A Linear Daily Unit Commitment Model to Improve the Transient Stability of Power System

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Abstract: As coherency of generators decreases, the risk of rotor angle instability increases, especially under severe contingencies. The slow coherency as a network characteristic may be controlled by the locations of committed synchronous generators. Unit Commitment (UC) problem is conventionally carried out regarding operational, and network constraints. A two-step strategy is developed to promote the slow coherency via the network constrained unit commitment (NCUC) model in a daily time horizon. The proposed slow coherency based UC (SCBUC) model is implemented in two steps. First, the conventional NCUC is executed. The most important generators with both economic and coherency merits are then determined as representative generators. In seconde step, the SCBUC is re-optimized according to the required information obtained from the first step, using a multi-objective function. The first part of the multi-objective function is devoted to the cost of generation, start-up, and shutdown of generators. The goal of the second part of the multi objective function is to maximize the coherency between the committed generators to reach a minimum transient stability margin. The proposed model is converted to a mixed integer linear programming (MILP) model. The performance of the proposed method in promoting slow coherency and transient stability is investigated using the dynamic IEEE 118-bus test system.

Index Terms: Unit commitment, transient stability, slow coherency, optimization, electrical distance

Nomenclature

Sets and Subscripts

t	Index for time
i, j	Index for bus number
w	Index for each segment of linearized function
Ω_b	Set of all buses
Ω_g	Set of generator buses
Ω_S	Set of representative generators
Ω_T	Set of hours in study horizon
Ω_W	Set of linearized segments
$\{\bullet\}^{pc}$	Subscript for the generation cost
$\{\bullet\}^{sc}$	Subscript for the start-up cost
$\{\bullet\}^{sd}$	Subscript for the shut-down cost
$\{\bullet\}^{max}$	Maximum value of a given variable
$\{\bullet\}^{min}$	Minimum value of a given variable

Parameters

a_i, b_i, c_i	Coefficients of generation cost function
C_i^{SUp}	Start-up cost of generator i
C_i^{SDn}	Shut-down cost of generator i
R_i^{up}	Ramp-up limit of generator i
R_i^{dn}	Ramp-down limit of generator i
UT_i^{on}	Minimum up time of generator i
DT_i^{off}	Minimum down time of generator i
P_i^{max}/P_i^{min}	Maximum/Minimum active power limit of generator i
Q_i^{max}/Q_i^{min}	Maximum/Minimum reactive power limit of generator i
AD_i^t/RD_i^t	Active/Reactive demand of bus i at time t
B_{wi}	The power generation at the start of segment w
S_{wi}	Slope of segment w in linearized cost function
G_{ij}/B_{ij}	Real/Image parts of admittance matrix between bus i and bus j
R_{SR}^t	Required amount of spinning reserve at time t
R_i^{max}	Maximum available reserve related to generator i
FL_{ij}	Maximum active flow of transmission line linking bus i and bus j
$SED_{i,s}^t$	Electrical distance between generator i and representative unit s at time t
H_i	Inertia time constant of generator i

Variables

u_i^t	Binary variable for on/off status of generator i at time t
p_i^t/q_i^t	Active/reactive generation of bus i at time t
$v_i^t\angle\theta_i^t$	Voltage phasor of bus i at time t
$X_{i,t}^{on}$	Number of continuous hours that generator i has been on at time t
$X_{i,t}^{off}$	Number of continuous hours that generator i has been off at time t
R_i^t	Spinning reserve by generator i at time t ($i \in \Omega_g$)
λ_{iw}^t	The length of power segment w at time t for cost function of generator i
y_i^t	Auxiliary variable for linearizing cost function of generator i at time t
$\alpha_i^t, \beta_i^t, \gamma_i^t$	Auxiliary variables for linearizing minimum up time constraints of generator i at time t
$\xi_i^t, \eta_i^t, \mu_i^t$	Auxiliary variables for linearizing minimum down time constraints of generator i at time t
$k_s(l)$	Slope of the l^th piecewise linear block of $(\theta_{ij}^t)^2$
$\Delta\theta_{ij}^t(l)$	The length of l^th piecewise linear block of θ_{ij}^t
$\theta_{ij}^{t+}, \theta_{ij}^{t-}$	Positive variables as replacement of θ_{ij}^t
ω_i	Rotor speed of generator i
$L_{i,s}^t$	Auxiliary variable in linearizing coherency constraint between generator i and representative unit s at time t
$DV_{i,s}^t$	Binary variable used to specify electrical distance of generator i, from its representative generator

1. Introduction

Unit Commitment (UC) is a fundamental problem in power systems optimal scheduling, whose primary goal is to determine the on/off status, and economic dispatch of generating units in a daily or weekly horizon [1]. The main objective in UC problem usually is the minimization of generation cost, startup cost, and emission cost. This problem encompasses various operational, and security constraints. Network constraints are an imperative part of UC problem [1], [2]. Network constraints mostly focus on fulfillment of steady state conditions using AC power flow constraints.

In recent years, by increasing penetration level of low inertia distributed generation technologies, several models have been proposed to include the transient stability in power system studies.

Two approaches are utilized for transient stability enhancement in operational studies such as unit commitment program. In first approach, the transient stability is considered using time domain simulations or transient energy functions in the optimization model of the power system operation studies. In simulation-based methods, it is required to solve the discretized nonlinear swing equations along with the steady state model of the original NCUC model. Also, digital power system simulators can be utilized to assess the transient stability as well as to determine the critical and non-critical generators using Extended Equal Area Criterion (EEAC) method. Also in energy function method, it is required to define a suitable transient energy function over the system state variables such as speed and rotor angles of generators. Although the first approach methods are valuable, however due to the computational complexity of discretized swing equation, the efficiency of the transient stability constrained NCUC model remains a major problem. In the second approach, the transient stability assessment is not directly included inside the optimization model of NCUC. Instead, an index is introduced to promote the transient stability of the power system, indirectly. In this regard, the second approach may be interpreted as an alternative for improving the transient stability in UC study. In this research, the transient stability of the unit commitment problem is improved indirectly using the coherency criterion. The transient stability is improved based on the increasing slow coherency criterion.

Transient stability has been considered in optimal power flow (OPF) model [3]-[6]. In transient stability constrained OPF (TSC-OPF) studies the optimal generation of generating units are determined in such a way that a minimum critical clearing time is preserved without considering the on/off status of generating units. In [7], a decomposition based approach has been developed to consider the transient stability in Security Constrained UC model using Extended Equal Area Criterion (EEAC). Also, the digital power system simulator has been utilized to identify the critical and non-critical generators. Similar work has been done in [7]. In [8], an Augmented Lagrange Relaxation (ALR) method has been utilized to solve the TSC-OPF as a sub-problem of UC program. Also in [8] a reduced space interior point method has been utilized to solve the TSC-OPF sub-problem directly. In recent years, the integration of renewable energy resources such as wind power, has created more complexities in UC models of modern power systems [9]. In [10]-[12], frequency stability constraints have been proposed to fulfill the safety of system frequency response. In previous proposed transient stability constrained UC models, the transient stability assessment is done directly using the swing equation with some simplification using EEAC method or a digital power system simulator. Less effort has been done to improve the transient stability of SCUC model indirectly.

Slow coherency between synchronous generators is a physical confirmation of a weak connection. As coherency of generators increases, the risk of rotor angle instability in power system decreases [13]. The coherency between synchronous generators depends on the network characteristics as well as the relative locations of generators. Therefore the coherency of generators is affected by the unit scheduling and their dispatch. In [14], it has been shown that the grid structure especially the electrical distances among the generator internal buses has a great impact on power system dynamics.

