A Simulation Model for a Competitive Generation Market

Irene Otero-Novas, Claudia Meseguer, Carlos Batlle, and Juan J. Alba

Abstract—The simulation of a wholesale electricity market should go beyond a simple optimization based on the operating costs of the generating units. A model of a competitive electricity market must consider the market structure, the strategy of the market participants and any other factor that lead to prices different from costs. This paper presents COSMEE, a model of a wholesale electricity market based on simple bids, that estimates expected bid prices and quantities, system hourly prices and generation schedules, taking into account the bidding strategies of generators and the structure of the market. The model reflects the profit-maximizing behavior of the market agents, subject to different types of constraints, COSMEE has been used to simulate a real wholesale market.

Index Terms—Agent's behavior, intertemporal links, iterative equilibrium, marginal price, simple bids.

I. INTRODUCTION

R ECENT changes in the electricity industry in several countries have lead to a less regulated and more competitive energy market where short term exchanges of electricity are based on the system marginal price. This wholesale price has typically been determined through an algorithm based on a unit commitment or an economic dispatch, as it is still implemented in the Argentinean or the British market. In these countries the spot price of electricity is based on the variable cost of the marginal unit and its start-up cost allocated to some hours [1]. This pricing rule can give different results when minimizing production costs and when minimizing consumer costs [2],[3], and can sometimes, when considering a market where some firms are relatively small, lead to stability and fairness problems which can arise from the presence of many near optimal solutions [4].

Recent trends in some countries such as Australia or Norway base this market clearing process on an auction where the price is set as the intersection of the supply and demand curves. In this last kind of markets generating units internalize in their offers not only their bidding strategy but also their technical constraints and their start-up cost allocation, as these are not explicitly taken into account in the market clearing process. This new market framework makes simulation models a necessary tool to define the strategies of the generators as well as to analyze the

Manuscript received December 29, 1997; revised July 7, 1998.

I. Otero-Novas, C. Meseguer, and C. Batlle are with Instituto de Investigación Tecnológica, Universidad Pontificia Comillas, Alberto Aguilera 23, 28015 Madrid, Spain (e-mail: {irene.otero; meseguer; carlos.batlle}@iit.upco.es).

J. J. Alba is with Grupo Endesa, Príncipe de Vergara, 187, 28002 Madrid, Spain (e-mail: jalba@endesa.es).

Publisher Item Identifier S 088: 350(00)01880-0.

potential effect of some regulate decisions, or risk management decisions or some other issues.

A simple and frequent approach to market simulation can be based on the use of a chronological simulation tool that carries out an optimization of the total system cost based on the costs of the individual generators. However, this method does not take into account the effect of the bidders' strategies, which in general will lead to bids that do not strictly reflect costs.

Different methodologies can be used to simulate the market behavior taking into account these strategic effects, depending on the market structure and the aim of the studies. Some models are based on game theory to analyze market power influences [5], or the effect of contracts or capacity payments in some markets [6], while other studies use the Cournot model of an oligopoly through an iterative method [7], [8]. In general, these models do not consider technical constraints and intertemporal links or consider them through the unit commitment dispatch.

The model presented in this paper simulates the electricity market behavior for different strategies and computes hourly marginal prices, margins and productions of units and firms. Its aim is to analyze the effect of different bidding strategies, possible regulatory decisions or some other issues affecting the market, on the behavior of the market agents.

The methodology used simulates the behavior of the energy market through an iterative method based on Wilson's rules proposed for the power exchange in the Californian market [9], that leads to a market equilibrium it is based on a generalization of the Cournot and Bertrand equilibria, as an oligopoly model in which some firms have the possibility of modifying prices. The iterative method uses this mixed model in a dynamic way, since in each iteration the market participants refine their beliefs about the other players' behavior through the information they get about productions and prices [10]. Hence, in each iteration players try to identify their best response to the market.

The model can simulate two kinds of markets: a) a perfectly competitive market (that will be called the uncoordinated simulation) in which each generation unit acts as an independent competitor and is basically a price-taker player, and b) an oligopolistic market (the so-called coordinated simulation) where groups of units belong to firms that try to maximize their profits.

