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Investment risk allocation in restructured electricity markets. The need of vertical arrangements

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Summary : None of the far-reaching experiments in electricity industry liberalization proved able to ensure the timely and optimal capacity mix development. The theoretical market model features failures attributable to the specific volatility of prices, the difficulty of creating complete markets for hedging, and we focus on this failure in this paper, the impossibility of transferring the various risks borne by the producer onto suppliers and consumers in order to allow development of capacity. Promotion of short term competition by mandating vertical de-integration tends to distort investments in generation by impeding efficient risk allocation. In the line followed by Joskow (2007), we develop an empirical analysis of the way of securing investments in generation by vertical arrangements between de-integrated generators and large purchasers, suppliers or consumers. Empirical observations of risk analysis show that the adoption of these arrangements may prove necessary. Various types of long-term contracts between generators and suppliers (fixed-quantity fixed-price contract, indexed price contract, tolling contract, financial option) appear to offer effective solutions of risk allocation. Vertical re-integration appears to be another effective way to allocate risk. But it remains an important complementary condition to efficient risk allocation: that retail competition is sticky or legally limited in order to transfer a large part of risks to consumers on the different market segments.

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1. Introduction

During the design of the market electricity reforms, the issue of investment in generating capacity generally received insufficient attention in the reference model for reforms. This model is a vertically and horizontally de-integrated industry facilitating entry and allowing effective competition on each market from wholesales to retail sales. Regulation tends to limit vertical integration and long term contract between producers and suppliers, and between suppliers and consumers and to incite historic producers-suppliers to divest in generation in order to limit the classical incumbents' advantages and to ease entries in view of effective competition.[1] The canonical business model in generation is the merchant plant, a stand alone producer which sells all this production on short term markets and without long term contract at fixed price and develops its new capacities under project financing by non recourse debt.

This insufficient attention was starkly highlighted by the crises on electricity markets that were partly due to inadequate capacity and by the focus of generators' investment decision on gas generation technologies which could create an excessive specialization of the technology mix. Then after these crises, theoretical and practical considerations on generation investment largely focused on incentives to develop peak generating capacity and ensuring a reserve margin to guarantee reliability, i.e. short-term security of supply. An abundant literature develops on this issue, in particular on the different ways of capacity payment (see for instance Oren, 2003, Cramton & Stoft, 2006; De Vries, 2007; Joskow, 2007).

But little attention was paid to the conditions for other investments in base load and semi-base load equipments, because of a strong belief in the quality of the price signal on the hourly markets and the subsequent incentive that infra-marginal rents of low variable cost equipments constitute to invest in the same technology (see for instance hunt and Shuttleworth, 1997 ; Oren, 2003 and 2008). In particular basic principles of risk management applied by competitors end in untimely development and non-optimal technology mix distorted in favour of low capital intensive and high fuel cost technologies as CCGT which can self-hedge. For the government and the regulator their development do not present the same risks for the whole system as inadequacy of total capacity and its impact on system reliability, but their excessive development contribute to increase the volatility of market price and to move away the optimal technology mix.

Problems also arise if insufficient attention is paid to the institutional and organizational conditions conducive to investment in different generation technologies by devising an efficient allocation of investment risks across the stakeholders able to bear them. In particular given the difference in both capital intensiveness and possibility to risk hedging, technology of combined cycle gas turbine (CCGT) appears

[1]In the first post-reform period in the United Kingdom the regulator imposes constraints on vertical integration in generation (no more than 15% in own generation assets within their own area. Europe is not different. In 2005 and 2007, the Directorate General of Competition of European Commission underscores that incumbents' vertical integration generation-supply and the historic suppliers' long-term sales contracts create a risk of foreclosure (European Commission; 2005a, 2007). In some of the liberalised US markets there are regulatory restrictions on long-term purchase contracts to provide an incentive for the suppliers to minimize their purchase cost of wholesale electricity in relation to the changing conditions of the market (Joskow, 2002; 2006). In California in the first reform the regulator had imposed straight divestiture of the generation assets and forbade long term purchase contracts to the three former utilities for a transition period of five years, right up to the crisis which provoked the bankruptcy of two of them.

to be unduly favoured in the competitors' investment choices at the expense of more capital intensive equipments, such as coal thermal and nuclear plants, while the respective expected levelized costs would show a significant advantage in the most probable scenarios of gas price evolution and CO2 cost internalisation policies. Investments in the latter technologies are more risky for the producers and they need to have possibility to allocate part of their investment risks on the suppliers or the consumers by vertical arrangements. But in the de-integrated market model which was, and is still considered as, the reference of electricity reforms, these arrangements which are propitious to investments in various technologies are impeded by regulation or undermined by the specific characteristics of competition on the wholesale and retail markets.

In this de-integrated market model, the consequence will be a non timely development of capacities and a non-optimal orientation of the overall technology mix in the different liberalized electricity markets as new equipments will be added to the fleet of the competitors to follow the demand growth and to replace the old ones at the end of their working life. As shown by R. Green (2006), if the mix of capacity is wrong and characterised by a lack of base-load equipments, marginal price will be unduly high during a large part of the year comparatively to a situation with an optimal mix; and finally it will be at the expense of the social surplus, the loss of the consumers being higher than the supplement of net profit of the producers.

We address here the organizational unsuitability of the de-integrated market model and the necessity to adapt it to long term issues of generation investment allowing not only adequate capacity development, but also optimality of the future technology mix. We shall refer to Transaction Cost Economics (Williamson, 1985, 1995) to explain the suitability of combinations of vertical arrangements to allow better investments decisions by competitors and we introduce financial considerations as central determinants for the needs of vertical arrangements, because of the complexity to manage risks in electricity markets.

In the second section, we analyse the theoretical and practical hurdles to investment that arise in the de-integrated market model, and we show that inadequate investment risk allocation can create barriers to entry in generation activity and more generally to investments. The third section identifies the conditions allowing vertical or quasi-vertical arrangements to be set for workable allocations of investment risks, in particular the way that investors could meet credible counterparts. Fourth section integrates the need of vertical arrangements in the issue of vertical re-integration in liberalized market.

Finally in the annex we bring some empirical observations on institutional and organisational conditions of generation investments in experience of different electricity markets since liberalization. We show all the successful generation investments have been the case of vertically integrated producers, or of long term contracts with consumers (suppliers, industrial customers), and that pure producers (the so-called merchant plants) without securing vertical arrangements are the exception, not the norm. These empirical observations are first motives to question the premises of the suitability of the decentralized electricity market model for reaching optimal technology mix and capacity adequacy.

2. Risk allocation as barrier to investment in generation in the decentralised market model

It is worthwhile to remind the simplicity of risk allocation in the former model of vertical monopolist utility and cost of service regulation. In this model utilities taking the decisions to invest in generation were comfortably insulated from the risk associated with those decisions. Given the cost-of-service regulation, their costs and risks of investment were carried on the consumers. So they built plants with debt financing at the bond-market rate and without risk premium. The rationales to change this cost-of-service regulation are well-known. Criticisms addressed to this regulation have begun with Averch &Johnson (1962). They show that this system encouraged the use of the most capital intensive technologies, and with this structure, the accent was placed on the increase in the capacity and not on the search for productivity. To counterbalance these limits, the industrial organization must be de-integrated as well as vertically and horizontally, to allow for effective competition by facilitating new entry in generation with capacity investment and in the retail activities.

In this reference business model for generation the merchant plant, in which an independent generator owns a portfolio of assorted production technologies and sells its electricity on short term market. It does not own a supply business and a portfolio of customers, or at the most only very partly. To identify failures which limit investment in electricity markets, we first consider the underlying four premises on generation investment by the de-integrated market players in the reference market model of a liberalized electricity industry. In the second sub-section, we will determine if the premises are sound approximations of the risk management problem of investors in electricity industry. Then, third sub-section will synthesize the obstacles in term of risk management applied to long term contracting in the generation of electricity.

2.1. The four beliefs of investment decisions and risk allocation in the reference model

In the line of the new paradigm of investment risk allocation in the liberalised electricity market proposed by Chao, Oren and Wilson (2008)[1], we stress four beliefs concerning the efficiency of risk management along the chain of business activities :

1. The former vertical integration of utilities regulated in cost of service can be replaced by bilateral contracts between generators and retail suppliers and large customers, assisted by organised markets for spot trading. Investment decision and technological choices will take place based on electricity price signal without regulation interferences.

[1] These authors develop in this paper a relevant and realistic revision of their hypothesis, given that they were the academics who promote the most de-integrated design of power markets in a very rigorous and formalized way in numerous papers (see for instance Chao and Huntington, 1998; Wilson, 2002).
We add the fourth belief on the role of intermediary of the suppliers in risk management by substituting it to the supposed willingness of the consumers to manage their own risks in their purchase of electricity that Chao, Oren and Wilson (2008) consider, in particular in relation to the reliability of supply, that arbitrarily we put in a secundary position in order to focus on the problem of the technology mix of the system and the preference for fuel diversity.

2. Generators could obtain capital on comparable terms directly from financial markets without relying on arrangements with suppliers which could transfer risks to their customers; such as formerly regulated utilities could do with its assured cost recovery. Innovative structure finance would offer new ways to finance new generation equipments in “project finance”, i.e. without non-recourse debt and very high leverage of 80% of debt and only 20% of equity.

3. A rapid and adequate development of markets for financial instruments will offer all the means for hedging risks of generators, suppliers and consumers, besides physical contracting. Various alternatives for managing market risk for producers by specific long-term financial contracts—long term options, contracts for differences, swaps—all play a role in securing investments in generation (Chao and Huntington, 1998). Moreover long term future markets would have an important informational function on the market fundamentals and the revenue advantage to invest in generation in the future. This hypothesis of complete market would give substance to Arrow-Debreu theoretical model of decision-making under risk in electricity markets for short-term and long term decision coordination and efficient choices (Arrow et Hahn, 1971). Institutional counterparts of the full set of markets of the Arrow-Debreu model would be organised future markets, but also claims on the profit of the companies (i.e. shares in those companies). These go a way towards hedging instruments to share and hence reduce the costs of risks.

