Active / Reactive Dispatch in Competitive Environment

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***Abstract*--** **Ancillary Services play an important role in power systems since they are crucial to ensure the security and quality of operation. However, this issue is sometimes forgotten and power systems tend to be analysed only from the point of view of electricity markets to schedule active power. In several countries, active and reactive dispatches were decoupled but in fact this causes several inefficiencies and technical difficulties since their schedules is not independent and the two of them determine the operation conditions of power systems. This paper describes an active / reactive dispatch model that retains the competitive aspects currently in force in power systems. It is based on an initial pool dispatch and on adjustment bids used to change generation or load values namely to accommodate losses or to curtail load if that is required to meet operation or technical constraints. This certainly contributes to clarify the roles of the Market and System Operators and to turn the decisions from the System Operator more robust and justifiable from a technical point of view.**

***Index Terms*--** **Active/reactive dispatch, System Operator, adjustment bids, nodal active/reactive marginal prices.**

I. Introduction

In several countries the electricity sector has suffered a major change in terms of its unbundling in a set of well identified activities: generation, transmission, distribution, retailing, technical coordination, commercial and trade and regulatory activities. This means that the extremes of the industry – generation and retailing – are conducted in a competitive environment while network activities as transmission and distribution wiring are provided in a monopoly basis. The operation of the system is now divided in commercial and trade issues on one hand and on technical activities on the other. Commercial and trade issues are assigned to market operator entities based on buying and selling bids and to bilateral contracts with different horizons.

The technical operation of the system is ensured by Independent System Operators – ISO's – that must be independent both from the demand and the supply in order to act in a transparent and objective way. In European countries, there is a trend to merge the transmission provider with the ISO leading to the concept of Transmission System Operator, TSO. However, this is not the only possible model since in other countries as in Brazil the ONS – National System Operator - is a separate entity that operates transmission lines owned by other entities.

Finally, electricity is not a true commodity since it is not possible to store it in large quantities in order to market it when the prices are more attractive and supply and demand are linked by wiring systems – transmission and distribution – for which there are well known physical laws circuit operation must comply with. In this sense, and because transmission and distribution areas are traditionally not subjected to the invisible hand of the market it is crucial to have regulatory agencies to set tariffs on some services and to impose minimum requirements related for instance to Quality of Service.

The particular nature of electricity has certainly contributed to format electricity markets in a temporal sequence of activities each one using the results obtained in previous steps. If one takes the Spanish electricity market as an example one can identify the following steps regarding the operation of the system in day n:

- in day n-1 the Market Operator receives buying and selling bids till 10 am;
- using this information, the Market Operator runs a symmetric pool market building aggregated demand and supply curves and determining the system marginal price and the set of generators to be dispatched. This dispatch can be obtained by running the linear problem (1) to (4) for each hour of the next day admitting there are nd buying entities and ng selling players.

$$\max Z = \sum_{j=1}^{nd} Cd_j.Pd_j - \sum_{i=1}^{ng} Cg_i.Pg_i \quad (1)$$

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

$$Pg_i \le Pg_i^{bid} \quad (3)$$

$$\sum_{j=1}^{nd} Pd_j = \sum_{i=1}^{ng} Pg_i \quad (4)$$

In this formulation, Pd_j^{bid} and Pg_i^{bid} are the demand and generation bidding quantities, Cd_j and Cg_j are the buying and selling bidding prices and Pd_j and Pg_i represent the dispatch final values. In practice, the supply bids include some complexity items related for instance with a minimum revenue requirement along the next 24 hours. This can be interpreted as a constraint linking the 24 linear problems as (1) to (4), one for each hour of the next day. If

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the initial dispatch does not comply with this constraint, it is modified adopting a substitution process of accepted bids till it becomes feasible. These generation bids can also include several blocks namely to allow a better approximation between bidding prices and the generation cost curve. As an illustration, Figure 1 represents the approximation of a quadratic generation cost curve by three step blocks with increasing bidding prices. Model (1) to (4) can accommodate this information without difficulties.

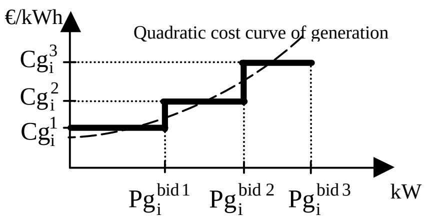

Figure 1 – Structure of the generator selling bids.

