A Model to Remarry the Active/Reactive Power Dispatches in Competitive Environment and Active/Reactive Marginal Prices Computation

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***Abstract*-- This paper describes a mathematical formulation for the active/reactive dispatch in electricity markets, including a number of issues present in market models used in several countries. Traditional market approaches are implemented considering a sequence of activities namely in terms of active power dispatch and ancillary services. However, these two problems are coupled in the sense that dispatching reactive power is not independent from the active power scheduling of generators. The proposed model admits that it is known the purely economic pool dispatch together with bilateral contracts and then it aims at dispatching reactive resources considering voltage and branch limit constraints and constraints reflecting the alternator capability curve. As a sub-result, this formulation also outputs nodal active and reactive marginal prices that can be useful to build tariff schemes. Finally, the paper includes a case study based on the IEEE 30 bus/41 branch system to illustrate the obtained results and their interest for electricity markets.**

***Index Terms*--Adjustment bids, integrated dispatch, marginal prices, Sequential Linear Programming, System Operator.**

I. Introduction

The implementation of market approaches in several countries has a number of common aspects as the unbundling of traditional vertically integrated utilities in a large number of players and agents dedicated to regulated activities, to market driven businesses and to technical coordination or regulatory activities. This restructuring typically lead to the adoption of competition in the extremes of the system, that is, in the generation and retailing activities implemented either in terms of bid-based forward markets, usually centralized in a day-ahead pool, or using bilateral contracts having different time horizons. The physical relation between generation and demand is ensured by network companies that provide their services in a monopoly basis, just because it is unfeasible to duplicate networks in the same geographic area in order to introduce competition. The absence of competition in these areas and the imperfect competition in other ones, together with the trend to reduce the direct intervention of the governments and the greater accent on technical robust justifications, are the basic reasons explaining the advent of independent regulatory agencies.

Apart from these problems, when talking about electricity markets one usually refers to the trade of active power. However, ancillary services as reactive power and voltage control and several time span reserves are also crucial in order to maintain system security. The technical coordination of system operation is assigned to Independent System Operators, ISO, or Transmission System Operators, TSO, that receive information from the purely economic dispatch and technical information about bilateral contracts to evaluate the technical feasibility of this set of injections and to assign reactive generation and reserves. In most cases, the active power dispatch – both by bid-based pool and by bilateral contracts – and the ISO or TSO technical activities are performed in a temporal sequence of actions and studies. The adoption of a chronologic sequence of actions to perform the active dispatch, the reactive dispatch and the dispatch of reserves is a decoupled approach that is likely to cause several inefficiencies. In the first place, several power system components are constrained by technical limits depending both on active and reactive power. This is the case of branch flow limits and synchronous generators in which an operation point is characterized by an active / reactive pair of values. This means that biding for active power and being dispatched by the Market Operator in the first place, immediately conditions the possible range that the reactive output can assume. The System Operator can impose changes on the active dispatch of a generator just because the required reactive power would not be possible given the Market Operator dispatch. In other cases, weak transmission networks can contribute to give market power to agents connected to some particular locations. Just consider a generator connected to a node of a weakly meshed network. This generator has power over the market since it may know that it has to be used because it is required in terms of reactive support/voltage control. Therefore, it will eventually not bid on the active power market, waiting the System Operator to dispatch it due to the reactive support/voltage control requirement.

These aspects illustrate how active and reactive power are

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married so that attempting to decouple their dispatch may lead to technical difficulties or prevent the adoption of the most adequate economic decisions. Therefore, having this concern in mind, this paper presents a formulation to solve the active and reactive power dispatches in a more integrated way while adopting a market framework and attempting to bring more realism to the whole process. The developed model includes two main steps. The first one aims at relating the demand and the generation side of power systems. This is currently being done using symmetrical pool mechanisms as detailed in section III.A. In a second moment, the ISO or the TSO interprets the pool hourly active power schedules, the injections from bilateral contracts and the involved nodes as a base dispatch that, however, may not be the final one. In the first place, the base dispatch has to be completed by allocating reactive power to the generators and capacitors. Secondly, since the operation of several components is constrained jointly by active and reactive power, this pair of values can lead to infeasible operation conditions for branches, transformers or generators so that the active/reactive dispatch has to be changed. This is performed by solving an optimization problem aiming at minimizing the cost of network active losses plus the eventual reduction of the revenues of the generators that have to alter their dispatch in order to fulfill a reactive power/voltage support requirement. This problem includes: (1) adjustment variables affecting the active power dispatch either due to the need to enforce operation or security constraints or to turn feasible some amount of reactive support together with the active power dispatch, given the generator capability curve; (2) variables representing the reactive output of generators and capacitors.