4. Consumers which in current terms, cover suppliers and large consumers, compete to buy electricity by bilateral forward contracts to different generators among which entrants and on the power exchanges by managing their risks by portfolio strategy. Downstream, suppliers have to manage a portfolio of different types of contracts with specific time-spans and price formulas adapted to the different segment of clienteles, with volume risks inherent to their customers’ switching. They are supposed to harmonise risk management between their portfolio of sourcing and their portfolio of sales contracts.

The suppliers and large consumers which are well informed and wish to hedge such risks are supposed to express their preference for technology mix and fuel diversity. When realised at the level of the overall market, it helps to limit the price volatility and offer possibility that capital intensive and low fuel cost equipments make the price on the hourly markets during some long annual period (Roques et al., 2005). When individually realised by consumers, they will hedge either by long term fixed price contracts with specialised producers by low fuel cost equipment or by physical and financial contracts with gas producers.

Going further in the Arrow-Debreu model direction as Roques et al. (2005) suggest, another hedge would be for consumers to hold shares in different specialised generating companies, in particular nuclear generation company which would earn extra profit during period of higher price, these extra-profit from the shares offsetting the higher costs of electricity purchase, or coal generation companies (if nuclear companies development is restricted by political constraints).

In this new paradigm, the revenues of any particular plant, the new as the existing ones, will be determined each hour by the market price determined by the balance between demand and capacity, the marginal cost of the last generating equipment and eventually by the market power of competitors, the effects of such factors on prices being supposed to be foreseeable in average.

Investment cost recovery for new plant will be allowed by generation gross margin (i.e. the difference between power prices and fuel costs) during each hourly market along the year, when the equipment is not among the marginal plants and hourly price is not aligned on its variable cost.[1] So a competitive market would give the right signal for investments when capacity development must respond to demand growth and old plants obsolescence and it would allow the fixed costs to be recovered.

2.2. Pitfalls and limits

First Belief. The first belief is that market signals were deemed effective for guiding investors and producers' choices to an optimal technology mix with regard to the seasonal loads. The market ensures inter-temporal optimality thanks to hedging instruments. The interplay of complete and well-informed markets would lead to optimal investment choices, like those of a regulated monopoly, while also yielding the benefit of incentives to long term efficiency by market pressures, in particular in timely capacity developments (Hunt, 2002). But generators and investors are confronted not only to a problem of cost minimization, but to a problem of combining return maximising and risks minimizing when choosing an equipment in a stock of technologies to invest (Gas Turbine, CCGT, Coal, Nuclear or Wind Farms). For simplification purpose in the comparison given by table 1, we put aside here some specific risks under the control of the regulators and the policy makers[2]. We concentrate on a limited set of economic risks: the risks on cost under the control of the company (construction cost, operation performance), and the risks that the investor must know how to manage t before deciding to invest and ask loans to lenders, namely the fuel price risk, the electricity price risk and the volume risk related to the wholesale competition and the demand variability.

Table 1. Characteristics of cost and risks of different electricity generation technologies

Technology	Capital size per unit	Lead time	Capital cost share	ɛegulatory ɨsk on onstruction ost	Fuel cost share	CO2 cost	Fuel price risk	Market price risk
Gas turbine (100 MW)	Very low (€20 million)	Very short	Low	Low	Very high	Medium	High	High (Volatily in peak)
CCGT (400-600MW)	Low (€100-200 millions)	Short	Low	Low	High	Mediun	High	Low (correlate to fuel price)
Coal (2x 700MW)	Large (€700-1000 millions)	Long	High	High	Medium	High	Medium	Medium
Nuclear (1500MW)	Very large (€2-3 billions)	Long	Very high	High	Low	Nil	Low	High if trend of low gas price)
Renewables (Wind farm 200MW)	Medium (€300 millions)	Medium	Very high	Medium	Nil	Nil	Nil	High

Source. Adapted from IEA, *Comparison of electricity generation costs*, 2005

[1] It is common to name infra-marginal rent the gross price-cost margin.
[2] These risks concern changes of market rules, environmental regulation, uncertainty on equipment sitting with possible important implications for investment costs, revenues and financing conditions....

The conclusions we stress from Table 1 are the following :

- Gas generation (gas turbine & CCGT) has relatively low cost of capital which reduces financial exposure, and generation tends to be quite flexible to follow the load on the market. Moreover when gas price increases, CCGT tends to become the marginal equipment on the hourly market, and "makes" the electricity marginal price during a part of the year. This has two opposite effects: a good correlation between gas price and electricity price during part of the year, but conversely if investment has been decided for supplying base-load, a risk of bankruptcy when the equipment is much less called when gas price increases sharply because of higher price bid offer, what is called the dispatchability risk;

- On the opposite coal plants are very capital intensive but the fuel cost is relatively low and coal price a low volatility. They are therefore more exposed to the financial risks of whether they can repay the capital based on the volume and price of electricity off taken from the project.

- So it is for mostly up-front capital investment in nuclear or renewable. With high operating leveraging, i.e. high net cash flows, small changes in revenues have large effects on profitability. So they have greater needs of risk management than the costs of CCGT with a low ratio of investment and capital costs.

To sum up, investments in the highly capital-intensive equipments (coal generation, nuclear plants, hydraulic plants, renewable) are hampered and distorted by excessive volatility, whereas they do not benefit from correlation between fuel input cost and electricity price, as do the CCGT plants.

Second belief. Consistently with this belief, lenders have adopted this method of project financing of merchant plants, but without securing vertical arrangements. The lender's collateral resides in the projected cash flow of the project and the resale value of the production asset. Originally, because of the confidence in the market mechanisms, the lenders who demand de-integrated structures and the greatest transparency for the market rules are so confident about the functioning of the new electricity markets that they do not require collateral in the form of long-term contracts guaranteeing the project's revenues. Merchant plants were supposed to have revenues by spot sales (on energy and operating reserves markets) or short term contracts. Loans are granted to a firm specifically created on the basis of its expected cash flow without being secured by a PPA at fixed price, or by risk management by a diversified assets portfolio.[1] The investor will take his decision to finance a project after exploring returns that different technologies may deliver under a number of different assumptions on fuel prices, influence of fuel price on electricity prices (and their spread), demand patterns and capital costs.

[1] It is noteworthy to quote the analysis of "Modern Finance" on corporate financing of companies which borrow from creditors to invest for complementing their generation mix. For Kane and Etsy (2004) the direct consequence of this financial arrangement is that there is a mutual exchange of options between the new investment creditors and the old creditors. Implicitly, new creditors purchase an option on cash flows from the company's other assets because managers are more likely to subsidise the new investment from other corporate assets than to risk bankruptcy of the company as a whole by defaulting on financing for the new investment. Simultaneously, however, company creditors acquire an option on the new asset as the company's managers might subsidise the company's existing liabilities with cash flows from the new investment.

But as it finances the project by raising as much as debt finance as possible via non recourse debt and project financing, this imposes the self- financial sustainability of the project by its net cash flow without backing on eventual cross subsidy from the producer's other generation assets in period of low energy price. This means that the profitability of each project will be critically dependent of the net revenues during the price spikes of the market after the commissioning of the equipment.

Third belief. The belief that a rapid and adequate development of markets for forward contracts and financial instruments will offer all the means for hedging risks of new generators, suppliers and consumers has been demolished by experience of the first decade of market reforms. The price volatility would normally be manageable by electricity producers, wholesale buyers and consumers if they could develop the contractual arrangements necessary to efficiently allocate the risks across generators, intermediaries, and consumers. The use of derivatives to manage electricity price risk is difficult, because the simple pricing model used to value derivatives in other energy industries does not work in the electricity sector (DOE, 2002, Geman, 2005, Defeuilley et Meunier, 2006).

The non-storability of electricity and the non-elasticity of real time supply and demand do not allow the future or the forward price to represent a correct anticipation of its price realisation. Price spikes are particularly difficult to anticipate in magnitude and duration. Moreover whereas in other commodities, intra-periodic variations can be considered as second order variations around a trend, intra-day variations on electricity markets can be superior to intra-week variations, as intra-week variations can be superior to intra-month and intra-annual variations. These characters dissuade banks and hedge funds from playing the role of counterparty on such markets for futures and OTC—though they commonly speculate on other commodity markets and create liquidity. This situation complicates investment decisions because investors do not attribute informational quality to spot price and forward price, in the sense that they hardly reflect the situation of fundamentals.

It is noteworthy that the problem for investment decision in generation units does not lie solely on the fact that long term derivatives cannot develop in such a context of risk profile. In any capital intensive industry promoters of large projects with long time horizons never meet counterparties to cover all risks with an option contract that enters into effect when the equipment is started up and covers its pay-back period[1]. In any industry long term derivatives do not fully capture investments in production. The problem is informational. To conclude on this third premise, the very specific price-risk profile combined with the complexity of the existing spot markets, deters development of a liquid market for derivatives and financial contracts that would facilitate management of risks.

In the logic of this third premise of financial optimism, the producers would have no interest to secure generation investment by long term forward contracts with suppliers or large consumers because they lose opportunities to make temporal high profits, as stress in an IEA report on generation investment (IEA, 2007) :

[1] In the oil industry an off-shore production project takes anywhere from 4-10 years from discovery to first production, and then produces for years or decades, while the futures market only trades out 6 years. It does not allow hedging the first year's production, until the project is well under way. Longer term over-the-counter could help such projects, but historically the bid/ask spreads - the difference between what the seller wants and what the buyer is willing to pay - on such thinly traded markets are prohibitive).