- the results of the Market Operator dispatch are communicated to the System Operator together with technical information about bilateral contracts. All this information is then used to evaluate from a technical point of view if these hourly dispatches are feasible or not. If not, there is an interaction between the Market and the System Operator in order to adjust injected powers in order to regain technical feasibility;
- when this technical feasibility is achieved, the system operator dispatches ancillary services (namely reactive power/voltage control, primary, secondary and tertiary reserves);
- at 20 pm of day n-1, and at 0 am, 4 am, 8 am, 12 am and 16 pm of the day n, they are run 6 Intraday Markets in order to allow adjustments on generated or demand powers for the 4 hour periods starting at 0 am, 4 am, 8 am, 12 am, 16 pm and 20 pm, respectively;
- finally, the System Operator runs the system in real time during day n.

Performing the active dispatch, the reactive dispatch and the dispatch of reserves in a decoupled way and as a set of chronological sequence of activities corresponds to an approach causing several inefficiencies. In fact, generator operation points are characterized by an active/reactive pair of values meaning that bidding for active power in the first place immediately conditions the reactive output of a generator. This means that a generator or the System Operator is more constrained when dispatching reactive power or other ancillary services as reserves.

Apart from this, weak transmission networks can contribute to give market power in some special locations. Just consider a generator connected to a node in some part of a low meshed network. This generator has power over the market since it may know its dispatch is essential for reactive support/voltage control. Therefore, it may not bid on active power, waiting the System Operator to dispatch it to contribute for reactive support/voltage control. All these issues suggest that to some extent this set of sequential and independent actions should be substituted by a more interconnected set of activities.

Having in mind these ideas and concerns, this paper is organized as follows. After this introductory section, Section II describes some available models to tariff reactive power and possible designs for ancillary services markets. Section III describes the proposed model together with the adopted solution algorithm. Section IV includes a Case Study to illustrate the proposed approach and highlight its advantages and Section V draws the most relevant conclusions.

II. Current Reactive Dispatch Models

The literature includes several publications describing models to dispatch and to value reactive power. For instance, reference [1] formulates a reactive power dispatch that considers transmission network constraints. This model assumes that individual generators communicate reactive power cost curves corresponding, for instance, to piece-wise linearized curves. The model integrates voltage constraints and several types of VAr controls and it adopts an OPF based calculation to solve it.

Reference [2] discusses how transmission providers can more efficiently manage and price reactive power. The authors recognise the unique characteristics of VAr, such as dynamic voltage control, VAr behaviour during peak and off-peak conditions, the low variable cost of VAr production and VAr reserves are also discussed. They also stress the fact that the importance of the voltage/VAr support is much larger than the typical prices assigned to reactive power, less than 1 percent of active power in well-designed systems. The paper introduces the VAr adjustment factor concept as the impact on reactive losses from a load change or a change on a transaction. It further discusses the application of locational definitions for reactive prices and it presents alternatives for reactive power pricing based on:

- reactive power valuation considering capital and operation costs and the determination of the portion to be attributed to the reactive power service. This portion would then be assigned to network users or to consumers based on embedded approaches;
- performance requirements and standards imposed to consumers and generators inside a control area. This means that when the reactive power demand or the reactive power generation is within a specified range, there would be no reactive power charge;
- local reactive power markets as a way to recognise and internalise the local nature of reactive power. For each area, it would be necessary to compute nodal VAr adjustment factors that would correspond to multiplier used to adjust generation and demand within an area and reflecting the locational value of reactive power.

The authors of reference [3] analyse the economic cost of reactive power in the context of the energy costing and pricing. This cost includes the explicit and opportunity cost from various generation sources. Based on these costs, the authors detail a reactive power dispatch minimizing the total cost of reactive power support leading to the calculation of the voltage and reactive profiles.

In reference [4] the authors propose a model to optimally scheduling reactive power that minimizes transmission losses and maximizing the voltage stability margin. The problem is formulated as multi-objective fuzzy problem solved by successive linearized iterations and allowing the maximization of the satisfaction felt regarding the values of voltage indicators.

Reference [5] presents a method for the simulation and analysis of alternative reactive power market arrangements based on combined reactive power capacity and energy payments. The authors quantify the value of reactive power support, both in terms of capability and use of each generator, using a security constrained reactive OPF. The problem aims at minimizing total costs for the provision of reactive power, corresponding to reactive capability costs and usage costs, subjected to the AC power flow constraints, reactive control limits and voltage limits while enforcing constraints related to a list of contingencies. The solution algorithm is based on a SLP approach.

