EFFECTS OF GAS-PRODUCTION CONSTRAINTS OVER GENERATION EXPANSION

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Abstract – Gas fueled power plants have been extensively built all around the world while they are a high efficiency, low-emission technology with short building time. During some years they were also very interesting from an economic point of view. Nevertheless, prices are currently increasing and besides gas is becoming more and more a strategic element, what may suggest the need to constraint the dependence on this fuel.

This paper presents a method for analyzing the impact of the measures that the system regulator could use in order to constraint the number of gas-fueled plants to be built. This may include mandatory reference planning, taxes on gas, or the promotion of substitutive technologies. The analysis uses a system-dynamics-based model that represents in detail the process of generation expansion. It consists of four major modules: market representation, price forecasting, investment decision and plant building.

The results in a particular system show that subsidizing renewable technologies, is a very interesting alternative, both from the cost point of view, and because it requires less additional measures to maintain reserve margin and reasonable prices.

Keywords: generation planning, long-term generation analysis, system dynamics

1 INTRODUCTION

In the last years, natural gas has become a very interesting alternative for generation expansion. Combined cycle gas turbine (CCGT) and gas turbine plants provide a high efficiency, low-emission technology with short building time and low investment cost that leads to interesting levels of profitability when natural gas prices stay in low values. In some countries, as it is the case of Spain, new investment in generation assets, out of renewable technologies, is being done only with this technology.

Electricity generation planning using mainly this technology may make sense from a purely economic point of view. Nevertheless, some experiences have shown that it can lead to critical situations. Russian-Ukrainian gas crisis in 2006, showed that third countries can be affected by gas shortages as a consequence of bilateral problems when a customer is simultaneously a transit country for the pipeline [1]. Other example of gas crisis was undergone by Chile in 2004 when due to global economic Argentinean crisis, gas supply was severely reduced. Additional examples of gas producers with potential strategic power include the Algerian Sonatrach supply to Spain and Italy and the Norwegian consortium Petoro that exports to Germany, France, Belgium and the UK among other countries.

Generation planning (as well as transmission lines and pipeline developments) has been focused in this fuel, with combined cycle plants under construction and planned around major cities [2]. As a matter of fact, the main countries that produce natural gas make a strategic use of it, jeopardizing supply of the demand.

Besides, natural gas has gone through periods of high prices and high volatility (for example in year 2005, see Fig. 1) that have made decrease its profitability as fuel for electricity generation. From the regulator point of view, natural gas cannot be the only long-term choice for electricity generation, diversification is desirable and should be promoted.

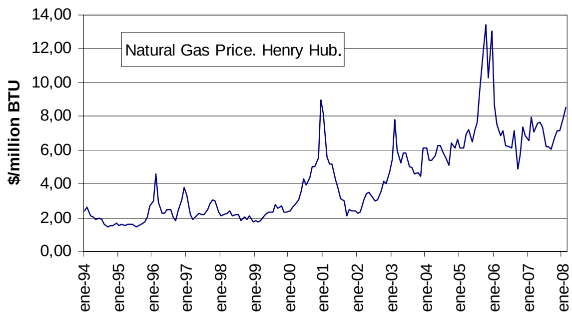

Fig. 1. Natural gas prices evolution. (Source: Dow Jones & Company. Downloadable from Federal Reserve Bank of St. Luis research.stlouisfed.org)

Different methods can be chosen by the regulator to constraint gas-based plants building including mandatory generation planning, taxes or other charges over gas, or incentives to alternative technologies able to displace gas. The most immediate method is to establish taxes over gas, or reduction in its capacity payments, with the drawback of increasing electricity prices. A second possibility is the use of a mandatory reference planning for gas plants. This alternative creates conflicts if generation companies want to build new plants but some of the permits must be refused. Quotes for gas-based plant expansion can also be implicitly imposed by delaying the obtaining of permits, this is a situation than can be realistic, but should be avoided due to its lack of transparency. Finally a third possibility is to promote alternative technologies [3]. This can be achieved for example by increasing capacity payments, or subsidizing production.

The consequences of these decisions over system expansion and operation are different and some side effect may appear. These aspects will be analyzed using a detailed representation of the market behavior and the investment decision process, based on the system dynamics technique.

The main contribution of this work is to address the problem of how to face the real risk of fuel scarcity when a very significant part of the generation depends on natural gas through a model that represents the process of generation expansion in an exhaustive way. The presented model can be used by the market regulator to assess the effect of different regulatory policies over plant planning.