> *"The investment risks are expected to be borne by the power companies, based on their expectations of future prices. They face the risk of losing money if they make the wrong decisions, but it balanced by the incentive of making greater rate of returns if their decisions are the good ones. Hedging risks through long term contracts could be seen as handing over these opportunities for greater to other parties who arguably are not in such a good position to make the decisions as the power companies themselves. Although the absence of long term contracts may lead to increased uncertainty, it may not be appropriate to consider this as introducing unstable investment decisions. The rewards will balance the higher risks. Potential investors must be able to form rational expectations of future prices that are not subject to manipulation by incumbent power companies".*

Another aspect of the third belief is that, in the business model of merchant plant with no PPAs, risk is managed individually for each unit without portfolio approach, given the logic of project financing. This approach supposes that each production unit manages its risks more efficiently in an idependent way than in interdependency with other productiosn units. It restricts them to hedge their investments by diversifying their risks between different technologies on the same market, whereas portfolio approach for merchant plants give significant benefits to the producers, as it has been shown by Roques et al. (2006)[1]. Moreover, with a diversified portfolio, new producers as companies benefiting from existing equipments can rely on "portfolio bidding" on the market, as it is usual that incumbent producers do in their markets. That means that they have the opportunity to subsidize new equipments by the cash flow of existing equipments by following the market price downturn and making bids for all of their production by different technologies at price under the cost price of the new equipments.

Finally in liberalised electricity markets, experience reveals that the business model of the merchant plant underwritten with project finance clearly fails, even when the CCGTs which allow the best risk management in a sort of self-hedging, are developed, as shows the bankruptcies of all the CCGT merchant plants in the US liberalised market and in the UK (Joskow, 2004; Michaels, 2006). Since them, investors and producers are now convinced that pure merchant plant is not a viable business model.

Fourth belief. But the last belief on the viablity of large consumers' and retailers' risk management has also limitations which hamper the possiblity to long term contracting by the new producers and beyond the possiblity to break the deadlock. Indeed investors and producers are now convinced that for making merchant plants viable, vertical arrangements yielding a risk allocation adequate for establishing the required financial arrangements are needed. But they fail on difficulty for establishing long term contracts with creditworthy buyers, given retailers' risk aversion to commit on long term. That is analysed further in the TCE perspective as passive opportunism, in the sense that wholesale buyers do not want to reveal their need of hedging by long term contracting with specialised generators at fixed price on long term in order to avoid opportunity costs of these contracts when market price downturns below contractual price.

[1]This theory indeed helps to find the best risk-return portfolio of power plants assets for a de-integrated producer (Roques, Newbery et Nuttal, 2006). If there are two or more possible projects in which it can invest, the investor will get a better rate of return for a given risk or a lower risk for a given rate of return if it holds a combination of these projects than if it holds any one on their own. Portfolio approach increases the costs of fossil-fuel generation over the standard estimate, and makes nuclear and renewables more competitive, though they currently appear more expensive.

In the more concrete terms of risk management, there is non manageability of the retailers's risks by developing a portfolio of long term contracts with new generators, or beyond this way, by taking shares or buying bonds of different specialised generators, as it could be on ideal electricity markets and financial markets (Roques et al. 2006).

Given these difficulties a generator could not rely on long term contracting for hedging its new generation investment in the de-integrated market model, what could be considered as a market barrier because of the impossibility to secure long term revenues for new generation equipments in the pure market model.[1] Even though the price-risk would be considerable, that does not, in and of itself, signify market failure. There is no theoretical reason why risks on the market price, should impede investments in generation. The problem results from the fact that the risk is not manageable for the investor for equipments other than CCGTs, because it could not be adequately allocated with buyers in comparison of the former situation with all the risk transferred to consumers through cost-of-service regulation.

With CCGTs, as mentioned, investors could benefit from the link between marginal cost and electricity price, as these equipments set the electricity price, that allows to shift much of the fuel and carbon price risk on the consumers. For the other equipments, this inflates risk management costs and, by raising the cost of capital with high risk premium (2.5 to 3% for nuclear project for instance), increase the anticipated trigger price the market must reach before deciding an investment in capital intensive equipments. But such projects should be better developed if an allocation of risks onto the consumers could be achieved in a way or another in the de-integrated market model.

3. Transaction cost minimization : workable combinaisons of investment and long term contracting

In this section we adopt the transaction cost economics perspective to explain the selection of institutional arrangements between new generators and wholesale buyers. In a first stage we point attributes of electricity transactions which incite new generators to search vertical arrangements. Then we come back on the basic dilemma for new generators and wholesale buyers which is optimizing their respective net revenue by combining their respective risks. Then we show how consumers' opportunistic behaviours restrict investment in generation. In the last sub-section, we show under which conditions different long term contracting options could be developed for mitigating the incentive of opportunistic behaviour by the use of safeguards.

3.1. Attributes of transaction on electricity markets

We refer to the Transaction Cost Economics, the body of the economic theory which explains the prevalence of vertical integration and hybrid arrangements on market transactions for allowing the development of specialised investments in context of uncertainty (Williamson, 1975, 1985 and 1996).

[1] We follow De Vries, L., Hakvoort, R. (2003) in this direction.

A major aspect of the uncertainty, endogenous to the transaction, is the opportunism of the parties, i.e. the capacity of one party to take advantage of the other party which is the more engaged in the transaction.[1] Referring to difficulties and risks of contracting, TCE explains the choice between different institutional arrangements, spot sales, incomplete contracts, and vertical integration in relation to the necessity to protect investments specific to transactions. It considers several attributes of the transactions as the determinants of this choice: equipment specificity to the transaction, i.e. a mix of large sunk cost, long live and non-redeployability of the equipment (i.e. the impossibility to be moved or used for another production) which is the most important determinant, but also as other determining attributes: measurability, externality, complexity, frequency and uncertainty in the environment of the transaction.

In the former electricity industries with no technological possibility to relate producer and off-taker in real time, the production assets were geographically specific to the area monopolies and time-specific in the sense that their instantaneous productions must be tightly coordinated in time with the system operation. Given their retail and transmission franchises and their technical authority in last resort on the generators, the local utilities would have been the monopsony power to exert their opportunism, both by imposing a purchase price and by giving priority to its equipments in real time technical dispatch in absence of utility regulation. But, provided that cost-of-service regulation could help these buyers to assume all the costs and risks because they could pass through their costs and transfer their risks on the consumers, wholesale contracts could be incomplete but include provisions to recover all the producers costs by covering the maximum of unlikely contingencies, in particular the fuel cost upheaval, system bottlenecks, etc. This helps the buyer to avoid opportunism and to help the seller to recover all their sunk costs in case of negative contingencies. This regulation allows long term contracts to coexist with vertical integration between generation, transmission and supply activities, for allowing the development of new generation equipment with low risks for the generators and low capital costs.

When numeric technology went and allowed bilateral transactions of any producer and consumer after third party access liberalisation, competition could be introduced at the different stages of the markets. New producers can sell their production on anonymous spot markets or bilaterally to any retailer or consumer. Geographical asset specificity to sell to the area monopoly disappears. Time-specificity is dispelled and externalities of the physical transactions are managed by the system operators (SO) which legally receive the technical authority for managing externalities by using market mechanisms for receiving offers of ancillary services and real time balancing (Glachant, 2004). Suppliers help the system balancing by being incited to physically balance their sourcing flows and their sales, the licence of load servicing entities (or of “balancing responsibility”) including provision for payment to the SO

The transactional problems of entrants in generation will depend upon the technology they use and in particular the importance of fixed costs, the equipment scale, the correlation between fuel cost and electricity price, its flexibility to follow the load of their purchasers and to be able to propose market-priced services to the system operator.

[1] ***Opportunism*** is Williamson’s concept of “self-interest seeking with guile.” In a world of opportunism individuals cannot be assumed to keep their promises, to fulfill their obligations, and to respect the interests of their trading partners unless ”safeguards” are in place. The task of economic organization, in Williamson’s terms, is to “organize transactions so as to economize on bounded rationality while simultaneously safeguarding them against the hazards of opportunism.”

Those which have the more capital intensive equipments, the less “self-hedged” by gas and electricity prices correlation and the less flexible (as nuclear plants and to a lesser extent coal plants) are obliged to develop a large range of transactions to sell their production and hedge their different risks, by comparison with the CCGT producers which benefit from the advantage of self-hedging. Complexity and frequency of transactions incite production players to search for other institutional arrangements than spot or short term sales for developing capacities in some technologies. The character of the uncertainty on electricity markets, rooted in its limited stochasticity, adds to this incentive for equipments presenting no advantage of correlation of its production costs with electricity price. As said, the non-storability of electricity results in an exceptional variability of market price and a slackened consistency of the price-making with the separation of hourly markets, making all hedging activities difficult.

3.2. The generators’ and consumers’ basic dilemma of optimizing revenues and sharing investment risks

In their seminal work of 1984 on the comparison of different models of reforms of electricity industries, Joskow and Schmalensee (1984) have been asserting that operators confronted with the uncertainty of outlets and short-term prices on wholesale markets, will look spontaneously for institutional arrangements that allow them to invest without risking the active or passive opportunism of purchasers. But they referred to the experience of the independent production contracts signed between entrants and utilities with a monopoly of supply, which at the time were developing in the USA. We have to generalise this assertion to a vertical de-integration situation where suppliers are confronted to competition in the retail and to market price cycle.

Producers could use fixed price long term contract to secure a generation investment, as we shall argue later. But counterparts which are less engaged in the transaction than the producer who has invested would be always incited to renegotiate or to break the contracts as soon as the market turns down.

