A Novel Approach of Rescheduling the Critical Generators for a New Available Transfer Capability Determination

Muhammad Murtadha Othman, *Member, IEEE*, and Stendley Busan

***Abstract*—The transition to a deregulated electric power system industry has created a highly competitive electricity market with immense power transfer activity performed between the market participants. A poorly-damped oscillation of small-signal instability is usually imminent during a stress power system condition attributed by the base case power transfer or available transfer capability (ATC) compounded with an outage of critical line. The contingency ranking by means of lowest damping ratio is introduced so that execution of the most critical line outage will incite to a poorly-damped oscillation during the base case ATC. The rescheduling of few critical generators determined by using the normalized participation factor is presented in this paper as a novel, non-intricate and cost-effective solution for estimating a new value of ATC while ensuring a secure power system operating condition. Sturdiness of the proposed method is verified through comparison with the weighted-average sensitivity of stability index required for rescheduling the critical generators performed in a case study of 39-bus New England system. Comparative study on the results of cost minimization in generators rescheduling has also been done based on the critical generators selected by the two methods.**

***Index Terms*—Available transfer capability, contingency ranking by means of lowest damping ratio, critical generators rescheduling, normalized participation factor, small-signal instability.**

I. Introduction

NOWADAYS, most countries around the world are moving towards the market-based deregulated of electric power industry. This includes power trade activity which requires the assessment of available transfer capability (ATC) plays a vital role in providing the information of power transfer that used as a reference by the market participants for bidding the lowest price of electricity trading performed in a deregulated power system. An immense dilation regarding to the numbers of independent power producers (IPPs) participated in a generation system has increased competitiveness in the electricity market of a deregulated power system. As a consequence, this phenomenon will render to an intense system operating condition which instigates toward the occurrence of small-signal instability in a power system network. Specifically, the small-signal instability may also caused by the insufficient damping and/or synchronizing torque of generators which arouse to the poorly-damped of generator rotor oscillations due to the consequences of post-disturbance condition. Pragmatically, the poorly-damped rotor oscillation is one of the causative reasons which stimulate the system protection devices yielding to a catastrophe phenomenon of partial or major power system breakdown.

Several technological advancements have been developed to mitigate the problem of small-signal instability which was analytically based on the installation of flexible AC transmission (FACTS) devices, power system stabilizers (PSS) and generation rescheduling technique. The detailed research work on inter-area oscillation considering FACTS device carried out in [1]–[4] does not inflict on the impact of ATC with consequences caused by the critical line outage.

Apart from the FACTS devices, an alternative solution for inter-area oscillation can be attained by adjusting the operating condition of a generator installed with the PSSs designed as additional equipment for the exciter or automatic voltage regulator (AVR). Nonetheless, the use of only PSS may not always be sufficient to solve the inter-area oscillation problems [2], [4]–[8]. Chung *et al.* [6] proposed the weighted-average sensitivity of stability index desired for rescheduling the critical generators in an attempt to reduce the amount of ATC which will improve the inter-area oscillation occurs during the system contingency. The applicability of this method is arising from its fast response in rescheduling the critical generators compatible for an immediate restoration of the inter-area oscillation which occurs only within a short time interval of 10 to 20 s subsequent to a disturbance [9]. Hoballah *et al.* [10] has introduced the combination of modified particle swarm optimization (PSO) and artificial neural network utilized as a new approach in solving the market based generators rescheduling while ensuring the enhancement of transient and oscillatory stability. In particular, the generators rescheduling were performed by referring to the market based energy bidding approach.

This paper introduces a straightforward approach of normalized participation factor index which is easily used to identify a set of critical generators for effective process of rescheduling so

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M. M. Othman is with the Committee of Research (CORE), Advanced Computing & Communication (ACC), Universiti Teknologi MARA, 40450 Shah Alam, Selangor, Malaysia, and also with the Faculty of Electrical Engineering, Universiti Teknologi MARA, 40450 Shah Alam, Selangor, Malaysia (e-mail: mamat505my@yahoo.com).

S. Busan is with the Mott MacDonald Sdn. Bhd., Thermal and Renewable Division, 93200 Kuching, Sarawak, Malaysia (e-mail: stendleybusan@yahoo.com).

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that dynamic and steady state stability is satisfied while ensuring a secure power transfer during the outage of critical line. The contingency ranking is presented to determine a set of critical lines and its outage may cause to the violation of small-signal stability limit based minimum damping ratio. Performance comparison with the weighted-average sensitivity of stability index is implemented in order to demonstrate robustness of the proposed method in rescheduling the critical generators required for determining a new ATC value subsequent to a critical line outage occurs in a New England 39-bus system. Effectiveness of the proposed method used for selecting the critical generators is also verified via the results of cost minimization in generators rescheduling.

II. Power System Components Model

This section will discuss briefly on the implementation of power system components model which becomes the key requirement for conducting the analysis of critical generators rescheduling so that the small-signal stability could be attained in relation to the occurrence of N-1 contingency during power transfer.

A. Generator Model

The analysis of critical generators rescheduling for small-signal stability is performed based on the two-axis synchronous generator model which also has been widely used by most researchers [11]. The Park's transformation discussed in [12] is used to reduce the intricacy of stator and rotor equations by changing its $a-b-c$ reference (stator) frame into a new set of variables referring to the $d-q-0$ reference (rotor) frame.

Further derivation of the Park's transformation equations will eventually arrived to the elimination of 0-axis in such a way that a new reference frame is only referring to the d- and q-axis. Hence, the concept of Park's transformation may commence with (1) until (4) pertaining to the $d-q$ reference frame derived thoroughly in [13]:

$$\frac{d\delta_g}{dt} = \omega_g - \omega_s \tag{1}$$

$$\frac{d\omega_g}{dt} = \frac{Pm_g}{M_g} - \frac{Pe_g}{M_g} - \left(\frac{D_g(\omega_g-\omega_s)}{M_g}\right) \tag{2}$$

$$\frac{dE'_{q_g}}{dt} = -\frac{E'_{q_g}}{T_{d0_g}} - \frac{\left(X_{d_g}-X'_{d_g}\right)I_{d_g}}{T_{d0_g}} + \frac{E_{fd_g}}{T_{d0_g}} \tag{3}$$

$$\frac{dE'_{d_g}}{dt} = -\frac{E'_{d_g}}{T'_{q0_g}} + \frac{I_{q_g}}{T'_{q0_g}}\left(X_{q_g}-X'_{q_g}\right) \tag{4}$$

where

$$M_g = \left(\frac{H_g}{\pi f_{rated}}\right) \tag{5}$$

Hg	inertia constant;
Pe_g	electrical power output;
Pm_g	mechanical power output;
ω_g	angular speed of the gth generator rotor;
ω_s	angular speed of rotating synchronous reference frame, $2\pi f_{rated}$;
g	number of generator, $g = 1, 2 \ldots, G$;
δ	rotor angle;
D	damping torque coefficient;
X_d	direct-axis synchronous reactance;
X_q	quadrature-axis synchronous reactance;
X'_d	direct-axis transient reactance;
X'_q	quadrature-axis transient reactance;
T'_{d0}	d-axis open circuit time constant;
T'_{q0}	q-axis open circuit time constant;
E_{fd}	voltage induced due to rotor field excitation;
E'_d	direct-axis voltage behind transient reactance;
E'_q	quadrature-axis voltage behind transient reactance;
$I_{d,g}$	direct-axis component of armature current of the gth generator;
$I_{q,g}$	quadrature-axis component of armature current of the gth generator.

By neglecting the armature resistance (R_a), the equation of output power can be obtained by [13]

$$Pe_g = E'_{d_g}I_{d_g} + E'_{q_g}I_{q_g} - \left(X'_{d_g}-X'_{q_g}\right)I_{d_g}I_{q_g}. \tag{6}$$

Extraction of (6) is performed in order to obtain the direct-axis voltage, V_d, and quadrature-axis voltage, V_q, of (7) and (8), respectively:

$$E'_{d_g} - R_{s_g}I_{d_g} + X'_{q_g}I_{q_g} = V_{d_g} \tag{7}$$

$$E'_{q_g} - R_{s_g}I_{q_g} - X'_{d_g}I_{d_g} = V_{q_g} \tag{8}$$

where

R_s	stator resistance;
V_d	direct-axis voltage;
V_q	quadrature-axis voltage.

The relationship between V_d and V_q is appeared to be the issuance of terminal voltage, V^g given in (9):

$$V_{d_g} + jV_{q_g} = V_g\sin(\delta_g-\theta_g) + V_g\cos(\delta_g-\theta_g) \tag{9}$$

where

δ_g	rotor angle of the gth generator;
θ_g	bus terminal voltage angle at gth generator;
V_g	bus terminal voltage at gth generator.