In a power system, the generators with similar dynamic responses are called coherent units [15]. In addition to enhancing transient stability margin [13], [15], increasing the coherency of generators has a great effect on mitigating low frequency power swings, especially in islanding conditions [16]. In previous studies no effort has been done to promote the slow coherency via the daily unit scheduling.

In literature, several approaches, including model-based and measurement-based methods, have been presented to discern the coherency of generators [13]. The model-based methods mainly rely on modal analysis. Hence, they are not suitable for UC problem, due to high computational burden. Since UC is an off-line task, the measurement-based methods are not applicable to UC problem too. In [14], it has been shown that the electrical distance between generators has a great impact on dynamic interactions between generators.

In this study, a two-step strategy is developed to improve the slow coherency of synchronous generators in daily scheduling of generating units. In the first step, the conventional network constrained UC (NCUC) model is solved. The coherency of committed generators is then determined using a coherency index. According to the obtained coherency and economic merits, for each area, a generator is selected as the representative generator of that area. In the second step, the SCBUC is optimized while the coherency is integrated inside the NCUC using the electrical distance criterion. An iterative-based process is considered to determine the weighting factors until providing target minimum Critical Clearing Time (CCT). The desired minimum CCT is considered as the stopping criterion for coherency improvement. To promote the computational efficiency of the proposed method, the SCBUC along with the AC power balance constraints are linearized and solved using CPLEX algorithm. The main contributions of this study are twofold:

- Developing an analytic framework to promote the slow coherency of network via a two-step SCBUC model.
- Providing the transient stability margin indirectly using the coherency concept
- Providing an iterative-based approach for adjusting

weighting factors of the proposed multi-objective function to reach the target minimum CCT

- Developing a MILP model for the proposed SCBUC model to assure the optimality of the obtained schedule.

Regarding the flowchart shown in Fig. 1, the structure of the proposed two-step strategy is described. First step of the proposed strategy contains some subsequent stages as follows.

- Executing the MILP model of NCUC program without considering the coherency constraint, as described in section 2 and using equations (5) and (7)-(32).
- Determining the representative generator in each region as described in section 3.1, using equations (33) and (34)
- Constructing the electrical distance matrix using data obtained from NCUC model as described in section 3.2, formulated in equation (35) and (36)

Second step of the proposed strategy acts based on some useful information obtained from the first step as follows.

- Constructing the objective functions of the proposed SCBUC including the operational cost of generators and coherency-based objective function as described in section 3.3 and section 4, using equations (37)-(44).
- Optimizing the multi-objective MILP-based SCBUC model and doing time domain simulations.
- Adjusting the ratio of weighting factors (i.e. (ρ_1/ρ_2)) in an iterative-based process as described in section 4, to achieve the target minimum CCT.

The goal of the first step of the proposed strategy is determining the representative generators using the results obtained from conventional NCUC model, and finally constructing the electrical distance matrix. The goal of the second step of the strategy is to formulate the multi-objective SCBUC including the operational cost and coherency of generators and adjusting weighting factors to reach the target minimum CCT based on an iterative process. The rest of this paper is organized as follows. In section 2, the non-linear and linear formulations of the NCUC model is presented. In section 3, the formulation of the slow coherency criterion as the most notable innovation of this work is described. In section 4, the multi-objective function of the proposed SCBUC is presented and the iterative-based process to reach the target minimum CCT is introduced. The simulation results on a modified IEEE 118-bus test system are presented in section 5. Finally, the paper is concluded in section 6.

2. linear formulation of the NCUC problem

The nonlinear forms of the objective function and the operational constraints of units could be found in [1]. Network constraints including load flow equations (i.e. (1)-(2)), bus voltage limits and line flow limits (i.e. (3)-(4)), are applied for each bus $i \in \Omega_b$ at each time $t \in \Omega_T$. In load flow equations (i.e. (1)-(2)), the variables p_i^t, q_i^t are fixed to zero in load buses. The reserve requirement (i.e. (5)) is defined for the entire network and each unit.

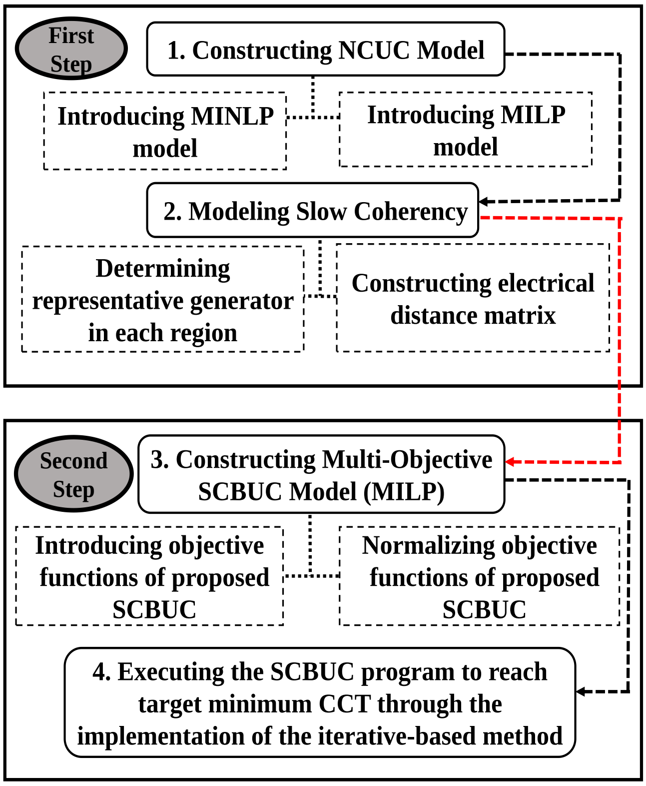

Fig.1 Flowchart of the proposed two-step strategy

$$p_i^t u_i^t - AD_i^t = \sum_{j \in \Omega_b} V_i^t V_j^t \left(G_{ij}\cos(\theta_{ij}^t) + B_{ij}\sin(\theta_{ij}^t)\right) \quad (1)$$

$$q_i^t u_i^t - RD_i^t = \sum_{j \in \Omega_b} V_i^t V_j^t \left(G_{ij}\sin(\theta_{ij}^t) - B_{ij}\cos(\theta_{ij}^t)\right) \quad (2)$$

$$V_{i,t}^{min} \le V_i^t \le V_{i,t}^{max} \quad (3)$$

$$-FL_{ij} \le (V_i^t)^2 G_{ij} - V_i^t V_j^t G_{ij}\cos(\theta_{ij}^t) - V_i^t V_j^t B_{ij}\sin(\theta_{ij}^t) \le FL_{ij} \quad (4)$$

$$\sum_{i \in G} R_i^t \ge R_{SR}^t \;,\; R_i^t \le P_i^{max} u_i^t - P_i^t \;,\; R_i^t \le R_i^{max} \quad (5)$$

The thermal limit of a given transmission line can be expressed based the maximum ampere-capacity or maximum active power. Since in this paper, the power flow model has been expressed based on the standard active and reactive power formulations, the thermal limits of transmission lines are expressed based on the maximum allowable active flow. Additionally, the thermal limits of transmission lines in most of IEEE benchmark test grids such as IEEE 118-bus test system are available based on the maximum active power flow limits.