At a first glance, interests of generators and large wholesale buyers are converging, as Chao, Oren and Wilson (2008) sum up. Indeed the fundament of this is that interests of producers and suppliers who have to look for hedging their risks appear to converge for signing long-term fixed-price fixed quantity contracts. Ideally such a contract protects the producer against sustained low prices while consents to get lower revenues during a period of high price to the benefits of the purchaser. And symmetrically the contract protects the supplier against sustained high prices while foregoing higher revenues to the producer during the periods of lower prices.

Moreover with a long contracting, the generator can use the contract as security to obtain loans to finance construction. And it could also use it as guarantee to negotiate a long term fuel supply contract in good conditions of risk allocation. But such hedging solutions are not so simple because there are inherent obstacles to long term arrangements with reluctance of large consumers and intermediaries (suppliers) - virtually the only credible counterparties for a generator in a long-term project - to enter into long-term contracts, because of diverging interests and incentives of opportunism.

As suggests by the Transaction Cost Economics, an important condition for the credibility of the suppliers' long term commitment and the subsequent confidence of a future investor to sign up a long term contract and then install its new equipment is the existence of guarantee which limits opportunistic behaviour of the counterpart[1]. A basic option for securing against this opportunistic behaviour is to include safeguards in the long term contract structure like hostages or common assets. The roots of opportunistic behaviour for buyers can be estimated by the difference between the exit costs from the long term contract and the possible gain given by an alternative option for energy sourcing on the spot market. So, following a number of authors (Michaels, 2006; Joskow, 2006; Chao, Oren and Wilson, 2008 for instance), in the electricity sector, if the possibility to shift their risks to their customers does not exist in one way or other, wholesale buyers are tempted to exit and break the long term contract.

The solution will lie either in an existing base of sticky consumers attached to historic suppliers, or a remaining franchise for the supply of households on them (Green, 2004; Newbery, 2001) or else the Joskow's solution which underlines the importance of last resort supplier provision to maintain a large segment of sticky consumers (Joskow, 2006). Indeed, in the US systems that are completely opened to competition in retail, the historic operators as suppliers of last resort can assume a large part of the investment since their diversified portfolio of retail clients contains a large base of sticky customers who are reasonably loyal to them, given this provision of last resort supplier. Under this provision, consumers who have opted out can come back to the historical supplier and benefit from the public price which remains under the supervisory of the local regulator. So when the retail market price increased in 2004-2005, a mass of customers came back to their utility (Chao et al., 2008).

This provides them with the stable market share they require to render long-term purchase fixed-price contracts attractive for them. It creates de facto a protective niche where the consumers benefit from public prices monitored by the regulators and disconnected more or less from the volatility of market prices. It makes them able to pass the price differential of their purchase contract over the wholesale market in their retail prices. In the European markets last resort supplier provisions exist but does not give to the consumers the same opportunity to switch back to the historic company (This provision mainly gives a protection in case of failures of the customers' supplier). That means that, if there is a risk of high market price on the retail market, consumers will not have the opportunity to come back[2]. So historic suppliers will keep a large fringe of inactive consumers to which they could transfer part of their sourcing risks, because these consumers have no interest to switch.

In fact suppliers as large consumers are reluctant to contract on long term with generators which could produce with stable costs and offer them stable prices by installing new equipment.

[1] In Transaction Cost Economics, opportunistic behavior is a key issue. Williamson (1985) considers that sometimes firms can behave cooperatively, but because it is not each time the case, safeguards are needed in the long term relations, given this uncertainty.

[2] The observation of the active retail markets in Europe allows identifying segmentation between a large majority of inactive consumers, few variations in the annual rhythm of switching from the historical suppliers, and a consolidation of the segmentation between active and inactive consumers (Wilson and Waddam-Price, 2007). In particular because the segment of active consumers will be more and more fluid under the learning effect, this market will be more and more complex to understand by the inactive consumers and more and more opposite to their decisional routines (Defeuilley, 2007).

Observing the markets reveals that the duration of bilateral physical contracts or financial options contracts, between generators and wholesale buyers (including large industrial consumers) is, at most, two years, generally one year and less. They are too short to accompany the development of specific new capacities. Producers rarely find counterparts for longer sales contracts. In addition, in the real markets, the vast majority of these medium-term bilateral contracts do nothing to hedge against price risk, since prices are simply harmonized with, and indexed to the hourly price on the power exchange, simplifying negotiations and curbing transaction costs.

A first interpretation would be consumers' passive opportunism because they avoid to show their need of hedging to these generators, or else their need of stable price disconnected for instance from the increasing influence of CO2 internalisation on the market price. In other words such wholesale purchasers which are well informed and wish to hedge such risks do not express their preference for technology mix and fuel diversity by contracting directly with entrants or specialised generators.

In fact, in the case of the suppliers the reason for which they do not wish to be bound by PPAs with fixed prices on a long time-span is elsewhere. The supplier is generally locked by his portfolio of mid-term sales contracts with flat prices without few possibilities to adjust the price upward shortly after wholesale price increases[1]. Their problem of price risk management is increased by the fact that, generally, regulators define favourable rules to consumers to switch in order to help retail competition. The latter have the legal opportunity to leave their contractors for switching to another one with a delay of few weeks. Moreover, in some markets such as the US liberalised ones, the consumers benefit from the provision of provider in last resort which allows them to switch back in any case to the historic supplier if the retail prices are changing. So in case of price downward, not only they have to follow the move of the price when contracts are renegotiated, but they are exposed to the risk of important switching before the end of running contracts.

In this context three reasons deter suppliers to commit to fixed-price and fixed-quantity contracts so as to fixed price non-firm contracts, with producers or entrants on a long period :

1. First the suppliers which are buyers on the wholesale contract and spot markets are also sellers on the retail market. This position of intermediaries which makes them exposed to a risk of price squeeze constitute a clear incentive to opportunistic behaviour in case of market downturn. They are generally constrained by two facts. First the majority of their sale contracts are at flat price. Second they do not possess a stable base of sales contracts allowing them to assume the risk of signing such long term contracts with new generators. They are vulnerable to a high risk of losing customers by switching if they do not follow wholesale price developments. With their long term fixed-price procurement contracts when there is a significant downturn in the wholesale market, any of the suppliers having signed fixed price contracts with generators that provide for price guarantees will be tempted to break these purchase agreements, because they

[1] There are three main types of retail contracts offered to small commercial consumers and households (Littlechild, 2002) : first the fixed-price contract for one to two years : second the standard variable contract where the supplier may adjust the contract price either at regular intervals, or when changes in supply costs occurs; and finally the market-based contract where the price directly reflects the spot price plus a margin (as it is used mainly in Norway).

are simultaneously subjected to substantial risks in their client base [1]. Medium and large customers are always on the lookout for a lower price and, in the event of a drop in wholesale prices, they will switch to new entrants which will capitalize on the new price if their original supplier does not pass the wholesale price decrease in their sale price. If they are locked to the long term contracts by incentives of high penalties, the risk of bankruptcy is high.[2]

2. Second the fixed quantity clause, which contributes to protect the investment in generation capacity, exerts restrictions on the need of flexibility of the suppliers which could not have only such contracts in their portfolio of sourcing. Indeed they prefer flexibility to meet their changing loads and to seek market shares in overall demand growth increment.

3. Conversely the non-firm contract places plant availability risk on the buyer, whereas the firm contract price reflects the cost to the merchant generator of bearing the plant availability risk.

So the benefits are not exactly symmetrical between producers and suppliers because the stakes for each party are not the same. Indeed by installing new equipment the producer irreversibly commit for a period of several decades while the supplier's advantage taken from the contract are confined to the duration of spike price periods. In the TCE perspective, it appears that if the buyer behaves in an opportunistic way and breaks the contract, there will be always a cost for the producers to search new purchasers and few chances to contract in equivalent terms on the price and the time-span. It is noteworthy that the incentive to opportunism is the same for large consumers which are committed in long term contracts. This risk of wholesale buyers' opportunism is the most constraining limitation, as it deters producers from signing long-term contracts with them, as emphasized by De Vries and Neuhoff (2004). Or even if long-term fixed-price contracts were signed, they would not provide credible guarantees for the producer investing in generating capacity. Before committing to an investment they must anticipate the possibility of losing revenues if any of the long-term contracts they may sign are challenged, or one of their major clients declares bankruptcy. Thus, they will be reluctant to engage in, and invest on the basis of, any long-term contracts on significant volumes.

3.3. Long-term contracting and safguards to mitigate opportunistic behaviours

Consequently we will consider the innovative ways to build long term contracts, with first the issue of long term relations between producers and large consumers and second the way to stabilize long term contracting between producers and suppliers.

[1] Simulating situations in which retail companies with existing long term contracts would incur losses, Green (2003) estimates the effects of such situation on the wholesale markets by combining models of electricity retail competition and of wholesale competition. Given market long term markets and enough volatility, he shows that retail competition might raise wholesale price up to around 20%.

[2] The example of TXU-Europe bankruptcy in 2002 made professionals discover the risk attached to the pure supplier model and the necessity to hedge the supply business by more flexible contracts with indexed price and physical assets. (Cf. *Power in Europe,* December 2004). TXU-Europe which had 17.8% of the British market share sold 3.8 GW on its capacity of 6.5 GW that it owned yet in 2000 and which allowed him to hedge 80% of its sales. This reduces its physical hedging to 20% of its sales. When the wholesale price downturns in the British market in 2002 with the change of market rules to NETA, TXU-Europe was locked by long term contracts negotiated at quite high prices during the former periods.

Innovative contracting allows different modes of risk allocations which could decide suppliers to commit. Indexed price contracting, tolling contracts, and option contracts, all these intermediate forms of contracting require at least one and usually both of the parties to bear risks of one kind or another.

1. Indexed-price contracts generally index the price of electricity to the cost of another commodity, in particular the cost of the fuel used to generate the electricity. Indexing the contract price of electricity to the price of the fuel stabilizes net cash flow for fossil fuel generation plants. With such an indexation in a CCGT project, the fuel price risk is allocated to the buyer because the buyer receives a variable-priced product [1].