As a result, this problem provides a technically feasible active/reactive dispatch based on the initial active power market dispatch, together with nodal marginal prices both for active and reactive powers that can help in building consistent tariff systems. This model corresponds to an enhancement of the formulation detailed in [1] in the sense that they are now included variables representing the amount of active power assigned to each generator in order to balance active losses. This will also enable the ISO or the TSO to allocate this power in a more transparent and technically robust way.

The proposed paper is organized as follows. After this introductory section, Section II addresses some available models to tariff reactive power as well as attempts to implement markets for ancillary services. In Section III we will describe the proposed model and Section IV details the adopted solution algorithm. Section V presents a case study to illustrate the proposed approach and to highlight its advantages. Finally, Section VI draws the most relevant conclusions.

II. Reactive Power Allocation Approaches

The importance of reactive power started to rise as in several countries, namely in Europe, the number and the capacity of wind parks rapidly increased. These wind parks are typically connected to remote weak distribution networks and, in several cases, are supplied by reactive power to create the generators induction magnetic field. As a result, distribution companies typically imposed connection requirements.

Recognizing the importance of reactive power several publications describe models to dispatch and to value it. In the first place, in reference [2] NGC proposed a reactive power optimization model under which individual generation units would offer Mvar piece-wise linear cost curves so that it was solved an optimization problem to minimize the sum of such costs by adequately changing the output of synchronous generators, capacitors and transformer taps.

In reference [3] the authors address the characteristics of reactive power/voltage support in terms of its local nature and of the conflicting objectives to be balanced in order to establish a price for this ancillary service. The authors also refer that the importance of an adequate reactive power/voltage support is much larger than the price usually assigned to it. Regarding the valuation of this service, they propose three approaches. The first one corresponds to compute operation costs and determine the part to allocate to the reactive service. The second implies imposing performance requirements and connection standards to consumers and to generators inside a control area so that, if they are met, there is no reactive power charge. Finally, the last approach is related with the creation of local reactive power markets for each control area. It would then be necessary to compute nodal reactive power adjustment factors corresponding to multipliers to adjust generation and demand and reflecting the reactive power locational value. In line with this third approach, reference [4] proposes a two-stage model to optimise active and reactive power scheduling. Once the final dispatch is obtained it is possible to compute active and reactive nodal prices reflecting the impact of changes of active power in the active generation cost in the first case and the impact of reactive power changes in the branch active losses.

Reference [5] discusses how one can assign a cost to reactive power, namely related with explicit and opportunity generation costs and also explicit costs from several transmission sources. In this approach, a generator opportunity cost is related with the profit of selling an amount of active power that is in fact not achieved because there is a reactive power requirement. Based on these ideas, it is formulated a reactive power dispatch problem solved by a successive linear programming approach.

Following the ideas applied by NGC after 1998, in reference [6] the authors present a linear programming based security constrained reactive optimal power flow model to allocate reactive support on a competitive basis. The objective function aims at minimizing total annual costs of reactive power capability reflecting biding prices for reactive power and utilization costs reflecting Mvarh price curves.

References [7], [8] and [9] propose a structure for the reactive power bids based on the synchronous generator capability curve. According to this diagram, there are operation regions in which the generator has no need to alter its active output to meet a reactive requirement, while there are

areas in which meeting a reactive requirement implies a change on the active output. In this case, the revenue of the generator on the active power market gets reduced and so it must be compensated for this opportunity cost.