2.1 Objective function

The objective function of the NCUC problem conventionally includes the generation cost, startup cost, and shutdown cost of units over a daily horizon. This objective function is linearized using (6)-(14). The auxiliary binary variable $\boldsymbol{y_i^t} = \boldsymbol{u_i^t u_i^{t-1}}$ is defined for linearizing the cost function. The expression given in (6) refers to the generation cost of thermal units at minimum allowed power generation. For each generator, the limit of active power is segmented by (7). Slope of each segment in the utilized piecewise linearizing method is determined by (8). The length of each power segment is limited by (9). There are various approaches to linearize the startup and shutdown costs [17]-[18]. Here, the startup and shutdown costs are linearized by (13) and (14), respectively.

$$f^{pc}\left(P_i^{min}\right) = C_i {P_i^{min}}^2 + b_i P_i^{min} + a_i \qquad \forall i \in \Omega_g \tag{6}$$

$$B_{wi} = p_i^{min} + (p_i^{max} - p_i^{min})\frac{w}{N}, \qquad \forall w \in \Omega_W, \forall i \in \Omega_g \tag{7}$$

$$S_{wi} = \frac{[f^{pc}(\tau_{wi}) - f^{pc}(\tau_{(w-1)i})]}{B_{wi} - B_{(w-1)i}}, B_{0i} = p_i^{min} \qquad \forall w \in \Omega_W, \forall i \in \Omega_g \tag{8}$$

$$0 \le \lambda_{iw}^t \le (B_{wi} - B_{(w-1)i})u_i^t, \forall w \in \Omega_W, \ \forall i \in \Omega_g, \forall t \in \Omega_T \tag{9}$$

$$f^{pc}(p_t^i) = u_i^t p_i^{min} + \sum_{w\in N} S_{wi}\, \lambda_{iw}^t \qquad \forall i \in \Omega_g, \forall t \in \Omega_T \tag{10}$$

$$-(1-u_i^{t-1}) \le u_i^t - y_i^t \le (1-u_i^{t-1}) \qquad \forall i \in \Omega_g, \forall t \in \Omega_T \tag{11}$$

$$0 \le y_i^t \le u_i^{t-1} \qquad \forall i \in \Omega_g, \forall t \in \Omega_T \tag{12}$$

$$f^{sc}(u_i^t) = (u_i^t - y_i^t) C_i^{SU_P} \qquad \forall i \in \Omega_g, \forall t \in \Omega_T \tag{13}$$

$$f^{sd}(u_t^i) = (u_i^{t-1} - y_i^t) C_i^{SD_n} \qquad \forall i \in \Omega_g, \forall t \in \Omega_T \tag{14}$$

2.2 Operational constraints

Ramping constraints: The nonlinear form of the ramping-up, and ramping-down constraints are discussed in [1]. Using the auxiliary binary variable y_i^t, the linear form of ramping constraints are expressed as given in (15)-(16) for each unit $i \in \Omega_g$ at each time $t \in \Omega_T$ respectively.

$$p_i^t - p_i^{t-1} \le (1 - u_i^t + y_i^t) R_i^{U_P} + (u_i^t - y_i^t) P_i^{min} \tag{15}$$

$$p_i^{t-1} - p_i^t \le (1 - u_i^{t-1} + y_i^t) R_i^{D_n} + (u_i^{t-1} - y_i^t) P_i^{min} \tag{16}$$

Power production limits: The active and reactive power generation of each generator is limited by its physical characteristics, which are given by manufacturer. These constraints are formulized by (17)-(18).

$$P_i^{min} u_i^t \le p_i^t \le P_i^{max} u_i^t \qquad \forall i \in \Omega_g, \forall t \in \Omega_T \tag{17}$$

$$Q_i^{min} u_i^t \le q_i^t \le Q_i^{max} u_i^t \qquad \forall i \in \Omega_g, \forall t \in \Omega_T \tag{18}$$

Minimum up-time limit: Due to technical reasons, each generator must be on /off for a specific number of hours after a start/shutdown action. The auxiliary variables $\beta_i^t = X_{i,t-1}^{on} u_i^{t-1}$, $\alpha_i^t = X_{i,t-1}^{on} u_i^t$, $\gamma_i^t = X_{i,t-1}^{on} y_i^t$ are respectively linearized by (19)-(20), (21)-(22), and (24)-(25). The minimum up-time equations then linearized using (23) and (26), for each unit $i \in \Omega_g$ at each time $t \in \Omega_T$, respectively.

$$-(1-u_i^{t-1})M \le X_{i,t-1}^{on} - \beta_i^t \le (1-u_i^{t-1})M \tag{19}$$

$$0 \le \beta_i^t \le u_i^{t-1} M \tag{20}$$

$$-(1-u_i^t)M \le X_{i,t-1}^{on} - \alpha_i^t \le (1-u_i^t)M \tag{21}$$

$$0 \le \alpha_i^t \le u_i^t M \tag{22}$$

$$\beta_i^t - UT_i^{on} u_i^{t-1} - \alpha_i^t + UT_i^{on} u_i^t \ge 0 \tag{23}$$

$$-(1-y_i^t)M \le X_{i,t-1}^{on} - \gamma_i^t \le (1-y_i^t)M \tag{24}$$

$$0 \le \gamma_i^t \le y_i^t M \tag{25}$$

$$X_{i,t}^{on} = u_i^t + \gamma_i^t \tag{26}$$

Minimum down-time limit: To linearize the minimum down-time constraints, the auxiliary variables $\xi_i^t = X_{i,t-1}^{off} u_i^{t-1}$, $\eta_i^t = X_{i,t-1}^{off} u_i^t$, $\mu_i^t = X_{i,t-1}^{off} y_i^t$ are utilized and The process of linearization of minimum down-time equations is the same as minimum up-time equations. The minimum down-time constraints then linearized using (27) and (28), for each unit $i \in \Omega_g$ at each time $\in \Omega_T$, respectively.

$$\eta_i^t - DT_i^{off} u_i^t - \xi_i^t + DT_i^{off} u_i^{t-1} \ge 0 \tag{27}$$

$$X_{i,t}^{off} = 1 + X_{i,t-1}^{off} - \xi_i^t - u_i^t - \eta_i^t + \mu_i^t \tag{28}$$

2.3 Linearizing AC power flow equations

A combinatorial technique relying on Taylor series expansion and utilizing binary variables are utilized to linearize the AC power flow equations. The non-linear terms of power flow equations given by (1) and (2) are replaced by the simplified approximation relying on Taylor series expansion as given in **Table 1**. It is noted that the approximations are determined at the normal operational point (i.e. $V_i^t = 1$، $V_j^t = 1$ ،$\theta_{ij}^t = 0$). The linearizing technique including auxiliary binary variables, as discussed in [19], is employed to linearize the term $\boldsymbol{{\theta_{ij}^t}^2}$. According to the constraints given in (17)-(18), the linearized form of the AC load flow equations can be formulized as follows.

$$p_i^t - AD_i^t = (2V_i^t - 1)G_{ii} + \sum_{j\in\Omega_g \,\&\, j\ne i} G_{ij}(V_i^t + V_j^t - \frac{1}{2}\sum_{l\in L} k_s(l)\, \Delta\theta_{ij}^t(l) - 1) + B_{ij}\theta_{ij}^t \tag{29}$$

$$q_i^t - RD_i^t = -(2V_i^t - 1)B_{ii} - \sum_{j\in\Omega_g \,\&\, j\ne i} G_{ij}\theta_{ij}^t - B_{ij}(V_i^t + V_j^t - \frac{1}{2}\sum_{l\in L} k_s(l)\, \Delta\theta_{ij}^t(l) - 1) \tag{30}$$

Where $\theta_{ij}^t = \theta_{ij}^{t+} - \theta_{ij}^{t-}$, $\sum_{l\in L}\Delta\theta_{ij}^t(l) = \theta_{ij}^{t+} + \theta_{ij}^{t-}$ .The slope of each segment is determined by (31).

$$k_s(l) = (2\,l - 1)\frac{\theta_{ij}^{max}}{L} \tag{31}$$

Accordingly, the nonlinear expression of active line flow given in (4), is linearized for each line from bus i to bus j as given in (32).