Intertemporal links and technical constraints are taken into account in the strategies. Since the clearing method is based on simple bids, generators have to update their strategies to other competitor's behavior in each iteration, not only considering their profit maximization goal, but also their technical constraints. Final offers reflect a way to maximize profits and to consider technical constraints in a competitive framework.

0885-8950/00\$10.00 © 2000 IEEE

The demand model covers a day, divided into chronological hourly blocks. It is an inelastic demand, i.e., it does not respond to price. The thermal generation is modeled, considering for each unit its maximum power, its minimum stable load, ramps and variable, no-load and start-up costs. Each unit belongs to one or to several firms and can act independently (uncoordinated simulation), maximizing its own profit or jointly (coordinated simulation), maximizing the firm's profit. The hydro generation model considers a maximum power, a minimum power which each unit will have to generate each hour (run-of-the-river generation) and an energy reserve available for that day.

The model has been applied to the analysis of the Spanish electricity market under realistic assumptions.

Section II briefly describes the simulation algorithm and its different modules. One of these, the module which determines optimal strategic decisions, is described with more detail in Section III. Section IV presents the main results of some simulations.

II. SIMULATION ALGORITHM

The simulation algorithm (Fig. 1) uses different modules, some of them repeated for each iteration. At each stage of the iterative process units modify their offers with the information they get from the market. These modifications can only be reductions of the bid price, to assure convergence, being the price decrement (ε) fixed.

1) Initial Offer: Sets the initial offers in price and quantity. The initial point should be high as the algorithm only allows decreasing bid prices from one iteration to another to assure convergence. This first bid is found for each thermal unit by the sum of its variable, the no-load and the start-up costs, thus allocating all the start-up cost to every hour. Afterwards, units will reduce this offer depending on the power and the hours dispatched, allowing them to allocate the start-up cost correctly. The first offer for the hydro units will be the value of the most expensive thermal unit.

2) Clearing Module: The clearing method computes the spot price as the price of the most expensive bid accepted to supply the demand. Technical constraints are not explicitly taken into account in the clearing process, and thus generators will have to internalize them in their offers. This internalization is carried out in the strategic modules.

3) Optimal Strategic Decisions: In this module generators decide their offers considering the results of the last iteration as a way of taking into account the behavior of other agents. This module is different for coordinated and uncoordinated simulations as units will follow different strategies in each approach, but in both cases it is divided in two different parts: Modifications of quantifies and modifications of prices.

4) Convergence: It checks whether the convergence criterion has been reached, i.e., whether generators do not improve their profits by changing their offers.

5) *Results:* If convergence is reached, results (marginal prices, profits and scheduled productions) are computed.

III. OPTIMAL STRATEGIC DECISIONS

This module considers the results from the last iteration and changes the bids of the generators according to the strategy



Fig. I. Simulation Algorithm.

chosen. First, quantities are modified and then prices, using the information provided by the last market clearing process. Since different types of markets can be simulated, both parts of this module, the quantity and the price revisions, will follow different rules for the uncoordinated and for the coordinated simulation.

Start-up costs are allocated by each generator in its offers. This can be done following different strategies, but through the iterative method units can allocate them to the hours in which they have been dispatched in each iteration.

Only decreasing prices are allowed in the modifications of bids, to assure convergence. Units must respect a lower bound for their price bids. This threshold is set using their cost data.

Units split their offers in two blocks: the minimum stable load and the controllable load from this value to the maximum power. The first block does not have a lower price threshold, as sometimes a unit would rather operate at a loss during some hours to avoid a start-up, if this loss is lower than the cost of an additional start-up.

Thermal units can be dispatched through the whole day or they can be dispatched only for the peak hours. For the units in the first situation, the lower bound will be the unit variable cost plus the no-load cost. Units having to start-up only for the peak hours will add to their price threshold the start-up cost allocation.