The Park's transformation approach unveils that (1) until (9) of a synchronous generator is referring to its own rotor rotating frame. Hence, the synchronously rotating frame represented by subscripts D and Q is used to express the current and voltage variables in terms of stator equivalent circuit which has a direct relationship between synchronous generator and system network [14]. Hence, synchronous operation of all generators can be monitored and assessed easily by the operators. In addition, the speed for each generator under a stable condition can be defined as the synchronous speed. Hence, the synchronously rotating frame reference for the generator terminal voltage and current can be obtained through the transformation from $d-q$ to $D-Q$ as given by

$$Ve^{j\theta_V} = (V_D + jV_Q) = (V_d + jV_q)e^{j(\delta-\pi/2)} \tag{10}$$

$$Ie^{j\theta_I} = (I_D + jI_Q) = (I_d + I_q)e^{j(\delta-\pi/2)}. \tag{11}$$

A thorough derivation of (11) is performed yielding to a new current formulation at $D-Q$ reference frame given in (12) and (13) [13]:

$$I_D = I_d \cos(\pi/2 - \delta) + I_q \cos(\delta) \tag{12}$$
$$I_Q = -I_d \sin(\pi/2 - \delta) + I_q \sin(\delta). \tag{13}$$

Simultaneously, similar steps used to derived (11), (12), and (13) are deployed to determine a new equation of terminal voltage at $D - Q$ reference frame. The final form of stator algebraic formulation expressed in (14) can be obtained from a detail derivation involving the equations of terminal voltage and current where both are referring to $d - q$ and $D - Q$ reference frames [13]:

$$(V_D + jV_Q) + (R_s + jX'_d)(I_D + jI_Q) = (E'_q + jE'_d)\, e^{j(\delta-\pi/2)} + (X'_q - X'_d)\, I_q e^{j(\delta-\pi/2)}. \tag{14}$$

The values of generator terminal voltage, $(V_D + jV_Q)$, and current, $(I_D + jI_Q)$, can be obtained from the load flow solution. By applying all of these values in (14), this will unveil the value of voltage behind impedance, $\bar{E}$, with its angle, δ, for every generator.

B. Exciter Model

Implementation of the IEEE type DC-1 exciter [13] at every generator plays a significant role in controlling the synchronous generator so that a constant output terminal voltage could be attained. The mathematical model of IEEE type DC-1 exciter can be expressed in the form of differential equations given as follows [13]:

$$\frac{dE'_{fd,g}}{dt} = -\frac{K_{E_g} + S_E\left(E_{fd,g}\right)}{T_{E_g}} E_{fd,g} + \frac{V_{R_g}}{T_{E_g}} \tag{15}$$

$$\frac{dV_{R_g}}{dt} = -\frac{V_{R_g}}{T_{A_g}} + \frac{K_{A_g}}{T_{A_g}} R_{F_g} - \frac{K_{A_g} K_{F_g}}{T_{A_g} T_{F_g}} E_{fd,g} + \frac{K_{A_g}}{T_{A_g}}\left(V_{ref_g} - V_g\right) \tag{16}$$

$$\frac{dR_{F_g}}{dt} = -\frac{R_{F_g}}{T_{F_g}} + \frac{K_{F_g}}{\left(T_{F_g}\right)^2} E_{fd,g} \tag{17}$$

where

$$S_E(E_{fd}) = A_x e^{B_x E_{fd}}, \text{ field saturation function.} \tag{18}$$

K_E	exciter gain;
T_E	exciter time constant;
V_R	voltage regulator output;
K_A	voltage regulator gain;
T_A	voltage regulator time constant;
K_F	rate feedback gain;
T_F	rate feedback time constant;
V_{ref}	reference voltage;
R_F	exciter rate feedback;
E_{fd}	voltage induced by rotor field excitation.

C. Load Model

The rescheduling of generating units with the inclination to improve the small-signal instability is performed on a system entailed with a static model of load demand conferred in (19) and (20), whereby those equations are originated from a polynomial characteristic of static load model [15]:

$$P_L = P_{Lo}\left(\frac{V}{V_o}\right)^2 \tag{19}$$

$$Q_L = Q_{Lo}\left(\frac{V}{V_o}\right)^2 \tag{20}$$

where

P_{Lo}	nominal value of real power;
Q_{Lo}	nominal value of reactive power;
V_o	nominal value of voltage at the load bus.

D. Network Model

In general, the algebraic equation of current-balance given in (21) is the most popular network model tangibly used in the analysis of small-signal stability [13]. Equation (21) is composed with the Y_N admittance matrix as well as the currents and voltages at $D - Q$ reference frames:

$$[I_{DQ}] = [Y_N][V_{DQ}] \tag{21}$$

where

$$Y_N(i,j) = \begin{bmatrix} G_{C_{ij}} & -B_{S_{ij}} \\ B_{S_{ij}} & G_{C_{ij}} \end{bmatrix}, I_{DQ} = \begin{bmatrix} I_D \\ I_Q \end{bmatrix}, \text{ and } V_{DQ} = \begin{bmatrix} V_D \\ V_Q \end{bmatrix}.$$

The polar form of bus admittance, Y_N, is separated into the real and imaginary parameters of conductance, G_c, and susceptance, B_s, respectively. It is worth mentioning that the Y_N is similar to a bus admittance matrix, Y_{Bus}, normally used in the load flow analysis.

III. Linearization of Components Model

Basically, the concept of linearization in power system components model is implemented to design the state matrix, A_T, which will then be used to compute the eigenvalues and eigenvectors for small-signal stability analysis of a system. The construction of state matrix, A_T, is summarized in the following procedure.

1) Establish the base case power flow solution and collect all the values of voltage, angle, real power and reactive power of each bus.
2) Compute the initial conditions of a system notably given in (1) until (17) with regards to the system parameters collected from step 1).
3) Construct the bus admittance matrix comprising of conductance, G_c, and susceptance, B_s, for the transmission lines as discussed in Section II-D.
4) Compute the Y_L matrix corresponding to the loads of a system. Y_L is embedded with the conductance, G_{Lo}, and susceptance, B_{Lo}, of load at nominal condition explicitly acquired from (19) and (20), respectively.
5) Construct the P_{ML} and P_{MG}. The elements of P_{MG} with $2n \times 2g$ matrix size and P_{ML} with $2n \times 2m$ matrix size represent as the status of generator and load connected to each particular bus, respectively, whereby n is the number

of bus, g is known to be the number of generator bus and m is the number of load bus.

6) Compute the system state matrix, A_T, using (22) that takes into account the entire matrix assembled in step 3) until step 6):

$$[A_T] = [A_g] + [B_g][P_{MG}]^T\left[Y'_{DQ}\right]^{-1}[P_{MG}][C_g] \tag{22}$$

where

$$\begin{aligned}\left[Y'_{DQ}\right] &= [Y_{DQ}] + [P_{MG}][Y_g][P_{MG}]^T + [P_{ML}][Y_L][P_{ML}]^T\\ YDQ &= YN\\ [A_g] &= diag[\,A_{g1} \quad A_{g2} \quad \cdots \quad A_{gG}\,]\\ [B_g] &= diag[\,B_{g1} \quad B_{g2} \quad \cdots \quad B_{gG}\,]\\ [C_g] &= diag[\,C_{g1} \quad C_{g2} \quad \cdots \quad C_{gG}\,]\\ [Y_g] &= diag[\,-D_{g1} \quad -D_{g2} \quad \cdots \quad -D_{gG}\,].\end{aligned} \tag{22a}$$

A detail derivation and explanation on the elements of A_g, B_g, C_g, D_g, and E_g can be obtained by referring to [12] and [13].

The small-signal stability of a system is acquainted based on the eigenvalue (modal) analysis of system state matrix, A_T.

IV. Contingency Ranking For Critical Line Outages Selection

It is undoubtedly understood that the contingency ranking analysis is carried out to discover the critical line outage which adversely affects on the stability of a system network and power transfer between areas. The contingency ranking used to determine the critical lines is executed according to the following procedure.

1) Determine the ATC for a particular transfer case acquired during the base case system condition [16], [17]. Busan *et al.* [16], [17] have explained elaborately on the cubic-spline with Ralston's technique used to compute the ATC at base case system condition in conjunction with a transfer case specified between the selling area and buying area. The power flow limit (LI_{limit}), voltage magnitude limit (V_{limit}), and generator rotor angle difference limit $(\Delta\delta_{limit})$ are the constraints considered in the base case ATC computation. In particular, cubic-spline is used for tracing the variations of voltage magnitude (V), power flow (LI), or generator rotor angle difference $(\Delta\delta)$ against power transfer (PT) that is increased between the two trajectory points (TJ) determined by the Ralston's method. The computation of ATC discussed in [16] and [17] involves intricate formulations and procedures which can be described based on its main mathematical concept given in (23). Equation (23) signifies that the ATC is a PT determined either by referring to V_{limit}, LI_{limit}, or $\Delta\delta_{limit}$ intersects the variations of V, LI, or $\Delta\delta$, respectively, between the two trajectory points:

$$ATC = PT \in (var|_{TJ} \cap ct) \tag{23}$$

$$var|_{TJ} = CS(PT|_{TJ}) \tag{23a}$$

where

$var\|_{TJ}$	variations of V, LI, or $\Delta\delta$ between the two PT trajectory points determined by the Ralston's method;
ct	system constraint of V_{limit}, LI_{limit}, or $\Delta\delta_{limit}$;
CS	cubic-spline function;
$PT\|_{TJ}$	power transfer increased between the two trajectory points of PT.

The cubic-spline with Ralston's technique is used to reduce a large number of repetitive power flow solutions with the intention to provide a fast and accurate ATC computation.

