the basis of installed capacity), with 2.5GW currently on-line producing around 8TWh per annum. On 26 June 2008 E.ON has completed its acquisition of a 65% stake in SNET ('Société Nationale d'Electricité et de Thermique'), previously owned by Endesa. The remaining shares are split as follows: 16.25% owned by the national coal-mining company Charbonnage de France (CDF); and 18.75% by EDF. The transaction marked a major step for E.ON in its endeavour to become a key player in the French energy sector[15]. E.ON agreement with GDF-Suez on July 31 2009 mentioned above confirms the strategy of the German group.

In addition to the Provence power station with 868MW installed capacity, Endesa France has coal-fired facilities at Emile Huchet (1.086GW), Hornaing (253MW) and Lucy (270MW). The company also plans to expand its CCGT capacity by over 3GW[16]. This expansion is going on with the construction of a 860MW CCGT on the Emile Huchet site which is planned to be operational by the first quarter 2010. Construction of 430MW CCGTs on Hornaing and Lucy sites is still under consideration. Work has also been undertaken on coal-fired facilities at Hemile Huchet and Provence on the main units in 2008, which will extend its exploitation for another 10 years up to 2025[17].

2.2.1.4 Poweo

Poweo is one of the major new entrants in the French market, with plans to develop 3.8GW of generation capacity by 2012. These projects represent 2.5GW in conventional thermal energy and 1.3GW in renewable energies, all at different stages of completion. These numbers have been revised downwards due to the global economic downturn and the subsequent freeze of its Le Havre project. Its first plant, a 412MW CCGT in Pont-Sur-Sambre, became operational in the first quarter of 2009.

In January 2007, Poweo signed a swap deal with EDF for 160MW of its CCGT capacity in Pont-Sur-Sambre and 160MW of baseload nuclear capacity from EDF, for a 15 year period. In addition to that, Poweo obtained sourcing rights within the nuclear auctions scheme implemented in 2008 upon the request from the French Competition Council, and secured an additional 179 MW over 15 years[18].

2.2.1.5 Direct Energie

Direct Energie is the other major independent new entrant in the French market that has been active in both retail and trading since 2003. In June 2009, the company reported over 450,000 customers in the residential and industrial sectors.

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15 Press release, 'E.ON's acquisition of SNET reflects the company's ambitions on the French energy market', 26 June 2008.

16 Endesa press release, 12 March 2008.

17 'E.ON presente ses objectifs de developpement industriel', Press release, 25 mars 2009.

18 '2008 full-year results', Press release 16 mars 2009.

Recently, Direct Energie announced a 800MW CCGT project in the North of France, in Verberie (Oise)[19]. Direct Energie also conducted an anti-trust case against EDF, which resulted in capacity auctions for new entrants (see section 2.4.2).

2.2.1.6 Alpiq

The two Swiss companies Atel and EOS have merged in December 2008 to become Alpiq. Alpiq is the main service provider in Switzerland, and it has strong European ambitions in generation and retail. Atel is developing a CCGT project in France (see section 4.8), and has announced another 400MW CCGT project in North of France[20]. EDF has a 25% market share in the new holding.

2.2.2 Transmission

The transmission network is made up of several tiers: a national grid where electricity is transmitted at 400kV (which is interconnected with neighbouring countries) and a set of regional networks ranging from 225kV to 63kV. The transmission network has a total length of about 100,000km.

2.2.2.1 Ownership structure

Since 1999, the high-voltage transmission grid has been controlled and operated by Réseau de Transport d'Electricité (RTE), a ring-fenced subsidiary of EDF. In September 2005, RTE became a subsidiary of EDF and a state-owned limited company. RTE owns all public networks of 50kV and above. Some small sections of the transmission grid are owned by other companies, such as the national railway company SNCF.

2.2.2.2 TPA and unbundling arrangements for connection and access

Both transmission and distribution networks must offer Third Party Access (TPA) to eligible customers. There are currently four tariff levels depending on the voltage involved, whereby each one comprises capacity and commodity charges that vary with the season and the time of the day. These tariffs can be found on the CRE website[21]. The existence of recent IPP entry that required line upgrades suggests that RTE is sticking with TPA arrangements although costs (especially when new HV lines are required) can be significant.

Following a consultation by CRE during 2008, new tariffs (TURPE 3) have been effective since 1 January 2009 and will last for four years in order to give network operators a better control over their costs and the investments needed[22].

2.2.2.3 New/planned infrastructure

Following a public consultation, it has been decided that a new high voltage line of 400kV would be constructed for the EPR nuclear plant at Flamanville in Normandy. The line is scheduled to be in service by the end of 2011 or early 2012[23].

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[19] 'Direct Energie veut investir 550 million d'euros dans l'Oise', Les Echos, 24 December 2008.

[20] 'Le suisse Atel investit 300 million d'euros dans une centrale thermique'. Les Echos, 7 October 2008.

[21] www.cre.fr – 'Accès aux réseaux'.

[22] CRE, Rapport d'activité, juin 2009.

[23] RTE Pojet de Ligne Cotentin Maine, Mars 2009.

Other large grid reinforcement programs are mainly based in the south of the country to prepare the system for the planned development of CCGT plants and the closure of the energy intensive Tricastin uranium enrichment plans. However these reinforcements are not going as quickly as planned and the technical performance of the system in the medium term still raises concerns[24]. Moves to upgrade the interconnector capacity with Spain have been in discussion for a while. In May 2008, the French government announced that it was in favour of an underground high voltage line despite its costs. Most of the complaints were indeed related to the risks involved with a traditional approach for the people living in the area. However, there has been little progress towards the implementation.

The 2020 renewable targets set for France (see 3.1.2) will require major investments in transmission infrastructure to accommodate the massive growth of renewable capacity. To date, RTE is able to provide transmission capacity for 6 to 7GW of renewables. Since the share of renewables in the mix will be growing, RTE anticipated €1bn of investment by 2020, half of which should be spent by 2010–2012, in order to provide connection for around 20GW of renewables[25].

2.2.3 Distribution and supply

Within France, distribution grids are defined as any transmission lines with a voltage below 63kV.

About 95% of the distribution network is controlled by EDF Réseau de Distribution (ERD), under concession agreements from local authorities. The rest is controlled by the so-called régies, which are usually municipal utilities operating in medium-size towns or rural areas. The six largest of these companies are Electricité de Strasbourg, Gaz et Electricité de Grenoble (GEG), Régie du SIEDS, Usine d’Electricité de Metz (UEM), SICAE de l’Oise and Sorégies.

2.3 Physical characteristics

2.3.1 Generation

In January 2009, the total installed generation capacity in France was 117.7GW, with 109.2GW connected to the RTE high voltage transmission network[26].

Since the first oil shock of 1973, France has pursued an active policy of achieving a large degree of energy self-sufficiency through nuclear power, given its lack of domestic energy resources. That choice remains a key consideration that guides French energy policy today. Figure 7 to Figure 9 show the dominance of nuclear in the current fuel mix. Whilst nuclear capacity represents around 55% of the generation capacity, it contributed to 77.3% of the 549.1TWh produced in France in 2008. Hydro (12.6%), thermal generation (9.8%) and wind (1%) made up the remainder of electricity generated in 2008.

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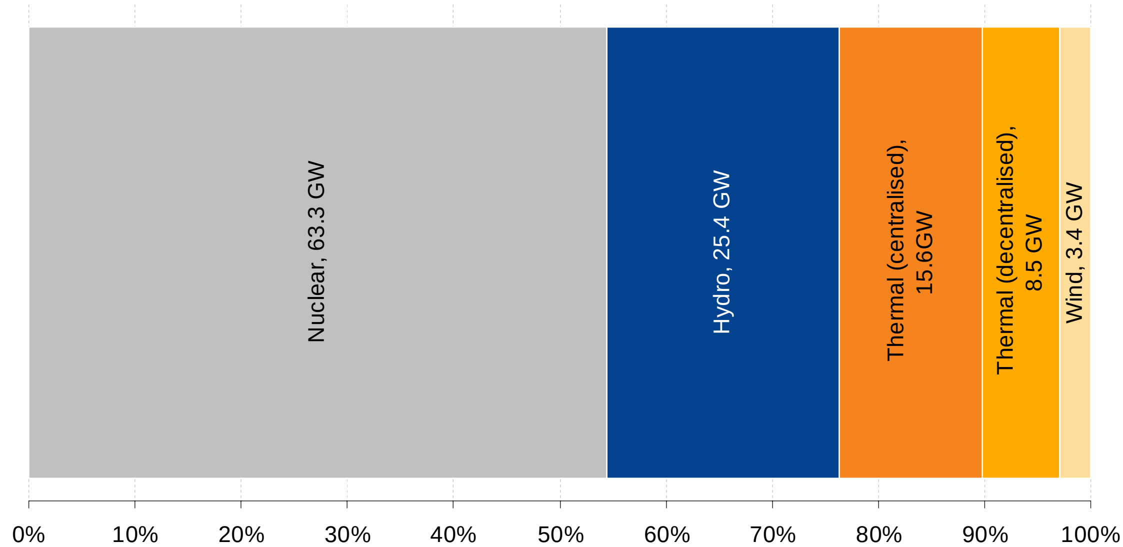
24 Source: Platts Power in Europe, Issue 507.

25 RTE, ‘Energies renouvelables et réseaux de transport d’électricité’, 1 juillet 2008; RTE, ‘Les nouveaux engagements de RTE en faveur d’un developpement durable, 21 Octobre 2008.

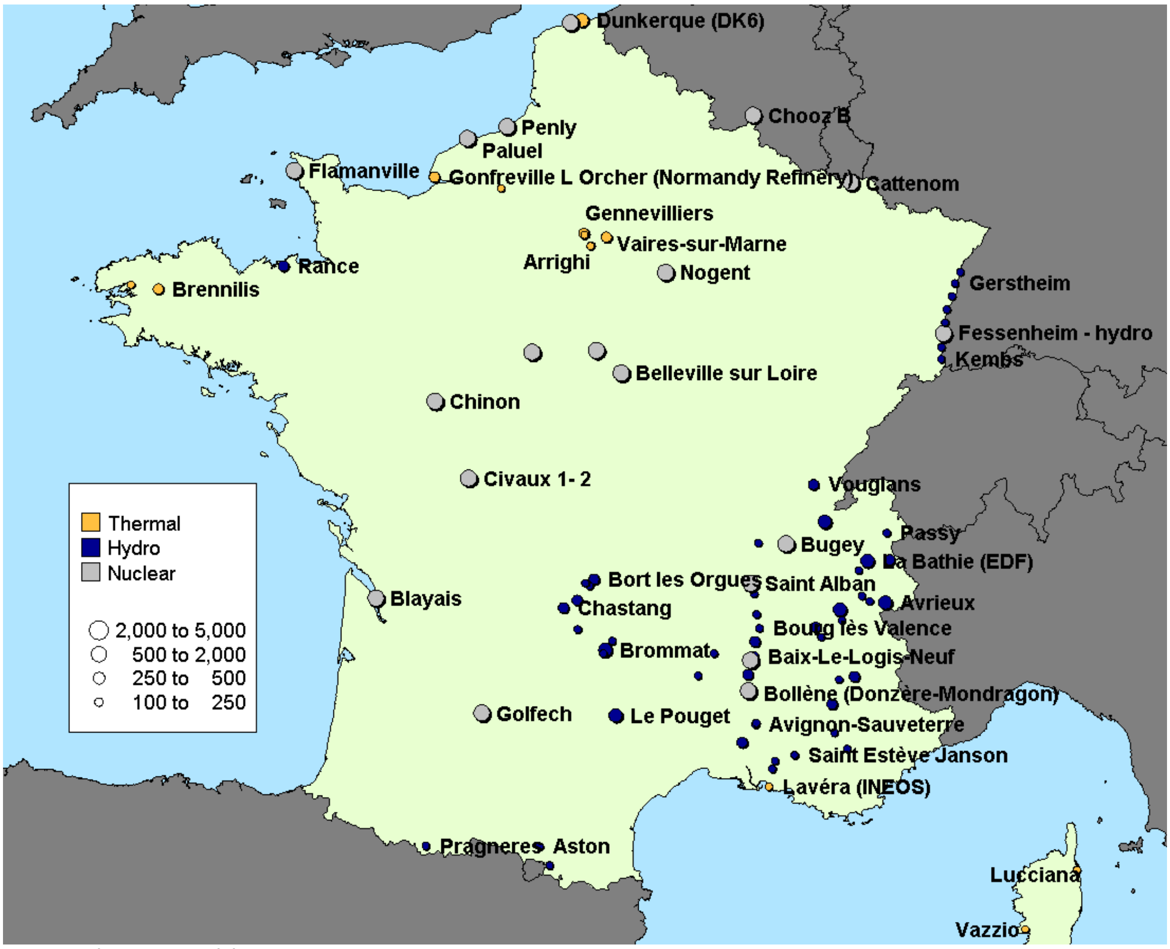
26 RTE Supply Demand Report 2009.

Figure 7 – Proportion of installed capacity in France by fuel type in 2008 (GW)



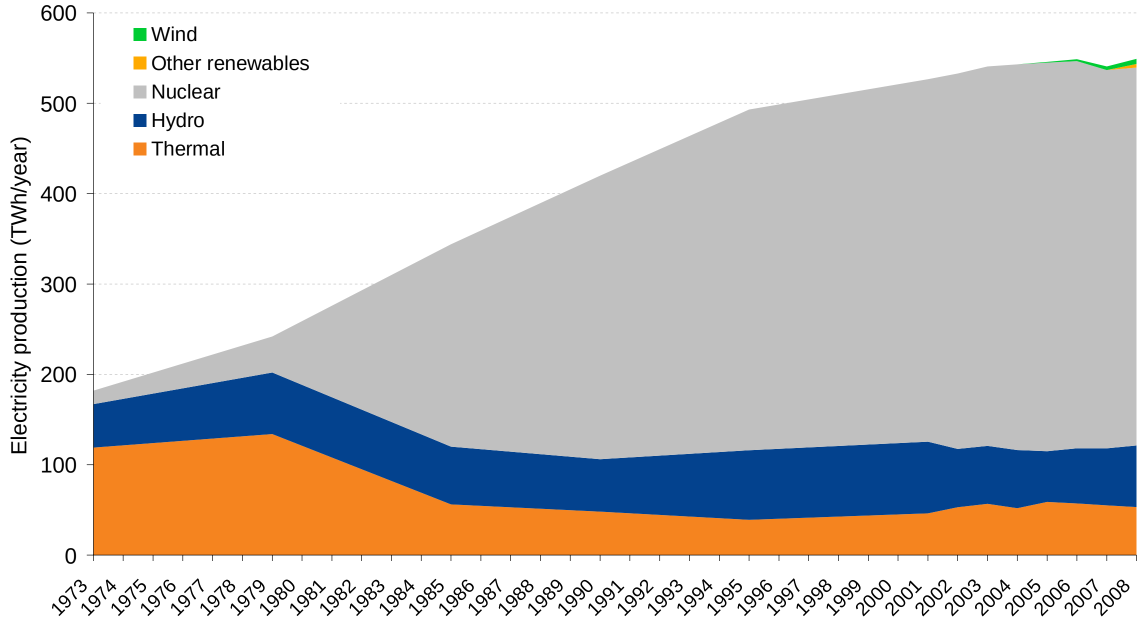
Source: RTE

Figure 8 – Centralised generation with capacity above 100MW in France in 2008



Source: Platts PowerVision

Figure 9 – Electricity generation by fuel (in TWh/year)



Source: Observatoire de l'Energie

2.3.1.1 Nuclear

French nuclear power stations are mainly Pressurised Water Reactors (PWR), built between 1977 and 1999, with each plant characterised by a size of 0.9GW, 1.3GW or 1.5GW. The minimum lifetime of the French nuclear power stations is forty years, but this lifetime is likely to be extended for at least part of the nuclear fleet[27].

EDF plans to increase by 6-7% the capacity of the 1.3GW-type reactors. This would provide an annual additional production of around 15TWh, compared with an annual production of 13TWh for the new EPR reactor in Flamanville[28].

Nuclear availability in France was around 83% in the first semester of 2008, 3% higher than the previous year. However, in the last decade availability has been decreasing slightly. The French rate is now lower than those measured in the US and in other European countries. Maintenance is the key driver behind this trend. EDF's objective for nuclear availability is to get it back to 85% within the next three to four years[29]. EDF is looking into the American maintenance management as it is the main reason why availability is higher in the US.

2.3.1.2 Centralised thermal generation

In 2008, there was 22.2GW of available centralised thermal generation in France. An additional 2GW of fuel oil power station were de-mothballed during 2008. The total is

27 'Bilan Prévisionnel de l'équilibre offre-demande d'électricité en France'. RTE, July 2007.

28 'EDF et Suez s'opposent sur la construction d'un deuxième EPR'. Les Echos, 30 November 2007.

29 'EDF seeks to restore reactor availability', Platts Power in Europe Issue 520.

made-up of 6.9GW of coal generation and 5.5GW of fuel-oil fired generation, with the remainder being mainly gas and some biomass.

The Large Combustion Plant Directive (LCPD)[30] sets limits on SO_2 and NO_X from 1 January 2008. A number of different options exist for coal and oil plant, one of which is to 'opt-out' by agreeing to limit power station operating hours and close before 2016. The LCPD is therefore likely to restrict generation from the opted-out coal plant to a lower level than would otherwise be the case, which will have a consequent effect on the rest of the merit order. In France, the LCPD will limit the total operation of 3.6GW of coal fired generation capacity out of the 6.9GW installed to a maximum of 20,000 hours between 2008 and 2015. These generators expect to be able to produce until 2013-2015 under these conditions.

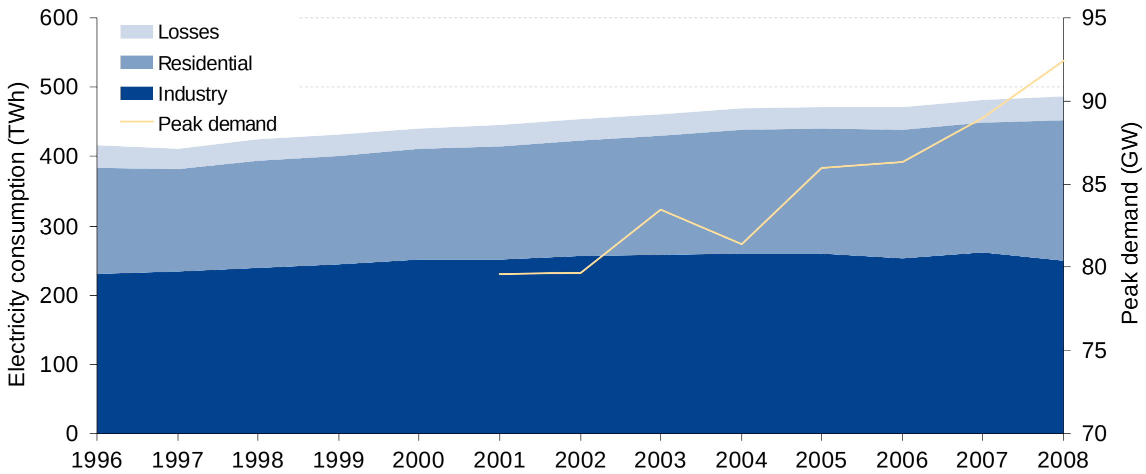
2.3.1.3 CHP

France has around 4.7GW of Combined Heat and Power (CHP) capacity. Most of the CHP electricity generation is sold to EDF through a purchase obligation at a feed-in tariff[31]. Most of these contract are set to expire between 2010 and 2014 and CHP plants will either have to sell their heat and electricity to the market (plants>12MWe, around half of the CHPs) or undertake some renovations to benefit from the new feed-in tariff from EDF (plants<12MWe) as detailed in section 3.1.2.

2.3.2 Demand

In 2008, total electricity consumption was 486.1TWh, increasing by 1.2% from 2007. Peak demand reached 92.4GW during in January 2008[32]. The evolution of demand by sector and peak demand is shown in Figure 10 and Figure 11.

Figure 10 – The electricity consumption pattern in France



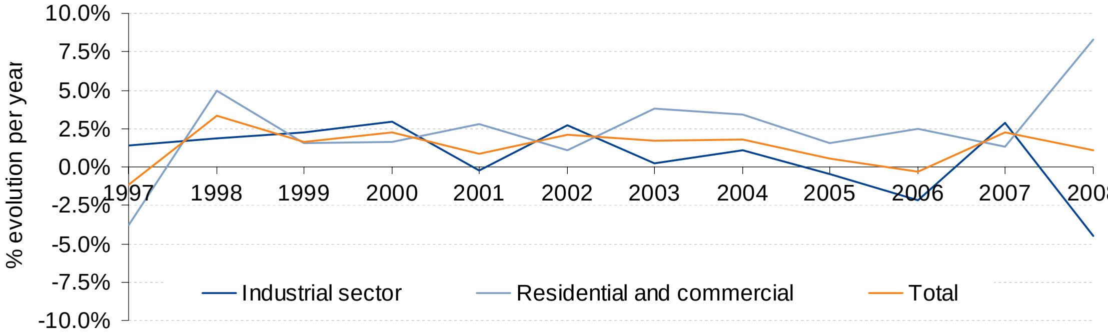
Source: RTE

[30] Directive 2001/80/EC.

[31] This was set-up in the so-called standard agreements '97-01' and '99-02'.

[32] RTE, Le Bilan Electrique Français, January 2009.

Figure 11 – Evolution of electricity consumption by sector in France



Source: RTE

2.3.3 Interconnection

Owing to the low marginal cost and the large amount of generation from nuclear power plants in the system, France is the largest exporter of electricity in Europe and is a net electricity exporter (on a contractual basis) to all neighbouring countries except Germany. France mainly exports its baseload power and imports during peak time, due to higher costs for peak power in France than in the neighbouring countries, especially Germany.

As shown in Table 4, exports have remained fairly stable between 2003 and 2005, whilst imports decreased in 2006. Further mid-merit and peaking capacity is being deployed in France, both by EDF and new entrants, and we could see imports reducing over time. Due to low nuclear availability in 2007 and 2008, imports were higher and exports lower than in the last 4 years.

It should be noted that contractual exchanges are significantly different from physical flows at the French border. For example, France imported 19TWh from Germany on a contractual basis, whereas the physical flow from Germany to France was 0.868TWh[33].

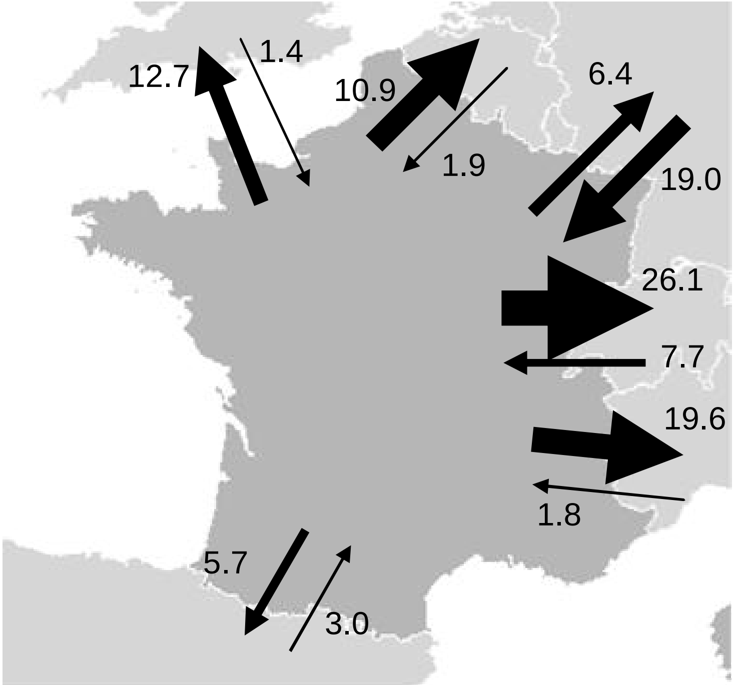
Table 4 – Historical evolution of contractual exchanges (TWh)

	Germany	Belgium	Switzerland	Italy	UK	Spain	**Balance**
2003	4.7	11.4	19.9	21.4	2.4	5.9	**65.7**
2004	-8.2	12.9	21.2	21.4	9.5	6.0	**62.8**
2005	-9.5	11.4	20.7	19.4	10.5	6.2	**58.7**
2006	-5.4	15.4	20.9	17.4	9.8	5.1	**63.1**
2007	-4.5	9.3	19.6	18.1	6.0	5.7	**54.2**
2008	-12.6	9.1	18.2	17.8	11.2	4.0	**47.7**

Note: Positive values mean exports whilst negative denotes imports.
Source: RTE statistics

33 UCTE, Memo 2008 (Value as of 14 April 2009).
Poyry modelling detailed in chapter 4 is based on physical flows.

Figure 12 – Contractual exchanges with neighbouring countries in 2008



Source: RTE statistics

2.4 Market operation and Trading

2.4.1 Market Structure

In addition to owning the transmission network and 95% of the distribution network, EDF produces and sells most of the electricity in France, as illustrated in Figure 13. The consequence is that EDF largely circumnavigates the wholesale market by selling the electricity it produces directly to end-consumers via bilateral contracts. As a result, only about 30% of total generation onto the system are traded on the wholesale market and less than 13% of sales to end-users.

As EDF does not participate significantly in the market, exchanges are not concentrated and the HHI[34] sits around 400 and 1000 for the wholesale market. In comparison, the HHI is around 9,000 for production in France, and in the region of 4,500 for production excluding EDF[35], which means that the remainder of electricity generation is also very concentrated. The GdF/Suez merger hardly impacted the HHI in production as EDF remains the larger producer in France.

Electricity is traded in France using either over-the-counter transactions which are characterised by bilateral contracts, or via the Powernext exchange on which both spot

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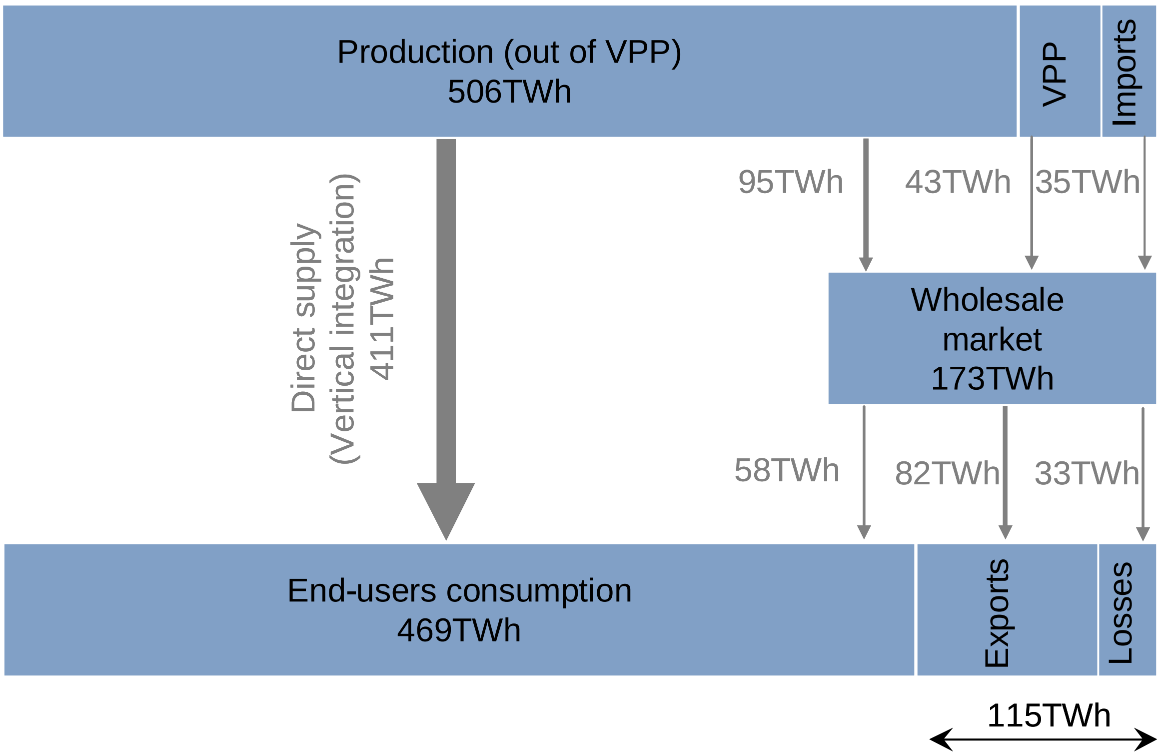
34 The Herfindahl-Hirschmann Index (HHI) determines market concentration by computing the sum of the squared market share of each competitor. In a ‘perfect monopoly’, in which one firm supplies 100 percent of the market, the maximum value of the HHI is at the maximum level of 10,000 (100 times 100). Markets with an HHI value below 1000 (e.g., 10 firms, each with a 10-percent market share) are presumed to be un-concentrated, while markets with an HHI of 1800 or more are considered to be highly concentrated.

(i.e. for the next day) and forwards (i.e. relating to long-term contracts to be fulfilled at a future date in up to several years' time) products are traded.

Around 80% of the volume actually delivered is traded over-the-counter, 15% through Powernext Day-ahead and the remaining 5% through Powernext Futures. Most spot products are traded through Powernext, whilst most baseload products are OTC transactions[35].

RTE and ERD, the transmission and distribution network, have to buy their losses in a transparent and non discriminatory way. Therefore, they organise call for tenders on the wholesale market, essentially on Future products. This helps to increase the liquidity of the French market: in 2008, RTE and ERD bought 33TWh, compared with 58TWh sold to end-users via the wholesale market.

Figure 13 – Structure of the French electricity market in 2008



Source: CRE

2.4.2 EDF Virtual Power Plants (VPP)

In 2001, the European commission urged EDF to make accessible some of its generating capacity available to competitors through Virtual Power Plants (VPP) auctions. A VPP contract is equivalent to booking some generation capacity, whereby an electricity supplier buys the right to use a power plant through auctions at a fixed cost in €/MW/year. Over the duration of the contract, the buyer has the right to ask for the actual delivery of power up to the capacity contracted for a variable cost in €/MWh. In the case of nuclear

35 CRE, Rapport d'activité, Juin 2008.

baseload, the latter cost reflects the variable cost of a French baseload nuclear power plant operated by EDF.

For the first six years of the auctions, EDF released 6GW of capacity accounting for some 40TWh of energy (43TWh in 2008). This capacity was made up of 1GW of cogeneration, 1GW of peak power, and 4GW of baseload power. Contracts have historically lasted from three months to three years, and since September 2006, EDF has auctioned a four-year baseload contract[36]. Variable prices for the latest auction in June 2009 were €10/MWh and €63/MWh for respectively base and peak power[37].

2.4.3 OTC

OTC transactions represent around 80% of wholesale exchanges in France and are mainly baseload products. Actual exchanged volumes are unknown, but volumes of OTC transactions resulting in physical deliveries grew steadily from 4TWh/month in January 2002 to an average of 21TWh/month in 2008[38]. This number has been relatively stable since then[39].

2.4.4 Day-ahead and Futures: Powernext market

2.4.4.1 Electricity products

On 26 November 2001 the French power exchange, Powernext, was launched with a single spot price for the wholesale market. In June 2004, Powernext started a forward market as well, selling contracts for the next three months, the next four quarters and the next two years. Powernext Day-Ahead trading has steadily increased since 2004 reaching a daily peak of over 222GWh in February 2009. CRE monitors the Powernext index to prevent misuse and manipulation, as this price is used to set imbalance charges. In June 2005, a carbon market was also opened, with up to 5.9MtCO_2 traded per month in February 2007.

After the launch of two new products in July 2007, the Day-ahead comprises three different elements:

- Day-Ahead Auction: electricity traded on day d for delivery the following day in 24 hourly intervals, auctioned at 11am;
- Day-Ahead Continuous: electricity traded on day d for delivery the following day on 11 standardised blocks of hours, in continuous trading from 7:30am to 11:30am; and
- Day-Ahead Intraday: electricity traded on day d for delivery on the same day or on the following day on 24 individual hours, traded from 7:30am to 11pm.

Volumes traded in 2008 reached 51.6TWh, compared with 44TWh in 2007. Powernext prices are influenced by fuel prices, weather conditions and the availability of power plants in both France and the neighbouring countries. Extreme price movements on the Powernext market strongly track extreme temperatures in France. For example, electricity prices spiked in winter 2007, due to extremely cold weather across Europe and

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36 ‘Last gasp for protectionism?’. Platts Power In Europe, Issue 505, 16 July 2007.

37 EDF website, http://www.edf.fr/accueil-com-fr/encheres-de-capacite/actualites-114006.html

38 CRE, ‘Observatoires des marches de l’electricite et du gaz 2008’.

39 CRE, Rapport d’activité, juin 2008.

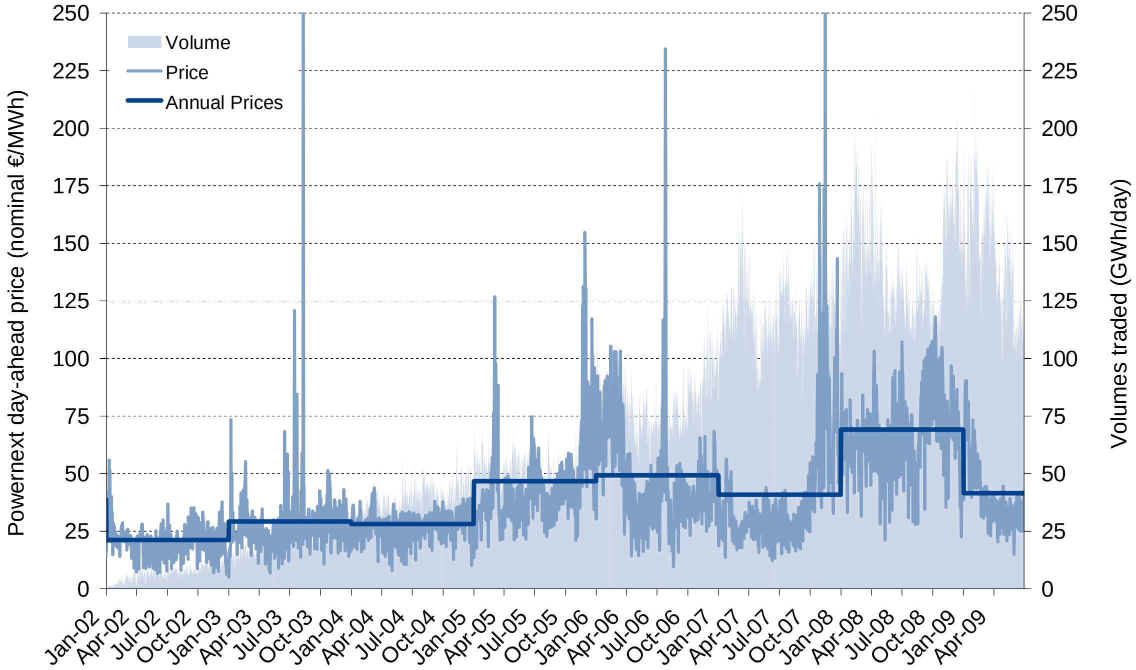
to a low availability of nuclear units in France[40]. Prices and volumes traded on Powernext Day-ahead are shown in Figure 14.

