Centre de Recherche en Economie et Droit de l'Energie

PROMOTING NUCLEAR ENERGY: MARKET PRICING OR REGULATED TARIFFS?

Jacques PERCEBOIS

Cahier de recherche n° 16.03.114

7 mars 2016

Centre de Recherche en Economie et Droit de l'Energie

CREDEN – Equipe ART Dev – Université Montpellier 1
Faculté d'Economie, Av. Raymond Dugrand, C.S. 79606
34960 Montpellier Cedex 2, France
Tél. : +33 (0)4 34 43 25 04

Promoting Nuclear Energy: Market Pricing or Regulated Tariffs?

Jacques Percebois, Professor, Montpellier University
(CREDEN, UMR CNRS ART-Dev 5281)

As of May 2014, the French Court of Auditors estimated the full cost (current economic cost) of nuclear energy produced in France with second-generation reactors at €59.80/Mwh (ref 4). This figure is considerably higher than the Court's estimate a few months earlier (€49) and well above the price of the regulated access tariff to historic nuclear power (*Accès Réguleé à l'Electricité Nucléaire Historique,* hereafter ARENH), set at €42. Such a disparity is logical because the ARENH corresponds to the cost price of the historic operator, Electricité de France (EDF), given the investments the utility company has already recovered. In its January 2012 report (ref 3), the Court of Auditors evaluated the production cost of electricity generated by a third-generation EPR reactor between €70 and €90. With a construction cost of some 8.5 billion euros for the Flamanville EPR reactor (a figure announced in 2013 and thus higher than the initial cost of 4 billion euros), the cost price of the nuclear MWh would be around €107/MWh. But this is a lead unit and if we take the series effect into account, the production cost should approach €80/MWh. EDF estimates the cost price of the electricity to be produced with the Hinkley Point C EPR reactor in England at €114/MWh. These figures should be compared with those of electricity produced by other means: €70 - €100/MWh for combined-cycle gas plants in 2014 (source: EDF), €82 - €85 /MWh for on-shore wind power (source: CRE), €142/MWh for photovoltaic (source: French Ministry of Ecology, Sustainable Development and Energy), €180/MWh for off-shore wind (source: CRE, based on tender responses). In any case, we are quite far from the prices observed on the wholesale electricity market in Europe: less than €40/MWh on average in 2014.

Europe has an excess power-generation capacity and market prices have lost a great deal of meaning in a context where part of the electricity injected into the transmission grid is remunerated off-market through very advantageous feed-in tariffs. Renewable electricity sources (wind and photovoltaic) participate in spot auctions at zero price, which distorts the market balance and sends a poor signal to investors, especially in a context of sluggish demand for electricity. Nuclear energy, like the renewables (sun and wind) has a particular cost structure, whereby fixed costs weigh much more heavily than variable costs. This means that it is necessary to cover at least the variable costs at off-peak periods so as to recoup the fixed costs at full and peak periods. This presupposes two conditions: (1) electricity pricing based on marginal costs, which presumes that the market price follows the merit order; and (2) a high availability factor for the power plants. The problem here is that the merit order is distorted by the presence of a considerable volume of electricity remunerated off-market via guaranteed purchase prices, thus stripping the price recorded on the market of all meaning. Another problem has to do with the fact that intermittent renewables like solar or wind power are not sufficiently dispatched into the grid during the full periods to recover the mark-up which would permit them to finance their fixed costs (i.e., the infra-marginal rent) (see ref 6). This situation explains why they are subsidised off-market, with the additional cost passed on to consumers through expensive cross-subsidisation through a kind of tax which is known as a Contribution to

Public Service Charges for Electricity (Contribution au Service Public de l'Electricité, hereafter CSPE).

Thus, because of its negative effects, the scheme for aiding renewable energies presently in force in Europe is likely to penalise investments in capital-intensive energies – and nuclear energy in particular. At the same time, it is understandable that operations with relatively high fixed costs, like nuclear power, need a certain long-term visibility in order to ensure the profitability of an investment which cannot easily adapt to the volatility of market prices caused by the variable cost of thermal energy (coal- or gas-fired power plants). This leaves only two solutions: either the market is left to function on its own, with the merit order as the only signal addressed to investors and at the risk of provoking major 'hit and run' effects (i.e., investments occur when the market takes off and the power plants are mothballed when prices fall – but the sluggishness of supply and demand alike must be taken into account here); or the volatility of wholesale market prices is tempered through corrective mechanisms which guarantee that investors will be able to recover their fixed costs with a normal rate of return on the capital invested. But it is not possible to introduce discrimination by establishing regulated prices for certain energy sources whilst letting the market price serve as a guide for others, especially when the regulated prices have an impact on market prices.

The nuclear revival is now a reality throughout the world, except in the United States, where the low price of shale gas penalises investments in all the alternative solutions (coal-fired plants, nuclear, etc.) and in Europe, where the dysfunction observed on the wholesale electricity markets penalises investors by the absence of financial aid. Outside of Europe and North America, nuclear energy benefits from regulated sales prices or financial support which ensure its long-term profitability. This is notably the case in Asia, and especially in China. In Europe, renewable energy profits from regulated prices but this is not the case for nuclear energy.

The ongoing reform of the renewable energy support system, which provides for replacing the feed-in tariffs (FIT) scheme by feed-in premiums (FIP), is a step in the right direction, but only as long as an equivalent system is introduced for nuclear energy, as is the case in the UK with a scheme close to that of the contracts for difference (CfD). Equity means identical treatment for energies with the same characteristics (nuclear and renewable, two energies with a high proportion of fixed costs) and different treatment for energies with different characteristics (thermal energies with a high proportion of variable costs and intensive carbon dioxide emissions, gas- and coal-fired plants).

In the remarks which follow, we will first analyse how the present support scheme for renewable energies disrupts the functioning of the wholesale electricity market in Europe and simultaneously weakens investment in nuclear energy; in a second section, we will show that a FIP scheme for renewable energies is perfectly compatible with a CfD scheme for nuclear energy, like the model now gaining favour in the UK for promoting the nuclear revival and which France would do well to draw on.

I. Nuclear power weakened in Europe by the system of guaranteed purchase prices for renewable energies

I.1. The FIT scheme: a costly mechanism

Guaranteed prices with purchasing obligation, or feed-in tariffs (FIT), which remain the main mechanism used in Europe for promoting renewable energy sources, are quite close to the system of export levies and refunds introduced by the Common Agricultural Policy (CAP) at its beginnings in the 1960s. And it now entails the same disadvantages observed after a few years with the CAP. The prices guaranteed to European farmers were disconnected from world agricultural prices (considered too volatile and insufficiently advantageous) and a system of tariff gates was set up between internal and worldwide market prices. In order to reach the higher level of the European internal market price, set to ensure the European producer an adequate income, the imported agricultural product is subject to a 'levy' (import tax), and to reach the lower level of the world market, the exported agricultural product benefits from a 'refund' (export subsidy).