2 MODEL DESCRIPTION

2.1 Overall structure

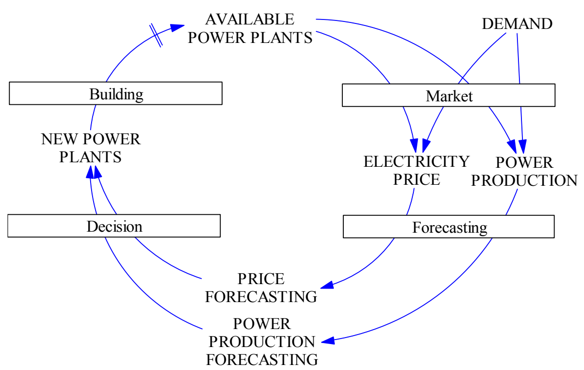

Fig. 2. Model overall structure.

Electric system is represented in the long-term run using a simulation model based on System Dynamics [4]. A more detailed description of the model can be found in [5]. In a global view, the feedback structure representing the new generation capacity investment decisions can be divided in four main blocks as shown in Fig. 2. Starting from demand and available power plants, a representation of the market determines electricity prices and power outputs for every plant. The second block represents the forecasting of prices for a determinate time horizon that market agents make, as well as plant production forecasting. These results allow making the decision -third step- of how many plants to build, which each generation company makes depending on its own characteristics and with its profitability criteria. Finally, new plants enter the system with some delay that represents permit obtaining and plant building. These blocks are explained in the following sections.

Simulation is performed sequentially and each block is actualized for each simulation year. The hypothesis that have been considered fit well to Spanish system and could also be acceptable for other systems.

2.2 Market

Starting from demand and available power plants, this block determines electricity prices and power outputs for every plant.

2.2.1 Spot Market

The spot electricity price is calculated by means of a strategic production costing model, extending the detailed model in [6] in order to deal with forward contracting. In this model, the bid function *B* of each company *i* for each load level is,

$$B_i(q_i) = C_i'(q_i) + \theta_i \cdot [q_i - F_i] \qquad (1)$$

Where C'_i is the marginal cost function of the company, q_i its production with F_i its forward sales and θ_i is a strategic parameter reflecting the conjectured price response, as in [7]. It is important to note that when a company can not control the market price, the slope of its residual demand function will be zero, and so the strategic parameter. Also, it can be observed that the market power effect is equivalent to modify the marginal cost of the unit in $\theta_i \cdot [q_i - F_i]$.

More concretely, the conjectured price response is defined as (being *p* the spot price):

$$\theta_i = \left|\frac{\partial p}{\partial q_i}\right| \qquad (2)$$

In general, it can be assumed that this conjectured price response can be inferred from the past market evolution, as this is nothing but the first derivative of the residual demand curve. However, as in our case the market evolution is endogenous, we have developed a method to estimate the influence of the system structure (mainly forward contracting, agents size and marginal cost functions) in this conjectured price response.

2.2.2 Conjectured-price-response estimation

We have developed a new estimation method based upon supply function equilibria considerations. Under the theoretical assumption that each company offers optimal supply functions to the market, the derivative of the inverse of this supply function, with respect to the output of the company, provides an estimate of the strategic parameter θ_i.

Thus, considering the revenues Π_i in the spot market, of a company *i*:

$$\Pi_i = p \cdot [q_i - F_i] - C_i(q_i) \qquad (3)$$

The supply function:

$$S_i(p) = q_i$$
$$S_{-i}(p) = \sum_{\forall j \neq i} q_j \tag{4}$$

And the quantity contracted in the forward as a proportional function of the demand d:

$$F_i = \alpha_i \cdot d \tag{5}$$

An optimality condition is obtained, maximizing Π_i (note that to solve this equilibrium, companies know quantities contracted by the other companies):

$$S_i(p) - \alpha_i \cdot d - \frac{\partial S_{-i}}{\partial p} \cdot \left(p - \frac{\partial C_i}{\partial q_i} \right) = 0 \tag{6}$$

Applying a homogeneity condition as follows, to equation (6):

$$S_i(p) = \beta_i \cdot S(p)$$
$$S_{-i}(p) = \beta_{-i} \cdot S(p)$$
$$\beta_i + \beta_{-i} = 1; \tag{7}$$
$$\beta_i = \frac{\overline{q_i}}{\overline{q}}; \beta_{-i} = \frac{\overline{q_{-i}}}{\overline{q}}$$

