Long term system adequacy in the energy system: Capacity obligations VS Reliability contracts: the French Electricity Market

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Abstract

There is no consensus on which energy market design provides the least distorting long-term investment incentives. Theoretical rationale suggests that "energy-only markets" with spot prices that are allowed to reflect scarcity rents should provide an optimal level of investment in generating capacity. However, different market designs with separate payments for capacity or reserve obligations have the advantage of not relying on infrequent price spikes to remunerate reserve capacity. In this paper we analyse potential regulatory mechanisms to ensure sufficient supply of electricity. We describe a dynamic model for long-term investment planning in restructured power systems. First, we study the effect of "Capacity Obligations" and "Reliability Contracts" schemes on the long term capacity adequacy in the system and we analyse how the pricing of CO2 and difference in construction delays for the new power plants would affect investment strategies and the effectiveness of the incentive mechanism. Second, we take into account the uncertainties in future demand and fuel prices and we study the effect of the adoption of the incentive mechanisms on the optimal timing of investments. Resolution of the investment model is based on dynamic programming method and real options theory. We show that reliability contracts mechanism assures the long term system adequacy and encourages earlier investments and appears to be a more cost efficient incentive mechanism than capacity obligations. It is also illustrated that the change in framework conditions and difference between technologies (cost structures and construction delays) would affect investment strategies but without influencing the effectiveness of reliability contracts scheme. Also the dynamic valuation of the investment problem would contribute to further postpone the investment decisions compared to the static assessment.

1. INTRODUCTION

Operation and planning in electrical power systems prior to deregulation have traditionally been characterized by a high degree of centralization and the typical organization of the industry was vertically integrated companies, incorporating all functions of production, system operations, transmission and distribution. The vertically integrated firms had monopolies in their own areas, and because of this, prices were regulated. They built to serve their own consumers, and had to build enough to serve them all, at all times. However, the ongoing restructuring of the electric power industry results in a decentralized decision making and in the future, investments by competitive producers will be controlled by the need for cost effectiveness in a risky environment, rather than the need to cover demand on a captive market. Competition would yield competitive prices and consumers would expect to have low prices, reliable service, fairly predictable bills and the opportunity to benefit from value-added services that may come available.

Instead, deregulation has brought wildly volatile wholesale prices and undermined the reliability of the electricity supply. The California crisis in the summer 2000 was considered as the first failure of deregulation. It was characterised by extraordinary high spot market prices, raising total energy costs to up to 10 times historical levels and shortages and subsequent rolling blackouts within the state. The basic problem underlying the crisis was a fundamental imbalance between the steadily growing demand for power and the limited increases in generation capacity during the 1990s due to the lack of investments. The crisis had a chilling effect on deregulation and reform in the rest of the United States and in many other places in the world. In fact, after the deregulation, the problem of ensuring enough generation capacity to meet future demand has become more complex to deal with due to several factors. The first one is the exposure to risk due to changed framework conditions. For instance, the recently adopted directive establishing a common European greenhouse gas emissions trading scheme (EU 2003/87/EC). The pricing of CO_2 can be of great importance for the revenue base for new power plant projects, and a big question is how CO_2 allowance prices will develop in the future, including how they will affect electricity and heat prices[1]. Also, regulatory risks such as the applications of price cap could also limit the realizations of the socially optimal level of investment [1], by limiting the revenues earned by generators and therefore, discouraging new investments. Regulatory restrictions as the obtaining of the necessary permits to invest may be another cause of underinvestment [2]. The second one is uncertainties in future demand, supply and fuel prices which would lead to reduce the effectiveness of market signals. In presence of uncertainty, market signals could be imperfectly interpreted due to the risk-averse behavior of potential investors, especially the peaking unit which produce only a few hours a year when the price is highest and as a consequence, they would receive no remuneration most of the time. Therefore, the high volatility of the income makes the investment very

[1] Fuel prices could also be affected indirectly by the CO_2 allowance price.

risky and as a result the firm will reject the opportunity to invest. The difficulty also comes from the consumers' side. Ideally, the consumers trying to have a better reliability would sign long term contracts to hedge themselves against high prices. However, in most cases, regulated tariffs lead to isolate the consumers from spot prices so they do not feel the need to protect themselves from spike prices. The lack of maturity creates a malfunctioning of the long-term market and cause a lack of generation investment. The third factor is the specific characteristics of electricity such as its non-storability and the larger construction delay required before the availability of the new power plant, so the new investor has to predict perfectly the future evolution of the market before deciding an irreversible and risky investment. Finally, the energy market design itself could be another cause of the lack of generation investments. For instance, the energy-only market[2] design, which requires the elimination of any price caps, allows full participation of the demand and lets each market agent to fully experiment the volatility of the market prices, fails to ensure sufficient generation capacity, specially in peaking periods when generation cost and demand are very high, since it ignores the existence of failure in actual market as the passivity of a significant part of the demand and the risk aversion of investors.

This paper aims at finding the optimal market design that could ensure earlier new investments in the system and enough generation capacity to meet future demand with efficient cost. We present a dynamic investment model, which can assess optimal cost efficient design and optimal timing of investments when different factors, affecting the realizations of the socially optimal level of investment, are taken into account. Four factors are introduced here. Firstly, the changes in framework conditions such as the implementation of tax-CO2 which, for instance, would discourage new investments in thermal technologies. Secondly, the specific characteristics of the new technology in term of cost structures and construction delays. Two technologies are modelled which differ by their investment costs, operating costs and construction periods. This will allow investigating how the difference between the characteristics of technologies would affect the optimal choice of technology and in turn, the system adequacy. Construction periods affect significantly the long term planning of investment and influence also the capacity adequacy in the system since the response time of generation investment to an increase in demand depends on the construction period of the new technology. The shorter the construction period is, the more it assures earlier availability and the more the system can avoid critical situations and satisfy volatile demand. In literature, there has been almost no research on how the choice between different production technologies unfolds in a dynamic context. An exception is in [3] where it is shown that the small-scale technology may be chosen in equilibrium and assuming risk neutrality, the effect of uncertainty on the choice of technology is found small. Third, uncertainties in future load and fuel prices are considered since they influence future prices in the electricity market and the profitability of the investment project and possibly also the

[2] It has been used in California where, coupled to serious market design flaws and other circumstances, has results is serious shortages of generation.

income from additional investment incentives, affecting then the optimal investment decisions. Finally, the failure of the energy-only market design to provide optimal incentives for new investments is analysed and we try to find the optimal incentive mechanism, assuring long term system adequacy and cost effectiveness. The optimal market design is found by comparing between incentive mechanisms that differ by their descriptions, implementations and motivations, [4] and [5]. Two mechanisms are modelled and compared here. The first one is the capacity obligation mechanism[3]. It ensures generation adequacy by imposing an installed capacity obligation on load serving entities (LSEs: large consumers, retailers…). The LSEs are required, every year, to have or to contract enough firm generation capacity above their peak load to cover their expected peak load plus a regulated margin. This leads to a creation of a capacity market, in addition to the energy market, that allows trading of capacity obligations among the LSEs. The capacity markets prompted by the obligation provide generators with the opportunity to collect extra revenue for their unutilized reserve generation capacity and provide incentives for the building of reserves beyond the reserves that meet the short term needs for ancillary services. The second one is the mandatory call options scheme. Here, an organized energy market is established where the regulator requires the system operator to purchase a prescribed volume of reliability contracts from generators on behalf of all the demand. The method is based on financial call option with auction procedure, so both their price and their allocation among the different plants are determined through competitive mechanisms. The system operator determines in advance the strike price for the auction which acts as a price cap for demand, the time horizon which is typically the peak period where the generator is required to generate the committed capacity at any time during that period. The generators submit one or several bids to the auction, expressing quantity (the capacity they want to sell) and price (the required premium). Finally, the market is cleared as a simple auction and all of the accepted bids receive the premium that was solicited by the marginal bid. This method stabilizes the income of the generators due to the premium earned from the auction and represents a market-based mechanism to hedge demand from the occurrence of high market prices. It really commits the generators to be available when the system needs them because of scarcity of supply [6]. The differences between the characteristics of the two mechanisms are presented in Figure 1.

In literature, other mechanisms are proposed in order to assure adequate supply of capacity in the system. For instance, with capacity subscriptions methods [7], consumers have the freedom to choose their level of reliability through the amount of maximum capacity that they subscribe to. With capacity payment mechanism[4], generators are given in peak periods, an additional capacity payment based on their availability (whether they get dispatched or not) or based on generated energy as an adder to the energy market clearing price

[3] It has been implemented in the eastern pools in the US including PJM NYPP and New England.