2. The so-called tolling agreements whereby the power purchaser delivers fuel to the generator and takes delivery of the resulting kWh more clearly allocates the risk of fuel price variability to the buyer. This one in fact leases the generation plant for converting natural gas to electricity. The seller is paid not only for the use of its facility, but also for simply being available to generate[2]. It is noteworthy that these types of indexed-price contracts do not fit with the risk profile of investment in capital intensive equipment with a low share of fuel cost or not all as nuclear, hydro or renewables plants. In their case a constant-price and fixed-quantity contract stabilizes the cash flow whatever fluctuations in the spot price.

3. Financial option contracts were a sort of insurance contract against volatile price. They are more favourable to the buyers'interest. Option contract enables them to hedge against high price risk without exposure to the quantity risk that it would have in the first types of contract if the contracted quantity exceeds the amount required to serve its market. In this category contracts for difference with symmetrical options "call" and "put" reflect the mutual incentive of producers and buyers for price insurance[3]. It is noteworthy that such contracts have been made possible by the fact that they benefited from this remaining franchise on which regulated tariffs could pass through the price cost of their contractual purchases to their captive customers.

We now distinguish between the long term contractual arrangements with large consumers and with suppliers.

Long-term contracting with large consumers. Three options are of interest in this issue : first the capacity development in joint venture. Second, the horizontal arrangements between associations of large consumers and producers. Last, the Virtual Power Plant solution. Large industrial consumers are among the potential counterparties for generators seeking to invest. Rather than develop their own equipment to hedge purchases in the face of erratic short-term price fluctuations, large consumers can seek to obtain more stable terms and avoid movements in wholesale prices with long-term supply contracts. If energy costs are an important share of their

[1] A variant is the "spark-spread contract" which enables the producer to hedge differences between fuel and power prices.

[2] The experience in California of the long term contracts which substitute to the power exchange after its crash in 2001 is illustrative of the diffusion of this innovative contracting. In their study of the long term contracts signed by the California Department of Water Resources (DWR) in 2001 after the crisis, Wiser et al. (2004) find that forty-one percent of the electricity is supplied in ''tolling'' agreements most of which give the DWR some flexibility to dispatch the facility. Fifty-nine percent of the electricity is supplied at fixed prices fixed quantity (i.e. non-dispatchable).

[3] It has been used as in the British market by the regional electricity companies (REC) and the entrants in the nineties, when the RECs retain a legal franchising on the households segment.

costs of production, they could search to access to physical resource of power plants the costs of which is independent of fossil fuel prices. But interests are not completely converging[1]. On the side of the generator to make this kind of contract interesting to invest in a new capacity, it must provide for sufficient volume and time to be associated with the construction cost recovery. Moreover the industrial consumer must be a creditworthy counterpart, in particular with limited risk of relocation or of bankruptcy and de-incentives to opportunism.

On the side of the industrial consumer there is always a risk to lose the opportunities of electricity purchase at lower price than the contractual one during the stage of low prices on the market. Concerning prices and producer' revenue, a "normal" margin is contractually guaranteed on the production share which is reserved to supply the industrial partner. The arrangement does not give opportunity to make more margin over cost when market prices are set at a high level. As examples concerning such capacity developments in European countries, electricity companies and large industrial consumers (chemicals, metallurgy) have made joint ventures to develop large CCGT units[2].

They divide the power between the needs of the industrial partner and sales on the wholesale market. In order to let an important power surplus which is independent of the constraining process need in steam or heat, the equipment is flexible and the electric power capacity is over-dimensioned above the industrial partner's need of power. The supplementary production is owned by the generator partner and could be sold on the market with high margin over cost during period of high market price.

Box 1 : European experience of long term contracts between producers and industrial consumers with development of a new large equipment on site

Among projects which have been developed in a contractual partnership between producers and industrial consumers, four cases concerned production on site.

1. In France a joint venture between GDF and Mittal Arcelor for the development of CCGT of 800MW on the Dunkirk site using blast furnace gas as 40% of the gas and the corresponding heat and electricity is off-taken by Arcelor (225 MWe) while GDF sells the remaining electricity on the electricity market;
2. In Belgium a long term partnership between Electrabel, RWE and BASF with a risk sharing arrangement for a large CCGT cogeneration of 400MW on site in Antwerp; each of them delivers up 150MW (with heat included for BASF);
3. In the Netherlands, a partnership around a large cogeneration plant of 400 MWe (and total of 820 MWth) near Rotterdam (Rijnmond site) organised by a 15-year contract (with a five year fixed price and remaining years with indexed price) between the project developer InterGen and the electricity supplier Nuon in a first stage (the contract has been sold in 2007 to another Dutch supplier Eneco);
4. In Italy an agreement between Suez-Electrabel and the chemical company Solvay for a combined cycle unit of 400 MWe in Rosignano (with 100 GJ/hour of steam off-take).

Source: "New Power Plant Tracker", *Power in Europe*, Issue 508, September 10, 2007

[1] Examples of such long-term contracts associated to the building of large equipment show that possible conflicts of interests between potential parties could be defused in each context.
[2] Partnerships are based in some cases on valuing a secondary fuel as blast furnace gas. In all the case they are based on the combined production of heat (steam) and power.

Another way for the large consumers to proceed is horizontal arrangements in consumer's cooperative of production or consortium of electricity purchase. The example of the Finnish TVO consortium which ordered a large nuclear plant in 2005 is illustrative of that way to share risks of a new generator installation in order to control their electricity supply cost.

A particular arrangement—an electric cooperative in generation owned by several very large consumers (pulp and paper) and local distributors—was already established well before the 1996 market liberalisation reform. Its purpose was to construct and operate large generating facilities yielding benefits from electricity sold at the cost-price in the framework of long-term contracts (40 years) signed ex ante and which gives off-take rights to each participant.

After the reform, this type of long-term arrangements was reproduced to allow the order for a three-billion euros nuclear reactor of 1700 MW in 2005. The large consumers want to be unaffected by the effects of random hydro inflow situation, future CO2 price and be protected against the market power risk. Fixed-price purchase agreements independent of the NordPool market price and harmonized with the levelized cost of around 30€/MWh at low cost of capital of 5% were signed for "ribbon" deliveries, allowing the generator to obtain corporate financing with high leverage ratio (75% of debt) and borrow at low rates (Tampere University, 2004).

Table 2. Comparison of the implications of large consumers in different arrangements

	Contribution to investment	Technical and commercial shared risk	Governance Issue	Margin over Cost to be accepted by consumers
Consortium producers –industrial consumers	High	High	High	Low
Consumers cooperative of production	High	Medium (depending on the terms of PPAs)	Medium	Low to medium
Long term VPP	Medium	nil	Low	Medium (depending on competition)

Last solution studied here of long-term arrangements between generators and industrial consumers is based on the same principle of the virtual power plant contract (VPP). This VPP contracts are a much lighter governance structure than in the two previous consortium arrangements. They are more flexible because they are not linked with new equipment. But the payment may be structured as if the consortium would have to build itself a new plant with a capacity corresponding to the contractual quantity, and to finance this virtual equipment: the consortium pays fixed initial upfront payment at the beginning of the contract and then a fixed price corresponding to the variable costs. This constitutes a form of hostage to limit buyers' opportunism incentives. But other provisions have to be added to prevent individual strategies of opportunistic exit in the event of unanticipated long lasting downturn of the market price below the contractual price.[1]

[1] Exit is only allowed to accommodate a modification to the industrial strategy as off shoring, or bankruptcy.

A priori this type of arrangement could be applied either to indistinct purchase of electricity or to finance a new one with a generation cooperative, but the time span of the commitment tends to be inferior to the cost recovery period of capital intensive equipment. We can refer to the French example of a cooperative for long-term purchases created in 2006 by the seven largest consumers (under the name of Exeltium) to acquire blocks of a fixed amount of electricity (35 TWh/year) at a the cost-price of nuclear production (i.e., near the cost of generation of large capital intensive equipments not exposed to CO2 cost) in the framework of one or several tendered contracts covering 15 to 20 years.[1] A similar arrangement exists in Belgium under the name of Blue Sky. These arrangements are a way to access to physical resources by buying drawing rights on existing equipments.

Let us notice that competition policy principles could be opposed to such arrangements. Jurisprudence shows that they could be accepted if the consumers group does not cover an important share of the industrial demand and if selection between producers is made by auctioning.

Behind logics of bilateral setting or offering to call for tenders, these arrangements suppose that producers find an interest to guarantee their revenues for a part of their production, and to give up opportunities of higher revenues on short term market. It is noteworthy that a generator may find it beneficial to bid with a contract price below the anticipated market price and sign that type of contract to supply purchasers whose consumption profile is constant throughout the year and uncorrelated with that of other consumer types. Lastly, the quoted examples of such arrangements are the results of political compromises after pressures of large industrial consumers to have direct access to physical resources; and this suggests that the proof of reproducibility of such arrangements linked to a virtual asset of a given technology has to be done.

Whatever it could be, contractual solutions that are designed to collateralize and secure investments in generation by market producers are of interest to very large consumers. But as they represent at the most a fifth of consumption in mature economies, they can be only one means of developing generation capacity in liberalized markets.

Long term contracting with suppliers : their need for a base of core consumers. Suppliers' commitment to long term PPA at fixed price with new generation entities should be in fact the major means to secure investment in capital intensive and high sunk cost equipment. But in the event that the retail market is completely open to competition with market rules that eliminate switching costs, retailers bound by long-term fixed-price contracts with generators are vulnerable to the previously mentioned price squeeze, because they risk losing their market share to entrants if they do not follow the price downturns on the wholesale price. But their loss of revenues exposes them to bankruptcy. Even with indexed price contract, risks exist that electricity price downturn is more important that the contractual price decrease.