Reference [6] presents a methodology to compute reactive nodal marginal prices based on a two-stage approach. In the first one, one aims at minimizing active operation costs, and stage 2 minimizes transmission losses. This model is then revised and completed in reference [10]. Reference [6] includes a case study based on the Interconnected 500 kV Argentinean System that confirms that nodal active prices are much higher than reactive ones.

Reference [7] is directed to the design of a workable payment structure for the provision of voltage control services within the Brazilian electricity sector. The authors identify the costs of the providers and discuss the methods to allocate them to the grid users. Regarding the costs, the authors organize them in explicit costs (including fixed costs, and variable maintenance and operation costs) and implicit costs (defined as losses or profits coming from reactive support). Payments should be structured in a capacity term to remunerate fixed costs and an usage payment reflecting variable costs.

Reference [8] describes the generator VAr support as an unbundled Ancillary Service. Apart from fixed investment costs, the paper refers that variable costs involved in VAr are negligible if the scheduled active generation together with a given amount of reactive generation leads to an operation point within the generator capability curve. However, if the capability limit is reached, the reactive support can only be ensured if the active power output is reduced. This corresponds to an opportunity cost reflecting the revenues a generator will not receive in the active power market due to a reactive support required by the ISO. These non-received revenues could then be used to price reactive support. This is just one of the reasons why active and reactive operation provisions can not be completely decoupled.

Reference [9] proposes a design for a VAr ancillary services market, including VAr costs for generators and capacitors evaluated as an expected payment function of the capability curve of generators. The adopted approach includes an uniform price auction as an incentive for generators to bid their true operation and opportunity costs. The authors argue that if nodal reactive prices were used, it would only be possible to recover a portion of the reactive power service.

Finally, reference [11] details the Spanish electricity market regulations namely how the System Operator acts to technically validate the dispatch from the Market Operator while ensuring branch and voltage limits. The authors propose to get 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. Once feasibility is guaranteed, voltage control resources are fine tuned for each hour of the next day by running an LP based OPF for transmission losses minimization.

III. Proposed Formulation

A. General Aspects

The proposed model consists of a sequence of two stages. The first one corresponds to the Market Operator Model having a pure economic purpose and it can be formulated according to the problem (1) to (4). The second stage is focused on the technical feasibility of system operation so that it corresponds to a System Operator function. This System Operator function is formulated as an optimization problem aiming at minimizing the cost of active branch losses together with the costs incurred in adjusting generator outputs or load values required to regain technical feasibility. Apart from the adjustment values and the final dispatch, this model also gives the nodal prices both for the active power and reactive power. Active power prices reflect the need to balance active losses and adjustment bids while reactive prices are related with the impact of reactive power variations on losses and on the voltage profile.

B. Adjustment Bids

The developed formulation is based on adjustment bids communicated both by generators and loads. They consist of a pair of values corresponding to a power and a price. For generators the power reflects the maximum variation that a generator can accept regarding the value scheduled by the Market Operator or its installed capacity if not dispatched by the Market Operator. The use of this adjustment resource, vg_i^{tol}, will then be remunerated at the price Cg_i^{ofadj}. A generator can then see its scheduled output increased or decreased. This corresponds to a single-block adjustment bid. The formulation can however accommodate multiple block adjustment bids for which the generators offer increasing adjustment prices.

Loads can also communicate adjustment bids basically corresponding to the possibility of reducing the demand of a certain amount as a resource the System Operator can use to obtain operation feasibility, considering an adjustment price.

C. Generator Operation Model

The System Operator can require a generator to produce reactive power as a way to ensure reactive balance and voltage control. It should be realized that generators are business entities scheduled by the Market Operator and certainly having expectations regarding their remunerations. Due to the typical alternator capability curve as illustrated in Figure 2, the operation point of a generator is determined by the pair active/reactive output so that the provision of reactive power will change it. If this point becomes out of the generator capability curve, the generator will most likely have to reduce its active output thus reducing its expected remuneration. This reduction should be considered as a cost of the system – often referred as an opportunity cost – and should modelled to formulate properly a reactive power dispatch problem.