[4] It has been implemented in the UK (before the new trading arrangements (NETA)), Spain and several Latin American countries.

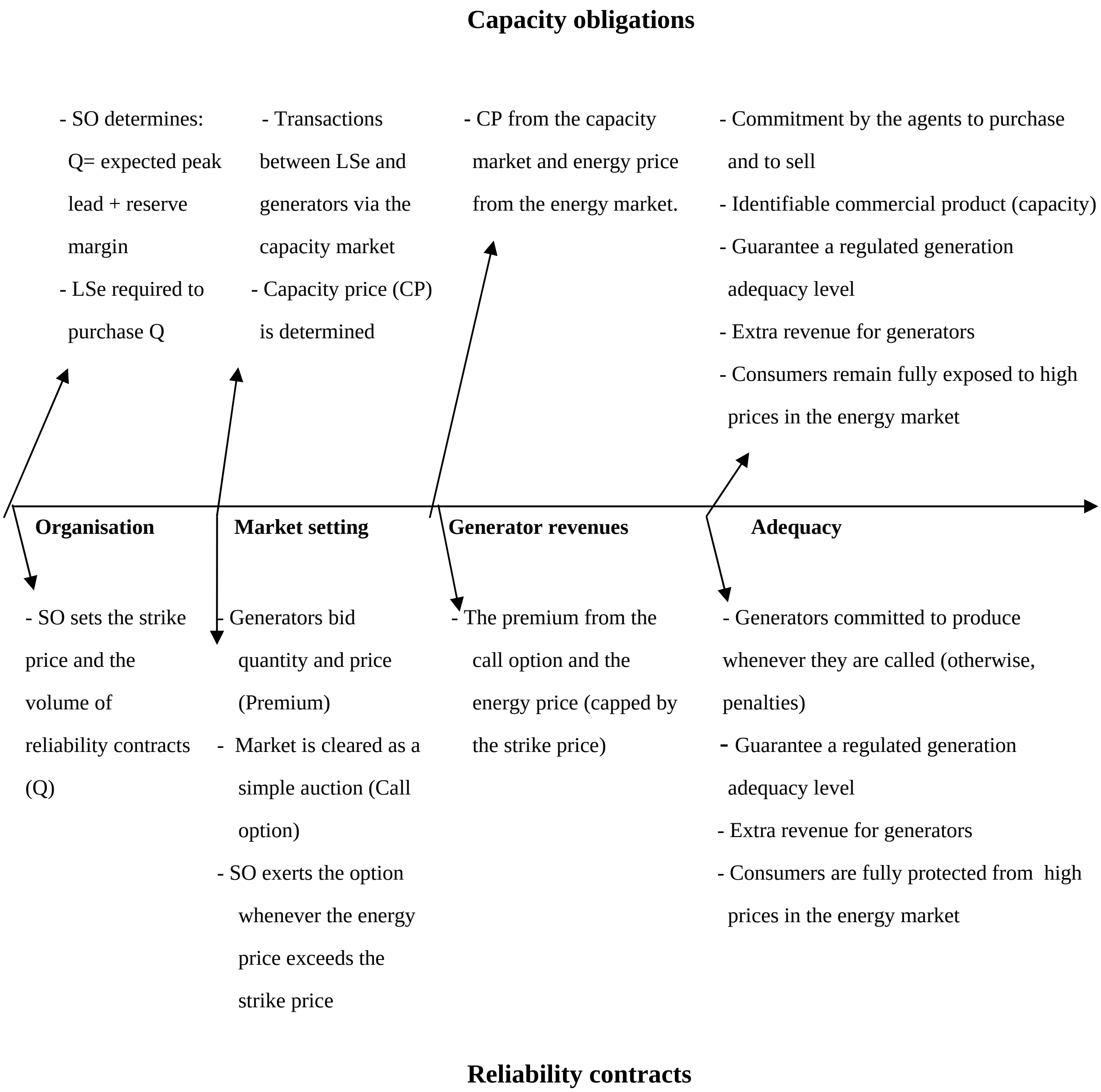


Figure 1: *Characteristics of reliability contracts and capacity obligations mechanisms*

Different methods were used in literature for modeling the effect of incentive mechanisms on optimal investment strategies. System dynamic models are largely used to simulate the optimal investments. It is illustrated in [8] that, without incentives, construction cycles could occur frequently and the industry would face repeated periods of under supply and the introducing of a constant capacity payment could diminish considerably the occurrence of these cycles. In risky environment, stochastic dynamic programming method is used for handling the uncertainties in generation expansion problems, [9] and [10]. With this technique, we can also look at the question of long-term generation capacity adequacy in restructured and competitive power systems and model the effect of different incentive mechanisms on the optimal timing of investments, where investment decisions are made by decentralised market participants [11]. The model presented in [11] takes into account how uncertainties in future demand, which in turn influence prices in the electricity market and possibly also the income from additional investment incentives, affecting then optimal investment decisions. The results clearly show that a dynamic capacity payment, is probably better capable of maintaining an adequate level of installed capacity if the demand grows faster or slower than expected. The model presented in [12] calculates optimal investment strategies under both centralized social welfare and decentralized profit objectives. It is shown that price cap below the value of lost load or monopolistic investment conditions, will contribute to postpone investment decisions further and a capacity payment will help trigger earlier investments but can also result in too much investment in peaking units.

The main aim of this paper is to compare between two market designs, capacity obligations and reliability contracts, in term of long term system adequacy and optimal timing of investments, particularly since there has been almost no previous research on how the reliability contracts can deal with this problem in the long term. In other worlds, do such instruments, principally the reliability contracts, solve the problem of supply adequacy and at what cost? By long term system adequacy we mean the existence, in peak periods, of enough installed available capacity of the appropriate characteristics to be capable of meeting the estimated peaking demand. In fact, the problem of capacity adequacy concerns only peak periods when demand and prices increase considerably and generation in this period needs high production cost. The experience with existing energy-only markets show the difficulty of the installed capacity for meeting the high and volatile demand within this period, which induce high prices and negative capacity balances in most of the cases. So, the implementation of incentive mechanisms encouraging new and earlier investments and ensuring enough and adequate capacities in this period is crucial. For the rest of the year, capacity adequacy is straightforwardly assured by base technologies requiring generally low variable costs and demand and prices vary generally in normally levels. Our study is derived from the one of [11], but it differs in several points. Firstly, the long term system adequacy concerns only peak periods rather than total period and is calculated according to the cost effectiveness of the mechanism rather than timing of investments. Secondly, the two incentive mechanisms modelled here have the advantage of imposing an obligation for generators to be available whenever they are called to produce while with capacity payment method studied in [11], no commitment is imposed and so, the level of adequacy cannot be guaranteed. Also, the reliability contracts method are determined via market-based mechanisms (organised auctions) rather than settled administratively with capacity payment scheme. Third, we analyse how the pricing of CO2 and difference in construction delays for the new power plants would affect investment strategies (technology choices, capacity expansions), the effectiveness of the incentive mechanism and in turn the long term system adequacy. Finally, for the stochastic analysis, two types of uncertainties, future load and fuel prices are taken into account, rather than only future load in [11]. In fact, the evolution of future fuel prices still highly reliant of economic and political factors and would evolve stochastically, affecting then the profitability of the new investment project, especially thermal units.

The main finding of this study is that reliability contracts would assure efficiently the long term system adequacy and encourage earlier and adequate new investments and appear to be a more cost efficient incentive mechanism than capacity obligations scheme. It is also illustrated that the change in framework conditions and difference between technologies (cost structures and construction delays) would affect investment strategies but without influencing the effectiveness of reliability contracts scheme. Finally, the dynamic valuation of the investment problem would contribute to further postpone the investment decisions compared to the static assessment.

This remainder of the paper is organised as follows. Section 2 outlines the proposed dynamic investment model formulation. Section 3 presents the empirical analysis and results from applying our model to the French electricity sector. Section 4 summarises and concludes.

2. Dynamic Model for optimal investments

In this section we describe a dynamic optimisation model for optimal investments in new generation assets in a deregulated power market. We focus on modeling aggregate power generation investments under deterministic and stochastic investment criteria. We use the dynamic programming method to find the optimal market design that could ensure earlier and enough generation capacity to meet future peak demand with efficient cost. Two market designs, capacity obligations and reliability contracts, are studied and compared to the energy-only market in term of long term system adequacy and optimal timing of investments. The dynamic investment model assesses optimal cost efficient design when different factors, affecting the realizations of the socially optimal level of investment, are taken into account such as the consequence of the pricing of CO2, he difference between the construction delays and cost structures of the new technologies and uncertainties in future demand and fuel prices.

