Strategic Generation Investment Using a Complementarity Approach

S. Jalal Kazempour, *Student Member, IEEE*, Antonio J. Conejo, *Fellow, IEEE*, and Carlos Ruiz, *Student Member, IEEE*

***Abstract*—This paper provides a methodology to assist a strategic producer in making informed decisions on generation investment. A single target year is considered with demand variations modeled through blocks. The strategic behavior of the producer is represented through a bilevel model: the upper-level considers both investment decisions and strategic production actions and the lower-level corresponds to market clearing. Prices are obtained as dual variables of power balance equations. Rival uncertainties (on offering and investment) are characterized through scenarios. The resulting model is a large-scale mixed-integer LP problem solvable using currently available branch-and-cut techniques. Results pertaining to an illustrative example and a case study are reported and discussed.**

***Index Terms*—Generation investment, mathematical program with equilibrium constraints (MPEC), strategic producer, uncertainty.**

NOTATION

The main notation used throughout the paper is stated below for quick reference. Other symbols are defined as required.

A. Indices:

t	Index for demand blocks running from 1 to T.
i/k	Indices for the new/existing generating units of the strategic producer running from 1 to I/K.
j	Index for other generating units (owned by other producers) running from 1 to J.
d	Index for demands running from 1 to D.
h	Index for available investment capacities running from 1 to H.
n/m	Indices for buses running from 1 to N/M.

B. Constants:

σ_t	Weighting factor of demand block t.
K_i	Annual investment cost of new unit i.
X_{ih}	Option h for investment capacity of new unit i.
$P_k^{\mathrm{ES}^{\max}}$	Capacity of existing generation unit k of the strategic producer.
$P_j^{\mathrm{O}^{\max}}$	Capacity of generation unit j of other producers.
$P_{td}^{\mathrm{D}^{\max}}$	Maximum load of demand d in block t.
$C_i^{\mathrm{S}}/C_k^{\mathrm{ES}}$	Marginal cost of new/existing unit i/k of the strategic producer.
C_{tj}^{O}	Price offer of unit j of other producers in demand block t.
U_{td}^{D}	Price bid of demand d in demand block t.
B_{nm}	Susceptance of line $n-m$.
$F_{nm}^{\max}$	Transmission capacity of line $n-m$.

Some of these constants include subscript w if referring to scenario w.

C. Variables:

X_i	Capacity investment of new unit i of the strategic producer.
$\alpha_{ti}^{\mathrm{S}}/\alpha_{tk}^{\mathrm{ES}}$	Price offer by new/existing unit i/k of the strategic producer in demand block t.
$P_{ti}^{\mathrm{S}}/P_{tk}^{\mathrm{ES}}$	Power produced by new/existing unit i/k of the strategic producer in demand block t.
P_{tj}^{O}	Power produced by unit j of other producers in demand block t.
P_{td}^{D}	Power consumed by demand d in demand block t.
θ_{tn}	Voltage angle of bus n in demand block t.

Some of these variables include subscript w if referring to scenario w.

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The authors are with University of Castilla-La Mancha, Ciudad Real, Spain (e-mail: SeyyedJalal.Kazempour@alu.uclm.es; Antonio.Conejo@uclm.es; Carlos.RMora@uclm.es).

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I. INTRODUCTION

A. Background and Aim

INVESTMENT decisions to be made by producers within a market framework are complex and risky decisions. This is particularly so in imperfect markets, which is the case of electricity markets. Investment decisions are complex because

TABLE I
RELEVANT FEATURES OF WORKS REPORTED IN THE LITERATURE AND THE MODEL PROPOSED IN THIS PAPER

Ref.	Model	Transmission constraints	Static/ Dynamic	Stochastic model	Uncertainty	Different investment technologies	Bilevel	Strategic offering	Approach
[1]	Cournot	No	Static	No	-	Yes	Yes	No	MPEC
[2]	Bilevel	Yes	Static	Yes	Unit outages	Yes	Yes	No	Genetic algorithm
[3]	Cournot	Yes	Static	No	-	No	No	No	Quadratic programming
[4]	Supply function	Yes	Dynamic	Yes	Demand and line outages	Yes	No	No	Heuristic
[5]	Cournot	No	Static	No	-	Yes	No	No	Iterative
[6]	Cournot (Stackelberg)	No	Static	No	-	Yes	No	No	Complementarity
[7]	Stochastic optimization	No	Dynamic	Yes	Demand	Yes	No	No	Discrete Markov chain
[8]	Cournot	No	Static	Yes	Demand, rival marginal cost and rival behavior	Yes	No	No	Quadratic programming
This paper	Supply function	Yes	Static	Yes	Rival offering and rival investment	Yes	Yes	Yes	MPEC

they require modeling the market functioning leading to complementarity models. They also require taking into account the uncertainty plaguing markets, which leads to stochastic complementarity models. Finally, investment decisions are complex because the behavior of rival producers has to be properly represented. In addition to the need for such a complex model, investment decision making is risky due to the long-term consequences of the involved decisions.

We consider in this paper a strategic producer trading in a pool-based market through supply function strategies. This producer seeks to derive its investment strategy for a future target period spanning one year, for which the demand is modeled through a piecewise constant curve approximating the load duration curve in that target year. The strategies of rival producers in the pool and their investment decisions are uncertain parameters represented in this paper through scenarios. In other words, we use scenarios to describe uncertainty pertaining to 1) rival offers and 2) rival investments.

Regarding technology selection, we consider base-loaded units (e.g., nuclear power plants) and peakers (e.g., CCGTs), and regarding the siting throughout the network of these units, we make no simplification, i.e., any plant can be located at any bus throughout the network.

The proposed model materialized in a large-scale stochastic complementarity problem that can be recast as a large-scale mixed-integer linear programming problem, which, in turn, can be solved using commercially available branch-and-cut algorithms.

The model considered is aimed at helping strategic producers in making informed decisions pertaining to generation capacity investment. In other words, the target of the proposed model is to identify these investment options most beneficial for the considered strategic producer.