Powernext Futures comprises contracts for Base (24h/24) and Peak (8h-20h) on three different durations:

- monthly contracts, up to three months in advance;
- quarterly contracts, up to four quarters in advance; and
- calendar contracts for the next three years.

Prices of calendar contracts are shown in Figure 15.

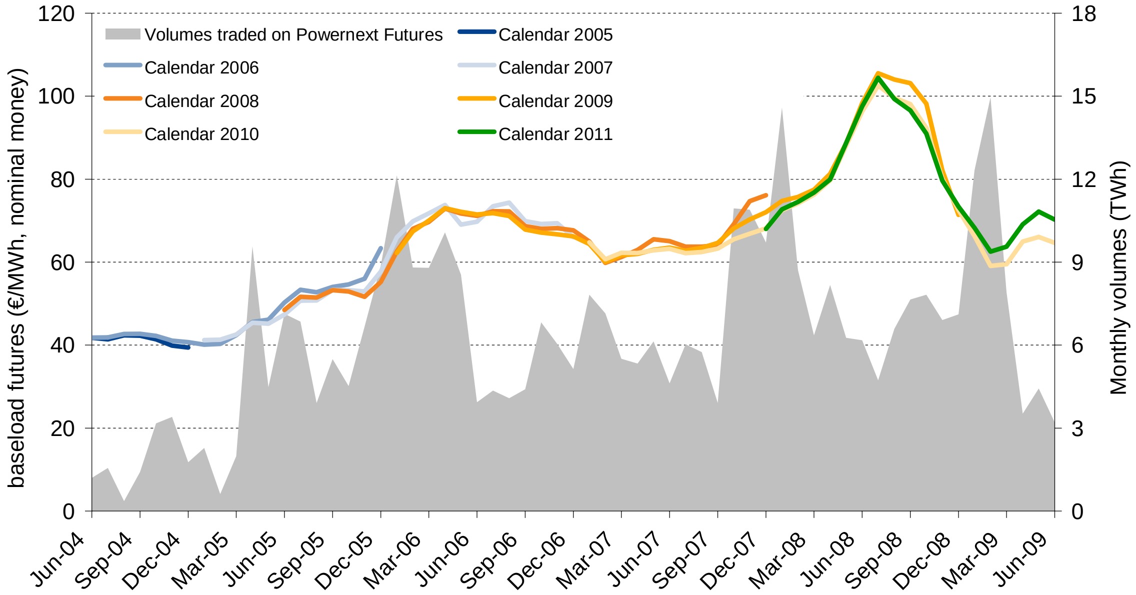
Figure 14 – Powernext Day-ahead prices and volumes



Source: Powernext

40 Platts, Power in Europe Issue 520.

Figure 15 – Calendar contracts monthly prices, and monthly volumes traded on Powernext Futures[41]



Source: Powernext

2008 was a year of particular activity for Power Exchanges across Europe; especially in terms of market integration[42]. With the incorporation of EPEX Spot SE[43] on 17 September 2008 there has also been an increased cooperation between Powernext SA and EEX AG on their respective electricity markets. The main changes that occurred in 2008 and in the first 6 months of 2009 are set out below:

- Cooperation agreement between EEX AG and Powernext SA signed on 6 March 2008;
- Start-up on 29 September 2008 of electricity spot market trading by EEX Spot on weekends with a view to harmonising EPEX Spot markets;
- Powernext Day-Ahead exchange transferred to EPEX Spot SE on 31 December 2008;
- EPEX Spot SE becomes 100% owner of the German, Swiss and Austrian spot electricity exchanges of EPS GmbH on 31 December 2008;
- Powernext Futures exchange to be transferred on 1 April 2009 to EEX Power Derivatives GmbH, which is owned 80% by EEX AG and 20% by Powernext SA; and
- Transfer on 2 April 2009 of open positions on Powernext Futures to European Commodity Clearing AG (ECC), which will provide clearing services for transactions on the French and German/Austrian electricity futures exchanges. In addition, ECC will provide clearing for trades on the EPEX Spot SE exchanges from 1 April 2009.

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41 Volumes include all contracts traded on Powernext Futures.

42 'Europe's power exchange consolidation', Platts 25 June 2009.

43 Based in Paris and owned 50/50 by EEX AG and Powernext SA.

2.4.4.2 Gas products

On 26 November 2008, Powernext simultaneously launched its gas spot market for PEG[44] Nord, PEG Sud and PEG TIGF and its gas futures market for PEG Nord. Products traded on the spot market include within-day, day-ahead and weekend spot contracts whereas monthly, quarterly and seasonal products are traded in the future market.

The market was launched with 11 members, of which five are acting as quote providers. On the first day, 35.6GWh was traded on the spot market and 856.75GWh on the futures market.

2.4.4.3 Interconnections

The French electricity transmission network is part of the UCTE synchronous zone, and is interconnected with all the surrounding countries: United Kingdoms, Belgium, Germany, Switzerland, Italy and Spain.

Access to interconnection is either done explicitly via interconnection capacity auctions, or implicitly via market coupling mechanism. A summary of the different contractual structures is shown in Table 5.

[44] Point d'Echange de Gas.

Table 5 – Contractual structure for interconnection access

Interconnector	Principle	Comments
UK (IFA)	Auction	- Year/Season (winter/summer)/Quarter/Weekend/Day auctions - Use it or lose it principle
Belgium (IFB)	Market coupling	- Implicit allocation of interconnection under the Tri-lateral coupling mechanism - In case of technical problem to operate this coupling, fallback auctions of interconnection capacity will be held
Germany (IFD)	Auction	- Year/Month/Day auctions - Use it or lose it principle - Netting principle - One-to-One strict principle - Participants must enter into a balancing with one German TSO
Italy	Auction	- Year/Month/Day auctions - Secondary market for re-sell of capacity - Unified approach for Italy/Switzerland/Austria/Slovenia
Spain (IFE)	Auction	- Year/Month/Day/Intra-day auctions - Secondary market for re-sell of capacity - Unified approach for Spain/Portugal through MIBEL

Source: RTE

2.4.5 Market coupling

2.4.5.1 Trilateral coupling

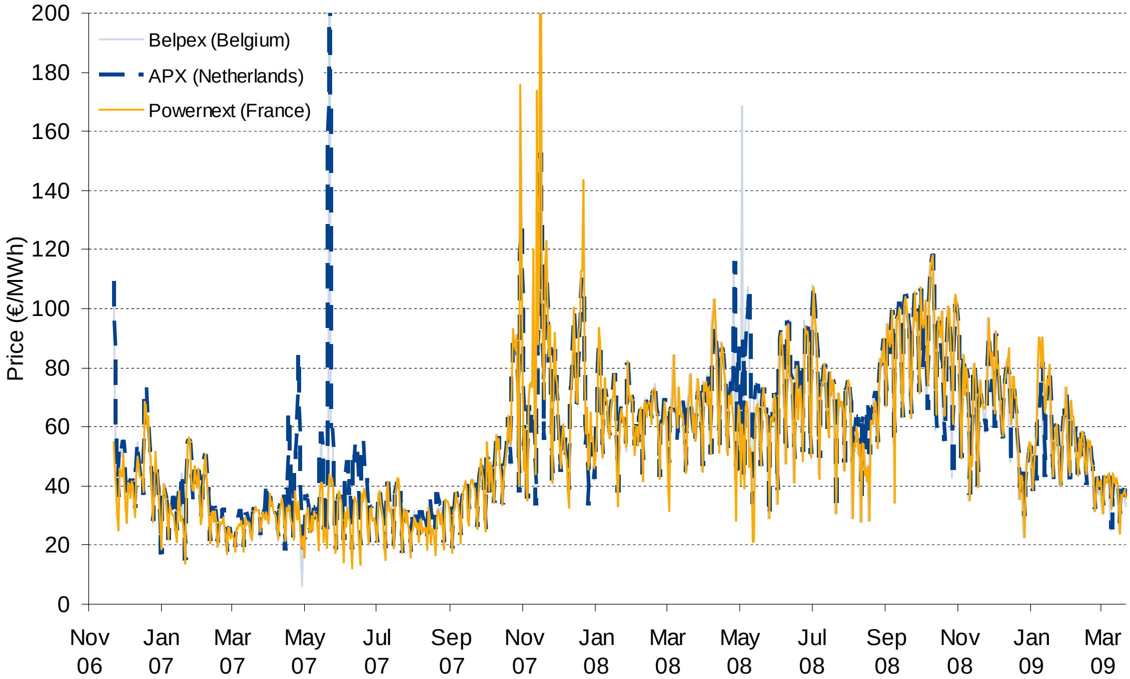
The Trilateral Market Coupling was introduced between Belgium, the Netherlands and France on 21 November 2006. The consortium responsible for the trilateral coupling consisted of the three TSOs, RTE (France), Elia (Belgium) and TenneT (Netherlands) and the three power exchanges, Powernext (France), Belpex (Belgium) and APX (Netherlands).

It was intended that market coupling would increase liquidity in day-ahead trading and make optimal use of the interconnection between the countries involved. Before this date, the Day-Ahead markets in each country operated independently, and interconnection capacity between the countries was allocated by means of explicit yearly, monthly and daily auctions. Under the new system, the three markets are treated as one: all bids are aggregated, all offers are aggregated, and the intersection of the resulting supply and demand curves sets the market price. When there is insufficient interconnection capacity to ensure price equality across the three markets, the markets decouple and more than one price emerges.

Market participants submit their purchase or sales orders each morning (at 11.00am Central European Time) for each hour of the following day. At market gate closure, all potential trades are then aggregated by hourly periods and ranked according to price. For each hour, the intersection of the aggregated supply and the aggregated demand curves determines the market results (i.e. the market clearing price and the market clearing volume). After this fixing is performed, the market results are made available to the participants. Contracts are then created which require participants in the three countries to deliver to, or to withdraw, from the network they are connected to the volume of electricity in accordance with their contracts. The market price is identical for all trades in each hour, but will vary depending on the time of the day.

Figure 16 shows the average daily spot prices for the three markets – Belgian, Dutch and French – from 22 November 2006, when coupling was introduced, to beginning of May 2008. During the first year of market coupling (2007), there was a single price for 60% of the traded hours, and a common French-Belgian price 85% of the time[45]. In 2008, prices on the three markets converged 72% of the time; convergence was 85% between France and Belgium, down from 90% in 2007, and 84% between Belgium and the Netherlands, up from 72%. The three prices on Powernext, Belpex and APX were identical 65 % of the time on an average basis of the 2 first years of coupling. Those results are improving and the convergence of day-ahead prices gets stronger: the average of identical prices was 60% of the time the first year, and increased up to 70% of the time the second year[46].

Figure 16 – Daily average Day-Ahead prices on the APX, Belpex, and Powernext exchanges (€/MWh, nominal prices)



Source: Platts and Pöyry Energy Consulting analysis

45 Press release, Belpex, 21 November 2007.

46 Press release, Belpex, 21 November 2008.

2.4.5.2 Pentalateral Coupling

Following the success of France, Belgium and the Netherlands, two other countries, Germany and Luxembourg, joined the existing market coupling. On 19 December 2008 a new company named Coreso, based in Brussels, was created. Its role is to harmonise the trading platforms and gate closures to ensure optimised use of grid capacity[47]. The first phase of its operations – providing integrated forecasts related to grid security in the afternoon for the next day – lasted until July 2009. In its second phase, the centre completes its operations to an around the clock monitoring of the electricity network. Its security analysis is updated every 15 minutes and provided to the national transmission operators.

Concerns remain over the interconnector capacity between the five markets and it has been suggested by ERGEG[48] that the current transmission capacity does not allow optimised cross-border trades.

On 1 October 2008, the Capacity Allocation Service Company for the Central West-European Electricity market (CASC–CWE) was created. Clearance from the European Commission was granted on 14 August 2008. This new company acts as a single auction office to implement and operate services for the yearly and monthly allocation of transmission capacity on the common borders between the five countries and will be based on standardized systems and rules. The objective is to facilitate cross border exchanges and therefore increase liquidity and competition in the five markets aforementioned.

Phase 2 of the implementation of CASC–CWE auction announced for spring 2009 is postponed at least until the end of the summer 2009 as further discussions are needed between the regulators and the TSOs[49]. This phase 2 consists in the organisation of all explicit auctions by CASC–CWE on the basis of the harmonised CWE Auction Rules. In this phase, the new and harmonised auction principles are put into force. Within the second phase, CASC–CWE will not only operate the yearly and monthly auctions, but also the daily auctions on German borders, as well as the registration of the participants, the secondary market, the programming authorizations, the data publication on internet and the financial guarantee and settlement process.

2.4.6 System balancing

On 31 March 2003, the French regulator (CRE, see 2.5.2) established a Balancing Mechanism in France following a proposition from the French TSO (RTE). The CRE is in charge of oversight and approval of rules that govern the Balancing Mechanism[50]. It is managed by RTE since its implementation.

As System Operator, RTE needs to balance generation and demand in real time. This task is not easy given incidents that can occur on the system (loss of a generation unit or

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47 ‘German, French and Benelux TSOs to establish company for market coupling’. Heren EDEM, 11 September 2007.

48 The European Regulators’ Group for Electricity and Gas (ERGEG), which the European Commission set up on 11 November 2003, is an Advisory Group of independent national regulatory authorities to assist the Commission in consolidating the Internal Market for electricity and gas.

49 CASC–CWE News, Postponement of Phase II, 2009.

50 Article 15, Loi du 10 Fevrier 2000.

a transmission line or an offset in demand forecast). RTE needs therefore to call upon generation and/or demand units directly connected to the transmission network in order to alter their scheduled program to react quickly to these events. Timeframe for reaction can vary from seconds to several minutes, depending on the importance of the incident. The Balancing Mechanism gives RTE the opportunity to know, in advance, what different solutions will be available in terms of costs and activation delays to restore system security.

Balancing offers are used by RTE for various needs: restore generation/demand equilibrium, congestion management (national or international) and system services (reconstitution of minima for primary and/or secondary reserves) or creation of system margins.

Offers in the Balancing Mechanism are implicit offers. Generation units (and demand units) connected to the transmission system need to send their scheduled program by 16h00 on day-1 to RTE. The program contains a range of different specifications including the scheduled generation capacity and the minimum/maximum generation capacity a unit can sustain (and for how long) without damage. The difference between the scheduled program and the technical availabilities provide RTE with the implicit volumes a unit can participate in the Balancing Mechanism.

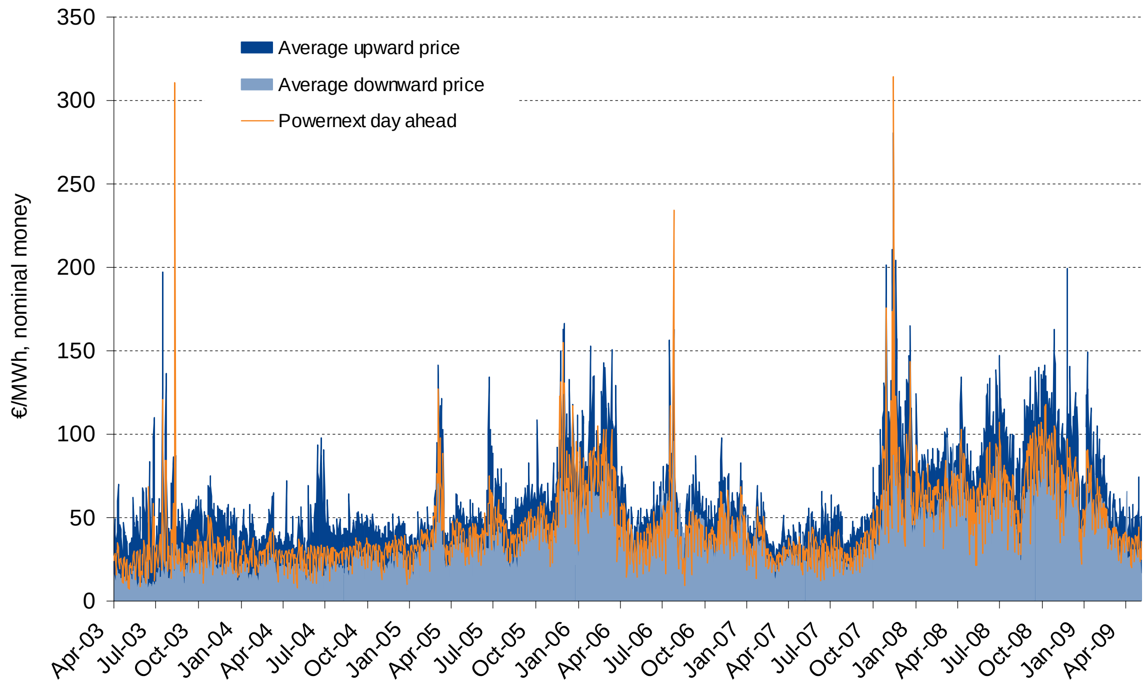
Offers are ranked by RTE on an economic order, i.e. cheaper offers are called first. Offers can be rejected when they tend to increase congestions or more flows on interconnections. There are a couple of reasons when RTE can bypass this rule when dealing with congestions, system services (primary and secondary reserves reconstitution) and margin reconstitution for example.

Participation in the Balancing Mechanism is not restricted to generation units in France specifically. Since March 2009 and the approval of new Balancing Mechanism rules by the regulator, a BALancing InterTso (BALIT) mechanism has been introduced. Under this new framework, RTE is able to receive and use balancing offers from the UK. This is a first step, which will be extended to other foreign TSOs in the future[51].

As shown in Figure 17, upward adjustment prices are generally much higher than spot prices, and downward adjustment prices are much lower, which makes the Balancing Mechanism a potential source of profits for generators.

[51] CRE, Annual Report 2009.

Figure 17 – Balancing prices compared to Powernext Day Ahead price (nominal prices, €/MWh)



Source: RTE, Powernext, Pöyry Energy Consulting analysis

2.5 Economic regulation

2.5.1 Recent developments

In order to allow new entrants to supply the French market at a tariff that can compete with the EDF regulated level, an anti-trust case in June 2007 ruled that that all new entrants are to be guaranteed electricity at a price that reflects EDF's average production costs. EDF therefore auctioned a yearly volume of 10.5TWh, for a price of €36.8/MWh in 2008 and the scheme is set to last until 2013 with a price in the region of €42/MWh[52]. As new entrant CCGTs are likely to have higher production costs than this new 'guaranteed price' this decision will negatively impact independent power producers (IPPs) seeking to arrange contracts with suppliers in the French market.

2.5.2 Role of the CRE

The Commission de Régulation de l'Energie (CRE) is the French Energy regulator and was created in March 2000. Its main mission is to oversee third party access (TPA) to the RTE grid and distribution networks and to determine tariffs for TPA. Its other responsibilities include protecting captive customers, investment planning for transmission and distribution (T&D), licensing new entrants and ensuring that public service obligations are respected.

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52 'EDF contraint de baisser de 29 % ses prix de gros pour stimuler la concurrence'. Les Echos, 11 December 2007.

The Ministry of the Economy, Finance and Industry (MINEFI), in conjunction with the regulator, plays an important role in planning future developments in generation and transportation, as well as in setting tariffs.

2.5.3 Third package

On 10 October 2008, the energy Council reached formal agreement on the Third Package proposals. A wide range of topics were covered including the establishment of a new Agency for European Energy Regulators, a new Transmission and System Operator body with a more formal role, levels of independence for national regulators and a new procedure for adopting common network rules. Additionally, agreements over the 'level playing field' and 'the third country' clauses constitute a step forward. The former legally prevents vertically integrated companies from purchasing transmission grids in other European countries that have chosen to unbundle their electric sector. The latter requires national regulators to assess whether the acquisition of a national electricity or gas network by a company from a third country fully complies with the EU's rules on unbundling.

Of particular interest to the French electricity market design is the possibility for European countries to choose between three different models of independent transmission systems. As it is the closest to the arrangement in place, France will most likely implement the 'Independent Transport Operator' model whereby a subsidiary of a vertically integrated company owns the transmission assets and is in charge of operating, maintaining and developing the network. In this model, the regulator controls that the transmission company is independent and does not discriminate users in terms of access and charges.

2.6 Environmental regulation

2.6.1 European Union Emissions Trading Scheme (EU ETS)

Under the Kyoto Protocol of December 1997, France is committed to legally binding targets to limit the emission of a bundle of six greenhouse gases, including carbon dioxide. Collectively, the EU is committed to an 8% reduction in greenhouse gas emissions from 1990 levels by 2008–2012. Based on the burden-sharing agreement between EU Member States, France's national target is to stay at 1990's emission level.

In 2003 the European Commission passed Directive 2003/87/EC, hereafter the Directive, which established the European Union Emissions Trading Scheme (EU ETS) with the objective of helping countries achieve their Kyoto obligations. The EU ETS is a cap and trade scheme, in which Member State define a National Allocation Plan (NAP) that:

- sets the total number of allowances to be issued, referred to as the cap; and
- details how these allowances will be allocated to the installations the Scheme covers.

2.6.1.1 Phase II

The Phase II NAP for France set the total emissions cap at 138.3mtCO_2, including an allocation of 132.8 million annual allowances to CO_2 emitting installations (with 4 million annual allowances for new entrants), and 5.5 million allowances to plants that emit nitrous oxide. The cap on the use of credits from the Kyoto Protocol's flexible mechanisms is 13.5%, and all allowances have been allocated for free[53].

Table 6 indicates the total cap calculation for France, according to the EC's method.

Table 6 – Carbon Cap calculation method

$$Cap = DE_{2005} \times GR_{05-10} \times CIGR \times (1-0.025) + CE + N_2O$$

DE_{2005}	Declared Emissions in 2005	131.25+0.015
$GR_{05\text{-}10}$	Growth Rate (2005-2010)	1.022*1.023*1.021*1.0226*1.0226
CIGR	CO_2 intensity growth rate in GDP	227.2/254.2
CE	Coverage expansion	5.1
N_2O	Opt-in N_2O	5.5
	TOTAL CAP	**138.3**

Source: www.ecologie.gouv.fr

Table 7 summarises the allocation for each sector for Phase II, compared with Phase I. It shows how the electricity sector faces a significant reduction in the number of allowances allocated. The NAP states that this is because this sector is less exposed to international competition and is able to pass through costs without having an adverse impact on their competitive position. Plants for the 'enlarged field' (meaning combustion higher than 20MW in various sectors) also see their emissions strongly abated.

Allocations by sectors are distributed according to the method advised by the EC on November 2006:

$$Allocation = Production_{2004-2005} \times (1 + AGR_{Production})^5 \times SE_{2004-2005} \times (1 - AIR_{SE})^5$$

With:

- $Production_{2004-2005}$: Average of the production for the sector, for years 2004 and 2005. Recent reference years were taken in order to take into account technical improvements of the sector.
- $AGR_{Production}$: Estimated annual growth rate for coming years, taking into account the five last years and technical elements specific to the sector.
- $SE_{2004-2005}$: Specific emissions of the process for one unit of production, determined on the average of emissions over 2004–2005 for the restricted field.
- AIR_{SE}: Average improvement rate, estimated for the coming years. The eight last years were taken into account, in addition to technical elements specific to the sector.

53 'Échange de quotas d'émission: la Commission approuve le plan national d'allocation de la France pour la période 2008–2012'. European Commission, 26 March 2007.

Table 7 – Comparison of NAP 1 and NAP 2

(MtCO2)	NAP 1 (2005-07)	NAP 2 (2008-12)	% NAP2 from NAP1 by sector	% of the total reduction
Urban heating	7.91	5.31	-33%	-9%
Combustion - energy	0.59	0.38	-36%	-1%
Combustion - industry	1.57	1.11	-29%	-2%
Electricity	35.92	27.24	-24%	-31%
Gas transport	0.88	0.84	-4%	0%
Refineries	19.36	15.04	-22%	-15%
Coking plants	0.32	0.25	-22%	0%
Steel	28.71	24.94	-13%	-13%
Cement	14.22	15.34	8%	4%
Lime	3.24	3.18	-2%	0%
Glass	3.98	3.73	-6%	-1%
Ceramics	0.04	0.02	-53%	0%
Tiles and Bricks	1.34	1.12	-16%	-1%
Paper and Pulp	5.16	4.33	-16%	-3%
Enlarged field	27.57	21.3	-23%	-22%
New Entrant Reserve	5.69	4	-30%	-6%
Sub-total	**156.5**	**128.1**	**-18%**	
Coverage expansion NAP2		4.674		
Opt-in N2O		5.5		
TOTAL	**156.5**	**138.3**		

Source: Pöyry Energy Consulting and the French Ministry of Ecology

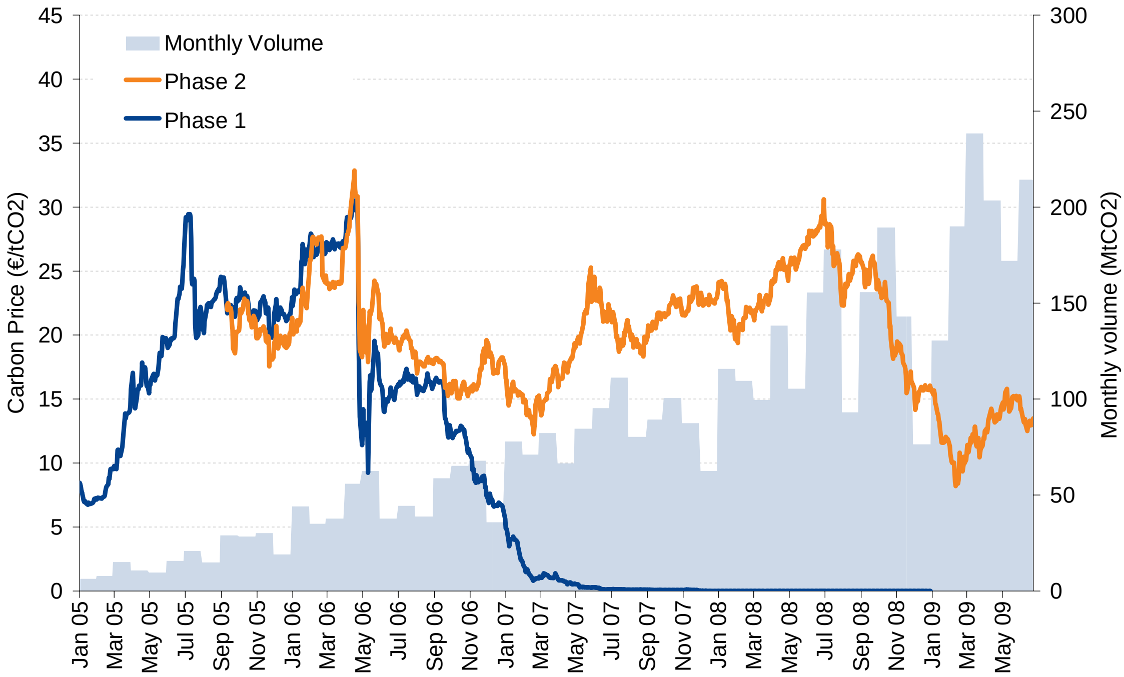
2.6.2 *Carbon prices*

In April 2006 details of the actual emissions for 2005 were made public, and revealed that the number of allowances would significantly exceed those required, and over time the carbon price dropped to several Euro cents. In response, the EU Commission sought to significantly tighten the cap for Phase II.

The carbon market has evolved and it is possible to trade:

- EU Allowances of different vintages, i.e. for 2008 to 2012;
- a strip of EU Allowances, that is an allowance for each year in Phase II;
- secondary CERs (sCERs), which are CERs that have been issued and can be traded; and
- options for the various carbon credits.

Figure 18 – Carbon price and monthly traded volumes for the EU ETS 2005–09



Source: Pöyry analysis of data provided by Point Carbon's Carbon Market Indicator data.

Figure 18 illustrates that during the first three years of the EU ETS, prices for Phase I carbon allowances ranged between a peak of around €30 per tonne of carbon dioxide (tCO_2) in April 2006 and a low of €0/tCO_2. The reason for this dramatic fall in prices was largely due to installations in a range of countries receiving far more allowances, around 80 million in total across the EU, than were needed to cover their emissions, meaning the whole phase I market was long in CO2.

Figure 18 also shows prices for Phase II carbon allowances – which have been trading since the beginning of 2006. Since October 2006, Phase II allowances 'de-linked' from Phase I allowances as it became obvious that the market was long CO_2 in Phase I but not in Phase II. Prices increased steadily to around €30/tCO_2 in summer 2008, before declining alongside oil and gas prices as the impact of the global recession fed through to commodity prices. Essentially, lower gas prices have made it cheaper to use gas fired power plants over coal and lower demand for energy has reduced the perceived overall tightness of the Phase II cap.

2.6.3 The future price of carbon

The future price of carbon depends on the total number of allowances issued and the resulting shortfall compared with business-as-usual emissions. The EU Commission is significantly tightening the cap in Phase III, leading to expectations of a higher carbon price. Owing to the possibility to bank allowances from Phase II to Phase III, many are expecting this proposal to lead to higher prices in Phase II, as installations may carry over some EUAs to use in Phase III.

A key factor is the extent to which Joint Implementation (JI) Clean Development Mechanism (CDM) schemes[54] are developed and utilised by EU participants. The CDM has enormous potential to generate credits, but initial delays in the implementation of the International Transaction Log and world-wide financing restrictions have raised doubts in the extent to which such credits will be available to utilise over Phase II and Phase III of the EU ETS. The EU has also imposed restrictions on the total volume that will be allowed until 2020 creating an upper limit to project credit utilisation of around 1600Mt.

2.6.4 The pass-through percentage

There is currently a widespread view that carbon costs are being passed through into wholesale electricity prices in Europe. However, it is far from clear that the level of pass-through is 100%, and the correlation analysis done by a range of analysts is inconclusive. Pöyry has undertaken substantial analysis of this matter; and in our view the level of pass-through varies considerably from country to country. In some of the Mediterranean countries in particular, it appears that there is regulatory and political pressure to resist opportunity cost pass-through. Spark and dark spreads have risen, on the whole, but the increases have not been consistent across countries; and factors other than carbon are influencing their development.

Forecasting future pass-through is complicated by the vertically integrated nature of the large power companies, such as RWE, E.ON and EDF. A vertically integrated company is by definition hedged against the wholesale price; and can choose not to pass through the full element of carbon costs into wholesale prices, in order to give its supply business a competitive advantage. Retail prices are slow to change, so even if there is the intention for there to be full pass-through at the retail level, it might take some time to materialise.

A further theoretical reason for not passing through the full costs is that the associated windfall gains might be perceived by a regulator or government as a target for windfall taxation. In future, some may favour a compromise of partial pass-through, allowing some increase in the wholesale price but simultaneously putting pressure on those competitors who are most exposed to it.

2.6.5 Plant output

A conventional coal-fired steam plant emits more CO_2 (over twice as much) per MWh of generation than a CCGT operating on natural gas. The extra costs faced by coal plant, as a result of the ETS, are correspondingly greater. This means that, ceteris paribus, we would expect coal output to decline and CCGT output to increase – and this effect has been incorporated in our analysis.

In turn, fuel prices are likely to change in response to the altering demand. Gas prices should rise, while coal prices fall (ceteris paribus). Pöyry has undertaken some analysis of these demand effects and concluded that they are likely to be second order: the possible changes in demand are small in the context of supply side uncertainties (levels of reserves). In this study, we have not incorporated these demand side effects on fuel prices.

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54 The CDM is the Kyoto project-based mechanism that allows ETS participants to invest in carbon-saving projects in non-Kyoto countries (principally Brazil, India and China), and use the carbon savings to offset against their emission targets. In Phase II, the CDM will be joined by JI (Joint Implementation), which allows investments in other Kyoto countries.

2.6.6 New entry and closure

In general, the allocation methodology used for distributing allowances to existing plant will only impact on the relative profitability of individual generators, rather than affecting the operation or price of the market as a whole. However, the way in which new entrants are treated in the National Allocation Plan could have a significant impact on the functioning of the market. This is because the EU ETS will have two potential impacts on new entry levels, depending on whether the Government in future chooses to provide a free allocation of allowances to new entrants or to require them to purchase allowances from the market.

In Phase III and beyond new entrants to the power sector will almost certainly be required to buy their allowances, suggesting that new entry price curves will increase to reflect the additional costs of new entry due to having to buy the allowances they need in order to operate. At the same time, the electricity market price will increase to reflect the opportunity cost of carbon (100% pass through). Since new entrants will usually be less carbon intensive than marginal plant in the existing market, then the new entry price curve will generally increase by less than the market price. If CO_2 prices are high enough, this impact alone could be sufficient to incentivise new entry ahead of capacity need.

We have assumed in our scenarios that new entrants have to purchase their allowances (or, at least, their business plans make this assumption); and hence that the new entry costs rise in line with the carbon price. While new entrants receive free allowances in Phases I and II, the number of free allowances allocated to the power sector are expected to decline significantly in the future, and we assume that developers will plan on the basis of having to purchase their allowances. However, if new entrants are allocated free allowances in future, it is possible that more new entry would be incentivised (than we have assumed) and that there may be a consequent reduction in the value of capacity. Prices in the market would then be less 'peaky' and there would be a reduced incentive for peaker new entry (e.g OCGTs).

This downward pressure on the value of capacity could be particularly marked if plant were to lose their free allocations upon closure (this is the current policy). If this were to happen, the effect would be to reduce the Net Avoidable Cost of keeping plant open on the system. This is likely to lead to more plant remaining open, than would otherwise have been the case, and a corresponding weakening in wholesale electricity price (again compared with what would otherwise have been the case).