2.1 Mathematical description of the dynamic investment model

Dynamic programming[5] [13] is one of the optimisation techniques that is appropriate for solving investment problems with sequential decisions. It is a general optimisation technique with applications within a range of different areas, including power system planning. The central idea in dynamic

[5] The theory of dynamic programming can be found in Bertsekas (2000).

programming is Bellman's principle of optimality[6]. It is therefore often solved stepwise, starting either from the beginning or the end of the period of consideration. We use this technique to solve the dynamic investment model.

The investor is assumed to have an exclusive right to invest in the system (monopoly situation, but still acts as a new entrant and as a price taker). He can choose to invest between two technologies, which differ by their investment costs, operations costs and construction periods. We suppose also that if an expansion decision is made, additional investments can not be made until the ongoing construction is finalised. We suppose that the year begins with the peak period and the investment decisions are taken in the beginning of this period. The effect of the strategies of other generators is represented in the model simply by a fixed increasing in the initial peak capacity in the system over the planning period which in turn, affects the peak spot prices evolution. So, the interaction between investor's decisions and competitors' decisions is represented with an exogenous manner and concerns only the electricity price evolution.

The investment problem is described as follows:

$$J_0 = \max_{u_{k,i}} \left[\sum_{k=0}^{T} (1+r)^{-k} . g_{mk} \left(x_{mk}, l_{mk}, n_{mk}, u_{k,i}, P_{mk}, VC_{mk,i}, C_{invt,k,i}, R_{j,mk} \right) \right] \quad (1)$$

$$x_{m(k+1)} = x_{mk} + u_{m(k-lt_i+1)} \quad (2)$$

$$x_{mk} \in \Omega_{x_{mk}}, u_{mk,\mathrm{i}} \in \Omega_{u_{mk,\mathrm{i}}} \quad (3)$$

Where,

J_0	Max expected payoff over the planning horizon T
g_{mk}	Payoff function, peak period mk
l_{mk}	Demand, peak period mk
n_{mk}	Fuel price, peak period mk
P_{mk}	Average spot price, peak period mk
$VC_{mk,i}$	Variable cost, technology i,, peak period mk

[6] The Bellman's principle of optimality states that: *"An optimal policy has the property that, whatever the initial action, the remaining choices constitute an optimal policy with the respect to the sub problem starting at the state that result from the initial action"*

$C_{invt,k,i}$	Adjusted investment cost, technology i, time step k
$R_{j,mk}$	Additional revenue from the incentive mechanism j, peak period mk
x_{mk}	Sum of available installed capacity, time step k, peak period mk
$u_{mk,i}$	Investment decisions, technology i, peak period mk
r	Real risk adjusted discount rate
lt_i	Construction period for technology i
$i = [1, 2]$	Technology 1 and Technology 2
$j = [1, 2, 3]$	1 for “Energy-only Market”, 2 for Reliability Contracts and 3 for Capacity Obligations
k	Time step k
mk	Peak period, time step k

The objective function, which is to be maximised, is the sum of discounted expected payoff function from energy sales and additional incomes from incentive mechanisms, $g_{k,mk}$ and the payoff concerns only investor’s revenues in the peak period of the year. The algorithm calculates optimal expansion decisions (the optimal investment trajectory) i.e., for each time step, the model finds $u^*_{mk,i}$ which indicate whether it is optimal to invest in technology 1 or technology 2 or no and the maximal expected profit, J^*_0 is calculated

For a good representation of the investor’s profit from electricity sales, we use aggregate and simplified descriptions of the electricity spot market, the variable cost and the investment cost.

For the price description, the function still captures some of the main causal relations in the spot market for electricity, such as the relation between available generation capacity and load level. We assume that the average electricity price over the peak period in year k, P_{mk} , is a function of the load factor *LF*, i.e. the fraction of average load to average power generation over the peak period [11]. Exponential function is used to express the functional relationship between peak average spot price and load factor, $P_{mk}(LF)$. The mathematical description of spot price is described as below:

$$P_{mk} = a * b^{\wedge LF} \qquad (4)$$

Where

$LF = \dfrac{l_{mk}}{x_{init} + x_{mk,util,Tot}}$ Load factor, time step k, peak period mk

x_{init} Installed initial capacity in peak period, time step 0

$x_{mk,util,Tot}$ Installed and available capacity, in peak period mk

a, b Constants to be estimated from historical data

For the modelling of the variable cost, it is supposed to be constant and modestly dependant on fuel prices for technology 1, however, for technology 2, we suppose that it is highly reliant on fuel prices and the relationship is expressed by a linear function which is described as follows:

$$VC_{mk,2} = c - d.n_{mk} \qquad (5)$$

Where

c, d Constants defining the relationship between variable cost and fuel prices

The investment cost is calculated by the sum of all fixed costs connected to the specific investment, from the period when the investment decision is made to the end of the planning period. To do so, we first calculate the constant annuity computed from the total investment cost that would be paid over the life time of the plant (6) and second, the adjusted investment cost is determined by the sum of the discounted constant annuity within the remaining part of the planning horizon.

$$Ann_{TIC_i} = \frac{TIC_i}{\sum_{j=1}^{nt_i} (1+r)^{-j}} \qquad (6)$$

$$C_{invt,i,k}(u_k) = Ann_{TIC_i} \cdot \sum_{s=1}^{N-K} (1+r)^{-j} \qquad (7)$$

Where,

Ann_{TIC_i} Fixed annuity for all time step in the planning period

$C_{invt,i,k}$ Adjusted investment cost, technology i, time step k

TIC_i Total investment cost, technology i

nt_i Life time for unit

After developing the three sub-models for spot prices, variable costs and investment costs, it is easy to calculate the profit from energy sales in the spot market. However, the payoff function of the investor in each period depends also from additional revenues received from incentive mechanisms. So, three payoff functions will be developed depending on the applied design.

2.1.1 Payoff function with "energy-only market":

In this scenario, the payoff function will depend entirely from the investor sales in the spot market. The profit is calculated assuming that investor can easily stop the generation when the spot price is below operating cost and has the ability to only operate technologies maximizing the instantaneous profit. The description of the payoff function is shown in (8)

$$g_{k,mk}(R_{1,k}) = \max_{x_{i,util,mk}} \left(\sum_{i=1}^{2} \mathrm{hf}_i \cdot x_{i,util,mk} \left(P_{mk}\left(x_{tot,util,mk}, l_{mk} \right) - VC_{mk,i}(n_k) \right) \right) - C_{inv,i,k} \qquad (8)$$

Where

$x_{i,util,mk}$ Installed and available capacity, technology i, peak period mk

$x_{tot,util,mk}$ Total installed and available capacity, peak period mk

hf_i Expected availability of the new technology i

2.1.2: Payoff function with Call Option:

Here, an organized market is established where the regulator requires the system operator (SO) to purchase a prescribed volume of reliability contracts from generators on behalf of all the demand. The method is based on financial call option with auction procedure where the SO determines in advance the following parameters:

- The strike price, *s:* it should not be too low, since it acts as a price cap for demand and somehow represents the frontier between the "normal" energy prices and the "near-rationing" energy prices.

- The time horizon: typically the peak period; the seller can be required to generate the committed capacity at any time during that period.

- The total amount of power to be bought, *Q*,

- The value of the explicit penalty, *pen.*

- The generators submit one or several bids to the auction, expressing quantity (the capacity they want to sell) and price (the required premium),

- The market is cleared as a simple auction and all of the accepted bids receive the premium that was solicited by the marginal bid.

During the periods when the spot price p exceeds the strike price *s,* the bids that were accepted in the capacity auction will have to refund the regulator —and, indirectly, consumers— for the difference ($\rho - s$) for each megawatt sold in the capacity market. This refund is represented as the "implicit penalty". Additionally, if the spot price is above the strike price and the production of a certain generator is lower than the committed capacity, then he would have to pay to the regulator an "explicit penalty".

In our study, we get the following assumptions for the realisation of the auction:

- The auction is organized every year in the planning period and concerns only the peak period.

- The system operator sets the strike price S, function of the expected average spot price in the peak period.

- We suppose that the price of the contract is equal to the marginal bid, offered by the new investor. The premium fee required by the investor is described as follows:

$$P_{rem,\,mk} = \int_{P>S} \left(P - S\right) dt + a.\sum_{i=1}^{2} Ann_{TIC_i} \qquad (9)$$

Where

$P_{rem,\,mk}$	The premium fee required by the generator
P	The spot price in the peak period
S	The strike price
a	The part of the investment cost to be covered by the premium

The first term in (9) represents the income that the investor will not receive from the spot market as a consequence of his option, since for him the market price has a maximum value S. The second term represents a proportion of the investment cost that will be covered by the premium.