A. Uncoordinated Simulation

When units are individually considered, they maximize their own profit without taking into account the firm they belong to. They internalize their technical constraints with the information they get from the market, marginal prices and their scheduled productions. This is the situation closest to a perfectly competitive market, where units act as price-takers rather than price-sctters.

1) Modification of Quantities: With the marginal prices from the last iteration each unit modifies its offered quantities in order to maximize its profits while considering its technical constraints.

The following notation is used,

$\mathcal{D}_{i+1}(n)$	Energy to be offered for nour <i>n</i> and iteration $i + 1$
	above the minimum generation (MWh)
$DD_{i+1}(h)$	Discrete shut down decision variables for hour h
• • • •	and iteration $i + 1$. 1 denotes a shut-down deci-
	sion, while 0 denotes not to shut-down the unit
$SD_{i+1}(h)$	Discrete start-up decision variables for hour h
	and iteration $i + 1$. 1 denotes a start-up decision,
	while 0 denotes not to start-up the unit
$STD_{i+1}(h)$	State of the thermal unit for hour h and iteration
	i+1. If 1 the unit will be connected, while 0 will
	denote the unit to be off
$E \max$	Maximum generation level for each hour (MWh)
MSG	Minimum stable generation (MWh)
Energ	Available energy for the day for hydro units
Dramp	Decreasing ramp (MW/h)
Iramp	Increasing ramp (MW/h)
$MP_i(h)$	Marginal price for hour h and previous iteration
	<i>i</i> (\$/kWh)
VC	Variable cost (\$/kWh)
NLC	No-load cost (\$/h)
SC	Start-up cost (k\$).
Each thorn	al and hydro unit will in turn formulate the fol-

Each thermal and hydro unit will in turn formulate the following maximization problem.

Thermal Units:

$$\begin{aligned} \max \sum_{h} \left[MP_{i}(h) \cdot (E_{i+1}(h) + \text{MSG} \cdot STD_{i+1}(h)) \\ -VC \cdot (E_{i+1}(h) + \text{MSG} \cdot STD_{i+1}(h)) \\ -NLC \cdot STD_{i+1}(h) - SC \cdot SD_{i+1}(h) \right] \end{aligned}$$
(1)

subject to the capacity constraints,

$$E_{i+1}(h) \le (E \max - \text{MSG}) \cdot STD_{i+1}(h)$$
(2)

up and down ramp rates,

$$E_{i+1}(h) - E_{i+1}(h-1) \le Iramp$$

$$E_{i+1}(h) - E_{i+1}(h-1) \le Dramp$$
(3)

and the state transitions constraints,

$$STD_{i+1}(h-1) - STD_{i+1}(h) + SD(h)_{i+1} - DD_{i+1}(h) = 0$$
(4)

Hydro Units: These units try to maximize their profits following different behaviors. If hydro units explicitly maximize their profits.

$$\operatorname{Max}\sum_{h} MP_{i}(h) \cdot E_{i+1}(h)$$
(5)

subject to the capacity constraints,

$$E_{i+1}(h) \le E \max \tag{6}$$

and the daily energy constraints,

$$\sum_{h} E_{i+1}(h) \le Energ \tag{7}$$

With this strategy hydro units will offer their maximum power for the most expensive hours until their energy limit is reached. This result can sometimes, depending on the demand shape and the hydraulic conditions, lead to lower prices in the hours where the hydro units have bid and thus decrease their profits. Better results for the hydro units' profits have been achieved when using a "peak shaving" strategy, which is the result of minimizing the total cost. This gives the optimal allocation for hydroelectric energy.

2) Modification of Prices: Once quantities to be offered in the next iteration (i+l) are found, prices to offer are computed. From the results of the last iteration (i) units can be classified for each hour into two categories

- a) Infra marginal units (units below the marginal price) will be fully dispatched and hence do not modify their offers.
- b) Units which have not been fully dispatched (because they have bid a price above or equal to the marginal price) will have an incentive to decrease the price offered in the next iteration. The unit will decrease its offer to a price $MP_i(h) \varepsilon$, if this value is not below its lower bound.