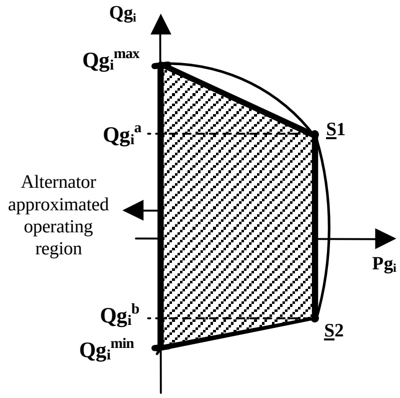

Figure 2 – Alternator capability diagram.

The alternator capability curve in Figure 2 is usually built as the composition of different curves, namely:

- Curve 1 - the field current limit in the rotor represented by the arc between Qg_i^{max} and $\underline{S}_1$;
- Curve 2 - the armature limit represented by the arc between $\underline{S}_1$ and $\underline{S}_2$;
- Curve 3 - the stability limit, represented by the arc between Qg_i^{min} and $\underline{S}_2$;

In order to increase its reactive power, the generator may have to reduce its active output in order not to violate those limits. This reduction will be balanced by other generators or by load shedding. In any case, the generator will not be able to fulfil the Market Operator dispatch and so it should be compensated using an adjustment price.

D. Formulation of the Problem

Once the Market Operator is run and provides an initial active schedule, the System Operator checks for technical feasibility. The problem to be run by the System Operator can be formulated using the AC power flow equations by (5) to (13).

$$\min \quad Z = \sum_{k=1}^{nl} \text{Losses}_k(V_k,\theta_k).\lambda^{MO} + \sum_{j=1}^{ng} |\Delta Pg_j|.Cg_j^{ofadj} + \sum_{l=1}^{nd} |\Delta Pd_l|.Cd_l^{ofadj} \tag{5}$$

$$\text{subj} \quad V_i^{min} \le V_i \le V_i^{max} \qquad i = 1, .., nn \tag{6}$$

$$Pg_j^{min} \le Pg_j^{MO} + \Delta Pg_j \le \sum_{b=1}^{nb} Pg_j^{bid} \qquad j = 1, ..., ng \tag{7}$$

$$-\frac{vg_j^{tol}}{100} \cdot Pg_j^{MO} \le \Delta Pg_j \le \frac{vg_j^{tol}}{100} \cdot Pg_j^{MO} \qquad j = 1, ..., ng \tag{8}$$

$$Pg_j^{min} \le \Delta Pg_j \le \frac{vg_j^{tol}}{100} \cdot \sum_{b=1}^{nb} Pg_j^{bid} \qquad j = ng+1,...,ngtotal \tag{9}$$

$$Qg_j \ge Qg_j^{min} + \frac{Qg_j^b - Qg_j^{min}}{Pg_i^{max}} \cdot (Pg_j^{MO} + \Delta Pg_j) \qquad j = 1,..., ng \tag{10}$$

$$Qg_j \le Qg_j^{max} - \frac{Qg_j^{max} - Qg_j^a}{Pg_i^{max}} \cdot (Pg_j^{MO} + \Delta Pg_j) \qquad j = 1,..., ng \tag{11}$$

$$Pinj_i(V,\theta) = (Pg_i^{MO} + \Delta Pg_i) - (Pd_i^{MO} + \Delta Pd_i) \qquad i = 1,..., nn \tag{12}$$

$$Qinj_i(V,\theta) = Qg_i - Qd_i \qquad i = 1,..., nn \tag{13}$$

$$S_k^{min} \le S_k(V,\theta) \le S_k^{max} \qquad k = 1,..., nl \tag{14}$$

In this formulation, nl is the number of branches, nn is the number of nodes, ngtotal is the total number of generators, ng is the number of generators dispatch by the Market Operator, and the index MO denotes quantities scheduled by the Market Operator. In this problem, one aims at minimizing the cost of losses valued at the Market Operator marginal price, λ^{MO}, together with the costs due to the required adjustments on generator or load values. This formulation includes the following constraints:

- constraints (6) and (7) impose the minimum and the maximum values on voltage magnitudes and on active generation. In this case, one admits that each generator can formulate its bids in terms of nb blocks;
- constraints (8) correspond to the range of active power adjustment bands for the ng generators dispatched by the Market Operator;
- regarding generators not scheduled by the Market Operator (indices ng+1 to ngtotal) they can increase their active power from zero till a percentage, vg^{tol}, of their installed capacity (9);
- constraints (10) and (11) impose the maximum and minimum reactive output of each generator considering its capability curve operation chart. Considering Figure 2, these two constraints result from linearizing the field limit current of the rotor and the stability limit curve and so they are related with Curves 1 and 3 mentioned in Section III-C. The armature limit, Curve 2 in Figure 2, is represented by the maximum active output of the generator;
- constraints (12) and (13) correspond to the AC power flow equations relating injected active and reactive powers with voltages and phases;
- finally, constraints (14) enforce branch flow limits in terms of the apparent power.