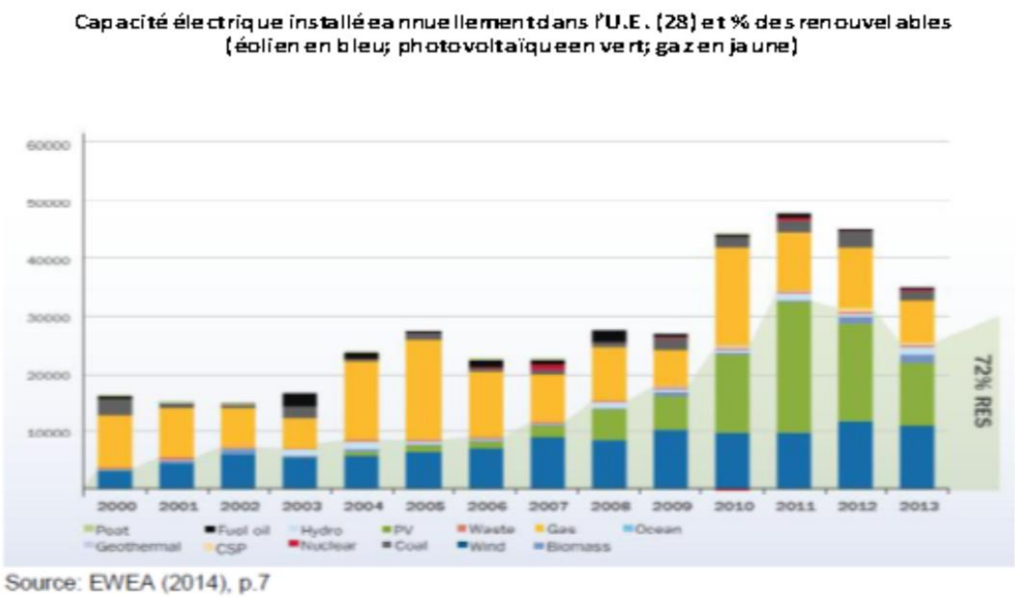
This system offers several advantages. It satisfies the farming sector because farmers consider that they do not receive support (they live from the fruits of their own labour). And in principle, it is a scheme which does not cost a great deal for public finances, at least when the volume of imported agricultural products is higher than that of exported products (as was the case when the CAP went into effect: Europe was at that time a net importer of agricultural products). For many years, import levies thus exceeded export refunds.

The scheme nonetheless has certain weaknesses. For one thing, European consumers are obliged to pay higher prices for agricultural products than those of the world market because the internal market price follows the guaranteed price. But the system's main weakness lies in the fact that remunerating farmers at a price disconnected from the world market eliminates any price signal and encourages farmers to overproduce: whatever they cannot sell on the internal market will be sold on the international market thanks to subsidies which will permit European products to compete with foreign ones. In practice, the system gave rise to structural surpluses of goods which ultimately had to be sold on the world market at the cost of ever-increasing subsidies.

The FIT scheme, which was introduced in the early 2000s in most EU countries to promote the penetration of renewable energies, is very close to the original CAP system and has had the same undesirable effects. Renewable energy benefits from an advantageous guaranteed price, set by public authorities, and a purchase obligation under a long-term contract (often around 15 to 20 years) with the incumbent operator. In general, this guaranteed price is considerably higher than the spot-market price for electricity and the additional cost is borne by all electricity consumers through the CSPE in France and the EEG Umlage in Germany. Producers of wind or photovoltaic power do not have to worry about the sale of their product and they are not responsive to the market price because their remuneration is set off-market. Since this intermittent electricity has priority in the transmission grid and benefits from a variable cost which is very low or null, it disturbs the functioning of the merit order. The logic of the merit order implies that power stations are brought online in function of their increasing marginal costs (variable costs), with the market equilibrium price based on the marginal cost of the marginal plant. When a plant with a low variable cost is itself the marginal plant ‘making’ the price, it recovers only its variable cost; it recovers its fixed costs when the marginal plant is one with a higher variable cost. And even then, this plant with a low variable cost must have a high load factor. Thus, a nuclear power plant recovers only its variable costs when it is the ‘marginal’ plant, in other words, during off-peak periods. At peak periods, the price depends on the considerably higher variable cost of a coal- or gas-fired plant, and this allows the nuclear plant to recover its fixed costs. At extreme peak periods, the equilibrium price must be based on the marginal plant’s variable cost but also on its fixed cost; otherwise, there is a risk of the ‘missing money’ signalled by Stoft (ref 10): the peak plant does not recover its fixed costs. Such a system based on marginal cost pricing would not allow renewable energies to recover their fixed costs because they are not brought online for sufficient periods of time, and rarely at the most gainful peak periods, owing to the intermittent nature of solar or wind power. Indeed, this is why payments for such energies occur off-market. It is consequently necessary to take into account the cost of the back-up tied to this intermittent supply, which requires anticipating reserve production facilities in order to resist the vicissitudes of sunshine or wind.

As can be seen from the chart below, within the European Union, the share of renewable energies in proportion to annual investments in the construction of power plants has exceeded 70 % since 2011, to the detriment of gas-fired plants, which previously represented the bulk of capacity-increasing investments. The system of subsidies granted to solar and wind power largely explains this situation.

Annual Installed Power Capacity in the E.U. *(wind in blue, P.V. in green, gas in yellow)*

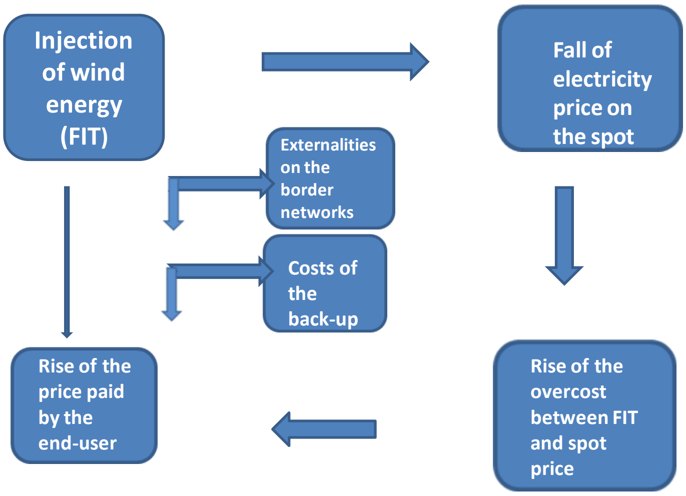


The cost of the back-up is not recorded in production costs of intermittent energies but it constitutes a negative externality for the power system as a whole. The gas-fired plants, which often come to the aid of these intermittent sources, are now victims of a price squeeze: the price of gas remains high in Europe since imported gas is indexed to the price of oil on the basis of long-term import contracts (fall of oil price observed in 2015 is too recent to alter this point), but at the same time, the price of coal is declining on the world market because of coal surpluses in the United States tied to the abundance of shale gas. American shale gas is, as it were, chasing American coal from the electricity production market and American coal is chasing natural gas from this same market in Europe. Since the load factor for combined-cycle gas turbines is reduced because of the priority given to renewable energy sources, these so-called back-up power plants are faced with sharply declining profitability. Numerous projects for combined-cycle gas turbines have been abandoned in Europe and many power plants have even shut down.