2.6.7 White certificates

The White Certificate scheme, in place since July 2006, is one of France's instruments[55] aimed at supporting energy efficiency improvements within certain energy-intensive user sectors in France. These certificates are mandatory and tradable, with companies subject to penalties in case of non-compliance. This new regulation particularly targets residential and commercial sectors, which have diffuse but significant energy consumption patterns. Energy saving potential is important, but traditional public instruments have proved to be not suitable, inefficient or lacking in public funds. The envisaged advantages of this scheme include:

- economic efficiency, using an instrument adapted to liberalised energy markets;

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[55] Law n° 2005-781 13 July 2005, enforced since July 2006.

- the introduction of a direct relationship between obliged parts and the main addressees of the measures, i.e. the households;
- transparency, whereby the energy suppliers can propose measures not planned yet; and
- the provision of new means to finance energy efficiency projects, estimated between €500m and €1000m over three years.

The mandatory targets of the White Certificate scheme require a saving of 54TWh in final energy consumption from 1 July 2006 to 30 June 2009[56]. Within this period, there are no annual deadlines. Even after 30 June 2009 white certificates can still be delivered, only if claimed for saving actions undertaken prior to this date. Compliance will be verified on 30 September 2009. If a generator does not have the required amount of certificates by then, it would have to purchase the missing ones in no more than two months. If the company fails to comply, it would have to pay 0.02€ per missing kWh cumac[57]. The price upper limit for a certificate on the market is thus set by the value of the penalty for non-compliance, at 0.02€ per kWh cumac.

The overall target is shared between suppliers who provide electricity, natural gas, LGP, domestic fuel (not for transports) and cooling and heating, and any economic player that can undertake energy efficiency projects and receive White Certificates.

All end-user sectors are eligible. Substitution of fossil energies with renewable energies is eligible, but only in a few select cases, for example heat production and sanitary hot water production. Energy savings linked with the EU ETS scheme are not however eligible for White Certificates.

The type of the eligible projects can be as broad as possible to allow for compliance with target in the most concurrent way. To illustrate, the following projects are eligible:

- substitution with low energy light bulbs;
- loft insulation, use of double glazing;
- installation of heating control mechanisms;
- replacement of domestic appliances with more efficient equipment; and
- replacement of boilers or water heaters by more efficient equipment or thermal renewable energy equipments.

As of 1 May 2009, the initial target of 54TWh was already met, with 60TWh cumac of final energy consumption saved[58]. For the next period, a more ambitious target of 100TWh will be set. Further details about the second phase for White Certificates will be released later this year by the French Government.

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56 Arrêté du 26 septembre 2006 fixant la répartition par énergie de l'objectif national d'économies d'énergie pour la période du 1er juillet 2006 au 30 juin 2009.

57 KWh cumac are cumulated and actualised KWh with a 4% discount rate over the life of the energy efficiency actions.

58 Ministere de l'Ecologie, de l'Energie, du Developpement Durable et de l'Amenagement du Territoire, Lettre d'Information Certificats d'Economies d'Energies, May 2009.

3. RENEWABLE ENERGY IN FRANCE

On the whole, France is seen as being relatively poor in developing renewable generation compared with other European countries, and was considered as 'far from commitment' by the European Commission. For example, France had approximately 3.4GW of installed wind capacity at the end of 2008, which is substantially below its 10GW target by 2010. Due to its extensive hydroelectric facilities, however, France produces between 11% and 16% of its energy from renewable sources, 12.6% in 2008.

The situation for wind energy is improving though and France was the fourth largest country in Europe in terms of capacity installed in 2008[59], as well as in terms of cumulative installed capacity.

In October 2007, a series of meetings between the State and a number of representatives (Industries, NGOs, consumer associations, etc.) defined a set of measures to promote ecology and sustainable development in the so-called 'Grenelle de l'Environnement'. This is part of a general drive towards sustainable development, which includes renewable electricity.

3.1 Regulatory framework

3.1.1 Current national framework

The framework for renewable electricity deployment in France has largely been influenced by the 'Grenelle de l'Environnement', which has been followed by the publication of the multi-annual investment programming plan (PPI) in 2009. Whilst application decrees have not been published yet, we consider that the 2006 PPI is now superseded by these new objectives, as well as previous EU 2010 targets[60].

The French support system is based on four main schemes, including:

- a purchase obligation and associated feed-in tariff;
- tenders for new renewable generation when a feed-in tariff doesn't seem appropriate; and
- tax relief for renewable generation.

For completeness, we will also describe the Guarantees of Origin and Green Certificate mechanisms in this report, but we don't consider that these are the main drivers of growth in renewable generation.

Table 8 shows the deployment targets for renewables in France for 2020.

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59 Source: EWEA, 2008 wind map.

60 See Directive 2001/77/EC 'On the promotion of Electricity Produced from Renewables Sources in the Internal Electric Market' (27/09/01).

Table 8 – French targets for new renewable capacity to be built by 2020

	PPI 2009, target for 2020
Onshore wind	19.0
Offshore wind	6.0
Biogas	0.5
Biomass	2.3
Hydro	3.0
PV	5.4
Total	**36.2**

Source: PPI 2009

3.1.2 *The impact of 2020 targets for renewable energy*

The March 2007 meeting of the European Council committed 27 EU Member States to a binding target for 20% of the EU's total energy consumption coming from renewables by 2020 as part of the post-Kyoto arrangements. Key aspects of this Renewable Directive published in June 2009[61] are the following:

- a 20% reduction in EU greenhouse gas emissions, as compared with 1990 levels, or 30% if other nations, specifically the U.S., China and India agree to similar action;
- an increase in the use of renewable energy to 20% of all energy consumed (including electricity, heat and transport) which although is a binding target, the proposals allows for flexibility in how each country contributes to the overall EU target;
- a binding minimum target for each member state to achieve at least 10% of their transport fuel consumption from biofuels, with certain caveats such that the binding character of this target is 'subject to production being sustainable' and to 'second-generation' biofuels becoming commercially available; and
- a 20% increase in energy efficiency.

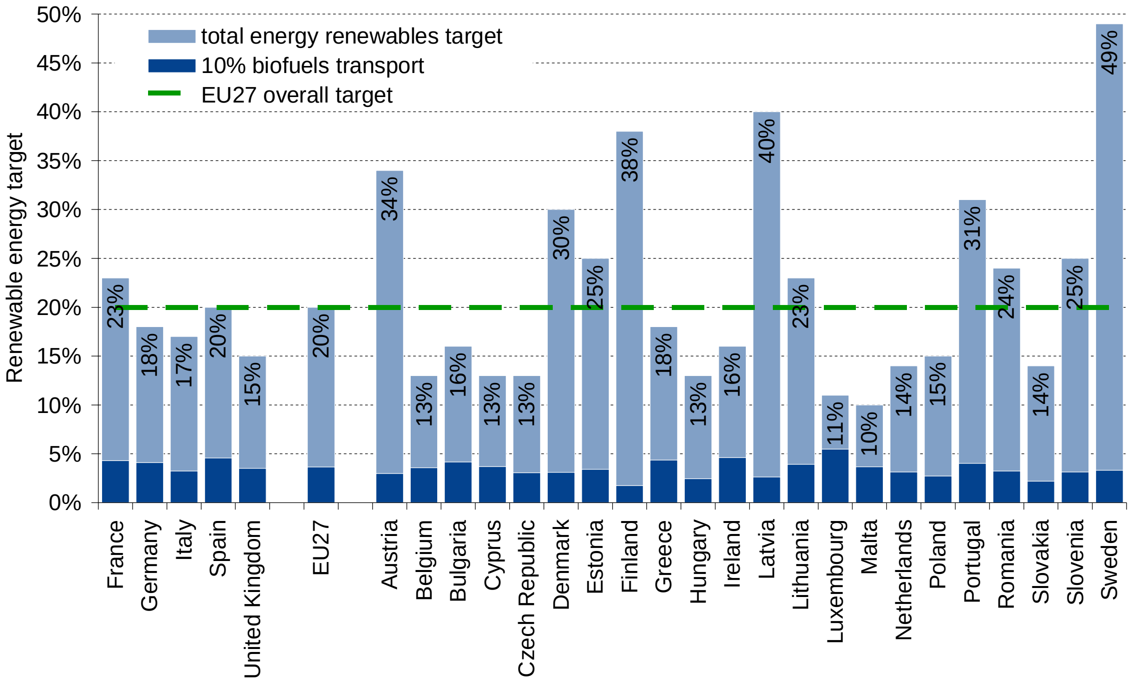
According to the EU Directive, drafted in January 2008[62] and approved in December 2008, national governments are expected to adopt a National Action Plan by June 2010, whereby they formalise the specific national target allocated to them and the measures to achieve it. The contribution to meeting the overall renewable energy target from individual countries varies significantly, as shown in Figure 19, with shares ranging from 10% (for Malta) to 49% (for Sweden) of final energy demand.

France's target share is to deliver 23% of energy from renewable sources by 2020, which represents a significant challenge. The difficulty of meeting renewable transportation fuels and renewable heating targets implies that renewable electricity generation will have to rise significantly if France is to comply with its 2020 EU target.

61 Directive 2009/28/EC, Official Journal of the European Union, 23 April 2009.

62 Proposal for a Directive of the European Parliament and of the Council on the promotion of the use of energy from renewable sources {COM(2008) 30 final} {SEC(2008) 57} {SEC(2008) 85}. European Commission, 23 January 2008.

Figure 19 – EU renewable energy targets



Source: European Commission

3.1.3 Purchase obligation and feed-in tariffs

The primary measure implemented to stimulate renewables is an obligation for EDF and other operating distributors of electricity to purchase renewable generation. Legislation, and associated government orders, from 2000 to 2005[63] established the obligation, the details of the prices, known as 'Feed-in Tariffs', to be paid and the lengths of the contracts. In 2006 and 2007, the levels of the feed-in tariffs were significantly increased[64].

Initially, only renewable plants whose installed capacity was less than or equal to 12MW qualified for the purchase obligation. However, as a result of the 2005 Energy Law[65], this criterion ceased to apply for wind farms from July 2007 onwards.

Under the purchase obligation, eligible renewable generators are paid a fixed price, for a fixed period, for every kWh of electricity fed into the grid. The 'Feed-in Tariffs', that is prices received, are based on investment costs and operational expenses avoided by buyers and, for certain technologies, a bonus for complying with objectives set by the

63 The obligation was first established by Loi 200-108 (10/02/00) 'Loi Relative a la Modernisation et au Developpement du Service Public de L'Electricite' and subsequently modified, most significantly, by Loi 2005-781 (13/07/05) 'Progamme Fixant Les Orientations de La Politique Energetique', and by Decree 10 July 2006.

64 Decree 10 July 2006 and decree 1st March 2007.

65 Law nº 2005-781, 13 July 2005.

2000 Energy Law[66] in terms of air quality, global warming prevention and technical innovation.

A decree in July 2006 decree considerably increased the feed-in tariffs for electricity produced from several renewable sources, including wind and solar PV. In addition, a decree in March 2007 also raised the feed-in tariff for electricity produced from hydro plant. A summary of the current feed-in tariffs for renewable generating plant in France is provided in Table 9.

Table 9 – Feed-in tariffs for renewables

Technology	Contract duration	Tariffs €/MWh	Comments
Biogas and landfill gas	15 years	75 - 90	€0-30/MWh Bonus for energy efficiency. €20/MWh Bonus for gasification
Onshore wind	15 years	82 (first 10 years)	€28-82/MWh for following 5 years. depending on load factor
Offshore wind	20 years	130 (first 10 years)	€30-130/MWh for following 10 years. depending on load factor
Solar - mainland	20 years	300	€250/MWh Bonus for integration in an existing building
Solar - overseas	20 years	400	€150/MWh Bonus for integration in an existing building
Geothermal - mainland	15 years	120	€0-30/MWh Bonus for energy efficiency
Geothermal - overseas	15 years	100	€0-30/MWh Bonus for energy efficiency
CHP	12 years	61-91.5	Depends on gas prices. capacity and lifetime
Hydro	20 years	60.7	€0-16.8/MWh for generation regularity

Source: DGEC

Taking the example of an onshore wind farm, the contract under the purchase obligation covers a 15-year duration from commissioning. However, the installation must be on-line within three years from the date of application for the contract. If the site is online after that time, the duration of the contract is reduced by the same delay.

Under the original 2000 Energy Law[66], a site was able to benefit from a further purchase agreement provided it still met the requirements set in the decree at the end of the term. However, this law was modified by Law 2004-803 (9 August 2004), under which the extension of the purchase obligation beyond 15 years was removed and as such a private power producer may only benefit from EDF's purchase obligation once. Once the contract period is completed, a renewable generator must sell its power on the open market. Therefore, Pöyry assumes that in the absence of significant change in policy, once a PPA has expired a renewable generator will be paid at the prevailing market price.

Onshore and offshore wind, hydro and biomass are seen as key technologies to meet France’s renewable electricity production targets, due to their relative maturity.

[66] Law nº 2000-108, 10 February 2000.

3.1.4 Call for tender

The second major support mechanism established for renewable energy by the 2000 Energy Law[66] is the tender process for renewable installations greater than 12MW. The selection criteria for these tenders are the project's economic and technological merits, reliability, respect for the environment, and acceptance by local authorities and populations. Electricity is bought at a fixed contractual price under a long-term Power Purchase Agreement (PPA) with EDF.

The details of the tenders undertaken to date by the authorities are summarised in Table 10.

Table 10 – Renewables tender

Renewable source	Tendered Capacity (MW)	Tendered published	Capacity approved (MW)	Results announced
Onshore wind	500	23/04/2004	278	12/12/2005
Offshore wind	500	11/02/2004	100	14/10/2005
Biomass/biogas	200	10/01/2004	216	12/01/2005
Biomass/biogas	300	09/12/2006	300	16/06/2008
Biomass	250	06/01/2009		
Solar PV	300	18/07/2009		

Source: Syndicat des énergies renouvelables[67]

The results of the onshore wind farm tender were announced on 12 December 2005. In total, only 278MW was approved, though this is thought to be a considerable improvement over the offshore wind tender, which only garnered 100 of the 500MW that was tendered. This low approval rate is thought to be the result of several factors, including the complex tendering procedure, which is insufficiently adapted for the emergence of new technologies.

In addition to the feed-in tariff for biomass and biogas, the French government has also launched a number of calls for tender. In June 2008, 22 biomass projects were accepted for a total capacity of 300MW, projects which will come on line before 2010[68].

Two new tenders are currently under process with results expected by mid-July 2009 regarding the first one on biomass and by January 2010 for the solar PV tender.

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67 'Bio-project licences awarded' Power in Europe, 17 January 2005; Syndicat des energies renouvelables. Communiqué 13 January 2005; Syndicat des energies renouvelables. Communiqué 14 September 2005, and; Syndicat des energies renouvelables. Communiqué 14 November 2005, Syndicat des energies renouvelables. Communiqué 16 June 2008.

68 DGEC.

3.1.5 Other schemes

3.1.5.1 Green certificates

Under the 2001 EU Renewable Energy Directive[69], Member States were required to put in place certification systems for renewable energy – i.e. administrative systems guaranteeing the 'origin' of electricity produced from renewable energy sources – by October 2003.

To meet this requirement, France has put in place a voluntary system of tradable 'Green Certificates' as a further means of promoting and supporting renewable energy. These certificates act as 'certificates of origin' and, in addition, are tradable.

Green Certificates are issued and administered by 'Observ'er'[70], a member of the Association of Issuing Bodies (AIB)[71] – the pan-European organisation promoting the standardisation of energy certificate systems. Certificates come in a single denomination with each Certificate corresponding to 1MWh of energy produced from a renewable source.

Observ'er monitors and reports on the level of activity within the market for Green Certificates. Table 11 shows the traded volume of Green Certificates as reported by Observ'er in December 2008.

Table 11 – Cumulative Trade in Green Certificates

Green Certificates	Number of certificates (million units)
Issued	6.1
Transferred	4.0
Exported	0.09
Imported	12.1
Withdrawn	15.2

Source: Observ'er (December 2008)

The value of a Green Certificate is based on the difference between the marginal cost of the electricity produced by the generator holding the Certificate and the wholesale price of electricity. Renewable generators are free to trade their output and their Green Certificates independently of one another. Significantly, however, any renewable generator benefiting from a feed-in tariff under the Purchase Obligation cedes its right to trade Green Certificates.

In France, Green Certificates are used by electricity suppliers who publicise Green Certificates contracts that guarantee a certain amount of electricity from renewable

69 Directive 2001/77/EC.

70 See www.observ-er.org.

71 See www.aib-net.org.

sources. The price of such certificates is usually between 0 and 3€/MWh, most of the time being around 0.5€/MWh.

However, there is an important distinction between France's voluntary system and obligatory certificate trading systems such as the UK's Renewables Obligation. The French system is not underpinned by a legal requirement on suppliers to source a specified proportion of their energy from accredited renewable generators.

3.1.5.2 Guarantee of origin

This mechanism was put in place by the 13 July 2005 Law[65], and elaborated by a decree in 2006[72]. These Guarantee of Origin certificates are issued by RTE, the French TSO, and are applicable to electricity produced from renewable sources or Combined Heat and Power plant (CHP). This Guarantee of Origin scheme is only applicable to producers who don't benefit from the feed-in tariffs described in section 3.1.2.

The price of each certificate comprises a fixed fee for each request of €800 for renewables or €1000 for CHP, and a variable fee of €0.005/MWh.

3.1.5.3 Tax relief

Further support measures apply to generators from renewables and CHP, as introduced by the finance laws between 2000 and 2006. These measures mainly consist of tax relief and exceptional amortization in order to support the generation and consumption of energy from renewables. An example is the acquisition of large renewable electricity generation equipment in French homes that, since January 2005, has been subject to a 40% tax relief on the price of the equipment (up to a maximum of €16,000 for a couple). As of January 2006, the level of tax relief was increased to 50%[73].

3.2 Renewable technologies

3.2.1 Wind energy

Wind energy is a major renewable generation technology which ranks second in installed capacity after hydro in France, and which is expected to provide most of the renewable energy generation growth in order to meet future targets.

A graph of installed capacity at the end of 2008 is provided in Figure 20.

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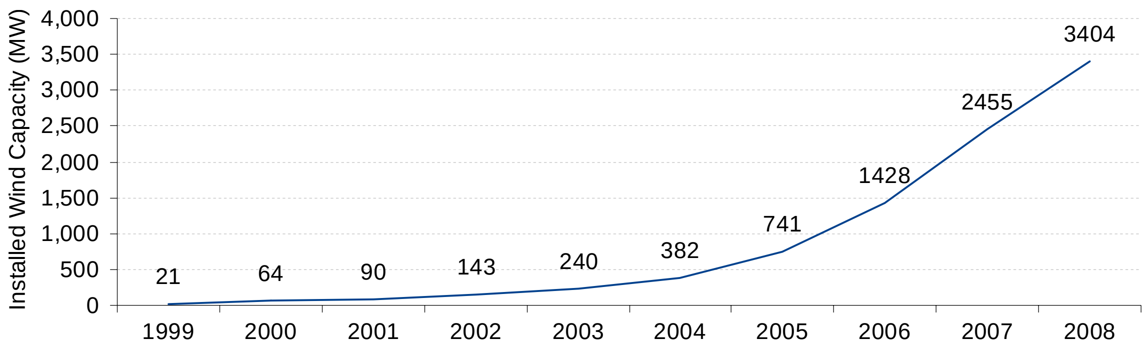
72 Decree 2006-1118, 5 September 2006.

73 Syndicat des Energies Renouvelables. Communiqué 1 Septembre 2005.

Figure 20 – Installed wind capacity by the end 2008



Source: DGEC, www.enr.fr and EurObserv'ER

Figure 21 and Figure 22 provide pictures of installed and granted permissions for wind construction by region at the end of 2008.

Figure 21 – Installed wind capacity at the end of 2008

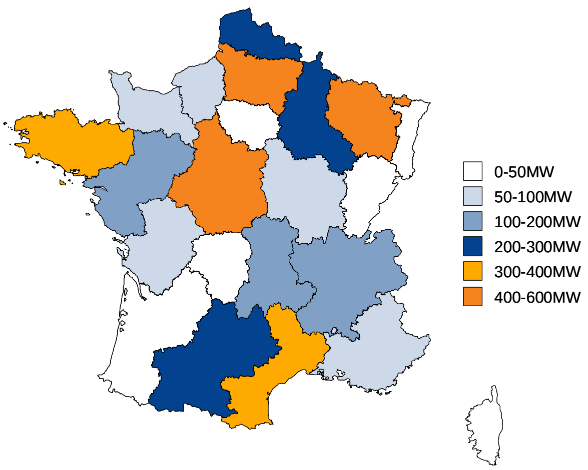
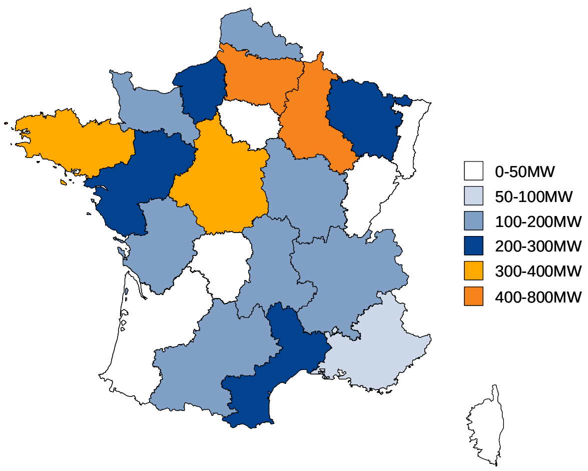


Figure 22 – Granted permissions for wind construction at the end of 2008



Source: France Energie Eolienne, Syndicat des Energies Renouvelables

3.2.2 Wind Development Zones (ZDE)

To qualify for the purchase obligation, wind farms have to be located in 'Zones de Développement de L'Eolien' (ZDEs), 'wind development zones'.

ZDEs, which are established at the level of the 'Départements', are proposed by 'communes' (the lowest tier of local government in France) and determined by the 'Préfet' (the executive body of the 'Départements'). ZDEs are associated with a surface a location, and a lower and upper bound of allowed capacity.

Once submitted, the Préfet must make a decision on any ZDE proposal within six months of its receipt. During this period, Préfets must consult local environmental authorities and all affected communes.

The Préfet is required to consider ZDEs proposals on the basis of their wind power potential, their connection potential and on the protection of landscapes and historic buildings. In making their decision, the Préfet can reject, approve or approve modified versions of proposed ZDEs. The 2005 Energy Law[65] leaves open the possibility of modifying ZDEs once established, subject to the same decision-making process as for the establishment of a new ZDE. This may mean that eligibility ceilings (or floors) may be employed at the regional level[74]. However, whilst Regions are also empowered to identify and zone areas deemed favourable for wind power development in their planning processes[75], ZDEs explicitly take precedence over any such zones.

3.2.3 Planning and Connection

3.2.3.1 Planning permission

Planning permission is required for wind farms greater than 12m in height. The process has two or three stages, depending on the characteristics of the proposed development. The 2005 Energy Law, as well as introducing the concept of ZDEs, made significant changes to the planning process for wind farms. These changes, like ZDEs, came into effect in July 2007 as shown in Table 12.

Table 12 – Planning requirements

	H < 12m	12m ≤ H ≤ 50m	H > 50m
Connection Agreement	Yes	Yes	Yes
Impact Assessment	No	Yes	Yes
Construction Permit	No	Yes	Yes
Public Inquiry	No	No	Yes

The average time it takes to obtain a permit for a wind farm in France is stable at around 13 months (fastest is four months, slowest 23). One-third of the applications (by capacity) were refused in the year to January 31, 2007. However, the chances of a permit being overturned by court action have dropped from 25% to 14%[76].

3.2.3.2 Connection

Because of the 12MW ceiling for benefiting from the feed-in tariff, which was in place until July 2007, all wind farms have had been connected to the distribution network (<63kV), mainly owned and managed by EDF Réseau Distribution (ERD). After July 2007, some wind farms larger than 12MW have been connected to the Transmission Network managed by RTE (see section 2.2.2.3).

74 ‘French wind at the crossroads’, Power in Europe, 18 July 2005.

75 Code de l’environnement (Article L553-4).

76 ‘Suez buys into French wind boom’. Platts Power in Europe, 3 December 2007.

Prices for connecting to the transmission network are calculated using a shallow cost principle, whereby no payment is required for any deep reinforcements to the transmission network. For connection to the distribution network, generators are charged for any necessary reinforcement work.

The time for connecting a wind farm to the distribution grid is quite short when there is spare capacity on the network, but may take up to five years when it is necessary to reinforce the higher voltage network. Poor coordination between the Transmission System Operator RTE and the Distribution System Operator ERD is mentioned as a source of delay.

One major source of dissatisfaction among decentralised generators is that ERD's initial estimates for connection costs (which are non-binding, in the Feasibility Study) are often subject to huge increases later on when the generator receives its PTF (Technical and Financial Proposal). The connection works themselves are subject to auction, and the generator may propose any company to participate in the bid process, provided this company is recognized by ERD. The PTF is binding for all parties, so the DSO does not bear the risk of a possible abandonment of the project, and the producer receives financial compensation in case of delays to the connection works.

On the whole, despite a significant effort from ERD to make the administrative procedures easier and shorter, the bottleneck for renewable projects seems to be the physical connection to the distribution network. The cost of grid access is sometimes excessive, and the administrative burden especially discourages small projects.

3.2.3.3 Public attitude

The French public position towards wind energy development is quite ambiguous. On the one hand, surveys show that the vast majority of the French population is favourable to wind energy, whereas, in practice, many associations fight against wind farm projects (25% of the building permits delivered by the public authorities were subject to appeals in the administrative court). The pressure group 'Vent de Colère' has mounted several high profile campaigns against proposed developments. In addition, few people agree about the best way to reduce the visual impact of wind turbines. It seems that until recently, small but scattered sites were favoured, whereas now larger sites are gaining preference.

3.2.4 Current regulatory uncertainty

In the last few years, there has been some regulatory uncertainty around wind investment:

- In August 2008, the feed-in tariff decree for wind farms was cancelled due to a legal flaw, causing confusion in the industry. A new (and identical) decree was subsequently re-issued three months later.
- The onshore wind industry fears that wind turbine could be classified as a dangerous industrial facility as part of the ICPE law relating to environmental protection[77]. Should this disposition be applied, wind developers think that the difficulty of obtaining construction permits would be greatly increased, and that it would seriously reduced onshore wind deployment.

Whilst we recognise that these factors create an unfavourable investment climate at the moment, we believe that the regulatory environment will improve in order to be consistent

77 'Le développement de l'éolien en péril', June 2009, Les Echos.

with the very ambitious targets set by the French government and the European Commission.

3.2.5 Calculation of the Feed-in tariff

This section is developed through a worked example in Annex B.

Initially, only renewable plants whose installed capacity was less than or equal to 12MW qualified for the purchase obligation. The 2005 Energy Law[78] removed this cap, with effect from July 2007 and the only conditions to benefit from the feed-in tariff for a wind farm is now to be located in a ZDE. This changes the Government's approach to wind farm development, as the 12MW maximum threshold was intended to foster small installations, whereas the removal of this cap is likely to encourage larger wind farm developments.

However this change is only applicable to mainland France. The 12MW cap is to remain in force for Corsica, overseas 'départements' and the islands of Mayotte and Saint-Pierre et Miquelon.

As stated in the previous section, the 2006 feed-in tariff decree for wind farms was cancelled due to a legal flaw and subsequently re-issued three months later on 17 November 2008[79]. Given that this more recent version is identical to the 2006 decree, we will still refer to it as the '2006 decree' to avoid confusion.

The 2006 decree dealing with wind energy provides that, for new installations, each MWh is bought at a price of €82/MWh during the first ten years of the 15-year purchase contract (onshore), and at €130/MWh during the first ten years of the 20-year purchase contract (offshore). For the end of the contract, a new off-take price is set, taking into account effective generation level (i.e. load factor) measured over the first 10 years. The tariff range is between €28/MWh and €82/MWh onshore, and between €30/MWh and €130/MWh offshore, as shown in Table 13 and Table 14. This tariff range, by taking into consideration the wind quality, is designed to ensure that each wind-farm can earn approximately the same amount of money.

These tariffs apply for mainland France. For Overseas Departments (DOM, Saint-Pierre-et-Miquelon and Mayotte), the feed-in tariff is €110/MWh.

Table 13 – Tariffs for onshore wind energy (T) – nominal €/MWh (excluding VAT)

Reference load factor	First 10 years	Next 5 years
Less than 2400 hours	82	82
2400 – 2800 hours	82	Linear interpolation
2800 hours	82	68
2800 - 3600 hours	82	Linear interpolation
More than 3600 hours	82	28

Source: Journal Officiel, 26 July 2006

78 Law nº 2005-781, 13 July 2005.

79 http://www.legifrance.gouv.fr/telecharger_rtf.do?idTexte=LEGITEXT000019919553&dateTexte=20081229

Table 14 – Tariffs for offshore wind energy (T) – nominal €/MWh (excluding VAT)

Reference load factor	First 10 years	Next 10 years
Less than 2800 hours	130	130
2800 – 3200 hours	130	Linear interpolation
3200 hours	130	90
3200 - 3900 hours	130	Linear interpolation
More than 3900 hours	130	30

Source: Journal Officiel, 26 July 2006

The tariffs presented in Table 13 and Table 14 have additional escalation factors, which will result in the tariffs being revised at the following times:

- at the time of application for the PPA; and
- for each year of the contract.

At the time of application the reference tariffs (T), as shown in Table 13 and Table 14, are adjusted by a **K** coefficient:

- if applied to after 31 December 2007, the reference tariff is adjusted downwards by a 2% discount rate running from 2008: $0.98^{(a-2007)}$; and
- upwards by wage index (WI[80]) and production price index (PI[80]) movement since July 2006:
  - $\left(0.5\times\frac{WIa}{WI'06}+0.5\times\frac{PIa}{PI'06}\right)$
  - where **'a'** is the year of application.

Therefore, the reference tariffs, both the initial and post-10 year tariff, at the **year of application** for the PPA, can be calculated as:

- $PPATariff = T \times K$
- where K = $0.98^{(a-2007)} \times \left(0.5\times\frac{WIa}{WI'06}+0.5\times\frac{PIa}{PI'06}\right)$

PPA Tariff, depending on the year of application, is shown in Table 15[81].

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80 WI and PI are translations of respectively ICHTTS1 ('identifiant' n˚ 0630215) and PPEI ('identifiant' n˚ 0850418) that are published on the INSEE website (www.indices.insee.fr).

81 The Base Tariff in real 2008 money is calculated with an inflation adjustment between 2006 and the year of application for the PPA.

Table 15 – Base Tariff calculation, depending on the application year (€/MWh)

Application year	Base tariff in Nominal money	Base Tariff in real 2008 money
2006	82.00	85.31
2007	83.44	85.11
2008	84.39	84.39
2009	84.35	82.70

Tariffs are also indexed annually on 1 November by the application of a coefficient **L** so that:

- $Tariff = PPATariff \times L$
- where: $L = 0.4 + 0.4\frac{WIc}{WIs} + 0.2\frac{PIc}{PIs}$
- where *c* is the current year and *s* is the year the PPA was signed.

A PPA contract for onshore wind lasts for fifteen years whilst that for an offshore wind farm lasts for twenty years. However, the installation must be on-line within 3 years from the date of application for the contract. If the site is online after that time, the duration of the contract is reduced by the duration of the delay (beginning by the first 10-year phase).

Table 16 – Summary of tariff calculations for onshore and offshore wind farms

	PPA tariff computation	Yearly actualisation	
2006 (decree)	Year of application	Year of PPA signature	Current year
WI'06	*WIa*	*WIs*	*WIc*
PI'06	*PIa*	*PIs*	*PIc*
	$PPATariff = T \times K$	$Tariff = PPATariff \times L$	

$$K = 0.98^{(a-2007)} \times \left(0.5 \times \frac{WIa}{WI'06} + 0.5 \times \frac{PIa}{PI'06}\right)$$

$$L = 0.4 + 0.4\frac{WIc}{WIs} + 0.2\frac{PIc}{PIs}$$

a= year of application, T=Tariffs as presented in Table 13 and Table 14

Source: Journal Officiel 26 July 2006 and Pöyry Energy Consulting

A private power producer can only benefit from EDF's purchase obligation once. A generator can opt-out from the feed-in tariff but will not be allowed to return once opted out. Once the 15 year (or 20 year) period is completed, the onshore (or offshore) generator must sell their power into the market.

A wind farm which has already produced electricity in a commercial contract and has never benefited from EDF's purchase obligation may also benefit from a contract as defined above, adjusted downward by an S coefficient:

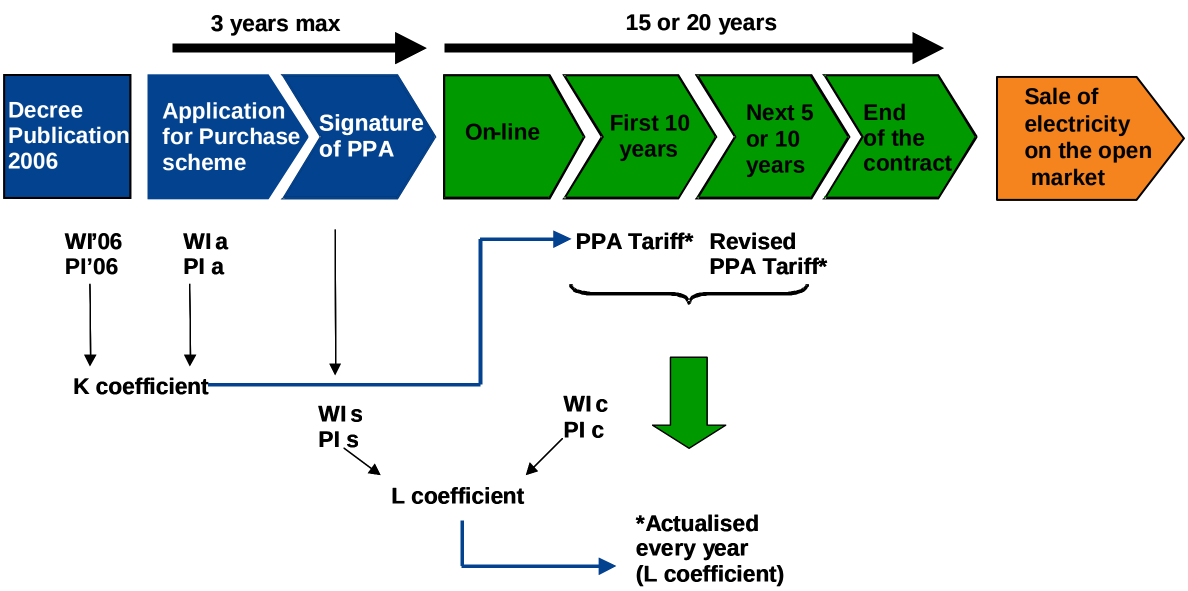
$S = (15/N)/15$ if N < 15 years

$S = 1/15$ if N ≥ 15 years

Where N is the number of years between commercial commissioning and PPA agreement.

