A TOOL FOR UNIT COMMITMENT SCHEDULE IN DAY-AHEAD IN POOL BASED ELECTRICITY MARKETS

Pham Nang Van[1], Nguyen Duc Huy[1], Nguyen Van Duong[2], Nguyen The Huu[2]

[1]Hanoi university of Science and technology; ngduchuy@gmail.com; van.phamnang@hust.edu.vn

[2]Ministry of Industry and Trade; nvduong.ie.vn@gmail.com; nguyenthehuu@gmail.com

Abstract - Operating the power system in a deregulated framework is now becoming a common trend in many countries in the world, including Vietnam. In order to ensure effective operation of the power market, there is a need for a good infrastructure for information exchange, and especially high performance computing tools which allows determining the optimal unit commitment schedule, based on price signal. These computing tools also serve to derive optimal bidding strategies for generating companies. Thi paper presents a computational tool for day ahead market clearing, based on price signals. The program has been tested with large size data, which proves its capability to handle the computational task of the Vietnam power market.

Key words - Power system operation; electricity market; day ahead unit commitment; marginal pricing; mixed integer linear programming.

1. Introduction

Nowadays, several countries in the world have moved towards the deregulation of the power market. This change in the power system operation provides more incentive for investors, as well as for power companies to optimize their operation. One early model for the deregulated power market is the "Single Buyer" model. In this deregulated framework, the single buyer receives bidding from generation companies (GENCO), and combines with forecast load demand to determine the optimal generation schedule (unit commitment - UC) for the next day. The objective function of this calculation is to minimize energy cost purchased from generating companies.

Currently in Vietnam, the National Load Dispatch Center (NLDC) has used some professional programs to determine the optimal generation scheduling. However, there is still a need to develop a domestic tool for calculating unit commitment. On one hand, this tool can be modified more easily, and with more flexibility to accommodate new rules in the power market operation. On the other hand, this kind of software serves as a fundamental tool for deriving GENCOs' optimal bidding strategies.

Conventional unit commitment program are based on dynamic programming and Lagrange relaxation algorithm. The Lagrange relaxation algorithm has been tested with large network model. However, there is an essential drawback associated with this algorithm [1] due to the fact that there can be several solutions which are similar in terms of objective function, but with different scheduling variables. In recent years, the programs based on Mixed Integer Linear Programming have been more and more commonly used [2-8]. One of the main advantages of MILP formulation is that there has been considerable progress in the performance of MILP solvers in recent years.

In this paper, a MILP formulation for the day-ahead market clearing problem is presented. The program developed in this work not only provides with solutions for day-ahead dispatching schedule but also determines the Locational Marginal Pricing. The program is tested with a large size problem which is based on actual data from the Vietnam pool based market. The computational performance of the program is shown to be very good. The paper is organized as follows: section 2 presents the mathematical formulation of the day-ahead price based unit commitment problem. Section 3 discusses the calculation of LMP based on the solution of the UC program. Section 5 presents numerical results for a 111 bus system, which is based on actual data of the Vietnam pool based electricity market.

2. Mathematical formulation

2.1. Objective function

The objective function of the unit commitment problem is to minimize total cost paid to the GENCOs, in order to satisfy the forecasted load demand. Figure 1 describes the market equilibrium.

The objective function can be described explicitly as follows:

$$F = \sum_{t=1}^{T} \sum_{i=1}^{N_G} \sum_{b=1}^{N_{Git}} c_{ibt} . P_{Gibt} \quad (1)$$

In Eq. (1), c_{ibt} is the bidding price of the generation unit i, corresponding to block b at time t, P_{ibt} is the generating power of the same unit at the same time; T is the duration considered in the unit commitment problem (T = *24*); N_G is the number of generating units in the system, N_{Git} is the number of bidding blocks at time t (N_{Git} = 3).