B. Coordinated Simulation

With this approach the model simulates an oligopolistic market in which each firm coordinates the bids of its units to maximize its profit. In the uncoordinated simulation, players, which are individual units, offer their maximum power and decrease their bid prices in hours where prices are above their lower bound. They try to get the maximum production dispatched since they can not modify the price individually. On the other hand, in the coordinated simulation, each time a market participant can decrease a unit bid, it analyzes how this decrement will affect its firm's profits, as players (which are now firms) can modify prices and can sometimes accept a lower production to raise prices. In this kind of simulation the strategy followed to modify the offers is as follows.

1) Modification of Quantities: Considering a firm which owns some thermal units, tu, and some hydro units hu, given the marginal prices from the last iteration this firm will maximize its own profits through the following objective function:

$$\operatorname{Max} \sum_{tu, hu \in \operatorname{Firm} h} \sum_{h(h) \in \operatorname{Firm} h} \sum_{i: (MP_i(h) (E_{i+1, tu, hu}(h) + \operatorname{MSG} \cdot STD_{i+1, tu}(h)) - VC \cdot (E_{i+1, tu}(h) + \operatorname{MSG} \cdot STD_{i+1, tu}(h)) - NLC \cdot STD_{i+1, tu}(h) - SC \cdot SD_{i+1, tu}(h)]. \quad (8)$$

Subject to constraints (2)–(4) for thermal units (tu) and constraints (6) and (7) for the hydro units (hu).

A new constraint will now be considered to limit the total production that the company will offer. This optimum generation level (GL) is first determined and then split for the units



Fig. 2. Coordinated simulation.

through the profit maximization. The new constraint for each firm will be:

$$\sum_{tu, hu \in \text{Firm}} \left(E_{i+1, tu, hu}(h) + STD_{i+1, tu} \cdot \text{MSG} \right) = \text{GL}.$$
(9)

This optimum generation level (GL) is obtained, based on the first order condition of the Cournot equilibrium. If we consider two firms A and B bidding into the pool and the result from the iteration i for hour h, as shown in Fig. 2, units from firm A which are infra marginal and thus have been fully dispatched, will not change their offers.

Those units that have not been fully dispatched will now consider two options: they can decrease the bid price in that hour for the next iteration (i + 1) or they can keep it with the same value. If they choose to decrease bid prices, they will increase the firm's profits as they will have more power dispatched, but profits will be reduced for infra marginal units that will find their income decreased if the marginal price is lowered to $MP_i(h) - \varepsilon$ [since the unit, if it wants to enter in the dispatch will have to offer at $MP_i(h) - \varepsilon$].

Depending on the amount of dispatched production each firm has, its maximum profit will come from the first situation (increasing the power dispatched despite the reduction in the marginal price) or from the second alternative (keeping the same level of production to avoid decreasing the marginal price).

Therefore in Fig. 2, units 3 and 4, which have not been fully dispatched, will have two possible options:

1. If they keep the same offers,

Profit =
$$MP \cdot (E_1 + E_2) - VC_{1,2} - NLC_{1,2}$$

2. If they reduce the offers,

Profit =
$$(MP - \varepsilon) \cdot (E_1 + E_2) - VC_{1,2} - NLC_{1,2}$$

+ $(MP - \varepsilon) \cdot (E_3 + E_4) - VC_{3,4} - NLC_{3,4}$.

This second situation increases the profit in

$$(MP - \varepsilon) \cdot (E_3 + E_4) - VC_{3,4} - NLC_{3,4}$$

but reduces it for the infra marginal units 1 and 2 in

$$\varepsilon \cdot (E_1 + E_2)$$

which depending on the amount of power each firm has dispatched, could be greater than the first term.

If the amount in which profits are reduced is higher than the increased amount, the optimum generation level (GL) will be $E_1 + E_2$. On the other hand, it will be $E_1 + E_2 + E_3 + E_4$.