2) Perform a line outage.
3) Establish the power flow solution and proceed to the next procedure as a result of convergence in the power flow solution. Otherwise, repeat step 2) for the execution of subsequent line outage. A line outage contributing to the divergence of power flow solution will not be included in this analysis.
4) Use (24) to determine the minimum value of system damping ratio, ζ, occurred at the dominant rotor angle mode of A_T or λ [18]. Section III divulges on the main concept of A_T which represents as the eigenvalue, λ [13]. The A_T is composed with the real (σ_h) and imaginary (ϖ_h) components of λ required for calculating the ζ:

$$Min(\zeta_h) = min\left(\frac{-\sigma_h}{\sqrt{\sigma_h^2 + \varpi_h^2}}\right). \tag{24}$$

5) Repeat the procedure from step 1) until step 4) with the intention to record the minimum ζ emerged at the dominant rotor angle mode of λ for each line outage.
6) Rearrange the list of transmission line corresponding to the minimum ζ sorted in an ascending order. This implies that a system will encounter an intense severity of small-signal instability due to the critical line outage delineated as first in the contingency ranking.

For the commencement of this procedure, it is imperative to determine the base case power transfer in step 1) so that a different list of critical line outages is obtained particularly for every transfer case. This action should be emphasized in the contingency ranking procedure so that the obtained results of base case power transfer and critical line outage will be applied similarly in steps 3) and 5), respectively for the procedure discussed in Section V which in turn contributing to the accurate results in critical generators selection, generators rescheduling, computation of new ATC and system stability. This implies that there shall exist interrelation between the procedure discussed in Section IV and Section V. Hence, the proposed methods can be considered as the contribution to a new approach in contingency ranking and generators rescheduling proven via the results discussed in Sections VI-B and VI-C, respectively. In addition, one should vigilant that utilizing the same critical line outage for different transfer cases will cause to an inaccurate result of ATC. Subsequently, ineffective use of transmission system and system instability will occur as a consequence from inaccurate information of ATC referred by the utility in the electricity market implementation [19]–[21].

V. Rescheduling of Critical Generators for a new ATC Determination With Small-Signal Stability

The following procedure elucidates on the ATC assessment incorporating with critical generators rescheduling for small-signal stability during critical line outage. Uniform distribution of changes in generation capacity and optimization of energy market are the two different methods of generators rescheduling explained in the procedure.

1) Establish a solved base case power flow solution.

2) Specify the selling area and buying area involved as the case study for ATC determination. The ATC will be computed by referring to the participation of all generators and loads in the selling and buying areas, respectively.
3) Determine the base case value of ATC transferred from the selling area to the buying area associated with the dynamic and steady state-system constraints [16]. The ATC is computed by using similar technique discussed in step 1) of the procedure in Section IV.
4) Record the real power of generator, P_{Gn}, and real power of load P_{Dn} increased at the selling area $(P_{G_n}^{inc}|_{sell})$ and buying area $(P_{D_n}^{inc}|_{buy})$, respectively.
5) Perform a critical line outage selected by means of contingency ranking assessment discussed in Section IV.
6) Execute the power flow solution while retaining $(P_{G_n}^{inc}|_{sell})$ and $(P_{D_n}^{inc}|_{buy})$ increased at the particular buses obtained in step 4).
7) Calculate the damping ratio, ζ, using (24) which require the information of λ or A_T recorded as the dominant rotor angle mode in step 4) of Section IV.
8) Record the ATC value computed in step 3) only if the system constraints of damping ratio limit, voltage magnitude limit, MVA line limit and generator rotor angle difference limit are fulfilled [16]. In relation to step 3), equation (23) used to determine the ATC is basically can be regarded as (25). Equation (25) represents that difference between the total base case generation $(\sum P_{G_n}^{base}|_{sell})$ and the total generation increased $(\sum P_{G_n}^{inc}|_{sell})$ in the selling area will provide the value of ATC or PT. Similarly to the buying area wherein a difference between the total base case loading condition $(\sum P_{D_n}^{base}|_{buy})$ and the total increased loading condition $(\sum P_{D_n}^{inc}|_{buy})$ will gives to the value of ATC or PT. Consecutively, perform step 5) to pursue with the subsequent case of critical line outage. Otherwise, proceed to step 9) whenever any system constraint is violated:

$$\begin{aligned} ATC = PT &= \sum_{n=1} P_{G_n}^{inc}|_{sell} - \sum_{n=1} P_{G_n}^{base}|_{sell} \\ &= \sum_{n=1} P_{D_n}^{inc}|_{buy} - \sum_{n=1} P_{D_n}^{base}|_{buy}. \end{aligned} \tag{25}$$

9) Use (27) to screen or identify the critical generators having a high tendency for causing the small-signal instability of rotor angle, $\Delta\delta$, and speed deviation, $\Delta\omega$. In particular, the critical generators are selected based on a non-zero value of P_{norm} encompassed under the proportions or segments of $\Delta\delta_g$, $\Delta\omega_g$ and λ_g as shown in (27a). Equation (27a) is introduced for the ease of small-signal stability analysis acquired through the concept of normalization which divides every element of participation factor, P_{bh}, with the largest participation factor value, $P_{max,h}$, in its respective column. Basically, the normalized participation factor expressed in (27a) is inherently composed with the product of left (η) and right (υ) eigenvectors denoted in (27b) derived from λ or A_T [12]. The participation factor in (27b) can also be defined as the sensitivity of h^{th} eigenvalue, λ, with respect to a change in the bth diagonal element of the state matrix, a_{bb} [22], [23], whereby λ or A_T is also used as a basic parameter in (24) to compute the ζ. Hence, it is plausible to mention that increasing or decreasing P_G at the critical generators will significantly vary the swing mode of $\Delta\delta_g$ and $\Delta\omega_g$ indicated by (27a) as well as the ζ in (24) wherein all these parameters are related to the dominant rotor angle mode of λ selected in step 7). This is proven via $\partial\zeta/\partial P_G$ given in [6] which brings to the meaning of changes in PG will have an effect on ζ, originated from dominant rotor angle mode λ and is also used as a basic parameter in (27a) to indicate the swing mode condition of $\Delta\delta_g$ and $\Delta\omega_g$. Other than to initially screen candidate generators for addition of damping controller, it is perspicuous that (27a) can also be used as a new and alternative approach to identify the critical generators required for effective rescheduling process and hence the best solution of power transfer is attained while ensuring stability of a system. This has been proven previously in [24]–[26] whereby (27a) basically derived from (27b) was used for the assessment of small-signal stability which refers to the differentiation of eigenvalue, λ, with respect to the control parameter, a_{bb}, which stands for the specified generation schedule. An alternative way which constitute of a fundamental method used to calculate (27b) has also been discussed thoroughly in [25], [26]. In addition, equation (27b) has also been used for the assessment of small-signal stability directly associated with the energy imbalance and power price [27], [28]. Basically, the energy imbalance represents as the difference between power generation, P_G, and power demand, P_D. With regards to [24] and [28], the above-mentioned discussion signifies that (27a) which basically derived from (27b) can be used to determine the critical generators so that effective rescheduling process can be performed for obtaining the best solution of power transfer while retaining small-signal stability of a system. This is entrenched with the fact that inter-area damping mode via participation factor is very sensitive to the generator rescheduling that has been proven in [24]. Determination of critical generators using P_{norm} given in (27a) is also relevance to $\partial\lambda_h/\partial P_{G_g}$ that is commonly used to determine the critical generators having poorly-damped inter-area oscillation mode [25]. $\partial\lambda_h/\partial P_{G_g}$ has been developed according to the sensitivity of eigenvalues with respect to the output power of generators. Jeng *et al.* [25] have introduced a formulation distinctively used to calculate $\partial\lambda_h/\partial P_{G_g}$, wherein an alternative way to calculate $\partial\lambda_h/\partial P_{G_g}$ can also be done by using the proposed (26). Equation (26) represents as the amalgamation between linearized power network $(\partial P_{G_g}/\partial\delta_g$ or $J)$ and participation factor (P) of (27b) wherein each respective equation has been discussed separately in [29]:

$$\begin{aligned} \frac{\partial\lambda_h}{\partial P_{G_g}} &= \left(\frac{\partial P_{G_g}}{\partial\delta_g}\right)^{-1} \times \frac{\partial\lambda_h}{\partial\delta_g} \\ &= J_g^{-1} \times \frac{\partial\lambda_h}{\partial\delta_g} \end{aligned} \tag{26}$$

where

$$\begin{aligned} \frac{\partial P_{G_g}}{\partial\delta_g} = J_g = \sum_{\substack{j=1 \\ j\neq g}} V_g V_j \,\big[&B_{S_{gj}} cos(\delta_g - \delta_j) \\ &- G_{c_{gj}} cos(\delta_g - \delta_j)\big] \end{aligned} \tag{26a}$$

In order to facilitate towards understanding on the formation of $\partial\lambda_h/\partial P_{G_g}$ in (26), hence, derivation of $\partial\lambda_h/\partial\delta_g$ is commenced by referring to the swing mode of $\partial\delta_g$ embedded in P_{norm} of (27a). On the overleaf, the ∂P_{G^g} in (26) is obtained predicated on the linearization of real power and reactive power that contradicts with the linearization of voltage and current as discussed in Section II-D. In (26), $(\partial P_{G_g}/\partial \delta_g)^{-1} = J^{-1}$ and $\partial \lambda_h/\partial \delta_g$ are interrelating with one another due to $\partial \delta_g$ available in both parts of the equation. This signifies that either $(\partial P_{G_g}/\partial \delta_g)^{-1} = J^{-1}$ or $\partial \lambda_h/\partial \delta_g$ can be used to notify the critical generators having poorly-damped oscillation mode. Therefore, it is desirable to identify the critical generators only by referring to $\partial \lambda_h/\partial \delta_g$ rather than $(\partial P_{G_g}/\partial \delta_g)^{-1} = J^{-1}$ in order to acquire efficacy in terms of computational time and cost that does not require intricate calculation involving another immense size of Jacobian matrix J. This implies that $\partial \lambda_h/\partial \delta_g$ is similar to (27a) and (27b) particularly at the swing mode $\partial \delta_g$ of P_{norm} and its utilization is sufficient to detect the critical generators. Other than $\partial \lambda_h/\partial \delta_g$, the remaining segments of swing modes in P_{norm} can also be used to identify critical generators encountering poorly-damped inter-area oscillation mode.