An overview of the process is provided in Figure 23.

Figure 23 – PPA Process



3.2.6 *Hydro and other technologies*

3.2.6.1 *Hydro*

France has a significant proportion of its electricity coming from hydroelectric dams (25GW, for an average annual production of 70TWh). No new major facilities have been built in the past 20 years and the average age of hydro facilities is around fifty years. A recent report revealed by the press said that EDF's hydro dams were in relatively bad condition and EDF are set to invest €500m in the next five years to maintain its current hydro facility production[82].

Further developments are being considered in order to reach its target of renewable electricity production. Table 17 shows the potential development of hydroelectricity[83].

82 'Barrages vétustes : EDF promet d'investir 500 million d'euros'. Les Echos, 23 February 2007.

83 'Rapport sur les perspectives de développement de la production hydroélectrique en France'. MINEFI, March 2006.

Table 17 – Potential for development of hydro by 2015

	New projects			Optimisation of	
	<100kW	<4.5MW	20-50MW	existing installations	Total
Power (MW)	600	500	475	300	1875
Energy (TWh/year)	1	1.7	1.9	2	6.6

Source: MINEFI

It is also estimated that an additional 0.4TWh could be produced with the exploitation of minimum flows downstream from the hydroelectric dams themselves, and that there is an additional potential development of pumped-storage hydroelectricity of 2GW.

Some of the long-term arrangements for the operation of hydroelectric facilities will expire in the coming years and these will be renewed through fair and transparent competition. According to EDF, the average remaining duration of these arrangements is 22 years, and 20% of the hydro capacity will have its permit renewed by 2020.

A plan to 'revive hydroelectric production' was announced on 23 July 2008 by environment minister Jean-Louis Borloo. The plan is to increase hydroelectricity production by 10% and peak power capacity by 2.5GW by 2020[84]. It should be noted however that the central view of the Transmission System Operator RTE is that new investments will only compensate for the larger reserved flows that will be imposed on hydro production for environmental reasons, and that hydro production will remain stable overall[85].

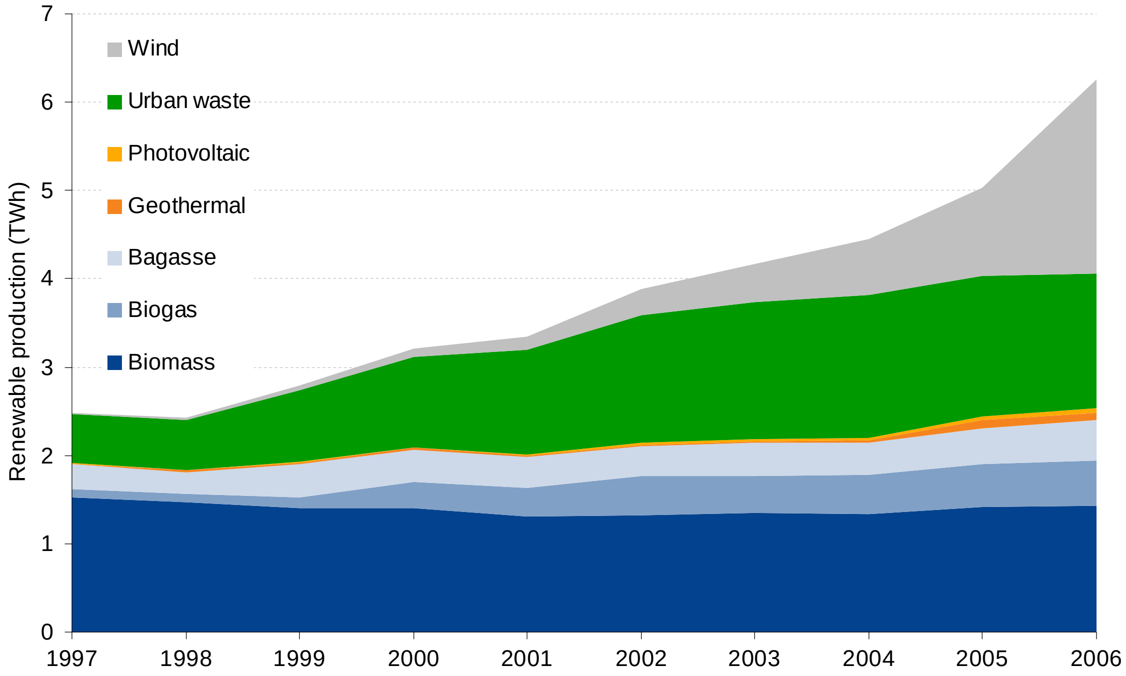
3.2.6.2 Other renewable technologies

Figure 24 shows that the only significant growth in renewable electricity generation from 1997 has been in Urban Waste and Wind technologies. France is likely to have more biomass and solar electricity production in the coming years, due to the outcome of call for tenders described in section 3.1.4.

84 'Relance du plan hydraulique français', 23 Juillet 2008, MEDAD.

85 'Bilan prévisionnel de l'équilibre offre-demande d'électricité en France, edition 2009', 22 July 2009, RTE.

Figure 24 – French renewables' output, excluding hydro (TWh)



Source: Platts with French Industry Ministry data

Solar photovoltaic (PV) installed capacity was 48MW at the end of 2008, up from around 11MW at the end of 2007[85] and is expected to reach 1GW around 2013. If the 2020 objectives of 5.4GW installed capacity were to be met, solar PV would be contributing to around 1% of electricity production in France.

4. PROJECTING WHOLESALE ELECTRICITY PRICES – INPUT ASSUMPTIONS

Wholesale price projections are produced using Pöyry's *EurECa* model, which projects electricity prices, output and cross-border flows for twenty five European countries, taking account of flows from a further six neighbouring countries. An explanation of the design and operation of *EurECa* is provided in Annex A. This chapter provides a summary description of core assumptions used for input to derive our electricity price projections. These assumptions may be classified under the following headings:

- economic assumptions;
- fuel prices (coal, gas and oil) and carbon prices;
- electricity demand; and
- new power station construction.

Table 18 provides a summary of the main assumptions used for each of the scenarios. The following sections provide further detail on each of the modelled inputs.

Table 18 – Main assumptions in Pöyry's electricity price scenarios

Electricity price scenario	Fuel prices	Demand growth	New conventionnal	New renewable build
High	High	High	High	Central
Central	Central with oil-indexed gas	Central	Central	Central
Low	Low	Low	Low	Central

4.1 Economic assumptions

For the nominal exchange rates we have used the forward Bloomberg composite rate as reported on a similar date to that taken for the oil forward curve (11 June), which is used as the basis of our short-term oil price projections (see section 4.4). Inflation rates have been derived by using the mean composite CPI forecasts from Bloomberg, based upon forecasts from major financial institutions.

We have used Bloomberg's exchange rate forecasts out to 2012 and inflation rate forecasts for 2009 and 2010 in all three economic zones – US, UK and the Euro-zone. We hold the nominal exchange rates constant from 2012 onwards, and inflation rates in all three areas constant from 2011 onwards. These assumptions drive the movements in inflation and real exchange rates seen in Table 19.

Table 19 – Exchange and inflation rates (real 2008 money)

	Real exchange rates			Inflation Rates		
	$ per £	$ per €	£ per €	US	UK	Euro-zone
2009	1.60	1.36	0.85	-0.3%	1.6%	0.3%
2010	1.69	1.33	0.79	1.8%	1.6%	1.3%
2011	1.76	1.33	0.76	1.9%	1.8%	1.7%
2012	1.76	1.33	0.76	2.0%	2.0%	2.0%
2013	1.76	1.33	0.76	2.0%	2.0%	2.0%
2014	1.76	1.33	0.76	2.0%	2.0%	2.0%
2015	1.76	1.33	0.76	2.0%	2.0%	2.0%
2016-2030	1.76	1.33	0.76	2.0%	2.0%	2.0%

Source: Bloomberg

4.2 Fuel prices

Table 21 to Table 23 provide details of the fuel prices used in the model with regard to French price projections. All figures are for fuel delivered at the power station in €/GJ (of gross, or high calorific value) on a variable cost basis. Prices for fuel delivered at the power plant include transport costs and taxes.

We assume the following calorific values in our modelling as detailed in Table 20.

Table 20 – Calorific value of fuels (gross)

Fuel	Calorific Value
Coal	26.38GJ/tonne
Heavy Fuel Oil (HSFO) and Light Fuel Oil (LSFO)	43.20GJ/tonne
Gasoil	45.60GJ/tonne
Gas	0.0381GJ/cubic metre

Table 21 – High delivered fuel prices (gross €/GJ, real 2008 money)

€/GJ	Coal coastal	Coal inland	Gas	LSFO	Gasoil
2009	2.5	2.9	6.6	5.7	9.6
2010	3.2	3.6	7.4	8.1	13.9
2011	3.3	3.7	7.5	8.6	14.8
2012	3.2	3.6	7.9	9.1	15.7
2013	3.1	3.5	8.2	9.3	15.9
2014	3.0	3.4	8.3	9.6	16.5
2015	2.9	3.3	8.5	10.0	17.1
2016	2.9	3.3	8.5	10.1	17.3
2017	2.9	3.3	8.5	10.2	17.4
2018	2.9	3.2	8.5	10.2	17.6
2019	2.8	3.2	8.4	10.1	17.4
2020	2.8	3.2	8.5	10.0	17.2
2021	2.8	3.2	8.5	9.9	17.0
2022	2.8	3.2	8.8	9.8	16.9
2023	2.8	3.2	9.1	9.8	16.8
2024	2.8	3.2	9.4	9.9	17.0
2025	2.8	3.2	9.7	10.0	17.2
2026	2.8	3.2	9.9	10.3	17.7
2027	2.8	3.2	10.2	10.6	18.1
2028	2.8	3.2	10.5	10.8	18.6
2029	2.8	3.2	10.9	11.0	18.9
2030	2.8	3.2	11.0	11.2	19.2

LSFO – Low sulphur fuel oil

Table 22 – Central delivered fuel prices (gross €/GJ, real 2008 money)

€/GJ	Coal coastal	Coal inland	Gas	LSFO	Gasoil
2009	2.1	2.5	4.7	5.3	8.9
2010	2.7	3.1	5.5	6.8	11.6
2011	2.8	3.2	5.9	7.1	12.2
2012	2.6	3.0	5.9	7.3	12.5
2013	2.4	2.8	5.8	7.2	12.4
2014	2.3	2.7	5.7	7.3	12.5
2015	2.2	2.6	5.6	7.4	12.6
2016	2.1	2.5	5.5	7.2	12.2
2017	2.1	2.5	5.5	7.2	12.2
2018	2.0	2.4	5.5	7.1	12.1
2019	2.0	2.4	5.4	6.9	11.8
2020	2.0	2.4	5.4	6.8	11.6
2021	2.0	2.4	5.4	6.7	11.4
2022	2.0	2.4	5.4	6.6	11.2
2023	2.0	2.4	5.5	6.6	11.2
2024	2.0	2.4	6.0	6.5	11.1
2025	2.0	2.4	6.4	6.6	11.2
2026	2.0	2.4	6.8	6.7	11.4
2027	2.0	2.4	6.9	6.8	11.6
2028	2.0	2.4	7.0	6.9	11.8
2029	2.0	2.4	7.2	7.0	11.9
2030	2.0	2.4	7.3	7.0	12.0

LSFO – Low sulphur fuel oil

Table 23 – Low delivered fuel prices (gross €/GJ, real 2008 money)

€/GJ	Coal coastal	Coal inland	Gas	LSFO	Gasoil
2009	1.8	2.1	3.9	4.8	8.1
2010	1.7	2.1	4.3	4.8	8.1
2011	1.6	2.0	3.7	4.8	8.0
2012	1.6	2.0	3.1	4.6	7.8
2013	1.5	1.9	2.9	4.2	7.1
2014	1.5	1.9	2.8	4.1	6.8
2015	1.5	1.9	2.6	4.0	6.8
2016	1.4	1.8	2.5	3.9	6.5
2017	1.4	1.8	2.3	3.9	6.4
2018	1.4	1.8	2.4	3.8	6.4
2019	1.4	1.8	2.3	3.8	6.4
2020	1.4	1.7	2.3	3.7	6.2
2021	1.3	1.7	2.5	3.7	6.2
2022	1.3	1.7	2.6	3.7	6.1
2023	1.3	1.7	2.6	3.6	6.0
2024	1.3	1.7	2.6	3.6	5.9
2025	1.3	1.7	2.7	3.6	5.9
2026	1.2	1.6	2.7	3.6	5.9
2027	1.2	1.6	2.7	3.6	5.9
2028	1.2	1.6	2.7	3.6	5.9
2029	1.2	1.6	2.8	3.6	6.0
2030	1.2	1.6	2.8	3.6	6.0

LSFO – Low sulphur fuel oil

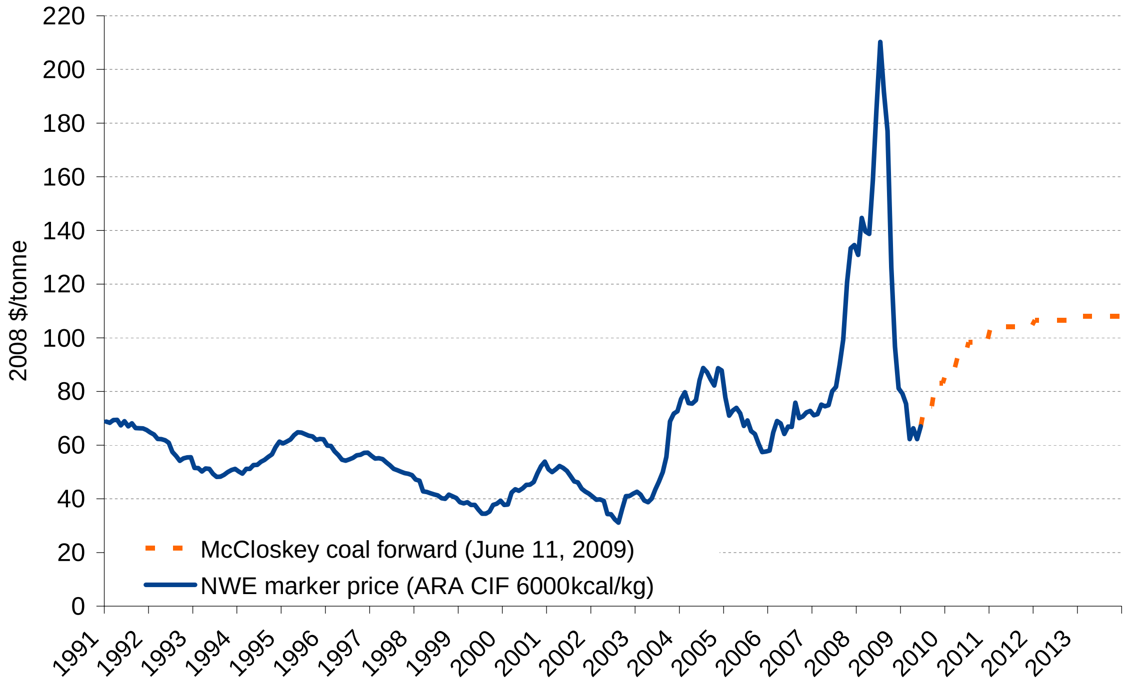
4.3 Coal Prices

In this section we describe in turn the recent history of the international coal market, and then our projections for future ARA CIF prices out to 2030. The coal price projections include a discussion of our modelling approach.

4.3.1 International coal market – recent history

Figure 25 illustrates the historical price of coal, traded at ports in North West Europe (NWE) as reported by McCloskeys Coal Information Service (MCIS).

Figure 25 – MCIS NWE marker price (ARA CIF 6000 kcal/kg NAR)



Source: Reuters

Below we describe the main features of coal prices since 2002, with a particular emphasis on the very high levels seen in 2008.

4.3.1.1 Coal price development over the period 2002–2007

In 2002, coal prices reached a low of around $35/tonne (in real 2008 terms). Low prices, and consequent low returns for mining companies, precipitated a consolidation in the industry and increasingly concentrated ownership in traditional coal exporting countries to Europe. Four dominant producers emerged during this period, namely BHP Billiton, Rio Tinto, Xstrata and Anglo. Overall global supply was restricted, with lower growth in production, and a shortage of new mines and infrastructure developments outside of China.

This restriction on global supply coincided with increasing demand for coal, especially in China and other parts of Asia, and constraints on the worldwide shipping capability of dry bulk goods, to exert significant upward pressure on prices during the latter half of 2003. The ARA spot price reached about $80/tonne by the middle of 2004. The freight price was considered the main driver of higher coal prices, with the benchmark Richards Bay to Rotterdam marker increasing from $5/tonne in 2002 to almost $40/tonne by the start of 2004. Freight prices continued to show signs of volatility and remained very high (in a historical context) over the next few years. This led to ARA coal prices fluctuating around the $60-80/tonne range until mid 2007.

In the second half of 2007 a very sharp increase took the MCIS NWE marker price above $100/tonne for the first time.

4.3.1.2 Coal price movement in 2008 and 2009

The rising trend continued into 2008 and the price rose to record levels of over $200/tonne by July 2008. However the second half of 2008 saw a complete turn-around with an equally rapid decrease in prices. Prices had decreased to around $80/tonne by the end of the year.

The first half of 2009 has saw coal prices (for near-term delivery) decrease from a level of around $85/tonne at the beginning of January to about $65/tonne by the end of March. The level of decline was significantly less steep than the price decrease seen over the second half of 2008, however weakening of demand for coal in both Europe and Asia meant that prices continued to fall. Over the second quarter of 2009, coal prices have remained in the range of $60–70/tonne due to the ongoing uncertainty over the short-term prospects for worldwide coal demand.

Further downward pressure on steam coal prices has come from the significant reduction in coking coal prices (used in steel production) as the global economy contracts. Certain types of coking coal can be also used in power generation which creates link between the steam coal market and the coking coal market.

It is also notable that the current coal forward curve[86] is in steep contango[87]. As an example, the forward price for coal on 31 March was $74/tonne for 2009 Q3 delivery, $95/tonne for 2010 delivery and $107/tonne for 2012 delivery, with all prices in real 2008 money. This type of forward curve is different from what has been historically observed in the coal market over the past few years, where the forward curve has generally been much flatter.

The development of this contango position is similar to the development in the oil forward market, and indicates a perceived oversupply situation in the current market. The higher prices in later years mean that a recovery in price levels might be expected, but the lack of liquidity in contracts for later years means that this is very uncertain. As outlined below, we use the forward price for two years in our Pöyry Central Projection before reverting to our projection for long-term price levels, which are slightly lower than the current ‘long-term’ forward prices.

4.3.2 International steam coal price projections

4.3.2.1 Key drivers of the coal price going forward

We believe that the coal price in the long term will be driven by long-run marginal costs required by each aspect of the coal delivery chain. This chain includes coal mine costs, inland transport costs, port costs and shipping costs. We see no major barriers to undermine the assumption that there can be enough mine development in established coal exporting countries to meet growing coal worldwide demand.

However due the nature of the international coal market and the reasonably long and complex investment cycle, there are likely to continue to be price movements away from the long-term fundamental price levels. A number of factors could determine the price in any one year and could also keep the price depressed or inflated for a reasonable period.

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86 McCloskey forward curve, as reported by Reuters.

87 An upward-sloping forward curve, with higher prices the further out compared to the current spot price.

Some of the important factors that could move coal prices away from fundamentals could be:

- Chinese coal export/import: China is both the world's largest coal producer and consumer. Currently it has an excess of supply over demand, enabling it to provide around 1-3% of its total coal production to the international market. However this amount can be up to 10% of the total international trade in steam coal. Therefore reasonable small fluctuations in Chinese demand relative to Chinese supply can affect the coal availability in the international market significantly. The ability of investment plans to anticipate or respond to these changes will be crucial in determining future coal prices.
- Port capacities: The development of port capacity to keep pace with mine expansion will be important for coal prices going forward. Port expansion is likely to be even more capital intensive than mine expansion and with a longer investment time-horizon. Any constraints or excess in port capacity could keep prices inflated or depressed for a number of years.
- Shipping: As we have seen in recent years, the shipping market can make up a large element of the final coal price. The competition for shipping capacity with other dry bulk goods (e.g. iron ore, grain), means that shipping price levels can vary considerably over short periods of time. Recent years have seen high shipping costs compared with fundamental prices, as there has been a shortage of new ships and a waiting list for new ships. We expect that the shipping element of the coal price will remain close to fundamental levels over the next few years due to the global economic slowdown, and the expected commissioning of a number of new ships.
- European coal demand: European coal demand is probably the most 'flexible' element of worldwide coal demand, as it is mostly used for power generation and there is the opportunity for a lot of countries to switch to gas-fired generation in the event of a high coal (or EU ETS carbon) price. However over the long-term we would expect the effect of this on coal demand to be mitigated by the 'self correcting' element of the coal/gas/carbon relationship. In the event of a low gas or high carbon price, the switching of coal-fired generation to gas would put downward pressure on the coal price and downward pressure on the carbon price.

4.3.2.2 Developing Pöyry coal price projections

The Pöyry steam coal price projections are based on the fundamentals of supply and demand and long-run marginal costs using *Olympus,* our worldwide coal model.

We develop coal cost information for exporting region using data provided by the IEA Clean Coal Centre together with our own assumptions. Estimates of mine investment costs are based on various mining company reports. Shipping costs take into account Capex, Opex and fuel costs. Demand projections are also developed based on IEA assumptions.

Olympus is a Linear Programming (LP) model dividing the world into individual regions (or zones). The model projects yearly coal trade and international prices to 2030, by notionally transporting coal from zones with an excess of supply over demand to zones with an excess of demand over supply, until all world demand for steam coal has been satisfied.

The model takes the following into account:

- the cost of production of coal (including future expansion) in each zone;

- the availability of coal in each zone;
- the demand for coal in each zone;
- the cost of transporting coal from where it is available to where it is needed; and
- an assumption of coal calorific vale in each region.

This model produces an annual coal merit order for each importing zone. The model is solved to satisfy coal demand at least cost, with the final ARA coal price calculated from the Western European coal supply curve.

The model works on an annual basis and gives results for coal of an average calorific value of 6000 kcal/kg (net as received).

4.3.2.3 Central case

The Central case assumes an adequate supply of coal to Europe with increasing production in coal exporting countries (Australia, Colombia, Indonesia) to counteract diminishing indigenous production in European countries. The price of coal trends towards the long run marginal cost (LRMC) of coal production and shipping. The ARA price in this case stabilises at $70/tonne by 2020 and remains at a similar level to the end of the projected period, i.e. out to 2030.

This gives an ARA price of around $70/tonne in real terms by 2020, and it remains at around that level until 2030.

4.3.2.4 Low case

The Low case assumes productivity gains in coal production costs along with increasingly large quantities of coal available for export from low cost countries. A lower oil price also decreases the fuel price for the transportation of coal. The Low case projects an ever decreasing ARA coal price (in real terms) over the period considered. The price decreases to $48/tonne in real terms by 2020 and $41/tonne by 2030.

4.3.2.5 High case

The High case assumes higher estimates of the LRMC in coal exporting countries, an increased investment cost for mine capacity expansion, and a higher fuel price for the transportation of coal. The export availability and import demand of steam coal remains relatively finely balanced. This gives an ARA price of around $70/tonne in real terms by 2020, rising slightly to $100/tonne by 2030.

4.3.2.6 Short-term price projections

The Pöyry steam coal price projections are based on the fundamentals of supply and demand. However as has been discussed, it can often take many years for the international coal market to respond to price signals and provide increased supply. Therefore short term prices (1-4 years, dependent on scenario) are based on more recent market prices, and by looking at the forward curve[88]. This approach is likely to give a more accurate reflection of near term prices.

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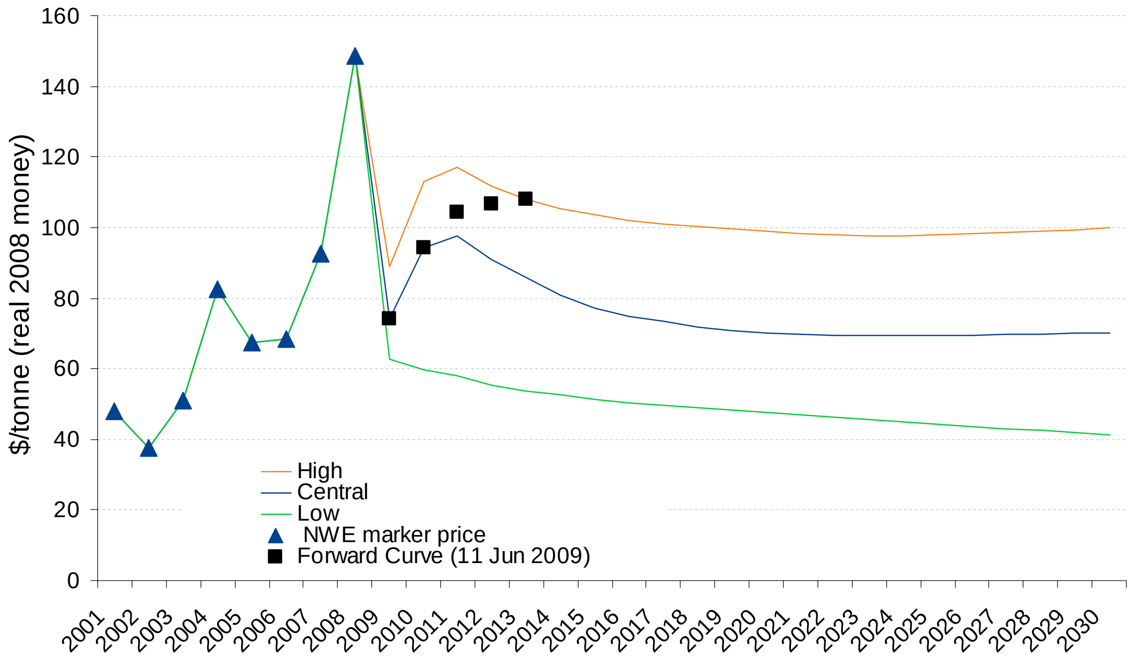
88 Short term prices are based on prices from the McCloskey forward curve, as reported by Reuters. The near-term prices are then interpolated with our long-term projections to calculate the current Pöyry price projections.

Figure 26 shows the final Pöyry coal price projections alongside a comparison with a recent forward curve.

Figure 26 – Coal price (CIF ARA) projections (in 2008 US$/tonne)



Source: McCloskey, Reuteurs and Pöyry Energy Consulting

Table 24 – Pöyry coal price (CIF ARA) projections (2008 US$/tonne)

$/tonne	High	Central	Low	Forward*
2009	88.8	74.0	62.9	74.0
2010	113.1	94.3	59.9	94.3
2011	117.1	97.6	57.9	104.2
2012	111.9	90.8	55.5	106.6
2013	108.1	85.7	53.8	108.1
2014	105.4	80.7	52.6	
2015	103.5	77.2	51.5	
2016	102.1	74.9	50.4	
2017	101.1	73.3	49.7	
2018	100.3	71.7	49.0	
2019	99.6	70.7	48.3	
2020	99.0	70.2	47.6	
2021	98.4	69.6	46.9	
2022	98.0	69.4	46.2	
2023	97.7	69.4	45.5	
2024	97.7	69.4	44.8	
2025	97.9	69.4	44.2	
2026	98.2	69.6	43.6	
2027	98.6	69.7	43.1	
2028	99.0	69.9	42.5	
2029	99.4	70.0	41.9	
2030	99.9	70.1	41.4	

* McCloskey Forward curve as reported by Reuters on 11 June 2009
These prices are based on a calorific value of 6000 kcal/kg CIF net as received (NAR)

4.3.3 Delivery costs for coal

For coal we have assumed a delivery cost of $15/tonne (2008 money) for inland plants and $12/tonne (2008 money) for coastal plants. These delivery costs are equivalent to €0.4/GJ and €0.3/GJ, respectively.

4.4 Oil

The relevance of oil prices to our projections of electricity prices is through oil indexation in gas prices and the possible use of oil products in power stations. The prices for these oil products – low sulphur fuel oil (LSFO) and gasoil[89] – are projected through applying parameters from the historic relationship between these products and Brent crude oil to our projections for Brent crude prices. This section outlines the approach we take to project prices for Brent crude, LSFO and gasoil. It begins by outlining the differences between the current and the previous projections, provides an overview of the types of oil available, outlines the movement in crude prices, and finally discusses the projections of Brent crude and LSFO and gasoil prices.

89 Gasoil is also called medium distillate oil (MDO).

4.4.1 Introduction

The relevance of oil prices to our projections of electricity prices is through oil indexation in gas prices and the use of oil products in power stations. The sections below describe the trends in historic crude oil prices and provide a background on how we have formed our current projections of the price of Brent crude.

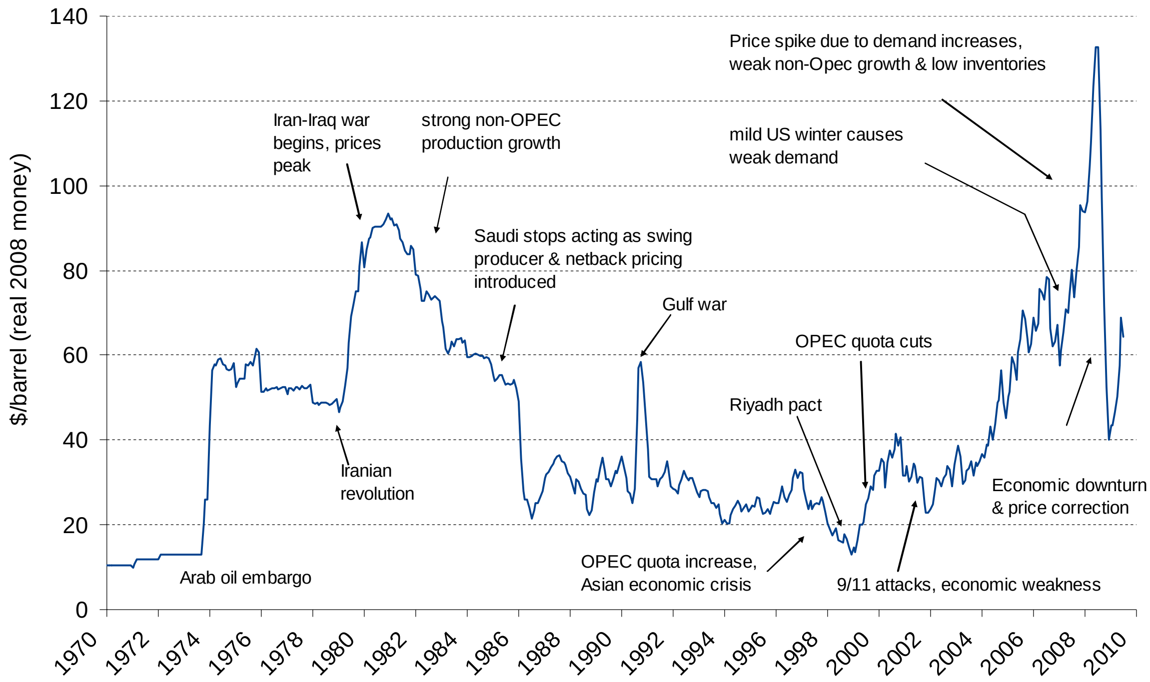
Our crude oil modelling methodology has changed from July 2009. Crude oil prices are now projected using Pöyry's crude oil model *Cronos*. A more detailed document which describes the inputs to the model is available if required.

4.4.2 Market Background

4.4.2.1 Historic prices

Figure 27 shows historic crude oil prices from 1970 to present. The paragraphs below describe recent price drivers in more detail.

Figure 27 – Historic crude oil prices ($/barrel, real 2008 money)



Source: EIA, Reuters, Pöyry Energy Consulting

4.4.2.2 Prices between 1998 and 2008

Prices in late 1998 were at $10/barrel (nominal). However from this period onwards, prices rallied, reaching levels of $140/barrel in mid-2008. The International Energy Agency (IEA) lists the following factors as a cause of the run up in crude oil prices during this period[90]:

90 IEA 2008, *Medium Term Oil Report.*

- Strong demand growth for crude oil driven by non-OECD growth, particularly China and India.
- Poor supply growth particularly from non-OPEC supply, which consistently underperformed expectations.
- Low levels of spare capacity in the market. Spare production capacity has existed in the oil market since the 1980's, however by 2004, all of the excess production capacity had been put in to use.
- Sharp rises in production costs due to tightness in the service sector and limited access to low cost reserves.
- A mismatch between product demand and refining capacity. Much of the demand growth during this period was in middle distillates. The interaction between refining capacity and underlying oil price is complex; however it is believed that the strong demand for this fraction was a major cause of the price increases.
- Geopolitical tensions such as the second Iraq war, strikes in Venezuela, concerns over Iran's nuclear program and production disruptions in Nigeria may also have contributed to the sharp increase in oil prices.

4.4.2.3 Prices from 2008 to present

The last two years have been a turbulent period for oil prices. At the beginning of 2007, oil prices were below $60/barrel. From this point onwards prices increased, with Brent crude reaching $140/barrel in July 2008, before falling back to below $50/barrel in early 2009. Pöyry believes the drop in crude oil prices during the second half of 2008 can be attributed to:

- A deepening of the financial crisis from August 2008 onwards.
- A decrease in the demand for crude oil, as the effects of the global financial crisis and high oil prices took effect. Oil demand fell in 2008 for the first time since the oil crises.
- A change in market sentiment. The sentiment in the market prior to July 2008 was that the supply/demand balance would remain tight and therefore the high prices seen would persist. However the deterioration in the outlook for the global economy and crude oil demand caused market participants to re-assess this view.

In September 2008, OPEC announced a cut in production of 4.2 million barrels per day (roughly 5% of global production) in an attempt to counteract the downward pressure on prices.

Prices during the first half of 2009 have recovered to the $60-70/barrel range. This is driven by signs of a recovery in the global economy, which is expected to lead to a recovery in crude oil demand.

4.4.3 Crude oil market model

4.4.3.1 Overview

The global crude oil market is extremely complex with tens of thousands of fields in production, each producing a crude oil with a unique composition. Constructing a detail field-level model of the entire market would be a difficult if not impossible task. Therefore the model presented here is, as with every model, a simplification. However we believe that the structure of the model is sound and allows us to produce projections of crude oil prices based on the scenario assumptions described in more detail below.