We obtain, with $d = S(p)$:

$$d - (N_i - 1) \cdot \frac{\partial d}{\partial p} \cdot \left(p - C'(\beta_i \cdot d) \right) = 0 \tag{8}$$

Where N_i is:

$$N_i = \frac{\beta_{-i}}{\beta_i - \alpha_i} + 1 \tag{9}$$

An equation similar to the one in (8) is solved in [8] . In [8], the supply function equilibrium with N symmetric companies and inelastic demand is calculated. The difference with our equation is that while N is the number of symmetric companies in [8], in our equation N_i is expressed by (9). It can be observed that this N_i can be considered as the number of companies that a company see similar than itself. So, we are assuming here that each company is solving its supply function as if it were competing against N_i companies similar than itself. The solution of this equation in [8] results in (p_r being a reservation price):

$$p(q_i) = \frac{p_r \cdot q_i^{N_i-1}}{\overline{q_i}^{N_i-1}} + (N_i - 1) \cdot \frac{q_i^{N_i-1}}{\beta_i^{N_i-1}} \cdot \int_{\frac{q_i}{\beta_i}}^{\frac{\overline{q_i}}{\beta_i}} \frac{C_i'(\beta_i \cdot x)}{x^{N_i}} \tag{10}$$

Thus, considering linear marginal costs:

$$C_i' = a_i + b_i \cdot q_i \tag{11}$$

An analytical solution can be obtained for the derivative of p with respect to q_i, giving a reasonable estimation of the strategic parameter θ_i. Finally, we have:

$$\left| \frac{\partial p}{\partial q_i} \right| = \theta_i = \mu_i \cdot d^{N_i - 2} - \zeta_i$$
$$\mu_i = \frac{(N_i - 1) \cdot (p_r - a_i)}{\beta_i \cdot \overline{d}^{N_i-1}} + b_i \cdot \frac{(N_i - 1)^2}{(2 - N_i)} \cdot \frac{1}{\overline{d}^{N_i-2}} \tag{12}$$
$$\zeta_i = b_i \cdot \frac{N_i - 1}{2 - N_i}$$

2.2.3 *Forward Market*

So far, forwarded contracted quantities F_i have been considered as known. These quantities are periodically decided by generation companies and depend on market and system conditions. There is an open discussion in the literature questioning whether forward contracting increases or reduces market power, starting with the seminal paper of Allaz an Vila [9]. This paper will accept the conclusion of this work.

Allaz and Vila compute an equilibrium model in two stages in order to obtain optimum quantities contracted in the future market. Main assumptions for this model are Cournot competition, symmetric duopoly, constant marginal costs for each company and a future market where contracts traded call for delivery during the next spot market. With this, a formula for the quantity to be contracted by each company in the future market is obtained as a function of costs, and demand elasticity. As an example, for the symmetric duopoly case these formulas can be expressed as:

$$f_{1i} = \frac{1}{5} \cdot \left(d + \sum_i q_{1i} - \frac{\partial c_{1i}}{\partial q_{1i}} \right) \tag{13}$$

In these formulas, f_{ji} is the quantity contracted by company i in the future market at instant j. When calculating quantity for future market 1, quantities for forward market 2 are estimations.

In this model Allaz and Vila hypothesis have been extended and a conjectured-price-response based market is considered, duopoly may be asymmetric, marginal cost are linear and risk aversion is considered.

Computing these formulas within the system dynamics model for each simulation step allows calculating quantities contracted in long -term contract markets that call for delivery in the next spot markets

One-year contracts are assumed, that call for delivery in the next spot market. That is, each year, a future market is simulated and then a spot market which takes into account the quantities contracted in that previous future market in the companies' strategy is calculated. To simplify, we consider that just the two main companies in the system are able to contract forward.

2.3 *Future price forecasting*

To compute the NPV, the companies make forecasts of prices and productions of a new group of each technology. To do this, an estimated price-duration curve is calculated for a given year in the future (in our case, 40 years after the current one) as if in that year there were an optimal generation portfolio in the system. Then, the current price-duration curve is approximated softly to the one estimated in the future during the following years. With this, an estimation of the future prices is obtained which takes into account the current situation and a reasonable hypothesis for the long-term (optimal portfolio). Once the forecasts of price-duration curves have been made, the estimated production of a new group of each technology is calculated considering it is going to be bided by its marginal costs.