The cost of this back-up is difficult to assess because it also depends on grid costs, and thus on the areas where the wind or solar production facilities are installed. If increasing the supply is not an option, the demand for electricity can be reduced when wind or sun make themselves rare and intermittent sources are lacking. This is the load management technique (demand-side management): each operator can – and should, moreover, with the implementation of a capacity market – have a portfolio of customers subject to peak-day load reduction (*effacement jours de pointe*, EJP, in French; see ref 9), which makes it possible to get beyond the peak in case of insufficient supply. In addition, the new technologies (smart meters and smart grids) should permit better matching of electricity supply and demand in real time by automatically switching off a large share of users' electrical equipment for a short period of time.

Some observers point out that the problem of the back-up concerns all kinds of power plants, including nuclear facilities (e.g., in the case of an unexpected reactor shutdown). This is partly true but there remains an important difference between wind and nuclear power: the availability factor of nuclear energy is between 80% and 90%, whilst that of wind power presently averages 17% to 20%.

Perverse effects of FIT system (source J Percebois CREDEN)



I.2. The FIT system: a source of perverse effects

Another aspect of the FIT scheme is the switching of the merit order curve. Renewable energy sources participate in spot-market auctions at no charge because they are remunerated off-market but this situation has negative effects on the equilibrium price, which is consequently below the 'fair' price. Electricity prices on the spot market have shown a continuous decline in Europe and this is especially true in countries such as Germany, where the share of intermittent renewable energies is particularly high. Today, the spot price is at the level of the ARENH, the base price at which EDF has to sell part of its nuclear electricity to its competitors; at times, it is even below the ARENH. This means that the ARENH, which was originally considered as a bottom price now tends to become a ceiling price for electricity suppliers. In some cases, spot prices are even negative; since 2009 this has often occurred in Germany, where the share of wind-generated energy is particularly high. But it has also been the case in France, in particular in June 2013. Since it is expensive to shut down gas- or oil-fired thermal power stations for only a few hours, it is preferable to pay an operator who will accept to take this over-abundance of wind power (generally at off-peak periods). This is the case for Swiss operators, who have strong storage capacities for hydroelectric energy (via pumped-storage power stations) and are consequently paid to transfer the surplus energy.

It is worth recalling that the start-up time of an open-cycle gas turbine (OCGT) is around 10 to 20 minutes according to the OECD-NEA, but 30 to 60 minutes for a combined cycle gas turbine (CCGT), 1 to 10 hours for a coal-fired plant and 2 to 3 days for a nuclear plant. The maximum variation gradient of the output per minute is 20% for a gas turbine and 5% to 10 % for a combined-cycle gas turbine, but only 1% to 5 % for a coal-fired plant or a nuclear plant (source: NEA, ref 8). The findings of the NEA show that the systemic costs of the so-called programmable technologies (nuclear, gas or coal) are relatively modest (around $3/MWh), but in the case of the intermittent technologies, owing to the constraints related to the back-up problem, they can be as high as $40/MWh for onshore wind energy, $45 for offshore wind energy and $80 for solar energy.

Nor do these figures take into account certain network 'overflow' costs provoked in the neighbouring countries because of the massive injection of the electricity which cannot be evacuated in the producer country for lack of the necessary infrastructures. This is the case, for example, in Poland, the Czech Republic or Belgium when the offshore wind power produced in the Baltic Sea cannot be transferred to Bavaria because of inadequate high-tension lines between northern and southern Germany and it has to use the Polish, Czech or Belgian grids. Some of these countries have introduced mechanisms (phase-shifting transformers) to prevent the influx of the unwanted electricity or plan to do so. It should be noted that the most substantial systemic costs are those related to the reserve rather than those of expanding the grids. According to a recent study carried out by E-CUBE Strategy Consultants (ref 4), the cost of reinforcing the grid would be about €5/MWh ($7) in Germany with a wind-power penetration rate of about 25% of the electricity mix. In fact, the cost depends a great deal on the geographic location of the renewable energy facilities in relation to the network configuration and, most often, this involves the distribution grid because of the low unit capacity installed. It is also possible, however, that local production of renewable electricity can economise on some grid costs if it makes up for a locally inadequate supply. But this can only be confirmed by a case-by-case study.

Renewable energy advocates point out that, far from constituting a drawback, the switching of the merit order curve offers advantages: these energy sources save on the fuel costs of polluting thermal power stations and thus acquire 'alternative energy value'. In other words, the presence of this intermittent electricity will cancel out the variable costs of a coal- or gas-fired plant. Replacing thermal energy by renewable electricity also avoids CO_2 emissions, and this benefit should also be taken into account in the economic calculation. Admittedly, the price of CO_2 is very low at present (€5 - €7 per tonne) but this is not likely to continue. Intermittent electricity can also avoid peak-load investments, which permits economising on variable costs but also fixed ones, such as those of an open-cycle gas turbine. In addition, the decrease in the market price represents a potential gain for end-users, or at least the ones whose contractual price is indexed to the spot price. This is less true for consumers with regulated selling price (RSP) contracts because in that case, the gain goes to the energy supplier. Consumers benefiting from the RSP derive no profit from it (and as of 2016, only households and small companies with the so-called blue tariff will continue to benefit from this RSP because the green and yellow tariffs for industrial users will be abolished at the end of 2015, as stipulated by the NOME Act on the new organisation of France's electricity markets). It should not be forgotten that the additional cost corresponding to the difference between the guaranteed price and the wholesale market price will be borne by consumers through the CPSE and, all other things being equal, this means a rise in the tax-inclusive price paid by all consumers. It is therefore necessary to compare the total of the 'alternative energy value' (or marginal cost effect) and that of the 'price-effect value' (or merit-order effect) to the off-market purchase price of renewable energies (FIT) in order to determine the real cost of the latter. In addition to this purchase price, moreover, there are also back-up costs in terms of production and transmission. These systemic costs are tied to the network investments necessary for connecting the renewable energy sources but also for reinforcing these networks. If the balance is negative today – renewable energies cost more than they bring in – some observers predict that the situation could be reversed in the near future owing to the drop in production costs for renewables on the one hand and the rise in the cost of fossil fuels and that of the price of CO_2 on the other. But declining oil prices since mid 2014 introduce additional uncertainties about gas and coal prices.

It is also necessary to consider the fact that a decrease in the spot price produces sunk costs for the thermal facilities in operation. If these facilities are no longer brought online, or not enough, they must be mothballed or shut down, which means that producers are obliged to constitute provisions for potential losses, as was recently the case for the French multinational GDF SUEZ. Indeed, more than 30,000 MW of gas turbines have been shut down, or are about to be (mothballing), in the European Union. Some combined-cycle gas turbines and the combustion turbines (gas turbines or combustion turbines operating with diesel fuel) were constructed on the basis of price signals sent by the market before the massive introduction of these renewable energies; as a result, the statutory priority of this fateful electricity which would not have appeared without off-market support is likely to jeopardise ex post a return on investment that was largely guaranteed ex ante. And it might well prevent future investments in cutting-edge technologies, which could increase the likelihood of system failure over time.