The price which *Cronos* outputs, is the price of light sweet crude delivered FOB to north-west Europe. This can be taken to represent the price of Brent crude benchmark.

4.4.3.2 Structure of Cronos

Due to depletion rates of existing crude oil capacity[91] it is very unlikely that demand will fall by enough to create a scenario where new crude oil production capacity is not required in any given year. This removes the need to examine the economics of existing crude oil production capacity in order to project future crude oil prices

We also believe that it is not possible to construct an economic model of the behaviour of Opec member countries, as their actions are often driven by political factors. Opec behaviour is an input to the model and is a key variant across the scenarios.

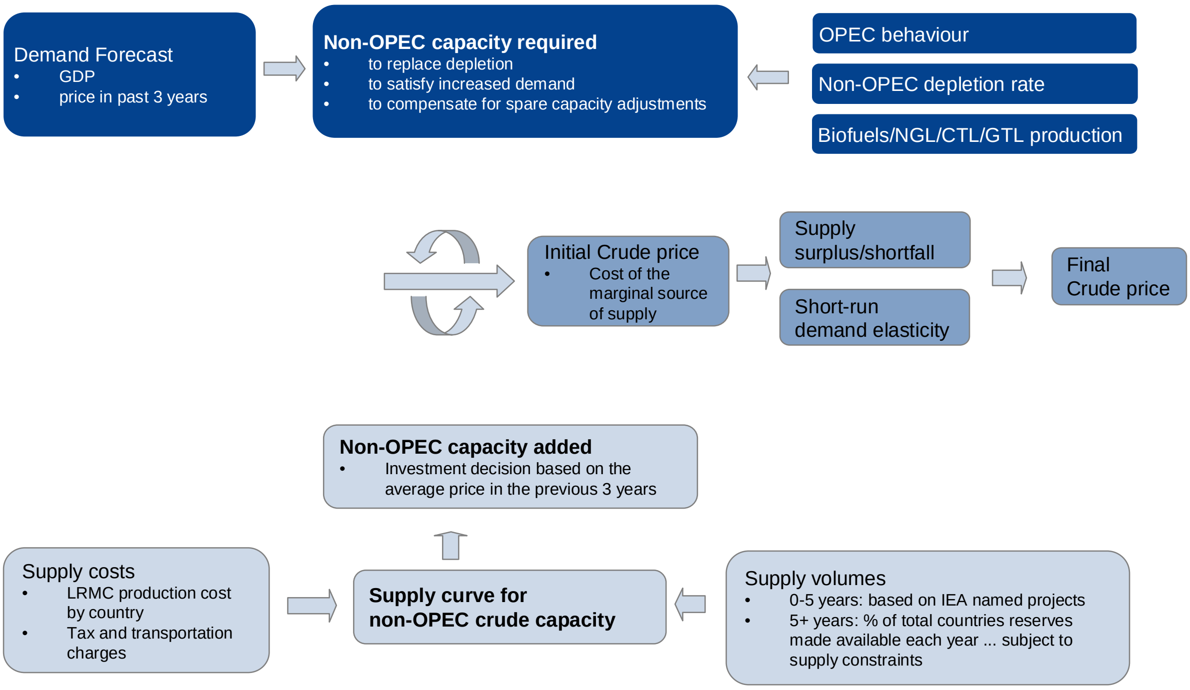
Cronos therefore projects crude oil prices by analysing the supply and demand for new crude oil production capacity in non-Opec countries:

- Demand is determined by the demand for new production capacity due to depletion of existing oil fields and demand growth.
- Supply is determined by constructing a non-OPEC supply curve for new production capacity.

Unconventional sources of liquids fuels – biofuels, coal-to-liquids (CTL) and gas-to-liquids (GTL), as well as processing gains are also inputs to the model. The assumptions made for these sources of supply are described in more detail below.

The structure of the *Cronos* model can be seen in Figure 28.

Figure 28 – Structure of Cronos



[91] The average depletion rate of existing non-OPEC capacity is estimated by the IEA to be 6.5% per year.

4.4.3.3 Scenario description

Three scenarios have been created which span a reasonable range of outcomes, with the aim of examining the effect on prices of a number of key drivers.

The assumptions in the High and Low scenarios have been selected so as to examine the long-term boundaries of future crude oil prices. It might be expected that in a high crude oil price world, countries would make more of their reserves available to exploit and access to reserves would be high also. However in order to design a more extreme scenario we examine a world in which demand is high and access to reserves remains low.

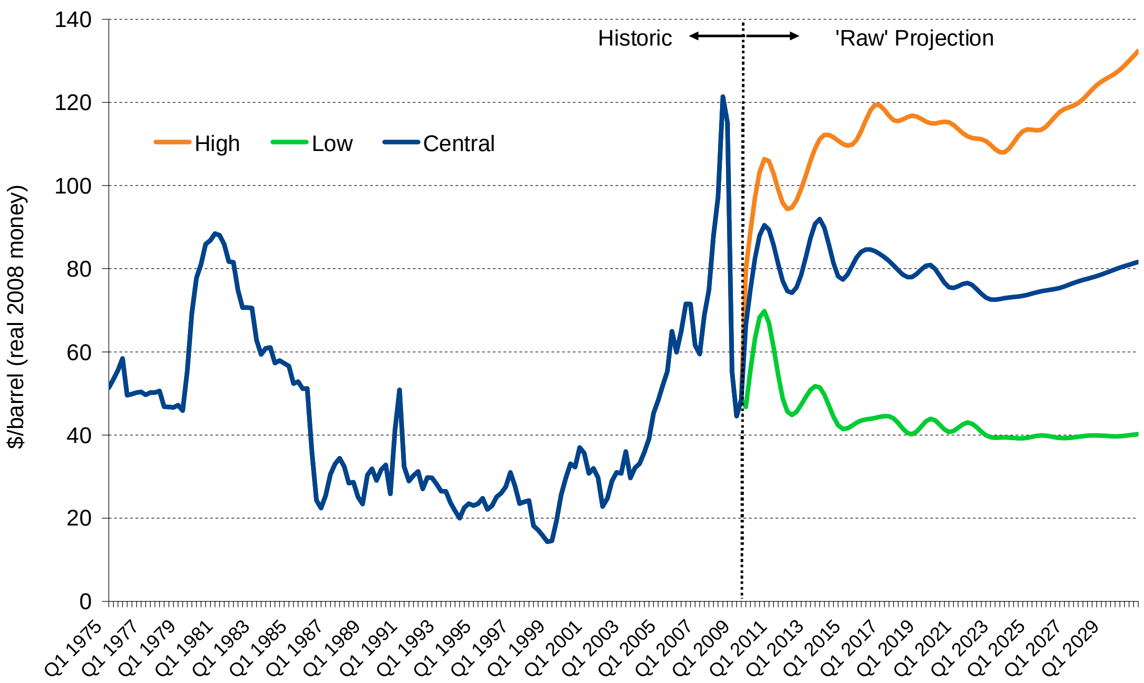
4.4.3.4 Raw Outputs

Figure 29 shows the 'raw output' from *Cronos*. Quarterly historic prices from 1975 to present are shown along with the projections of future crude oil prices in each of the 3 scenarios.

It can be seen that there is a large amount of volatility in prices, particularly in early years. This is due to:

- investment decisions being taken on recent prices rather than an expectation of future prices; and
- the interaction between price and demand. When prices have been high for some time, demand begins to reduce putting downward pressure on prices.

Figure 29 – Historic and projected quarterly Brent crude prices
($/barrel, real 2008 money)

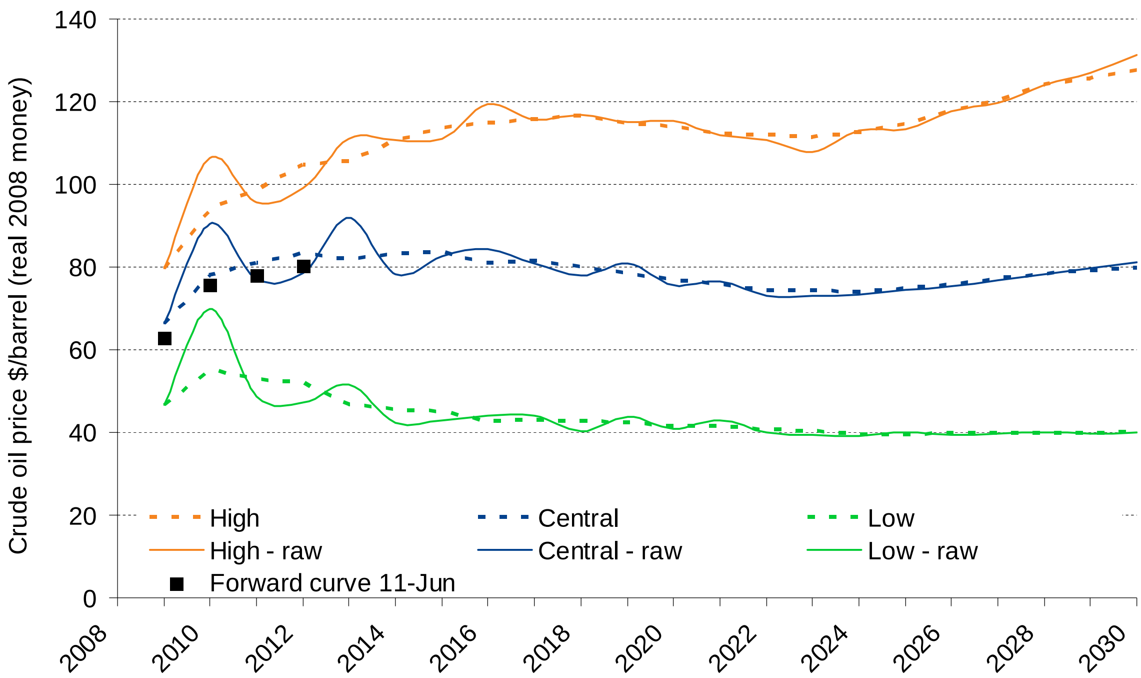


4.4.4 Crude oil price projections

Our gas and electricity projections are of sustainable long-term (or underlying) levels and the range of outcomes does not cover short-term spikes. Thus it is appropriate to smooth the crude oil price projections produced here prior to using them in our gas and electricity modelling.

Figure 30 presents a comparison of our raw and smoothed crude oil price projections.

Figure 30 – Comparison of raw and smoothed outputs



4.4.4.1 Crude oil price projections

Figure 31 and Table 25 present Pöyry's projected prices for Brent crude, along with a comparison with our April 2009 projections.

Figure 31 – Projections of Brent Crude prices (US$/barrel, real 2008 money)

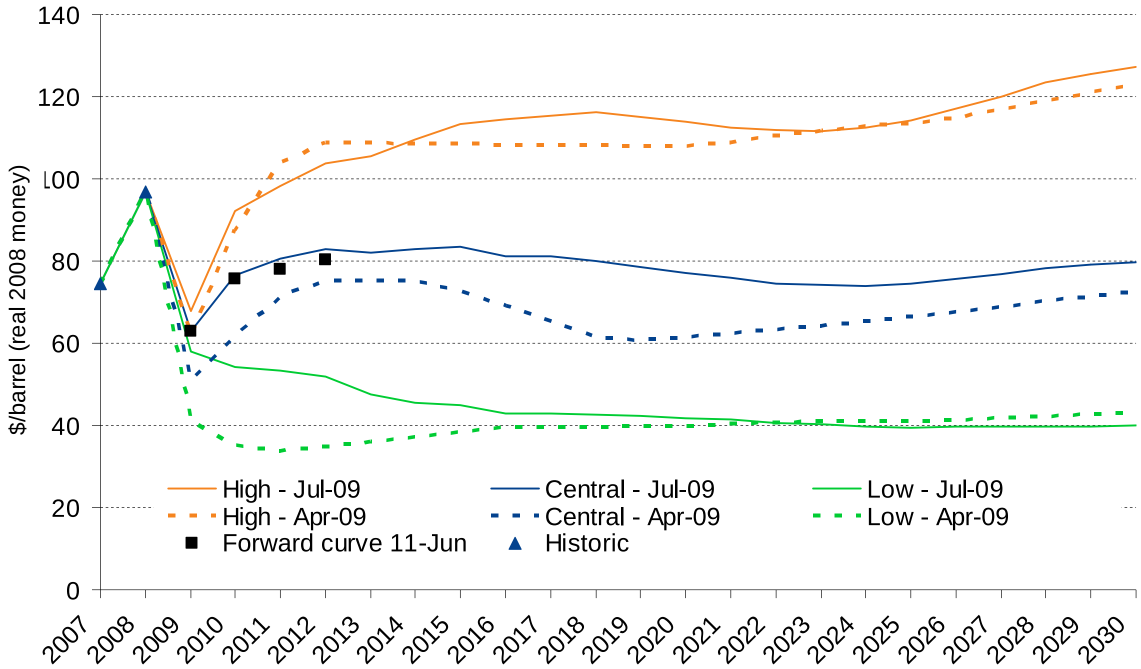


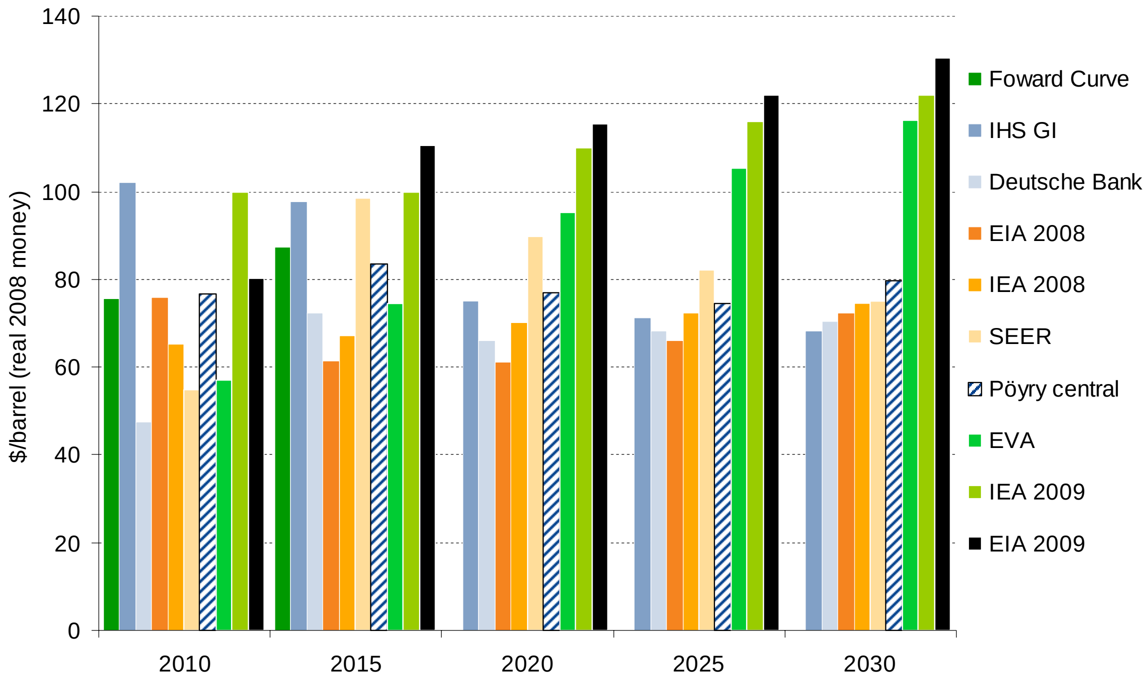
Table 25 – Projections of Brent Crude prices ($/barrel, real 2008 money)

$/barrel	High	Central	Low
2009	67.8	62.8	57.8
2010	92.2	76.6	54.1
2011	98.1	80.7	53.4
2012	103.7	82.9	51.9
2013	105.6	82.0	47.4
2014	109.6	82.8	45.6
2015	113.3	83.6	45.1
2016	114.6	81.2	43.0
2017	115.5	81.1	42.9
2018	116.3	80.1	42.7
2019	115.2	78.5	42.4
2020	114.0	77.0	41.7
2021	112.4	75.9	41.4
2022	111.8	74.5	40.6
2023	111.5	74.1	40.3
2024	112.4	73.9	39.7
2025	114.2	74.5	39.5
2026	117.2	75.6	39.6
2027	120.1	76.8	39.7
2028	123.5	78.2	39.7
2029	125.4	79.0	39.8
2030	127.2	79.7	39.9

4.4.4.2 Comparison of long term crude oil price projections

Figure 32 compares Pöyry's Central crude oil price projection for with other long-term crude oil price projections. The data for other projections is based on information from the EIA's Annual Energy Outlook 2009. It can be seen that in the long-term the projections range from $68/barrel to $131/barrel by 2030, which demonstrates the large uncertainty which exists over the long-term price of crude oil.

Figure 32 – Comparison of long term crude oil price projections



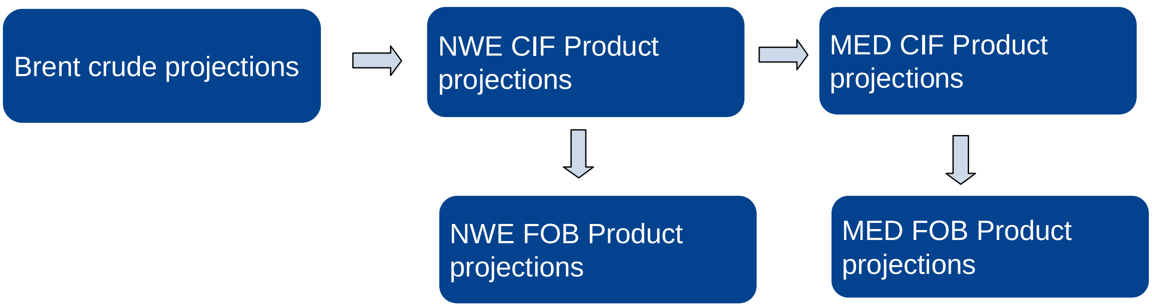
Source: US Energy Information Administration

4.4.5 Product price projections

Once our Brent crude projections have been finalised, our oil product prices are projected using our Brent crude projections and a correlation based on historic price data.

Figure 33 shows how this process is performed. Our NWE CIF products are projected from our Brent crude projections. Other projections are then produced as shown using a correlation between historic product prices.

Figure 33 – Formation of Pöyry's oil product projections



4.4.6 Qualifications

As discussed previously, the oil market is extremely complex and the future outlook for the market is extremely uncertain.

The *Cronos* model does attempt to capture some of the market volatility, however it does not capture all of it and so there may be significant variation of prices about the underlying level, from year to year. The projections supplied are not to be regarded as firm predictions of the future, but rather as illustrations of what might happen.

4.5 Gas

The Pöyry approach to modelling liberalised gas markets is driven by the underlying economics of supply and demand. The starting point for French gas price projections is the economic cost of producing and transporting gas to France.

4.5.1 Gas modelling methodology

Gas prices are projected using our pan-European and US gas model, Pegasus ('Pan-European GAS + US'). The model examines the interaction of supply and demand worldwide on a daily basis. Pipeline imports and interconnections between the UK, NW Europe, Spain, Italy, Central and South East Europe and Turkey are modelled in detail, alongside all existing and proposed LNG terminals, and their interaction with the global LNG market.

Examining daily demand and supply across these markets gives a high degree of resolution, allowing the model to examine weekday/weekend differences, flows through the interconnectors and gas flows in and out of storage in detail.

Pegasus itself is comprised of a series of modules. The main solving module is based in XPressMP, a Linear Programming (LP) package, which optimises to find a least-cost solution to supply gas to seventeen zones over a gas year. Figure 34 shows sixteen of the zones and the remaining 'Rest of the World zone' includes all the other LNG terminals. The solution is subject to a series of constraints, such as pipeline or LNG terminal sizes, interconnector capacities and storage injection/withdrawal restrictions.

Figure 34 – Geographic coverage of Pegasus

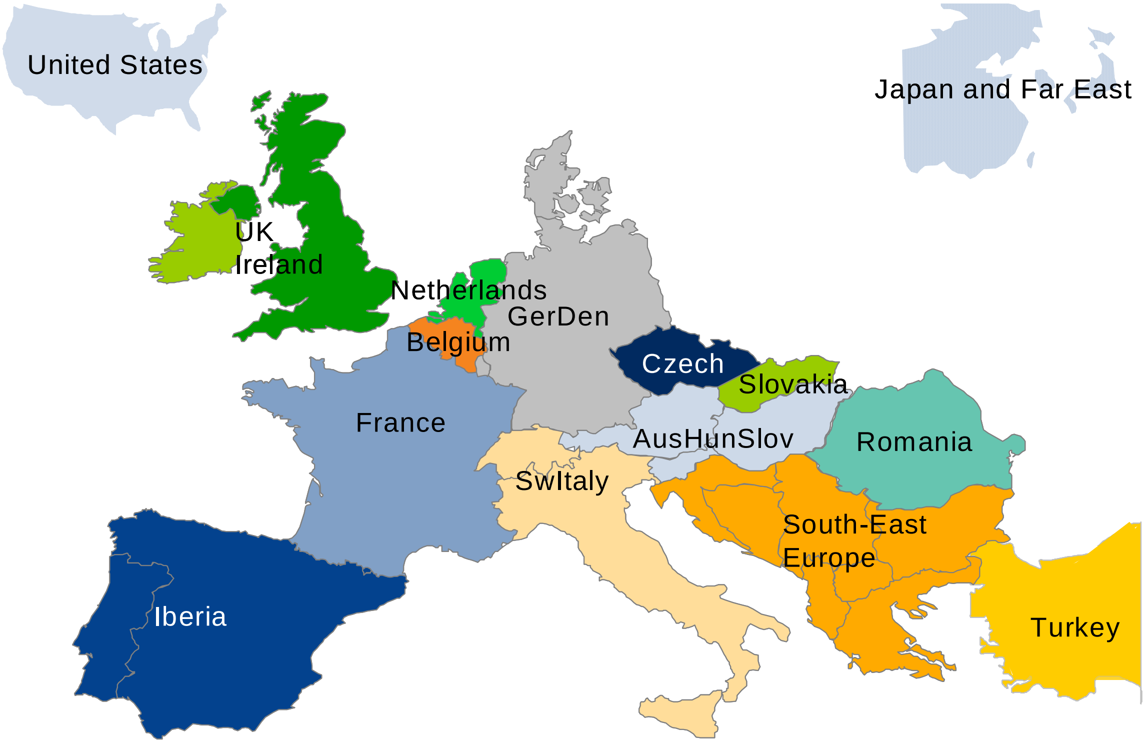
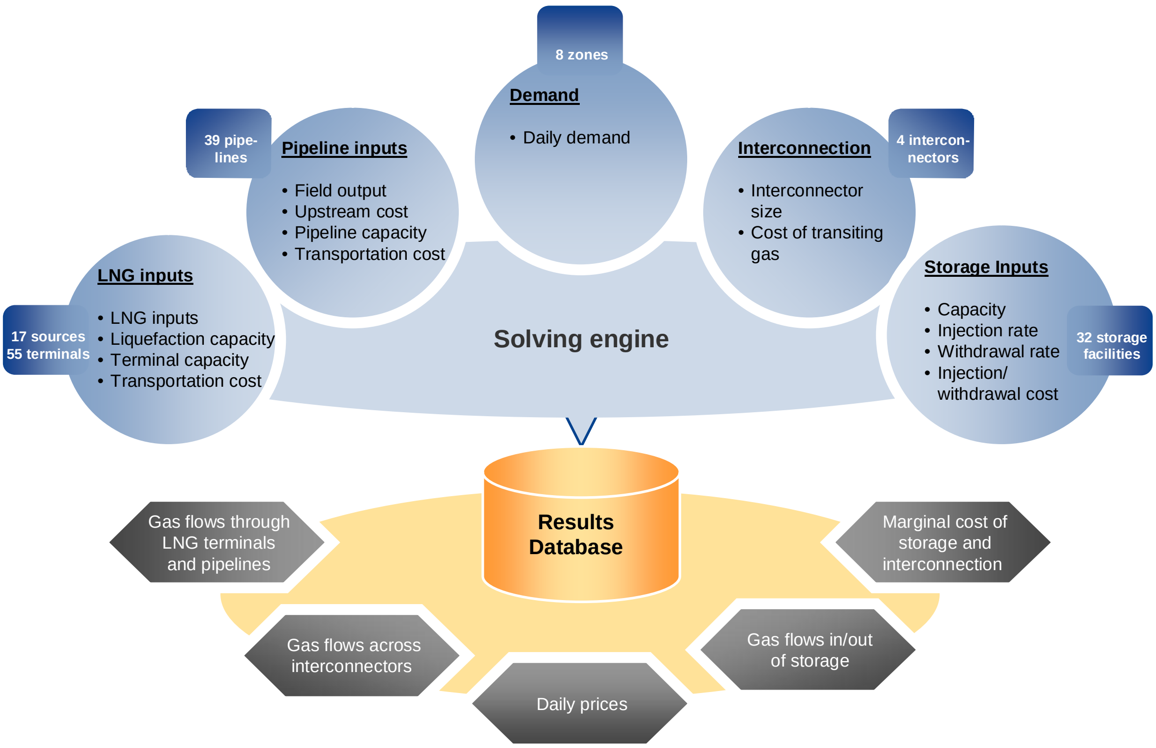


Figure 35 – Structure of Pegasus



The solving module takes input files generated by a series of Excel/VBA modules, which allow a variety of scenarios to be created by changing variables such as supply, demand, costs, storage and interconnectors. The outputs from the model, such as prices and flows of gas, are sent to a database to allow easy extraction of data at either a daily, monthly or annual resolution.

Interconnection through BBL and IUK between the UK and the Netherlands and Belgium markets, respectively, is important given the influence of oil-indexed long-term contracts. The optimisation algorithm in Pegasus minimises the cost of supplying gas to both NW Europe and the UK, subject to both the capacity and the cost of transiting gas across the interconnectors. This tends to lead to imports into the UK during winter to supply the peaky UK winter demand, and exports from the UK during summer. These patterns naturally change over time with differing assumptions on gas cost and new import projects and their location. The daily resolution in the model means that during the shoulder months, the interconnectors 'flip-flop' back and forth between import and export – exactly as we have seen historically.

Modelling storage accurately is key to understanding price formation in the UK and Europe, as it affects both summer and winter prices, along with weekday/weekend prices. Pegasus models each current and forecast UK gas storage field, each with its own injection and withdrawal rates, total storage capacity and cost of injection/withdrawal. The optimisation algorithm used not only means that gas is injected into storage during the summer and withdrawn during the winter, as expected, but also that injection takes place for high cycle facilities during the winter weekends and Christmas periods due to lower demand, as seen in reality.

We also model European and US storage in three generic types – depleted field, salt cavern and LNG. This lower level of detail is sufficient for European storage due to the non-commercial nature and opaqueness of use of much of the storage facilities.

In the new global Pegasus, the worldwide LNG market is modelled. All existing, under construction, proposed and conceptual LNG liquefaction projects worldwide are included under different scenarios, from a total of seventeen countries (or 'sources'). Similarly all LNG re-gasification terminals worldwide are also modelled. In Europe and the US each terminal is identified separately, except in the longer term when generic LNG terminal capacity may be included in addition. The terminal capacity in the Far East, Canada and South America, and the rest of the World, is grouped within zones.

LNG cargoes can be 'delivered' from any source to any LNG terminal. As a result, LNG cargoes can be delivered to different destinations depending on which market is most profitable for a particular cargo – for example, LNG will deliver preferentially to Montoir-de-Bretagne in France or Zeebrugge in Belgium when prices are higher than in the UK. Thus the French market is linked to the UK market not just through the interconnectors but also via LNG arbitrage. Furthermore, the interaction with the US and the rest of the Worlds' LNG markets means that gas markets become linked worldwide based upon supply and demand for LNG.

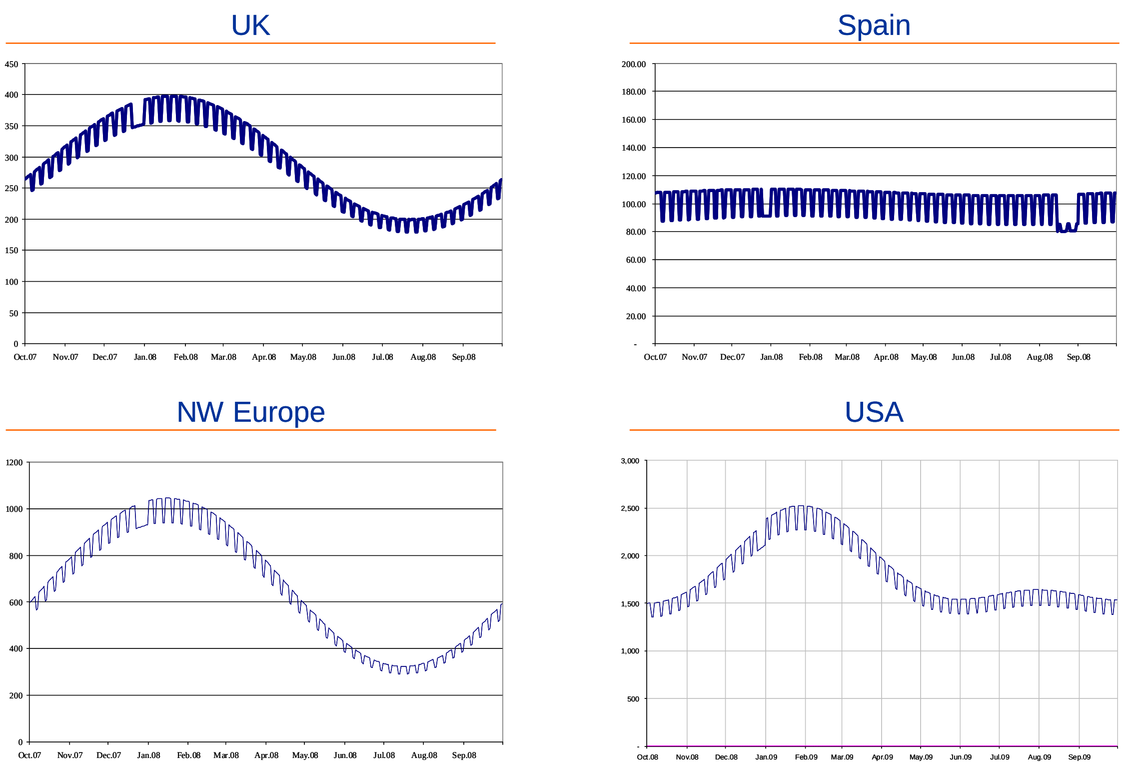
As a core part of our modelling, we carry out iterations with our electricity model to understand the effect of changes in gas price on demand for gas, and changes in demand for gas on price. This iteration between the two models ensures that our assumptions on gas prices and gas demand remain realistic and reflects the elasticity of gas demand given high gas prices.

4.5.2 Modelling assumptions

4.5.2.1 Gas demand

Gas demand is projected through individual forecasts for each zone of domestic, industrial and commercial, power generation and exports/transit gas. We profile the annual gas demand figures for each zone based around a sinusoidal function derived from historical data. The daily gas demand also accounts for the difference in demand between weekday, weekend and the Christmas shutdown period, again based on historical differentials. Four sample curves showing daily demand in the UK, overall NW Europe, Spain and the US over one year are presented in Figure 36.

Figure 36 – Example of daily gas demand input in four zones



4.5.2.2 Gas supply and import projects

Indigenous production and pipeline import capacity is forecast based upon market intelligence and information from industry participants.

The many interconnections between zones are based on data published by Gas Transport Europe and proposed pipelines, such as Nabucco, are also included as a series of interconnections.

4.5.2.3 Oil-indexation assumptions

For all scenarios, Pöyry assumes that in the early years gas prices on the Continent are heavily influenced by the effect of oil-indexation, particularly gas coming from the FSU. In the Abundant scenario (used for the Low wholesale electricity price scenario), transition to a competitive market, and thus price setting by the marginal player, is assumed to occur by 2014. In both the ‘Balanced: oil-indexation’ and the Constrained scenario (used for the Central oil-indexed and High wholesale electricity price scenarios, respectfully) full competition throughout Continental Europe never occurs, and thus gas prices are influenced strongly by oil-indexed contracts.

Under the 'oil-indexed' scenarios – the Balanced: oil-indexation and the Constrained scenarios – the Continental gas supplies from Norway and Russia remain oil-indexed and these dominate gas prices. UK gas and storage prices are not oil-indexed and are set by the long-run costs. LNG supplies are also set to increase throughout European gas markets and each market must compete for LNG with the rest of the world, making gas price setting much more complex.

The winter gas prices in France and the UK are largely set by storage cost and availability. Many new gas storage projects gas markets have been proposed in the UK and Europe and have progressed to a point at which we have included them coming on line in the next ten years or so.

4.5.2.4 Storage assumptions

Pegasus optimises the use of storage by using it to reduce the overall cost of supplying gas. Thus in the winter, rather than using very expensive sources of gas, or demand-side shedding, the model preferentially withdraws gas from storage when it is optimal to do so. In this case the marginal therm of gas (and hence the marginal price) will come from withdrawing one unit from storage along with the associated injection of one unit at some point in summer, and the corresponding cost of injection and withdrawal. The model assumes that storage is full at the start of the gas year (1 October) and full at the end of the gas year (30 September), and thus must inject any gas withdrawn from storage.

4.5.3 Summary of price projections

Three scenarios describe the general levels of supply, demand and transportation capacity for natural gas, and the effect that these levels would have on the price for natural gas. A general overview of the scenarios is as follows:

- High (Constrained). Across the globe, gas remains the fuel of choice for major markets, leading to high demand. High carbon prices means that gas tends to be favoured in Europe, both for power generation and for residential/I&C. In particular, the US and Far East look to LNG to meet energy needs, leading to a continued tight worldwide LNG market. Technological progress is limited for alternative technologies to replace conventional energy sources. Russia maintains its successful strategy of being first to sign-up European exports, squeezing Caspian and North African export potential, so Russia is dominant supplier to Europe and maintains oil-indexed long-term contracts. Competitive pressure from new LNG sources is limited owing to the tight LNG market.

- Central (Balanced oil-indexed). Demand (I&C and residential) rises and new projects come on in a timely manner to meet new demand. Some LNG comes to Europe, but in the medium-term new competition from LNG is limited. Russian continues to provide the lion's share of European imports, but there is some success in Caspian states marketing activities, and some pipeline import competition begins to develop, but despite sustained development of hubs and trading, prices remain oil-indexed across Europe. There is some seasonality due to trading, minimising take-or-pay, and storage costs.