$$-FL_{ij} \le (2V_i^t - 1)G_{ij} - G_{ij}\left(V_i^t + V_j^t - \frac{1}{2}\sum_{l\in L} k_s(l)\, \Delta\theta_{ij}^t(l) - 1\right) - B_{ij}(\theta_{ij}^t) \le FL_{ij} \tag{32}$$

Table 1 Taylor expansion of nonlinear terms in power flow equations

Nonlinear Function	Taylor Expansion Formulation	Simplified Formulation
$V_i^t V_j^t \cos(\theta_{ij}^t)$	$V_i^t + V_j^t + \cos(\theta_{ij}^t) - 2$	$V_i^t + V_j^t - \frac{{\theta_{ij}^t}^2}{2} - 1$
$V_i^t V_j^t \sin(\theta_{ij}^t)$	$\sin(\theta_{ij}^t)$	θ_{ij}^t
$(V_i^t)^2$	$2V_i^t - 1$	$2V_i^t - 1$

3. Coherency evaluation index

The aim of modeling presented in this section is to extract the criterion which can be used to increase the coherency between generators and improve the transient stability margin indirectly .The electrical distance between the internal nodes of generators has a great impact on their dynamic interactions and coherency [14]. Also in [20]-[21], the electrical distance between generators has been considered as a measure of their coherency. The main purpose of the proposed SCBUC model is to increase the coherency of synchronous machines to reach a minimum CCT as the transient stability margin. Coherency is measured between each pair of generators. In this study the coherency of each generator is measured with respect to the Center-of-Inertia (COI) reference. In this regard, the generator with the highest coherency with the COI reference is selected as the representative generator. The SCBUC problem is solved in such a way that the electrical distance between the committed units and the representative unit in each region is minimized. The coherency constraint is considered in SCBUC model based on the procedure given in section 3.1 to section 3.3.

3.1 Determining representative generator in each region

For modeling the slow coherency in NCUC problem using the electrical distance reduction method, representative generators should be considered to measure the electrical distance in each area. Therefore, representative generators are determined as a reference to measure the electrical distance in each area. The representative generators have two important features. First, they have economical merits (e.g. committed in all times based on the conventional NCUC). Second, they have maximum rotor speed correlation with COI rotor speed of their specified coherent area. Indeed, representative generators are generators with high inertia so the impact of minor changes of network topology in the process of selecting these representative generators is not significant and representative generators are selected with a reasonable approximation.

The boundary of each region is selected based on the slow coherency technique proposed in [16]. Now, for each region a representative generator is determined as follows.

- Executing the conventional NCUC program, without considering the coherency constraint.
- Calculating the speed of the COI using (31).

$$\omega_{COI} = \frac{\sum_{i=1}^{n} H_i \omega_i}{\sum_{i=1}^{n} H_i} \tag{33}$$

- Calculating the correlation between the speed of committed generators (e.g. generators *i*) and the speed of the COI in each region using (34).

$$CR_{i(COI)} = \frac{n\sum_{t=1}^{n}[\omega_i(t)\omega_{COI}(t)] - \sum_{t=1}^{n}[\omega_i(t)] \times \sum_{t=1}^{n}[\omega_{COI}(t)]}{\sqrt{A * B}} \tag{34}$$

$$A = n\sum_{t=1}^{n}\left(\omega_i(t)\right)^2 - \left(\sum_{t=1}^{n}\omega_i(t)\right)^2$$

$$B = n\sum_{t=1}^{n}(\omega_{COI}(t))^2 - (\sum_{t=1}^{n}\omega_{COI}(t))^2$$

- Selecting the generators with maximum correlation coefficient and economic priority (i.e. committed in all times using conventional NCUC), as the representative generator in each group.

3.2 Constructing electrical distance matrix

To calculate the electrical distance between generating units and the representative generator, the modified Zbus (i.e. $\boldsymbol{Zmod_{ij}^t}$) including load model and synchronous reactance of generators is now constructed. The reactances of the generators and their step-up transformers are added to the relevant array in Zbus matrix. The modified Zbus is calculated according to (35).

$$Zmod_{i,s}^t = Z_{i,s}^t + \left(X_d^i + X_{Tr}^i\right) + (X_d^s + X_{Tr}^s) \tag{35}$$

The electrical distance between a given unit i and the representative unit s is considered as the coherency index:

$$SED_{i,s}^t = \left|Zmod_{i,s}^t\right| \tag{36}$$

3.3 The objective function of slow coherency

The aim of the proposed objective function is to minimize the operational cost and electrical distance (i.e. maximizing coherency to enhance transient stability) simultaneously. In the following, the coherency constraints are formulated based on the electrical distance matrix.

The coherency constraints are presented in (37)-(40). The total cost of coherency (i.e. the electrical distance) of the committed generators can be calculated by (41). According to the constraints given in (37)-(40), if a generator is on-line, its electrical distance from the related representative generator should be computed. Otherwise, it should not be included in the objective function.

$$DV_{i,s}^t - 1 \le u_i^t - L_{i,s}^t \le 1 - DV_{i,s}^t \quad \forall i \in \Omega_g, \forall t \in \Omega_T, \forall s \in \Omega_S \tag{37}$$

$$0 \le L_{i,s}^t \le DV_{i,s}^t \quad \forall i \in \Omega_g, \forall t \in \Omega_T, \forall s \in \Omega_S \tag{38}$$

$$\sum_{s \in \Omega_S} DV_{i,s}^t = 1 \quad \forall i \in \Omega_g, \forall t \in \Omega_T \tag{39}$$

$$CED_{i,s}^t = L_{i,s}^t SED_{i,s}^t \quad \forall i \in \Omega_g, \forall t \in \Omega_T, \forall s \in \Omega_S \tag{40}$$

$$CCF = \sum_{t\in\Omega_T}\sum_{i\in\Omega_g}\sum_{s\in\Omega_S} CED_{i,s}^t \quad \forall i \in \Omega_g, \forall t \in \Omega_T, \forall s \in \Omega_S \tag{41}$$

4. The multi-objective MILP-based SCBUC model

The weighted summation of the normalized values of both objectives is introduced as the objective function [22]. The two objectives are normalized by (42), in which the operational cost (i.e., F_1) and the cost of coherency (i.e., F_2) are expressed as given by (43)–(44).

$$Z = \sum_{i=1}^{2} \rho_i \frac{F_i(x) - F_i^{min}}{F_i^{max} - F_i^{min}} \tag{42}$$

$$F_1 = \sum_{t\in\Omega_T}\sum_{i\in\Omega_g}(u_i^t p_i^{min} + \sum_{w\in\Omega_W} S_{wi}\,\lambda_{iw}^t) + \sum_{t\in\Omega_T}\sum_{i\in\Omega_g}(u_i^t - y_i^t)C_i^{SU_P} + \sum_{t\in\Omega_T}\sum_{i\in\Omega_g}(u_i^{t-1} - y_i^t)\,C_i^{SD_n} \tag{43}$$

$$F_2 = \sum_{t\in\Omega_T}\sum_{i\in\Omega_g}\sum_{s\in\Omega_S} CED_{i,s}^t \tag{44}$$

Each normalized objective in (42) has a value between 0 and

1. Hence, by tuning the weighting factors ρ_i, the sets of solutions can be obtained. Also by increasing the weighting factor of F_2 the generation cost of NCUC is increased. However the network operator may will to pay a given additional cost to promote the coherency based on his/her experiences. Practically, the minimum CCT is determined by the operator due to the requirements of the network protection system. The minimum CCT highly depends on the delays of protective relays, circuit breakers. In this scheme weighting factors should be set using a suitable procedure to achieve the target minimum CCT . Therefore, in order to improve the transient stability margin using minimum CCT criterion the ratio of weighting factors (i.e. (ρ_1/ρ_2)) should be adjusted (i.e. reduced) in favor of the coherency-based part of the multi-objective function.

