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Security Constrained Unit Commitment in Regulated and Deregulated Power Markets

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ABSTRACT

In this paper, Security-Constrained Unit Commitment (SCUC) model is proposed in a restructured power system. This model consists of a closed-loop modified Unit Commitment (UC) and Security-constrained Optimal Power Flow (SCOPF). An elastic model for load has been used. The objective of this SCUC model is to obtain the maximum social welfare-based system operating cost while maintaining the system security. In conventional power systems, the demand was forecasted before market operation and determined as a fixed constant. Supplying this demand was therefore considered as a constraint. However, in restructured power system which is based on Standard Market Design (SMD), DISCOs offer the demand and their proposed prices; therefore the demand is modeled as an elastic load. Independent System Operator (ISO) is responsible for operating the power market. The ISO performed the power market using the SCUC software to obtain feasible and economical operation as much as possible. In this paper, SCUC problem in both conventional and restructured power systems is compared and simulation results for these models are presented.
KEYWORDS: Independent System Operator, Restructured Power system, Social welfare

1. INTRODUCTION

The worldwide deregulation of the traditionally monopolized and vertically integrated electric power industry in the last decade has led to a competitive industry. The whole industry of generation, transmission and distribution, wholesale and retail has been unbundled into individual competing entities which need to adopt new efficient economic behaviors. The Unit Commitment (UC) problem is the problem of determining the on/off schedule of the power generating units of a power system. While in the monopolized industry the objective was to meet the forecasted demand plus the spinning reserve to minimize the production cost, subject to each individual unit's operation constraints and system constraints, in the competitive industry the objective for each generation company is now to maximize its profit. A company does not have the obligation to serve the entire load if it is not profitable.

The traditional SCUC-SCOPF solution is an open-loop two-stage process. If SCOPF is unable to get a feasible solution based on the unit commitment at the first stage, additional security measures will have to be called upon. For instance, the system operator may be allowed to use heuristic methods to adjust unit commitment when SCOPF cannot obtain a satisfactory solution. However, such heuristic strategies will depend on the operator’s experience and may not represent the least-cost solution. In this paper, a closed-loop approach is presented for solving contingency dispatch based on SCUC.

The proposed model is a closed-loop and iterative two-stage process which consists of a modified UC and SCOPF modules. Because of considering the elasticity for load in this model, the SCOPF is not confronting with a constant load as a constraint for each hour. Indeed, considering the elastic load causes the SCOPF process can obtain feasible solution for each contingency. In short, the load shedding (LS) process, like UC and SCOPF, is a matter of economic subject. In this model, DISCOs can offer their load curtailment cost to contribute in SCOPF problem too.

Solving methods of unit commitment can be divided into three species: classical ones, which are suboptimal algorithms based on priority list and equal incremental operating cost [2]; optimization ones, such as Lagrangian Relaxation (LR) [3] dynamic programming [4]; intelligent searching ones, which use various intelligent techniques [5]. The first sort can solve the problem quickly, but only give suboptimal results, and from the point of view of optimization theory, they aren't precise. The second sort of algorithms is based on rigorous mathematical model, but there is dimension disaster in dynamic programming, and modeling conditions are very critical in such algorithms. In this paper, a linearalizing approach is implemented to prevent dynamic programming disadvantages. The third sort of algorithm requires mathematically a less complex model but is more time consuming.

The method is used in this paper based on Dantizig-Wolfe and Benders dual decomposition theory. In this method coupling constraints involving all units are considered in the primal solution stage, local unit constraints are considered

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separately for each unit in the dual optimization stage, the solution settles down through iteration between the two stages. Since problem is non-convex, there will be duality gap between the primal values and the dual values, that is to say, the optimality of the result is conditional on the character of the problem. If the number of units to be committed is larger, the optimality is satisfactory [6].

This paper is organized as follows: UC and SCOPF in traditional and restructured power system are introduced respectively on parts 2 and 3. In section 4, results of simulation on a test system is presented and the last part consists of conclusions.

2. Unit Commitment (UC)

The unit commitment is one of the most important problems in power system operation. The objective function of vertically integrated utility system was minimizing the operation cost. This model is identified as a cost-based operation.