- Low (Abundant delinked). LNG demand from other countries is much lower, allowing LNG to flow into Europe. Russia fails to exercise control over Caspian and North African states, and so new pipelines bring competitive gas into Europe. Increasing technological developments and energy efficiency lead to gas demand at the lower end of forecasts for I&C and residential. New entrants access upstream LNG, and use LNG terminals to bring gas to market, increasing competitive pressures. With increased trading, and competition from LNG, North African and Caspian gas, Russia is forced to lower prices, leading to long-term competition and delinking by 2014. In all our scenarios the 'over capacity' situation in the next five to seven years results in a relatively limited use of storage and considerable exports though the interconnectors to the Continent.

Table 26 and Figure 37 below show Pöyry's gas price projections for France at a notional balancing point.

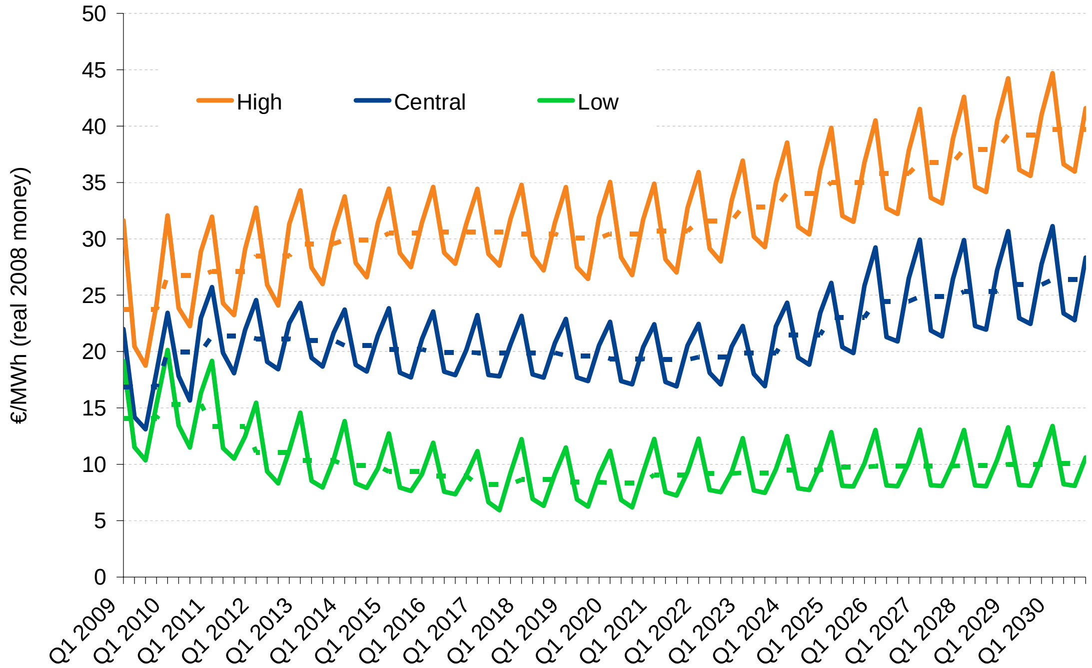
Table 26 – French gas prices at a notional balancing point
(€/MWh, real 2008 money)

€/MWh	High	Central	Low
2009	23.7	16.9	14.1
2010	26.7	20.0	15.3
2011	27.1	21.4	13.4
2012	28.5	21.1	11.1
2013	29.6	21.0	10.3
2014	29.9	20.5	9.9
2015	30.5	20.2	9.3
2016	30.6	19.9	8.9
2017	30.6	19.9	8.2
2018	30.4	19.9	8.6
2019	30.1	19.6	8.4
2020	30.4	19.4	8.4
2021	30.7	19.3	9.1
2022	31.6	19.5	9.2
2023	32.8	19.9	9.2
2024	34.0	21.5	9.5
2025	35.0	23.0	9.8
2026	35.8	24.5	9.8
2027	36.8	24.9	9.9
2028	37.9	25.3	9.9
2029	39.2	25.9	10.0
2030	39.7	26.4	10.1

The delivered prices, as compared to prices at the notional balancing point, are not used during the modelling of Pöyry electricity price projections (we model the exit charge as being a fixed cost to power stations and as such it is included in our capacity payment). We do however use the full delivered cost of gas when we project our CCGT new entrant costs.

For peaking gas, we assume a peaker would require gas on up to 80 days per annum and have based the cost of winter supply on the cost of a storage service. For France we base the cost on GdF's Lorraine storage (fixed at 77 days) and the cost is around €5/MWh. This would be a premium paid over and above the cost of summer gas to fill storage, and as such we have assumed a lower premium of €5/MWh over the cost of annual baseload gas.

Figure 37 – French seasonal gas price projections at a notional balancing point (€/MWh, real 2008 money)



4.6 EU ETS modelling

The European Union Emissions Trading Scheme (EU ETS) obliges generators to have sufficient carbon allowances to cover the carbon dioxide (CO_2) production. A full description of how this scheme is implemented in France appears in section 2.6.1.

Phase II of the European Union Emissions Trading Scheme (EU ETS) runs from 2008 to 2012 and sets a cap on the carbon emissions of large point source CO_2 emitters in the EU. These caps are applied at an installation level and are tradable between participants effectively creating a price for EU carbon emissions.

Fuel prices and new capacity build are fundamental drivers of the carbon price in EU ETS so it is necessary to take account of movements in these drivers between scenarios in order to develop internally consistent carbon and electricity price projections.

Movements in coal and gas prices will lead to changes in the relative cost of coal and gas fired generation and hence changes in the price of carbon needed to cause a switch from coal to gas fired generation (known as fuel switching abatement). More than anything else, movements in relative fuel prices drive these plant 'switching costs' and the cost of power sector carbon abatement – the more attractive is coal-fired generation compared to gas, the higher the carbon price.

We have used our carbon model to project reasonable CO_2 prices (up to 2020). In the Central and High scenario, the CO_2 price has been projected on the basis that the renewable target for Europe as a whole in 2020 is met, even though we don't assume this in our capacity assumptions for France. Figure 38 and Table 27 below present our projections of the EU ETS carbon price for our three scenarios. Over time we expect the full price of carbon to be passed through to the electricity price in all countries. We assume that 100% of the carbon price is already passed through into the French wholesale electricity price, which is consistent with existing evidence.

Despite increases in coal prices, relatively larger gas price increases in our High and Central Scenarios have led to a favourable outlook for coal fired generation and significantly higher abatement costs. Combined with an outlook that looks increasingly strict for Phase III of the EU ETS (2013–2020) we see a large increase in our High and Central scenario carbon prices in both the short and long term.

The Low scenario sees a large fall in gas prices over the medium term and a smaller relative fall in coal prices. The favourability of gas fired generation in this scenario leads to lower abatement costs and hence lower carbon prices falling down to €10/tonne by Phase III.

Figure 38 – Pöyry projections for the value of carbon (€/tCO_2, real 2008 money)

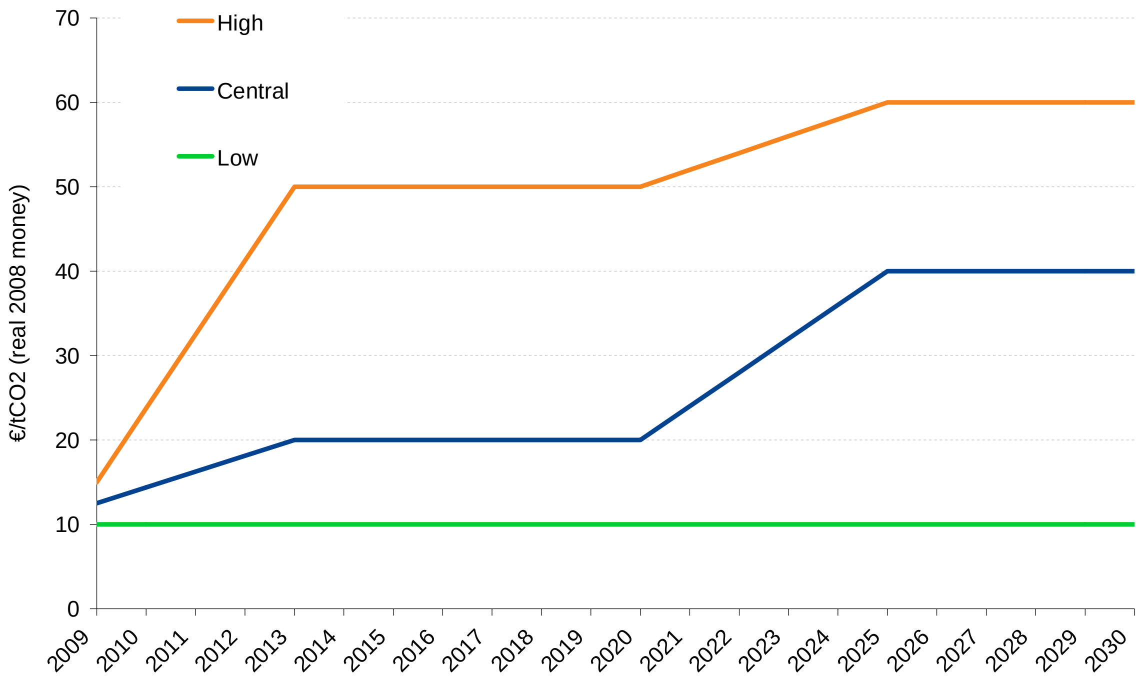


Table 27 – Pöyry projections for the value of carbon (€/tCO_2, real 2008 money)

€/tCO2	High	Central	Low
2009	15.0	12.5	10.0
2010	23.8	14.4	10.0
2011	32.5	16.3	10.0
2012	41.3	18.1	10.0
2013	50.0	20.0	10.0
2014	50.0	20.0	10.0
2015	50.0	20.0	10.0
2016	50.0	20.0	10.0
2017	50.0	20.0	10.0
2018	50.0	20.0	10.0
2019	50.0	20.0	10.0
2020	50.0	20.0	10.0
2021	52.0	24.0	10.0
2022	54.0	28.0	10.0
2023	56.0	32.0	10.0
2024	58.0	36.0	10.0
2025-2030	60.0	40.0	10.0

4.7 Electricity demand

Our demand projections include demand met by CHP and renewable plant. Where possible we present demand figures which have been 'weather corrected' using smoothed historical peaks[92]. For historical demand data we have also used data recorded by RTE[93]. These projections are based on a combination of the forecasts for total system demand in 'RTE 2008-2013 Bilan Prévisionnel – June 2007' the October 2008 update and the 'European Trends in Energy and Transport, Trends 2007–2030'.

For the very short term we have taken account of the impact of the global economic downturn on electricity demand. We assume that electricity demand will be affected in 2009 and 2010 hence the negative or low growth rates in these years. Starting in 2011 we project a recovery from the economic crisis which is translated into the growth rates over 2011 and 2012. From 2013 onwards projections returns to RTE forecasts based on 'RTE 2008-2013 Bilan Prévisionnel – June 2007' and accounting for the October 2008 update document.

In the longer term, we base our demand projections on the European Commission forecasts for electricity demand in France. In the EC report, the growth rate of French electricity demand over the period 2020–2030 is around 0.8% less than the growth rate in the period 2010–2020.

Table 28 presents our annual growth rate projections for electricity demand in France.

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92 The reason for this is to ensure that we are not projecting forward from a particularly low or high historical peak demand value.

93 All demand growth figures are weather and load management corrected.

Table 28 – Summary of growth rates used in projections of annual demand

	High	Central	Low	Basis for figures
2009	-1.4%	-3.2%	-5.4%	RTE, Pöyry
2010	0.1%	-0.9%	-2.2%	RTE, Pöyry
2011	2.9%	3.5%	3.8%	RTE, Pöyry
2012	2.1%	2.3%	2.2%	RTE, Pöyry
2013	1.4%	1.2%	0.7%	RTE
2014–2019	1.2%	1.0%	0.5%	RTE
2020	Linear interpolation between 2019 and 2021			
2021–2030	0.4%	0.2%	-0.3%	EU Trends

Source: RTE, EC and Pöyry Energy Consulting

A similar methodology has been applied to derive our peak demand projections to 2030.

We use the maximum peak demand to determine a level of capacity that would be required in France to ensure that this demand, plus an adequate reserve margin, is met.

RTE scenarios contain figures for total, average peak and extreme peak system demand. The average peak growth rate shown in Table 29 is the RTE's prediction of the growth rate in a 'normal' year which we apply to a smoothed historical function to obtain an average annual growth rate. The extreme growth rate refers to the Peak in a 1/10 winter and according to the RTE it is a probable representation of necessary system margin. We have used the 'normal' growth rate in our modelling of French peak demand.

Our normalised projections for total system and peak demand to 2030 are provided in Table 29 and illustrated in Figure 39[94].

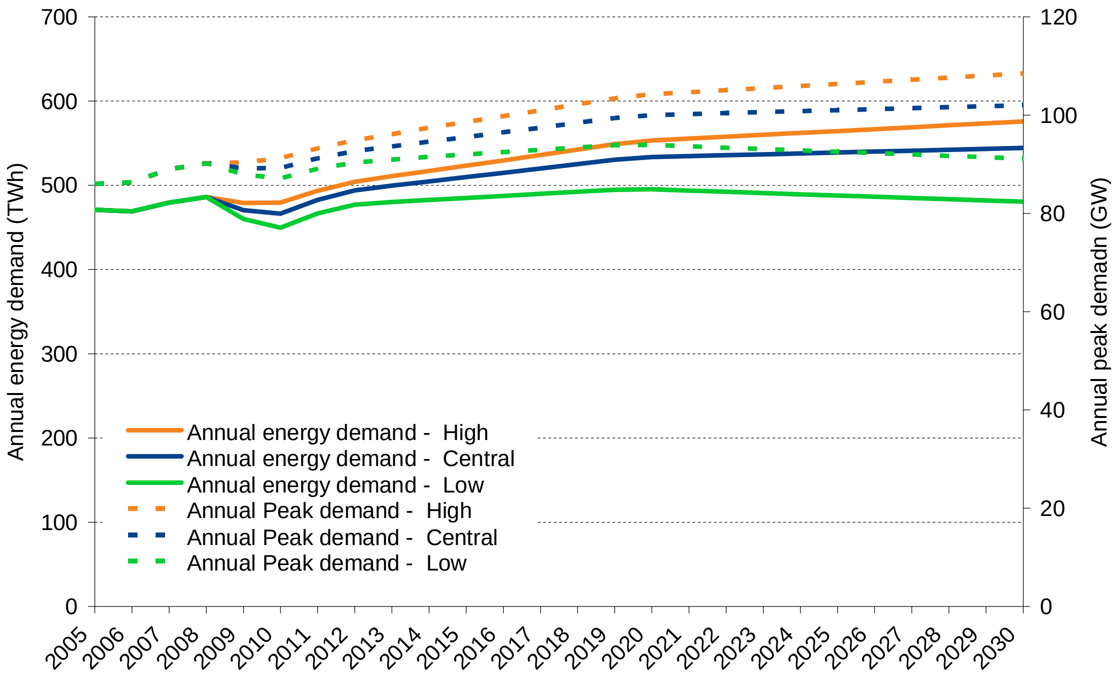
94 Weather corrected annual energy values are available from the RTE website. The maximum demands have been adjusted by 1300MW per 1 degree deviation in temperature from 'normal', and then smoothed to remove any year-on-year spikes.

Table 29 – French total system demand (TWh) **and maximum peak demand** (MW)

	Volume demand (TWh)			Peak demand (MW)		
	Low	Central	High	Low	Central	High
2007	479.4	479.4	479.4	89,000	89,000	89,000
2008	486.1	486.1	486.1	90,185	90,185	90,185
2009	460.1	470.5	479.1	87,950	89,184	90,361
2010	449.7	466.4	479.6	87,137	89,233	91,239
2011	466.7	482.7	493.5	89,065	91,193	93,193
2012	477.0	493.9	504.1	90,344	92,665	94,827
2013	480.1	499.7	510.9	90,940	93,620	96,120
2014	482.6	504.7	517.1	91,540	94,585	97,432
2015	485.0	509.7	523.3	91,997	95,531	98,601
2016	487.4	514.8	529.6	92,457	96,487	99,784
2017	489.8	520.0	535.9	92,920	97,451	100,982
2018	492.3	525.2	542.3	93,384	98,426	102,193
2019	494.7	530.4	548.9	93,851	99,410	103,420
2020	495.2	533.6	553.2	93,945	100,007	104,247
2021	493.7	534.7	555.5	93,663	100,207	104,664
2022	492.3	535.7	557.7	93,382	100,407	105,083
2023	490.8	536.8	559.9	93,102	100,608	105,503
2024	489.3	537.9	562.2	92,823	100,809	105,925
2025	487.8	539.0	564.4	92,544	101,011	106,349
2026	486.4	540.0	566.7	92,267	101,213	106,774
2027	484.9	541.1	568.9	91,990	101,415	107,201
2028	483.5	542.2	571.2	91,714	101,618	107,630
2029	482.0	543.3	573.5	91,439	101,821	108,061
2030	480.6	544.4	575.8	91,164	102,025	108,493

Source: RTE, EC and Pöyry Energy Consulting.

Figure 39 – Historic and projected system demand in France, including demand met from CHP and renewable plant



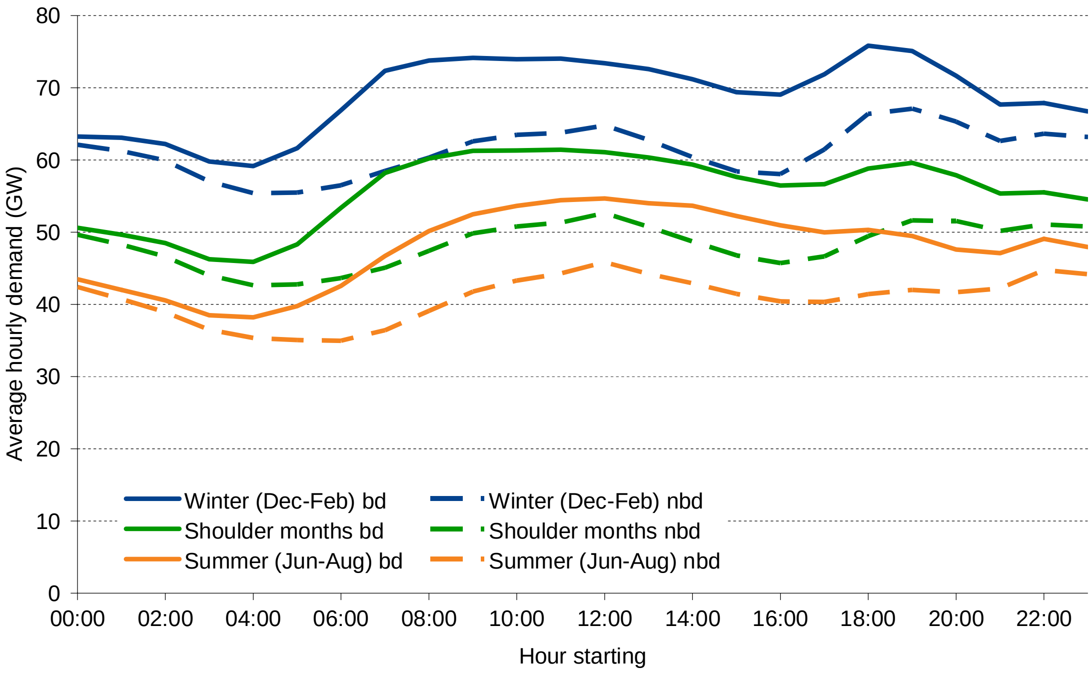
Source: RTE, EC and Pöyry analysis

In our European generation model, *EureECa*, we model 24 sample days – a business day and non-business day for each month. We do not explicitly model the peak day as it is unlikely that the peak days in the different countries will occur simultaneously[95]. New capacity requirements and additions, however, are based on expected peak day maximum demand in each individual country.

The sample day demand profiles are hourly demand values calculated as the average from the years 2005 to 2008, as reported by RTE. Figure 40 shows the shape of the business day (BD) and non-business day (NBD) profiles used for the different seasons.

95 Note, however, that we do ensure that there is sufficient capacity on the French system to meet demand, with a suitable reserve margin, on the maximum peak day.

Figure 40 – Demand profile within-day (GW)



Source: RTE, UCTE and Pöyry analysis

4.8 Generation capacity construction and retirement

The status of current plants and future projects, and decommissioning dates, have been taken from a number of sources including Platts PowerVision, company websites as well as Pöyry-based assumptions.

Retirement dates are based on an operating duration of around 40 years for coal power plants and 30 years for CCGTs. As for the nuclear pressurised water reactors, the assumed lifetime is 50 years.

The European Commission Combustion Plants Directive (LCPD) sets limits on the emissions of sulphur dioxide, oxides of nitrogen and particulates from the combustion of coal, oil and natural gas. It is the key driver behind the phasing out of older thermal power plants until 2015. However, generators such as EDF and E.ON France have chosen to upgrade many thermal power plants in order to maintain them in service beyond 2015. Table 30 provides a list of the plants that will not be operating past 2015.

Table 30 – Assumed closure dates for a number of French coal-fired and oil-fired plants

Plant name	Type	Capacity (MW)	Last year of operation
Aramon	Coal	700	2015
Bouchain	Coal	250	2015
Emile Huchet	Coal	345 + 125	2015
Hornaing	Coal	253	2015
La Maxe	Coal	250	2015
Le Havre	Coal	250	2015
Lucy	Coal	270	2015
Provence	Coal	268	2015
Vitry sur Seine	Coal	2 x 250	2015
Blenod	Fuel oil	3 x 250	2015
Cordemais	Fuel oil	2 x 685	2015

Source: Platts and Pöyry Energy Consulting

The plants under construction listed below in Table 31 have been included in our modelling with their respective expected starting date. It is assumed that these plants will have efficiencies consistent with similar types of plants.

We assume that generic new CCGTs, OCGTs and coal-fired plants come on-line when needed, such as there is adequate supply at all times. We only explicitly include the power plants that are currently under construction in the model, and base our generic new entry assumptions on existing projects, market analysis and RTE's forecasts.

Table 31 – Proposed new plants in France

Status	Company	Type	Location	Capacity (MW)	Online in
Under constr.	Poweo	CCGT	Pont sur Sambre	400	2009
Under constr.	GDF Suez	CCGT	Fos sur Mer	480	2009
Under constr.	GDF Suez	CCGT	Fos sur Mer	425	2010
Under constr.	GDF Suez	CCGT	Montoir de Bretagne	435	2010
Under constr.	E.ON France	CCGT	Saint Avold	425	2010
Under constr.	EDF	CCGT	Montereau	360	2010
Under constr.	EDF	CCGT	Blenod	440	2011
Under constr.	EDF	CCGT	Martigues	930	2012
Under constr.	Atel	CCGT	Bayet	420	2011
Under constr.	EDF	Nuclear	Flamanville	1600	2012
Approved	E.ON France	CCGT	Hornaing	430	2010
Approved	E.ON France	CCGT	Lucy	420	2010
Approved	E.ON France	CCGT	Lacq	860	2010
Approved	Poweo	CCGT	Toul	400	2011
Approved	Direct Energie	CCGT	Verberie	892	2012
Proposed	Direct Energie	CCGT	Sarreguemines	800	Late 2012
Proposed	EDF	CCGT	Martigues	930	2010
Proposed	Atel	CCGT	Bayet	400	2011
Proposed	Poweo	CCGT	Beaucaire	800	2013
Proposed	Poweo	CCGT	Blaringhem	800	2012
Proposed	Poweo	CCGT	Le Havre	600	On hold
Proposed	GDF Suez	Gas Turbine	St Brieuc	200	2010
Proposed	E.ON France	Coal	Le Havre	700	2012
Proposed	EDF	Nuclear	Penly	1600	2017

Source: Platts, press articles

4.8.1 *Projected Renewables Construction*

For the purpose of projecting the contribution of renewables in France, we have used the following methodology:

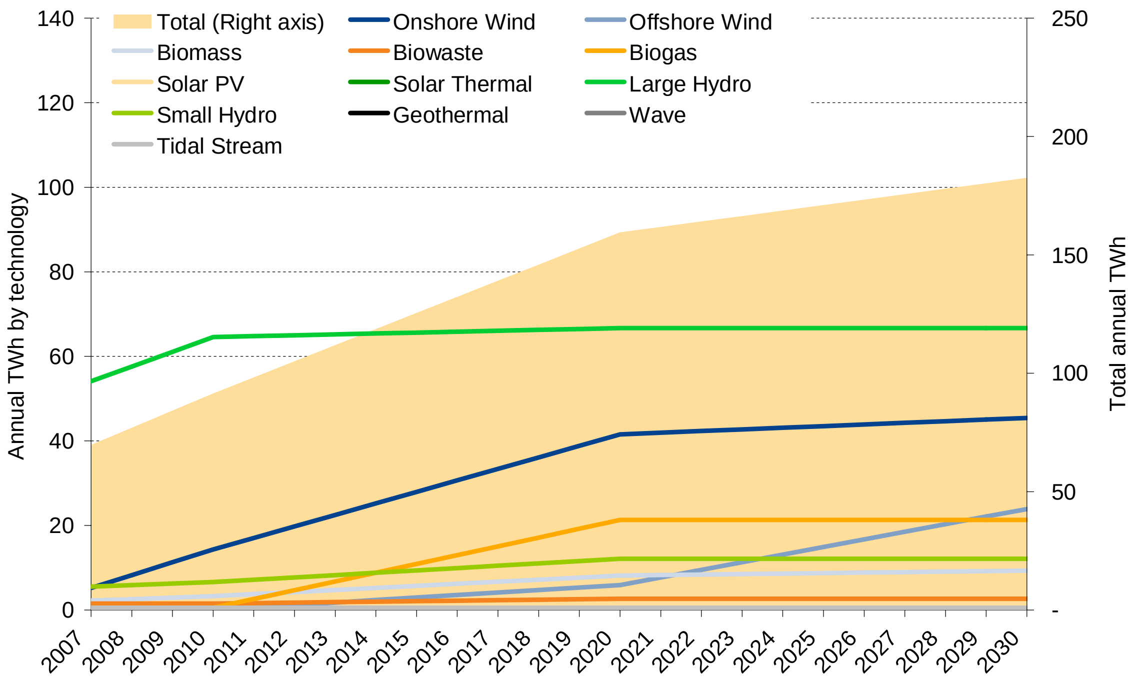
- In the short term (2008–2015), our projection of renewables development is based on RTE's expectations as stated in their generation adequacy report[96]. These are not assuming compliance with the French renewables targets, as stated in section 3.1.2, but rather a probable deployment.
- Our long term projection (2015–2030) is based on the expectation of the European Commission as forecast by their model PRIMES and detailed in their report 'European Energy and Transport – Trends to 2030'[97]. This EU-wide model simulates current trends and policies as implemented in the Member States by the end of 2006, and therefore does not take into account the implications of the proposed EU 2020 renewables targets.

96 'Bilan Prévisionnel de l'équilibre offre-demande d'électricité en France'. RTE, June 2007.

97 'European Energy and Transport: Trends to 2030 – Update 2007'. European Commission, Directorate-General for Energy and Transport.

Figure 41 shows our projections for new renewable generation capacity up to 2030. We have assumed the same level of deployment for all three scenarios.

Figure 41 – Renewable capacity projections (in TWh)



4.8.2 *Interconnectors*

France has existing interconnectors with the UK, Spain, Germany, Belgium, Italy and Switzerland. Using information from RTE, we have modelled these interconnectors as shown in Table 30. In all scenarios, we have modelled increases in interconnection capacity with Spain (in 2010 and 2013), Belgium (2010 and 2013) and Italy (2013 and 2018).

Table 32 – Seasonal interconnection capacity (GW)

Exports	UK	Spain	Belgium	Germany	Switzerland	Italy
2008	2.0	1.4	3.5	2.9	3.2	2.7
2009	2.0	1.4	3.5	2.9	3.2	2.7
2010	2.0	1.4	3.5	2.9	3.2	2.7
2011	2.0	2.6	3.5	2.9	3.2	2.7
2012 onward	2.0	2.6	3.8	2.9	3.2	2.7

Imports	UK	Spain	Belgium	Germany	Switzerland	Italy
2008	2.0	0.5	2.5	3.3	2.3	2.7
2009	2.0	0.5	2.5	3.3	2.3	2.7
2010	2.0	0.5	2.5	3.3	2.3	2.7
2011	2.0	1.0	2.5	3.3	2.3	2.7
2012 onward	2.0	1.0	2.8	3.3	2.3	2.7

Source: Pöyry Energy Consulting analysis, ETSO

4.8.3 Hydro

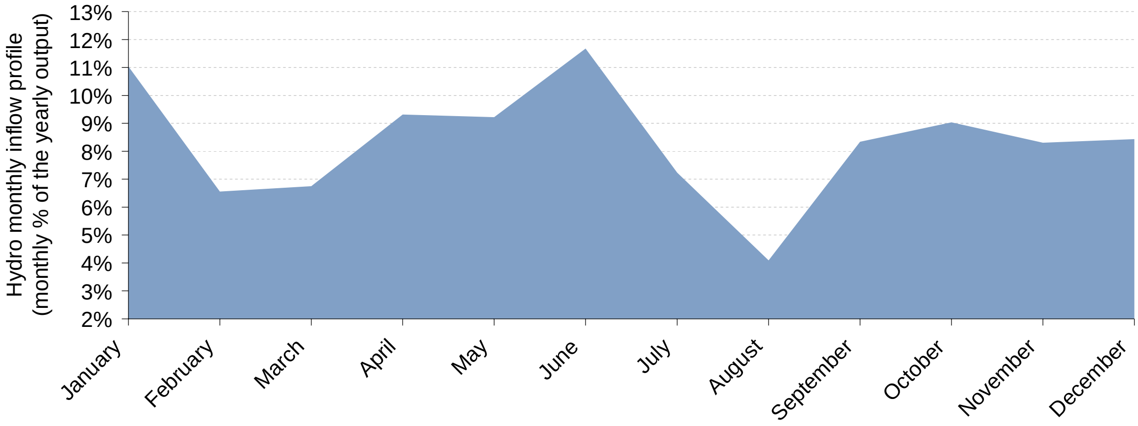
We model non-pumped storage hydro generation in EurECa by optimising its use subject to a number of parameters:

- total hydroelectric capacity and generation are assumed to stay flat at 17.2GW for 66TWh annually;
- the minimum output in any one hour period in each year is 3GW, which is approximately the uncontrollable capacity run-of-river; and
- we assume an inflow profile, which determines the proportion of annual inflow energy into the country's reservoirs each month (see Figure 42).

We have assumed an inflow profile equal to the average historical hydro production in France over the last fifteen years and we allow the model for a limited amount of within-year flexibility. There is a full flexibility of hydro use within-month and within-day, subject to the conditions above.

For modelling of pumped storage, we assume a total of 2.2GW is connected to the French grid.

Figure 42 – Hydro inflow profile (TWh/month)



4.8.4 Evolution of generation capacity between 2007 and 2030: summary

Based on our assumptions regarding total conventional generation, renewable plant, CHP capacity and imports versus our demand projections, we have derived three different capacity scenarios, High, Central and Low.

In the long-term we assume that new capacity will enter the French market to meet the increase in demand. We have assumed a level of generic OCGT and CCGT new entry to ensure that the capacity margin remains adequate at times of maximum summer demand – this is the critical period for the French system due to the large volume of CHP plant that does not run at that time. In addition to the EPR in Flamanville, we see new nuclear plants being built after 2021 in all three scenarios, to a different extent depending on electricity demand growth. We have also included imports (increasing or decreasing) from neighbouring countries over time.

Figure 43 to Figure 45 illustrate how the above assumptions translate into firm capacity[98] at maximum peak by plant type for the High, Central and Low scenarios respectively. Note that imports are not shown in the figures.

[98] The measure of capacity is 'firm capacity at time of a peak demand', calculated assuming plant availabilities in winter or summer accordingly and a realistic hydro availability. It should be noted that at times of peak demand; a much higher hydro capacity would be available to call upon.