E. Solution Algorithm

The adopted solution algorithm decouples the problem in two sub problems. The first one corresponds to the Market Operator clearing the price and amount offered by each individual participant. Using this information as well as with other data previously specified by all participants, the System Operator checks for the feasibility of the previous economic dispatch running problem (5) to (14). This problem outputs the final active and reactive dispatch as well as adjustments to the initial active powers scheduled by the Market Operator.

The Market Operator problem is a linear optimization one and we used the linprog function of the MATLAB software. Regarding the System Operator, the problem is non-linear given the nature of the objective function, the AC power flow equations and the limits on branch flows. In this case, we used the fmincon function of the MATLAB software. The fmincon function uses a Sequential Quadratic Programming method.

Since it is also our objective to evaluate active and reactive nodal prices and given their easier calculation in terms of linear problems, we are now considering the use of a Sequential Linear Programming approach to solve the System Operator problem.

IV. CASE STUDY

A. Test Network Data

The formulation described in Section III was tested using the IEEE 24 Bus Test System in Figure 3. The original data of this system can be obtained in reference [12].

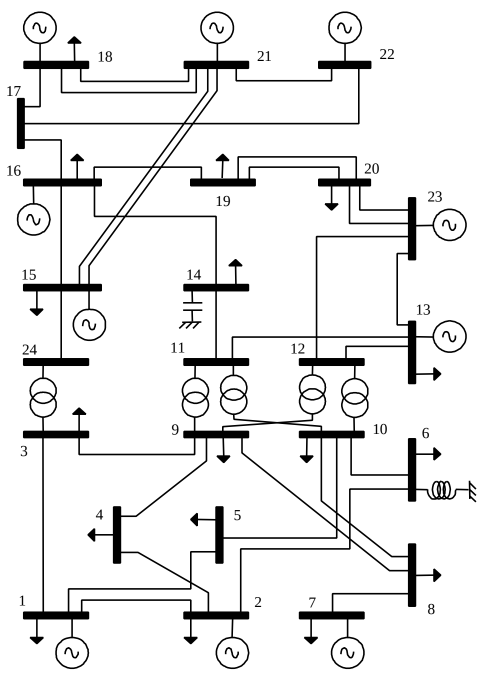

Figure 3 – IEEE 24 Bus Test System.

In our simulations we used 0.90 and 1.10 pu for the voltage limits, the phase reference bus is node 21 and the power base is 100 MVA. Table 1 indicates the structure of the generator bidding blocks, Table 2 presents the points of the approximated capability curve of each generator considering the ideas in Section III.C, Table 3 details the adjustment bids of the generators (amount to be adjusted in percentage and adjustment price) and Table 4 includes load data (active and reactive powers, bidding price and adjustment price).

B. Market Operator

In the first place we ran the Market Operator Model using the generator bids in Table 1 and demand bids in Table 4. Regarding Table 1, the generator bids have three blocks per generator, except for bus 16, each one with including the available power and price. The demand bids are in columns 2 and 4 of Table 4 and include the power and price. The dispatch results are presented in Table 5 in terms of the cleared active generations and loads. The Market Operator clearing price is 35.0 €/MW.h.

Table 1 – Structure of the generator selling bids.

bus i	$Pgi^{bid\,1}$ (MW)	Cgi^1 (€/MW.h)	$Pgi^{bid\,2}$ (MW)	Cgi^2 (€/MW.h)	$Pgi^{bid\,3}$ (MW)	Cgi^3 (€/MW.h)
1	94.0	50.0	150.0	75.0	192	90.0
2	96.0	60.0	154.0	80.0	192	90.0
7	150.0	10.0	230.0	25.0	300	35.0
13	300.0	15.0	450.0	24.0	591	35.0
15	90.0	10.0	160.0	22.0	215	35.0
16	100.0	15.0	155	35.0	-	-
18	250.0	37.0	350.0	45.0	400	60.0
21	250.0	35.0	350.0	44.0	400	60.0
22	150.0	5.0	225.0	15.0	300	35.0
23	300.0	15.0	550.0	24.0	660	35.0