[1] In the case of the accepted bid after auction in 2006, the price offered by the chosen producer (38 €/MWh) for a first contract of 18 TWh per year (in fact, this is the French historic operator) corresponds to the complete cost of generation by existing nuclear reactors at their replacement cost if they would be re-built in the same industrial and regulatory conditions than before. Let us notice that the consortium has to finance the first payment which covers the large upfront cost of virtual equipment by borrowing. This type of arrangement presents a financing advantage for the contractors in the sense that lenders agreed to lend money to the consortium with high gearing, deconsolidated and non-recourse debt for the members of the consortium.

So as mentioned, anticipating opportunism of suppliers, producers hesitate to sign PPAs and investors to lend money with these PPAs as collateral. They need creditworthy purchasers as shown by the attitude of lenders who now accept project financing in the USA only if the IPP has a PPA with a historic supplier which has still a regulated monopoly segment (Chao et al, 2008).

But there are disagreements around the conclusion that complete retail competition precludes the signing of long term contracts. The IEA report on conditions of generation investment (IEA, 2007) and Littlechild (2002) argue against this analysis. For the first one, suppliers have different means to manage their risks; in particular they could manage them by co-managing their risks in their portfolios of sourcing contracts and sales contracts. In particular every supplier should seek to maximize their share of market-based retail contracts with price directly reflecting the spot price. For the latter author, "*if the contract is really worth signing, the retail supplier could match any price reductions to customers and still come out ahead. A consequence of retail conception/competition is that suppliers who wish to sign long term contracts have to back their own judgement rather than pass the risks to consumers; this is likely to improve the quality of decision making*" (Littlechild, 2002).

In other words, as a financial company which makes fixed interest rates mortgages available while short run rates vary, a supplier transforms short term forward contracts at fixed price in the retail to long term forward contracts in power purchase with producers, provided that it could renegotiate the contractual retail price when retail contracts are ended up in relation to change in wholesale spot price. In the real world suppliers do not exactly develop in this direction.

The complementarities between long term contracts and a sticky retail segment. In the real world, the different types of consumers do not react in the same way to price signals, and most of them are quite risk adverse. That means than there is on one side a real risk of customers switching in case of wholesale price downturn, in particular from the side of industrial consumers and in some markets from active household consumers if the regulatory and structural conditions of retail competition favour aggressive commercial strategies. The competition is quite different between most of the American liberalized ones and the most active European ones in which high cumulated rates of switching (i.e. the total of switching since the opening of the markets) are observable when effective unbundling, historical supplier's brand changes and lowering switching costs have been realised by the regulator[1].

In the more general case, in the other US and European markets, on the households and commercial segments, there are a number of inactive customers which are pasted to their original supplier, and in confidence prefer flat prices contracts or else the standard variable contract where the supplier may adjust the contract price at regular intervals. This is a matter of fact which is not simply linked to the dominant suppliers' strategies of branding and consumer loyalty building; In this perspective, Chao, Oren and Wilson (2008) who in the past have promoted the most de-integrated market design in their numerous theoretical works, now consider that "*a basic lesson of liberalized electricity markets is that customers (on the households segments) are deeply adverse to price volatility and to continually monitor and control their consumption. (…). There is a continuous role for (historic suppliers) in providing intertemporal smoothing of retail prices*", as did formerly the cost-of-service regulated

[1] :In 2005, the shares of switching customers are respectively 11% in Finland, 13% in Spain, 25% in Norway, 32% in Sweden, and 45% in Britain for the most important ones (Defeuilley, 2007). In the US liberalized markets only the Texas retail market exhibits high switching rates of 30%.

utility. In other words, given that this large part of the consumers do not want to manage the price risk, the incumbent suppliers should assume this function for them, but in exchange can pass through major part of their sourcing risks to them. And it converges with the producers' interest to meet suppliers able to commit in long term purchase contracts at fixed price.

To go further in this direction, the historic supplier must retain, either *de jure* or *de facto*, a significant segment of its clientele that is either captive or quasi-captive. Either the historic suppliers may legally retain their resale monopoly on part of the market (the segment of small consumers in their distribution area) or, after a complete opening of retail to competition, the retail market reform remains incomplete and leaves the supplier a significant base of "sticky" customers. Both of these conditions would enable them to pass the cost differential of the purchase contract over the wholesale market in their retail prices.

This situation appears to be the solution for curtailing opportunism risk of the suppliers who might enter into long-term contracts, provided that regulation of retail supply lets such imperfect competition situation. It must be underlined that it essentially concerns only the historic suppliers. It allows these suppliers to shift their risk onto some consumers and pass changes to the wholesale price on to their retail prices without risking the loss of too many clients. Chao, Oren and Wilson (2008) stress these complementarities when they conclude (p.30): "*The role of (historic suppliers) could be ideally complementary of those of lowering capital cost (for generation investment) when they sign long term contracts with IPP or invest in generation*".

Backing the contractual credibility of the suppliers to a consumer franchise. Newbery (2002) and Green (2004) who usually defends the value of market principles for wholesale exchange develop a stronger position. They advocate retaining consumer franchise and reverting to monopoly in retail supply to households, in order to ensure a stable customer base and facilitate investment. They argue that the complete opening of retail to competition does not induce any improvement in short-term efficiency, since wholesale price movements are not reactively transmitted to retail prices, and competition is only exercised on the already reduced margins of supply. While total retail competition extends volume risk for the intermediary and contributes to hamper their commitment in investment.

But a new problem will be raised for the regulator. If a partial monopoly is maintained by new franchise for small consumers, the challenge is to ensure that local monopolies have sufficiently strong incentives to negotiate low prices with generators. This can work in two ways: regulating by either comparing across distributors (yardstick competition) or by tendering long-term contracts (Green, 2004). But if the sector is quite fragmented in distribution and supply, regulation could be complex and information costly, as stressed by Littlechild (2006)[1]. He notices that a disadvantage of retail monopoly is that utilities and regulators who do not have to test their judgements in the market, are typically not well placed to judge the costs and risks of long term contracts or physical hedging by installing and producing by own generation assets (not clear). They can nevertheless force customers to be associated to such contracts and bear the resulting costs and risks.

[1] The regulator would have to define a future path of evolution of spot prices and forward price and refer to a benchmark of purchase strategy by the historic suppliers, to assess the different risks and allocate them between producers, supplier's and consumers.

In such situations some authors consider that the control problem could be solved by auctioning the long term contracts of suppliers with partial franchise in order to benefit from the pressures of market mechanisms. Rothkopf (2007) recommends that auctions must be under the control of the regulator and new capacity should be procured by forbidding any entity with significant ties with the supplier from participating to the auction. It is only if no independent candidate can be selected that these entities could compete. Let us note however that the complexity of the supplier's regulation in the *half-slave half-free* situation is not only the lot of the supplier's partial franchise In the former case of no legal monopoly in distribution but stickiness of consumers to historic suppliers, the regulator needs also to ensure that suppliers who are strong in the mass market segment do not exagerate the transfer of costs across market segments. In these two contexts of either imperfect competition in the retail supply with large core consumers or partial franchise, experience shows that suppliers do not hesitate to sign long term contracts as well as shorter term ones in different markets: Britain, Germany, Norway, New Zealand, Sweden the Netherlands (see box 3) and several States in the USA, even if volumes are small.

4. Opening the range of vertical arrangements: towards re-integration ?

Long term contracting between new generators and suppliers which could commit thanks to the guarantee offered by their core customers is not the unique solution. Partial or complete vertical re-integration represents an another hedging optionfor the IPP to secure investment in generation: it allows to the vertical entity that off-taken quantities and sales prices of its new productions will be guaranteed in a way or another and the fuel risk could be transferred on to the supply unit, i.e. the internal buyer.[1] So it is for the suppliers to hedge part of its sourcing. This leads to analyse in a second stage the fitness of vertical industrial organisation based upon both a successively grown portfolio of various generation technologies and a developed set of customer relations, with the stake to invest in a variety of generation technologies to lower in average its production costs.

4.1. Vertical integration of production and supply : an efficient alternative to long –term contracts

Given the alternatives between long-term contracts and vertical integration, the quest for vertical integration between generation and supply can be understood, from the two respective perspectives of the electricity producer and the electricity supplier, as a strategy for reducing endogenous risks (opportunistic behaviours) and uncertainty effects for the players set in the two levels of the new value chain. Other attributes of transactions – frequency, complexity, uncertainty related to possibility of market power exercise in the environment of the transactions– appear to give more decisive advantage to vertical integration over spot transactions, but also on long term contracts for a large part of the production of new generators, and conversely for the sourcing of the suppliers.

[1] We put apart the issue of long term contracts in the transition period where a de-verticalization is organised by the regulators by blocking the retail price of the suppliers and their consequences on the competition. There is a vast literature about this choice of stepped liberalisation process in the USA, in particular after the Californian crisis and its consequences on bankruptcy of the historic distributor-suppliers restricted in their possibility to long term contract (For an synthesis, see Michaels R., 2006 ; Mansour E., 2005)

The generator's perspective**.** In this first perspective, the inherent guarantees to the vertical arrangement suffice to obtain corporate finance arrangement which intrinsically generates low transaction costs, and also lower debt cost. It keeps advantage on the merchant plant/hybrid finance model which emanates from the now amended merchant plant model by associating the signing of long term contracts before building the equipment. The PPAs add to the transactional complexity of the merchant plant's project financing agreements which already set on a high number of contracts between various parties and entities, which are required by the investors to allow the best control on risks.