The security constraint unit commitment (SCUC) is defined as a complex mixed-integer nonlinear problem. Actually, the output of the SCUC program has two parts, namely defining the units in operation, which are determined by “0” and “1” (integer variables) for on and off units respectively, and determining the quantity of the generation level of operating units

SCUC provides a financially viable unit commitment (UC) that is physically feasible. The generation dispatch based on SCUC is made available to corresponding market participants [7].

The unit commitment is a very significant optimization task, which plays a major role in the daily operation planning of power systems, especially in the framework of the deregulated power markets. The UC objective is to minimize the total operating cost of the generating units during the scheduling horizon, subject to a number of system and unit constraints [8].

The objective function of vertically integrated utility system was minimizing the operation cost. Therefore, this model is named cost-based operating system where the cost-based production, startup, and shutdown functions are considered in the UC formulation [9].

UC can provide an hourly commitment of generating units with minimum bid-based dispatch cost. The objective function (1) is composed of bid-based fuel costs for producing electric power and startup and shutdown costs of individual units for the given period. A typical set of constraints in UC includes:

1) power balance;
2) generating unit capacity;
3) system reserve requirements;
4) ramping up/down limits;
5) minimum up/down time limits;
6) maximum number of simultaneous on/offs in a plant;
7) maximum number of on/offs of a unit in a given period;
8) maximum energy of a unit in a given period

In monopolized and vertically integrated utility the objective was to meet the forecasted demand plus the spinning reserve to minimize the production cost, subject to each individual unit's operation constraints and system constraints. (Refer to Fig.1)

In the competitive power market the objective for each generation company is now to maximize its profit. A company does not have the obligation to serve the entire load if it is not profitable [10]. On the other hand, in developed restructured power systems, the objective function is maximizing the social welfare. This model is the developed Bid-based one which the demand's offers are considered too.

In such a model, bidding and offering proposals are ordered in ascending and descending order, respectively.

The intersection of the two curves is the point of market clearing price.

2.1 UC-Problem Formulation

In this part the UC problem is formulated. The objective function in traditional approaches is shown in (1) which is consists of three parameters: cost of generation, start up and shut down costs. The cost function was described by a quadratic or linear piecewise function. The hourly UC constraints listed below include the system power balance (2), system spinning and operating reserve requirements (3), (4), ramping up/down limits (5), (6), minimum up/down time limits (7), (8) and unit generation limits (9). Additional system-wide constraints such as fuel constraints (10) and emission limits (11) are included in this formulation for representing the market interdependencies.

$$Min \sum_{i=1}^{NG}\sum_{t=1}^{NT}[F_{ci}(P_{it})*I_{it}+SU_{it}+SD_{it}] \tag{1}$$

$ST:$

$$\sum_{i=1}^{NG}P_{it}*I_{it}=P_{D,t}+P_{L,t} \quad (t=1,...,NT) \tag{2}$$

$$\sum_{i=1}^{NG}R_{S,it}*I_{it}\geq R_{S,t} \quad (t=1,...,NT) \tag{3}$$

$$\sum_{i=1}^{NG} R_{O,it} * I_{it} \geq R_{O,t} \quad (t=1,\dots,NT) \tag{4}$$

$$P_{it} - P_{i(t-1)} \leq [1 - I_{it}(1 - I_{i(t-1)})]UR_i + I_{it}(1 - I_{i(t-1)})P_{i,\min} \quad (i=1,\dots,NG)(t=1,\dots,NT) \tag{5}$$

$$P_{i(t-1)} - P_{it} \leq [1 - I_{i(t-1)}(1 - I_{it})]DR_i + I_{i(t-1)}(1 - I_{it})P_{i,\min} \quad (i=1,\dots,NG)(t=1,\dots,NT) \tag{6}$$

$$[x_{i(t-1)}^{on} - T_i^{on}] * [I_{i(t-1)} - I_{it}] \geq 0 \quad (i=1,\dots,NG)(t=1,\dots,NT) \tag{7}$$

$$[x_{i(t-1)}^{off} - T_i^{off}] * [I_{it} - I_{i(t-1)}] \geq 0 \quad (i=1,\dots,NG)(t=1,\dots,NT) \tag{8}$$

$$P_{i\min} \leq R_{it} + P_{it} \leq P_{i\max} \quad i=1,2,\dots,NG \;\; t=1,2,\dots,T \tag{9}$$

$$\sum_{t=1}^{NT} \sum_{i \in FT} [F_{fi}(P_{it}) * I_{it} + SU_{f,it} + SD_{f,it}] \leq F_{FT}^{\max} \tag{10}$$

$$\sum_{t=1}^{NT} \sum_{i=1}^{NG} [F_{ei}(P_{it}) * I_{it} + SU_{e,it} + SD_{e,it}] \leq E_S^{\max} \tag{11}$$