B. Literature Review and Contributions

In pioneering reference [1], three models of generation investment in competitive electricity markets are considered. The first model assumes perfect competition, thus being similar to a centralized capacity expansion model. The second model (open-loop Cournot game) extends the well-known Cournot model to include investments in new generation capacity. The third model (closed-loop Cournot game) separates the investment and sale decisions including investment in the first stage and sales in the second stage. In [2], the strategic generation capacity expansion of a producer considering incomplete information of rival producers is modeled through a two-level optimization problem. A genetic algorithm approach is used to find a Nash equilibrium. The effects of competition and transmission congestion on generation expansion are considered in [3], where a Cournot model is used. In [4], a noncooperative game for generation investment is modeled using two tiers. In the first tier, the generation investment game is examined, and in the second tier, the energy supply game is considered. The solution procedure is based on a reinforcement learning algorithm. Reference [5] is a relevant paper that considers the generation expansion planning problem in an oligopolistic environment using a Cournot model and including no network constraint. The solution is found using an iterative search procedure, which assumes complete information of the rivals. In [6], two different approaches pertaining to generation expansion in a electricity market are presented. Both of them consider the Cournot model although they differ in how the producer determines its optimal capacity. In the first approach, a mixed complementarity problem (MCP) is used, while for the second one, a mathematical program with equilibrium constraints (MPEC) approach is considered (Stackelberg model). In [7], a stochastic dynamic optimization model is used to evaluate generation investments under both centralized and decentralized frameworks, but not modeling the network. Long-term uncertainty in demand growth and its effect on future prices are modeled via discrete Markov chains. In [8], the value of information pertaining to rival producers such as their marginal costs and conjectures on their behavior as well as demand levels are analyzed for making decisions on generation investment. The model is based on a Cournot approach but includes no network constraint. For clarity, we summarize in Table I the relevant features of the model proposed in this paper and other works reported in the literature.

In the technical literature, most works using a bilevel approach similar to the one proposed in this paper pertain to offering strategies [9], [10], transmission expansion [11], [12], and vulnerability analysis [13]. Also, further details on the mathematical model used in this paper, an MPEC, can be found in [14].

Considering the works analyzed in the literature review and summarized in Table I, the contributions of this paper are threefold:

1) To propose a generation investment model for a strategic producer participating in a pool with supply function offers. This model is able to optimally locate throughout the network generation investments and to select the best production technologies. The resulting model is an MPEC.
2) To recast the MPEC in step 1 above into a mixed-integer linear programming problem solvable using currently available branch-and-cut algorithms.
3) To comprehensively analyze an example of small size and to provide results for a large case study.

C. Paper Organization

The rest of this paper is organized as follows. Section II describes and clarifies the features of the considered stochastic complementarity model. Section III formulates the model as a stochastic MPEC that is recast as a mixed-integer linear programming problem. Section IV provides a comprehensive analysis of an example of reduced size, and results from a realistic case study. Section V provides some relevant conclusions obtained from the study reported in this paper. Finally, an appendix provides linearization technicalities.

II. Model Features

A. Planning Horizon, Demand, and Network Representation

Following a common approach in the technical literature [1]–[3], [5], [6], [8], we consider for the expansion exercise a single future target year—e.g., a single year 20 years into the future—and establish the optimal investment for that year. This expansion analysis, known as static expansion planning, is the purpose of the paper. Once the optimal generation mix for the target year (e.g., year 20) is known and considering the generation mix of the initial year (year 0), it is rather simple to derive an appropriate building schedule to "go" from the generation mix of the initial year to that of the target year. Note that this static approach constitutes an appropriate tradeoff between modeling accuracy and computational tractability. Needles to say, a dynamic approach (in which investments throughout the 20 years are simultaneously considered) provides higher accuracy but at the cost of potential intractability.

The demand in each bus of the system for the planning year is represented using a stepwise load-duration curve as shown in Fig. 1. Demand blocks (approximating the load duration curve) represent the demand variations across the hours of the target year. The number of steps considered should be tailored to adequately represent the load behavior throughout the buses of the electric energy system under consideration.

A dc representation of the transmission system is embedded within the considered investment model. This way, the effect of locating new plants at different buses is adequately represented.

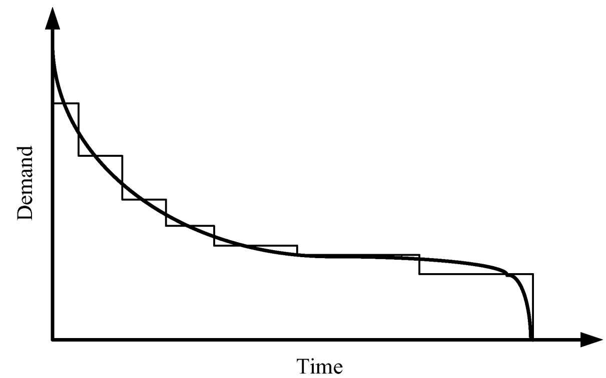

Fig. 1. Piecewise approximation of the load duration curve for the planning year in a particular bus.

Congestion cases are also easily represented. For simplicity, active power losses are neglected.

B. Bilevel Investment Model

The investment decision making and the strategic offering of the considered producer is described through a bilevel model. The upper-level problem represents both the investment decisions of the producer and its strategic offering corresponding to each demand block and scenario. Offering is carried out through a step-wise supply function per demand block and scenario, which generally differs from the corresponding marginal cost function.

This upper-level problem is constrained by a collection of lower-level problems that represent the clearing of the market for each demand block and scenario. The target of each of these problems is maximizing its corresponding declared social welfare. Locational marginal prices (LMPs) for each of these problems are derived as dual variables of power balance constraints.

The optimality region of each of these lower-level problems is represented by its Karush-Kuhn-Tucker (KKT) conditions. Considering the upper-level problem and replacing the lower-level problems by these sets of KKT conditions results in an MPEC. The equilibrium constraints are the sets of KKTs that represent the clearing of the market in each demand block and scenario.

Efficacious linearization techniques are then used to convert the above MPEC into a mixed-integer linear programming problem, which can be solved using commercially available branch-and-cut software [15].

C. Uncertainty of Rival Offering and Rival Investment

Strategic offering by units belonging to rival producers is represented via scenarios. These scenarios can be constructed based on historical data pertaining to rival offers. The number of considered scenarios needs to be carefully selected because a large number of scenarios entails intractability.

Investment actions by rival producers are also modeled via scenarios. Since investment options are generally not many, a reduced number of alternative scenarios allows properly representing rival investments in the planning year.