Table 2 – Points of the approximated capability curve of each generator.

bus i	Pgi^{max} (MW)	Qgi^{max} (MVAr)	Qgi^a (MVAr)	Qgi^b (MVAr)	Qgi^{min} (MVAr)
1	192	130.0	90.0	-70.0	-100.0
2	192	120.0	80.0	-60.0	-90.0
7	300	200.0	150.0	-160.0	-180.0
13	591	250.0	150.0	-150.0	-200.0
15	215	150.0	120.0	-85.0	-100.0
16	155	100.0	70.0	-55.0	-80.0
18	400	250.0	150.0	-120.0	-200.0
21	400	250.0	150.0	-100.0	-200.0
22	300	220.0	125.0	-100.0	-180.0
23	660	300.0	185.0	-165.0	-280.0

Table 3 – Generator adjustment bids.

bus i	vg_i^{tol} (%)	Cg_i^{ofadj} (€/MW.h)	bus i	vg_i^{tol} (%)	Cg_i^{ofadj} (€/MW.h)
1	40.0	110.0	16	40.0	112.0
2	40.0	115.0	18	40.0	130.0
7	40.0	120.0	21	40.0	160.0
13	40.0	105.0	22	40.0	103.0
15	40.0	100.0	23	40.0	118.0

Table 4 – Demand bids (for the Market Operator and for adjustments).

bus j	Pdj^{bid} (MW)	Qdj (MVAr)	Cdj (€/MW.h)	Cdj^{ofadj} (€/MW.h)
1	108	31.5	80.0	295.0
2	97	28.3	93.0	290.0
3	180	52.5	99.0	289.0
4	74	21.6	88.0	288.0
5	71	20.7	101.0	296.0
6	136	39.7	50.0	300.0
7	125	36.5	91.0	285.0
8	171	49.9	85.0	295.0
9	175	51.0	75.0	296.0
10	195	56.9	35.0	288.0
13	265	77.3	20.0	287.0
14	194	56.6	92.0	305.0
15	317	92.5	94.0	301.0
16	100	29.2	92.0	294.0
18	333	97.1	90.0	296.0
19	181	52.8	36.0	298.0
20	128	37.3	96.0	291.0

C. System Operator – Case 1

In this simulation we considered the limit of 200 MVA for the branch flow in line 7-8 instead of the original 175 MVA limit. This leads to an operation case in which there is no congestion. Table 6 shows the results of the active/reactive dispatch using Model (5) to (14). In this case the power flow in branch 7-8 is 183.77 MVA and Table 6 includes voltages and phases and the final active and reactive generation and loads. These final values correspond to the generation and load values cleared by the Market Operator (in Table 5) plus the adjustment values obtained by the System Operator.

Table 5 – Market Operator economic dispatch.

bus i	Pdi^{MO} (MW)	Pgi^{MO} (MW)	bus i	Pdi^{MO} (MW)	Pgi^{MO} (MW)
1	108	0	13	0	579.62
2	97	0	14	194	-
3	180	-	15	317	206.76
4	74	-	16	100	146.76
5	71	-	18	333	0
6	136	-	19	181	-
7	125	290.89	20	128	-
8	171	-	21	-	238.03
9	175	-	22	-	290.64
10	12.01	-	23	-	649.31

Table 6 – Integrated dispatch of the System Operator – Case 1.

bus i	V_i (pu)	θ_i (deg)	P_{di}^F (MW)	Q_{di}^F (MVAr)	P_{gi}^F (MW)	Q_{gi}^F (MVAr)
1	1.055	-18.08	108	31.500	53.11	118.935
2	1.055	-18.34	97	28.292	0	120.000
3	1.009	-12.99	180	52.500	-	-
4	1.010	-15.41	74	21.583	-	-
5	1.022	-14.96	71	20.708	-	-
6	0.999	-14.08	136	39.667	-	-
7	1.100	-4.73	125	36.458	290.89	115.529
8	1.035	-9.23	171	49.875	-	-
9	1.022	-8.98	175	51.042	-	-
10	1.029	-8.45	12.01	3.504	-	-
11	1.044	-2.37	-	-	-	-
12	1.046	-0.02	-	-	-	-
13	1.096	5.69	0	0	579.62	151.925
14	1.046	-3.73	194	56.583	-	-
15	1.079	-1.71	317	92.458	206.76	121.150
16	1.079	-1.26	100	29.167	146.76	71.595
17	1.093	-0.89	-	-	-	-
18	1.100	-1.54	333	97.125	0	200.150
19	1.074	0.74	181	52.792	-	-
20	1.086	4.14	128	37.333	-	-
21	1.100	0	-	-	238.03	76.795
22	1.100	5.39	-	-	290.64	-14.748
23	1.100	6.59	-	-	649.31	149.431
24	1.041	-5.73	-	-	-	-