Indeed, several advantages can be obtained from the proposed method among them is the use of (27a) which scrutinize in detail to identify the actual critical generator running at the high participation of swing mode $\Delta \delta_g$ and $\Delta \omega_g$ thus becoming as a major contributor to $\zeta > 3\%$. A detail selection of critical generators is not the case for weighted-average sensitivity given in [6] and this will be discussed through the results proven in Section VI-D. The proposed method also has the advantage in terms of its straight-forward approach in calculating the normalized participation factor (P_{norm}) that can be done immediately once the value of λ is obtained. On one side, the changes of ζ and P_G embodied in $\partial \zeta/\partial P_G$ is a basic formulation used in the weighted-average sensitivity method which requires a slightly disturbed value of $P_G + \Delta P_G$ [6] and this scarcity clearly discern its concept compared with the straight-forward approach introduced by the proposed method. In an outlying situation wherein the generators rescheduling method is using the weighted-average sensitivity method, this implies that steps 6) and 7) should be executed twice abreast with before and after implementation of a slightly disturbed generation capacity, $P_G + \Delta P_G$, in each generator. The outcome will be two different values of ζ attributed by the difference in generation capacities and these parameters are required for the $\partial \zeta/\partial P_G$ calculation which is then used for critical generators selection performed in step 9). Indeed, this will not be a crucial issue for the proposed critical generators selection method performed in step 9) whereby the P_{norm} is obtained customarily by performing a single execution of steps 6) and 7) without the need of a slightly disturbed generation capacity, $P_G + \Delta P_G$, in each generator. Indeed, selection of critical generators either by using the P_{norm} or weighted-average sensitivity method [6] shall be executed in every repetitive process of subsequent critical line outage which begins from step 5) up to the last procedure that is step 15). By comparing with the weighted-average sensitivity method, it is perspicuous that selection of critical generators using the P_{norm} will reduce the computational burden and time incurred in the repetitive process of subsequent critical line outages especially for a large power system.

Hence, the non-zero normalized participation factor at dominant rotor angle mode of λ given in (27a) can be considered as a new approach in the critical generators selection required for rescheduling that yields to a new ATC value and this has not been discussed previously by the researchers:

$$P_{G_n}|^{crit} = P_{G_n}|_{\widehat{P}_{norm}} \tag{27}$$

where

$\tilde{P}_{norm}$ non-zero value of P_{norm} situated under the column of dominant rotor angle mode λ having minimum value of ζ. Subsequently, the non-zero value of P_{norm} is selected based on the generating units that shove toward the occurrence of inter-area oscillation. Particularly, the non-zero value of P_{norm} is selected by referring to the opposite sign of real right eigenvector (υ) occur between the two groups of generators located in different area and this will be discussed by means of a case study given in Section VI-C:

$$P_{norm} = \begin{array}{c} \begin{array}{ccccc} \lambda_1 & \lambda_2 & \lambda_3 & & \lambda_h \end{array} \\ \begin{bmatrix} \frac{P_{11}}{P_{\max 1}} & \frac{P_{12}}{P_{\max 2}} & \frac{P_{13}}{P_{\max 3}} & \cdots & \frac{P_{1h}}{P_{\max h}} \\ \frac{P_{21}}{P_{\max 1}} & \frac{P_{22}}{P_{\max 2}} & \frac{P_{23}}{P_{\max 3}} & \cdots & \frac{P_{2h}}{P_{\max h}} \\ \frac{P_{31}}{P_{\max 1}} & \frac{P_{32}}{P_{\max 2}} & \frac{P_{33}}{P_{\max 3}} & \cdots & \frac{P_{3h}}{P_{\max h}} \\ \vdots & \vdots & \vdots & \ddots & \vdots \\ \frac{P_{b1}}{P_{\max 1}} & \frac{P_{b2}}{P_{\max 2}} & \frac{P_{b3}}{P_{\max 3}} & \cdots & \frac{P_{bh}}{P_{\max h}} \end{bmatrix} \end{array} \begin{array}{c} \Delta\delta_1 \\ \Delta\omega_1 \\ \Delta E'_{q_1} \\ \vdots \\ \Delta R_{F_g} \end{array} \tag{27a}$$

$$P = \begin{bmatrix} P_{1h} \\ P_{2h} \\ \vdots \\ P_{bh} \end{bmatrix} = \begin{bmatrix} U_{1h}U_{h1} \\ U_{2h}U_{h2} \\ \vdots \\ U_{bh}U_{hb} \end{bmatrix} = \frac{\partial \lambda_h}{\partial_{a_{bb}}}. \tag{27b}$$

10) Reschedule the output power, P_G, of critical generators obtained in step 1) which will reduce the amount of ATC and also recuperates the small-signal, transient or steady-state system instability. There are two different techniques used for generators rescheduling wherein the first is referring to the uniform distribution of changes in generation capacity (ΔP_G) and the second is where the optimization of energy market is involved in generators rescheduling. Basically, the rescheduling is performed by increasing the P_G of critical generators located at the buying area, reciprocal to the reduced P_G of critical generators in the selling area. The first technique utilize (28) and (29) to perform generators rescheduling in the buying area and selling area, respectively. Equation (28) represents as the increase of generation capacity in the buying area and is performed by referring to the changes in generation capacity (ΔP_G) uniformly distributed throughout the critical generators, $P_{G_n}^{base}|_{buy}^{crit}$. For the selling area, equation (29) is used to reduce the generation capacity based on the uniform allocation of (ΔP_G) at the critical generators, $P_{G_n}^{inc}|_{sell}^{crit}$:

$$P_{G_n}^{new}|_{buy}^{crit} = P_{G_n}^{base}|_{buy}^{crit} + \frac{\widehat{P}_{norm_n}|_{buy}}{\sum_{n=1} \widehat{P}_{norm_n}|_{buy}} \cdot \Delta P_G \tag{28}$$

$$P_{G_n}^{new}|_{sell}^{crit} = P_{G_n}^{inc}|_{sell}^{crit} - \frac{\widehat{P}_{norm_n}|_{sell}}{\sum_{n=1} \widehat{P}_{norm_n}|_{sell}} \cdot \Delta P_g. \tag{29}$$

The distribution of (ΔP_G) is basically based on the ratio of normalized participation factor $(\hat{P}_{norm})$ with respect to the sum of normalized participation factor $((\hat{P}_{norm}))$ for all critical generators. The first rescheduling technique is introduced with the aim to sustain the stability of a system. Indeed, the proposed method can be further improved by comparatively resembles with the situation utterly taking place in a deregulated power system which allows utility to adjust or shift the existing energy market so that remedial action could be taken by the generating companies to ensure the system stability is attained. Hence, optimization of energy market is introduced in the second technique of generators rescheduling by considering cost minimization of Δ_{G_n} as the objective function given in (30) [10], [30], [31]. The linear bidding strategy is used to design the expression in (30). Usually, the generating companies are given opportunity to participate in the energy bidding required for an effective implementation of generator rescheduling by increasing and decreasing the generating capacity until the system is in a stable condition. The opportunity cost should be paid to the generating company that is willing to perform desired changes in the generating capacity reduction at the selling area. Meanwhile, the additional cost should be paid to the generating company that carry out changes in the increased of generating capacity at the buying area shown in (30) at the bottom of the page, subject to

$$\Delta P_G = \sum_{n=1} \Delta P_{G_n}|_{buy}^{crit} = \sum_{n=1} \Delta P_{G_n}|_{sell}^{crit} \tag{30a}$$

where

$\alpha_n^+ \& \beta_n^+$	additional cost coefficients specified to each critical generator in the buying area;
$\alpha_n^- \& \beta_n^-$	opportunity cost coefficients specified to each critical generator in the selling area;
$\Delta P_{G_n}|_{buy}^{crit}$	changes of increased capacity in each critical generator located at the buying area;
$\Delta P_{G_n}|_{buy}^{sell}$	changes of reduced capacity in each critical generator located at the selling area.