III. Model Formulation

A. Bilevel Model

The considered bilevel model for strategic generation investment is explained below. Fig. 2 shows the bilevel structure of the model. The upper-level problem represents the profit maximization of the strategic producer subject to the selection of some investment options and to the lower-level problems. Each lower-level problem (one per scenario and demand block) represents the market clearing with the target of maximizing the social welfare and is subject to the power balance at every bus, power limits for production and consumption and transmission constraints. The formulation of the model is stated as follows:

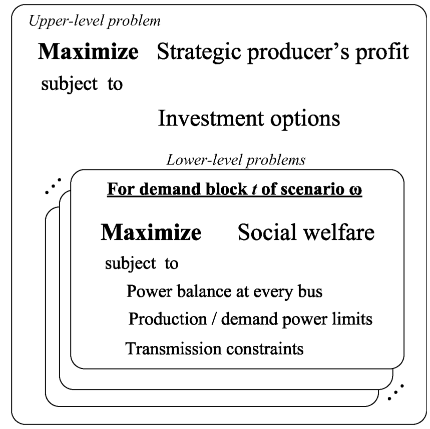

Fig. 2. Bilevel structure of proposed generation investment model.

$$\text{Minimize} \quad \sum_i K_i X_i - \sum_w \varphi_w \sum_t \sigma_t \left\{ \left(\sum_{i,[n:i\in\Psi_n]} P^{\mathrm{S}}_{tiw}\lambda_{tnw} - \sum_i P^{\mathrm{S}}_{tiw} C^{\mathrm{S}}_i \right) + \left(\sum_{k,[n:k\in\Psi_n]} P^{\mathrm{ES}}_{tkw}\lambda_{tnw} - \sum_k P^{\mathrm{ES}}_{tkw} C^{\mathrm{ES}}_k \right) \right\} \quad (1)$$

subject to :

$$X_i = \sum_h u_{ih} X_{ih}, \ \sum_h u_{ih} = 1, \ u_{ih} \in \{0,1\}, \quad \forall i \quad (2)$$

$$\lambda_{tnw}, P^{\mathrm{S}}_{tiw}, P^{\mathrm{ES}}_{tkw} \in \arg\min \left\{ \sum_i \alpha^{\mathrm{S}}_{tiw} P^{\mathrm{S}}_{tiw} + \sum_k \alpha^{\mathrm{ES}}_{tkw} P^{\mathrm{ES}}_{tkw} + \sum_j C^{\mathrm{O}}_{tjw} P^{\mathrm{O}}_{tjw} - \sum_d U^{\mathrm{D}}_{td} P^{\mathrm{D}}_{tdw} \right. \quad (3)$$

subject to :

$$\sum_{d\in\Psi_n} P^{\mathrm{D}}_{tdw} + \sum_{m\in\Omega_n} B_{nm}(\theta_{tnw} - \theta_{tmw}) - \sum_{i\in\Psi_n} P^{\mathrm{S}}_{tiw} - \sum_{k\in\Psi_n} P^{\mathrm{ES}}_{tkw} - \sum_{j\in\Psi_n} P^{\mathrm{O}}_{tjw} = 0 : \lambda_{tnw}, \quad \forall n \quad (4)$$

$$0 \le P^{\mathrm{S}}_{tiw} \le X_i : \mu^{\mathrm{S}^{\min}}_{tiw}, \mu^{\mathrm{S}^{\max}}_{tiw}, \quad \forall i \quad (5)$$

$$0 \le P^{\mathrm{ES}}_{tkw} \le P^{\mathrm{ES}^{\max}}_{k} : \mu^{\mathrm{ES}^{\min}}_{tkw}, \mu^{\mathrm{ES}^{\max}}_{tkw}, \quad \forall k \quad (6)$$

$$0 \le P^{\mathrm{O}}_{tjw} \le P^{\mathrm{O}^{\max}}_{jw} : \mu^{\mathrm{O}^{\min}}_{tjw}, \mu^{\mathrm{O}^{\max}}_{tjw}, \quad \forall j \quad (7)$$

$$0 \le P^{\mathrm{D}}_{tdw} \le P^{\mathrm{D}^{\max}}_{td} : \mu^{\mathrm{D}^{\min}}_{tdw}, \mu^{\mathrm{D}^{\max}}_{tdw}, \quad \forall d \quad (8)$$

$$-F^{\max}_{nm} \le B_{nm}(\theta_{tnw} - \theta_{tmw}) \le F^{\max}_{nm} : \nu^{\min}_{tnmw}, \nu^{\max}_{tnmw} \quad \forall n, \forall m \in \Omega_n \quad (9)$$

$$-\pi \le \theta_{tnw} \le \pi : \xi^{\min}_{tnw}, \xi^{\max}_{tnw}, \quad \forall n \quad (10)$$

$$\left. \theta_{tnw} = 0 : \xi^{1}_{tw}, n = 1 \right\} \quad \forall t, \forall w. \quad (11)$$

The optimization variables of each lower-level problem (3)–(11) are: $\lambda_{tnw}, P^{\mathrm{S}}_{tiw}, P^{\mathrm{ES}}_{tkw}, P^{\mathrm{O}}_{tjw}, P^{\mathrm{D}}_{tdw}, \theta_{tnw}, \mu^{\mathrm{S}^{\min}}_{tiw}, \mu^{\mathrm{S}^{\max}}_{tiw}, \mu^{\mathrm{ES}^{\min}}_{tkw}, \mu^{\mathrm{ES}^{\max}}_{tkw}, \mu^{\mathrm{O}^{\min}}_{tjw}, \mu^{\mathrm{O}^{\max}}_{tjw}, \mu^{\mathrm{D}^{\min}}_{tdw}, \mu^{\mathrm{D}^{\max}}_{tdw}, \nu^{\min}_{tnmw}, \nu^{\max}_{tnmw}, \xi^{\min}_{tnw}$, and $\xi^{\max}_{tnw}$. In addition to the optimization variables above, the upper-level problem (1), (2) includes the following optimization variables: $\alpha^{\mathrm{S}}_{tiw}$, $\alpha^{\mathrm{ES}}_{tkw}$, X_i, and u_{ih}.

The objective function (1) is the minus profit (investment cost minus operations revenue) of the strategic producer where φ_w is the probability associated with scenario w. LMP λ_{tnw} is the dual variable of the balance constraint at bus n, time t, and scenario w, obtained from the lower-level problem. Note that $i \in \Psi_n/k \in \Psi_n$ identifies the new/existing generating units of producer i/k located at bus n. For each available investment technology i (e.g., nuclear, coal, oil, CCGT, etc.), (2) allows the strategic producer to choose among the available MW-investment options, being one of the options no investment (e.g., 0, 200, 500, or 1000 MW). The LMPs and the productions belong to the feasible region defined by the lower-level problems.