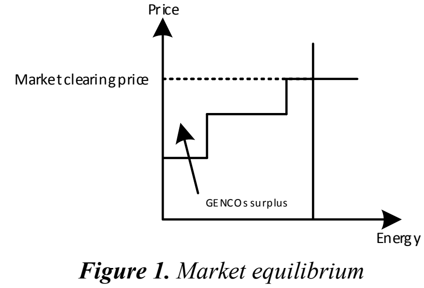

Figure 1. *Market equilibrium*

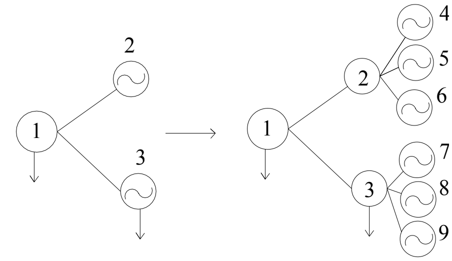

Figure 2. *Handling of 3 blocks of generation bidding*

In this paper, to account for GENCOSs' 3-step bid, we propose using 3 pseudo units to replace one real unit, as depicted in Figure 2. At one time, only one pseudo-unit can operate.

2.2. Constraints for power plants

2.2.1. Minimum and maximum active power

At all times, the active power of each generating unit is subject to its minimum and maximum limit. This constraint is expressed as follows:

$$P_{Gi\min}.u_{\mathrm{i,t}} \le P_{Git} \le P_{Gi\max}.u_{\mathrm{i,t}} \quad t=\overline{1,24},\ i=\overline{1,\mathrm{N}_G} \quad (2)$$

$$P_{Git} = \sum_{b=1}^{N_{Git}} P_{Gibt} \quad (3)$$

$$0 \le P_{Gibt} \le P_{Gibt}^{\max} \quad \forall i, b, t \quad (4)$$

where: P_{Git} is the active power of unit i at time t, $\mathrm{P}_{\mathrm{ibt}}$ is the active power of the unit i, block b at time t, $P_{ibt}^{\max}$ is the upper limit of block b; $u_{i,t}$ is a binary variable, indicating whether the unit is operating (if the unit is active, $u_{i,t} = 1$ and $u_{i,t} = 0$ otherwise).

Since one generating unit now consists of 3 pseudo units as in Figure 2, a maximum of only one pseudo unit can be active at one time. Therefore we have the following constraint:

$$u_{i,t}^1 + u_{i,t}^2 + u_{i,t}^3 \le 1 \quad (5)$$

2.2.2. Constraint on ramp-up/ramp-down rate

The limit on the ramp-up and ramp down rate of generating units are expressed as follows:

$$P_{Gi,t-1} - P_{Git} \le R_i^{down} \quad \forall i,t \quad (6)$$

$$P_{Git} - P_{Gi,t-1} \le R_i^{up} \quad \forall i,t \quad (7)$$

In expressions (5) and (6), R_i^{down}, R_i^{up} are respectively the limits on maximum ramp-up and ramp-down rate of unit i.

2.2.3. Minimum up-time

Thermal generating units normally has a constraint on minimum up-time. These constraints are expressed as follows [2]:

$$\begin{gathered}\sum_{n=t}^{t+Minup_i-1} u_{i,n} \ge UT_i.\left[u_{i,t} - u_{i,t-1}\right] \\ \forall i=\overline{1,N_G};\ \forall t=\overline{2,\left(T-UT_i+1\right)}\end{gathered} \quad (8)$$

In (7), UT_i is the minimum up-time of unit, and $u_{i,n}$ is the state of unit i at time n.