Table 7 – Integrated dispatch of the System Operator – Case 2.

bus i	V_i (pu)	θ_i (deg)	P_{di}^F (MW)	Q_{di}^F (MVAr)	P_{gi}^F (MW)	Q_{gi}^F (MVAr)
1	1.016	-18.49	108	31.500	71.71	115.061
2	1.016	-18.84	97	28.292	0	120.000
3	0.978	-13.51	180	52.500	-	-
4	0.967	-16.05	74	21.583	-	-
5	0.979	-15.41	71	20.708	-	-
6	0.953	-14.65	136	39.667	-	-
7	0.965	-4.36	125	36.458	274.21	51.872
8	0.935	-10.03	171	49.875	-	-
9	0.979	-9.38	175	51.042	-	-
10	0.984	-8.62	12.01	3.504	-	-
11	1.013	-2.21	-	-	-	-
12	1.014	0.27	-	-	-	-
13	1.068	6.21	0	0	579.63	151.925
14	1.026	-3.69	194	56.583	-	-
15	1.072	-1.68	317	92.458	206.76	121.150
16	1.071	-1.20	100	29.167	146.76	71.595
17	1.090	0.86	-	-	-	-
18	1.100	-1.54	333	97.125	0	221.309
19	1.064	0.90	181	52.792	-	-
20	1.075	4.42	128	37.333	-	-
21	1.100	0	-	-	238.03	110.468
22	1.100	5.40	-	-	290.64	-11.893
23	1.089	6.95	-	-	649.31	186.863
24	1.024	-5.79	-	-	-	-

D. System Operator – Case 2

In this case, the active flow limit in branch 7-8 was reduced to 150 MVA so that there was a congested. This led to:

- the use of an adjustment bid of a generator to reduce its output. In this case, generator 7 reduced its active output from 290.89 to 274.21 MW;
- the use of an adjustment bid of generator 1. In this case, the use of this bid had two objectives: to compensate the mentioned reduction of generator 7 output and to balance active losses. In this case, generator 1 passed from 0.0 to 71.71 MW. This increase can be split in the referred two parts. One of them is 16.68 MW and corresponds to the amount required to compensate the reduction of the output of 7 so that there is no load shedding. The remaining, 55.03 MW correspond to the active losses in the network.

E. Marginal Prices

The two previous simulations also give the values of the nodal active and reactive prices presented in Table 8.

Table 8 – Active and reactive nodal marginal prices.

	Case 1		*Case 2*	
bus i	λ_i^P (€/MW.h)	λ_i^Q (€/MVAr.h)	λ_i^P (€/MW.h)	λ_i^Q (€/MVAr.h)
1	111.16	-0.51	115.89	9.41
2	111.41	-0.54	116.40	9.43
3	103.98	3.63	105.46	12.19
4	108.18	3.38	112.58	14.93
5	108.32	2.79	112.60	14.62
6	107.39	4.85	112.05	18.03
7	93.40	-0.18	119.89	-1.03
8	99.81	3.02	102.72	20.88
9	99.18	3.78	100.37	15.52
10	100.17	3.85	101.56	16.76
11	98.34	3.00	96.79	13.18
12	98.24	2.67	95.97	14.44
13	92.39	1.11	87.68	11.53
14	99.62	2.31	97.98	8.98
15	98.78	0.84	96.16	3.50
16	98.10	0.85	95.52	4.17
17	97.97	0.59	94.95	0.49
18	98.40	0.34	95.13	-1.45
19	96.70	0.13	93.89	6.65
20	94.55	-0.97	90.86	8.11
21	97.54	0.46	94.51	0.01
22	94.24	1.04	91.33	-0.23
23	93.10	-1.79	88.63	8.52
24	102.25	2.57	101.00	7.70

Finally, Figure 4 displays the voltage profiles obtained for the two simulations. The straight line corresponds to Case 1 and the dashed line corresponds to Case 2.