Simultaneously, equations (31) and (32) are used to compute a new generation capacity for each critical generator allocated by $\Delta P_{G_n}|_{buy}^{crit}$ and $P_{G_n}|_{sell}^{crit}$ in the buying area and selling area, respectively:

$$P_{G_n}^{new}|_{buy}^{crit} = P_{G_n}^{base}|_{buy}^{crit} + \Delta P_{G_n}|_{buy}^{crit} \tag{31}$$

$$P_{G_n}^{new}|_{sell}^{crit} = P_{G_n}^{inc}|_{sell}^{crit} - \Delta P_{G_n}|_{sell}^{crit}. \tag{32}$$

11) Perform a solved power flow solution.
12) Use (24) to calculate the ζ which requires the information of dominant rotor angle mode λ or A_T.
13) Repeat steps 10)–12) until there is no intrusion in any system security constraint of small-signal, transient or steady-state stability limit. The attainment of small-signal stability is affirmed via the minimum ζ which transcends above the damping ratio limit of 3% [6]. The outage of critical line during base case power transfer is actually an inevitable disaster occurs during the pragmatic operation of a power system. This may cause to a higher voltage deviation which will be one of the causative reasons that shove towards system instability. Therefore, generators rescheduling are performed by repeating steps 10)–12) until the system instability is restored.
14) Record a new amount of ATC obtained in step 10) resulted from the rescheduling of critical generators. A new value of ATC can be computed by using (33):

$$ATC = \left(\sum_{n \neq n|_{crit}} P_{G_n}^{inc}|_{sell} + \sum_{n = n|_{crit}} P_{G_n}^{new}|_{sell}^{crit} \right) - \sum_{n=1} P_{G_n}^{base}|_{sell}. \tag{33}$$

It can be observed in (33) that the ATC is obtained by referring to a difference between the total base case generation and the total generation increased in the selling area. Moreover, the total amount of generation increased in the selling area is obtained from the combination of total generation increased in the non-critical generating units $(\sum_{n \neq n|_{crit}} P_{G_n}^{new}|_{sell}^{crit})$ given in step 4) and the total generation increased in the critical generating units $(\sum_{n \neq n|_{crit}} P_{G_n}^{inc}|_{sell})$ given by (29).
15) Return to step 5) to perform generators rescheduling for the next critical line outage occurs at the same transfer case. Stop the process when it reached to the last critical line outage.

Illustration in Fig. 1 is provided for explicit understanding on the proposed procedure of generators rescheduling.

VI. Results and Discussion

This section discusses on the results of ATC spanning with the impact of critical generators rescheduling while emphasizing on the recuperation of small-signal, transient or steady-state instability subsequent to a critical line outage. Robustness of the proposed rescheduling methods utilized for a new ATC determination is explored on a case study of New England 39-bus system illustrated in Fig. 2 [32], [33]. A single-line diagram of New England 39-bus system is designed with 10 generator units, 29

$$ObjectiveFunction = min \left[\sum_{n=1}^{\square} \left(\int_{P_{G_n}^{base}|_{buy}^{crit}}^{P_{G_n}^{base}|_{buy}^{crit} + \Delta P_{G_n}^{\square}|_{buy}^{crit}} (\alpha_n^+ + \beta_n^+ \cdot y) - \int_{P_{G_n}^{base}|_{buy}^{crit} - \Delta P_{G_n}^{\square}|_{buy}^{crit}}^{P_{G_n}^{base}|_{buy}^{crit}} (\alpha_n^+ + \beta_n^+ \cdot y) \right) + \sum_{n=1}^{\square} \left(\int_{P_{G_n}^{inc}|_{sell}^{crit}}^{P_{G_n}^{inc}|_{sell}^{crit} + \Delta P_{G_n}^{\square}|_{sell}^{crit}} (\alpha_n^- + \beta_n^- \cdot Y) - \int_{P_{G_n}^{inc}|_{sell}^{crit} - \Delta P_{G_n}^{\square}|_{sell}^{crit}}^{P_{G_n}^{inc}|_{sell}^{crit}} (\alpha_n^- + \beta_n^- \cdot Y) \right) \right] \tag{30}$$

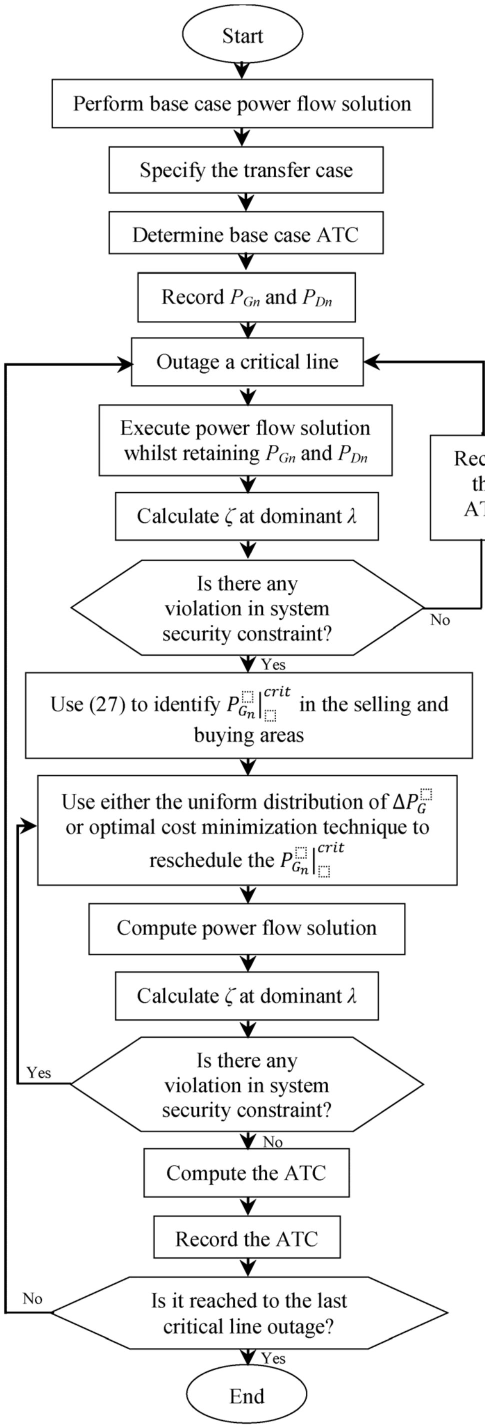

Fig. 1. Proposed procedure of generators rescheduling technique.

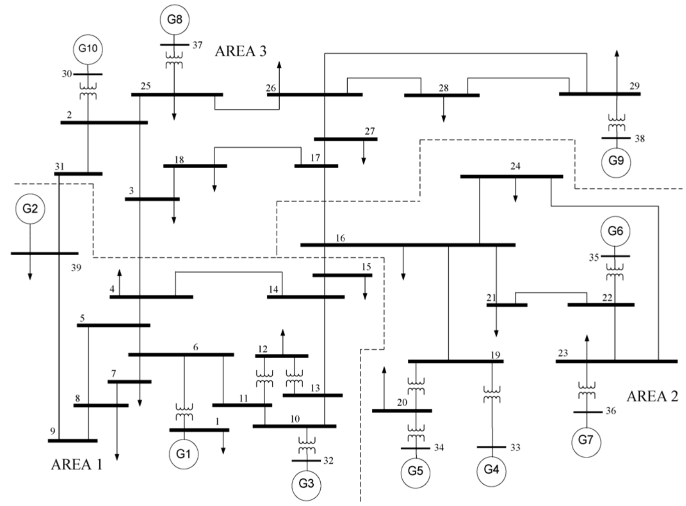

Fig. 2. New England 39-bus system.

load buses, and 46 transmission lines as [33]. The IEEE type DC-1 exciter [13] is installed at each generator. However, the generator is not equipped with PSS so that investigation could be made on the impact of proposed method directly towards the performance of critical generators rescheduling in damping out the inter-area oscillation. Detail information about the system is tabulated in the Appendix. The ATC is analyzed based on several cases of power transferred amongst the three areas configured in the New England 39-bus system.

The following discussion will elaborate further on several studies related to the rescheduling of critical generators for a new ATC determination. Firstly, Section VI-A will discuss on each scenario or transfer case particularly referring to the base case power transfer (base case value of ATC) without considering the impact of contingency and generator rescheduling. Secondly, Section VI-B will explain in detail on the most critical line outage resulting to a small-signal instability which only occurs at a particular scenario or transfer case during the base case value of ATC. In this section, the remaining scenarios or transfer cases are not afflicted with the small-signal instability albeit the most critical line outage imminent during the base case value of ATC. Eventually, in order to restore the small-signal instability, generator rescheduling will be performed only for the scenario or transfer case having the minimum ζ less than 3% and this will be discussed elaborately in Section VI-C and Section VI-D.

A. Stability of Small-Signal Based Minimum Damping Ratio at Base Case Power Transfer

This section will attest on the stability of small-signal based minimum damping ratio which is occurred during the base case ATC performed without taking into account the critical line outage. In conjunction to this matter, steps 5) and 9)–15) is not executed for the procedure discussed in Section V so that the critical line outage will not be included in the course of base case ATC determination.

Table I evince on the result of damping ratio corresponding to the base case ATC determined referring to each interarea transfer case. The damping ratio is computed by using (24) based on any eigenvalue which is indicated as a pair of complex number for the rotor angle mode. With regards to every transfer case, it is obviously seen that the rotor angle mode 38,39 can be categorized as dominant due to the least damping ratio exceeds slightly above 3% which occur at frequency oscillating below 1 Hz. The validity of this result can be observed by referring to the rotor angle mode 33,32 and 36,37 having a damping ratio which is greater and more stable compared to the damping ratio corresponding to the rotor angle mode 39,38. However, the system is said to be in a secure condition since there is no intrusion on the small-signal stability limit with all of the minimum ζ are above 3% [6].