The generator payoff function will be:

$$\begin{aligned} g_{mk}\left(R_{2,mk}\right) = & \int_{p<s} \left[\sum_{i=1}^{2} hf_i \,.\, x_{i,\,util,\,mk} . \left(P - VC_i \right) \right] dt \\ & + \int_{p>s} \left[\sum_{i=1}^{2} hf_i \,.\, x_{i,\,util,\,mk} . \left(S - VC_i \right) \right] .dt \; + \; P_{rem,\,mk} \; - \; C_{inv,\,i,\,k} \end{aligned} \qquad (10)$$

The first term in (10) represents the income that the investor will receive from his energy sales, since the market price is below the strike price. The second term represents his income when the spot price exceeds the strike price, so the system operator exerts his option and commits the generator to be available and to sell electricity at the strike price.

2.1.3: Payoff function with Capacity Obligation:

The implementation of a capacity obligation mechanism ensures generation adequacy by imposing an installed capacity obligation on load serving entities, LSEs (large consumers, retailers…). Particularly, the LSEs are required, in peak periods, to have or to contract enough firm generation capacity to cover their expected peak load plus a regulated margin. This leads to a creation of a capacity market that allows trading of capacity obligations among the LSEs. This mechanism is implemented in our model in order to study its effect on investment attractive in term of capacity expansions and system adequacy.

The practical implementation of the approach is similar to the capacity payment mechanism in [10] and is presented as follows:

- The system operator sets the level of contract coverage of firm generation capacity to all LSEs; the quantity will be the estimated peak load plus a reserve margin.

- The LSEs are committed to participate in the capacity market only in periods when expected system adequacy in the peak period (capacity factor calculated by the ratio between available capacity and peak load plus a margin) is low:

  - If the expected capacity factor, CF, is bellow a certain CF_{limit} (critical situation), all LSEs are required to purchase, in the capacity market, the adequate capacity imposed by the system operator. Generators will earn additional revenue for each MWh sold in the market and the committed capacity has to be available at the time of delivery. The mathematical description of the generator revenues from the capacity market is described in (11)

  - If the expected CF is above CF limit, the system operator evaluates that the system adequacy of the market is assured and in turn, no capacity obligation will be imposed.

$$P_{CO,mk} = d_1 . e\wedge\left(\frac{d_2}{CF_{mk}}\right) \quad \text{if } \mathrm{CF}_{\mathrm{mk}} < CF_{\lim it} \tag{11}$$

Where,

$P_{CO,mk}$ Revenue / MWh for generator in the CM

$CF_{mk} = \dfrac{x_{\max}(x_{mk})}{l_{\max,mk}(l_{mk})}$ System capacity factor

$x_{mk} = x_{init} + \sum_{i=1}^{2} hf_i \cdot x_{i,new,mk}$	Total available capacity, peak period mk
$l_{max,mk}(l_k) = l_{mk} . c_{l,max}$	Peak load in the system plus a reserve margin, in peak period mk
CF_{limit}	Capacity factor limit
$c_{l,max}$	Constant ratio between max and average peak load
d_1, d_2	Constants defining the linear relationship between CP and CF

Exponential function is used to express the functional relationship between the generator's payment from capacity market and the capacity factor in the peak period (figure2). The payment increases as the capacity factor decreases, so there is more incentive to invest when the expected CF is low. We note also that, when the expected CF exceeds CF_{limit}, no capacity obligations will be imposed to LSEs and generators earn no revenue.

When applying this mechanism, the payoff function for the investor in period mk will be:

$$g_{mk}(R_{3,k}) = \max_{x_{i,util,k}} \sum_{i=1}^{2} hf_i \cdot x_{i,util,mk}\left(P_{CO,k} + P_k\left(x_{tot,util,mk}, l_{mk}\right) - VC_{mk,i}\right) - C_{inv,i,k} \qquad (13)$$

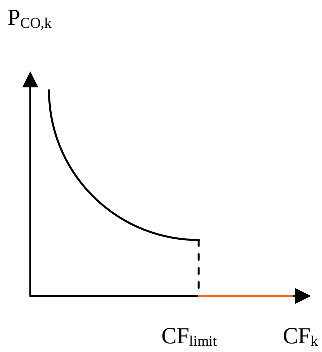


***Figure 2**: Relationship between P_{CO} and CF*

2.1.4 Optimal strategy:

The valuation of the capacity mechanisms will be done by comparing between the total incentive costs, the evolution of the capacity balances in the last five peak periods when we expect a great increase in the demand, the evolution of the consumers' payments and the technology choices for the three designs. We also study the consequence on optimal strategies of the pricing of CO_2 and the difference between the construction delays and cost structures of the new technologies.

The effect of incentive mechanisms on future prices and capacity balances is shown in figure 3. We can see that call options schemes would reduce prices in peak periods due to the strike price imposed by the system operator, while capacity obligation mechanisms assure more installed capacity in peak periods due to the twice remuneration of the capacity in this period

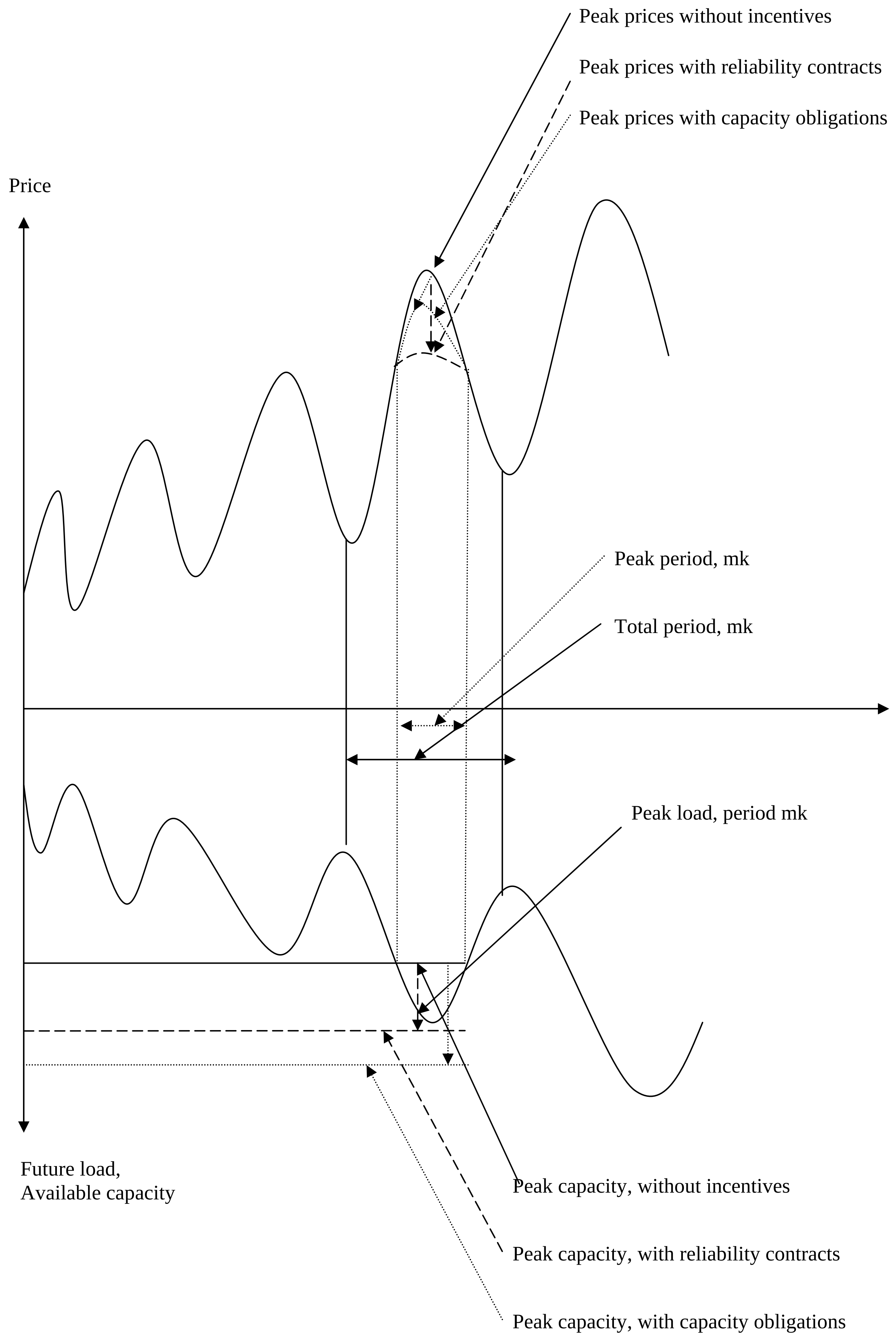


Figure 3: *Long term of the two incentive mechanisms on future prices and peak capacity in the system*

3. Case Study:

3.1. General input data:

The parameters in the models are estimated based on historical data for French Electricity Market[7], and found in [14], [15],[16] and [17]. Table 1 shows the main parameters used in the model.