Figure 43 – Firm capacity at maximum peak in the High scenario by plant type

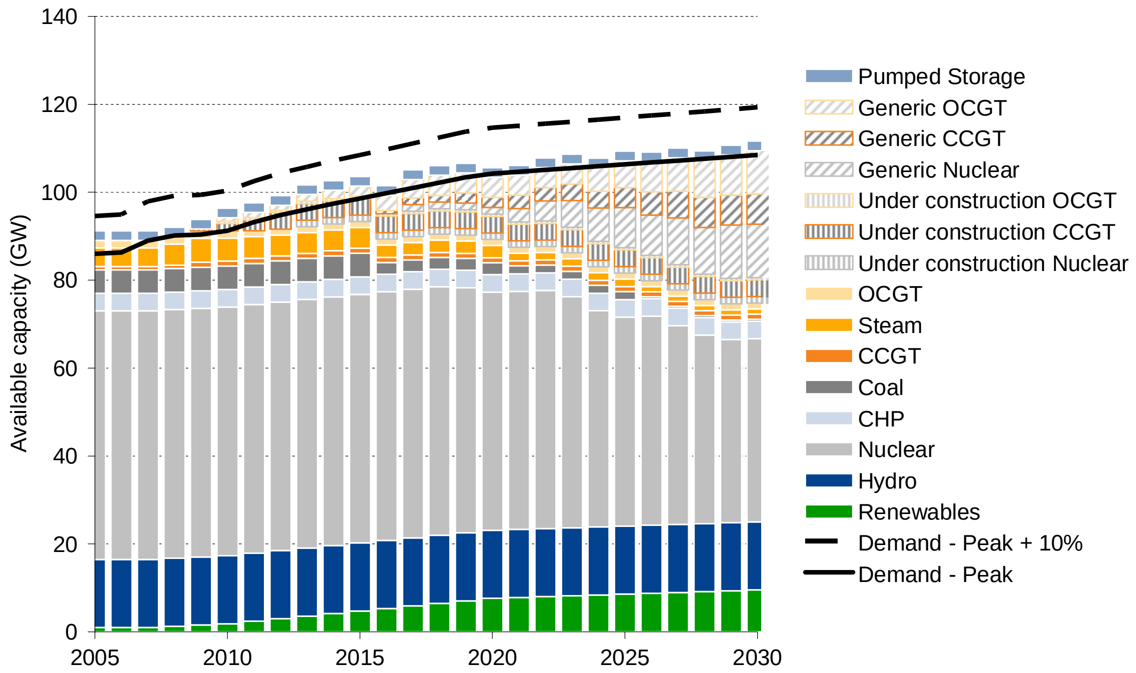


Figure 44 – Firm capacity at maximum peak in the Central scenario by plant type

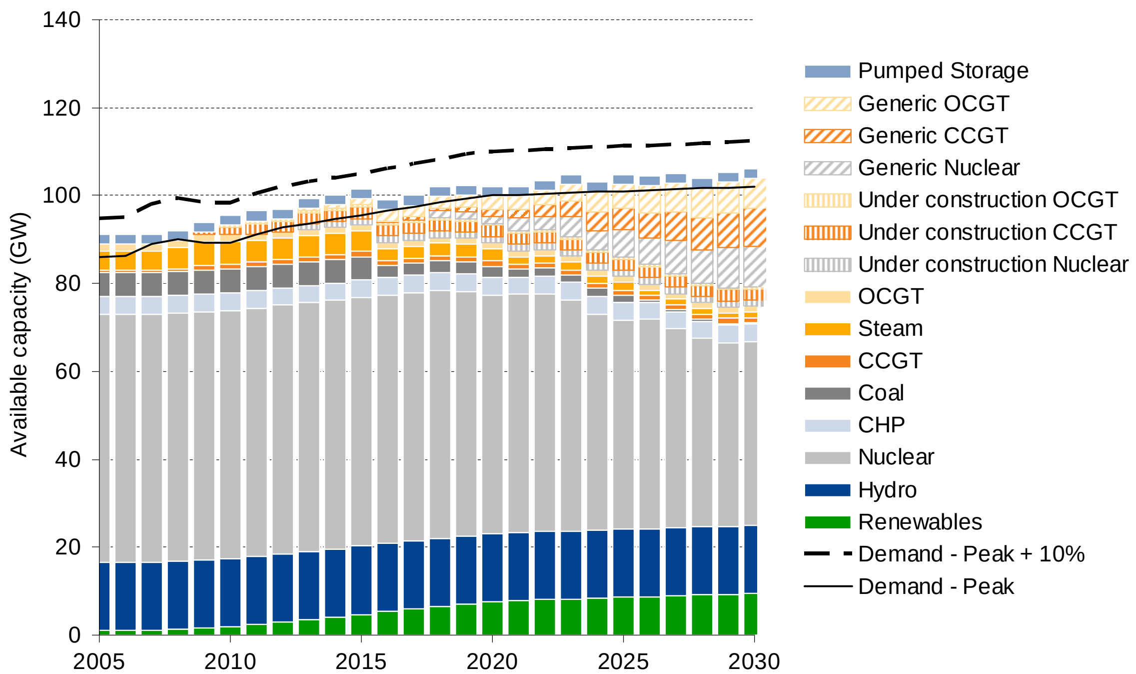
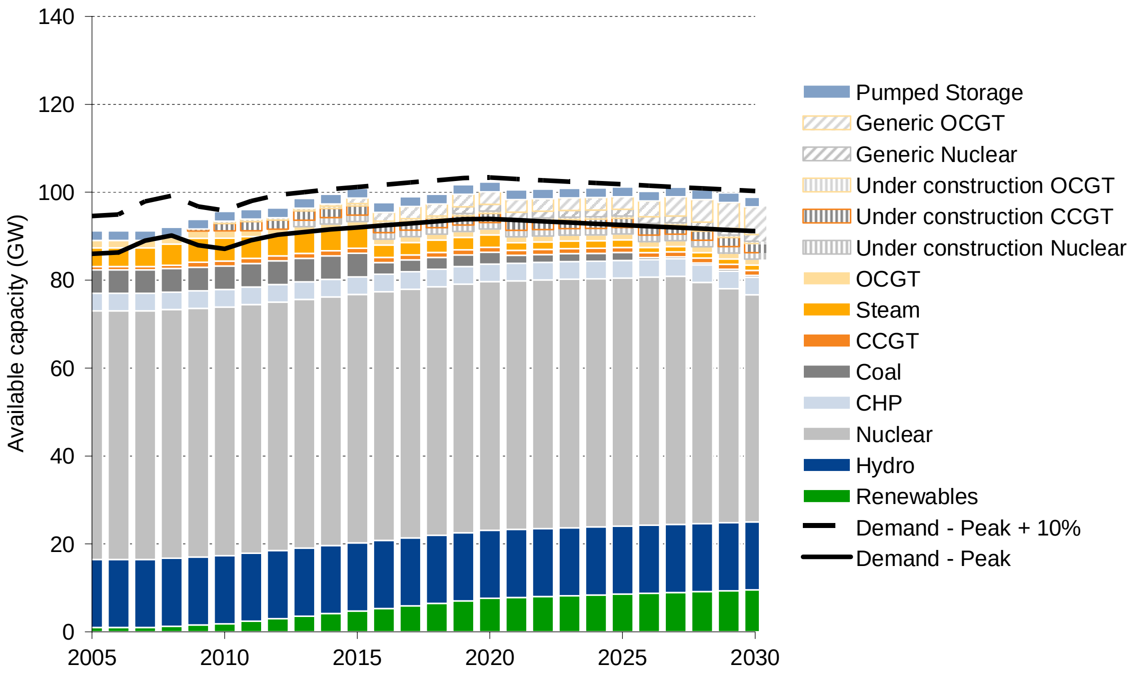


Figure 45 – Firm capacity at maximum peak in the Low scenario by plant type



4.9 Thermal power station characteristics

4.9.1 Plant efficiency

The plant efficiencies for existing plants have been estimated by comparing the age of the genset with a similar age and type of genset for which we know the efficiency. Some interpolation has been used for those years in which we have no plant of the same age. As a result, the efficiencies vary by genset age and type of plant.

We assume average annual efficiencies for electricity sent-out, net of internal power station consumption, compared with the gross (or higher) calorific value of the fuel to the station. These are known as higher heating value (HHV) efficiencies.

For power stations burning fossil fuel, Pöyry uses an individual efficiency for each and every genset. Those for oil-fired and conventional gas-fired plants are in the approximate range of 30% to 36%. Coal-fired plants (with FGD) have efficiencies of about 33–37%.

Existing gas turbine ‘peakers’ have efficiencies of around 30%. For new gas-fired OCGTs we assume an efficiency of 37.5% based on a number of quoted efficiencies for new plant.

For new build CCGTs the figure is linked to the date of plant commissioning – as follows:

- commissioned between 2009 and 2015 inclusive: 51% rising to 53%;
- commissioned between 2015 and 2020 inclusive: 53 rising to 54% and
- commissioned after 2020: 54%.

For new gas-fired OCGTs we assume an efficiency of 37.5% based on a number of quoted efficiencies for new plant.

4.9.2 Variable other work costs

Variable other works costs (VOWC) cover the non-fuel variable costs that a power station incurs in operation. We have assumed VOWC costs for different plant types as shown in Table 33.

Table 33 – VOWC (2008 €/MWh)

€/MWh	VOWC
Gas turbine	0.82
CCGT	0.82
IGCC	0.83
Gas-fired steam cycle	1.15
Oil-fired steam cycle	1.31
Coal-fired steam cycle	1.50
Nuclear	14.00

With regards to CCGTs we only treat strictly marginal costs as being in VOWC, and capture maintenance costs in station 'fixed costs'.

4.9.3 No-load and start-up costs

Information on no-load and start-up costs for existing plant is not readily available. We have used values based on our experience. The level of cost will depend on the actual operation of a particular genset, such as how long it operates for, and to what extent it is part-loaded. Details of these figures are shown in Table 34.

Table 34 – Start-up and No-load energy

	Start up energy (Gross GJ/GWh)	No load energy (Gross GJ/GWh)	Start-up maintenance cost (€/GW)
Gas turbine	1,208	1,588	14,400
CCGT	3,463	1,200	14,400
IGCC	3,463	857	14,400
Gas-fired steam cycle	4,680	846	16,000
Oil-fired steam cycle	4,680	846	16,000
Coal-fired steam cycle	1,360	857	16,000
Nuclear	0	0	16,000

4.9.4 *Plant availability*

The assumptions on availability are shown in Table 35. The availability types indicate which availability pattern each of the plant will follow. The availabilities are calculated for each month, based on a seasonal availability profile where maintenance is concentrated in summer.

These availabilities also take account of temperature effects where these reduce the plants' effective capacity (such as for CCGTs and OCGTs).

Table 35 – Net guaranteed capacity and availability patterns

Plant Type	Winter	Spring/Autumn	Summer	Annual
Combined Cycle	94%	88%	85%	88%
Gas Turbine	95%	95%	90%	94%
Steam cycle (coal-fired)[99]	76%	69%	67%	70%
Steam cycle (gas-fired)	94%	88%	80%	88%
Steam cycle (oil-fired)	88%	82%	80%	83%
Nuclear (PWR)	87%	74%	67%	75%
Nuclear (EPR)	93%	82%	76%	84%
Wind	32%	23%	17%	24%
Biomass	66%	66%	66%	66%
Other renewables	52%	52%	52%	52%

99 We have modelled some coal plants with a lower availability because they are contracted with EDF to provide support services and therefore won't run at their full technical availability.

4.9.5 CHP

For CHP capacity figures, our analysis draws heavily on data presented in the CEREN report ‘CHP Statistics and Impacts of the Gas Directive on the Future Development in Europe’ dated 21 October 2002. Specifically, much use is made of data in Tables A and B1 of Section 3.12 on France. There has been no significant evolution of capacity in France over the last five years.

The data on efficiencies and fuel consumption in the above report are with respect to ncv – the net, or lower, calorific value of the fuel. Pöyry conventionally uses gcv – the gross, or higher, calorific value. We have therefore converted from NCV to GCV throughout, using conventional factors of 0.903 for gas and 0.95 for coal and oil.

4.10 The cost of new entry

In developing our projections of generic new entry we need to ensure that if we assume new entry is required then the wholesale electricity prices need to be consistent with the long-run marginal cost (LRMC) of new entry. We consider two cases for the ‘new entrant’ power station:

- the new entrant is an advanced CCGT, operating at baseload (that is, up to its technical availability; and
- the new entrant is an OCGT plant operating as a mid-merit or peaking plant, and in the limit operating only at times of very high demand.

Data for each of these three new ‘new entrant’ cases are presented in Table 36 and draw upon:

- a wide range of published sources;
- Pöyry’s knowledge of actual projects (particularly of CCGTs developed in the UK and elsewhere in Europe); and
- the expertise and experience of engineers within the wider Pöyry Plc.

Table 36 – Pöyry new entry assumptions for France (real 2008 money)

	Advanced CCGT	Supercritical Coal	Current OCGT
Capital cost (€/kW) [100]	650 – 900[101]	1300 – 1700[102]	431
Fixed Other-Works Costs (FOWC) (€/kW) p.a.)	32[103]	36[103]	34[103]
Variable Other-Works Costs (VOWC) (€/MWh)	0.82	1.5	0.82
Efficiency (HHV[104])	54[105]%	42%	37.5%
Rate of return	8%–12%[106]	8%–11%[107]	11%
Economic lifetime (years)	20	20	15

Our experience of the project finance of independent power projects (IPPs) across Europe shows that their projected cash flows for a CCGT under a central view of the future, taken at the time, can be broadly characterised as meeting a 10% rate-of-return (pre-tax, real) over an accounting period of 20 years from commissioning.

Applying these financial criteria to the above data for an advanced CCGT technology[108] gives the following new entrant formula for the Central scenario:

Advanced CCGT: ***17.54 + 6.67*g (2008 €/MWh)***

where g is the price of gas, input in €/GJ.

For a supercritical coal plant, our experience suggests that projected cash flows under a central view of the future can be broadly characterised as meeting 9% rate-of-return (pre-tax, real) over an accounting period of 20 years from commissioning. The lower rate of return is due to the fact, that coal plants are more likely to be developed by large utilities

100 This comprises all capital costs to be covered by the financing of the plant except for interest-during construction and debt service reserve.

101 Capital costs for CCGTs range from €650/kW in the Low case to €750/kW in the Central case and €900/kW in the High case. Scenarios refer to the top and bottom of the new entry band, as presented in Figure 48. The Central view of Capex is used in all scenarios to compare LRMC and wholesale prices.

102 Capital costs for supercritical coal plant range from €1300/kW in the Low case to €1500/kW in the Central case and €1700/kW in the High case.

103 Assuming for baseload and peaking plant that these costs of scheduled plant overhauls are fixed.

104 Higher Heating Value. These are average lifetime efficiencies.

105 This value is only achieved post 2020, with slightly lower efficiencies for plant built before.

106 Values range from 8% in the Low scenario, 10% in the Central and 12% in the High.

107 Values range from 8% in the Low scenario, 9% in the Central and 11% in the High.

108 Assuming a load factor of 85%, a construction period of 2 years and an operating period of 30 years for the CCGT.

that generally require lower rate-of-returns than IPPs. Applying these financial criteria to the above data for a supercritical coal plant[109] gives the following new entrant formula:

Supercritical coal plant: ***29.88 + 8.57c (2008 €/MWh)***

where c is the price of coal, inclusive of carbon costs, in €/GJ.

We use these formulae to derive our medium-term and long-term new entrant projections. It should be noted that these projections are intended as a guide; for new entry to be economically justifiable we might expect prices to be above these guidelines initially, falling below them by the end of the project lifetime.

The upper bound to the value of capacity is calculated as the new entry cost of an OCGT. Open-cycle gas turbines (OCGTs) are less efficient, but cheaper than CCGTs. As such they can be the most economic option for peaking or mid-merit plants (subject to being able to access sufficiently flexible gas purchase contracts). We assume such a plant has 98% availability, but only operates during periods of extremely high demand. Such a plant would effectively have no variable fuel or carbon costs. This upper bound to the value of capacity is calculated to be €13.8/MWh using the values for the OCGT given in Table 36, assuming a construction period of two years and a 15 year economic life time. Our projections of the value of capacity are discussed in more detail in section 5.1.2

109 Assuming a load factor of 85%, a construction period of 4 years.

5. WHOLESALE ELECTRICITY PRICE PROJECTIONS

This chapter details Pöyry projections for wholesale electricity prices in France for 2009 to 2030. These projections represent the wholesale price at the station gate in France, which is on the grid side of the station transformer, before transmission losses are taken into account.

5.1 Developing our price projections

We construct our price projections for each scenario by combining the following components:

- the projected system marginal price; and
- the projected value of capacity.

While there is only a single price per hour in the day-ahead market, i.e. no explicit capacity payment, we model each component separately and combine them together to give the day-ahead wholesale price.

5.1.1 System marginal price

The system marginal price (SMP) is calculated as the variable operating cost (comprising fuel, carbon, variable, start-up and no-load cost components) of the most expensive plant required to run during each half-hour. The SMP is calculated using Pöyry's *EurECa* model, which projects electricity prices, output and cross-border flows for twenty-five European countries, taking account of flows from a further six neighbouring countries.

5.1.2 Value of capacity

The value of capacity is calculated to ensure that the total revenue a generator would receive from the market is such that the generating plant receives enough revenue to cover its fixed costs and will thus be available when required. We have analysed two possible levels of capacity value, based on the underlying value of generation capacity. These are summarised in Figure 46 and discussed below.

In a medium to long-term equilibrium, the price earned by generators should reflect the cost of efficient new entry, whether or not capacity is priced explicitly (if this were not the case, prices would rise or fall until an equilibrium situation were reached). The value of capacity is likely to be broadly in line with the annual capital and fixed costs (Net Effective Costs, or NEC) of a peaking plant (such as an open-cycle gas turbine). In instances where this capacity value is not sufficient for new entry plant[110] to be brought online when required, we raise or lower the value of capacity so that total revenue is sufficient to bring new capacity into the market, and of the broad type (baseload, mid-merit, peaking) that is required.

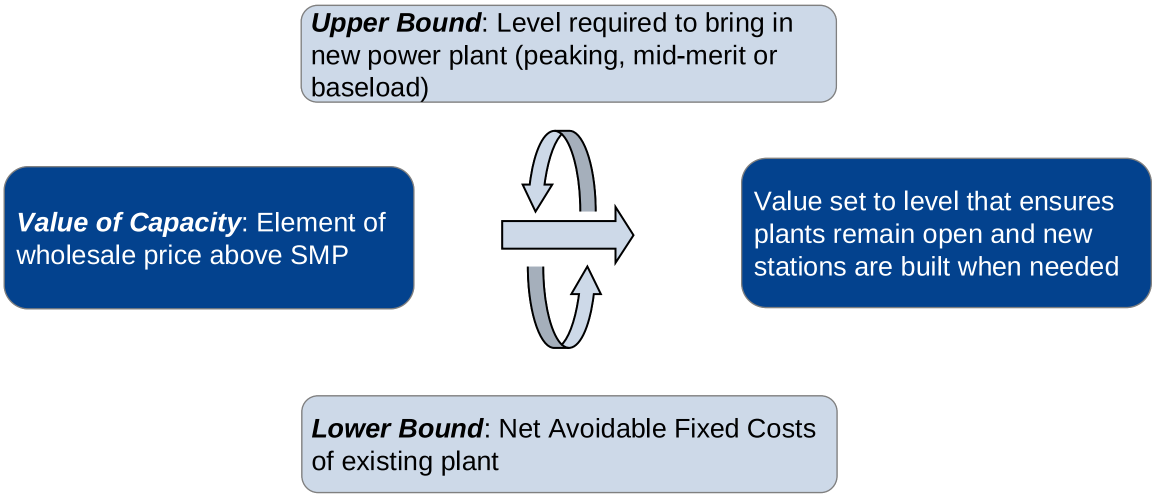
In the short to medium term, the value of capacity could fall to a level just sufficient to retain existing plant on the system (i.e. to cover the fixed costs of keeping the plant open

110 Depending on the wholesale electricity price scenario being considered at the time. Most new entry will be in the form of CCGT or coal, because of the lack of a capacity payment mechanism to incentivise peaking plant.

and available to operate, if needed)[111]. We refer to this as the 'net avoidable fixed cost' (or NAFC) of retaining plant on the system. We use a value equivalent to around €4.35/MWh (averaged across the year)[112]; we understand that this broad level is reasonable to use in the European context.

The annual value of capacity is then initially set to NAFC or NEC on the basis of whether or not new entry is required. The value of capacity is adjusted following a comparison between the wholesale price and the new entry costs of expected new entrants, to ensure those new entrants will recover their costs.

Figure 46 – Formation of the value of capacity



The principle of Value of Capacity is based on the assumption that the market will remunerate new capacity at a reasonable level. We acknowledge that on any given year the Value of Capacity may be quite different from what we project (higher or lower), although we do not see such a situation as being sustainable.

We have found evidence of the requirement for a minimum level of Value of Capacity in wholesale electricity prices in order to maintain existing plants on the system, in Great Britain and continental Europe. This has been particularly explicit in Great Britain in 2001 and 2002, when the wholesale price was very close to the System Marginal Price (Value of Capacity of nearly zero) which resulted in numerous small power producers going bankrupt and consequently to a high level of M&A activity. Similarly, we believe that historical spark spreads in North West Europe are higher than what would be achieved in a market purely based on System Marginal Price.

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111 Such a situation could arise where new investment is occurring ahead of need. For example, in the England and Wales Pool, new investment in baseload CCGTs was beyond the level necessitated by demand growth and plant retirements, and capacity payments to incentivise enough plant to remain on the system were sufficient to match supply with demand.

112 This calculation is based on a fixed cost of around €38/kW p.a which is roughly equivalent to the annual fixed costs of an existing coal plant.

The pattern of fixed cost recovery is quite difficult to predict, given that the Value of Capacity is implicit in most markets. However, we observe that this element is concentrated on a relatively small number of periods, which we assume correspond to hours of tight capacity margin.

5.2 Developing our scenarios

We have used our modelling expertise to create three scenarios that we feel cover a reasonable and internally consistent set of outcomes for wholesale prices within France, with the aim of examining the effect on prices of a number of key drivers:

- fuel prices (coal, oil and gas);
- gas market liberalisation;
- CO_2 prices;
- electricity demand;
- new power station construction and plant retirements; and
- costs and performance of new entrants.

These three scenarios can be summarised as follows, and as in Table 37 below:

- High: The High scenario examines the effect of high fuel prices driven primarily by crude oil prices returning to over $100/bbl in 2011 and remaining above this level, reaching $123/barrel in real terms in 2030. The high oil prices in turn drive up gas prices through indexation. Coal prices are at $100/tonne for most of the modelled timeframe. This scenario is also characterised by high carbon prices which rise upwards from €20/tCO_2 in 2009 to €60/tCO_2 by 2020 reflecting high abatement costs in a high gas price and high electricity demand scenario. Significant build of thermal plant, including CCS coal in some countries, occurs in this scenario.
- Central: In the Central scenario, our Central oil price projection rises to $75/bbl by 2011 and remains in the $60-80/barrel level through to 2030. It is assumed that gas liberalisation throughout Europe either does not occur, or does not break the contractual linkages between oil and gas. Carbon prices slowly rise upwards until they reach a long-term (Phase III) price of €25/tCO_2 in 2013. In Phase IV they rise further, driven by the economics of CCS coal, and reach €40/tCO_2 by 2030.
- Low: In the Low scenario, low demand for electricity is combined with a relatively high system margin and low fuel prices. We assume that gas prices break the link with oil, causing them to fall to the long-run marginal cost of gas supply. For all the modelled period the carbon price remains at a floor price (€10/tCO_2) that reflects our view of international carbon credit opportunity costs. Below this price, our modelled supply and utilisation of carbon credits from Joint Implementation and Clean Development Mechanism projects is severely restricted, as they are assumed to flow to other parts of the world (e.g. Canada and Japan) than Europe. Low demand growth means that the quantity of thermal plant built under this scenario is low.

There is no particular reason why, for example, oil prices should be high at the same time as gas prices, once the gas market is liberalised. However, our approach ensures that we capture the full range of plausible price futures; for example, electricity prices would be higher with high gas and high coal prices, as we have in our High scenario, than with high gas and low coal prices.

Evaluation of all possible combinations of input assumptions would result in a very large number of scenarios. Some of these would be internally inconsistent. A more practical approach is to select a much smaller number of scenarios, combining internally-consistent combinations of input assumptions, for detailed evaluation.

In examining the economics of specific generation projects, there would be merit in considering a wider range of fuel price combinations. It would also be important to consider an individual plant's position in the merit-order to determine its operating profile and therefore revenues, rather than just assuming the plant will price-take and operate at base-load. For details of our assumptions regarding new entry, refer to section 4.8.

One of the core uncertainties in the future is the effect of the EU ETS (EU Emissions Trading Scheme) and a subsequent value of carbon. However, given plans for full auctioning from 2013, full pass-through is likely to occur which helps to reduce these uncertainties. Our three scenarios examine the impact that different carbon prices may have on the final wholesale electricity price, with pass-through gradually increasing during Phase II.

Table 37 – Summary of scenarios

	Fuel and carbon prices	Demand	New thermal build	Value of capacity
High	High	High	High	Increasing to high from 2015 and for the rest of modelled period.
Central	Central with oil-indexed gas prices	Central	Central	Slightly increasing to from until 2014 and for the rest of modelled period.
Low	Low	Low	Low	Slightly increasing to from until 2015 and for the rest of modelled period.

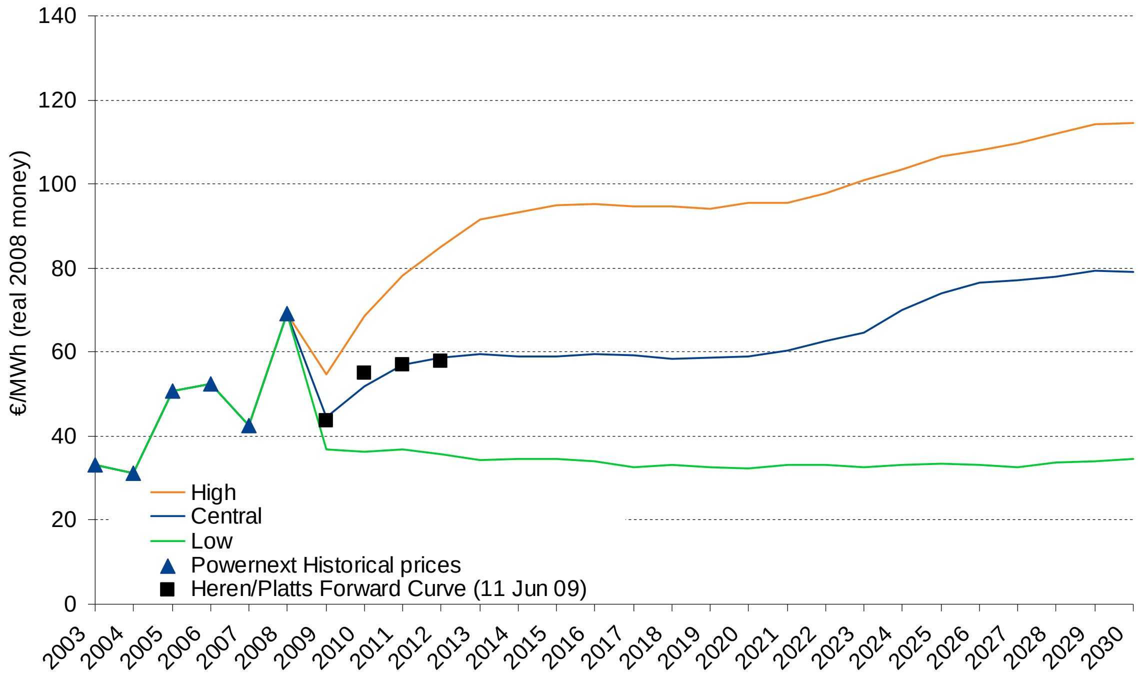
The EU ETS and its impact on the French electricity market are considered in more depth in sections 2.6.1 and 4.6. For the purposes of our modelling of prices with a value of carbon, we assume that the full (opportunity) cost of carbon is passed through into electricity prices.

5.3 Projections

The results in terms of wholesale price projections of the three scenarios with a value of carbon are summarised in Figure 47 and Table 38. These projections are discussed in further details in the following sections. Figure 47 also shows the current forward as of 11 June 2009, which we use as a rough comparator against our projections. Forward prices are continually changing and generally based on a low level of liquidity.

Table 39 presents our peak wholesale electricity price projections, whereby the peak period is defined as weekdays for the period 08:00–20:00 inclusively (as defined by Powernext).

Figure 47 – Wholesale electricity price projections for France – baseload (€/MWh, real 2008 money)



Source: Platts and Pöyry Energy Consulting analysis

The scenario paths of time-weighted average (TWA) price projections compared with the new entry costs for baseload CCGTs (see section 4.10) are shown in Figure 48. We do not expect CCGTs to operate at baseload in the French market, but we do expect long-run average wholesale prices to be reasonably consistent with the long-run marginal cost levels of potential CCGTs operating at a high load factor, given the need for new capacity in the market.

The centre of the new entry band in each scenario is calculated using our central assumption of capital cost and internal rate of return given in Table 36 and the relevant scenario assumptions for fuel and carbon costs relating to the wholesale electricity price scenario under consideration, for example: high fuel and carbon costs in the new entry band for the High wholesale electricity price scenario. The upper and lower bound of the new entry band in each scenario is calculated using the high and low capital costs and internal rate of return assumptions respectively (see Table 31), while keeping the same fuel and carbon costs.

Table 38 – Wholesale electricity price projections for France – baseload (€/MWh, real 2008 money)

€/MWh	High	Central	Low
2009	54.7	44.6	36.9
2010	68.5	51.8	36.3
2011	78.1	56.9	37.0
2012	85.2	58.6	35.8
2013	91.6	59.4	34.4
2014	93.4	59.0	34.5
2015	95.0	59.0	34.6
2016	95.1	59.4	33.9
2017	94.8	59.1	32.7
2018	94.6	58.4	33.1
2019	94.0	58.7	32.5
2020	95.6	58.9	32.2
2021	95.6	60.5	33.2
2022	97.7	62.7	33.1
2023	101.0	64.5	32.7
2024	103.4	70.1	33.1
2025	106.6	73.9	33.4
2026	107.9	76.4	33.2
2027	109.6	77.2	32.6
2028	111.9	77.8	33.6
2029	114.2	79.2	33.9
2030	114.5	79.1	34.5

Table 39 – Wholesale electricity price projections for France – peak (€/MWh, real 2008 money)

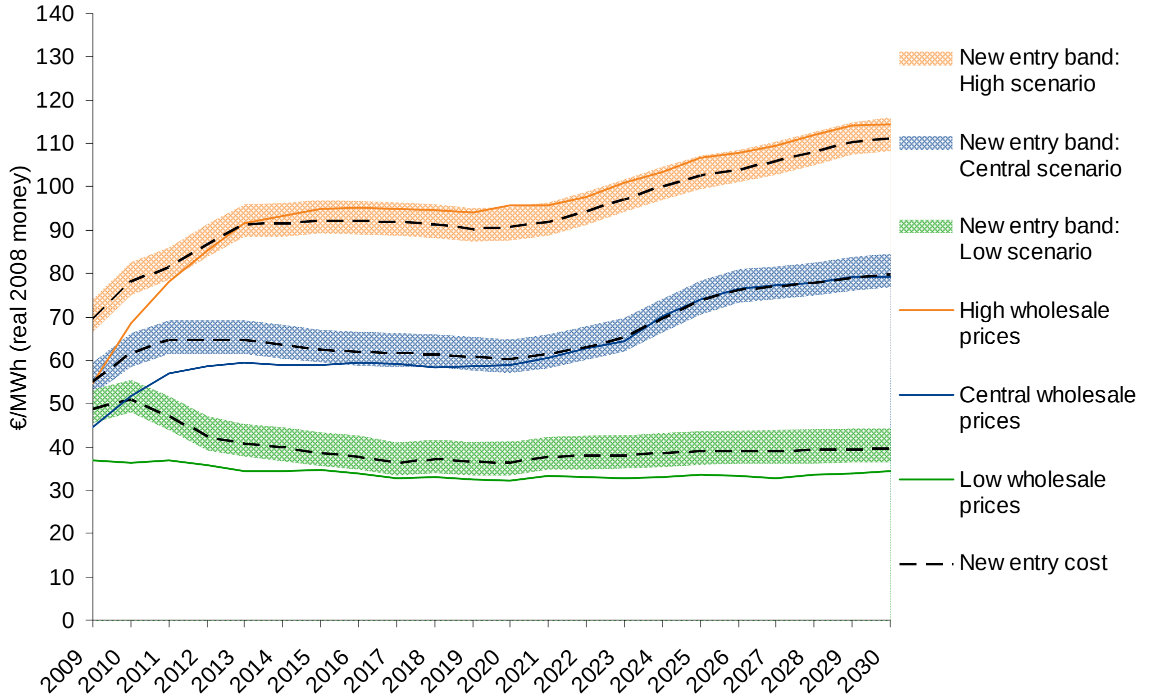
€/MWh	High	Central	Low
2009	75.4	62.1	52.2
2010	91.4	70.9	51.5
2011	103.9	77.4	53.8
2012	112.6	80.4	54.2
2013	120.3	82.6	52.9
2014	124.1	83.3	54.1
2015	127.1	84.5	55.6
2016	127.1	85.2	55.2
2017	127.1	85.3	53.4
2018	126.6	84.2	54.0
2019	125.0	84.9	53.8
2020	127.4	84.7	53.2
2021	126.2	85.8	54.4
2022	129.2	88.3	54.2
2023	132.2	89.7	53.4
2024	134.7	95.9	54.1
2025	138.8	100.1	55.3
2026	139.9	102.7	55.2
2027	141.7	103.8	54.2
2028	144.7	103.8	54.8
2029	146.9	105.6	54.8
2030	146.8	105.4	55.5

5.3.1 High

In our High scenario, the two most important drivers of high electricity prices are high demand and high fuel prices, with gas fired generation generally expensive relative to coal fired generation.

High oil prices and the continuation of oil-indexation across NWE cause the gas price to increase to around €30/MWh in 2014 and up to around €40/MWh by 2030. With ARA coal at around US$100/tonne and carbon prices rising to €50/tCO2 for Phase II and €60/tCO2 for Phase III and beyond, we project a rapid increase in wholesale electricity prices from around €75/MWh in 2009 to €127/MWh in 2015. Until 2022, the wholesale price remains at around its 2015 level. In the outer years, wholesale electricity prices rise in line with increasing gas prices and growing demand, remaining at the top of our new entrant bands and reaching €146.8/MWh by 2030.

Figure 48 – Wholesale prices and baseload CCGT new entry prices: High, Central and Low scenarios with carbon (€/MWh, real 2008 money)



5.3.2 Central

Our Central projection sees new entry commissioning from 2009 with the value of capacity reaching high levels from 2014 onwards to support the new plants coming online in Europe.

Overall, wholesale electricity prices remain at around €64/MWh for the majority of the modelled period. In the outer years, electricity prices start to move upwards in line with a rise in gas prices during this period.

CCGTs achieve load factors from 40% to 70% at the beginning of their life decreasing slowly to low levels, especially after 2025, as newer more efficient CCGTs and new nuclear capacity enter the market.

5.3.3 Low

The key drivers for the Low scenario are low demand and low fuel prices. The relatively high system margin leads to a low value of capacity. Wholesale electricity prices in this scenario remain under the new entry band for the entire period until 2030. This is also the case at lower load factors. Thus, there is no conventional new entry in the Low scenario.

In the Low scenario, gas prices are fully de-indexed from oil by 2014 and fall to low levels, under €10/MWh in real terms. This decline in gas prices, combined with coal prices remaining under $50/tonne from 2017 and gradually decreasing to $41/tonne by 2030, ensures that wholesale electricity prices are below €35/MWh from 2013 onwards.

5.4 Spark-spreads

For a gas-fired power station, electricity prices only tell half the story. Fuel prices are an important element of total costs. The difference between the power price and the variable production cost of using gas is termed the spark spread.

5.4.1 Clean spreads

In addition to the spark spreads described above (otherwise known as dirty spark spreads), we also show the clean spark spreads which take the full opportunity cost of carbon into account. The clean spark (dark) spread is the difference between the wholesale price of a unit of electricity and the sum of fuel and carbon costs of producing a unit of electricity at a CCGT (coal-fired power station)[113].