In references [10] and [11] the authors identify the costs of reactive power providers and discuss methods to allocate them to grid users. In the first of them, these costs are organized in explicit ones (fixed costs, and variable maintenance and operation costs) and implicit ones (losses or profits due to reactive support) and the payments should be structured in a capacity term to remunerate fixed costs and an usage fee reflecting variable costs. In the second one, the authors consider that the dominant component on the cost structure of the reactive power ancillary service is related with the opportunity costs corresponding to the lost revenues of a generator in selling active power because of a reactive power/voltage support requirement. Finally, recognizing the coupling between active and reactive power and the difficulty in dealing with system constraints, reference [12] details the activities of the Spanish TSO to validate the dispatch from the Market Operator while ensuring branch and voltage limits. The authors propose getting a final solution in two stages. In the first one, they aim at obtaining a feasible solution re-dispatching generators and minimizing the total system cost. Afterwards, voltage control resources are fine tuned for each hour of the next day by running an LP based OPF problem aiming at minimizing transmission losses.

III. Integrated Dispatch Using Adjustment Bids

A. Market Operator Initial Uniform Price Auction

Typical electricity markets are organized in terms of a set of activities that are usually assigned to different entities. In day n-1 the Market Operator receives selling and buying bids from market agents that, in their simplest version – Simple Bids – include pairs (price, quantity). The Market Operator orders selling bids by the ascending order of its price and buying bids in descending order of the corresponding price so that they are built aggregated generation and demand curves. The crossing between these two curves leads to the Clearing Quantity and to the Clearing Price, interpreted as the short-term marginal price of the generation system. This can be modeled by (1) to (4).

In this formulation C_{dj} and C_{gi} are the buying and selling prices, Pd_j^{bid} and Pg_i^{bid} are the maximum demand and generation quantities, P_{dj} and P_{gi} are the demand and generation at the final solution and N_D and N_G are the number of buying and selling bids.

$$max\, Z = \sum_{j=1}^{N_D} Cd_j . Pd_j - \sum_{i=1}^{N_G} Cg_i . Pg_i \qquad (1)$$

$$subj \quad 0 \le Pd_j \le Pd_j^{bid} \qquad (2)$$

$$0 \le Pg_i \le Pg_i^{bid} \qquad (3)$$

$$\sum_{j=1}^{N_D} Pd_j = \sum_{i=1}^{N_G} Pg_i \qquad (4)$$

The objective function Z in (1) is denoted as the Social Welfare Function and it corresponds to the surplus between the aggregated demand and generation curves. This objective function is subjected to limits on the demand (2) and on the generation (3) and to a demand / supply balance equation (4).

This formulation can be enhanced in several ways. In the first place, generators can transmit to the Market Operator bids structured in multiple blocks. This allows bids to better follow the generators' cost curve and eventually the first block can be declared indivisible. This would mean that, if scheduled by the Market Operator, the first block should be entirely dispatched, as a way to cope with minimum limits of thermal generators. Secondly, generators can also include in their bids other information that transforms the initially independent 24 hourly schedules into a single coupled one. This would mean passing from the referred Simple Bids to Complex Bids, and this information can correspond to up and down ramps, for instance.

B. Synchronous Generator Capability Diagram

The ISO or the TSO has to evaluate the technical feasibility of the pool schedule together with the injections from bilateral contracts. One of the technical aspects to be evaluated is related with the capability curve in Fig. 1 characterizing the operation of synchronous generators. This diagram results from several curves representing different operation aspects. In the first place, Curve 1 between Qg_i^{max} and $\underline{S}_1$ represents the rotor field current limit. Secondly, Curve 2 between $\underline{S}_1$ and $\underline{S}_2$ is the armature limit and finally Curve 3, the arc between Qg_i^{min} and $\underline{S}_2$, represents the stability limit.

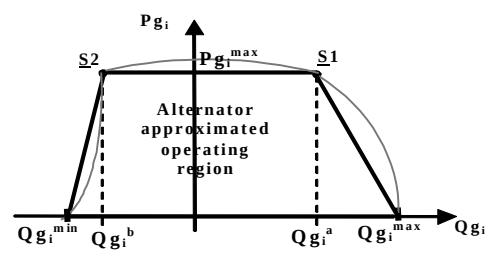

Fig. 1. Capability diagram of a synchronous generator.