The introduction of CO2 tax will affect only the variable cost of technology 2 due to its higher dependence on fuel prices, by adding a supplementary cost of 4 €/MWh.

Name in the models	Value
x_{init} /	63700 MW
l_0/ n_0	54700 MW / 4,5 $
l_{growth}/ n_{growth}	1000 MW / 0,1 $
$u_{mk,1}$ / $u_{mk,2}$	1500 MW / 750 MW
TIC_1/TIC_2	1.600.000€/MW / 571000€/MW
$VC_{mk,1}$ /$VC_{mk,2}$	11€/MWh / (5,718 n_k – 0,45561)/MWh
Tax-Co2	0 or 4€/MWh
lt_1 / lt_2	7 years / 3 years
nt_1 / nt_2	60 years / 30 years
r	0,08
af	648 hours

Table 1 *Initial input parameters for the investment model*

3.2. Results:

This section is concerned with identifying optimal investment decisions for the three market designs and studying how investment incentives i.e. reliability contracts (RC) and capacity obligations (CO) could ensure the long term system adequacy. The capacity adequacy level is calculated by the capacity balance in the peak period. The optimal capacity adequacy is assured when capacity balance is positive and no more than 3000 MW in order to avoid over capacity situations. The best mechanism will be that assures the optimal adequacy level in the critical periods (last five periods) and with

[7] The opening of the French electricity market was achieved with the creation of Powernext SA in 2001. We have referred on monthly historical data for load and electricity price in Powernext to estimate the parameters in the spot price model.

efficient cost. We also look into the consequences for investment strategies if the pricing of CO2 is taken into account and how the difference between construction delays and cost structures for the new power plants could affect the optimal decisions of the new investor.

A planning horizon of 18 years is used for the case study and the six different scenarios analysed here are shown in table 2.

Scenarios	
EOM	Energy-only market
RC	Reliability contracts
CM	Capacity obligations
EOM1	Energy-only market with tax-Co2
RC1	Reliability contracts with tax-Co2
CM2	Capacity obligations with tax-Co2

Table 2*: Definition of scenarios in the case study*

For the call options scenarios (RC and RC1), the premium fee earned by the investor in the auction is supposed to cover 30% of his cost of investment plus the income that he will not receive from the spot market as a consequence of his option and we represent load and spot prices with daily distributions in order to compare between daily price and the administrative strike price which is set to 80% of the average peak price. The time horizon of the auction is the peak period in the year and the investor is committed to produce his total capacity submitted in the auction. For the capacity obligations scenarios (CM and CM1), they are modelled as explained in section 2.1.3 with a CF_{limit} equals to 1.1

Result 1: Long term capacity adequacy in the system is assured when introducing incentive mechanisms

We can see from figure 4 that when introducing incentive mechanisms (RC and CM), the capacity balances still positive in the last five periods, while, with no incentives, system needs to rely on imports in order to meet the total demand in the last two periods.

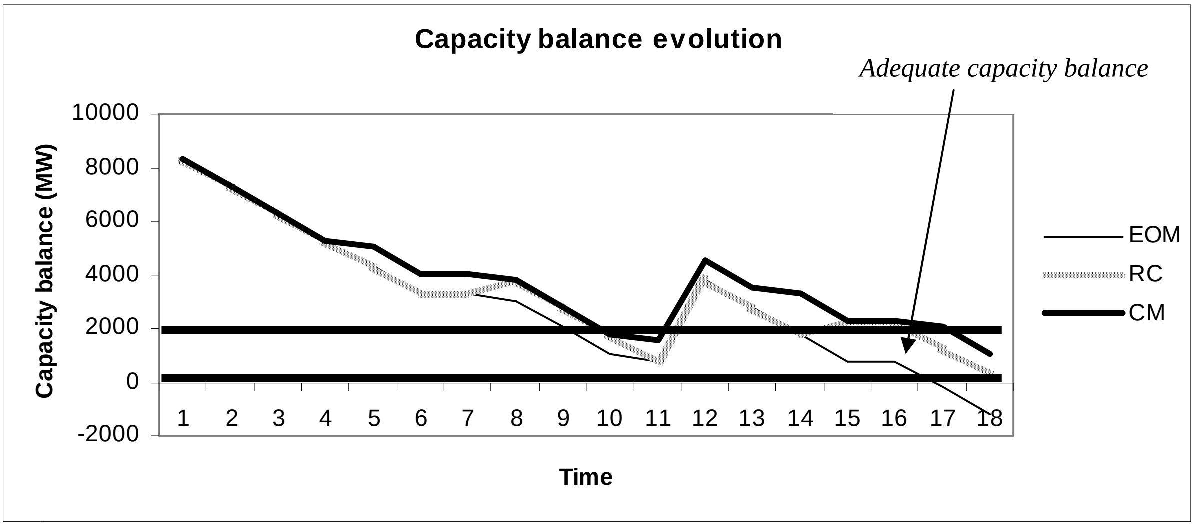


Figure 4: *Capacity balances evolution in the planning period for the three market designs: energy-only market, call options and capacity obligations*

An interesting result here is that call options scheme assure optimal level of capacity adequacy in the system where capacity balances in critical periods are positives and lower than with capacity obligation, which results in too much investments, leading to over capacity situations. This is shown in figure 5 where the total added capacity in the system is equals to 3750MW with capacity obligations and only 3000MW with call options scheme.

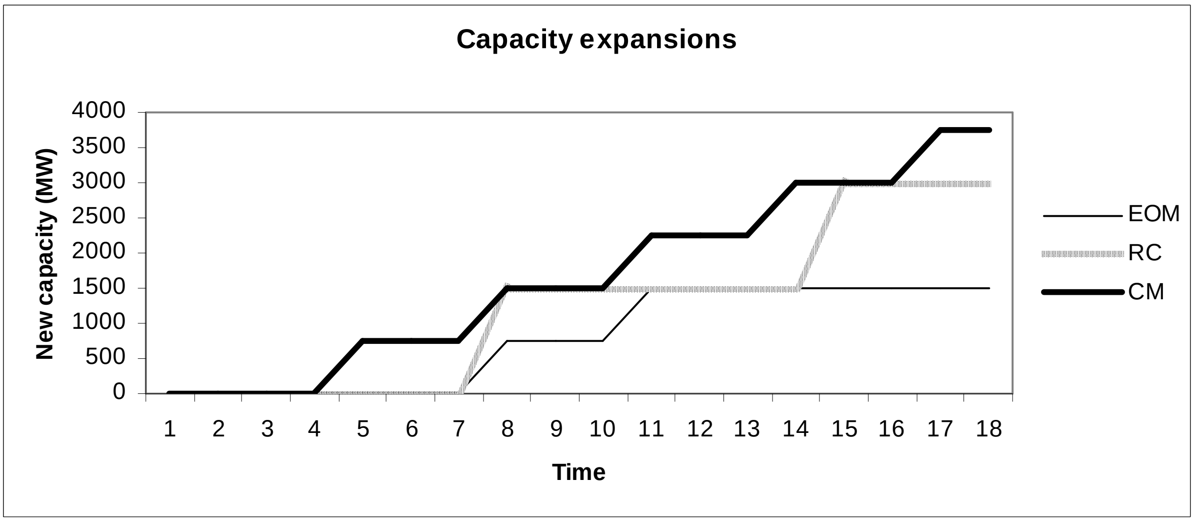


Figure 5: *Capacity expansions in the planning period for the three market designs: energy-only market, call options and capacity obligations*

We can explain the divergence in these results by the differences in the signals given by each incentive mechanism. On the one hand, the price of capacity for capacity obligation mechanism is determined administratively by the system operator and may be very volatile and high since it depends on the capacity factor in the system, leading to increase the extra revenue from available capacities earned by the participant in the capacity market, especially in periods where the capacity factor is low.

So, there is more incentive to invest in the system when applying this mechanism, profiting from the twice remuneration of capacities and inducing over capacities situations. On the other hand, the premium fee earned by the new investor when applying call options scheme is determined via market based mechanism and the extra revenue only corresponds to the part of the investment cost covered by the auction. Also, the electricity price is capped by the operator, so, the prescribed level of capacity adequacy is attained and the incentives for new investments are given with adequate manner.