The decrease in the price of electricity on the wholesale market jeopardises the competitiveness of nuclear plants currently in operation, and thus largely amortised, because this price is sometimes lower than the ARENH level (which is held to be the cost price of the nuclear MWh for second-generation reactors in France). This situation clearly compromises the profitability of the next-generation reactors, which have no chance of competing with artificial market prices since the production cost of the MWh obtained with these reactors is considerably higher than the ARENH price.

The random nature of wind power production (as well as solar, which remains marginal today) raises yet another question: that of the increased volatility of electricity market prices. Benhmad and Percebois (ref 1) have used an econometric approach to demonstrate that the injection of wind-generated electricity in Germany tended not only to lower the price on the wholesale electricity market but also to increase the volatility of the spot electricity price. This volatility has a cost because it requires the operators to hedge on the futures markets via financial products.

It is important, however, not to place the responsibility for all these undesirable or perverse effects and additional costs on renewable energies alone. Indeed, the main cause lies with the low demand for electricity throughout Europe. The European electricity system is faced with overcapacity because no one anticipated the stagnation of demand owing to the crisis but also because of energy efficiency policies. Renewed economic growth, demographic pressure (particularly in France, for this is not the case in Germany), new uses for electricity (especially the rapid expansion of electric vehicles) would be likely to reverse the trend and nothing excludes the possibility of new tensions between electricity supply and demand on the European market in 2017 or 2018.

The effects of a massive injection of intermittent renewable energy remunerated off-market are thus complex and relatively unfavourable to consumer well-being, even if the opposite is true in certain exceptional cases. Several factors must be taken into account:

1) **The merit order effect**: the decrease in the spot price benefits consumers supplied through market offerings but not those paying for their electricity on the basis of

regulated selling prices (RSP). It should also be borne in mind that, in some cases, the renewable energy consumed by a French consumer may be financed by a German consumer, which leads to cross-border income transfers.

2) **The marginal cost effect**: fuel savings (or CO_2 emissions avoided) via the replacement of thermal electricity by green electricity benefits all consumers.

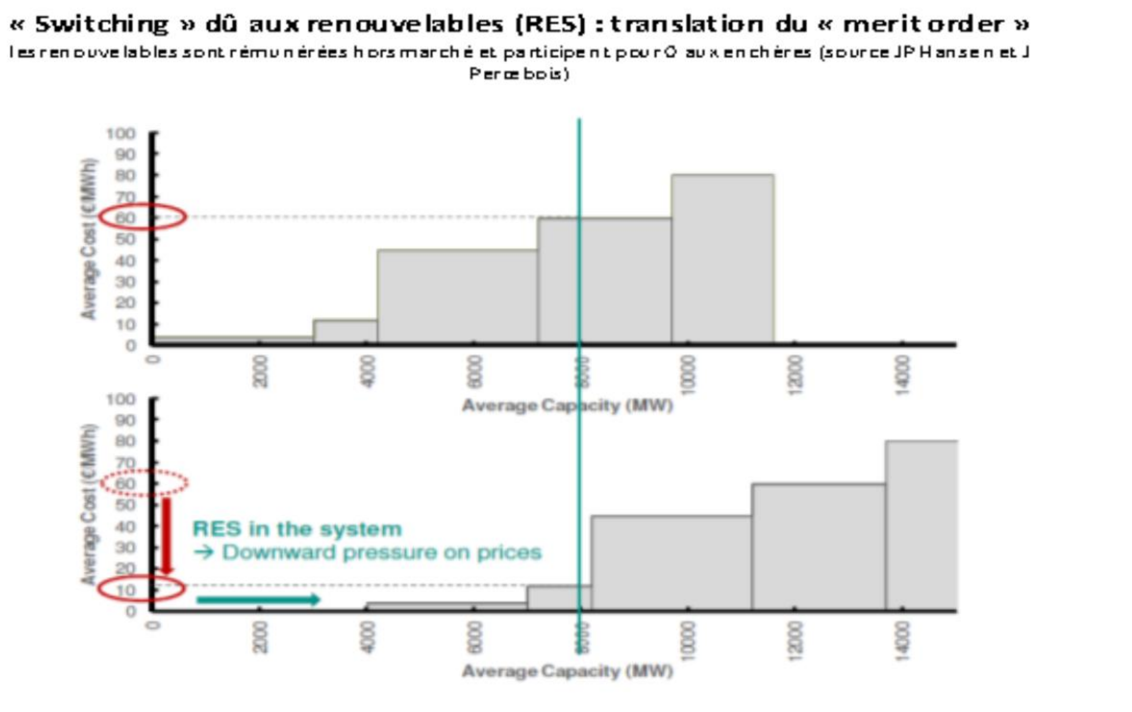
3) **The back-up effect**: the necessity of back-up power stations in order to alleviate the problem of intermittency constitutes a cost for all consumers.

4) **The network effect**: transmission-grid externalities tend to increase network access tariffs, which has an impact on all consumers' electricity bills. Here too, there can be cross-border transfers.

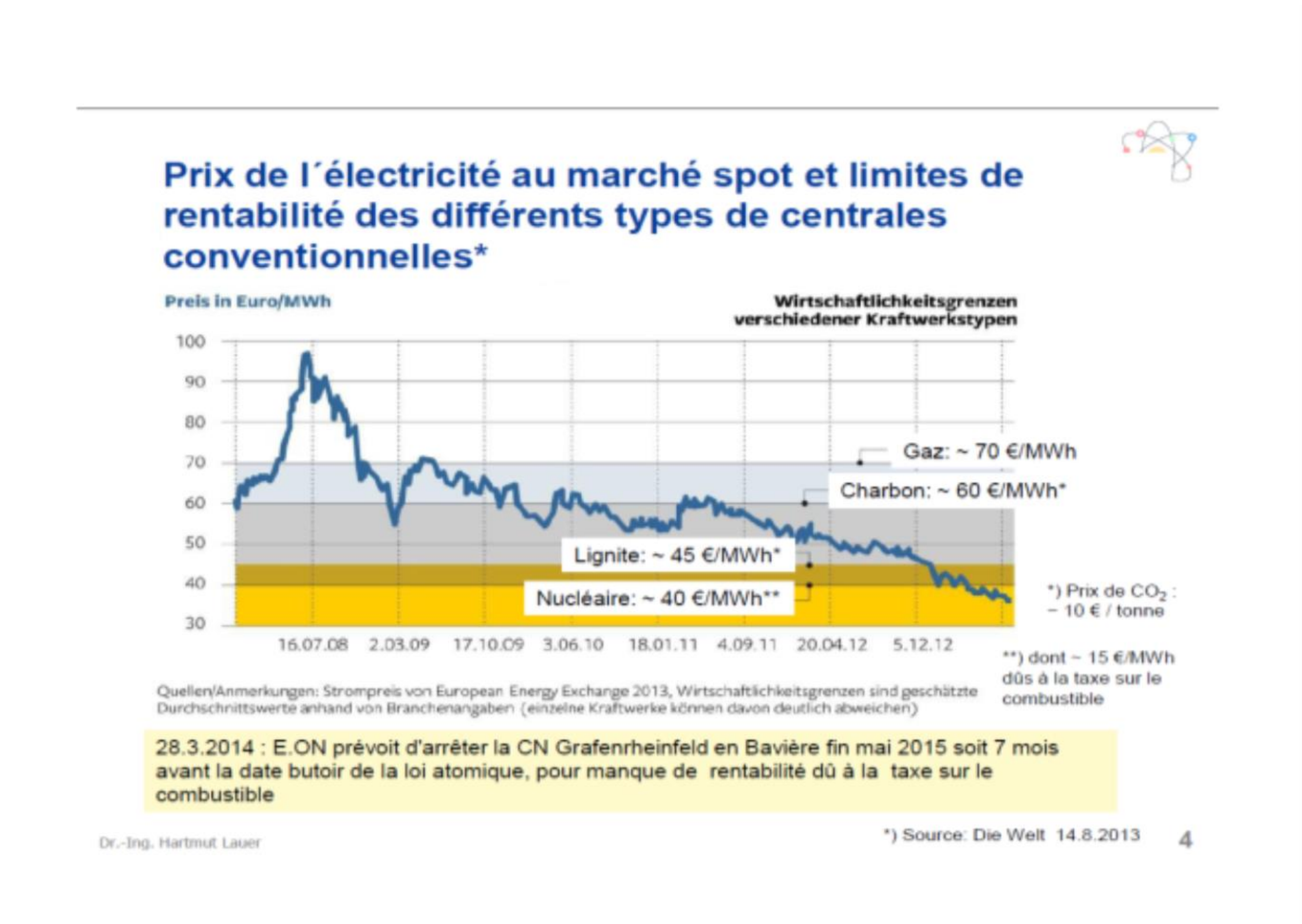
5) **The sunk cost effect**: the losses incurred by producers whose facilities are not cost-effective are in part borne by shareholders and in part recovered by sales prices and thus ultimately paid by the consumer.