C. Generator and Load Adjustment Bids

According to Fig. 1, the operation of an alternator is characterized by a point in the PQ plan so that, once it is scheduled in the active power market, its possible reactive output depends on the feasibility region delimited by its capability curve. Therefore, a generator may have to reduce its active output due to a particular reactive power requirement, for instance to enforce the voltage magnitude in a particular area. This reduction has to be balanced by other generators or by load shedding. In terms of the expected revenues this can lead to an opportunity cost. This is the basis to design a reactive power market in which generators communicate not only pairs of active power/prices but also adjustment bids to use if necessary. The ISO or TSO can use these bids not only to allocate reactive support but also to enforce system constraints if there is any violation. They integrate the

acceptable maximum variation, vg_i^{tol}, that the initial schedule of a generator can suffer together with an adjustment price, Cg_i^{adj}. If a generator was not dispatched in the daily market, its maximum adjustment can correspond to a percentage on its installed capacity. Similarly, loads can communicate adjustment bids integrating a price they want to receive for reducing their demand. This is not new in power systems since in several countries there is already the possibility of establishing interruptible contracts.

D. Mathematical Model Formulation

The optimization problem to run in order to allocate reactive support and to adjust the initial active schedule, if required, is given by (5) to (18), for a system with Ng generators, Nd loads, and Nb branches. The objective function (5) minimizes the sum of three terms. The first one is the cost of active losses given by the contribution of each generator to balance losses, $?Pg_i^{loss}$. This power is valued at the marginal price of the initial auction, ρ^{MO}. The second and the third terms correspond to the adjustment costs due to variations of the initially scheduled generation and load expressed as products of adjustment quantities by prices.

$$Min\ Z = \sum_{i=1}^{Ng}(DPg_i^{loss}.r^{MO}) + \sum_{i=1}^{Ng}|DPg_i^{adj}|.Cg_i^{adj} + \sum_{j=1}^{Nd}|DPd_j^{adj}|.Cd_j^{adj} \quad (5)$$

$$subj\ \ DV_i^{min} \le DV_i \le DV_i^{max} \quad (6)$$

$$Dq_{ij}^{min} \le Dq_{ij} \le Dq_{ij}^{max} \quad (7)$$

$$0 \le DPg_i^{loss} \le DPg_i^{max} \quad (8)$$

$$-\frac{v_i^{tol}}{100} \times Pg_i^{MO} \le DPg_i^{adj} \le \frac{v_i^{tol}}{100} \times Pg_i^{MO} \quad (9)$$

$$0 \le DPg_i^{adj} \le \frac{v_i^{tol}}{100} \times Pg_i^{max} \quad (10)$$

$$DPg_i^{min} \le DPg_i^{adj} + DPg_i^{loss} \le DPg_i^{max} \quad (11)$$

$$-Pd_j^{MO} \le DPd_j^{adj} \le 0 \quad (12)$$

$$Qg_i \le Qg_i^{max} - \frac{Qg_i^{max} - Qg_i^{a}}{Pg_i^{max}}(Pg_i^{MO} + DPg_i^{adj} + DPg_i^{loss}) \quad (13)$$

$$Qg_i \ge Qg_i^{min} + \frac{Qg_i^{b} - Qg_i^{min}}{Pg_i^{max}}(Pg_i^{MO} + DPg_i^{adj} + DPg_i^{loss}) \quad (14)$$

$$DS_{ij}^{min} \le DS_{ij}(DV, Dq) \le DS_{ij}^{max} \quad (15)$$

$$\sum_{k=1}^{Nb} DP_{ij}^{loss}(DV, Dq) = \sum_{i=1}^{Ng} DPg_i^{loss} \quad (16)$$

$$DP_i^{inj}(DV_i, Dq_i) = (DPg_i^{adj} + DPg_i^{loss}) - DPd_i^{adj} \quad (17)$$

$$Q_i^{inj}(V_i, q_i) = Qg_i - Qd_i \quad (18)$$

The above objective function is constrained by voltage limits (6) and phase differences (7). The active output of a generator i can change regarding the initial one due to a contribution to balance losses, $?Pg_i^{loss}$, or to an adjustment required to enforce a system constraint, $?Pg_i^{adj}$. In this sense, constraint (8) imposes a limit to the contribution of each generator to balance losses, constraints (9) and (10) impose limits to the technical or operational adjustment for generators scheduled or not yet scheduled and (11) imposes limits for the addition of these two types of generation changes. Constraint (12) represents the possible load shedding and (13) and (14) represent the upper and lower curves of the capability diagram of each generator, that is, curves 1 and 3 referred in 3.3. Constraint (15) represents the admissible range of the apparent power flowing in branch i-j. Constraint (16) represents the balance between total system losses and sum of losses allocated to generators and constraints (17) and (18) are the active and reactive power injection equations.