Modification of Prices: Once the quantities to be offered have been found hourly prices to offer will be determined. At each hour those units who will offer more energy for that hour, than the energy they had accepted at iteration i, the will reduce their previous offer to $MP - \varepsilon$. Otherwise, if they had all their offer previously accepted they will not change their last offer:

1.
$$Egen_i(h) < Eoffer_{i+1}(h) \Rightarrow P_{i+1}(h) = MP_i(h) - \varepsilon$$

2. $Egen_i(h) = Eoffer_{i+1}(h) \Rightarrow P_{i+1}(h) = P_i(h)$

where

 $Egen_i(h)$ Energy dispatched at iteration *i*.

Eoffer _{i+1} (h)	Energy to offer for iteration $i + 1$, found at the
	modification of quantities module.
$P_{i+1}(h)$	Price to offer the energy E offer _{<i>i</i>+1} (<i>h</i>).
$MP_i(h)$	Market price for iteration <i>i</i> .

IV. EXAMPLE

The model described in this paper, called COSMEE, has been written in C and GAMS (General Algebraic Modeling System) languages. GAMS has been used to solve the profit maximization modules using the CPLEX optimization software with mixed integer programming, following the primal simplex.

The model has been applied to the Spanish wholesale market which has started to operate on January 1998. In Spain, the marginal price is obtained through a simple bid matching procedure with additional conditions that allow the generators to take into account some running requirements.

However, the Spanish wholesale market has additional features that could affect the marginal prices, such as the treatment of the competition transition costs (also called stranded costs) and the required consumption of domestic coal, making the strategies that the agents could follow more complex. The stranded cost payments are inversely related to the market price, as they increase when the market price decreases. This may have some influence on the market price.

In this example the market behavior has been analyzed for two different strategies (the uncoordinated and the coordinated), showing the effect of the actual market structure, but without considering the remarks mentioned before.

Each simulation covers a day divided into 24 hours; demand was considered to be constant during each hour. Hence, 24 load levels were chronologically considered. There are 67 thermal units and 19 equivalent hydro units. Some units are jointly owned by different firms and so their profits will correspond to each firm according to its share. However for the coordinated simulation only one firm takes the bidding and commitment decisions. Nuclear units were considered must-run.

The number of iterations depends on the scenario characteristics and the type of simulation. For the scenario used as an example here, the uncoordinated simulation required 21 iterations, which took 4.2 minutes on a Sun Spare Station Ultra 1, 0.2 minutes per iteration. For the coordinated simulation 10 iterations were required when the hydro units acted as price-takers and 8



Fig. 3. Hourly marginal prices (Uncoordinated simulation).

iterations hydro units acted as price-setters. The time taken for each iteration of the coordinated simulation was slightly higher than for the uncoordinated.

The two different strategies, uncoordinated and coordinated, were simulated for the same scenario.

The scenario presented in this paper corresponds to a working day in February 1998 with wet hydraulic conditions, and a total demand of 497 GWh.

A. Uncoordinated Simulation

Fig. 3 shows the hourly marginal prices for the uncoordinated strategy as well as the hydro and thermal productions. Each unit acts individually, trying to maximize its profits as well as handling its technical constraints. Hydro units allocate their available production to minimize the total cost, thus following a "peak shaving" technique. Final prices are very close to the costs of the marginal unit for each hour, as units are basically price-takers and finally bid at their costs including the start-up cost allocation.

The obtained average price is $2.56 \notin/kWh$, the average price for the valley hours is $1.51 \notin/kWh$ and for the peak hours $2.87 \notin/kWh$. This is the result achieved by an almost perfectly competitive market where load is supplied at the minimum cost. The final dispatch was compared to a unit commitment [11], and was found to be almost identical.

B. Coordinated Simulation

The hourly marginal prices curve for a coordinated simulation are shown in Fig. 4. Firms are now trying to maximize their profits rather than individual profit of each unit. This strategy gives different results not only for prices but also for benefits and for the final dispatch. Prices are now higher, specially during the peak hours. For these hours some firms reduce their production (compared to the uncoordinated simulation) in some mid-order units to avoid the reduction in prices. As these firms have a large share of dispatched production, their total profits will be increased despite their decreased production, as the price received by their remaining production, is higher.