Switching of the "merit order" curve due to Renewable Energies paid off-market

(source: Hansen, Percebois 2010)



The figure below shows that the decrease in spot electricity prices observed since 2008 has gradually compromised the competitiveness of thermal plants operating with gas, coal or lignite, and even that of nuclear power stations, because the spot price fell below €40/ MWh in 2013 and 2014. At €70, the gas-fired plants are no longer competitive; at €60, plants operating with coal and lignite no longer recover their full cost and around €40 per MWh, the installed nuclear plant which is partly amortised is no longer cost effective. As for third-generation nuclear power, it has no chance of being competitive with current market prices.



I.3. Towards a feed-in premium system?

There is consensus in Europe about the pressing need to reform the present system of support for increasing the use of intermittent renewable energies. Several options are worth considering:

1) Decreasing the level of the feed-in tariffs (FIT) and prohibiting the injection of variable renewable energy when the spot electricity price becomes negative or falls below a certain threshold. The FIT system is expensive for the end consumer; it has often been

modified and certain yo-yo effects have had regrettable consequences on the wind and photovoltaic industries. Purchase prices have sometimes been sharply lowered, only to rise dramatically soon afterwards, thus precluding any long-term strategic vision for the industry.

2) Opting for a 'green certificate' scheme: providers required to sell a minimal quota of green electricity (via the Renewable Portfolio Standard) can either generate this electricity themselves, buy it from another provider who has a surplus, or acquire 'green certificates' from producers who are not subject to an obligation but inject green electricity into the grid.

3) Promoting a feed-in with premium (FIP) system rather than the FIT: renewable electricity producers sell at the spot market price but also receive a premium (fixed or variable) in function of either the quantity of energy injected (MWh) or installed capacity (MW). This premium may be calculated ex ante or ex post. Its advantage is that providers are responsive to the market price because their main income comes from the sale of their electricity on that market. The premium is only a supplement which can in fact be regularly adjusted in function of the market situation and which can be indexed to non-energy indicators (e.g., inflation, economic growth rate, etc.). In this case, the income received is variable rather than fixed, unlike the two previous systems, at least if the premium is fixed whilst the sales price on the spot market remains variable.

4) Choosing a Total Subsidy Scheme (TSS) to be distributed amongst providers: the policy-maker sets the monetary amount of the incentives to be allocated and then chooses

a means of dividing up the funding (e.g., through auctions).

5) Organising auctions: the public authority launches an invitation to tender for an installed capacity (and thus, indirectly, a quantity of kWh produced) and classes the bids according to the merit order (increasing costs). It can then opt for auctions with a reserve price (paid at the marginal cost) or auctions with an asking price (paid as bid). The latter system has the advantage of being less expensive for the collectivity and eliminating certain rents. But the 'winner's curse' described by Chari and Weber (ref 2) is unavoidable: successful bidders only win the auction because they have asked a lower price than their rivals and they may therefore regret not being more demanding. Admittedly, had they been more ambitious, they would have reduced the possibility of being selected, but in case of victory, their profit would have been greater. Since each participant tends to anticipate this curse, they all increase the asking price and as a result, this system becomes expensive for the collectivity.

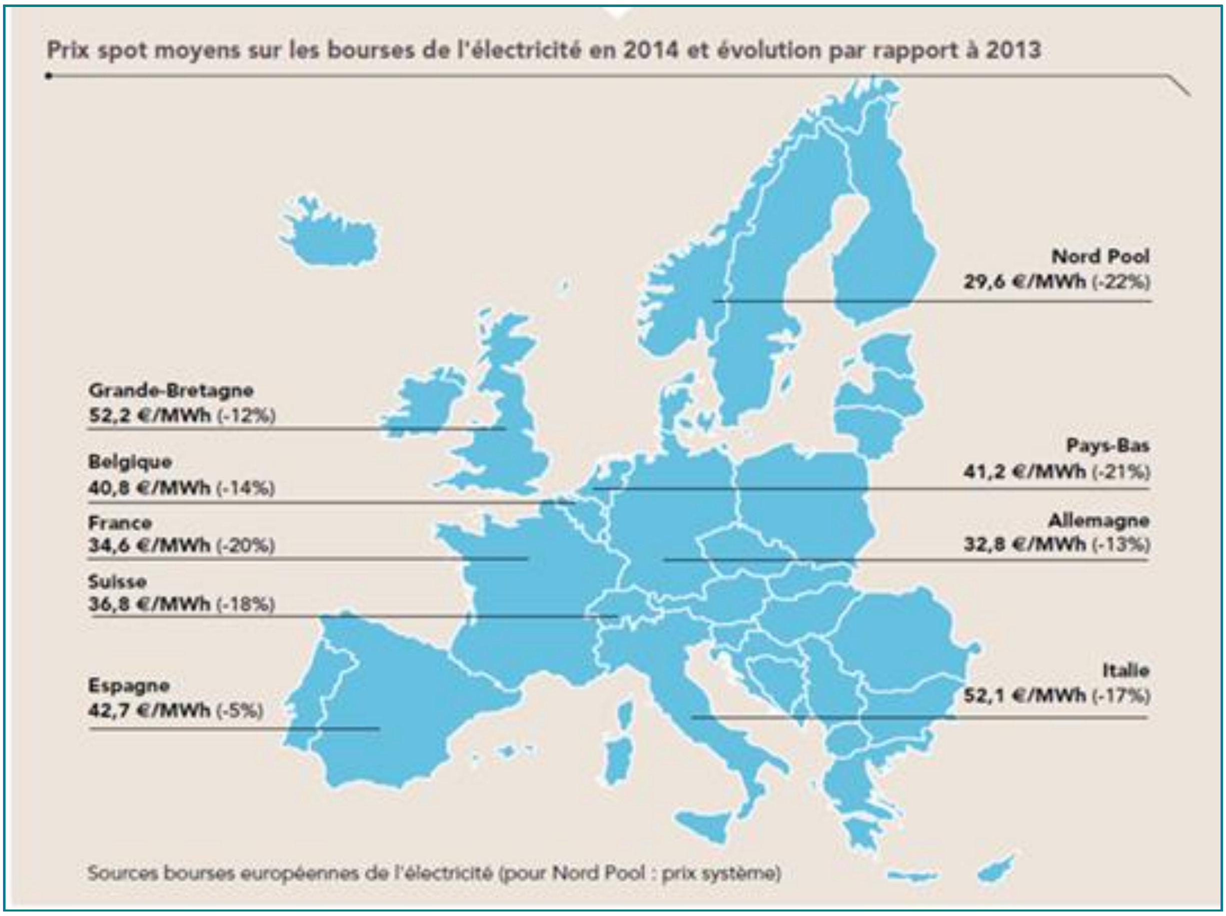
6) Requiring renewable energy producers to consume part of their electricity themselves before feeding it into the grid; only a fraction of their production will benefit from a guaranteed income. The pricing system will then have to be revised because these consumers will remain connected to the grid and call on the incumbent operator when their domestic production is insufficient or faulty. A standby tariff thus has to be negotiated.