IV. Solution Algorithm

The above problem was solved using an SLP – Sequential Linear Programming – approach by successively linearizing the original problem departing from the economic dispatch obtained by the Market Operator: In the first place, the Market Operator solves an uniform price auction using the linear problem (1) to (4). Afterwards, using this economic dispatch together with the injected powers associated with the Bilateral Contracts, it is run an AC power flow in order to characterize in a complete way this operation point of the system. Then, the above operation point is used to linearize all non-linear expressions in the problem. This involves linearizing the branch active losses, the branch flow apparent power and the expressions of the active and reactive injected powers. This means getting linearized expressions to be used in constraints (15) to (18). Once this is done, the linearized problem is fully built and it is now solved. Then one evaluates the convergence of the iterative process checking the changes on voltages, phases and on the objective function in successive iterations. When these differences are smaller than specified tolerances, we get the solution for the non-linear problem. If convergence was not yet obtained, we update generations, loads, voltages and phases considering the adjustment values so that we can run a new AC power flow to fully characterize the new operation point.

V. Case Study

A. Network Data

The formulation described in Section III was tested using the IEEE 30 bus/41 branch Test System. In the simulations we used 0.94 and 1.07 pu for the voltage limits, node 1 as phase reference and 100 MVA as power base. Table I details the generator bidding blocks, Table II details the points of the approximated generator capability curves and their adjustment bids and Table III includes load data. There are synchronous compensators varying from –40 to 40 Mvar in node 5, – 10 to 40 Mvar in node 8 and –6 to 24 Mvar in nodes 11 and 13.

Table I
Generator selling bids (pairs quantity/price)

bus i	$P_{gi}^{bid\ 1}$ (MW)	C_{gi}^{1} (€/MWh)	$P_{gi}^{bid\ 2}$ (MW)	C_{gi}^{2} (€/MWh)
1	260.2	22.5	300	32.8
2	40	26	70	35

TABLE II
POINTS OF THE CAPABILITY CURVE AND GENERATOR ADJUSTMENT BIDS (MAXIMUM ADJUSTMENT IN % AND ADJUSTMENT COST)

bus i	P_{gi}^{max} (MW)	Q_{gi}^{max} (Mvar)	Q_{gi}^{a} (Mvar)	Q_{gi}^{b} (Mvar)	Q_{gi}^{min} (Mvar)	v_{gi}^{tol} (%)	C_{gi}^{adj} (€/MWh)
1	300	85	45	-40	-80	50	45
2	70	50	50	-40	-40	52	48

TABLE III
DEMAND BIDS (ACTIVE AND REACTIVE POWER, BID PRICE FOR THE MARKET OPERATOR AND ADJUSTMENT PRICE)

bus i	P_{dj}^{bid} (MW)	Q_{dj} (Mvar)	C_{dj} (€/MWh)	C_{dj}^{adj} (€/MWh)
2	21.7	12.88	30	70
3	2.4	1.23	28	75
4	7.6	1.54	27	80
5	94.2	19.13	31	73
7	22.8	11.04	29	74
8	30	29.76	27	69
10	5.8	1.91	26.5	80
12	11.2	7.53	27.3	75
14	6.2	1.55	28.2	82
15	8.2	2.39	27	86
16	3.5	1.79	26.4	75
17	9	5.81	29	77
18	3.2	0.93	31	79
19	9.5	3.45	32	74
20	2.2	0.72	34	72
21	17.5	11.30	28.1	81
23	3.2	1.64	30	83
24	8.7	6.75	33	74
26	3.5	2.26	27	76
29	2.4	0.87	29	77
30	10.6	1.51	28	80

B. Market Operator Dispatch

In the first place, the Market Operator ran the auction according to the model (1-4). Table IV details the cleared quantities and the market clearing price was 26.0 €/MW.h.