Result 2: In the call options scheme, the expected peak prices are lower and less volatile compared to capacity obligation mechanism and consumers' surplus from price reductions are much greater with call options.

From figure 6, we can see that peak prices are lower with incentive mechanisms (RC and CM), compared to the first design and especially in the end of the planning period, which can be explained by the undesirable capacity adequacy level in this scenario due to the lack of new investments, involving prices that will not stay within a socially acceptable range. When introducing incentive mechanisms, prices decrease significantly, mainly with the call options scheme where the strike price imposed by the operator acts as price cap which prevents the peak prices from reaching high levels and consumers are fully protected from any high prices in the energy market.

Figure 6*: Expected peak prices for the three market designs: energy-only market, call options and capacity obligations*

Also, it is clearly shown in figure 7 that the consumers' surplus in term of price reductions when introducing incentive mechanisms are largely higher with call option compared to capacity obligation mechanisms. An important weak point of the capacity obligations is that consumers remain fully exposed to the potential high prices in the energy market and an application of a price cap in the market is needed.

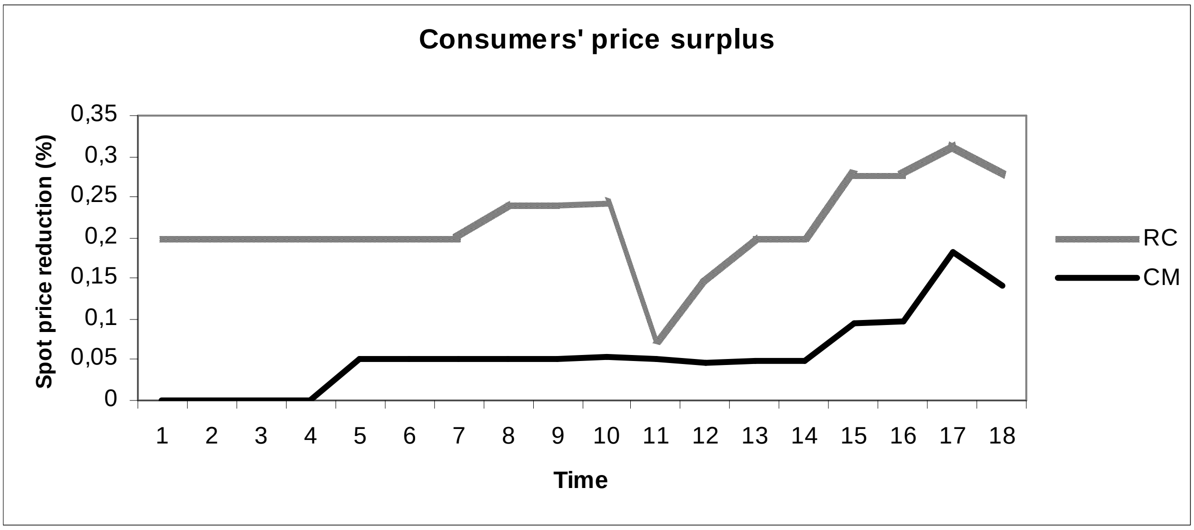


Figure 7: *Consumers' surplus from price reductions for the incentive mechanisms: call options and capacity obligations*

***Result 3: Call options scheme is the more cost efficient mechanism and leads to stabilise consumers' payments*.**

We distinguish here between the additional cost paid by the consumers for assuring optimal adequacy level and the total cost paid for each MWh bought from the market, including energy price and incentive cost. Figure 8 illustrates the evolution of the specific cost of the two incentive mechanism. It is shown that the incentive cost paid by the consumers is stable and close to 20 €/MWh over all periods when the call options is applied, while, the cost is increasing and reaches great levels, up to almost 50€/MWh at the end of the planning period with capacity obligation mechanism. The difference here is that incentive costs are largely dependent on the capacity factor in the system for the capacity obligation design and more the capacity factor decreases, more the additional payment increases. However, with call options, the premium is set via market based mechanism and gives a stable income for generators on the one hand and hedges consumers from the occurrence of high prices and high additional incentive cost on the other hand.

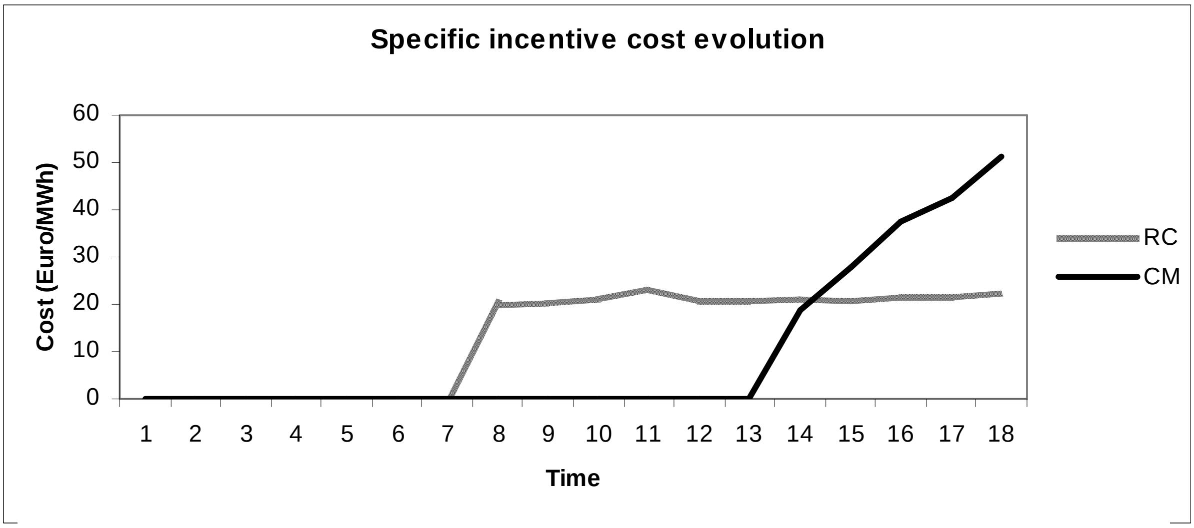


Figure 8: *Specific incentive cost of the incentive mechanisms: call options and capacity obligations*

For the total costs paid by the consumers (including energy prices and specific incentive cost), figure 9 also shows a stable and low payment over the planning period when applying the call options mechanism, which vary between 20€/MWh and 45€/MWh. However, the implementation of capacity obligation mechanism involves increasing costs which attaint 100€/MWh in the end of the planning period. Here, a strong advantage from the call options method is that consumers are fully protected from any high prices and the cost needed to assure the adequate capacity adequacy level stay within a socially acceptable range