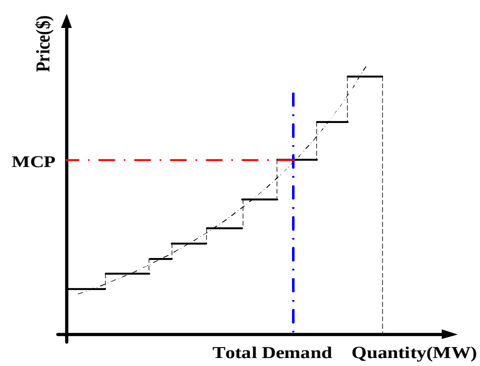

Fig.1. Market clearing in conventional power system with fix load

But in deregulated power systems, a social welfare-based objective function should be applied. Equ.12 shows this objective function. Since Maximization of social welfare is the objective of optimization, a model like economical models is used. In order to finding settlement point of market, bid function of suppliers should be sorted in an ascending manner first. Fig. 2 shows one of these files.

However, for consumers, offers should be sorted in a descending manner. In this situation, the accumulating supply curve and accumulating demand curve should be crossed for finding optimum point.

Equ.12 consists of three terms; the first one is accumulating demand curve which may be different for each hour. The second one is accumulating supply curve. Subtracting the second term from the first will give the cross point of two curves.

From the prospect of imaging, achieving the settling point of the market will occur if the area between the supply curve and the demand curve becomes maximal. Fig. 2 shows it clearly. In formulation of this model, there is another term which is added to the objective function and provides the maximization of supplied load. So the amount of load is considered in the objective function. Consideration of the two first elements will lead to point “A” as market settling point and consideration of the third one will change it to point “B”.

$$MAX \; [(Offer * Demand - Bid * Supply) + Demand] \tag{12}$$

The objective function of social-welfare model is introduced in (13) and other constraints of UC problem in restructured power system is as traditional model which was described first (14-21).

$$MAX \left[\begin{array}{l} \sum_{i=1}^{NB}\sum_{j=1}^{NU}\sum_{k=1}^{NK}\sum_{t=1}^{NT}[C_d(i,j,k,t)P_d(i,j,k,t)-C_g(i,j,k,t)P_g(i,j,k,t)] \\ +\sum_{i=1}^{NB}\sum_{j=1}^{NU}\sum_{t=1}^{NT}P_D(i,j,t)-\sum_{i=1}^{NB}\sum_{j=1}^{NU}\sum_{t=1}^{NT}SU(i,j,t)-\sum_{i=1}^{NB}\sum_{j=1}^{NU}\sum_{t=1}^{NT}SD(i,j,t) \end{array} \right] \quad (13)$$

$S.T.:$

$$\sum_{i=1}^{NB}\sum_{j=1}^{NU}P_S(i,j,t)*I(i,j,t)=\sum_{i=1}^{NB}\sum_{j=1}^{NU}P_D(i,j,t)*J(i,j,t)+P_{L,t} \quad (14)$$

$(t=1,\ldots,NT)$

$$\sum_{i=1}^{NB}\sum_{j=1}^{NU}R_S(i,j,t)*I(i,j,t)\geq R_{S,t} \qquad (t=1,\ldots,NT) \quad (15)$$

$$\sum_{i=1}^{NB}\sum_{j=1}^{NU}R_O(i,j,t)*I(i,j,t)\geq R_{O,t} \qquad (t=1,\ldots,NT) \quad (16)$$

$$P_S(i,j,t)=\sum_{k=1}^{NK}P_g(i,j,k,t) \quad (17)$$

$(i=1,\ldots,NB),(j=1,\ldots,NU),(k=1,\ldots,NK),(t=1,\ldots,NT)$

$$P_D(i,j,t)=\sum_{k=1}^{NK}P_d(i,j,k,t) \quad (18)$$

$(i=1,\ldots,NB),(j=1,\ldots,NU),(k=1,\ldots,NK),(t=1,\ldots,NT)$

$$P_{i,j,\min}*I(i,j,t)\leq P_S(i,j,t)+R(i,j,t)\leq P_{i,j,\max}*I(i,j,t) \quad (19)$$