7) Requiring energy producers to store the surplus electricity (via a system of batteries, recourse to pumped-storage power stations, water electrolysis to produce

hydrogen, or even the 'methanation' process associating hydrogen and CO_2 to produce methane). With this 'power to gas' system, part of the hydrogen can then be injected into the natural gas network or used in vehicles. Such a solution is admittedly not profitable in the current economic situation but this might change in the near future.

At present, France is probably moving towards an FIP system, as Germany has been doing since August 2014. This means that intermittent energy producers will be required to sell all or part of their energy on the spot market and will receive an income supplement in the form of a premium (most likely a fixed premium for capacity installed) intended to help them to finance the fixed costs of their facilities. France's recent law on energy transition provides for such a scheme, at least for large-scale renewable facilities. But the inertia of the system is such that the consequences of an expensive guaranteed purchase price policy which has disrupted the functioning of wholesale electricity markets in Europe will continue to be felt for a long time.

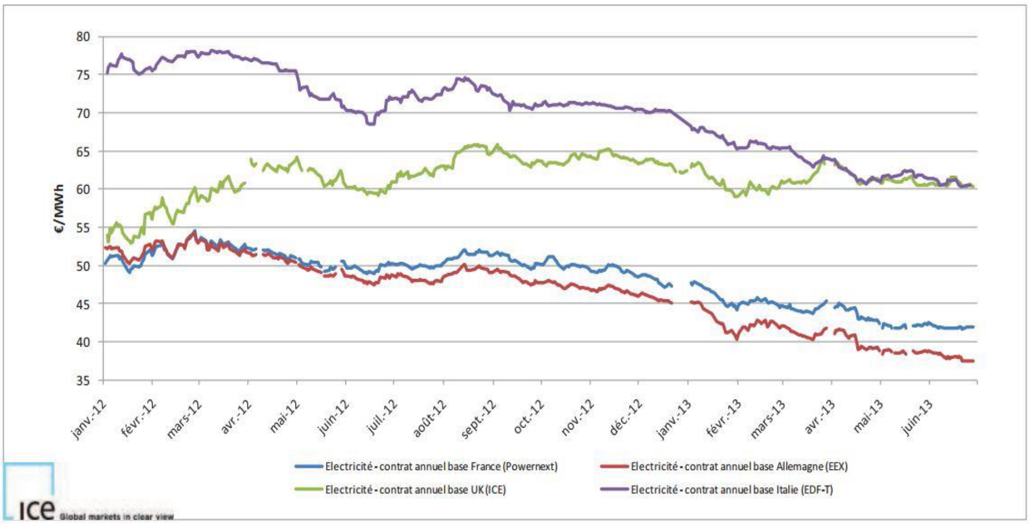
Average prices observed on the Spot Markets in Europe (with 2014/2013 fall)



Spot Electricity Prices Evolution

(Germany in red; France in blue; UK in green; Italy in black)

Prix de marché de l'électricité en Allemagne, en France, en Italie et au Royaume-Uni



II. Restoring 'equal opportunity' for nuclear energy in Europe via a Contracts for Difference scheme?

At the beginning of 2015, there were 437 nuclear reactors in operation worldwide, for an installed capacity of about 392 GWe IEA, ref 7). Amongst the 31 host countries identified, there were 100 reactors in the United States, 58 in France and 33 in Russia. Within the European Union, there were 131 reactors installed (in 14 of the 28 Member countries), with a total capacity of 122 GWe. Half of the nuclear energy produced in the EU comes from France.

Four new nuclear reactors are currently under construction in the EU: one EPR in

Finland, 1 EPR in France and two VVER-400 (Russian technology) in Slovakia. Worldwide, 72 reactors, with a capacity of about 75 GWe, are under construction, including 29 in China and 10 in Russia. Many reactors have been ordered or programmed (179 according to the International Atomic Energy Agency, including 60 in China, 31 in Russia and 18 in India), and this is true for countries with significant hydrocarbon resources like Saudi Arabia and the United Arab Emirates. According to the New Policies Scenario of the International Energy Agency's World Energy Outlook 2014 (ref 7), the installed nuclear capacity worldwide would increase from 392 GWe in 2013 to 624 GWe in 2040; however, the share of nuclear-generated electricity, which is around 11% today, would hardly exceed 12%. In absolute value, the quantity of nuclear energy produced would thus increase sharply but it would remain modest in relative value because many coal- and gas-fired plants will be constructed around the world. The share of the OECD countries in installed nuclear capacity worldwide should decrease from 80% in 2013 to 52% in 2040, whilst that of the Asian countries would show a significant increase. China alone would represent 44% of the new installed nuclear capacities by 2040. Taken together, India, South Korea and Russia would represent 30% of these new capacities. The new investments to be financed by 2040 worldwide are estimated at $1500 billion. In nearly all of these countries, the financing will take place within a planned economy, where consumer and taxpayer will be paying for the investments together. Electricity prices will be largely subsidised, with no wholesale market. Nuclear energy will thus be financed to a large extent by taxes.