Second, whereas the long-term contract allows the sharing of investment risks (construction, fuel price, market price, volume risk) between different parties by a variety of provisions, while under vertical integration all of them would be managed by a single entity. That means in particular that adaptation to uncertainty is more efficient under the "hierarchy" which is inherent to the firm as a governance structure than in the framework of long term arrangements which, as being incomplete contracts, include provisions for adapting the contract but with delays and transactions costs.

In case of price downturn, the risk of massive customers switching the trading and marketing division of an integrated firm has not the same incentive to opportunism, provided that the wholesale price will not established below the cash cost (fuel, etc.) of new equipments. While an independent supplier committed in a long term contract at fixed price or even at indexed price will be tempted to do it whatever the threshold of profitability of the producer, the trading department of any (quasi-)integrated electricity company looks only for opportunity of some short term arbitrages. And in case of long depression of market price under its cash cost, it is only the managers of the company which could decide to mothball the equipment. In the de-integrated situation with a long term contract, the purchasing party could be tempted to break the contract in situation of dramatic price downturn, which could make the producer bankrupted in market price is lower than its fixed cost.

In more mundane terms, the vertically integrated generator controls the risks associated with asymmetrical changes in profit margins at each stage under the effect of market prices fluctuations. That which is lost by one unit is recuperated by another. In the perspective of the integrated supplier, this one stabilizes and secures also the terms of its wholesale purchases, even if it does not completely control its volumetric and price risks in resale. Advantage is still clearer when vertical integration is organised with a historical supplier which benefits from a large segment of core consumers on which some market risks could be transferred.

The suppliers' perspective. On the suppliers' side, the symmetrical advantage could also play. When competition is effective and fluid on the retail market, vertical integration for the majority of their sourcing makes risk management easier than in the pure supplier model with some long term contracts with fixed price or indexed price. Incentives to adopt vertically integrated arrangement for the majority of their sourcing are twofold. First there are transactions costs savings, with regard both to negotiating the contract and monitoring contract performance (amending clauses, renegotiating, etc.).

Second complexity in risk management is increased by their responsibility of load servicing entity as "balancing responsible". This gives to physical hedging some advantages to a vertical integration in majority (not clear) over a sourcing strategy only based on long term contracts with new or existing producers. Indeed in a long term arrangement between a supplier and any new producer, there is a clear opposition between its need of volume flexibility and the generator's need of off-take guarantee. In their sourcing strategy, suppliers develop a portfolio of one/two year contracts of energy block purchases and monthly/weekly contracts of energy peak, but they have a permanent need of volume adjustments by purchases on the day-ahead, or by real time re-sales in case of temporary over-contracting. This creates a fundamental risk for the supplier that it cannot hedge on the forward market, given its random profile. Neither has it transfers this risk on its customers, given the rigid characters of the sale contracts. Consequently suppliers have interest to make up their hedging strategy by contracts of different time-spans and by some physical hedging by buying or installing flexible generation equipment such as CCGTs in particular for their sourcing during peak and mid-load hours in the week[1]. In other words, the supply business is a higher risk business subject to the normal bankruptcy risk faced by companies in competitive markets. The risk management advantages of generation and retail integration are very important, such that stand-alone retail electricity companies have struggled.

4.2. Combining generation portfolio, consumers portfolio and vertical arrangement

Vertical re-integration is generally associated to a diversified portfolio of generation equipments, what gives an advantage in terms of hedging to investment projects of the vertically integrated company by comparison to a merchant plant project even backed to a long term contract with a credible party, as point by Chao, Oren ,Wilson (2008).

In the producers' perspective, ownership of a diversified portfolio of generating equipments gives them a greater capacity to spread the operating risk attributable to the volatility of input prices (fuels, CO2 permits), as well as market risk. This capacity could be acted in trade strategy of portfolio bidding, as said above. Moreover, even for non-integrated producers, a diversified portfolio gives them an advantage for accessing to cheaper debt. Lenders are attracted by diversified portfolio of assets, and reluctant to lend to merchant plants (Lacy, 2006).

When they benefit from a large and diversified asset base, they are able to obtain loans under corporate financing arrangements and consequently, owing to simple financing structure, a normal debt-equity ratio (50/50) and save on capital costs and risk premium. In fact, the generators have an advantage to develop a diversified portfolio of generation assets upon the financial players which are supposed to manage risks by diversification of their financial assets in the electrical industry. As we pointed above, it is because there is no possibility to address all the consumers' needs of risk hedging by diversified forward contracting with specialised generators or by consumers' shareholding in their stock, because incompletude of electricity markets, large information costs and transactions costs.

[1] The example of Centrica's strategy of sourcing for its electricity sales in its development strategy of dual fuel supply after 1998 is interesting in this respect. In a first stage it entered in different long term contracts. But the development of physiscal assets progressively becomes the most important element. Centrica buys a number of existing gas-fired power stations of a total of 1650 MW and in 2007-2008 is developing a new one of 890 MW. It will supply more than half of their power sales by his physical assets. This suggests that for a pure electricity supplier, vertical integration presents a necessary complement for risk management to long term and short term contracts.

In the TCE perspective, the approach which thinks the modern corporation as a series of separately financed projects --approach which falls both within the province of the Arrow-Debreu theory of optimal investment under uncertainty than the theory of modern finance as developed for instance by Etsy, 2004 – can be disputed in particular because it misses the interaction effects among projects, and among equipments, as Williamson (1996, p.188) criticizes to project finance.

An electricity company with a diversified portfolio of generation assets, could produce in an optimal way for its market share along the different hourly electricity demands expressed on the market, given the non storability of electricity. If it could commit both in investment in large capital intensive units with low operational cost and in flexible, low capital intensive generation units from the standard technology, it could have chance not only to manage ideally market risks, but also to minimise its averaged generation costs. At the end, lenders and investors understand that their risks are better controlled by corporate finance to an asset-diversified power producer than by project finance for each equipment to be developed.

The same reasoning could be developed in the perspective of the supplier who wants to diversify its risks by a majority of vertical integration, besides some contracts and spot purchases. It has an advantage to own and operate flexible CCGT, some coal generation plants and non fossil fuel plants, in particular windpower plants and nuclear plants. It is the evolution that could be observed in the Centrica's strategy of electricity sourcing.

Scale economies by size and diversification. Scale economies by the size of a company specialised in electricity generation and supply could capture the advantage of asset diversifications. The possibility to produce in different markets, underlying to their large size, reduce the risks of individual investment on one particular market. Downstream a large supplier could benefit from its large-size portfolio of contracts as a hedge, via risk aggregation on a wide scale. Large size in the supply business adds an advantage given that the risk exposure is generally correlated to the size of the business. Moreover, if they benefit from a position of historic supplier on their home-market, vertical integration in these markets gives them another advantage to make consumers bear part of investment risks in this market. Lenders are attracted by diversified portfolio of assets (Lacy, 2006). Since they benefit from a large and diversified asset base and a large balance sheet, they benefit from good ratings and on capital costs and risk premium.

To these advantages in risk management and cost of capital we shall add their possibility to negotiate long term contracts for their fuel purchase with favourable conditions. So it is a means for the biggest among them to have bargaining power in their dealings with the manufacturer's oligopoly. These different advantages help them to invest not only in two hundred millions € in CCGT project, but ten to twenty times more in capital intensive projects as a nuclear plant with corporate financing and a normal capital cost.

5. Conclusion

None of the far-reaching experiments in electricity industry liberalization on the basis of the de-integrated market model proved able to develop capacity along the optimal technology mix. The theoretical market model features a market barrier attributable to the specific volatility of market prices and the impossibility of transferring the various investment risks borne by the generator onto suppliers and consumers in order to allow development of capacity with various technologies. Regulating competition by the quest for the maximum transparent market rules for all stages of the electric industry, including the retail market, tend to hamper investments in generation by restricting possibilities of long term contracting and efficient allocation of investment risks on consumers.

We analysed through the transaction cost economics perspective different ways of securing large capital intensive investment in generation equipments in a context of uncertainty and wide transactional complexity. Analysis of the way of securing investments in generation by vertical arrangements entered into by new generators and large consumers highlights the importance of hostage in complex governance structure, in particular the joint ownership of new generation equipments, to make possible some developments. As for vertical arrangements with suppliers, analysis suggests that regulatory adjustments for allowing credible commitments by generators' counterparts may prove theoretically justified, in particular by helping historic suppliers to keep *de facto* or *de jure* a large share of core consumers. Moreover vertical integration between generation and supply business, as well as generation asset portfolio present both some advantages in terms of transaction costs and risk management in this respect. Finally large size of vertical and horizontally integrated companies appears to be an economic advantage to manage investment risks at low capital cost.

However discussion should have to be raised about eventual drawbacks of these different arrangements on the effectiveness of competition and its imperfection with increased risk of market power exercise. Vertical arrangements typically hamper competition by limiting entries. So it is for large size of vertical and horizontal companies when horizontal concentration in their home market is quite high. Indeed barriers to entries and risk of market power abuse could balance the social benefits coming from the larger capacity to invest in capital intensive generation equipments by controlling costs and risks. This issue of market concentration must be balanced with the issue of investment in generation. In particular, if the complexity of liberalized electricity industry leads to opt for these institutional arrangements and industrial organisation to preserve the long term social efficiency, ensuring the stability of this model must force regulators and competition authorities to consolidate their market monitoring.

Annex

Experiences of capacity developments on liberalized markets

We first turn to empirical observations on experiences of investment in generation within different liberalized markets to confirm the necessity for long term contracts and vertical arrangements to invest in generation. Putting aside the experience of developing capacity only for peak loads, the record of investments in generation capacity after market liberalization of the electric industries in the United States and in Europe shows that institutional conditions of successful capacity development in base load and semi-base load equipments are long term contracts and vertically integrated company. The failure of pure producers without long term contracts is indicative of an intrinsic obstacle to viable risk management in this organisational model.