$(i=1,\ldots,NB),(j=1,\ldots,NU),(k=1,\ldots,NK),(t=1,\ldots,NT)$

$$P_S(i,j,t)-P_S(i,j,t-1)\leq$$
$$[1-I(i,j,t)][1-I(i,j,t-1)]UR_{i,j}+[I(i,j,t)][1-I(i,j,t)]P_{i,j,\min} \quad (20)$$

$(i=1,\ldots,NB),(j=1,\ldots,NU),(t=1,\ldots,NT)$

$$P_S(i,j,t-1)-P_S(i,j,t)\leq$$
$$[1-I(i,j,t-1)][1-I(i,j,t)]DR_{i,j}+I(i,j,t-1)[1-I(i,j,t)]P_{i,j,\min} \quad (21)$$

$(i=1,\ldots,NB),(j=1,\ldots,NU),(t=1,\ldots,NT)$

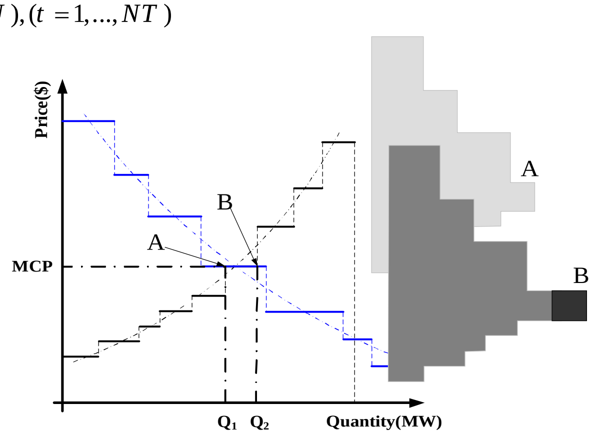

Fig.2. Market clearing in restructured power system subject to maximizing social welfare

3. Security Constrained Optimal Power Flow (SCOPF)

The conventional optimal power flow (OPF) model would solve the economic dispatch (ED) problem while considering the network security constraints at steady-state [11], [12]. It is conceivable that in the event of a contingency, the steady-state setting of optimal operation would threaten the system security if the system state cannot be transferred quickly to a new steady-state operating point. In this sense, security-constrained optimal power flow (SCOPF) includes ac contingency dispatch to respond to the challenges of the conventional OPF.

Once the hourly commitment of units is calculated, SCOPF will consider the ac contingency dispatch represented by corrective (post-contingency) and preventive (pre-contingency) dispatch control actions. The ac contingency dispatch will result in minimizing the cost of system operation while satisfying the system security, fuel, and environmental constraints. A proper set of corrective and preventive control actions for managing contingencies could represent a trade-off between economics and security in restructured power systems.

Note that the preventive dispatch is very conservative and could be expensive and even infeasible for considering all potentially dangerous contingencies. In contrast, a corrective control action applies to allowable post-contingency control adjustments for eliminating controllable contingencies. A preventive dispatch based on uncontrollable contingencies will be included in the steady-state solution of SCOPF for maintaining the economics and the secure operation of a system in the event of a contingency [13], [14].