The minimization of the minus social welfare of each lower-level problem is expressed by (3). Note that C^{O}_{tjw} depends on w to model rival offering uncertainty. A dc linear approximation of the network is used to represent the power balance at each bus as well as the line capacity limits. Equations (4) enforce the power balance at every bus. Equations (5)–(8) enforce capacity limits for the new and existing units of the strategic producer, the units of other producers, and the demand. Note that to model rival investment uncertainty, the upper bound of (7) depends on w. Constraints (9) enforce the transmission capacity limits of each line. Note that $m \in \Omega_n$ identifies the buses m connected to bus n. Constraints (10) enforce angle bounds for each node, and constraints (11) impose $n = 1$ to be the slack bus in each scenario. Dual variables are indicated at the corresponding equations following a colon.

The lower-level problems are continuous and linear as the market operator takes X_i, $\alpha^{\mathrm{S}}_{tiw}$, and $\alpha^{\mathrm{ES}}_{tkw}$ as parameters.

For notational clarity, we have not included additional subscripts to describe production-offer and demand-bid blocks. However, such blocks are considered in the case studies.

For the sake of simplicity, some features of real-world markets are not included in the proposed model, such as forward contracting, risk modeling, capacity payments, and renewable credits. Note, however, that capacity payments or renewable credits translate generally into a reduction/increment in the annualized cost of investment of conventional units, which can be easily integrated into the proposed model.

B. MPEC

The MPEC corresponding to problem (1)–(11) is stated below. It is obtained by replacing lower-level problems (3)–(11) by their corresponding KKTs:

$$(1)-(2) \tag{12}$$

$$-U_{td}^{\mathrm{D}} + \lambda_{tnw} + \mu_{tdw}^{\mathrm{D^{max}}} - \mu_{tdw}^{\mathrm{D^{min}}} = 0, \quad \forall t, \forall n: d \in \Psi_n, \forall w \tag{13}$$

$$\alpha_{tiw}^{\mathrm{S}} - \lambda_{tnw} + \mu_{tiw}^{\mathrm{S^{max}}} - \mu_{tiw}^{\mathrm{S^{min}}} = 0, \quad \forall t, \forall n: i \in \Psi_n, \forall w \tag{14}$$

$$\alpha_{tkw}^{\mathrm{ES}} - \lambda_{tnw} + \mu_{tkw}^{\mathrm{ES^{max}}} - \mu_{tkw}^{\mathrm{ES^{min}}} = 0, \quad \forall t, \forall n: k \in \Psi_n, \forall w \tag{15}$$

$$C_{tjw}^{\mathrm{O}} - \lambda_{tnw} + \mu_{tjw}^{\mathrm{O^{max}}} - \mu_{tjw}^{\mathrm{O^{min}}} = 0, \quad \forall t, \forall n: j \in \Psi_n, \forall w \tag{16}$$

$$\sum_{m \in \Omega_n} B_{nm}(\lambda_{tnw} - \lambda_{tmw}) + \sum_{m \in \Omega_n} B_{nm}\left(\nu_{tnmw}^{\max} - \nu_{tmnw}^{\max}\right) + \sum_{m \in \Omega_n} B_{nm}\left(\nu_{tmnw}^{\min} - \nu_{tnmw}^{\min}\right) + \xi_{tnw}^{\max} - \xi_{tnw}^{\min} + \left(\xi_{tw}^{1}\right)_{n=1} = 0 \quad \forall t, \forall n, \forall w \tag{17}$$

$$(4), (11) \tag{18}$$

$$0 \le P_{tiw}^{\mathrm{S}} \perp \mu_{tiw}^{\mathrm{S^{min}}} \ge 0 \quad \forall t, \forall i, \forall w \tag{19}$$

$$0 \le P_{tkw}^{\mathrm{ES}} \perp \mu_{tkw}^{\mathrm{ES^{min}}} \ge 0 \quad \forall t, \forall k, \forall w \tag{20}$$

$$0 \le P_{tjw}^{\mathrm{O}} \perp \mu_{tjw}^{\mathrm{O^{min}}} \ge 0 \quad \forall t, \forall j, \forall w \tag{21}$$

$$0 \le P_{tdw}^{\mathrm{D}} \perp \mu_{tdw}^{\mathrm{D^{min}}} \ge 0 \quad \forall t, \forall d, \forall w \tag{22}$$

$$0 \le \left(X_i - P_{tiw}^{\mathrm{S}}\right) \perp \mu_{tiw}^{\mathrm{S^{max}}} \ge 0 \quad \forall t, \forall i, \forall w \tag{23}$$

$$0 \le \left(P_k^{\mathrm{ES^{max}}} - P_{tkw}^{\mathrm{ES}}\right) \perp \mu_{tkw}^{\mathrm{ES^{max}}} \ge 0 \quad \forall t, \forall k, \forall w \tag{24}$$

$$0 \le \left(P_{jw}^{\mathrm{O^{max}}} - P_{tjw}^{\mathrm{O}}\right) \perp \mu_{tjw}^{\mathrm{O^{max}}} \ge 0 \quad \forall t, \forall j, \forall w \tag{25}$$

$$0 \le \left(P_{tdw}^{\mathrm{D^{max}}} - P_{tdw}^{\mathrm{D}}\right) \perp \mu_{tdw}^{\mathrm{D^{max}}} \ge 0 \quad \forall t, \forall d, \forall w \tag{26}$$

$$0 \le \left[F_{nm}^{\max} + B_{nm}(\theta_{tnw} - \theta_{tmw})\right] \perp \nu_{tnmw}^{\min} \ge 0 \quad \forall t, \forall n, \forall m \in \Omega_n, \forall w \tag{27}$$

$$0 \le \left[F_{nm}^{\max} - B_{nm}(\theta_{tnw} - \theta_{tmw})\right] \perp \nu_{tnmw}^{\max} \ge 0 \quad \forall t, \forall n, \forall m \in \Omega_n, \forall w \tag{28}$$

$$0 \le (\pi - \theta_{tnw}) \perp \xi_{tnw}^{\max} \ge 0 \quad \forall t, \forall n, \forall w \tag{29}$$

$$0 \le (\pi + \theta_{tnw}) \perp \xi_{tnw}^{\min} \ge 0 \quad \forall t, \forall n, \forall w. \tag{30}$$

The collection of equality constraints (13)–(18) and complementarity constraints (19)–(30) is equivalent to the lower-level problems (3)–(11). MPEC (12)–(30) is transformed in a mixed-integer linear programming problem as explained in the Appendix. Note that this MPEC problem involves all optimization variables of problem (1)–(11) plus the binary variables used to linearize complementarity constraints as described in the Appendix.

IV. Case Studies

The objectives of this section are twofold:

1) To show the interest of the proposed methodology to analyze the effect that strategic generation investment may have on electricity markets.
2) To highlight the relevance of the proposed methodology to assist a strategic producer in its investment decisions.