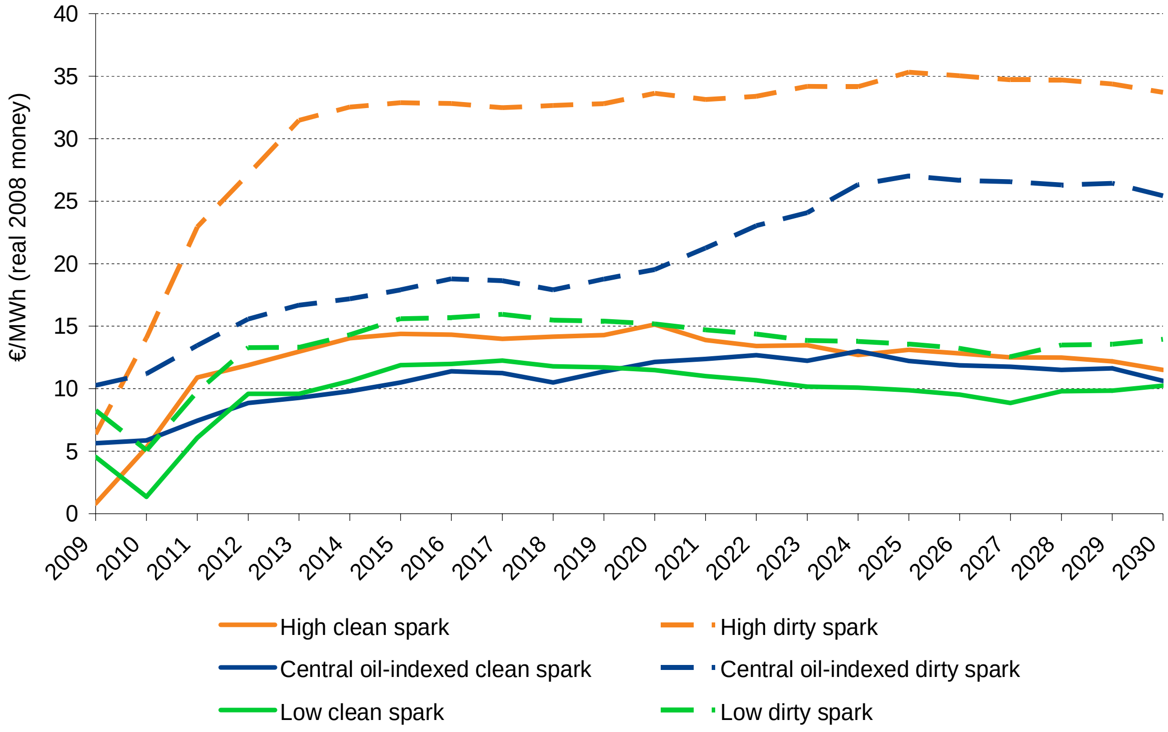
The relative magnitude of clean and dark spreads over the next twenty years will be one of the factors taken into account in any commercial decision of whether to build new CCGT or coal-fired generation. However, there are a number of other important factors, such as:

- the relative capital costs of new gas and coal plant;
- the ability to obtain regulatory and planning consent;
- the likelihood of the introduction of new regulations relating to power station emissions; and
- the possible mandating of carbon capture and storage technology for all (new) fossil-fuel power stations.

Figure 49 shows the clean spark spread for a new-entrant CCGT from our July 2009 price projections. Our projections of clean spark spread are presented on the basis of a 49.13% efficient CCGT. This reflects the efficiency level that is a common industry standard for companies engaged in the trading of future spark spreads.

[113] The spark spreads are calculated using an average lifetime HHV efficiency of 49.13% for a CCGT. An average lifetime HHV efficiency of 37% for a coal plant is used to calculate the dark spreads.

Figure 49 – Projections of French clean and dirty sparks spreads (based on 49.13% efficiency, in €/MWh, real 2008 money)



Source: Pöyry Energy Consulting analysis

As already stated in previous sections, CCGTs in France are likely to run mostly as peaking plants. In France, baseload electricity is mainly produced by nuclear power plants, with low variable costs. Load factors for CCGTs are on average around 60% in both the Central and High scenarios. It should be noted that the load factor is heavily influenced by the merit order in neighbouring countries; the relative costs of coal and gas generation elsewhere in Europe significantly affect the running hours of French CCGTs[114].

As shown in the supply curves in Figure 53 and Figure 54, CCGTs' load factor may be significantly affected by nuclear availability. If nuclear availability came back to 85%-90% for example (compared with around 83% in 2008), CCGTs average load factor would be expected to decrease in the short run.

5.5 Marginal generation by fuel type

Figure 50 to Figure 52 show the yearly proportion of time for which each fuel type is the marginal form of generation. For any year until 2030, in both the Central and High

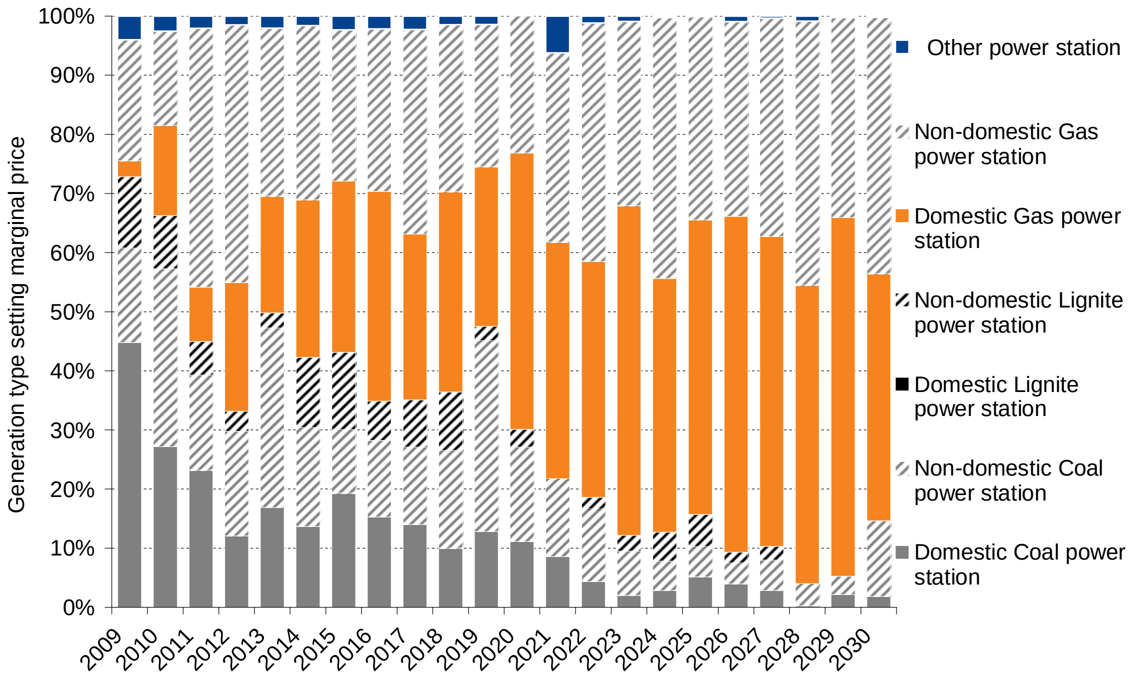
[114] This analysis has been carried out for a generic new entry CCGT in France and does not refer to any of the existing projects. For any further study on a specific project, using accurate characteristics of the power plant (efficiency, variable other work costs, etc.) is advisable.

scenarios, a thermal plant is projected to be the marginal generator at least 95% of the time within each year, while this rate is 76% in the Low scenario.

5.5.1 High scenario

Until 2010 in the High scenario, the marginal generation type is coal power generation as shown in Figure 50 below. From 2011 onwards, gas power generation becomes the marginal price setting generation type.

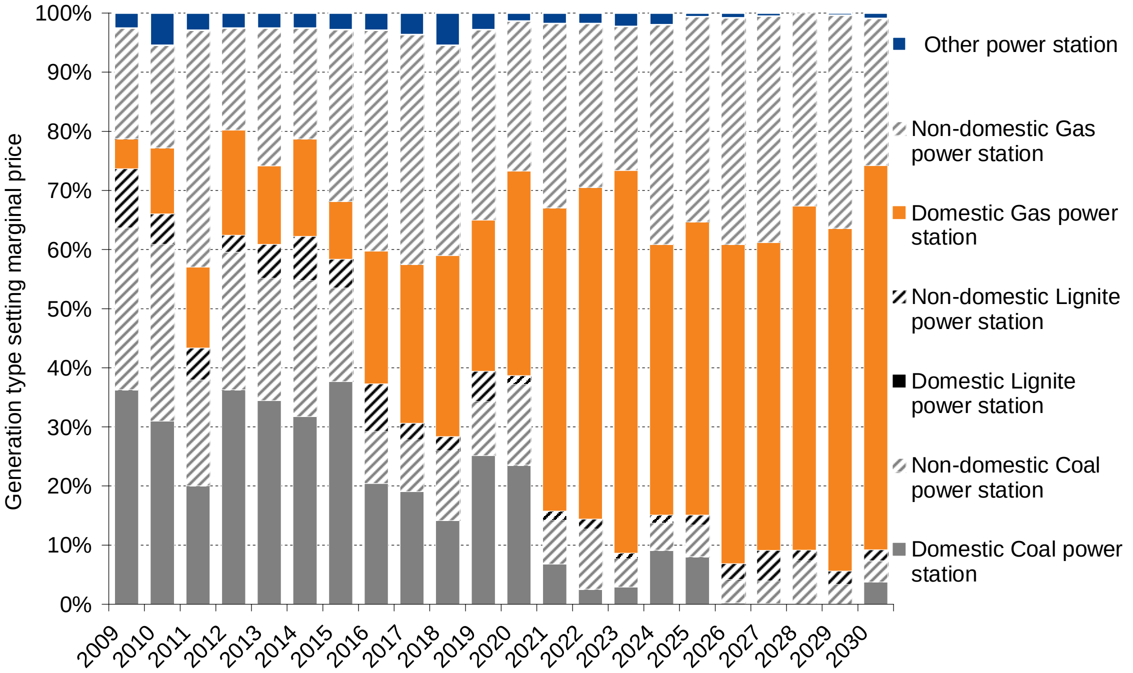
Figure 50 – Marginal generation type in the High scenario (yearly percentage)



5.5.2 Central scenario

In the Central scenario, coal power generation remains the marginal generation type until 2015 as shown on Figure 51 below. In the following years until 2030, the marginal generation type is gas powered generation and is roughly split 50/50 between domestic and foreign power station.

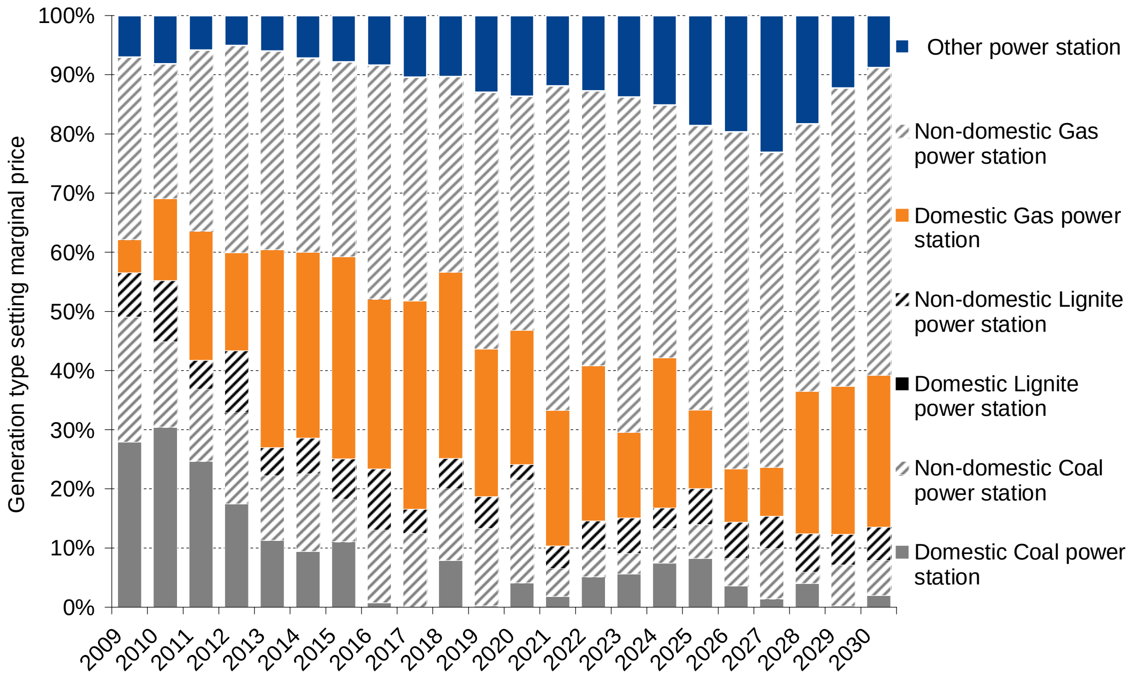
Figure 51 – Marginal generation type in the Central scenario (yearly percentage)



5.5.3 Low scenario

In the Low scenario as shown below on Figure 52, starting as early as in 2011, non domestic gas power generation is the marginal generator most of the time. A significant difference with the two other scenarios is also the share of other power station which is the marginal generator as much as 14% of the time in 2027, while it reached a maximum of 5% in both the Central and High scenarios.

Figure 52 – Marginal generation type in the Low scenario (yearly percentage)



5.6 Supply curves and price duration curves

Fundamental to the operation of Pöyry's model, *EurECa,* is the generation of a supply curve for each hour. Rather than showing supply curves for all years across multiple scenarios, only the Central scenario supply curves are shown, for a 2010 and 2020 winter business day as examples.

These supply curves represent only the fuel costs of the plant, and as a result ignore the impact that start-up costs may have. Furthermore, value of capacity payments are not reflected in the supply curves, which means that the implied prices from the intersection of supply and demand are lower than the final wholesale prices presented above.

The supply curves present the Maximum National Demand and the Maximum Net Demand; the latter taking account of the net modelled position of the country in terms of imports and imports with foreign countries.

A price duration curve representing the variation of prices for a number of sample years is presented in Figure 55.

Figure 53 – Supply curve for Central scenario for 2010 Winter business day (€/MWh, real 2008 money)

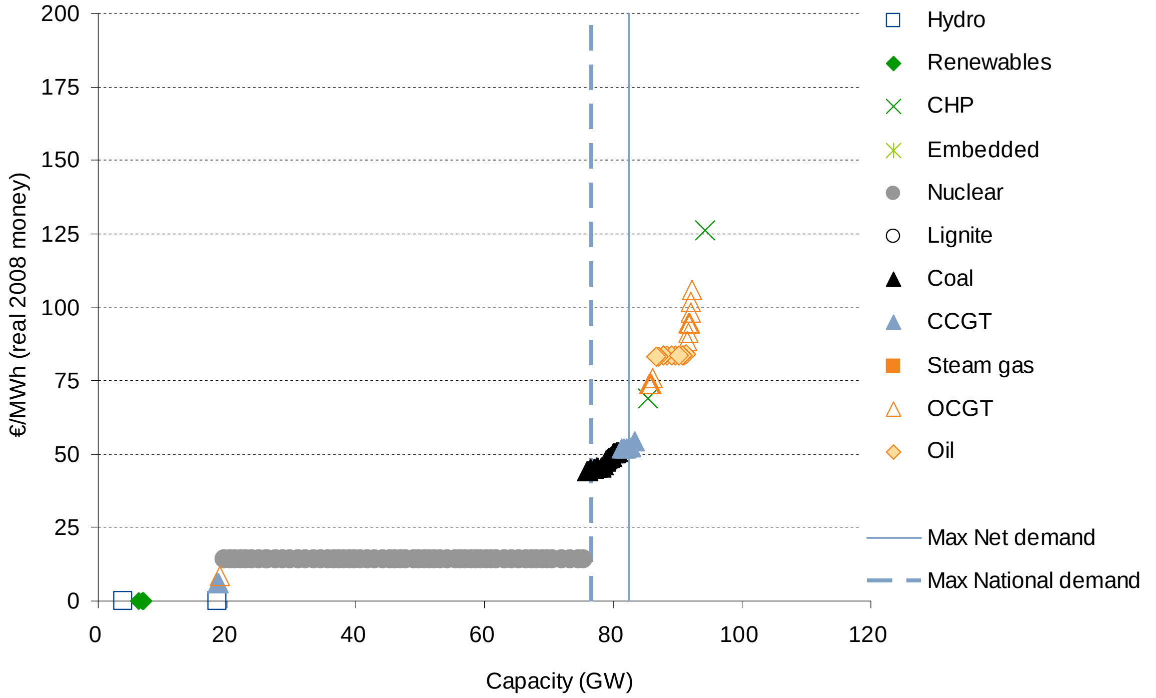


Figure 54 – Supply curve for Central scenario for 2020 Winter business day (€/MWh, real 2008 money)

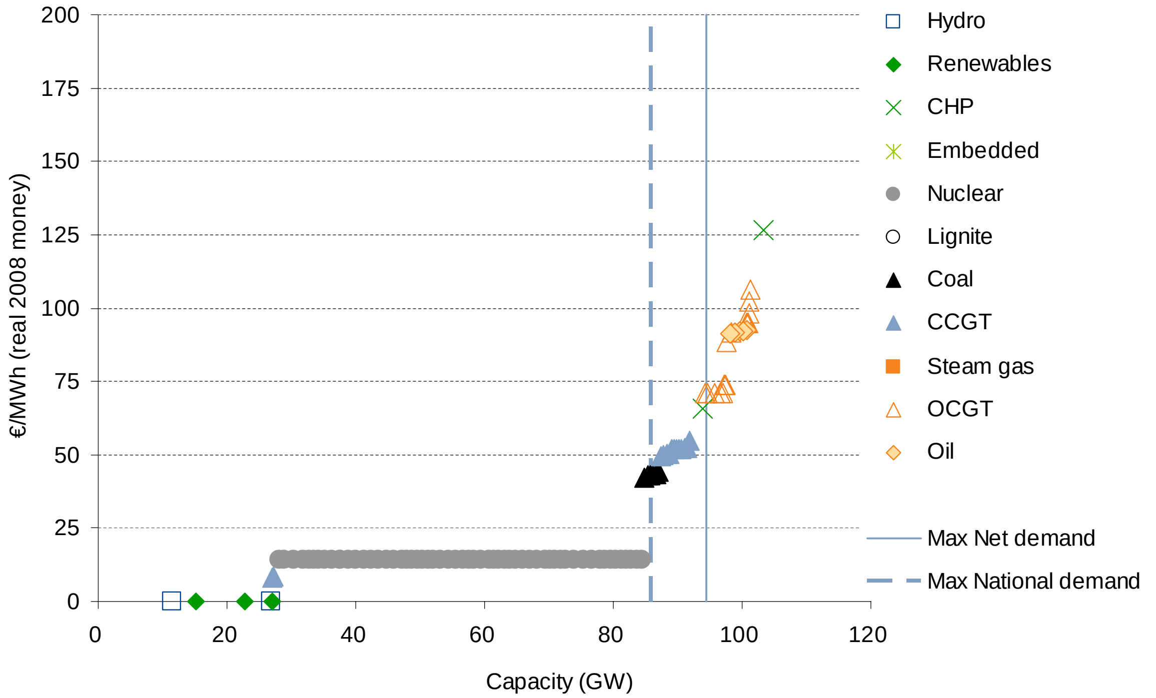
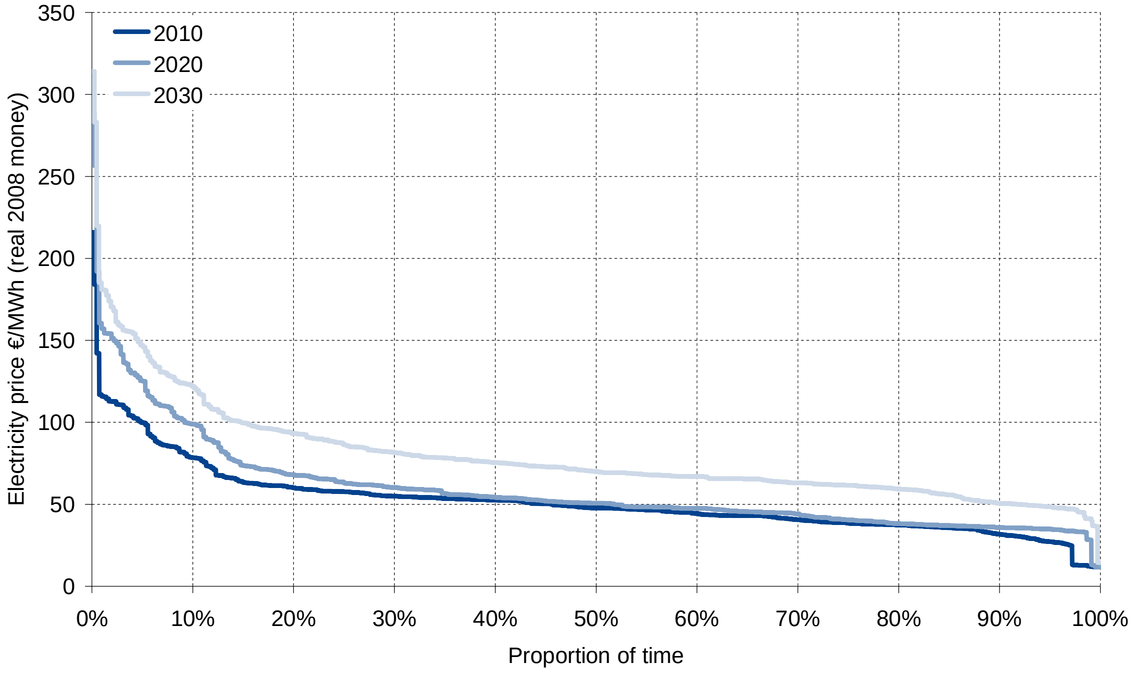


Figure 55 – Price duration curve for the Central scenario (€/MWh, real 2008 money)



5.7 Concluding comments

These projections are of the underlying level of prices in the market. There may, however, be significant variation of prices about the underlying level, from year to year, driven by factors not modelled here, such as weather, significant plant outages or technical failures. In particular the value of capacity may be much lower than values suggested here in any one year.

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ANNEX A – EURECA METHODOLOGY

Our electricity model, known as EurECa (European Electricity and Carbon model) is based on linear programming. The model has a database of every medium-large non-hydro genset in (nearly) all of Europe, and we update this database regularly. EurECa can model the whole of Europe or any portion of it. It can be used for projecting both physical behaviour (generator output, fuel use, electricity flows between countries, atmospheric emissions) and economic behaviour (electricity prices and generator revenues).

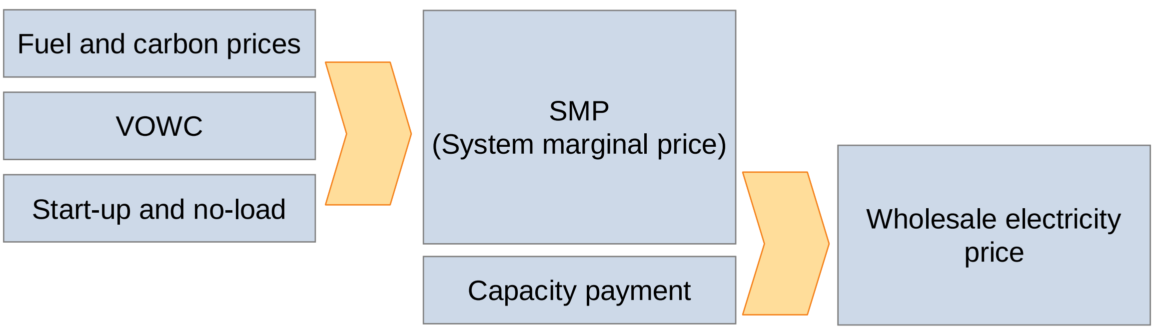
The inputs to the model are the power station database, hydro and pumped storage assumptions, demand assumptions and fuel prices. Twenty-four sample days per year are used to build up hourly results.

EurECa optimises electricity production across Europe by minimising the total variable cost of generation as well as start-up and no-load costs, subject to:

- meeting regional demand on an hourly basis, in each characteristic day;
- hydroelectric reservoir generation constraints in each country;
- pumped storage constraints in each country;
- interconnection constraints between countries or regions;
- pollution constraints (e.g. SO2 limits under the LCPD);
- commercial constraints (such as take-or-pay levels in fuel contracts);
- heat load requirements at CHP plants; and
- multi-fuel constraints that allow individual stations to switch between fuels.

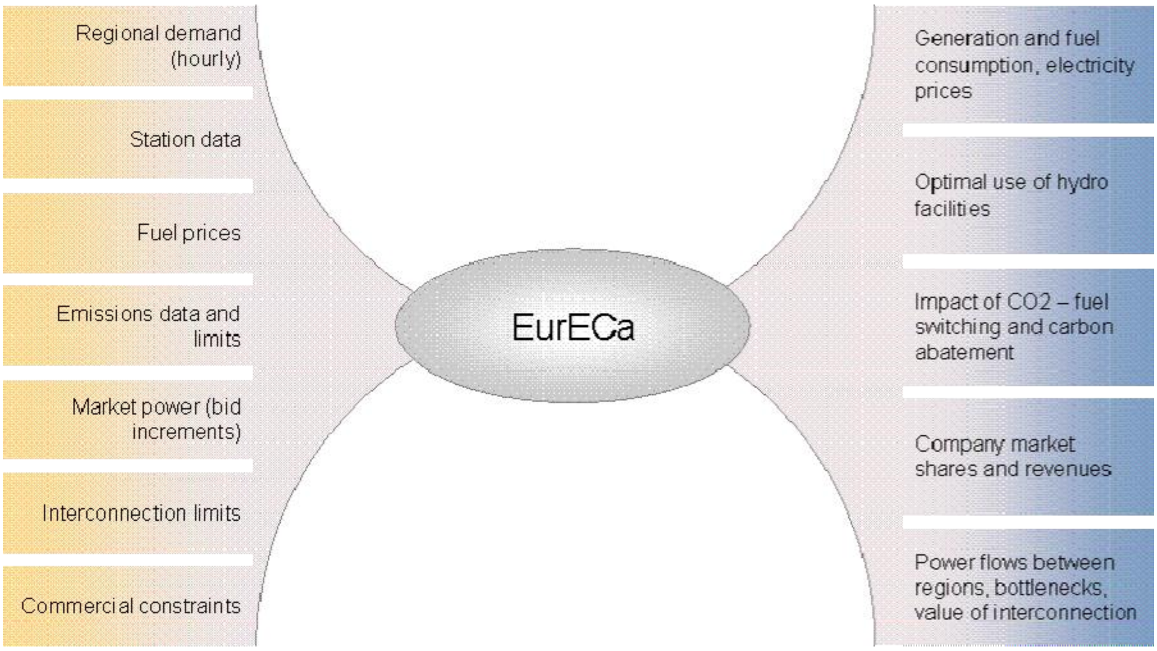
From this optimisation the model produces a System Marginal Price (SMP) for each country and in each period based on variable costs (fuel costs, carbon costs, and variable other works costs). It then calculates a wholesale electricity price in each country as described in Figure 56. In each country the capacity payment is spread throughout the year as a function of the demand profile, so that it is highest when the demand is highest. (As an alternative, in cases were there is significant historical price data, the capacity element of the wholesale price may be spread on the basis of this historical evidence).

Figure 56 – Calculation of wholesale electricity prices in EurECa



EurECa may be used not only to estimate future wholesale prices, but also to assess the commercial performance of individual companies or power stations. It can also be used to quantify the utilisation and value of interconnectors. With respect to CO_2, EurECa has been extensively used to develop abatement curves in the EU power sector, and the impact of the ETS on market prices. As well as the carbon intensiveness of each fossil fuel, we take account of the current and future degree of pass-through to electricity prices in each country separately. EurECa is summarised in Figure 57.

Figure 57 – Summary of EurECa – Inputs and Outputs



ANNEX B – FEED-IN TARIFF TO A WIND FARM

B.1 Introduction

In this Annex, the potential value of renewable energy in France is assessed through worked examples for two wind farms. These examples relate to the present form of support in France, which applies to projects applying for a tariff after 2006. This Annex expands upon the description of the renewable support mechanism provided in Section 3.2.5.

The income to a wind farm comprises of three phases, each of which is explored further below:

- for the first ten years income is based on a base tariff determined by the year in which the project applies for its PPA;
- for the subsequent five years income is based on a tariff determined by the load factor of the windfarm over its first ten years of operation; and
- in all subsequent years the windfarm will not be eligible for any feed-in tariff but may expect to secure an income equal to the wholesale price of electricity in France.

The worked examples are provided for two windfarms, based on the criteria set out in Table 40.

Table 40 – Example wind farms

	Application	Signature	Commissioning	Load factor
Example Windfarm 1	2009	2009	2011	30% (2628h/year)
Example Windfarm 2	2009	2009	2011	25% (2190h/year)

B.2 Initial Base Tariff to a wind farm

For the first ten years of the contract, the Base Tariff applicable to an individual wind farm is determined by the year of application for the PPA, subject to the windfarm being commissioned within three years of this application date. Whilst the feed-in tariff is determined in nominal money, we have also presented the base tariff in real 2008 money, to be consistent with the rest of this report. The statute sets the base tariff at €82/MWh in 2006, with the value to projects applying in subsequent years being adjusted by Wage and Price production indices. Table 41 shows that the Base Tariff in real 2008 money is €82.7/MWh for the two example windfarms.

Table 41 – Base Tariff calculation, depending on the application year (in €/MWh)

Application year	Base tariff in Nominal money	Base Tariff in real 2008 money
2006	82.00	85.31
2007	83.44	85.11
2008	84.39	84.39
2009	84.35	82.70

B.3 Subsequent Base Tariff to a wind farm

For the remaining five years, the Base Tariff is based on the load factor as shown in Table 42.

Table 42 – Base Tariff for onshore wind energy (nominal €/MWh)

Reference load factor	First 10 years	Next 5 years
Less than 2400 hours (<27.4%)	82	82
2400 – 2800 hours	82	Linear interpolation
2800 hours (32.0%)	82	68
2800 - 3600 hours	82	Linear interpolation
More than 3600 hours (>41.1%)	82	28

Source: Journal Officiel, 26 July 2006

The load factor for Example windfarm 1 is 30%, which means it qualifies for a tariff at a linear interpolation between €68/MWh and €82/MWh for the second period of the PPA, exactly €74.02/MWh. This tariff is then adjusted by Wage and Price production indices which gives a Base Tariff of €76.14/MWh. Example Windfarm 2 has a lower load factor of 25% therefore keeps the same tariff for the second period of the PPA as for the first one, €82/MWh adjusted to €82.7/MWh.

B.4 Calculation of the tariff over time

The annual tariff paid to a wind farm is calculated as the base tariff, subject to a partial inflation adjustment that increases the tariff annually by 60% annual inflation rates[115], such that the tariff reduces in real terms over the life of the PPA.

Table 43 shows the different steps for the actual income calculations, including the expected tariffs in real 2008 money (assuming annual inflation rates of 2.0% in 2008 and thereafter).

[115] We assume in this annex that Wage Index (WI) and Price production Index (PI) escalators set out in the statute are equivalent to the annual rate of consumer price inflation.

Table 43 shows the level of income for the two examples, in real 2008 money, which demonstrates the three distinct income phases of the wind farms:

- the first phase of the PPA (for ten years);
- the second phase of the PPA, with a potentially lower tariff (for five years); and
- for the remaining life of the wind farm, the electricity is then sold at the market price.

Table 43 – Detailed actual income for the example wind farm 1 (PPA applied for in 2008, signed in 2008 and a 30% load factor), in €/MWh

€/MWh	Base Tariff nominal money	Actual income nominal money	Actual income real 2008 money
2011	84.35	86.56	81.57
2012	84.35	87.60	80.93
2013	84.35	88.65	80.30
2014	84.35	89.72	79.67
2015	84.35	90.79	79.04
2016	84.35	91.88	78.42
2017	84.35	92.99	77.81
2018	84.35	94.10	77.20
2019	84.35	95.23	76.59
2020	84.35	96.37	75.99
2021	76.14	88.04	68.06
2022	76.14	89.10	67.52
2023	76.14	90.16	66.99
2024	76.14	91.25	66.47
2025	76.14	92.34	65.95

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ANNEX C – ILEX ENERGY REPORTS

ILEX Energy Reports provide detailed descriptions of European energy markets coupled with market-leading price projections for wholesale electricity, gas, carbon and green certificates. ILEX Energy Reports and price projections are currently available for the:

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  - Cyprus
  - France
  - Germany
  - Great Britain
  - Greece
  - Ireland
  - Italy
  - the Netherlands
  - Poland
  - Romania
  - South East Europe
  - Spain
  - Switzerland
  - Turkey
- renewables markets in:
  - Italy
  - Poland
  - Romania
  - Spain
  - United Kingdom
- the biofuels market in Europe.

ILEX Energy Reports are produced by Pöyry Energy Consulting, formerly known as ILEX Energy Consulting.

In addition to ILEX Energy Reports, Pöyry also produces a number of other reports, including electricity reports for Norway, Sweden and Finland, a renewables report for Sweden, and a report of the EU Emissions Trading Scheme with carbon price projections.

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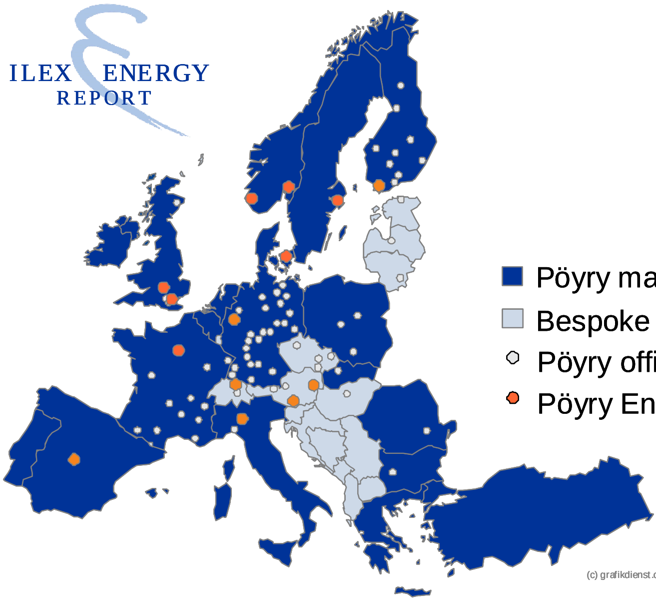
ILEX ENERGY REPORT



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