At hour $t = 1$ and $t = 24$, the constraints on minimum up-time are expressed as Eq. (8) and (9).

$$\sum_{n=1}^{Minup_i} u_{i,n} \ge UT_i.\left[u_{i,1} - u_{i,0}\right] \quad (9)$$

$$\begin{gathered}\sum_{n=t}^{T} u_{i,n} - \left[u_{i,t} - u_{i,t-1}\right] \ge 0 \\ \forall i=\overline{1,N_G};\ \forall t=\overline{\left(T-UT_i+2\right),\mathrm{T}}\end{gathered} \quad (10)$$

2.2.4. Minimum down-time constraint

Thermal generating units also have a limit with regard to the minimum down-time after shutting down, before the unit can be started up again. The minimum down-time constraints are expressed as follows [2]:

$$\begin{gathered}\sum_{n=t}^{t+DT_i-1} \left[1-u_{i,n}\right] \ge DT_i.\left[u_{i,t-1} - u_{i,t}\right] \\ \forall i=\overline{1,N_G};\ \forall t=\overline{2,T-DT_i+1}\end{gathered} \quad (11)$$

$$\sum_{n=1}^{DT_i}\left[1-u_{i,n}\right] \ge DT_i\left[u_{i,0} - u_{i,1}\right] \quad (12)$$

$$\begin{gathered}\sum_{n=t}^{T}\left\{1-u_{i,n} - \left[u_{i,t-1} - u_{i,t}\right]\right\} \ge 0 \\ \forall i=\overline{1,N_G};\ \forall t=\overline{T-DT_i+2,T}\end{gathered} \quad (13)$$

In Eq. (10-12), DT_i is the minimum down-time requirement of unit i.

2.2.5. Operating state of generating units

The state of one generating unit being started up and being shut-down are mutually exclusive. Hence, we need to add the following constraints [11]:

$$\begin{gathered}y_{i,t} - z_{i,t} = u_{i,t} - u_{i,t-1} \\ \forall i=\overline{1,N_G},\ \forall t=\overline{1,T}\end{gathered} \quad (14)$$

$$\begin{gathered}y_{i,t} + z_{i,t} \le 1 \\ \forall i=\overline{1,N_G},\ \ \forall t=\overline{1,T}\end{gathered} \quad (15)$$

where $y_{i,t}$ is a binary variable reflecting the start-up state of generating unit i at time t (1 if the unit starts at the beginning of time t); $z_{i,t}$ is a binary variable reflecting the shut down state of unit i (1 if unit i shuts down at the beginning of time t).

2.3. System constraints

2.3.1. Active power balance

Branch currents and bus voltages in the power system obey the Kirkhop equations, which are non-linear. In order to solve the power flow equations, an iterative algorithm needs to be used. However, in unit commitment programs, a DC formulation is often used for its simplicity. In the DC power flow formulation, the reactive power loss and active power loss are ignored. Besides, the branch flows are assumed to be proportional to the angle difference between the sending end bus and the receiving end bus. With these assumptions, active power flowing into a bus i can be expressed by the following equation:

$$P_i = \sum_{j=1}^{N_L} B_{\mathrm{ij}}\left(\delta_i - \delta_j\right) \quad (16)$$

$$\sum_{i=1}^{N}\left[P_{Gi} - P_{Di} - P_i\right] = 0 \quad (17)$$

where N_L is the number of branches in the power system, P_i is active power injected at bus i into the network, N is the total number of buses, P_{Gi} is active power generated at bus i, P_{Di} is active power demand at bus i; δ_i is voltage angle at bus i.

2.3.2. Power flow limit on system branches

In the DC power flow method, the branch flow is determined by the following equation:

$$P_{ij} = B_{ij}\left(\delta_i - \delta_j\right) \quad (18)$$

The branch flow limit is thus expressed as follows:

$$P_{ij}^{\min} \le P_{ij} \le P_{ij}^{\max} \quad (19)$$

2.3.3. Spinning reserve requirement

In order to regulate the system frequency, the system should maintain at all time a certain amount of active power reserve, which is the active power that can be dispatched from online generating units. The amount of required reserve depends on the reliability criteria for each power system. In a general form, the spinning reserve constraint can be written as follows:

$$\sum_{i=1}^{N_G} u_{i,t} P_{Gi}^{\max} \ge P_{Dt} + P_{Rt} \quad \forall t \quad (20)$$