To achieve the first objective, we present an illustrative example in which, for the sake of clarity, the features of the market agents/components (generators, demands, network, etc.) have been simplified. The second objective is addressed in Section IV-B, where a large case study is considered.

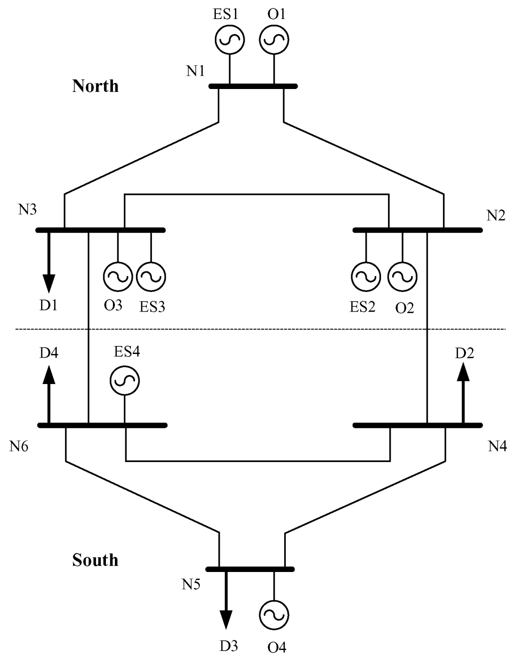

Fig. 3. Six-bus test system.

A. Illustrative Example

The considered network in this illustrative example is depicted in Fig. 3 and includes two separated areas (north and south) interconnected by two tie-lines. In the northern area (buses N1, N2, and N3), generation prevails while in the southern one (buses N4, N5, and N6), the consumption does. In this figure, "ES" identifies existing units belonging to the strategic producer and "O" units of other producers.

Table II provides data for the existing units of the strategic producer and other units considered in this example. Each row refers to a particular type of generation unit. The second column contains the power capacity of each unit, which is divided in two generation blocks (columns 3 and 4) with associated production costs (columns 5 and 6).

Table III gives investment options including two technologies: 1) base technology with high investment cost but small production cost, and 2) peak technology with low investment cost but high production cost. We consider that each investment option includes two production blocks. For the sake of simplicity, note that the size of each of the two blocks is considered equal to half of the installed capacity. Costs for these two generation blocks are provided in the last two columns of Table III.

Table IV provides demand bids (energy and price) for each demand block. Each column corresponds to a demand ($D1$ to $D4$), while each row corresponds to a demand block. The cells of this table identify the actual values of the energy bids (MWh)

TABLE II
TYPE AND DATA FOR THE EXISTING GENERATING UNITS

Unit Type	P[MW]	Block1 [MW]	Block2 [MW]	Cost1 [€/MWh]	Cost2 [€/MWh]
Oil	12	5	7	23.41	23.78
Oil	20	15	5	11.09	11.42
Hydro	50	25	25	0	0
Coal	76	30	46	11.46	11.96
Oil	100	25	75	18.60	20.03
Coal	155	55	100	9.92	10.25
Oil	197	97	100	10.08	10.66
Coal	350	150	200	19.20	20.32
Nuclear	400	200	200	5.31	5.38

TABLE III
TYPE AND DATA FOR INVESTMENT OPTIONS

Unit Type	K_i[€/MW]	X_{ih}[MW]	Cost1 [€/MWh]	Cost2 [€/MWh]
Base tech.	75000	0, 500, 750, 1000	6.01	6.31
Peak tech.	15000	0, 200, 250, 300, 350, 400 450, 500, 550, 600, 650, 700 750, 800, 850, 900, 950, 1000	14.72	15.20

TABLE IV
DEMAND BLOCKS [MWh] AND PRICE BIDS [€/MWh]

	$D1$		$D2$		$D3$		$D4$	
	Demand	Price	Demand	Price	Demand	Price	Demand	Price
Block 1	600.0	38.75	540.0	36.48	510.0	35.75	480.0	33.08
	150.0	36.81	135.0	34.65	127.5	33.96	120.0	31.42
Block 2	480.0	33.69	420.0	30.09	360.0	28.72	330.0	28.52
	120.0	32.00	105.0	28.59	90.0	27.28	82.5	27.10
Block 3	390.0	30.66	360.0	28.30	330.0	27.36	300.0	26.20
	97.5	29.12	90.0	26.89	82.5	25.99	75.0	24.89
Block 4	330.0	28.08	300.0	26.22	270.0	25.21	240.0	23.47
	82.5	26.68	75.0	24.91	67.5	23.95	60.0	22.30
Block 5	240.0	25.69	210.0	24.34	180.0	23.55	165.0	22.71
	60.0	24.41	52.5	23.13	45.0	22.37	41.3	21.58
Block 6	210.0	23.49	180.0	21.98	150.0	21.33	135.0	20.61
	152.5	22.32	45.0	20.88	37.5	20.27	33.7	19.58
Block 7	180.0	22.76	150.0	21.35	135.0	20.71	120.0	19.80
	45.0	21.62	37.5	20.29	33.7	19.68	30.0	18.81

TABLE V
LOCATION AND TYPE OF EXISTING UNITS (ILLUSTRATIVE EXAMPLE)

Strategic producer units				Other units			
k	Unit type	P[MW]	Bus	j	Unit type	P[MW]	Bus
1	Coal	350	1	1	Coal	350	1
2	Oil	100	2	2	Oil	197	2
3	Coal	76	3	3	Coal	155	3
4	Oil	20	6	4	Oil	100	5

and corresponding prices (€/MWh). Note that each demand considers per block two bids with different sizes and prices.

The considered weighting factors corresponding with each demand block are 0.5, 0.5, 1.0, 1.0, 1.0, 1.5, and 1.5 derived from the load duration curve of the planning year, each multiplied by 1251.43 (8760/7), i.e., the total hours in a year divided by the number of considered demand blocks.

Table V provides the location of the existing units throughout the network. Note that each unit is defined by its type and maximum capacity.

Finally, we consider that all lines have the same susceptance, $B_{nm} = 10$ p.u. (100 MW base).