2.4 Investment decisions

This model uses an alternative method to differentiate the agents when they decide their investments based on credit risk theory ideas. In many real situations, agent's decisions are based on net present value (NPV) that is computed for each of them using a different discount rate. Differences in this discount rate are related to credit risk. Discount rate uses to be constituted by risk-free rate r, that is commonly known, and a risk premium w, that is related to credit risk.

If no dividends are paid to shareholders ($\gamma = 0$) the value v of a quantity V that is lent in time t to be returned in time T is affected by this risk:

$$v(t,T) = e^{-w(T-t)} \cdot V \tag{14}$$

This credit risk can be advantageously modelled using the Black-Scholes-Merton debt pricing model (See chapter 5 of [10]. In this model a debt is failed by a company if its assets value A_T goes below its debt V. Company assets value is its equity value plus its debt. Consequently, at time of debt issue and evaluating shares value as a call option C over assets with V strike:

$$v(t,T) = A_t - C(A_t, V, r, \gamma, T-t, \sigma) \tag{15}$$

$$C(A_t, V, r, \gamma, T-t, \sigma) = A_t \cdot e^{-\gamma(T-t)} \cdot N(v_1) - V \cdot e^{-r(T-t)} \cdot N(v_2) \tag{16}$$

$$v_1 = \frac{\log A_t - \log V + \left(r - \gamma - \sigma^2/2\right) \cdot (T-t)}{\sigma \cdot \sqrt{T-t}} \tag{17}$$

$$v_2 = v_1 - \sigma \cdot \sqrt{T-t} \tag{18}$$

$N(x)$ is probability for a standard normal to be below x and σ is a parameter that can be estimated from company value A_t evolution volatility. From the previous expressions w can be obtained.

The use of this schema in the model requires separately computing agents' discount rate $r+w$ for each simulation step to compute NPV of a possible investment. Assets value A_t and debt D_t must be also recomputed at each step.

A_t includes company liquid assets L_t and infrastructures I_t. Liquid assets are updated as:

$$L_{t+1} = L_t + M_t - rD_t + D_t' - NI_t - \varphi_t \tag{19}$$

M_t is operational profits, rD_t debt interest, D'_t new debt, NI_t new investment (assuming $D'_t = NI_t$) and φ_t debt redemption.

I_t can be updated making I equal to its nominal value B. Let aB_t be infrastructures depreciation, then:

$$B_{t+1} = B_t - aB_t + NI_t \tag{20}$$

Other alternative is to compute I from market value. If infrastructures profitability is assumed as constant with a value:

$$r'_t = \frac{M_t}{B_t} \tag{21}$$

then infrastructures, with a estimated life spam T', have a value:

$$I_t = \sum_{t'=0}^{T'} e^{-r \cdot t'} \cdot r'_t \cdot B_t \tag{22}$$

Debt is also updated, using the following expression.

$$D_{t+1} = D_t + N_t - \varphi_t \tag{23}$$

By computing the above equations for each simulation step, and applying Black-Scholes-Merton debt pricing model, a value for the discount rate of each company is obtained based on its financial and economic structure. This discount rate allows computing a different NPV for each company which leads to different investments.

A different aspect regarding investment decisions is the total quantity that a company is going to invest depending on the expected profitability calculated. Each company invests each year just in the most profitable technology and builds a number of groups of this technology which is function of the NPV and which has a maximum value expressed as a percentage of the assets value of the company. Additionally some IPPs are represented with a fixed discount rate and a joint investment limit defined as a percentage of total demand.

2.5 New plants building

Regarding the building block of the overall scheme two delays are considered: one for obtaining the construction permits and one for building the new plant (different delays for each technology). Once a permit is obtained, the investment may be revaluated, and the company may decide not to use the permit.

3 CASE STUDY

In order to assess the impact of different measures over gas-fueled plants productions, system reserve margin, prices and costs, a base case has been defined. It represents a hypothetical large-scale electric power system freely inspired in the Spanish one. From this situation different reductions have been considered using gas quota reductions (for example in order to comply with a mandatory reference planning), taxes over gas and subsidies for wind power, as a substitutive technology.

3.1 System description

The scope of the study is split into 20 years. The model time resolution is 1 year, but price is calculated for every block of 10 hours (each block representing a load level) of the 12 periods w (months) in which a year is divided.