TABLE IV
RESULTS OF THE MARKET OPERATOR AUCTION

bus i	P_{gi}^{MO} (MW)	P_{di}^{MO} (MW)	bus i	P_{di}^{MO} (MW)	bus i	P_{di}^{MO} (MW)
1	260.2	-	12	11,2	21	17.5
2	23.2	21.7	14	6.2	23	3.2
3	-	2.4	15	8.2	24	8.7
4	-	7.6	16	3.5	26	3.5
5	-	94.2	17	9.0	29	2.4
7	-	22.8	18	3.2	30	10.6
8	-	30,0	19	9.5	-	-
10	-	5.8	20	2.2	-	-

C. Case 1 results

In the first simulation, there were no congested branches, no load shedding and no changes in the active power initially scheduled to the generators 1 and 2 required by particular reactive outputs. Table V details the final dispatch.

Branch active losses are fully compensated in node 2 (16.817 MW) because this is the most advantageous strategy to minimize losses. Just recall that, according to the objective function (5), branch active losses are valuated at the uniform price coming from the Market Operator auction and they do not depend on the adjustment prices offered by each generator.

TABLE V
FINAL DISPATCH FOR CASE 1

bus i	Pg_i^{Final} (MW)	Qg_i^{Final} (Mvar)	Pd_i^{Final} (MW)	Qd_i^{Final} (Mvar)	bus i	Pd_i^{Final} (MW)	Qd_i^{Final} (Mvar)
1	260.201	-17.625	-	-	16	3.500	1.793
2	40.020	50.000	21.700	12.876	17	9.000	5.813
3	-	-	2.400	1.230	18	3.200	0.933
4	-	-	7.600	1.543	19	9.500	3.448
5	-	38.443	94.200	19.128	20	2.200	0.723
6	-	-	-	-	21	17.500	11.304
7	-	-	22.800	11.043	22	-	-
8	-	40.000	30.000	29.755	23	3.200	1.639
9	-	-	-	-	24	8.700	6.752
10	-	-	5.800	1.906	25	-	-
11	-	24.000	-	-	26	3.500	2.261
12	-	-	11.200	7.526	27	-	-
13	-	24.000	-	-	28	-	-
14	-	-	6.200	1.554	29	2.400	0.871
15	-	-	8.200	2.392	30	10.600	1.510

D. Case 2 results

In this second simulation, the thermal limit of branch 1-2 was reduced from 200 MVA to 150 MVA leading to congestion in this branch once one considers the initial Market Operator dispatch in Table IV.

As a result, the outputs of the generators in nodes 1 and 2 are adjusted not only to balance active losses (fully allocated, 16.197 MW, to node 2 as in Case 1) but also to eliminate the congestion in branch 1-2. According to the results in Table VI, there is a reduction in the output of generator 1 by 27.329 MW, a generation increase in node 2 by 12.064 and load shedding in node 2 by 15.265 MW. The final generation in node 2 comes therefore from the initial one assigned by the Market Operator (23.2 MW), increased by 12.064 MW from the adjustment bid and by 16.197 MW to balance active losses, thus leading to 51.461 MW.

TABLE VI
FINAL DISPATCH FOR CASE 2

bus i	Pg_i^{Final} (MW)	Qg_i^{Final} (Mvar)	Pd_i^{Final} (MW)	Qd_i^{Final} (Mvar)	bus i	Pd_i^{Final} (MW)	Qd_i^{Final} (Mvar)
1	232.854	13.976	-	-	16	3.50	1.793
2	51.461	12.821	6.418	3.808	17	9.00	5.813
3	-	-	2.40	1.230	18	3.20	0.933
4	-	-	7.60	1.543	19	9.50	3.448
5	-	33.844	94.20	19.128	20	2.20	0.723
6	-	-	-	-	21	17.50	11.304
7	-	-	22.80	11.043	22	-	-
8	-	40.000	30.00	29.755	23	3.20	1.639
9	-	-	-	-	24	8.70	6.752
10	-	-	5.80	1.906	25	-	-
11	-	24.000	-	-	26	3.50	2.261
12	-	-	11.20	7.526	27	-	-
13	-	23.642	-	-	28	-	-
14	-	-	6.20	1.554	29	2.40	0.871
15	-	-	8.20	2.392	30	10.60	1.510

E. Voltage profiles for Cases 1 and 2

Fig. 2 displays the voltage profiles obtained for the two Cases. The two curves display the same evolution but the voltages in Case 2 are under the values in Case 1. This occurs because congestion leads to active generation adjustments in nodes 1 and 2 and there is also a modification of the values assigned to the reactive power generation.