For market-economy countries where there are wholesale electricity markets (in practice, the European Union), nuclear investments are in principle financed through the prices paid by the end consumer, which reflect the wholesale market price because the regulated selling prices are scheduled to disappear. The wholesale market price represents, on average, 40% of the tax-inclusive price paid by a household consumer in France, with the remainder corresponding to the cost of regulated access tariffs (for transmission and distribution) and various taxes and contributions (including the CSPE). But operators who want to invest in a power plant today must take two risks into account: on the one hand, the price level of electricity on the wholesale market and, on the other, the volatility of that price on the same market. Given the uncertainties about wholesale price trends, they are likely to prefer investments with a relatively short payback period, which favours gas- and coal-fired power stations. They can also cover the risks on the financial markets but these are not sufficiently liquid to allow hedging over long time periods. In the case of an investment like nuclear energy, which has a long pay-back period, it is thus necessary to obtain guarantees about the sales price of the electricity which will be produced during forty, fifty or sixty years. In the emerging economies, an approach like the BOT scheme (build, operate, transfer) might be considered: the operator constructs and operates the power plant but makes a contractual agreement with the local government or local public enterprise, which guarantees that the electricity produced will be purchased, over the long term, at a price ensuring the operation's cost effectiveness. In the EU, it would be possible to resort to the FIT mechanism introduced for renewable energies but in view of the criticisms it has raised, other solutions might be envisioned, such as the FIP or the CfD (Contract for Difference). The latter, which was selected in the

UK for the two planned EPR reactors, seems to offer a good compromise between the need to have confidence in the market and the necessity of guaranteeing the profitability of a highly capital-intensive investment.

The ongoing reform of the wholesale electricity market in Europe, in particular with the establishment of a capacity market, should also modify the way of taking the remuneration of fixed costs into account, and this could be a further asset for nuclear energy.

II.1. The case of the UK, or how to reconcile market logic and the guarantee of profitability

It must be indicated at the outset that England's nuclear power stations (the two EPR reactors programmed at the Hinkley Point C site) will not benefit from a subsidised feed-in tariff but from a system close to the CfD. In practice, the EDF-led consortium responsible for constructing and operating the two reactors will not be remunerated off-market, as would be the case with a feed-in tariff applied to renewable energies (wind and photovoltaic). It will sell its electricity at the market price, which means that the price signal remains strong since the investor's primary income will be earned on the wholesale market.

With its recent approval of the agreement between the consortium and the UK Government, the European Commission has confirmed the investment in this vast project will be guaranteed. Once the EPRs come into operation, if the market price for electricity is lower than what is considered to be the project's break-even point (the reference price, which is a kind of virtual guarantee price), the consortium will receive a top-up payment corresponding to the difference between this virtual guarantee price and the market price for a period of 35 years. Conversely, if electricity prices soar and the project payback is greater than the price guaranteeing a given break-even point, the consortium will have to share the profits, this time for a period of 60 years: 70% for the consortium and 30% for UK authorities beyond a break-even point of 11.4%; 40% for the consortium and 60% for UK authorities beyond a break-even point of 13.5%. The reversibility of this agreement is essential. The income supplement will only be granted ex post and in function of a theoretical break-even point for the capital invested. It may be that the future winner will be the UK rather than the consortium. The obvious question is who will finance the income supplement: the UK energy consumers (whether this is nuclear or not) or the taxpayers or a combination of the two? As things stand, it will probably be the taxpayers.

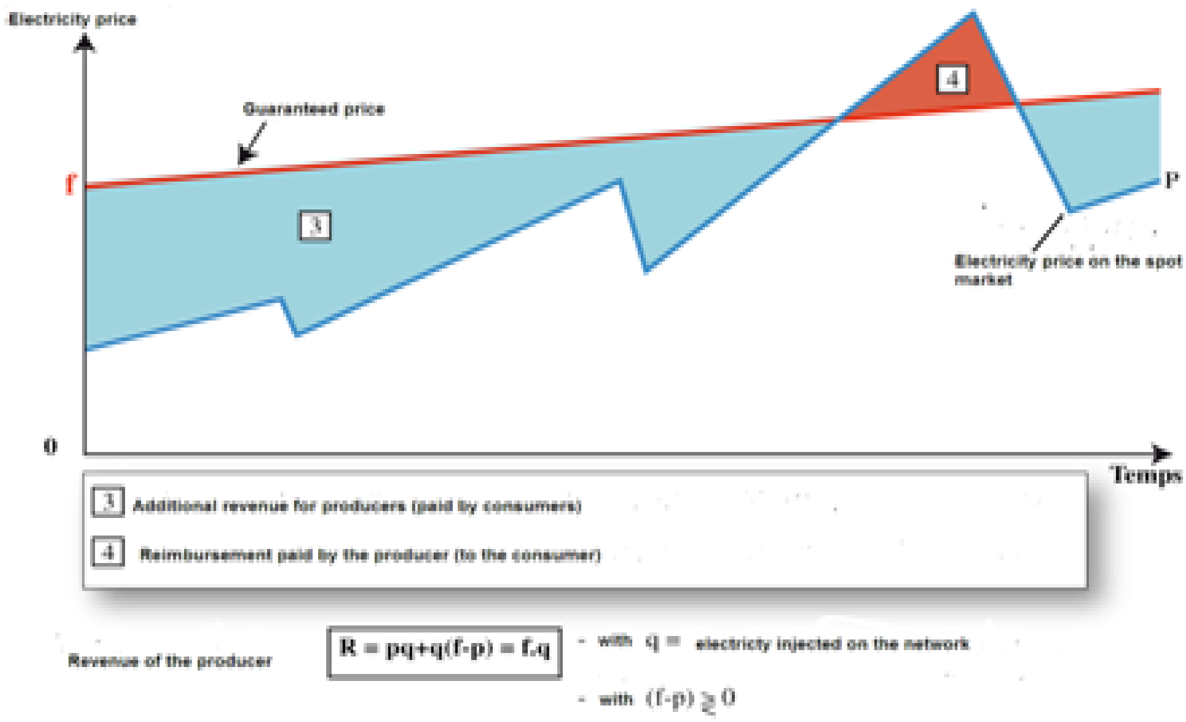
The diagram below depicts the scheme and demonstrates that the system is reversible: if the market price is too high relative to a compensation rate set ex ante, the electricity seller has to pay part of the revenues to UK authorities so as not to exceed the agreed-upon rate of return on capital (the reference price guarantees the targeted break-even point for the capital invested).

The first difference between the CfD and the FIT is that in the case of the former, the operator's primary income comes from the wholesale market price, whilst in the latter, this price is of no concern to the operator. The second difference is that with the CfD, the income supplement is calculated in function of an 'objective' rate of return on capital invested and can be either positive or negative (reversibility principle). With the FIT, the income is based on a regulated price set in absolute value from the outset, irrespective of any concern for profitability (if the tariff is too advantageous, the return on capital can be excessive, leading to a windfall effect).

The difference between the CfD and the FIP (where a premium is paid ex post in function of installed capacity) is that the income received with the CfD is adjusted to keep the guaranteed rate of return on capital constant and that this income should remain relatively stable over time in constant currency, whilst the income received with the FIP is variable because it is obtained by adding together a variable sales price (the wholesale market price of the MWh) and a fixed premium generally calculated per installed MW. As a result, the return on capital invested varies as well.

What message has the European Commission sent in approving the financial package proposed for Hinkley Point C? It has recognised that an investment in nuclear energy cannot be undertaken today without Government support and prospects of long-term profitability. The nuclear industry obeys a logic of 'long time': the new reactors have a lifespan of sixty years and this means that the return on investment is also a long-term process. At a time when nuclear energy is picking up again throughout the world, it is important to give it a new boost in Europe. It is a cutting-edge technology, in particular for fighting against global warming in association with renewable energy sources. Moreover, it has convinced new countries like Saudi Arabia, which is also seeking to invest in the consortium led by EDF in the UK. This will create an encouraging precedent for other investment projects of this scope which are now underway.