The energy is supplied by five generation companies (*c1* to *c5*) with different sizes. The main characteristics of thermal units are shown in Table 1. Non-supply energy has a cost of 180 €/MWh. A CO_2 emission rate is considered for each unit. For gas-fueled plants, this rate is 0.35 tCO_2/MWh. Besides, a capacity payment of 40000 €/MW for all the technologies is received. Table 2 shows the number of hydro units of each firm and their aggregated characteristics for the first period *w* of any year. An average scenario of hydro production is considered for every year.

An initial base load is also included for every year. This consist of a pumping storage of 1000 MW in the 50% of the hours of every period *w* and a cogeneration production of 5000 MW for the 50% hours of least demand of every period *w* and 8000 MW for the rest.

An hourly load based in the one of the Spanish electricity market in 2003 is considered to calculate the hourly loads of the years of the model. A 3% constant growth is considered for the rest of the following years being 2005 the first year.

€/MWh	c1	c2	c3	c4	c5
Up to 5	400 (1)	0 (0)	0 (0)	0 (0)	0 (0)
5 to 10	4600 (5)	0 (0)	2000 (2)	0 (0)	0 (0)
10 to 15	100 (1)	0 (0)	0 (0)	0 (0)	0 (0)
15 to 20	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
20 to 25	2500 (7)	1900 (5)	3000 (9)	1900 (5)	0 (0)
Over 25	9900 (40)	1800 (8)	5500 (19)	1900 (5)	0 (0)

Table 1: Capacity (MW) and Number (in parenthesis) of thermal groups by company ranged by cost

	c1	c2	c3	c4	c5
#	2	10	3	0	2
E (GWh)	78.66	236.64	16.67	0	28.6
Pmax (MW)	1423	5681	485	0	606
Pmin (MW)	706	1301	64	0	241

Table 2: Aggregated hydro power characteristics by utility for first period of any year. Number of hydro plants (#), energy (E), maximun output (Pmax) and minimum output (Pmin).

	IC	*VC*	*FC*	*PC*	*ER*	*LS*
	k€/MW	*€/MWh*	*€/kW*	*MW*	*tCO2/MWh*	*years*
Nucl.	1250	11.5	53	1000	0	40
CCGT	619	22	29	400	0.37	30
Fuel	800	40	21.5	300	0.8	30
Coal	1200	17	32	500	0.95	30
Coal b	1167	14	32	500	0.88	30
Gas t	416	32	20	250	0.65	25
Wind	1211	0	28	1	0	25

Table 3: General characteristics for technologies. Investment costs (IC), variable costs (VC), fix costs (FC), plant capacity (PC), CO_2 emission rate (ER), life-span (LS).

To make results more realistic, an agent that only considers wind power as technology to build has been included.

3.2 Base case

A case has been executed as reference for the rest of studies to be made. This case includes a subsidy of 10€/MWh for wind power. Fig. 3 and Fig. 4 show the evolution of reserve margin (available capacity over maximum yearly demand), gas quota (including CCGT and gas turbines) and prices for the first 10 years. A gas quota of almost 51% is reached keeping reserve margin over 1 and with a notable decrease in prices. Total system costs are 275.96 billions of euros including market cost, capacity payments and renewable energy subsidies. Average quota in years from six to ten will be used to compare the results of the different policies. In this case its value is 46.4%.

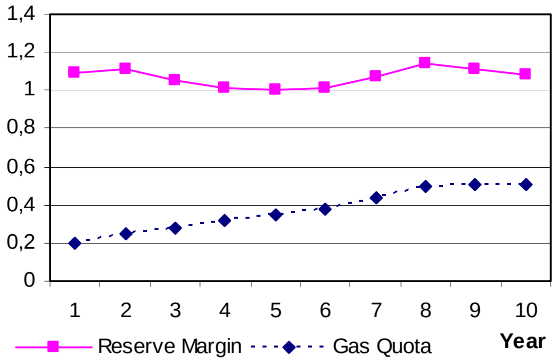

Fig. 3. Reserve margin and gas quota for base case.

Fig. 4. Average price for base case.