The solution process of the proposed SCBUC is as follows.

- Optimizing SCBUC problem, with $(\rho_1, \rho_2) = (1{,}0)$, as given in (42) to compute $\boldsymbol{F_1^{min}}$ and $\boldsymbol{F_1^{max}}$.
- Optimizing SCBUC problem with $(\rho_1, \rho_2) = (0{,}1)$, as given in (42) to compute $\boldsymbol{F_2^{min}}$ and $\boldsymbol{F_2^{max}}$.
- Constructing and optimizing the SCBUC with new multi-objective function as given in (42) with given weights.
- The ratio of weighting factors are reduced in an iterative-based process as described in **Fig. 2** to provide the target minimum CCT.

As shown in **Fig. 2,** the multi-objective MILP-based SCBUC model is optimized through an iterative-based process. In the iterative-based process, the weighting factor of F_1 decrease and the weighting factor of F_2 increase in steps of 0.05. This sort of change will magnify the importance of coherency-based objective function in the proposed multi-objective function. Iteration process continues until the target minimum CCT is reached.

5. Simulation Results

In this section the proposed MILP-based SCBUC model is simulated on a modified IEEE 118-bus test system, shown in **Fig.3**. This system consists of 54 generators and 90 load points. The operational and dynamic data of this system can be found in [23] and [24], respectively. The required spinning reserve in each hour is assumed to be 20% of the total system load in that hour (i.e. $\sum_{i\in G} R_i^t = 0.2\sum_{i\in G} AD_i^t$). The maximum available spinning reserve of each unit is assumed as 20% of its maximum output power. The simulations are carried out in two distinct cases. In case A, the NCUC model is solved and the results are obtained. In case B, the SCBUC model is solved, in which the schedule obtained by the NCUC model, is utilized to determine the representative generators using time domain simulations in DIGSILENT. The correlation between generators' speeds, as given by (34), is employed to evaluate the improvement in the coherency of generators. The stopping criterion for determining weighting factors is to reach the CCT of 100ms. The optimization models are solved using CPLEX in GAMS [25]. The simulations are performed using a PC with Intel core i7, 4.2GHz 7700 CPU and 32GB RAM- DDR4. Since the NCUC model has been linearized, a feasible and optimal solution is obtained using the CPLEX

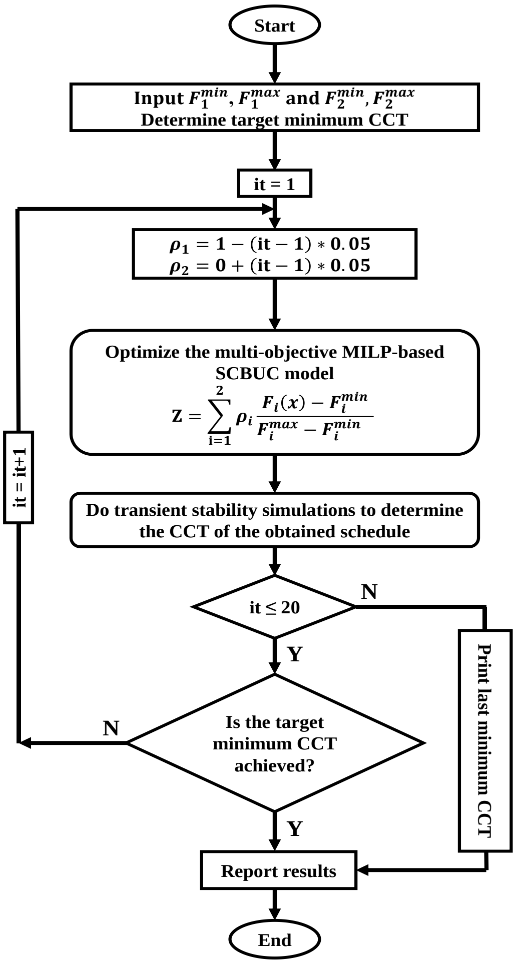

Fig.2 *Iterative-based process to determine* weighting factors

algorithm. As the proposed MIP formulation is an approximation of the original MINLP problem, it is noted that cannot be interpreted as the optimal solution of the original MINLP problem. Although we have utilized the approximated linear AC power flow model, but the MIP model of NCUC has much lower complexities with respect to the optimal solution of the approximated MILP formulation the MINLP models of NCUC.The relative gap of CPLEX algorithm, which indicates the duality gap is adjusted to zero in all simulation cases.

5.1 NCUC model

In this case the NCUC problem without considering coherency constraint is solved. Actually in this case the weighting coefficients are considered as $\rho_1 = 1$ and $\rho_2 = 0$ hence, operational cost (i.e.,F_1) is optimized and the cost of coherency (i.e.,F_2) is just calculated. The obtained results, including hourly schedule of units, hourly power production and reserve are presented in **Fig.4**. Now, the obtained commitment schedule is utilized to determine the representative generators using the coherency index. Furthermore the electrical distance matrix is then utilized as the input of SCBUC.

5.1.1. Determining the representative generators:

The commitment schedule obtained using the NCUC model

Table 4 Daily costs of NCUC and SCBUC models

Model	Objective function(z)		
NCUC	F1 is optimized and F2 is just calculated	$\left(z = 1 * \frac{F_1 - F_1^{min}}{F_1^{max} - F_1^{min}} + 0 * \frac{F_2 - F_2^{min}}{F_2^{max} - F_2^{min}}\right)$	**Z = 0**
SCBUC	F1 and F2 are simultaneously optimized	$\left(z = 0.5 * \frac{F_1 - F_1^{min}}{F_1^{max} - F_1^{min}} + 0.5 * \frac{F_2 - F_2^{min}}{F_2^{max} - F_2^{min}}\right)$	**Z = 0.03117215**
Model	**F1($)**	**F2(p.u)**	
NCUC	**861701.150**	**414.6765**	
SCBUC	**881765.165**	**299.6945**	

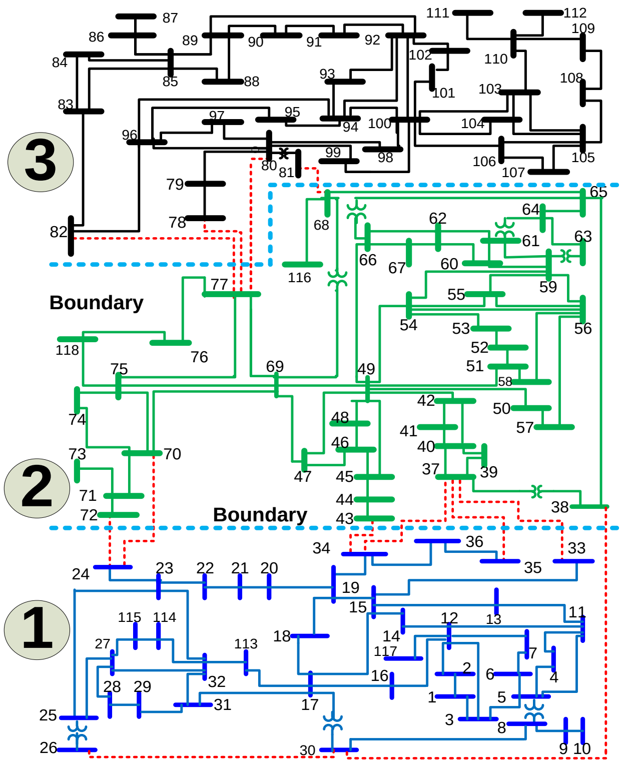

Fig.3 *Single-line diagram of the IEEE 118-bus system*

is now analyzed by DIGSILENT to determine the representative generator of each group. Although the slow coherency of generators does not vary significantly by the change of initial condition and disturbance [12], here, a 0.2^{sec} three-phase short circuit fault is applied on all network branches in two operating points, i.e. high demand T12 and low demand T5, to evaluate the coherency of generators. According to the correlation index and the economic merits of generators the representative generators of all three regions are selected. According to **Fig. 4**, the generators that are on-line in all times have economic priority and may be considered as the candidate units. Hence, G10, G12, G25, G26, and G113 in the first group, G49, G65, G66, G70, G76, and G77 in the second group, and G80, G89, G92, and G100 in the third group are considered as the candidate units. The average coherency between these generators and center of inertia for various faults and in hour T5 and T12 is determined. **Table 2** presents an example of these calculations. For instance, the units G12, G66, and G92 are chosen as the selected generators in first, second, and third group, respectively, in hour T5 and T12 (i.e. $\Omega_S = \{G12, G66, G92\}$). Similarly, this analysis is carried out for