The traditional SCUC-SCOPF solution is an open-loop two-stage process. If SCOPF is unable to get a feasible solution based on the unit commitment at the first stage, additional security measures will have to be called upon. For instance, the system operator may be allowed to use heuristic methods to adjust unit commitment when SCOPF cannot obtain a satisfactory solution. However, such heuristic strategies will depend on the operator's experience and may not represent the least-cost solution. In this paper, a closed-loop approach will be presented for solving ac contingency dispatch based on SCUC. Accordingly, a new unit commitment solution could be sought when ac dispatch alone is unable to guarantee the convergence of SCOPF. In order to focus on the description of the proposed functions, we resort to pre-defined contingencies. However, in practice, automatic contingency selection is applied to potential contingencies before submitting the contingency list to our algorithm for further analyzes. Automatic contingency selection methods fall into two classes: screening and ranking [15]–[17]. A common screening method is to use the results of the fast decoupled power flow (FDPF) algorithm for each contingency case. In addition, selection can be performed by various ranking schemes, which compute a scalar performance index (PI) for each contingency derived from the dc power flow solution for the contingency.

Another selection approach is by bounding, which explicitly exploits localization. The effects of an outage diminish rapidly with electrical distance from the outage and beyond a certain tier of buses surrounding the outage become negligibly small for contingency analysis purposes.

3.1 SCOPF Problem Formulation

Once the hourly units are committed, SCOPF is calculated using a piecewise linear bid-based production cost function and offer-based price from demand side.

In the previous section the UC program was modeled by mathematic relations. The output of that program is used as the input of the SCOPF subproblem. The cost function is defined as the production level so that the security constraints are satisfied. The upward index " ^ " shows the defined parameters on UC stage. Equ. (22) shows production level of units for m-*th* probable events. If the existing units didn't satisfy the needs of the system, the program is cut to UC subprogram.

Equ. (23) shows the balance of generation and demand. Constraints (24) and (25) represent the power balance and system spinning/operating reserve requirement.

Note that the ratio of system spinning/operating reserve requirement to the total load should be fixed for this new generation level.

Equ. (26) and (27) show the generation and demand in the market for each GENCO and DISCO in each hour and (28) shows the generation limit. Equations (29) and (30) show increase and decrease constraints for generation of units.

$$MAX \quad \left[\sum_{i=1}^{NB} \sum_{j=1}^{NU} \sum_{t=1}^{NT} P_D^m(i,j,t) * \hat{J}(i,j,t) - \sum_{i=1}^{NB} \sum_{j=1}^{NU} \sum_{t=1}^{NT} P_S^m(i,j,t) * \hat{I}(i,j,t) \right] \tag{22}$$

$S.T.:$

$$\sum_{i=1}^{NB} \sum_{j=1}^{NU} P_S^m(i,j,t) * \hat{I}(i,j,t) = \sum_{i=1}^{NB} \sum_{j=1}^{NU} P_D^m(i,j,t) * \hat{J}(i,j,t) + P_{L,t}^m \tag{23}$$

$(t = 1,...,NT)$

$$\sum_{i=1}^{NB} \sum_{j=1}^{NU} R_S^m(i,j,t) * \hat{I}(i,j,t) \geq \frac{R_{S,t}}{\sum_{j=1}^{NU} P_D(i,j,t)} \left(\sum_{j=1}^{NU} P_D^m(i,j,t) \right), \ (t = 1,...,NT) \tag{24}$$

$$\sum_{i=1}^{NB} \sum_{j=1}^{NU} R_O^m(i,j,t) * \hat{I}(i,j,t) \geq \frac{R_{O,t}}{\sum_{j=1}^{NU} P_D(i,j,t)} \left(\sum_{j=1}^{NU} P_D^m(i,j,t) \right), \ (t = 1,...,NT) \tag{25}$$

$$P_S^m(i,j,t) = \sum_{k=1}^{NK} P_g^m(i,j,k,t) \tag{26}$$

$(i = 1,...,NB), (j = 1,...,NU), (k = 1,...,NK), (t = 1,...,NT)$

$$P_D^m(i,j,t) = \sum_{k=1}^{NK} P_d^m(i,j,k,t) \tag{27}$$

$(i = 1,...,NB), (j = 1,...,NU), (k = 1,...,NK), (t = 1,...,NT)$

$$P_{i,j,\min} * I(i,j,t) \le P_S^m(i,j,t) + R^m(i,j,t) \le P_{i,j,\max} * I(i,j,t) \quad (i=1,\ldots,NB),(j=1,\ldots,NU),(k=1,\ldots,NK),(t=1,\ldots,NT) \tag{28}$$