First, MPEC (12)–(30) is solved considering single-scenario cases and then multiple-scenario cases are analyzed. For the first single-scenario case, MPEC (12)–(30) is solved without transmission limits on the network, which constitutes the uncongested case. Cases A and B are cases where the capacity of both tie-lines (lines 2–4 and 3–6) is limited to 450 MW and 150 MW, respectively. Also, a centralized generation investment (i.e., least-cost planning) is considered for the uncongested single-scenario case. Table VI provides results on generation investment and profit for the strategic producer. Column 2 refers to the uncongested case while columns 3 and 4 to cases A and B, respectively. The last column pertains to the centralized investment case. This table gives the investment in each bus (rows 2 to 7), the total investment (row 8), the total profit (row 9), the investment cost (row 10), and the operations profit (row 11). Note that the investment and profit results for the uncongested case and case A are the same. However, due to transmission limits on the tie-lines in case A, the base technology is located in the southern area. In both of these cases, no tie-line is congested; thus, the clearing prices throughout the network are the same in each demand block as shown in Fig. 4. In case B, the tie-lines are congested, and the total investment is higher than in the previous cases. Note that in case B, all investments are located in the southern area and the profit of the strategic producer becomes comparatively higher. The prices at each bus for each demand block in this case are depicted in Fig. 5. Due to the prevailing demand in the southern area, the tie-lines are congested for most demand blocks. Observe that this phenomenon makes LMPs different throughout the network [this can be easily derived from (17) since $\nu_{tnmw}^{\min}$ or $\nu_{tnmw}^{\max}$ are not necessarily zero]. In particular, for demand blocks 1–5, congestion occurs and the southern area exhibits higher prices than the northern area where generation prevails. On the contrary, congestion does not occur at low demand blocks 6 and 7, and therefore, prices become identical throughout the network.

TABLE VI
INVESTMENT RESULTS (ILLUSTRATIVE EXAMPLE)

	Uncongested	Case A	Case B	Centralized
Bus 1 [MW]	-	-	-	-
Bus 2 [MW]	500 (base)	-	-	500 (base)
Bus 3 [MW]	-	-	-	800 (peak)
Bus 4 [MW]	200 (peak)	200 (peak)	600 (peak)	-
Bus 5 [MW]	-	500 (base)	-	-
Bus 6 [MW]	-	-	500 (base)	-
Total [MW]	700	700	1100	1400
Profit [M€]	45.55	45.55	47.64	-
Investment cost [M€]	40.50	40.50	46.50	49.50
Operations profit [M€]	86.05	86.05	94.14	-
CPU time [s]	3.17	3.36	17.48	13.83

The centralized generation expansion case renders, as expected, higher investment than the other cases.

Two additional cases including one scenario are examined below considering and not considering strategic offering. In the case of no strategic offering, the strategic producer offers at its marginal cost. For simplicity, the considered network is reduced to two buses, north and south, and no transmission limits on tie-lines are taken into account. The results are given in Table VII. Note that offering marginal costs results in comparatively lower investment and lower profit.

Next, we examine two stochastic cases considering some relevant scenarios. Scenarios should be selected representing in

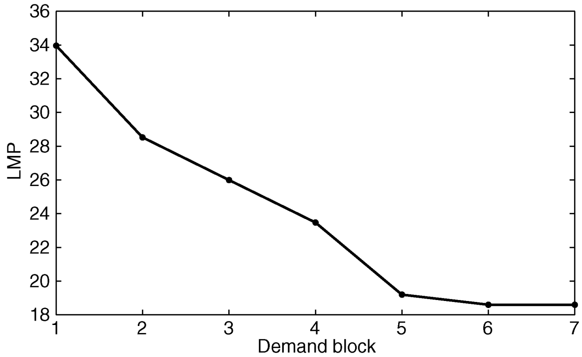

Fig. 4. Clearing prices in uncongested case and case A (illustrative example).

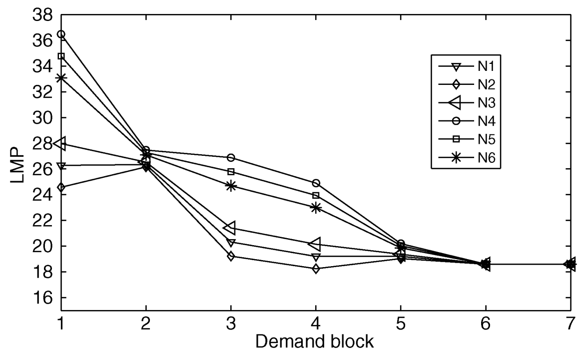

Fig. 5. Clearing prices in case B (illustrative example).

TABLE VII
INVESTMENT RESULTS CONSIDERING AND NOT CONSIDERING STRATEGIC OFFERING (ILLUSTRATIVE EXAMPLE)

	No strategic offering	Strategic offering
North (base tech.) [MW]	-	-
North (peak tech.) [MW]	-	-
South (base tech.) [MW]	-	500
South (peak tech.) [MW]	350	200
Total investment [MW]	350	700
Profit [M€]	31.40	45.55
Investment cost [M€]	5.25	40.50
Operations profit [M€]	36.65	86.05
CPU time [s]	5.84	0.75

the best possible manner the real-world alternative values of the uncertain parameters as well as their associated probabilities. Scenarios pertaining to rival offers need to be selected covering all possible rival offering strategies, and scenarios pertaining to rival investment should be based on the financial status and prospective investments of rival producers. Note that the appropriate selection of scenarios is outside the scope of this paper. The first case involves four scenarios including two rival offering scenarios and two rival investment scenarios. The second case involves 12 scenarios including three rival offering scenarios and four rival investment offering scenarios. The details of rival producer scenarios are given in Table VIII. In this table, column 2 characterizes rival investment uncertainty considering alternative investments consistent with the alternatives in Table II, and column 3 identifies their location in the network. Note that in the cases of no investment, only the rival offering uncertainty is modeled. The fourth column of

TABLE VIII
RIVAL PRODUCER SCENARIOS

Case	Rival investment	Bus	Cost factor	Probability
4 scenarios	No investment	-	0.9	0.24
	No investment	-	1.0	0.36
	400 MW	South	0.9	0.16
	400 MW	South	1.0	0.24
12 scenarios	No investment	-	0.9	0.08
	No investment	-	1.0	0.24
	No investment	-	1.1	0.08
	400 MW	South	0.9	0.05
	400 MW	South	1.0	0.15
	400 MW	South	1.1	0.05
	197 MW	North	0.9	0.05
	197 MW	North	1.0	0.15
	197 MW	North	1.1	0.05
	400 MW and 197 MW	South-North	0.9	0.02
	400 MW and 197 MW	South-North	1.0	0.06
	400 MW and 197 MW	South-North	1.1	0.02

TABLE IX
INVESTMENT RESULTS FOR THE STOCHASTIC ILLUSTRATIVE EXAMPLE

	One scenario	4 scenarios	12 scenarios
North (base tech.) [MW]	-	-	-
North (peak tech.) [MW]	-	350	500
South (base tech.) [MW]	500	-	-
South (peak tech.) [MW]	200	350	200
Total investment [MW]	700	700	700
Profit [M€]	45.55	32.25	31.38
Investment cost [M€]	40.50	10.50	10.50
CPU time [s]	0.75	5.08	70.68

Table VIII gives the factors pertaining to rival offers available in Table II, i.e., a rival offering strategy is obtained multiplying the production costs of all rival units by the corresponding factor. The last column of Table VIII presents the probabilities corresponding to each scenario.