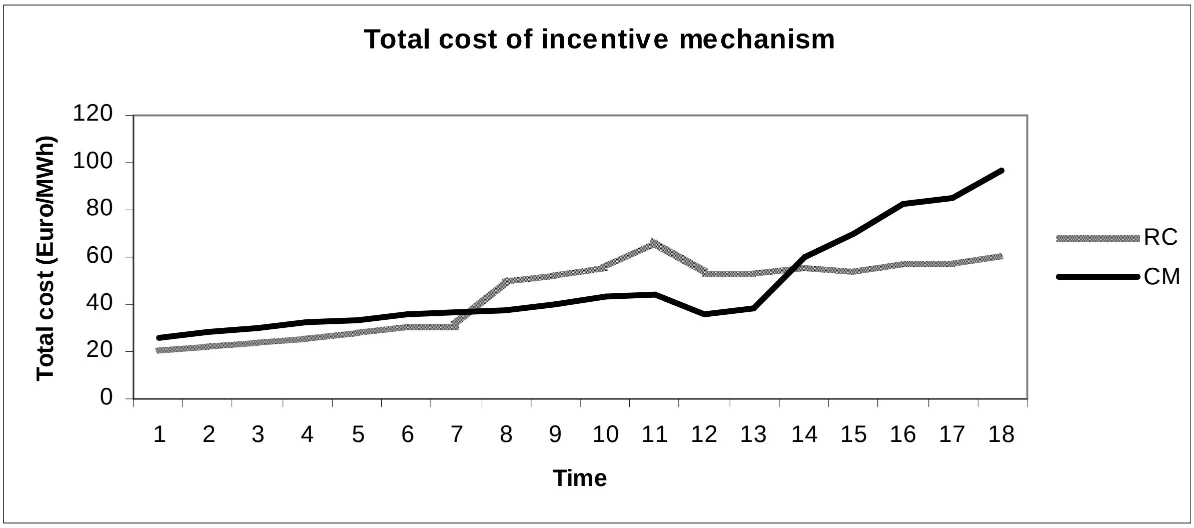
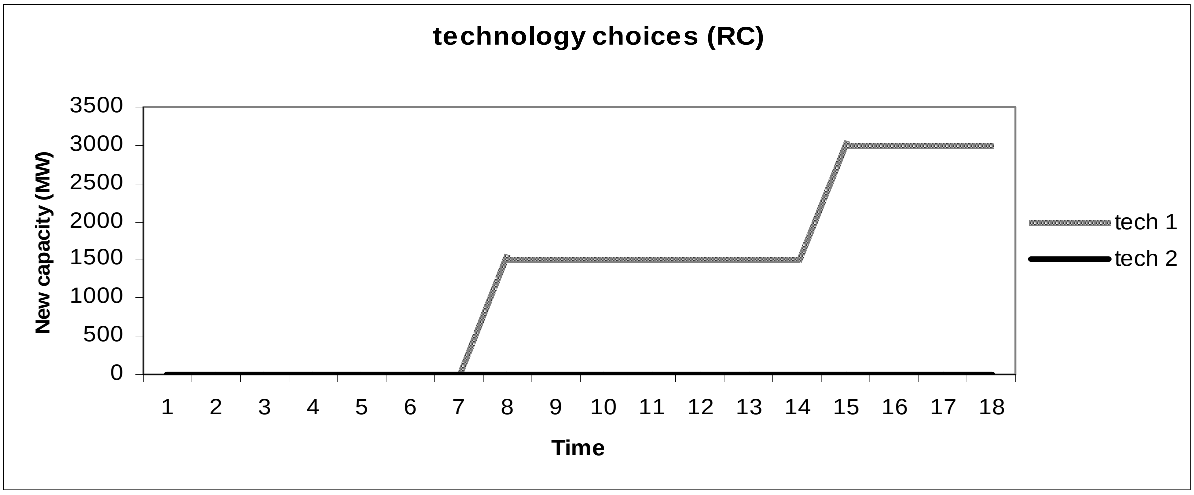


Figure 9*: Evolution of the total cost paid by consumers when applying the incentive mechanisms: call options and capacity obligations*

Results 4: Capacity obligation mechanism stimulates more investments in short lead time technology, while, with call options, only differences between costs structures of new technologies are crucial in optimal technology choices.

We now study optimal technology choices for the two incentive mechanisms. Figures 10 shows optimal choices between technology 1 requiring long construction delay, high investment cost and low variable cost and technology 2 characterised by its short construction delay but, largely dependant on fuel prices. It is shown that with capacity obligation mechanism, only technology 2 is chosen. However, with call options scheme, investor prefers technology 1. This can be explained by two factors. Firstly, with capacity obligations mechanism, generator expects perfectly the application of the capacity market, so earlier he has an available capacity in critical periods, the more he can profit from the twice remuneration of his capacity and thus, he prefers technology 2 which requires short construction delay, guaranteeing an earlier availability in the system.

Secondly, when applying the call options scheme, the premium earned by the participant in the auction covers principally a part of the investment cost of the technology and investor prefers to invest in technology 1 to benefit from its low variable cost and take advantage from the possibility of bidding an offer in the auction which will cover a significant part of the investment cost of the technology which is very high.



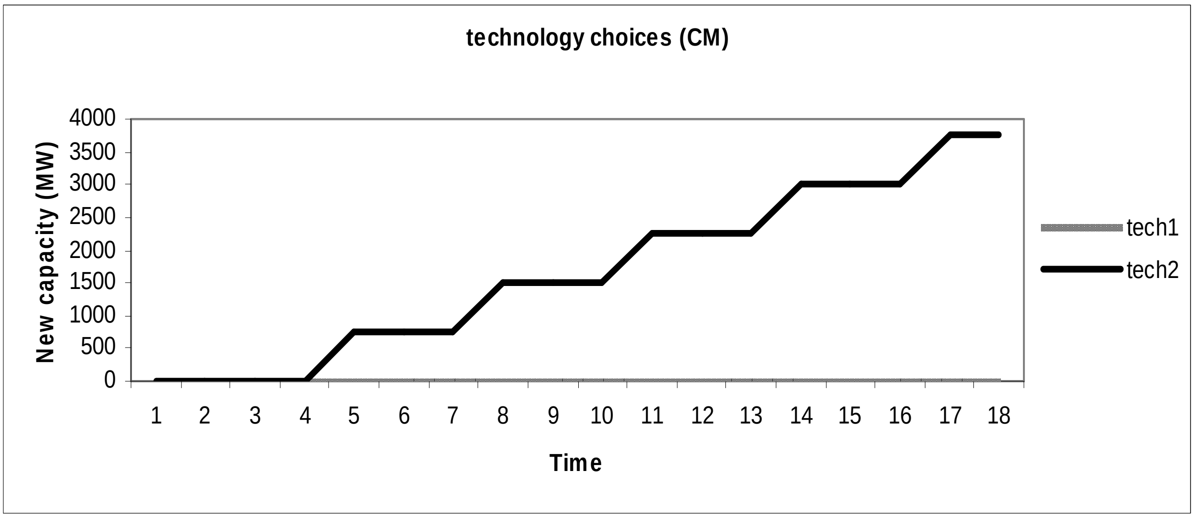


Figure 10*: Technology choices in the two market designs: call options and capacity obligations*

Result 5: The implementation of Tax-Co2 would change the optimal technology choices without affecting the effectiveness of the call options scheme.

We now study the effect of the pricing of CO2 on optimal technology choices and in turn, the capacity adequacy in the system. The Tax-Co2 will affect only the variable cost of technology 2 due to its higher dependence on fuel prices, by adding a supplementary cost of 4 €/MWh. The results of technology choices in figure 11 show a shift in optimal choices and investor chooses to invest in both technology 1 and technology 2 for capacity obligation design, however, the introduction of Tax-Co2 in the call options design, does not affect the optimal choice and the optimal investment path concerns also technology 1. As without tax-Co2, call options scheme stimulates more investments in technology 1, due to its cost effectiveness and to the possibility of covering a large part of the investment cost for the new investor when bidding in the auction. However, the Tax-Co2 implementation in the capacity obligation scenario has reduced the competitiveness of technology 1, in term of shorter construction delay and investor chooses to invest in both technology 1 and technology 2 profiting in the one hand from the cost effectiveness of technology 1 and the shorter construction delay of technology 2.