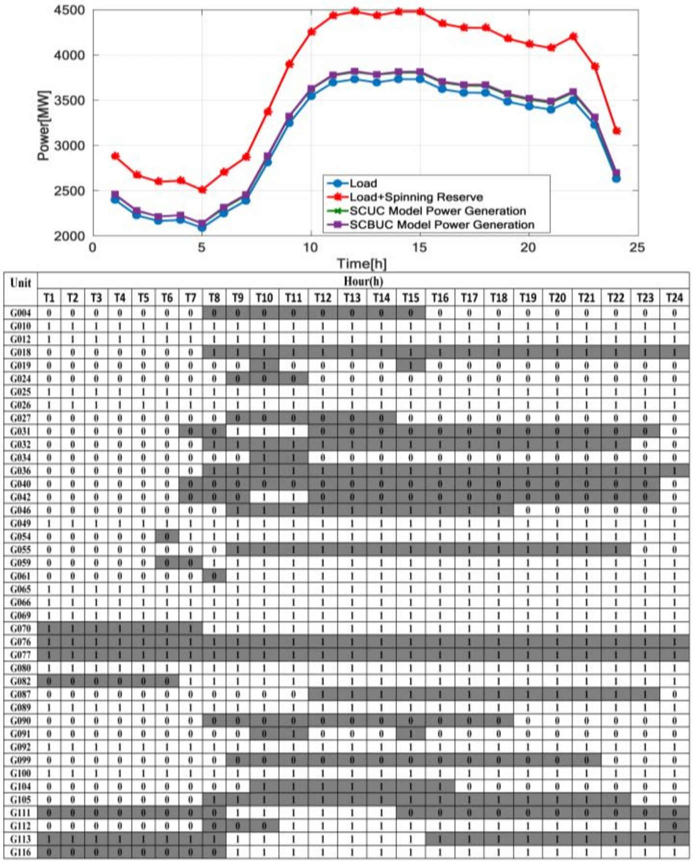

Fig.4 *Unit schedule using NCUC and SCBUC models*

5.2 The MILP-Based SCBUC model

all 24 hours. Now the electrical distance matrix is constructed. The set of representative generators and the electrical distance matrix are passed to the SCBUC model. After determining the representative generators in each group, the SCBUC model incorporates the slow coherency of generators in UC problem. In this case, the multi-objective model including coherency constraint is solved. The SCBUC problem is first solved with only one objective function (i. e. F1 or F2) and the values of $F_1^{min}(p_i^t, u_i^t, y_i^t) = 861701.150(\$)$ and $F_2^{min}(DV_{i,s}^t, u_i^t)$=261.4023 (p.u) are obtained. Similarly, the program is executed to individually maximize each objective and the values (i.e. daily values) of $F_1^{max}(p_i^t, u_i^t, y_i^t) =$ 2217674.3087($) and $F_2^{max}(DV_{i,s}^t, u_i^t)$ =1081.437 (p.u) are obtained. The proposed SCBUC model is solved and ratio of weighting factors (i.e. (ρ_1/ρ_2)) is reduced in an iterative-based process as shown in **Fig. 2.** The obtained normalized objective

Table 5 The hourly operational and coherency costs using NCUC and SCBUC models

	Model	Time (h)							
		T1	T2	T3	T4	T5	T6	T7	T8
Operational Cost F1($)	NCUC	27294.79	24479.29	23736.88	23908.1	22842.87	24935.81	26767.73	32596.88
	SCBUC	27451.54	24521.45	23823.39	23922.85	22865.42	24997.64	26889.66	32875.18
Coherency Cost F2(p.u)	NCUC	4.74	4.74	4.74	4.74	4.74	4.74	7.30	11.37
	SCBUC	2.25	2.25	2.25	2.25	2.25	2.25	4.70	8.57
	Model	Time (h)							
		T9	T10	T11	T12	T13	T14	T15	T16
Operational Cost F1($)	NCUC	38153.07	42327.34	44501.69	44501.74	43696.59	44175.82	44683.97	42845.43
	SCBUC	39265.01	43195.93	45140.96	45239.43	44705.71	45042.21	45422.22	43988.11
Coherency Cost F2(p.u)	NCUC	21.92	26.30	31.36	25.20	26.83	25.24	26.30	23.89
	SCBUC	15.00	20.79	26.22	20.32	19.15	19.15	21.07	17.25
	Model	Time (h)							
		T17	T18	T19	T20	T21	T22	T23	T24
Operational Cost F1($)	NCUC	42236.58	42205.11	40892.55	40130.64	39658.33	40993.40	37525.04	29943.91
	SCBUC	43454.62	43225.28	41771.54	41069.38	40535.56	41920.25	39078.35	31363.45
Coherency Cost F2(p.u)	NCUC	22.83	22.77	21.07	21.13	21.09	21.09	15.90	14.64
	SCBUC	15.95	15.95	15.32	14.81	14.81	14.81	11.52	10.77

Table 3. Objective costs for different pairs of weighting coefficients

ρ_1	ρ_2	F_1($)	F_2(pu)	NCF_1	NCF_2
100	0	861701.150	414.6765	0	0.1869118
95	5	862420.856	363.5875	0.0005307	0.1246108
90	10	863065.730	347.5910	0.0010063	0.1051037
85	15	867304.622	328.7090	0.0041324	0.0820778
80	20	872525.55	314.7965	0.0079825	0.065112
75	25	874156.704	313.0650	0.0091857	0.063001
70	30	875474.169	306.7200	0.0101572	0.0552631
65	35	879574.45	301.6575	0.0131812	0.0490896
60	40	881446.3	301.1390	0.0145616	0.0484573
55	45	881765.165	301.0840	0.0147967	0.0483902
50	50	882635.84	299.8665	0.0154388	0.0469055
45	55	885137.738	299.6945	0.0172839	0.0466958
40	60	887410.475	299.1800	0.01896	0.0460684
35	65	887813.881	283.1880	0.019257	0.0265668
30	70	892080.485	282.6620	0.022404	0.0259253
25	75	896615.744	270.2215	0.0257487	0.0107546
20	80	897421.379	269.3475	0.0263428	0.0096888
15	85	899633.369	269.2265	0.0279742	0.0095413
10	90	904130.55	269.0585	0.031291	0.009336
5	95	920171.332	269.0280	0.0431204	0.00929
0	100	925189.246	261.4023	0.0468211	0

costs are presented in Table 3, for different pairs of weighting coefficients. The NCF1 and NCF2 are the normalized values of objective functions F_1 and F_2, respectively ($NCF_i = \frac{F_i(x)-F_i^{min}}{F_i^{max}-F_i^{min}}$).The desired amount of minimum CCT is practically considered to be between 100ms to 200ms. In this work, the minimum CCT is considered to be equal to 100ms [26]. According to the simulation results given in next part, after eleven iteration the weighting coefficients as $\rho_1 = \rho_2 = 0.5$ provides a minimum CCT of 100ms. The new commitment schedule of generating units, considering the coherency constraint, is presented in **Fig. 4**, where the differences compared to the first case are highlighted. The simulation results are given in **Table 4** and **Table 5.**