On the other hand, this message must not be seen as a form of injustice against renewable energies. The European Commission has never said that assistance to these energy sources should be suspended. Rather, it wants producers to sell this energy at the market price, with a compensatory premium if the market-level tariffs are too low. This system is fairly close to the one introduced in England for nuclear power, albeit with certain differences. It would be based on the FIP scheme, whereby producers sell renewable electricity at the spot price and benefit ex post from a premium per MW installed (or possibly a premium per MWh fed in). The income received is thus variable because it is the sum of a fixed premium and a variable market price.



II.2. The capacity market, an asset for the nuclear industry?

One of the criticisms directed at the wholesale market as it operates today within the European Union is that it pays for energy (MWh injected) and not directly for power (MW). Admittedly, the capital is indirectly remunerated through the price per MWh, when this exceeds only the variable costs, but this is not the case for a facility which is not dispatched into the grid (even if it remained useful as a back-up in case of a possible system failure). And this is inefficient in collective terms. If the wholesale market functioned optimally, fixed costs would be covered by the infra-marginal rent for the baseload plants and by the scarcity rent for the peaking plants, so that the income from MWh sales would suffice to ensure the profitability of the entire power-generation park. But the wholesale market does not function optimally, on the one hand because the injection of electricity purchased off market reduces the infra-marginal rent and, on the other, because the peak price does not always permit the recovery of the fixed costs of the peaking plant (cf. the missing money problem discussed above). This situation does not encourage investment intended to deal with consumption peaks.

With the capacity market which is scheduled to be introduced in France by 2016 under the NOME Act, providers should have the necessary capacities to match their supply to the demand of their customers. This can be achieved either by having a portfolio of customers subject to peak-day load reduction or by investing in peak capacities, if not by storing the electricity (hydroelectric dams, pumped-storage systems). This 'capacity scheme' can be complemented by a capacity market for exchanging capacities (MW) between mandatory participants by means of certificates. Other possible solutions include:

1) The R4 strategic reserve mechanism: the operator of the transmission grid auctions off capacities which can be used in case of possible system failure. The remuneration is set by tender and this R4 reserve, which is added to the R1, R2 and R3 reserves anticipated by each producer, is not available on the market but constitutes a kind of generator of last resort which can only be used by the grid operator.

2) The capacity payment mechanism: the regulator determines a fixed price which remunerates the availability of the installed capacity, thus encouraging producers to invest. This is in fact a feed-in premium system where the premium is set ex ante per installed MW, but which is limited to peak capacity alone.

Remunerating installed capacity independently of its load factor encourages operators to invest in peak capacities. Operators will receive additional payment if they can guarantee that their power stations will be able to generate electricity at a given moment during peak periods. Some countries, like Germany, are hostile to a capacity market which would remunerate capacity independently of energy because they fear new 'gold-plating' for regulated electricity companies, which would be encouraged to over-invest in fossil-fired plants (the Averch-Johnson effect, see ref 6 and 9). It should be pointed out that it is also necessary – and rightly so – to remunerate consumers who accept to reduce their loads during peak periods, which raises problems in terms of measuring this reduction.

In principle, this mechanism has little impact on nuclear facilities because they are baseload plants. The cost price of the nuclear MWh is calculated over an operating period which is much longer than that of a classic thermal power station, in a context where the prices observed on the wholesale market are quite volatile over the short term. The capacity market should help to smooth out consumption peaks and thus price peaks, which would limit the remuneration obtained by the baseload suppliers during peak periods. Investors in the nuclear industry are therefore wary of facing sunk costs if market prices are insufficient to cover an investment which is only profitable over the long term and they prefer capacities with shorter payback periods and lower risks. Since hedging instruments do not provide a cover over the very long term, investors demand institutional guarantees. And the contract for difference scheme is one form of guarantee.

It is conceivable to grant nuclear facilities a premium which would remunerate installed capacity in the event that the price observed on the wholesale electricity market would not permit a return on investment. This would be a kind of FIP scheme but would only be applied below a bottom price for the electricity sold on the spot market and in this case, would amount to guaranteeing a minimum return rate for nuclear energy. The system is thus close to the contracts for difference scheme but unlike the latter, it does not provide for deducting the infra-marginal rent beyond a certain ceiling, in other words, when the wholesale market price becomes very high. There would be a bottom price, but no ceiling price.

It is also conceivable that the amount of the premium paid could be reviewed periodically, through a mechanism known as the 'expenses and revenues clawback account', which is used for network investments (transmission and distribution of the electricity). This means guaranteeing an objective rate of return on the capital invested and deducting the infra-marginal rent when this rate is exceeded, which comes back to the CfD system in the strict sense. The incentive to invest would not be as strong as that of the UK scheme because beyond the objective rate of return (ceiling price), all profits are recovered by public authorities (and/or redistributed to consumers), whilst with the British scheme the profits are shared between the producer and the Government.

*

*   *

The functioning of today's spot electricity market does not send the right signals to investors, not only because it is a short-term market but also because that functioning is distorted by the presence of electricity at a regulated price set off market. There are two possible solutions to this problem: either the market is left on its own to send the signals to all investors (including those in renewable energies), which is likely to give rise to large fluctuations in investment cycles related to the sharp volatility of the spot prices, or a minimum of regulation is introduced in order to limit the costly surges of under- and over-capacity. But in the latter case, it is necessary to treat all the energy sources in an equal way and guarantee the nuclear industry that it will also recover its fixed costs over the long term. In essence, that means that there is a need for an energy policy with a long-term vision of electricity supply and demand, taking into account an industrial vision of nuclear industry, but this does not exclude the fact that the market can also send signals to correct the planner's inevitable errors.

References

(1) Benhmad F. and Percebois J. (2015) “Wind Power feed-in Impact on Electricity Prices in Germany, 2009-2013” in The European Journal of Comparative Economics (in press)

(2) Chari V. And Weber R.J. (1992) “How the US Treasury should auction its Debt?” in Federal Bank of Minneapolis Quarterly Review

(3) Cour des Comptes (2012) “Rapport sur les coûts de la filière électronucléaire”, La Documentation Française, Paris

(4) Cour des Comptes (2014) “Le coût de production de l’électricité nucléaire; actualisation 2014” Communication à la Commission d’enquête de l’Assemblée Nationale, 27 mai

(5) E-Cube Strategy Consultants (2014) “L’impact micro et macroéconomique des energies renouvelables en Région Wallonne”, avril

(6) Hansen J.P. and Percebois J. (2010) “Energie: économie et politique” , de Boeck Ed.

(7) I.E.A. (2014) “World Energy Outlook”, Paris

(8) OECD-NEA (2012) “Nuclear Energy and Renewables; System Effects in Low-

Carbon Electricity”

(9) Percebois J (2013) “The French Electricity Market: Competition, Nuclear, rent and Price Regulation” in F. Sioshansi (Ed) “Evolution of Global Electricity Markets , Elsevier, June

(10) Stoft S. (2002) “Power System Economics: Designing Markets for Electricity” MIT Press