3. Locational Marginal Pricing

3.1. Theoretical overview

One of the technical problems in power system operation is managing the branch flows so that they can remain below acceptable limits, which depend on stability/thermal constraints. The most common approach to deal with branch flow limit (or congestion management) in the power market is Locational Marginal Pricing (LMP). Due to space limit, we do not go into details the theory behind LMP. In essence, LMP is the sensitivity of the objective function F with regard to the demand power at each bus [13]:

$$LMP_i = \frac{\partial F}{\partial P_{Di}} \quad (21)$$

In the optimal solution of the unit commitment, LMPs is in fact the Lagrange multipliers corresponding to the power balance constraints at system buses. In theory, LMP based method is really effective to handle congestions due to branch flow limit [9]. However, its implementation in practice requires exact knowledge of the branch flow limits. It is not always easy to determine branch flow limits, because there are several underlying technical considerations: thermal, voltage stability, angle stability, etc. Currently, in Vietnam, a more simple version of LMP is adopted. In this model, the branch flow limits of only 2 branches are used: between the Northern grid and the Central grid, and between the Central grid and the Southern grid. This model is refered to as ZMP (Zonal Marginal Price). In ZMP model, it is assumed that there is no branch flow limit within one area (North, Central, South).

3.2. Post UC calculation of Locational Marginal Prices

The LMPs are obtained after solving the DCOPF problem at each hour. The LMP at each bus is in fact equal to the sensitivities of constraint (17) at the same bus. In order to obtain sensitivity measures, the optimization problem should be a Linear Programming problem, with only continuous variables. The Unit Commitment problem, however, is a MILP which contains binary variables. Therefore, in most market clearing programs, the UC and LMP are calculated using two-step procedures [13]:

1. In step 1, the UC problem (1) is solved, which gives the optimal values for binary as well as continuous variables.
2. In step 2, the binary variables obtained from step 1 are fixed. The optimization problem is solved again with the continuous variables. At this step, the LMP for system buses can be obtained.

The results in this study show that the optimal values for the continous variables obtained in step 1 and step 2 are the same. Step 2 is carried out only to determine LMP.

4. Problem size

The optimization problem presented in section 2 is a Mixed Integer Linear Programming problem, with large number of variables. In our program, the optimization variables are organized as in Figure 3.

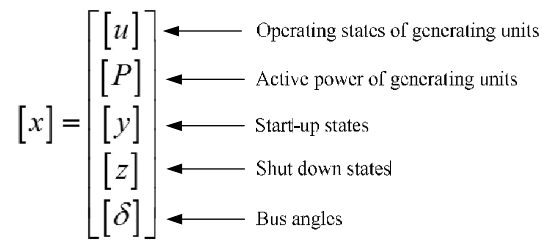

Figure 3. *Structure of optimization variables*

If the system has N buses, N_G generating units and a total of T time periods, the size of each variable blocks in Figure 3 are given by:

$$[x] = \begin{bmatrix} [u]_{T.N\times 1} \\ [P]_{T.N\times 1} \\ [y]_{T.N_G\times 1} \\ [z]_{T.N_G\times 1} \\ [\theta]_{T.(N-1)\times 1} \end{bmatrix}_{((3.N+2.N_G-1).T)\times 1} \quad (22)$$

In summary, the vector of optimization variable $[x]$ has $(3N+2N_G-1)\times T$ variables, of which $(N+2N_G)\times T$ are binaries. In this paper, the optimization model is applied to a power system model that is based on actual data of the Vietnam power system in 2014. The total number of buses is 111, in which 108 are generation buses.

It should be noted that in the ZMP formulation (see section 3), there is no branch flow constraint within one region. Therefore all load of each region can be aggregated into a single load bus. Hence, there are only 3 load buses, representing load demands of the North, Central and South areas. With the above parameters, the proposed optimization problem has 46848 variables, of which 7848 are binaries. The total number of constraints is 80112, of which 58980 constraints are nonlinear.