These higher prices are mainly achieved for the peak hours, where the demand over which units are competing is bigger. During the valley hours, demand is mainly satisfied by run-of-the-river production and minimum stable generation. Competition during these hours is greater, since most units push prices down to make sure that they generate their minimum stable generation and avoid a start-up. This makes final prices close to the units' costs, as it happened for the uncoordinated simulation. For these hours simulation prices show a Bertrand price competition as demand could be entirely satisfied by one of the two larger firms [10], which makes prices fall to the competitive situation. The average price is now 4.2¢/kWh, which is 1.63¢/kWh higher than for the noncoordinated simulation. During the valley hours the average price is 2.25 ¢/kWh, which is only 0.75¢/kWh higher than in the previous simulation, while during the peak hours the average price is 4.33¢/kWh which is 1.53¢/kWh higher than in the competitive simulation. Thus the main price difference is reached during the peak hours.

Firm's profits have been increased from the noncoordinated simulation as marginal prices have been raised in most hours.

All firms were initially supposed and modeled to act as Cournot competitors that could modify prices. However, not all the firms have the same production percentage and hence, not all of them act as Cournot competitors. In fact, one of them acted as a marginal competitor, offering its production



Fig. 4. Hourly marginal prices (coordinated simulation).

close to variable costs and trying to produce the maximum power despite the decrease in price. Its behavior does not vary from the uncoordinated simulation, although its profits were nevertheless increased as its production was not reduced but prices were raised by the other firms.

For this simulation two different hypothesis considering hydro behavior were considered: a) hydro units offering a zero price and so acting as price-takers and b) hydro units acting as price-setters and setting the marginal price for some hours.

The results from these two approaches are shown in Fig. 4. The average price is higher in the case where hydro units were acting as price-setters, reaching now a value of 4.86 ¢/kWh. The price difference only appears for the peak hours where hydro units are allocating their production, as for the valley hours hydro units only generate run-of-the-river production. Although some hydro units do not generate all the production estimated for that day when acting as price-setters, their profits have increased as the marginal price reaches a higher value.

V. CONCLUSIONS

The COSMEE model is a useful tool for analyzing the behavior of a wholesale electricity market based on simple bids, where market participants must internalize in their offers their technical constraints, complex cost structures and bidding strategies. It is mainly focused on the analysis of the effect of different strategies that players could follow.

COSMEE belongs to a generation of modeling tools, designed for competitive electricity markets, which go beyond the traditional production costing and unit commitment algorithms. It relies on the cost structure of each generator, but the market simulation does not only take into account those costs, but also the market structure, the allocation of start-up costs and other considerations that lead to prices being different from variable costs.

Participants in the actual markets have been found to follow mixed strategies where profits are maximized but other considerations, such as market shares, stranded costs recovery, regulator's and new entry's threat or capacity payments, distort the basic Cournot approach, making other possible strategies appear.

The strategies simulated in this paper achieve values close to the Spanish market's results, as in both cases start-up costs are allocated during the peak hours, and valley hours drop to competitive level, leading to similar price-shapes. The real average price for February has been an intermediate value between the uncoordinated and the coordinated prices obtained from COSMEE, and close to the coordinated simulation. In general, prices achieved by COSMEE have been found to be around $0.30\phi/kWh$ higher than the actual prices in the market, because the market seems to follow other strategies that consider some of the issues mentioned before. The implementations of these strategies is presently under development as well as the modification of the model to simulate the market in a yearly horizon, incorporating mid term strategic considerations.

REFERENCES

- H. Rudnick, R. Varela, and W. Hogan, "Evaluation of alternatives for power system coordination and pooling in a competitive environment," *IEEE Trans. on Power Systems*, vol. 12, no. 2, pp. 605–613, May 1997.
- [2] J. M. Jacobs, "Artificial power markets and unintended consequences," IEEE Trans. on Power Systems, vol. 12, no. 2, pp. 968–972, May 1997.