$$P_S^m(i,j,t) - P_S^m(i,j,t-1) \le [1-\hat{I}(i,j,t)][1-\hat{I}(i,j,t-1)]UR_{i,j} + [\hat{I}(i,j,t)][1-\hat{I}(i,j,t)]P_{i,j,\min} \quad (i=1,\ldots,NB),(j=1,\ldots,NU),(t=1,\ldots,NT) \tag{29}$$

$$P_S^m(i,j,t-1) - P_S^m(i,j,t) \le [1-\hat{I}(i,j,t-1)][1-\hat{I}(i,j,t)]DR_{i,j} + \hat{I}(i,j,t-1)[1-\hat{I}(i,j,t)]P_{i,j,\min} \quad (i=1,\ldots,NB),(j=1,\ldots,NU),(t=1,\ldots,NT) \tag{30}$$

4. The Proposed Algorithm

Firstly, the independent system operator gathers generation bids and their corresponding amounts from GENCOs and demand offers and their corresponding amounts from DISCOs for each hour in a day-ahead market. In the first loop of program, a UC is done without consideration of network constraints. Results of corrected UC are on-off status of units and accepted demand on each hour. Based on what was discussed, due to load elasticity, demands which have higher offers than accepted GENCOs will be supplied.

According to economic science, this is the social welfare maximization. Outage of this stage which is initial condition for SCOPF will be given to the "master of SCOPF" program which solves SCOPF problem for steady state condition. In this loop, generation of power plants should supply network constraints like maximum power transferred on each line, node's voltages, etc.

If the program is infeasible in this loop, it will cut the UC loop for creating changes on unit's commitment scheduling and elimination of deviations.

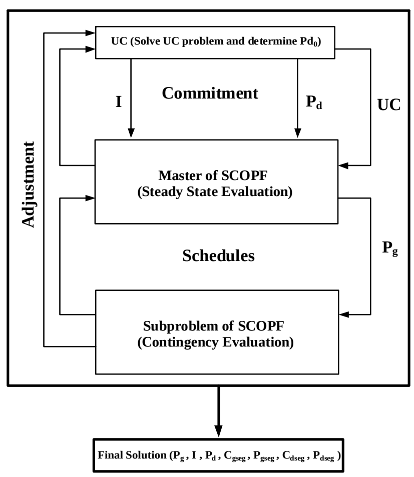

Fig.3. SCUC Problem in Restructured Power System

If this program is infeasible, an internal cut of the UC program with load reduction will correct the UC loop. On traditional systems, when the SCOPF program doesn't have any feasible solution, the program will eliminate the deviations of constraints with calling load shedding commands. On that structure, because of load's inelasticity, there might be none-important loads which aren't curtailed while there might be some important loads which are curtailed. The benefit of this program comes from consideration of a weighted factor for amount of curtailed load which considers economical manners on load curtailment. Therefore, it is possible to consider incentive based programs for load curtailment.

The result of this program sends the initial generation scheduling of each unit for feasibility check on contingency state to the SCOPF sub problem loop. In this loop, for probable contingencies which have statistical characteristic, constraints of network should be satisfied like master loop. It means that for probable contingencies which are line or unit outages, SCOPF program has optimal answer. Otherwise, the program on the first stage will cut to the master loop and if the expectations are not met, the main cut will be declared to the UC program. The final results of this program are optimal variables which are:

- On-off status and amount of generation of each unit
- highest accepted price of generation
- Amounts of accepted demands and their lowest accepted price

Fig. 3 shows this algorithm clearly. Based on the market structure, the market may clear on two forms, Pay As Bid (PAB) pricing and Uniform Pricing, which only on PAB, receipts and payoffs are different. On the uniform pricing structure, market clearing price is the base of receipts and payoffs but on PAB pricing, each market participant will pay receipts based on what was offered or bided. The Uniform Pricing is considered in this study.