3.3 Limitation of gas quota

Two different levels of gas constraint have been considered. A reduction to 45% and other to 40% (maximum limit per year). In the first case the obtained average quota for years six to ten, is 41,2% and 36,8%. This constraint is imposed on the number of permits for building new plants. The model has been extended to allow asking for permits for a second technology in the same year if the limit imposed by the quota is reached. The effects of constraint are evident from year 5 (see Fig. 5), what is related with plants obtaining permit and building time. The maximum allowed quota is not reached because decisions are discrete (only an integer number of plants can be built) and because constraint is imposed over the number of permit given to the agents, but they make the final decision based on their profit forecasting.

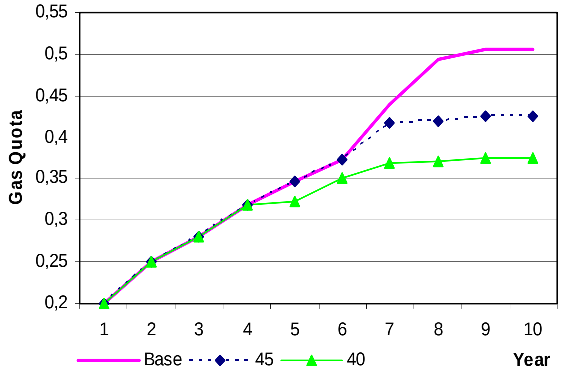

Fig. 5. Gas quota evolution for different level of gas quota constraint.

Reserve margin (Fig. 6) in both cases goes under 1, because there is not a technology that substitutes gas. This means that adequate capacity payments should be established as an additional measure to gas quota constraint.

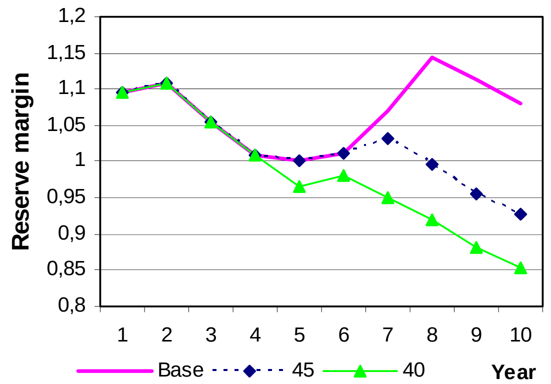

Fig. 6. Reserve margin evolution for different level of gas quota constraint.

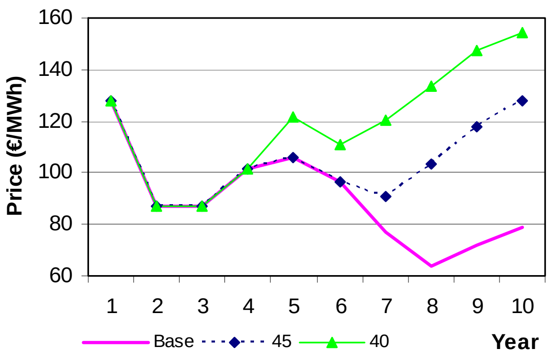

Fig. 7. Prices for different level of gas quota constraint.

Prices have a dramatic increase due to the presence of non-supplied energy, what allows to evaluate cost of this measure. It is 321.59 billions of euros for the 45% case and 364.79 for the 40% case.

3.4 Taxes over gas

Different values for taxes have been established over gas in the range from 5 to 25 €/MWh which have lead to reductions of quota in year 10 from 52% to 30%. In order to establish a comparison, those cases with a similar value in the mean comprising years six to ten have been chosen. A level of taxes of 10€/MWh produces a reference quota of 42,8 % (which is the closest to 45% case (41,2%), and with 20.5€/MWh we obtain the same quota as in the 40% case (36.8%). Further studies might require a greater precision, but this is enough for an initial comparison, a normalization of costs before drawing conclusions will be made.

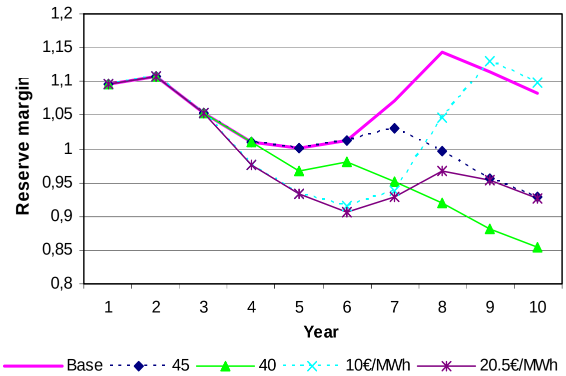

Fig. 8. Reserve margin evolution for different level of gas quota constraint and taxes over gas.