B. Contingency Ranking Analysis

Table II present the results of the most critical line outage obtained from the contingency ranking analysis at base case area-

TABLE I
ROTOR ANGLES MODES, EIGENVALUES AND DAMPING RATIO AT LOW-FREQUENCY CONDITION OF BASE CASE POWER TRANSFER

Sell Area	Buy Area	Base case ATC (MW)	Rotor Angle Mode (Referring to the column number of matrix A_T)	Eigenvalues	Min. ζ (%)	Freq. (Hz)
1	2	180	33,32	-0.3185 ± j3.8174	8.32	0.56043
			37,36	-0.2358 ± j5.8592	4.02	0.92426
			39,38	-0.2160 ± j6.2675	3.45	0.99646
1	3	322	33,32	-0.3162 ± j3.8230	8.24	0.60845
			37,36	-0.2346 ± j5.8786	3.99	0.93561
			39,38	-0.2125 ± j6.2596	3.39	0.99624
2	1	277	33,32	-0.3452 ± j3.5213	9.76	0.56043
			37,36	-0.2314 ± j5.8073	3.98	0.92426
			39,38	-0.2084 ± j6.2610	3.32	0.99646
2	3	466	33,32	-0.3579 ± j3.4113	10.43	0.54292
			37,36	-0.2307 ± j5.7877	3.98	0.92114
			39,38	-0.2018 ± j6.2653	3.22	0.99715
3	1	343	33,32	-0.3569 ± j3.5617	9.97	0.56686
			36,37	-0.2490 ± j5.5272	4.50	0.87968
			39,38	-0.2360 ± j6.2245	3.79	0.99066
3	2	343	33,32	-0.3493 ± j3.6781	9.45	0.58538
			36,37	-0.2507 ± j5.5325	4.53	0.88052
			39,38	-0.2376 ± j6.2323	3.81	0.99191

to-area ATC performed on the New England 39-bus system. By referring to the contingency ranking assessment, the line outage with the least damping ratio value is chosen as the most critical line outage for a particular interarea base case power transfer. Hence, only the most critical line outage for every base case power transfer is stored and it is shown in Table II. In Table II, it is observed that the base case power of 343 MW transferred from selling area 3 to buying area 2 yielding to the most secure damping ratio of $\zeta = 3.31\%$ as compared to the other base case power transfer cases. It is noted that this damping ratio value is larger than the threshold small-signal stability limit of 3%. Hence, this damping ratio value implies that the occurrence of inter-area oscillation at the frequency of 0.92973 Hz has been damped effectively by the system itself and this is referring to the case study of selling area 3 to buying area 2. Furthermore, the power transfer of 343 MW is actually not limited due to the impact of inter-area oscillation. This means that the capability of the system to securely transfer the maximum power of 343 MW is basically limited by the physical capability of the transmission line. The same condition also experienced by the system for the other cases of power transfer such as from selling

TABLE II
POWER SYSTEM STABILITY CONDITION FOR THE AREA-TO-AREA BASE CASE POWER TRANSFER WITH THE MOST CRITICAL LINE OUTAGE

Area of Transfers		Base case value of ATC (MW)	Most Critical Line Outage	Dominant Eigenvalue (Mode 39)	ζ (%)	Freq. (Hz)
Sell Area	Buy Area					
1	2	180	13-14	-0.1871 + 5.8948i	3.17	0.93819
1	3	322	10-13	-0.1885 + 5.9765i	3.15	0.95118
2	1	277	8-9	-0.1859 + 6.0649i	3.07	0.96526
2	3	466	8-9	-0.1813 + 6.0839i	2.98	0.96828
3	1	343	15-16	-0.1907 + 5.8375i	3.27	0.92907
3	2	343	15-16	-0.1932 + 5.8417i	3.31	0.92973

area 1 to buying area 2, selling area 1 to buying area 3, selling area 2 to buying area 1 and selling area 3 to buying area 1. The minimum damping ratio of 3.17%, 3.15%, 3.07%, and 3.27% is obtained due to the outage of line 13-14, 10-13, 8-9, and 15-16, respectively. On the other hand, the most critical system condition for base case power transfer is obtained for the transfer case from selling area 2 to the buying area 3. This is due to the most minimum damping ratio of 2.98% which indicates the system is most poorly-damped due to the line outage of 8-9 while transferring 466 MW of power. The most poorly-damped inter-area oscillation occurs at 0.96828 Hz. For mitigation purposes, re-dispatching the generation is performed to this research.

For this reason, 3% is adequately chosen as the damping ratio limit for a secure system operation since significant reduction of damping ratio that is 2.98% emerged notably during the outage of most critical line 8-9 with 466 MW of power transferred from selling area 2 to buying area 3. The difference can be seen obviously comparing to a stable system condition with damping ratio above 3% (but not more than 4%) at the dominant rotor angle mode 39 for the rest of case studies shown in Tables I and II. By referring back to the base case power transfers without line outage depicted in Table I, it is worthwhile to mention that the rotor angle mode 39 is categorized as dominant due to the least damping ratio exceeds slightly above 3% which occur at frequency oscillating below 1 Hz. This approach is relatively similar to the concept introduced in [34] that used to determine the damping ratio limit particularly referring to the case of power transfer. The damping ratio limit of 3% is chosen in this case study in tandem with a typical machine operates with the oscillating frequency of about 1 Hz that would only contribute to a damping ratio of between 3% and 5% [35]. Indeed, the exact value of damping ratio limit will not be determined in this case study since it requires extensive number of sensitivity studies performed on the variations or perturbations of system operations and system parameters [35]–[37].

C. Improvement of Small-Signal Stability Based on a New Area-to-Area ATC Determined by Rescheduling the Critical Generator

The most critical line outage causing to the perturbation of small-signal stability can be recuperated by reducing the base case amount of ATC through the action of critical generators rescheduling. The previous analysis discussed in Section VI-B attested that the system is afflicted with the small

TABLE III
RESULT OF A NEW ATC AND SMALL-SIGNAL INSTABILITY IMPROVEMENT ASSOCIATED WITH THE RESCHEDULING OF CRITICAL GENERATORS

Area of Transfers		Most Critical Line Outage	Base case ATC		New ATC		Reduced Power Transfer (MW)
Sell Area	Buy Area		ATC (MW)	Min. ζ (%)	ATC (MW)	Min. ζ (%)	
1	2	13-14	180	3.17	180	3.17	NA
1	3	10-13	322	3.15	322	3.15	NA
2	1	8-9	277	3.07	277	3.07	NA
2	3	8-9	466	2.98	456	3.01	10
3	1	15-16	343	3.27	343	3.27	NA
3	2	15-16	343	3.31	343	3.31	NA

signal instability affirmed by the minimum ζ of 2.98% which is lower than 3% specified as the small-signal stability limit. The results can be acquired from Tables II and III. This scenario is happened as a consequence of outage at critical line 8-9 compounded with the impact of base case ATC of 466 MW for the transfer case from selling area 2 to buying area 3. Therefore, rescheduling the critical generators in both areas are performed as an effective action for improving the minimum ζ which capitulate to 3.01%. Consequently, the same result is acquired from the two proposed methods of generators rescheduling which are the uniform distribution of ΔP_G and optimization of energy market. This may yields to a new base case ATC value of 456 MW which is originated from the ATC of 466 MW after going through the power transfer reduction of 10 MW. The rescheduling process is executed by increasing the output power of critical generators in the buying area and this is reciprocal to the output power reduction of critical generators in the selling area. Prior to the execution of rescheduling process, the selection of critical generators in the selling and buying areas is performed beforehand by referring to the non-zero value of normalized participation factor associated with inter-area oscillation.

Based on the dominant rotor angle mode 38,39, a list of generators that shove toward the occurrence of inter-area oscillation during the base case ATC can be obtained by referring to the opposite sign of real right eigenvector (v) occur between the two groups of generators located in different area and this is shown in Table IV. By taking one case as an example, during the base case ATC, it is observed that generators G4 and G5 in area 2 are encountering opposite sign of real v with the generators G8 and G10 in area 3. This implies that generators G4 and G5 in area 2 are in the state of inter-area oscillate with the generators G8 and G10 in area 3. Thus, the selection of critical generator involved in rescheduling is only referring to the list of generators that shove toward the occurrence of inter-area oscillation and this will be discussed thoroughly in the following paragraph.