- [3] S. Hao, G. A. Angelidis, H. Singh, and A. D. Papalexopoulos, "Consumer payment minimization in power pool auctions," in PICA'97 Technical Session, May 1997.
- [4] R. Johnson, S. Oren, and A. Svodoba, "Equity and efficiency of unit commitment in competitive electricity markets," in Power Conference. Berkeley, CA, Mar. 1996.
- [5] N. Lucas and P. Taylor, "Characterizing generator behavior: Bidding strategies in the pool. A game theory analysis," Utilities Policy, pp. 129-135, Apr. 1993.
- [6] R. W. Ferrero, S. M. Shahidehpour, and V. C. Ramesh, "Transactions analysis in deregulated power systems using game theory," IEEE Trans. on Power Systems, vol. 12, no. 3, pp. 1340–1347, Aug. 1997. [7] S. Borestein and J. Bushnell, "An empirical analysis of the potential for
- market power in California's electricity industry," University of California Energy Institute, Berkeley, Tech. Rep., 1997.
- [8] W. W. Hogan, "A market power model with strategic interaction in electricity networks," Center for Business and Government, John F. Kennedy School of Government, Harvard University, Cambridge, MA, Tech. Rep., 1997. R. Wilson, "Activity rules for a power exchange," in *Power Conference*.
- [9] Berkeley, CA, Mar. 1997.
- [10] H. R. Varian, Microeconomic Analysis. New York, NY: W.W. Norton & Company, 1992.
- [11] Instituto de Investigación Tecnológica, "EXMEN," (in Spanish), , Tech. Rep. prepared to Endesa, Feb. 1997.

Irene Otero-Novas was born in Lugo, in 1972. She received the Electrical Engineering degree from the Universidad Pontificia de Comillas (ICAI), Madrid, Spain. She has worked on a common project between Electricité de France (EDF) and Red Eléctrica de España (REE) on network stability analysis through artificial intelligence techniques. She currently is a Ph.D. student in the Instituto de Investigación Tecnológica (IIT) where her area of interest is regulation of the electricity industry and modeling of wholesale electricity markets.

Claudia Meseguer was born in Murcia, Spain, in 1966. She obtained the B.S. degree in Industrial Engineering from the Universidad Politécnica de Madrid. She is a Researcher and Consultant at the Instituto de Investigación Tecnológica, Universidad Pontificia Comillas where she has finished the Ph.D. degree. Her areas of interest include regulation, operation, and planning of electric power systems. She has participated in several consultancy and research projects concerning wholesale marginal prices, design and simulation of wholesale electricity markets, capacity payments, and other issues related to the introduction of competition in the electricity industry,

Carlos Batlle was born in Madrid in 1972. He obtained the electrical engineering degree from the Universidad Pontificia de Comillas (ICAI), Madrid, Spain, after spending his final year at the Ecole Polytechique Federal de Lausanne (EPFL), Switzerland where he submitted his diploma dissertation in artificial intelligence. Currently, he is a Ph.D. student at the Instituto de Investigación Tecnológica (IIT) and his area of interest is regulation of the electricity industry.

Juan J. Alba is currently Deputy Manager in charge of regulatory affairs, within the generation business unit of the Endesa Group, the leading electricity generation and distribution company in Spain and a major utility in Latin America. He is involved in the design of the new Spanish electricity market. Previously, he was a Researcher and Consultant at the Instituto de Investigación Tecnologica, Universidad Pontificia Comillas, where he has worked in the design and simulation of wholesale electricity markets, competitive bidding, ancillary services markets, capacity payments, and other issues related to the introduction of competition in the electricity industry. He has also been active in the application of artificial intelligence techniques in electricity generation and transmission. He was born in 1963, he graduated in electrical engineering from Universidad Pontificia Comillas (Madrid) in 1986, and he obtained the Ph.D. degree in electrical engineering from the same university in 1996.