A. Generation developments in the US market

It is noteworthy that only half of the US states have liberalised their markets. In the other half, electricity industries remain in the cost of service regulation but only 10% of investment has been done there between 1997 and 2005 because of the maturity of the market in these states. The U.S. states which had liberalised their electricity industry witnessed a boom of investment in the late 1990s incited by a series of price spikes and anticipations of new capacity needs. Over 230 GW of new generating capacity was added mainly in these states between 1997 and 2005, among which a lot of gas turbines for production during peak and two third were CCGTs supposed to partly replace incumbent's old conventional gas plant. This massive wave was made mostly by Independent Power Producers (IPPs) in merchant plants relying on project financing with highly leveraged arrangements and without long term contracts. The important issue is that IPPs are risky companies and they have to pay a high capital cost[1].The problem is that most CCGT projects went bankrupt after 2001 when gas prices increase and limit their dispatchability and average wholesale market prices collapsed at the same time[2]. In consequence, the large pure producers (Dynergy, Mirant, Williams, etc.) were quite jeopardized by successive years of lower revenues and profitability.

In response, Lenders have since then been much more cautious in their approach to financing new power projects. Lenders, Banks and financial markets have *de facto* changed their reference model of electricity markets, and now favour vertical integration and long-term contracts. Today banks only lend money for generation investment in corporate financing, or they lend to vertically integrated incumbents and merchant plants in project finance only if the project is backed to long term contracts with credible counterparts. These are exclusively the historic suppliers which retain a large segment of core consumers or a regulated business in some of the incompletely liberalised markets (Joskow, 2007; Chao, Oren and Wilson, 2008).

[1] Some of the most prominent are financially distressed and reorganized after bankruptcy.

[2] When gas price rose sharply, load factors of new gas plants were depressed and net cash flows did not allow debt payment. By 2004, 90 GW turned back to lenders, 23 GW had been bought by private investors and 10 GW had been repurchased by regulated utilities.

Since 2004, investments were made by traditional utilities in states with non liberalized markets investment and almost exclusively realized by municipals that have not been subject to restructuring and by quasi-vertical integrated companies under corporate financing. As an example in California, over 90% of the 8 GW of new capacity installed since the 2001 crisis has been financed by long-term fixed-price and fixed-quantity contracts that a state agency purchase. The ultimate consequence is that viability of investments in new generation by IPPs is substantially impaired.[1]

B. Generation developments in the British market

In the UK which is the front runner in liberalization, after the first reform of 1990, there have been a large stream of new investment in generation, despite initial spare capacity, under two types of arrangements First investment by the two dominant producers which modernized their portfolio of coal generation assets affected by new environmental regulation with installation of 5 GW of CCGTs and were backed to vested contracts with the regional distributors-suppliers; Second investment by new entrants after the signature of bilateral 15-year option contracts (as they are option, the strike prices are more or less independent of the spot price) with distributors-suppliers which retain a regulated captive market segment. Most of the new capacity (around 7.5 GW) was built by these new entrants to generation that were themselves minority subsidiaries companies of the former distributors-suppliers. These ones look for having some hedging against the market power of the two dominant generating companies, diversifying their purchases and earning unregulated income[2] (Newbery, 2001).

After 1998, in confidence with market price prospects, a number of CCGTs projects (5,8 GW in total) -- among which some “merchant plants” developed by oil and gas subsidiary companies were programmed backed to a long term contract of “tolling”[3] -- before being suspended by the moratorium encouraged by the regulator to limit overcapacity[4]. Almost all the new projects are developed by vertical companies[5] with very few exceptions. Independent generators[6] with no foot in supply and large suppliers[7] with no generating equipment to hedge their risks preferred to retire from this market or were eliminated by bankruptcies after the downturn of the market following the switch from the mandatory Pool to NETA and the drop in wholesale prices in 2001–2002. In contrast, it is important to notice that vertically integrated generators-suppliers were able to pass their costs on to small and medium-sized consumers, which have few benefited from this price decline (Newbery, 2006).

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[1] For example, Calpine has obtained regulatory approvals for sitting and construction of three new plants in California for which it has not obtained investment funds.

[2] The Enron’s 1875-MW CCGT “*Teeside project*” which was developed as a merchant plant was the exception.

[3] In a tolling contract the power purchaser delivers fuel to the generator and takes delivery of the resulting power produced. It is a way to allocate the fuel price risk on the buyer.

[4] But only two of them were effectively realized after 2002 given the trend in Britain has been toward vertical integration.

[5] E.ON-UK, EdF Energy, RWE-NPower, SSE, Scottish Power, Thames Power, and Centrica for supplying its dual fuel retail market.

[6] Such as Edison Mission, AEP.

[7] Such as the TXU-Europe.

C. Generation developments in other European markets

In Europe[1], since liberalisation, investments in production were made mainly in South European countries (Italy, Spain, Portugal, Greece) where there was a need of new capacities for base-load and mid-load production in growing demand markets. They have been almost exclusively made by vertical companies (ENEL, ACEA, AEM in Italy; Endesa, Iberdrola and Fenosa in Spain), generators which already have developed a supply business (ENIPower, Edison in Italy) and generators linked to historical suppliers (EDP in Portugal, PPC in Greece) by long term Power Purchase Agreements (PPA) in Portugal and Greece.

The entries into generation by creating facilities are carried out either on the basis of quasi-long term contracts with an incumbent distributor-supplier or by vertical integration, i.e. by alliances between suppliers and generators affiliated to foreign utilities. We could name some instances in Italy (the alliance of Suez-Electrabel with the Roman distributor ACEA with two CCGT projects, the alliance of Endesa with the Brescian distributor ASM with two other large CCGT projects, etc) and Spain (Gas Natural's CCGT installations for supplying electricity in dual fuel to some large industrial gas customers, etc.) (see Box A)

Box A. Recension of entries of IPPs under long term contractual arrangements with historic suppliers in electricity and gas in Europe since 1998
(Effective realisations and current projects)

In Germany a 400MW-CCGT project developed by Electrabel in relation to the sourcing of two important local distributors (in Saar in particular) that it took over;

In Germany the 800 MW-CCGT project in North Wesfalia developed by the Norwegian Statkraft and the Dutch Essent (it controls of a local distributor), and after signature of several 15-year PPAs with municipalities;

In the Netherlands the 400MW-CCGT project developed by EDF in partnership 50/50 with the distributor Delta ;

In France the 400MW- CCGT plant to be built by the pure supplier Poweo and the Austrian Verbund ;

In France the 400 MW-CCGT project (Montoir) by Gaz de France for penetrating the dual fuel energy market;

In Italy the 375 MW CCGT projects of the partnership Electrabel-ACEA (Leini; Pontinia; Rossignano);

In Spain the 800 MW-CCGT projects developed by Gas Natural (Gualdalajara ; Paracuellos) for penetrating the dual fuel energy market;

In Portugal the 800MW-CCGT projects of Tejo Energia and GalpPower with PPAs contracted with EDP.

Source: "New Power Plant Tracker", *Power in Europe*, Issue 508, September 10, 2007

[1] All the projects and realisation of new generation equipments are inventoried by the journal *Power in Europe* in its regular "New Power Plant Tracker". (Power in Europe, Cf. Issue 508, September 10, 2007)

In the Nordic countries Norway, Sweden, Finland which were among the front runners of the reforms of their industries with a low vertical integration, systems are mature, dominated by hydro production and in Sweden a mixed of nuclear and hydro. They tended to be in overcapacity. Very few investments in generation have been made. The regulators have, however, become worried about the recent lack of investment, particularly in peaking units. The new EPR nuclear reactor[1] ordered in Finland is the only project for the base load supplies of power and it is realised by a generation cooperative of large industrial users.

In The Netherlands', Germany', France' and Belgium's mature markets, capacity developments were almost exclusively made from 1998 to 2006 by national and foreign energy companies in the development of very large CCGT projects on industrial sites with cogeneration of heat and power in partnership with large industrial consumer, which let a large surplus of electricity to sell on the market.

With the beginning of the new cycle of investment which begins in the second half of the decade in these countries, most of the projects are announced by the vertical companies. Almost all the entries by capacity development are based on vertical arrangements (see box 2) but there exist some exceptional cases of merchant plants set in markets where the average annual price (including revenues of opaque ancillary service markets) are high, namely the Italian and Spanish markets.

Box B. Realisations of pure merchant projects in Continental Europe since 1998

In Italy, the CCGT projects of the Swiss company EGL with a tolling contract with the parent company : the Rizziconi plant of 760 MW commissioned in 2007 and the Calenia plant of 760 MW

In Italy, the CCGT projects of the Austrian Verbund in partnership with the Benedetti financing group (with the two Sorgenia projects of 770 MW),

In Italy the CCGT projects of Tirreno Power project which is less archetypical because it is a joint company of different partners (Electrabel, ACEA, Verbund, etc) which some have supply business in retail sales.

In Spain, a project of CCGTs of 1200 MW, developed by AES (71%) and Gaz de France (26%), which is backed up on a tolling contract of 24 years with GDF but without prior power sales agreements with electricity suppliers or large consumers.

In Germany, the Concord Power project of CCGTs of 800 MW in Lubmin (Mecklembourg) promoted by Saalfel Group with no PPA relations with electricity suppliers.

In Germany, the Soteg (Luxemburg) and Gazprom's project of CCGTs of 800 MW in Eisenhutt (Brandenberg) with non PPAs relations, but a gas agreement with Gazprom.

Source: "New Power Plant Tracker" *Power in Europe*, Issue 508, September 10, 2007.

Based on these facts, the question we raise now concern the risk allocation configurations for investing in generation of electricity in de-integrated market models. We will assume that the way for investment risks allocation exclusively on the producer can create barrier to invest in generation activity.

[1] EPR (European Pressurized Water Reactor) will be implemented for the first time in the nuclear unit called Olkiluoto 3 in Finland.

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