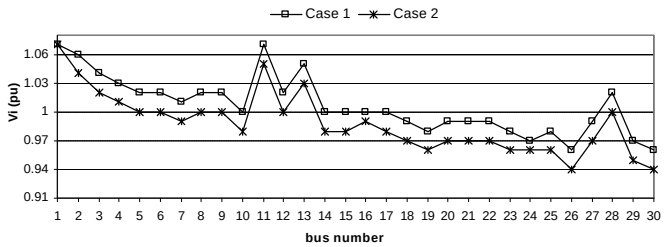

Fig. 2. Voltage profiles for Cases 1 and 2.

F. Active and Reactive Nodal Marginal Prices

We also obtain the active and reactive nodal marginal prices, as presented in Fig. 3. In Simulation 1, both nodal prices are quite flat reflecting the absence of congested branches. The active price in node 1 directly reflects the adjustment cost of generator 1 and then tends to increase to the maximum value of 49.559 €/MW.h in node 30. This reflects the increasing impact of the cost of losses in buses further way from node 2. In Simulation 2, the congestion in branch 1-2 originates larger oscillations in active and reactive prices. The negative active price in node 1 is due to the fact that a load increase in this node is directly compensated by generator 1, thus reducing its negative adjustment. This means that the value of the objective function is reduced by 45.0 €. If the load increases in node 2, it happens that generator 2 has already completely exhausted its maximum adjustment of 52 % of the initially allocated power of 23.2 MW. This means that if the load in node 2 increases, it will be curtailed and the cost of load shedding in node 2 is 70.0 €/MW.h. Regarding the active price in node 3, increasing the load in node 3 contributes to reduce the flow in branch 1-2 and this makes room to reduce the load shedding in node 2. On node 3, the price of 19,875 €/MW.h results from combining –70.0 €/MW.h (load shedding reduction in node 2) and 45.0 €/MW.h (generator adjustment in node 1). For the remaining nodes, the active prices follow in general the ones from Simulation 1, except for nodes 5 and 7, although they are more reduced. This small reduction is explained by a similar reason to the one presented for the behaviour of the price in node 3, although increasing the load in nodes 4 to 30 (except nodes 5 and 7) does not relieve the congestion in branch 1-2 as increasing the load in node 3.

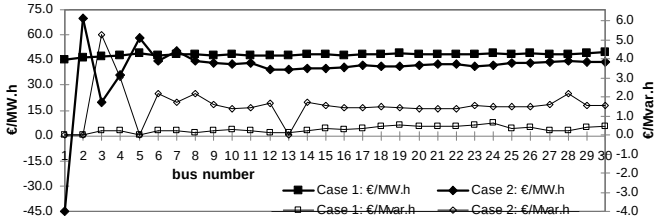

Fig. 3. Active and reactive nodal marginal prices profiles.

Regarding the reactive power, the prices in Simulation 2 are in general higher than in Simulation 1 with a spike in node 3. Increasing the reactive load in node 3 increases the apparent power flow in line 1-2 and so the load shedding in node 2 gets larger thus leading to a larger reactive price. In the remaining nodes, except in nodes 5 and 13, this effect is also present but it is not as strong as in node 3.

VI. Conclusions

In this paper we presented an active/reactive dispatch model that preserves the competitive nature of electricity markets. The model is based on the auction run by the Market Operator and afterwards uses adjustment generation and load bids. Apart from that, the model remarries active and reactive power in terms of the capability diagram of synchronous generators, of using the AC power flow equations and using apparent power to formulate the thermal branch limit constraints. It should also be referred that as a final result the model gives the values of marginal nodal active and reactive prices that can be used to build more consistent tariff systems. These characteristics increase the realism and potential interest of the developed model.

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VIII. Biographies

Mário Helder Rodrigues Gomes was born in Mozambique in 1972. He received his licentiate and MSc degrees from Faculdade de Engenharia da Universidade do Porto (FEUP) in 1997 and 2000 in Electrical and Computer Engineering. In 1997 he joined the Polytechnic Institute of Tomar. He currently has a grant from the PRODED government financed program and he is completing his PhD at FEUP.

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