5. Application results

5.1. System description

The optimization problem presented in sections 2 to 4 is applied for a real large system, which is based on actual data of Vietnam power system in 2014 [12]. The bidding prices of generating units consist of 3 blocks, as shown in Table 1.

Table 1. *Example of generation bidding data*

Block	1		2		3	
	Pmin	Pmax	Pmin	Pmax	Pmin	Pmax
Power	160	260	260	320	320	400
Price (VND/kWh)	1220		1280		1360	

Besides the bidding data in Table 1, GENCOs should also provide technical constraints for the generating units, such as ramp rates, maximum and minimum up-time/downtime. The optimization problem is programmed in MATLAB language [11]. In order to solve the MILP problem, CPLEX software [13], version 12.6 is used. The program is run on a personal computer with 4GB of RAM, and Intel Core i3 processor. With this computing platform, it takes approximately 30s to solve the market clearing problem.

The market clearing is calculated for two operating scenarios: normal operating scenario and a contingency scenario, in which one 500kV circuit between the North and the Central areas is lost.

5.2. Optimization results

5.2.1. Normal operating scenario

The optimal daily schedule for of generating units for the normal operating condition is shown in Figure 4. Each color represents one generating unit. The ZMP for Northern, Central and Southern grid are shown in Figure 5, and the branch flows between areas are shown in Figure 6.

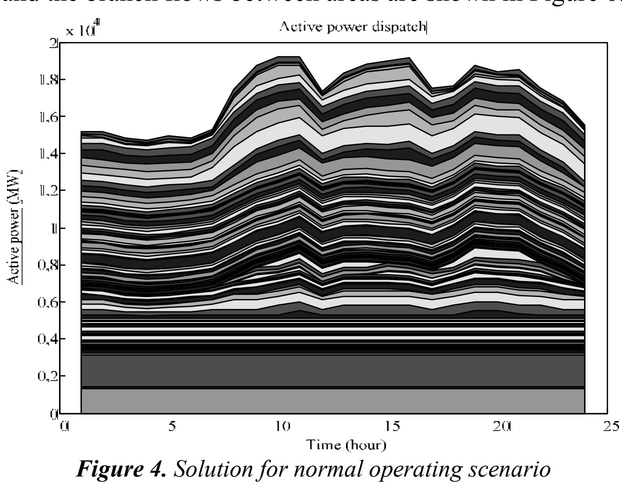

Figure 4. *Solution for normal operating scenario*

From Figure 6, it can be seen that the interface between the Central and the South area is almost always utilized up to its maximum capacity. This is due to the fact that there are many hydro power plants in the Northern areas, with cheaper bidding prices than the thermal units in the South system. Since the connection between the Central area and the South area is almost always at maximum active power transfer, the ZMP of the South system is higher than that of the Central and the North system. On the other hand, the ZMP of the North system and the Central system are always equal.