Fig. 3 elucidates on the result of normalized generator participation factor for all of the generators situated in the selling area 2 and buying area 3 inclusive with the outage of critical line 8-9 arisen during the inherent base case power transfer of 466 MW. The result is obtained before both of the proposed rescheduling techniques are performed as shown in Tables II and III. By referring to Fig. 3, the non-zero value of normalized participation factor indicates that the inter-area oscillation is incurred at the critical or highly participated generating units of G1, G3, G5, and G9. With regards to (27a), at a low frequency below 1 Hz, the inter-area oscillation can be seen as the correlation of $\Delta\delta$ as well as $\Delta\omega$ between the generators located in different areas. It is explicitly observed in Fig. 3 that the critical generator G9

TABLE IV
RIGHT EIGENVECTORS FOR THE DOMINANT ROTOR ANGLE MODE 38,39

Area	Generator Bus (Generator Number)	Mode 38,39
		Right Eigenvector
1	1 (G1/Slack)	0.6814 + j0.0534
1	39 (G2)	-0.0327 - j0.0042
1	32 (G3)	0.5317 - j0.0003
2	33 (G4)	-0.0349 - j0.0195
2	34 (G5)	-0.3529 + j0.0001
2	35 (G6)	0.1309 - j0.0449
2	36 (G7)	0.1239 - j0.0356
3	37 (G8)	0.0169 - j0.0014
3	38 (G9)	-0.5102 + j0.0454
3	30 (G10)	0.0939 + j0.0109

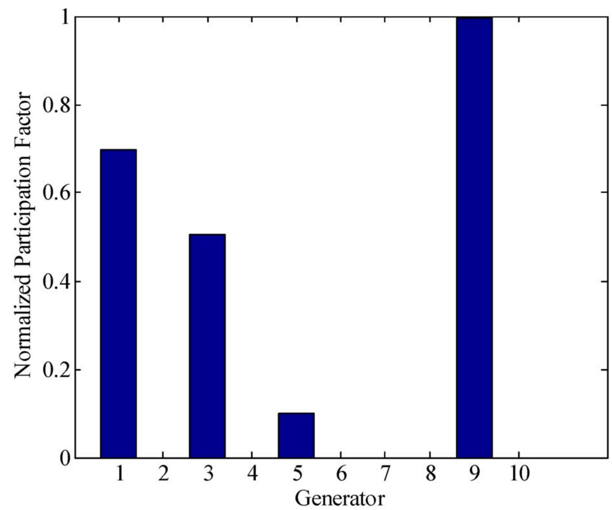

Fig. 3. Normalized participation factor of each generator for the base case power transfer from selling area 2 to buying area 3 with critical line outage of 8-9.

in buying area 3 is inter-area oscillates with the critical generator G5 in selling area 2 contributing to a poorly minimum ζ of 2.98% occurred at the low frequency of 0.96828 Hertz as shown in Tables II and III. In order to significantly improve the minimum ζ, rescheduling is performed between the two critical or highly participated generators by reducing the output power of generator G5 in selling area 2 as opposed to the amount of increased output power at generator G9 in buying area 3. A significant improvement of small-signal instability can be perceived in Table III when the minimum ζ is increased up to 3.01% that is slightly above the specified limit and the base case power transfer of 466 MW is reduced to 456 MW. This is the same result given by the two proposed methods used for solving the generators rescheduling problem. Therefore, the new ATC value of 456 MW is used as a reference to ensure a secure power transferred from selling area 2 to buying area 3 without violating the small-signal stability threshold limit and other system constraints during the outage of critical line 8-9.

Further analysis is carried out on the output power of all generators referring to the four case studies which are base case system condition, base case power transfer without rescheduling the $P_{G_n}|^{crit}$, new ATC after rescheduling the $P_{G_n}|^{crit}$ using Method 1 and new ATC after rescheduling the $P_{G_n}|^{crit}$ using Method 2 shown in Table V. Method 1 signifies for the case of critical generators selection using normalized participation

TABLE V
OUTPUT POWER OF EACH GENERATING UNIT BEFORE AND AFTER RESCHEDULING PROCEDURES
FOR ATC DETERMINATION CONSIDERING THE OUTAGE OF MOST CRITICAL LINE 8-9

Area	Gen. Bus (Gen. Num.)	Base Case Gen. (MW)	Generation Capacity during Power Transfer with Outage of Most Critical Line 8-9										
			Before Reschedule (MW)	After Rescheduling						Mismatch (MW) in Comparison with Before Rescheduling			
				Critical Generators Selection Using NPF Technique			Critical Generators Selection Using WAS Technique						
				NPF Index	Output Power for Method 1 (MW)	Output Power for Method 2 (MW)	WAS Index	Output Power for Method 3 (MW)	Output Power for Method 4 (MW)	Method 1	Method 2	Method 3	Method 4
1	1 (G1 /Slack)	541	550	0.70	550	550	-6.26×10^{-4}	550	550	0	0	0	0
1	39 (G2)	1000	1000	0	1000	1000	-0.03×10^{-4}	1000	1000	0	0	0	0
1	32 (G3)	650	650	0.51	650	650	-3.73×10^{-4}	650	650	0	0	0	0
2	33 (G4)	632	757.32	0	757.32	757.32	-0.71×10^{-4}	746.24	744.86	0	0	-11.08	-12.47
2	34 (G5)	508	608.74	0.10	598.74	598.74	-18.86×10^{-4}	599.82	605.20	-10	-10	-8.92	-3.53
2	35 (G6)	650	778.89	0	778.89	778.89	0.49×10^{-4}	778.89	778.89	0	0	0	0
2	36 (G7)	560	671.05	0	671.05	671.05	0.29×10^{-4}	671.05	671.05	0	0	0	0
3	37 (G8)	540	540	0	540	540	0.20×10^{-4}	547.88	548.49	0	0	7.88	8.50
3	38 (G9)	830	830	0.99	840	840	29.02×10^{-4}	842.12	837.51	10	10	12.12	7.51
3	30 (G10)	250	250	0	250	250	-0.37×10^{-4}	250	250	0	0	0	0
Optimal Cost of Generators Rescheduling ($/h)						3120			3896.10				
ATC			Base Case ATC = 466 MW		New ATC = 456 MW	New ATC = 456 MW		New ATC = 446 MW	New ATC = 450 MW				
Min. ζ (%)			2.98		3.0067	3.0067		3.0148	3.0013				

*Remarks
NPF: Normalized Participation Factor.
WAS: Weighted-Average Sensitivity.
Method 1: Normalized Participation Factor and Uniform Distribution of ΔP_G.
Method 2: Normalized Participation Factor and Optimal Cost Minimization.
Method 3: Weighted-Average Sensitivity and Uniform Distribution of ΔP_G.
Method 4: Weighted-Average Sensitivity and Optimal Cost Minimization.

factor and the uniform distribution of ΔP_G is used for critical generators rescheduling. On the other hand, Method 2 represents for the case of critical generators selection using normalized participation factor and critical generators rescheduling are performed based on the optimal cost minimization. For the three cases of power transfer with and without rescheduling the $P_{G_n}|^{crit}$, the results of generator output power are still referring to the transfer case of selling area 2 and buying area 3 associated with the outage of critical line 8-9. Simultaneously, the results articulate on the output power for all generators in selling area 2, which is significantly different compared to the base case system condition. The increased of generation in selling area 2 and load demand in buying area 3 will induce the power transfer for the cases of before and after rescheduling the generators. By referring back to Table III, it is worthy to mention again that the attainment of Method 1 and Method 2 in generators rescheduling is the same result of new ATC equal to 456 MW obtained from the reduction of 466 MW which represents as the base case ATC before the rescheduling process is performed. Similar for both cases of Method 1 and Method 2, the reduction to a new ATC value of 456 MW is attributed by the increased output power of 840 MW at generator G9 in buying area 3 for compensating 10 MW reduction of output power yielding to 598.74 MW at generator G5 in buying area 2. Simultaneously, by rescheduling both critical generators of G9 and G5, it can be seen that the small-signal stability is procured by improving the minimum ζ of 3.01% which exceeds the limit of 3%. Compendium of the results is that the normalized participating factor plays an important role in rescheduling the critical generators for significant improvement of small-signal instability occurred during the power transfer with the outage of critical line. Efficacy of the proposed rescheduling techniques are verified through performance comparison with the existing index known as weighted-average sensitivity of stability index which was developed by Chung *et al.* [6]. This will be discussed elaborately in the next section.

D. Performance Comparison between the Normalized Participation Factor and the Weighted-Average Sensitivity of Stability Index Technique for Critical Generators Rescheduling

The section explicates on the effectiveness of normalized participation factor in critical generators selection which will improve the performance of generation rescheduling hence consummates small-signal stability of the system and the result is compared with the weighted-average sensitivity of stability index developed in [6]. The comparison is performed to assess the competency of both selection techniques toward rescheduling the critical generators and also its tangible impact to a new value of ATC without contravenes the damping ratio limit of 3%. In short, the weighted-average sensitivity of stability index is used to evaluate the performance of each generating unit which adversely effect on the dominant rotor angle mode stability emerged in the course of power transfer. The positive value of the stability index implies that the critical generators shall be increased and vice-versa so that the rescheduling process will elevates small-signal stability of the system. The performance comparison between the two techniques used to select several critical generators for rescheduling is endeavored in accordance with the previous case study of power transferred from selling area 2 to buying area 3 taking into consideration the outage of critical line 8-9 and this is exemplified in Table V. Once the critical generators are selected either by using the normalized participation factor or weighted-average sensitivity method, then rescheduling the selected critical generators are performed either by using the uniform distribution of ΔP_G or optimal cost minimization. Therefore, the analysis is carried out thoroughly based on the four combinations of generator selection and rescheduling techniques namely as Method 1, Method 2, Method 3, and Method 4. It is worthwhile to notify that Method 1 signifies for the case of critical generators selection using normalized participation factor and the uniform distribution of ΔP_G is used for critical generators rescheduling. On the other hand, Method 2 represents for the case of critical generators selection using normalized participation factor and critical generators rescheduling are performed based on the optimal cost minimization. This is followed by Method 3 denoted as the name for critical generators selection using weighted-average sensitivity and uniform distribution of ΔP_G is used for critical generators rescheduling. Method 4 is regarded as the name for critical generators selection using weighted-average sensitivity and optimal cost minimization is used in the critical generators rescheduling. In addition, the analysis is also performed with an attempt to investigate vigorousness of the combined critical generators selection technique and rescheduling technique which will utterly improves the ATC value with regards to the damping ratio limit attained throughout the outage of critical line.