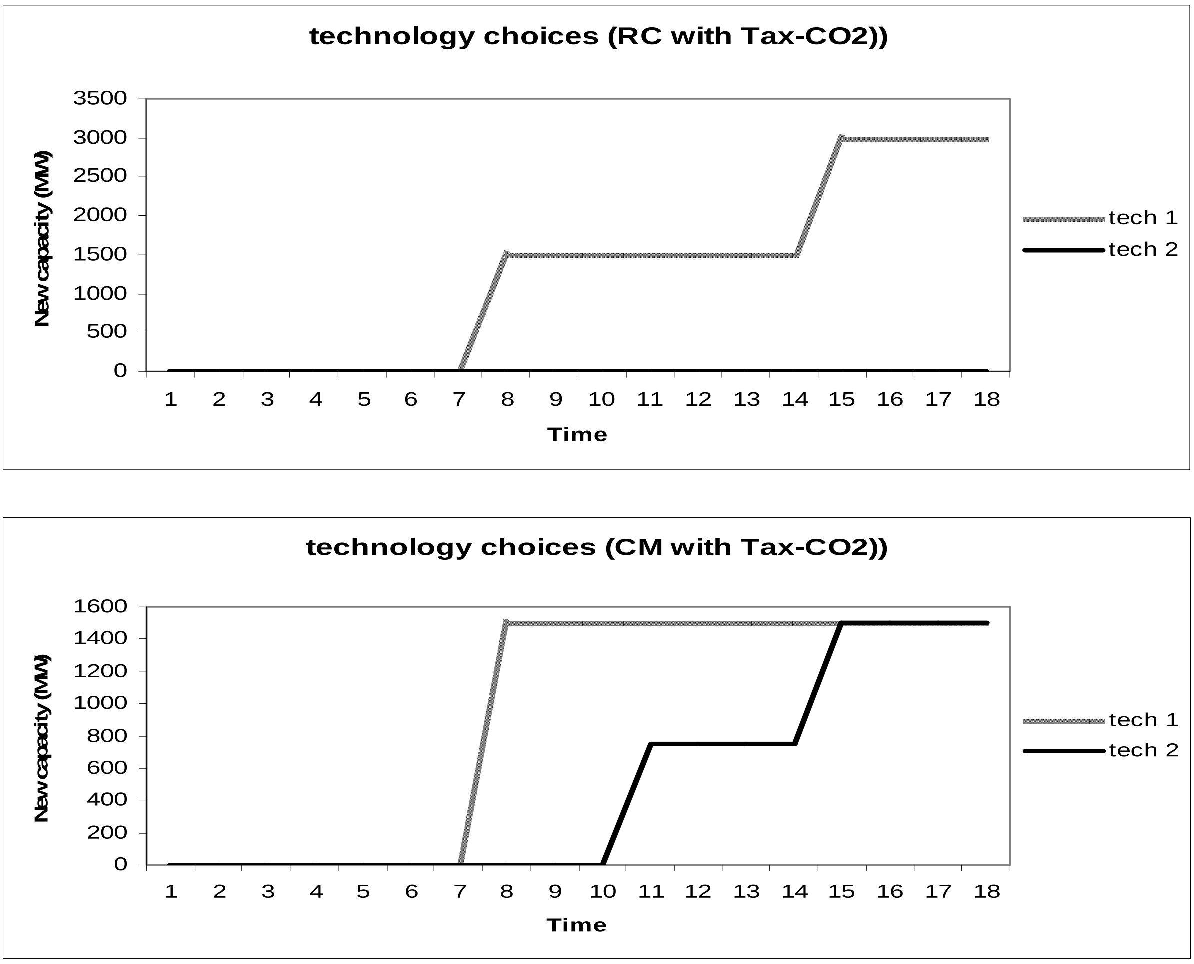


Figure 11: *Technology choices in the two market designs with Tax-Co2: call options and capacity obligations*

it is shown in figure 12 that the two incentive mechanisms still assuring the adequate level of capacity adequacy in the last five periods, where levels evolve closely.

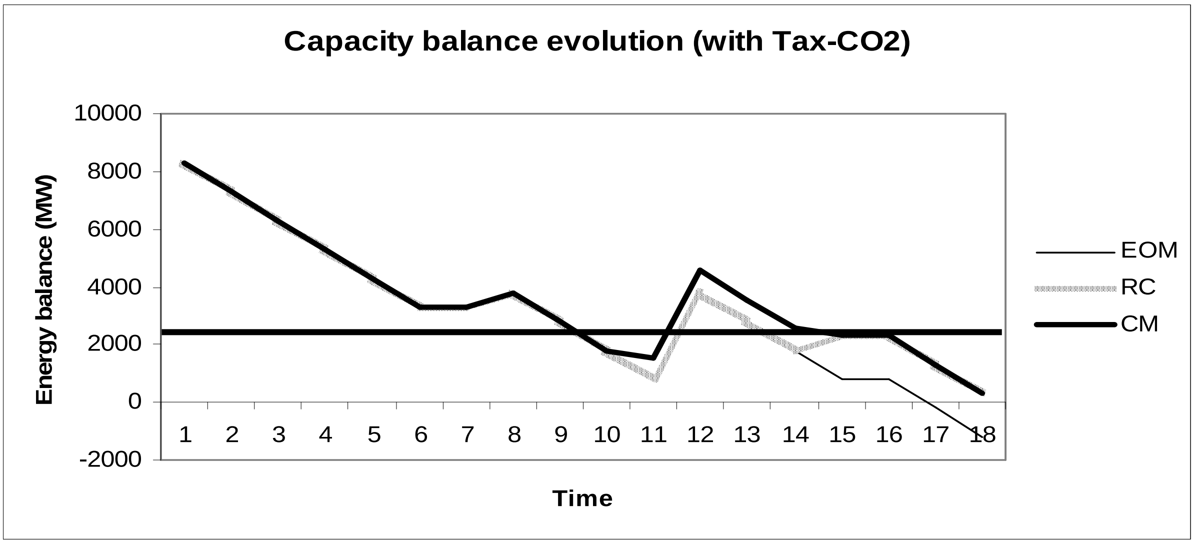


Figure 12: *Capacity balances evolution in the planning period for the three market designs and with Tax-Co2: energy-only market, call options and capacity obligations*

So, the tax-Co2 implementation has reduced the levels of new capacity additions in the capacity obligation mechanisms and brought it back down to the levels in call options scenario. However, the total cost paid by the consumers for each market design, over the planning period (Figure 13), evolve similarly to scenarios without Tax-Co2, with a stable and low payment when applying the call options mechanism and an increasing and higher costs with capacity obligation design.

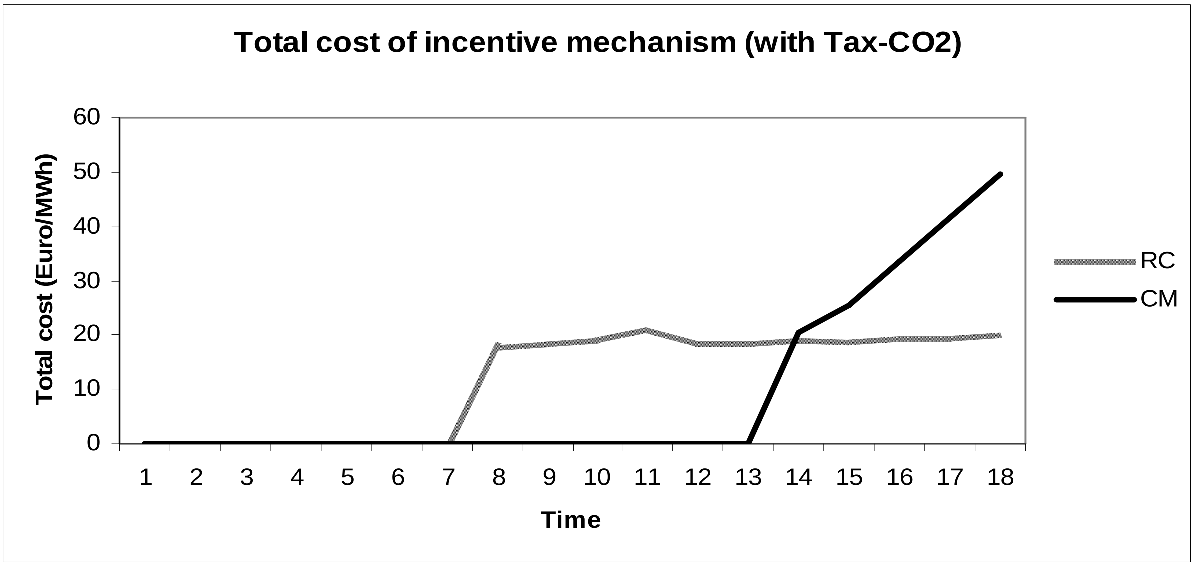


Figure 13: *Evolution of the total cost paid by consumers when applying the incentive mechanisms and with Tax-Co2: call options and capacity obligations*

4. CONCLUSION

While there is compelling evidence to suggest that the electricity industry liberalisation has, in general, improved productive efficiency, and reduced operating and maintenance costs, there is as yet insufficient experience to assess the long-term benefits from liberalising the electricity industry. One key issue lies in the ability of a liberalised electricity industry to deliver appropriate investment incentives and maintain generation adequacy in the long-term. There is as yet no clear academic consensus on which market design provides the least distorting long term investment incentives. In liberalised markets investment must be profit motivated, and under current EU Directives capacity choices are left to the market, except if there is a potential threat of shortage. The reliability and the adequacy of electricity supply has been the principal motivation for many technical and economic regulations imposed on market designs by regulators. To address the problem of adequate generation capacity in electrical power markets, some sort of regulatory capacity mechanism in addition to the spot market have been employed or proposed.

In this paper, we have illustrated a dynamic investment model for solving the problem of adequate generation capacity. We have compared between two incentive mechanisms, call options and capacity obligations, in order to find the optimal market design that could ensure enough generation capacity to meet future peak demand with efficient cost. The dynamic investment model is solved with the dynamic programming method, allowing to assess optimal cost efficient design and optimal investment strategies when different factors, affecting the realizations of the socially optimal level of investment, such as the pricing of Co2, construction delays and cost structures of new technologies, are taken into account.

The main finding of this study is that reliability contracts would assure efficiently the long term system adequacy and appear to be a more cost efficient incentive mechanism than capacity obligations scheme which results in too much investment. It is also illustrated that the change in framework conditions and difference between technologies (cost structures and construction delays) would affect investment strategies but without influencing the effectiveness of the reliability contracts scheme.

This analysis could be extended in several ways. Firstly, we could study the effect of other mechanisms such as capacity payment and capacity subscriptions. Secondly, the feedback of the demand’s side could also be analysed. Finally, game theoretical method could be used to study the effect of competition among market participants on the long term system adequacy.

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