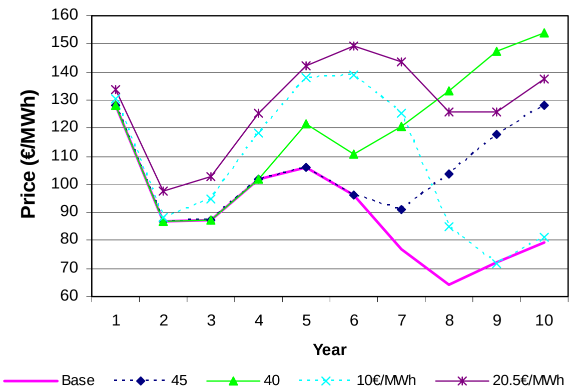

Fig. 9. Prices for different level of gas quota constraint and taxes over gas.

Significant differences appear in reserve margin evolution and prices as shown in Fig. 8 and Fig. 9. Taxes of 10 €/MWh maintain a reasonable reserve margin and prices levels, despite of growing in the first years, go back to values very close to base case in years 9 and 10. With the level of 20.5 €/MWh things change dramatically, reserve margin falls to small values and prices go up. Again, additional measures should be taken in order to guaranty demand supply.

Cost are 325.60 y 389.65 billions of euros for 10 and 20.5 €/MWh respectively.

3.5 Subsidies to wind production

Subsidies have been set for wind power production ranging from 30 to 35 €/MWh which have lead to reductions of quota in year 10 from 52% to 35.79%. With a 30 €/MWh subsidy a reduction to 42,51% has been obtained in mean, in years 6 to 10. This value is 36,76% for a 33 €/MWh subsidy.

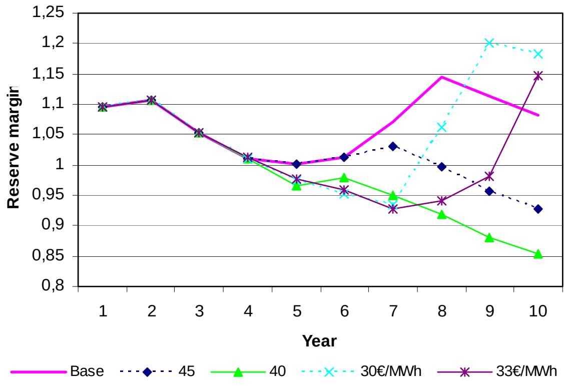

Fig. 10. Reserve margin for different level of subsidies to wind production.

Fig. 10 and Fig. 11 show how these subsidies affect reserve margin and prices. Reserve margin goes over base case values and prices notably go down. Costs are 296.87 y 299.32 billion of euros for 30 and 33 €/MWh subsidies.

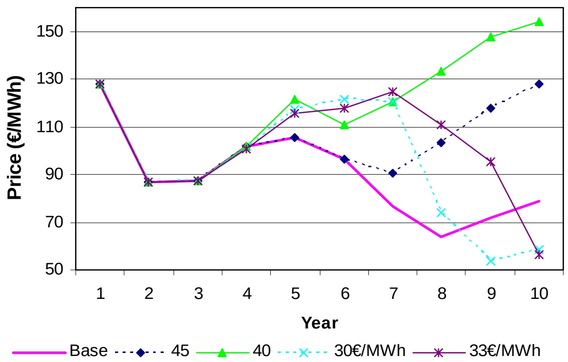

Fig. 11. Prices for different level of subsidies to wind power.

4 CONCLUSIONS

Quota objective	*Quota constraints*	*Taxes over gas*	*Wind power subsidies*
45 %	8,78	13,83	5,42
40 %	9,30	11,92	4,75

Table 4: Increase in cost (billions of €) normalized per percentage quota point reduction.

Three different methods have been tested with a system-dynamics based model in order to reduce gas quota over a system loosely based on the Spanish one: explicit constraint over gas plants building (as result of a mandatory reference planning), setting taxes on gas and establishing subsidies on an alternative renewable technology as wind power generation. They have different advantages and drawbacks from a practical point of view.

The third method has revealed as the most suitable in our simulations: it preserves reserve margin values, slightly reduces average prices and its global normalized cost for the final user (including market cost, capacity payments and subsidies) is the lowest as shown in Table 4. However, with this method there are some years with non-supplied energy that would require regulator action.

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