Table IX gives the generation investment results for cases involving one, four, and 12 scenarios. The case involving one scenario corresponds with the one in the third column of Table VII. Although the total investment in all cases is the same, Table IX shows that the profit of the strategic producer decreases as the rival uncertainty increases.

B. Case Study

This section presents results for a case study based on the IEEE one-area Reliability Test System (RTS) [16]. Similarly to the previous example, we consider a load duration curve divided into seven demand blocks. The demands for the first block in all buses are those in [16], and for the next six blocks, all demands are multiplied by 0.90, 0.75, 0.65, 0.60, 0.55, and 0.50, respectively.

Demands 11, 13, and 15 (located at buses 13, 15, and 18 in the original system) bid the first demand block at 40.00 (€/MWh), other demands located in the northern area (buses 14–24) at 38.00 (€/MWh), and other demands located in the southern area (buses 1–13) at 35.00 (€/MWh). For the next six demand blocks, all demand bids are multiplied by 0.95, 0.90, 0.85, 0.80, 0.75, and 0.70, respectively. The weighting factors of demand blocks are those provided in the illustrative example.

As in the illustrative example, Table II gives data for the generating units and Table X provides their location in the network.

TABLE X
LOCATION AND TYPE OF EXISTING UNITS (CASE STUDY)

Strategic producer units				Other units			
k	Unit type	P[MW]	Bus	j	Unit type	P[MW]	Bus
1	Oil	20	1	1,2	Oil	20	1
2	Coal	76	2	3,4	Oil	20	2
3	Oil	100	7	5	Coal	76	2
4	Coal	155	13	6	Oil	100	7
5	Oil	100	15	7	Oil	197	13
6	Oil	197	21	8-12	Oil	12	15
7	Coal	76	23	13	Coal	155	16
				14	Oil	100	18
				15-18	Hydro	50	22
				19	Coal	155	23
				20	Coal	155	23

TABLE XI
INVESTMENT RESULTS FOR THE STOCHASTIC CASE STUDY

	One scenario	4 scenarios	12 scenarios (reduced version)
Base tech. [MW]	-	-	-
Peak tech. [MW]	750 [bus 15]	550 [bus 11]	450 [bus 23]
Total investment [MW]	750	550	450
Profit [M€]	82.97	65.66	61.95
Investment cost [M€]	11.25	8.25	6.75
CPU time	12.14 [s]	3.95 [hours]	3.76 [hours]
Error gap (%)	0.10	1.00	1.75

The scenarios considered in the stochastic cases are the same as those in the illustrative example, available in Table VIII, but considering bus 15 for rival investments.

Since most transmission lines in a power network are designed to operate at safe margins with respect to their capacities, congestion only occurs at some critical lines that are generally well identified. Therefore, the buses connected through lines that are not likely to suffer congestion are gathered into a single bus without altering significantly the results of the study. This simplification might be a computational requirement since network constraints increase considerably the computational burden of the proposed model. Hence for the sake of simplicity and to decrease the computational burden in the case of 12 scenarios, we reduce the number of buses in the system to nine, merging buses 1 to 13 into a single one and buses 17 to 20 in another one.

Table XI gives the generation investment results involving one and four scenarios considering 24 buses and 12 scenarios considering nine buses. The last row of this table shows the optimality gap. Enforcing lower gaps may lead to higher accuracy, but increases computational burden as well. From Table XI, it can be concluded that higher uncertainty results in lower profit, and investment in new units with reduced capacity.

C. Computational Issues

MPEC (12)–(30) is solved using CPLEX 11.0.1 [15] under GAMS [17] on a Sun Fire X4600 M2 with four processors clocking at 2.9 GHz and 256 GB of RAM.

The computational times required for solving the considered problems are provided in Tables VI, VII, IX, and XI. The required time increases with the size of the problem and with the congestion of any line. Note also that the computational time increases very significantly with the number of scenarios.

V. CONCLUSION

This paper provides a methodology to assist a strategic producer in making decisions pertaining to generation investment. The features of the proposed model and the simulations carried out allow deriving the following conclusions:

1) The proposed model adequately represents the physical system: demand and network.
2) The strategic behavior of the considered producer is adequately captured via supply function offering and LMPs.
3) The considered market framework is accurately represented through the proposed bilevel model.
4) Rival uncertainties (on offering and investment) are appropriately represented using scenarios.
5) The resulting model, although computationally expensive, is tractable.

Further work is needed to ease the computational burden of the resulting mixed-integer linear programming problem and to include dynamic decision-making features. Benders' decomposition is an appealing alternative.

APPENDIX
LINEARIZATION

MPEC (12)–(30) includes the following nonlinearities:

1) The term $\sum_{i,[n:i\in\Psi_n]} P^{\rm S}_{tiw}\lambda_{tnw} + \sum_{k,[n:k\in\Psi_n]} P^{\rm ES}_{tkw}\lambda_{tnw}$ in the objective function.
2) The complementarity conditions (19)–(30).

A. Complementarity Linearization

The complementarity condition

$$0 \le a \perp b \ge 0 \tag{31}$$

can be replaced by

$$a \ge 0, \quad b \ge 0, \quad a \le \psi M, \quad b \le (1-\psi)M, \quad \psi \in \{0,1\} \tag{32}$$

where M is a large enough constant [18].