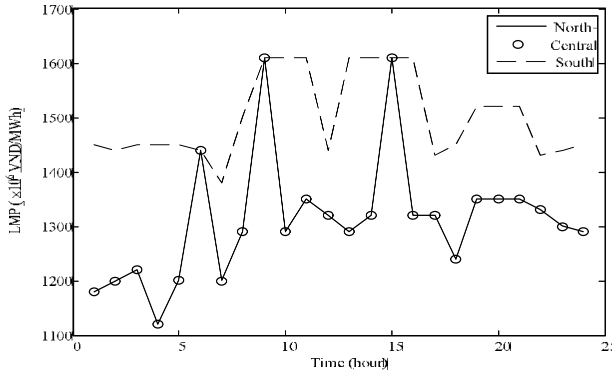

Figure 5. *Zonal marginal prices, normal operating scenario*

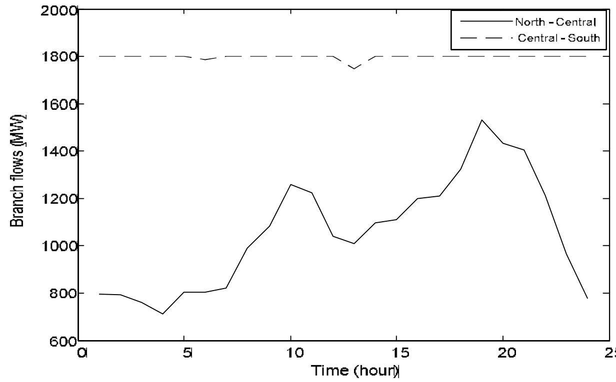

Figure 6. *Branch flows between areas, normal scenario*

5.2.2. Contingency scenario

In the contingency scenario, it is assumed that one 500kV circuit between the North and the Central area is lost. Hence maximum power transfer capacity of the North - Central interface is reduced to 900MW. The power transfer between regions in this case is shown in Figure 7.

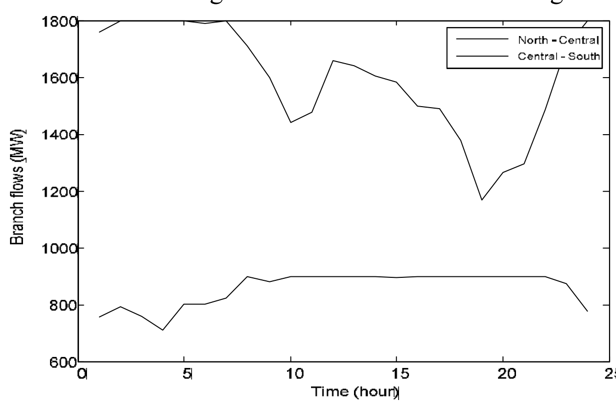

Figure 7. *Branch flows for contingency operating scenario*

It can be seen from Figure 7 that the interface between the North and the Central areas is almost always fully utilized. In fact, due to reduced limit on the North-Central interface, electricity from cheap hydro power plants from the Northern area can not be transferred to the Southern area. The power transfer between the Central area and Southern area even decreases near peak load hours (19h), because most power generation from the Central area at peak load hours is used to serve its own load.

The ZMP for this scenario are shown in Figure 8. At times when the interface between Central and South areas is not fully utilized, their ZMP are equal. Another remark can be drawn from this result is: As the transmission capacity is limited, the receiving system (Southern area) has to pay higher price for electricity.

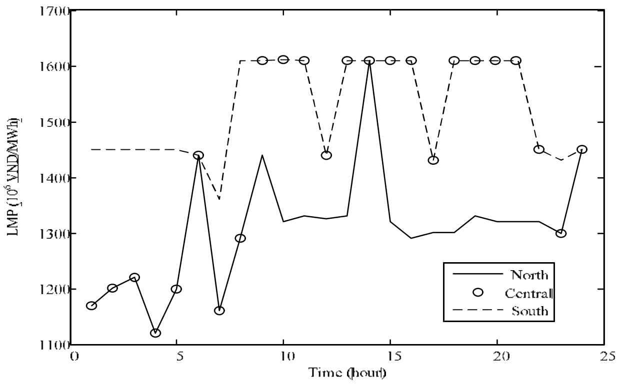

Figure 8. *ZMP for contingency operating scenario*

6. Conclusion

In this paper, a program for determining the optimal unit commitment, based on price signal of generating units has been developed in MATLAB environment. The program takes into account 3 bidding blocks for each unit, as well as several practical constraints of the unit commitment problem, such as active power balance, ramp rate, minimum up-time and down-time, etc. The optimization problem is solved successfully and quickly for large scale power system model of Vietnam.

The program developed in this work can be easily modified to determine dispatching schedule for actual Vietnam power system, which consists of both day-ahead market and long-term contracts. Based on the developed optimization tool, the various aspects of power market operation can be studied. Moreover, the program will help generation companies study the market behavior, which allows them to determine suitable bidding strategies.

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