5. Problem Solution Using Decomposition Algorithm

One of the proposed optimization problems in large scale is incorporating the decomposition algorithm. Up to now, several methods have been proposed for this purpose. Dantzing and Wolfe showed that large scale optimization problems can be divided into two parts: main problem and sub-problem. Although convergence rate to the optimal result is low, the result will be globally optimal [6], [18], [19]. Benders (1962) proposed a multi-stage structure where the problem was divided into one main part (which was generally the cost function) and several sub-problems (depending on the number and combination of constraints). It is evident that the more the number of the problem constraints, the less the rate of convergence to the optimal result. The optimization basics are as follows: If the cost function or the constraints are violated at any part of the main problem or sub-problem, it is announced to the other side by some cuts. Hereby, if one of the constraints is violated in one of the sub-problems for some initial conditions, it is cut to the main problem so that the initial conditions change in the next stage in such a way that the constraints of the sub-problem are not violated and fair results are achieved in the main problem. In case of achieving satisfactory results in the main problem and the sub-problem, the convergence rate of the problem with the dual problem (which has been considered in the sub-problem) is studied. If these two values are close to each other or they overlap, the result is globally optimal. Otherwise, it is cut to the main problem so that satisfactory results are achieved by changing the initial conditions. This method is time consuming complicated for large scale problems and is possible to lack any outputs due to the high volume of computations.

The main structure of the mentioned method is studied in reference [20]. In this structure, the convergence rate is highly increased if the sub-problems are in standard form. In this paper, it has been tried to linearize the problem constraints due to the large number of constraints and the high volume of computations. Linearization of the SCUC problem is a very complicated process [21]-[23].

6. NUMERICAL RESULTS

The proposed method in this paper has been applied and studied on IEEE-RTBS test system. IEEE-RTBS system has 11 generating units with 240-MW total installed capacity and its peak load is 185MW. Information about units capacity, start up and shut down costs, Ramp rate, lines profiles and etc. is introduced in [24]. Fig. 4 shows the single line diagram of test system. Maximum demand in each hour is presented in Table 1. In a traditional environment which has no elastic load, demand is equal with this table's data.

According to result of study, if there was no contingency in the network, outputs of UC subprogram in traditional method and proposed method are the same. But in traditional environment, if there were some special contingencies like outage of units G1.1 or G1.3 which are the worst contingencies of system, outputs are faced with uneconomical load shedding. Also there is no feasible solution for contingency on line L.4.

Table 2 shows the units' on-off status for base case and Table 3, 4 and 5 show the outputs for outage of units G1.1, G1.3 and line 4 respectively. Fig. 5 shows the generation level for base case and contingency scenarios.

Table 1: Load Data for the RBTS [24]

Hours	**P_D, MW**				**Hours**	**P_D, MW**			
	$D_{2,5,6}$	D_3	D_4	Total		$D_{2,5,6}$	D_3	D_4	Total
1	13.40	56.95	26.80	123.95	*13*	19.00	80.75	38.00	175.75
2	12.60	53.55	25.20	116.55	*14*	19.00	80.75	38.00	175.75
3	12.00	51.00	24.00	111.00	*15*	18.60	79.05	37.20	172.05
4	11.80	50.15	23.60	109.15	*16*	18.80	79.90	37.60	173.90
5	11.80	50.15	23.60	109.15	*17*	19.80	84.15	39.60	183.15
6	12.00	51.00	24.00	111.00	*18*	20.00	85.00	40.00	185.00
7	14.80	62.90	29.60	136.90	*19*	20.00	85.00	40.00	185.00
8	17.20	73.10	34.40	159.10	*20*	19.20	81.60	38.40	177.60
9	19.00	80.75	32.25	170.00	*21*	18.20	77.35	36.40	168.35
10	19.20	81.60	30.80	170.00	*22*	16.60	70.55	33.20	153.55
11	19.20	81.60	30.80	170.00	*23*	14.60	62.05	29.20	135.05
12	19.00	80.75	32.25	170.00	*24*	12.60	53.55	25.20	116.55

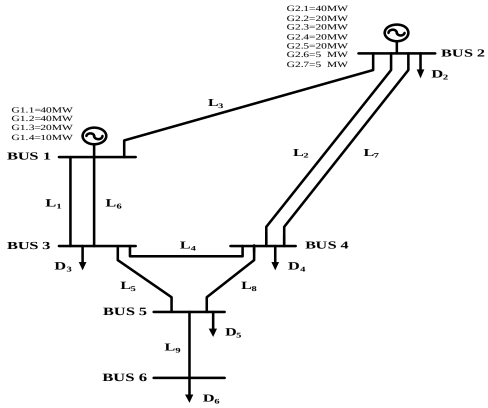

Fig.4. Single line diagram of the RBTS [24]