B. Objective Function Linearization

To find a linear expression for $\sum_{i,[n:i\in\Psi_n]} P^{\rm S}_{tiw}\lambda_{tnw} + \sum_{k,[n:k\in\Psi_n]} P^{\rm ES}_{tkw}\lambda_{tnw}$, we use the strong duality theorem and some of the KKT equalities. The strong duality theorem says that if a problem is convex, the objective functions of the primal and dual problems have the same value at the optimum. Thus after applying the strong duality theorem to each lower-level problem (3)–(11), we get $\forall t, \forall w$

$$\sum_i \alpha^{\rm S}_{tiw}P^{\rm S}_{tiw} + \sum_k \alpha^{\rm ES}_{tkw}P^{\rm ES}_{tkw} + \sum_j C^{\rm O}_{tjw}P^{\rm O}_{tjw} - \sum_d U^{\rm D}_{td}P^{\rm D}_{tdw} = -\sum_i \mu^{\rm S^{max}}_{tiw} X_i - \sum_k \mu^{\rm ES^{max}}_{tkw} P^{\rm ES^{max}}_k - y \tag{33}$$

where

$$y = \sum_j \mu^{\rm O^{max}}_{tjw} P^{\rm O^{max}}_{jw} + \sum_d \mu^{\rm D^{max}}_{tdw} P^{\rm D^{max}}_{tdw} + \sum_{n(m\in\Omega_n)} \nu^{\rm min}_{tnmw}F^{\rm max}_{nm} + \sum_{n(m\in\Omega_n)} \nu^{\rm max}_{tnmw}F^{\rm max}_{nm} + \sum_n \xi^{\rm min}_{tnw}\pi + \sum_n \xi^{\rm max}_{tnw}\pi. \tag{34}$$

From (23) and (24)

$$\sum_i \mu_{tiw}^{\mathrm{S}^{\max}} X_i = \sum_i \mu_{tiw}^{\mathrm{S}^{\max}} P_{tiw}^{\mathrm{S}} \quad (35)$$

$$\sum_k \mu_{tkw}^{\mathrm{ES}^{\max}} P_k^{\mathrm{ES}^{\max}} = \sum_k \mu_{tkw}^{\mathrm{ES}^{\max}} P_{tkw}^{\mathrm{ES}}. \quad (36)$$

Substituting (35) and (36) in (33) renders

$$\sum_i P_{tiw}^{\mathrm{S}} \left(\alpha_{tiw}^{\mathrm{S}} + \mu_{tiw}^{\mathrm{S}^{\max}}\right) + \sum_k P_{tkw}^{\mathrm{ES}} \left(\alpha_{tkw}^{\mathrm{ES}} + \mu_{tkw}^{\mathrm{ES}^{\max}}\right) = -\sum_j C_{tjw}^{\mathrm{O}} P_{tjw}^{\mathrm{O}} + \sum_d U_{td}^{\mathrm{D}} P_{tdw}^{\mathrm{D}} - y. \quad (37)$$

On the other hand, from (14) and (15)

$$\lambda_{tnw} = \alpha_{tiw}^{\mathrm{S}} + \mu_{tiw}^{\mathrm{S}^{\max}} - \mu_{tiw}^{\mathrm{S}^{\min}}, \quad \forall n : i \in \Psi_n \quad (38)$$

$$\lambda_{tnw} = \alpha_{tkw}^{\mathrm{ES}} + \mu_{tkw}^{\mathrm{ES}^{\max}} - \mu_{tkw}^{\mathrm{ES}^{\min}}, \quad \forall n : k \in \Psi_n \quad (39)$$

thus

$$\sum_{i,[n:i\in\Psi_n]} P_{tiw}^{\mathrm{S}} \lambda_{tnw} = \sum_i \alpha_{tiw}^{\mathrm{S}} P_{tiw}^{\mathrm{S}} + \sum_i \mu_{tiw}^{\mathrm{S}^{\max}} P_{tiw}^{\mathrm{S}} - \sum_i \mu_{tiw}^{\mathrm{S}^{\min}} P_{tiw}^{\mathrm{S}} \quad (40)$$

$$\sum_{k,[n:k\in\Psi_n]} P_{tkw}^{\mathrm{ES}} \lambda_{tnw} = \sum_k \alpha_{tkw}^{\mathrm{ES}} P_{tkw}^{\mathrm{ES}} + \sum_k \mu_{tkw}^{\mathrm{ES}^{\max}} P_{tkw}^{\mathrm{ES}} - \sum_k \mu_{tkw}^{\mathrm{ES}^{\min}} P_{tkw}^{\mathrm{ES}}. \quad (41)$$

Additionally, from (19) and (20)

$$\sum_i \mu_{tiw}^{\mathrm{S}^{\min}} P_{tiw}^{\mathrm{S}} = 0, \quad \sum_k \mu_{tkw}^{\mathrm{ES}^{\min}} P_{tkw}^{\mathrm{ES}} = 0. \quad (42)$$

Using (42) to simplify (40) and (41) renders

$$\sum_{i,[n:i\in\Psi_n]} P_{tiw}^{\mathrm{S}} \lambda_{tnw} + \sum_{k,[n:k\in\Psi_n]} P_{tkw}^{\mathrm{ES}} \lambda_{tnw} = \sum_i P_{tiw}^{\mathrm{S}} \left(\alpha_{tiw}^{\mathrm{S}} + \mu_{tiw}^{\mathrm{S}^{\max}}\right) + \sum_k P_{tkw}^{\mathrm{ES}} \left(\alpha_{tkw}^{\mathrm{ES}} + \mu_{tkw}^{\mathrm{ES}^{\max}}\right). \quad (43)$$

Finally, considering (37) and (43)

$$\sum_{i,[n:i\in\Psi_n]} P_{tiw}^{\mathrm{S}} \lambda_{tnw} + \sum_{k,[n:k\in\Psi_n]} P_{tkw}^{\mathrm{ES}} \lambda_{tnw} = -\sum_j C_{tjw}^{\mathrm{O}} P_{tjw}^{\mathrm{O}} + \sum_d U_{td}^{\mathrm{D}} P_{tdw}^{\mathrm{D}} - y. \quad (44)$$

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S. Jalal Kazempour (S'08) received the B.Sc. degree in electrical engineering from the University of Tabriz, Tabriz, Iran, in September 2006 and the M.Sc. degree from the University of Tarbiat Modares, Tehran, Iran, in March 2009. He is currently pursuing the Ph.D. degree at the University of Castilla-La Mancha (UCLM), Ciudad Real, Spain.

His research interests include economics of electric energy systems, the applications of equilibrium, as well as investment problems.

Antonio J. Conejo (F'04) received the M.S. degree from the Massachusetts Institute of Technology, Cambridge, in 1987 and the Ph.D. degree from the Royal Institute of Technology, Stockholm, Sweden, in 1990.

He is currently a full Professor at the University of Castilla-La Mancha, Ciudad Real, Spain. His research interests include control, operations, planning and economics of electric energy systems, as well as statistics and optimization theory and its applications.

Carlos Ruiz (S'07) received the Ingeniero Industrial degree from the University of Castilla-La Mancha, Ciudad Real, Spain, in 2007. He is currently pursuing the Ph.D. degree at the University of Castilla-La Mancha.

His research interests include electricity markets and MPECs.