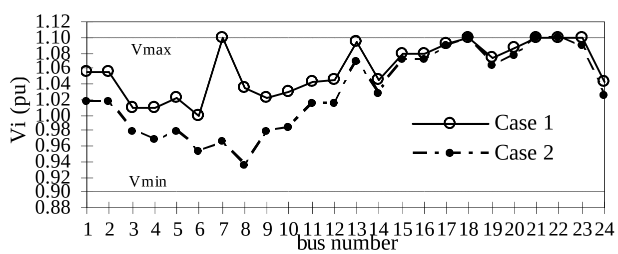

Figure 4 – Network voltage profiles for the two cases.

F. Comments

The results obtained in these two simulations deserve the following comments:

- in the first place, it should be noticed that in Case 1 the final active generation and load values are equal to the ones cleared by the Market Operator. The only exception comes from bus 1 in which the cleared Market Operator power is zero and the final value is 53.11 MW. This exactly corresponds to the active losses in the system;

- it is also interesting to notice that the phase reference bus is different from the bus used to balance active losses. Bus 21 was specified in the beginning as the phase reference bus. However, the generator selected to balance active losses – generator in bus 1, in this case - results from the simulation in the sense it is selected so that active losses plus the global generator adjustment cost are minimized;
- regarding the reactive generation, in both simulations the generator in bus 2 reached its maximum limit, 120 MVAr. However, since the initial active value cleared by the Market Operator is zero, there is no opportunity cost, as there is no need to adjust active power. This means that this generator will only be remunerated by its reactive generation. In this case, Simulation 1 lead to an unacceptable situation as the reactive nodal price is negative, meaning that generator would have to pay an amount to the System Operator. This possibility comes from the fact that the operation model of the generators admits that all operation points inside the capability curve are equally possible. This result suggests that some kind of regulatory provision should be adopted to relate the final active and reactive dispatches;
- active nodal prices reflect both the impact in the amount of the used adjustment bids and in active losses if there is a change of the active power in each load. This means that the prices follow the prices in adjustment bids used by the System Operator plus a component reflecting the impact in active losses. According to several experiments, the impact in active losses from increasing loads are, in some cases, negative translating cases in which a load increase reduces the global value of active losses. This negative impact ultimately explains that in some nodes the active nodal prices are bellow the adjustment prices;
- reactive nodal prices basically reflect the impact of reactive load variations in active losses. This is clear in Simulation 1 in which the prices remain reduced, positive in most cases. In a similar way to the above interpretation, the negative prices obtained for some nodes mean that a reactive load increase leads to a reduction of active losses. In Simulation 2 the price increases in several nodes since a reactive load increase also requires the use of adjustment bids apart from the impact in active losses;
- when analyzing the voltage profiles it can be noticed that in Case 2 the node having lower voltage – node 8 – coincides with the node in which the reactive price is higher. An increase in the reactive load in node 8 leads to a reduction of the voltage in that node and increases the active losses contributing to increase the nodal price.

V. Conclusions

In this paper we presented a model to perform the active / reactive dispatch as an activity under the responsibility of the System Operator and based on the economic bid based dispatch of the Market Operator. The model allows the allocation of active losses together with reactive power based on the use of adjustment bids and aiming at minimizing active losses together with the global adjustment cost. The use of adjustment bids is not only required to balance active losses but can also be due to congested situations requiring changes on the economic dispatch cleared by the Market Operator.

It should also be emphasized that a reactive output required by the System Operator may lead to changes on the active scheduled power. This is valued as an opportunity cost for which generators should be remunerated. In this sense, this formulation can be viewed as an attempt to build a complete model to frame the technical activities of the System Operator.

Future enhancements will certainly include the incorporation of information about bilateral contracts, the simulation of constraints translating couplings between the active and reactive outputs of generators as well as the presence of voltage / reactive power control equipments (as capacitors and tap changers) and the design of an approach to remunerate the services provided by them.

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VII. Biographies

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

João Tomé Saraiva was born in Porto, Portugal in 1962. In 1987, 1993 and 2002 he got his MSc, PhD, and Agregado degrees in Electrical and Computer Engineering from the Faculdade de Engenharia da Universidade do Porto, FEUP, where he is currently Professor. In 1985 he joined INESC Porto – a private research institute – where he was head researcher or collaborated in several projects related with the development of DMS systems, quality in power systems, and tariffs due for the use of transmission and distribution networks. Several of these projects were developed under consultancy contracts with the Portuguese Electricity Regulatory Agency.