The total daily operational and coherency costs of NCUC and SCBUC models are given in **Table 4**. Also, the hourly operational and coherency cost using NCUC and SCBUC models are reported in **Table 5**. According to **Table 4**, using the SCBUC the total operational cost (i.e. F_1) is increased by 2.328% and the coherency cost (i.e., F2) is decreased by

Table 2 The average coherency w.r.t center of inertia

Gen Number	High load(T12) Average correlation	Low load(T5) Average correlation
Group 1		
G10	0.892	0.907
G12	0.908	0.929
G25	0.820	0.847
G26	0.886	0.891
G113	0.850	0.884
Group 2		
G49	0.875	0.896
G65	0.916	0.935
G66	0.921	0.943
G70	0.888	0.903
G76	0.826	0.887
G77	0.834	0.881
Group 3		
G80	0.744	0.875
G89	0.893	0.911
G92	0.896	0.957
G100	0.656	0.961

28.162%. It means that the system operator will pay an additional cost (i.e. 881765.165-861701.150) to promote the coherency to provide a minimum CCT of 100ms. Indeed by considering the stopping criterion of CCT=100ms, the major challenge in SCBUC to quantize slow coherency index is removed. The modified electrical distance matrix is reported for some hours in **Table 6**. According to **Table 6**, in low demand hour T5, the units G70, G76, G77, and G113 are de-committed due to their long electrical distance from the representative generator. Also, the units G82, G111, and G116 have been on, due to their short electrical distance from the representative generators. For numerical verification, in high demand hour T12 a three-phase short circuit fault is applied in line 30-38, and the rotor speeds of the committed

Table 6 Comparison of unit scheduling using NCUC and SCBUC and their electrical distance from representative generator

Time		Units going from on to off state and their distance from representative unit						Units going from off to on state and their distance from representative unit					
T5	Gen Number	**G070**	**G076**	**G077**	**G113**	-	-	**G082**	**G111**	**G116**	-	-	-
	Distance(pu)	0.3265	0.47375	0.47375	0.3395	-	-	0.16425	0.1976	0.18125	-	-	-
T8	Gen Number	**G018**	**G032**	**G036**	**G076**	**G077**	**G105**	**G004**	**G031**	**G040**	**G042**	**G061**	**G090**
		G113	-	-	-	-	-	**G111**	**G112**	**G116**	-	-	-
	Distance(pu)	0.598	0.526375	0.60475	0.47375	0.47375	0.5033	0.278	0.2695	0.228625	0.22625	0.281875	0.2648
		0.339	-	-	-	-	-	0.19775	0.20675	0.1814	-	-	-
T10	Gen Number	**G018**	**G019**	**G032**	**G034**	**G036**	**G046**	**G004**	**G024**	**G027**	**G090**	**G091**	**G099**
		G055	**G076**	**G077**	**G104**	**G105**	-	**G112**	**G040**	-	-	-	-
	Distance(pu)	0.598	0.764225	0.52625	0.9008	0.60475	0.555	0.278	0.284575	0.27975	0.26475	0.512	0.25325
		0.5425	0.473775	0.47375	0.5033	0.5035	-	0.256825	0.225775	-	-	-	-
T12	Gen Number	**G018**	**G032**	**G036**	**G046**	**G055**	**G076**	**G004**	**G027**	**G031**	**G040**	**G042**	**G090**
		G077	**G087**	**G104**	**G105**	-	-	**G099**	-	-	-	-	-
	Distance(pu)	0.598	0.526375	0.60475	0.555125	0.5425	0.4737	0.278	0.27975	0.269425	0.2286	0.226175	0.2648
		0.47375	0.477575	0.50325	0.503375	-	-	0.25325	-	-	-	-	-
T15	Gen Number	**G018**	**G019**	**G032**	**G036**	**G046**	**G055**	**G004**	**G031**	**G040**	**G042**	**G090**	**G099**
		G076	**G077**	**G087**	**G091**	**G104**	**G105**	**G111**	-	-	-	-	-
	Distance(pu)	0.598	0.764225	0.52625	0.604825	0.55525	0.5426	0.278	0.26925	0.228625	0.226175	0.2648	0.253275
		0.47375	0.4737	0.4775	0.512075	0.50325	0.5034	0.1975	-	-	-	-	-
T19	Gen Number	**G018**	**G032**	**G036**	**G046**	**G055**	**G076**	**G031**	**G040**	**G042**	**G099**	**G111**	-
		G077	**G087**	**G105**	**G113**	-	-	-	-	-	-	-	-
	Distance(pu)	0.598	0.526375	0.60475	0.555125	0.54275	0.473	0.2695	0.2285	0.226175	0.253275	0.197575	-
		0.47375	0.477575	0.5035	0.338975	-	-	-	-	-	-	-	-

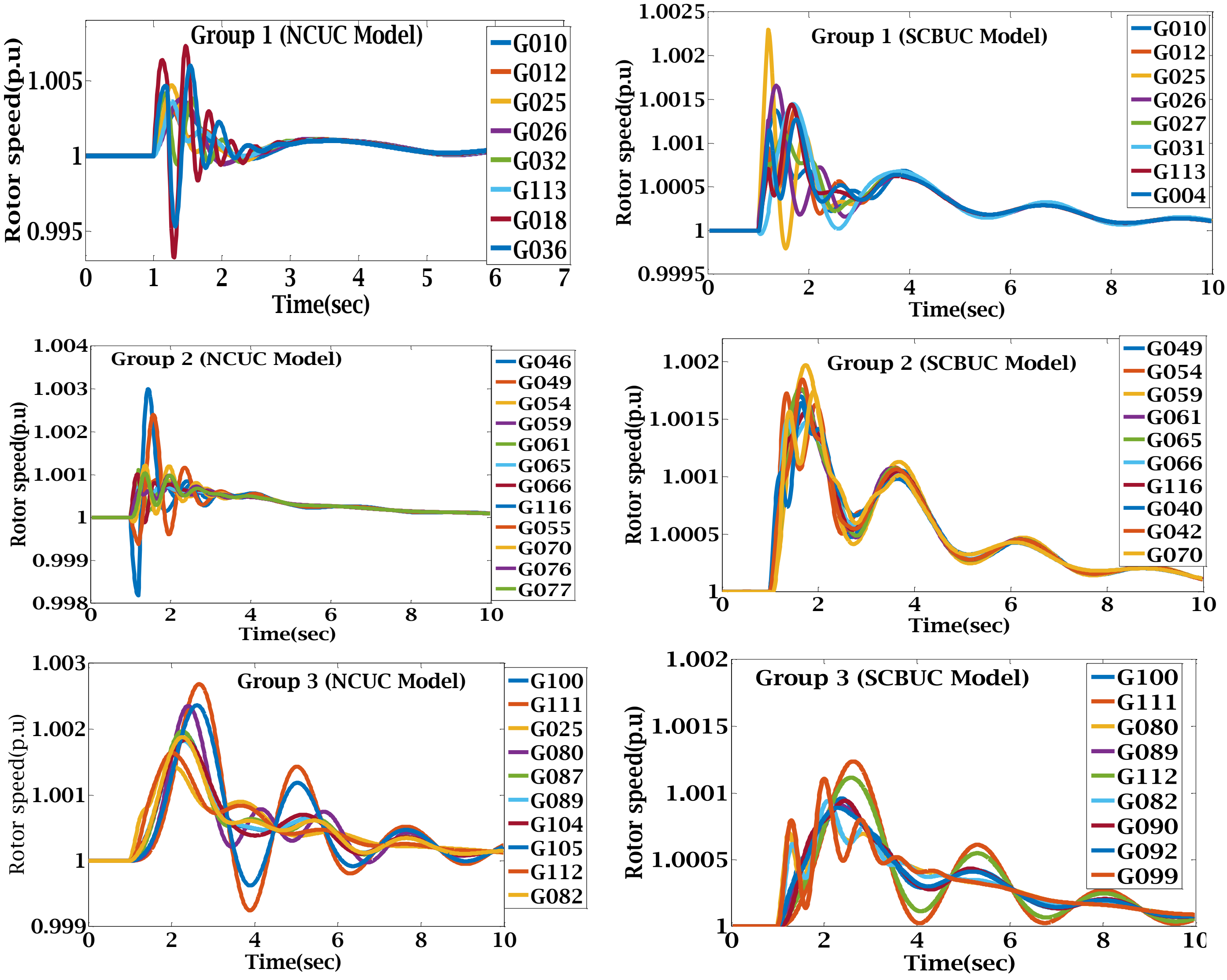

Fig. 5 Comparison of generators' speeds with and without considering coherency constraint