Table 2: SCUC Program Results-Base Case

Daily Cost=43888.324 $, AMCP=11.619 $/MW	
Unit	Hours (1-24)
1.1	0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
1.2	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
1.3	0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 0 0 0
1.4	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
2.1-5	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
2.6	0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
2.7	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1

Table 3: SCUC Program Results-Line.4 Outage

Daily Cost=43524.006 $, AMCP=11.581 $/MW	
Unit	Hours (1-24)
1.1	0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
1.2	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
1.3	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 0 0 0 0
1.4	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
2.1-5	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
2.6	0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
2.7	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1

Table 6 is the MCP for each hour. In the scenario of line outage, because of power transmitting limitation, the amount of supplied load decreased and marginal price gets fixed for hours 8-16 and led to lower MCP than base case. Prices which are different from base case have been shaded in table 6. The bold numbers show MCPs which are less than MCPs of base case.

Table 4: SCUC Program Results-G1.1 Outage

Daily Cost=42629.844 $, AMCP=11.888 $/MW	
Unit	Hours (1-24)
1.2	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
1.3	0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
1.4	0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0
2.1-5	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
2.6	0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
2.7	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1

Table 5: SCUC Program Results-G1.3 Outage

Daily Cost=44705.914 $, AMCP=11.793 $/MW	
Unit	Hours (1-24)
1.1	0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
1.3	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
1.4	0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0
2.1-5	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
2.6	0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
2.7	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1

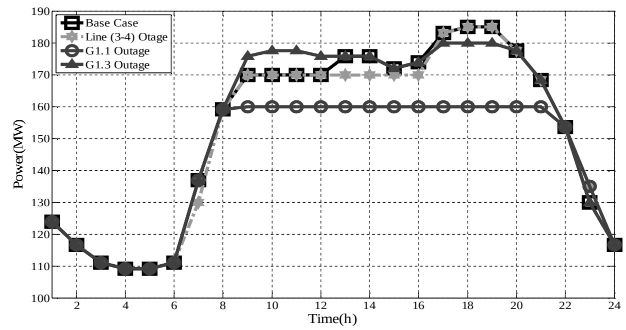

Fig.5 Generation level for base case and contingency scenarios

Table 6: Market Clearing Price For Each Scenario

	Scenarios (m0-m3)			
	Base Case	L4 Outage	G1.1 Outage	G1.3 Outage
1	10.0364	10.0364	10.0364	10.0364
2	10.0220	10.0220	10.0220	10.0220
3	10.0148	10.0148	10.0148	10.0148
4	10.0076	10.0076	10.0076	10.0076
5	10.0076	10.0076	10.0076	10.0076
6	10.0148	10.0148	10.0148	10.0148
7	12.0152	**10.5091**	12.2648	12.0152
8	12.0584	12.0584	12.5182	12.0584
9	12.0728	12.0728	12.5182	12.511
10	12.0728	12.0728	12.5182	12.5146
11	12.0728	12.0728	12.5182	12.5146
12	12.0728	12.0728	12.5182	12.5110
13	12.2648	**12.0728**	12.5182	12.5110
14	12.2648	**12.0728**	12.5182	12.5110
15	12.2576	**12.0728**	12.5182	12.5038
16	12.2576	**12.0728**	12.5182	12.5074
17	12.2792	12.2792	12.5182	12.5182
18	12.2792	12.2792	12.5182	12.5182
19	12.2792	12.2792	12.5182	12.5182
20	12.2648	12.2648	12.5182	12.5146
21	12.0728	12.0728	12.5182	12.0728
22	12.0440	12.0440	12.5074	12.0440
23	10.5091	12.0152	12.2576	10.5091
24	10.5005	10.5005	10.5005	10.5005

5. Concluding Remarks

In this paper, the SCUC problem is introduced in two stages, UC and SCOPF, and their mathematic model are presented in a traditional environment and proposed method for restructured power system. Then, the impact of elastic load on SCOPF program is modeled. Result of simulations shows that the proposed method is more efficient than the traditional ones, especially in evaluation of contingencies in power system.

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