Table 7 Comparison of average coherency indices in different hours

Group Number	Time(h) T5: SCBUC model average correlation	Time(h) T5: NCUC model average correlation
Group1	0.985	0.926
Group2	0.956	0.850
Group3	0.899	0.768

Group Number	Time(h) T8: SCBUC model average correlation	Time(h) T8: NCUC model average correlation
Group1	0.910	0.895
Group2	0.930	0.813
Group3	0.855	0.732

Group Number	Time(h) T12: SCBUC model average correlation	Time(h) T12: NCUC model average correlation
Group1	0.957	0.936
Group2	0.932	0.850
Group3	0.887	0.730

Group Number	Time(h) T8: SCBUC model average correlation	Time(h) T8: NCUC model average correlation
Group1	0.961	0.935
Group2	0.942	0.856
Group3	0.884	0.822

generators in both NCUC and SCBUC model are depicted in Fig. 5. According to Fig. 5, the coherency of generators in Group1 is slightly improved. This improvement is more significant in Group2, where the average coherency index is increased from 0.84285 to 0.9646. This improvement is the result of replacing units G76, G77, G46, and G55 (with respectively 0.473775, 0.47375, 0.55512, and 0.5425 pu. electrical distance) by units G31, G40, and G42 (with respectively 0.26942, 0.2286, and 0.22617pu. electrical distance). Similarly, the coherency of units in third group is considerably improved, where the average coherency index is increased from 0.82256 to 0.891326. The average coherency indices, which are calculated by applying short circuit faults on all lines in four different hours, are presented in **Table 7**. Based on **Table 7**, the coherency of units in SCBUC model is significantly improved compared with NCUC model.

5.3 Transient stability improvement

Slow coherency positively affects the transient stability of committed synchronous generators. More coherent group of generators acts as a stronger equivalent generator in COI reference of that group. In this paper, the weighting factors of multi-objective function are determined to reach a minimum Critical Clearing Time. the weighting factors are changed based on the iterative process described in section 4 from $(\rho_1, \rho_2) = (1,0)$, i.e. no coherency, in step of 0.05 up to the point at which the transient stability margin of CCT=100ms is obtained. In **Table 8**, the minimum CCT values are reported on a peak load hour (i.e. T12) and a sample light load hour (i.e. T5) for some weighting coefficients.

Note that the CCT calculation is not a part of optimization model. Alternatively, by decreasing the electrical distance between committed generators and their related representative generator, as the representative of COI of each group, the coherency and in turn the transient stability are improved. This

Table 8 CCT results for different weighting factors

Time (h)	Minimum CCT(sec) (ρ_1, ρ_2): $(\mathbf{1}, \mathbf{0})$	$(\mathbf{0.9}, \mathbf{0.1})$	$(\mathbf{0.7}, \mathbf{0.3})$	$(\mathbf{0.8}, \mathbf{0.2})$	$(\mathbf{0.6}, \mathbf{0.4})$	$(\mathbf{0.5}, \mathbf{0.5})$
T5	0.052	0.052	0.068	0.079	0.095	0.101
T12	0.061	0.073	0.087	0.909	0.117	0.122

Table 9 CCT values for different machines assuming $(\rho_1, \rho_2) = (0.5{,}0.5)$

Fault Location	Critical Clearing Time(CCT) NCUC		SCBUC	
	T5	**T12**	**T5**	**T12**
B4	-	-	-	0.521
B10	0.305	0.162	0.421	0.275
B12	0.580	0.175	0.566	0.312
B18	-	0.162	-	-
B25	0.342	0.214	0.368	0.256
B26	0.421	0.228	0.415	0.274
B27	-	-	-	0.697
B31	-	-	-	1.781
B32	-	0.557	-	-
B36	-	0.356	-	-
B40	-	-	-	0.874
B42	-	-	-	1.312
B46	-	0.168	-	-
B49	0.078	0.215	0.11	0.235
B54	-	0.42	-	0.42
B55	-	0.254	-	-
B59	-	0.619	-	0.461
B61	-	0.415	-	0.354
B65	0.083	0.447	0.123	0.306
B66	0.09	0.485	0.126	0.324
B70	0.052	0.378	0.101	0.914
B76	0.081	0.227	-	-
B77	0.081	0.181	-	-
B80	0.082	0.121	0.118	0.213
B82	-	0.265	0.521	0.465
B87	-	0.061	-	-
B89	0.377	0.061	0.315	0.315
B90	-	-	-	0.974
B92	0.074	0.081	0.232	0.526
B99	-	-	-	0.329
B100	0.086	0.187	0.25	0.338
B104	-	0.726	-	-
B105	-	0.426	-	-
B111	-	0.812	1.125	0.725
B112	-	1.064	-	0.78
B113	0.942	0.699	-	0.491
B116	-	0.221	0.161	0.122

goal (i.e. providing a minimum CCT of 100ms) is achieved at $(\rho_1, \rho_2) = (0.5, 0.5)$.

According to **Table 8**, it can be seen that the minimum CCT of the network has been improved from 0.052sec at T5 and 0.061sec at T12 to 0.101sec at T5 and 0.122sec at T12, respectively.

Indeed, the additional cost related to the coherency (i.e. 20064.015 $ as obtained in SCBUC model) is indirectly interpreted as the cost of providing a transient stability margin of CCT=100ms. The detailed CCT values for all generators at light load (T5) and peak load (T12) have been reported in **Table 9.** It can be seen that the proposed slow coherency constrained UC model has improved the minimum CCTs, beyond the threshold of 100ms.

6. Conclusion

In this paper a MILP model for considering slow coherency constraint in daily unit scheduling was proposed. The stopping criterion for coherency improvement is to reach a minimum value of CCT as the transient stability margin. Direct integration of transient stability criterion in NCUC is very challenging in both the globality of the commitment schedule and the computational burden. Using the proposed two-step SCBUC, it was shown that the transient stability may be improved indirectly by promoting the slow coherency via the concept of electrical distance.

According to the obtained results, neglecting the coherency constraint can lead to commitment of the poorly coherent generators. However, by slightly increasing the total cost of generation, the schedule of units can be modified to improve their coherency. Although coherency is a dynamic phenomenon, this study presented a two-stage algorithm to formulate coherency based on the electrical distance between generating units.

The simulation results showed that the proposed approach can considerably improve the transient stability of daily unit scheduling by increasing the coherency of generators. The weighting factors of the multi-objective function may be selected accurately through the iterative-based process to provide a minimum value of CCT as the transient stability margin. Although a full coherent commitment schedule may be ideal, however the operator may select the desired value of coherency by its willingness to pay the additional cost for transient stability improvement. Future works can investigate the effects of this improvement on small signal stability of power system.

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