Tabulation of the results shown in Table V unravels the output power generations for the two conditions of base case as well as the four methods used for generators rescheduling. It is worthwhile noting that the selection of critical generators is performed during the base case ATC value of 466 MW. The proposed critical generators selection technique is executed yielding to the values of normalized participation factor index similar to those results depicted in Fig. 3. Once the selection of critical generators is confirmed with the obtained indexes, rescheduling process is executed instantaneously either by using Method 1 or Method 2 for the determination of new ATC values. By means of weighted-average sensitivity of stability index particularly used in Method 3, the rescheduling process is conducted by reducing the total output power of 20 MW at both critical generators G4 and G5 having negative index in selling area 2 which is counterweigh by the increased total output power of 20 MW at critical generators G8 and G9 with positive index in buying area 3. Generators G6 and G7 delineated with the positive index in selling area 2 as well as the generator G10 delineated with the negative index in selling area 2 are not considered in the rescheduling process. It is obvious that for more than one critical generator were involved in the respective areas, Method 3 that used to reschedule the output power generation shall be distributed proportionally among the critical generators. This is equivalent to the generators rescheduling concept used in Method 1 which

TABLE VI
BUS DATA FOR NEW ENGLAND 39-BUS SYSTEM

No.	Type	Load Demand		Generation		Vm (p.u)
		P (MW)	Q (MVAr)	P (MW)	Q (MVAr)	
1	SL	9.2	4.6	0	0	0.9820
2	PQ	0	0	0	0	1.0000
3	PQ	322	2.4	0	0	1.0000
4	PQ	500	184	0	0	1.0000
5	PQ	0	0	0	0	1.0000
6	PQ	0	0	0	0	1.0000
7	PQ	233.8	84	0	0	1.0000
8	PQ	522	176	0	0	1.0000
9	PQ	0	0	0	0	1.0000
10	PQ	0	0	0	0	1.0000
11	PQ	0	0	0	0	1.0000
12	PQ	7.5	88	0	0	1.0000
13	PQ	0	0	0	0	1.0000
14	PQ	0	0	0	0	1.0000
15	PQ	320	153	0	0	1.0000
16	PQ	329	32.3	0	0	1.0000
17	PQ	0	0	0	0	1.0000
18	PQ	158	30	0	0	1.0000
19	PQ	0	0	0	0	1.0000
20	PQ	628	103	0	0	1.0000
21	PQ	274	115	0	0	1.0000
22	PQ	0	0	0	0	1.0000
23	PQ	247.5	84.6	0	0	1.0000
24	PQ	308.6	-92	0	0	1.0000
25	PQ	224	47.2	0	0	1.0000
26	PQ	139	17	0	0	1.0000
27	PQ	281	75.5	0	0	1.0000
28	PQ	206	27.6	0	0	1.0000
29	PQ	283.5	26.9	0	0	1.0000
30	PV	0	0	650	0	1.0475
31	PQ	0	0	0	0	1.0000
32	PV	0	0	650	0	0.9831
33	PV	0	0	632	0	0.9972
34	PV	0	0	508	0	1.0123
35	PV	0	0	650	0	1.0493
36	PV	0	0	560	0	1.0635
37	PV	0	0	540	0	1.0278
38	PV	0	0	830	0	1.0265
39	PV	1104	250	1000	0	1.0300

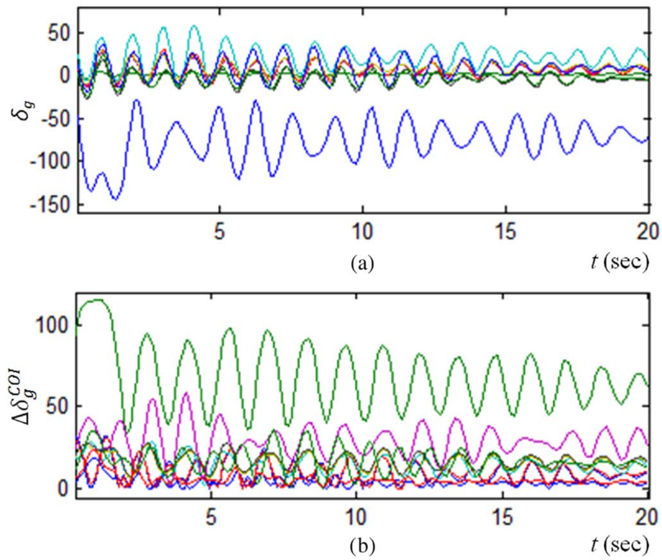

Fig. 4. Results of (a) generator rotor angles (δ_g) and (b) difference between relative rotor angles and centre of inertia $(\Delta\delta_g^{COI})$, determined by using Method 1 and Method 2.

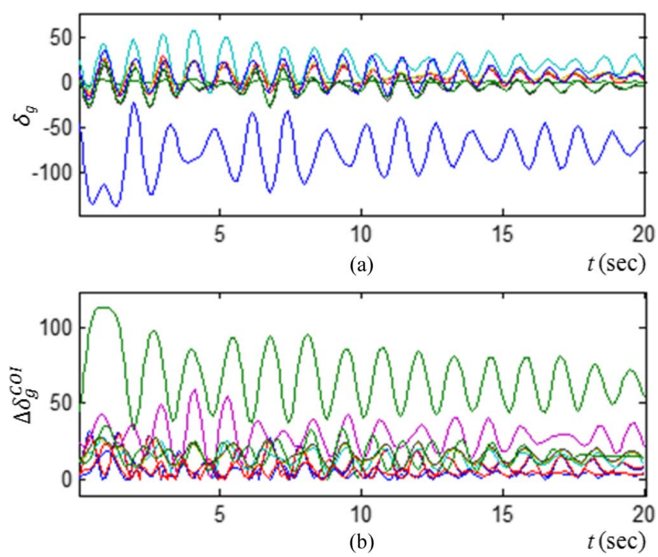

Fig. 5. Results of (a) generator rotor angles (δ_g) and (b) difference between relative rotor angles and centre of inertia $(\Delta\delta_g^{COI})$ determined by using Method 3.

basically based on the ratio of output power for a critical generator with respect to the sum of output power for all critical generators. Therefore, the consequence of stability index based weighted-average sensitivity used for critical generators selection in Method 3 is that it will substantially reduce the base case power transfer by 20 MW to elevate the minimum ? above the small-signal stability limit of 3%. Table V attest that the proposed technique of Method 1 confers a new value of ATC which is 10 MW higher than the result obtained by using the Method 3. With regards to Method 1, this is similarly happened to Method 2 that also provides a new ATC value with 10 MW higher than the result obtained by using Method 3. Once more, the effectiveness of normalized participation factor in critical generator selection is proven by improving the performance of Method 1 and Method 2 yielding to a new ATC value with

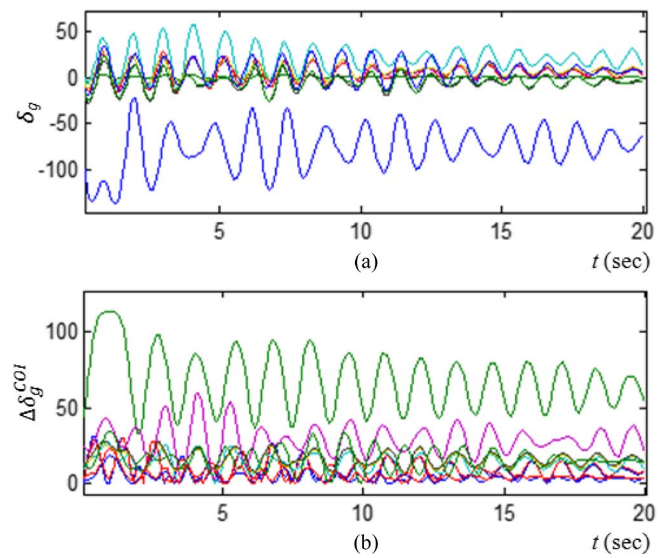

Fig. 6. Results of (a) generator rotor angles (δ_g) and (b) difference between relative rotor angles and centre of inertia $(\Delta\delta_g^{COI})$ determined by using Method 4.

TABLE VII
ADDITIONAL AND OPPORTUNITY COST COEFFICIENTS OF EACH GENERATOR FOR ENERGY BIDDING

Bus No	α^+ (\$/MWh)	β^+ (\$/MWh^2)	α^- (\$/MWh)	β^- (\$/MWh^2)
1	5	15.4	5	30
39	3	15.6	2.7	12
32	2.5	14.6	2.5	14
33	3	13.2	2.1	13
34	3.9	15.8	2.9	21
35	4	17	3.8	22
36	2.5	16.3	4	29
37	4.3	14.4	3.5	23
38	3	10.2	2.7	21
30	4.3	27.6	2.7	17

6 MW higher than the result provided by Method 4. This signifies that the normalized participation factor used in Method 1 and Method 2 can be considered as an effective method in selecting only a few best critical generators for rescheduling process and hence, maximum permissible amount of new ATC is attained while emphasizing on the small-signal stability limit of the system. The results given by Method 1 and Method 2 also prove that only two generators which are G5 and G9 located in area 2 and area 3, respectively are actually encounter high participation of swing mode which become major contributors to the violation of damping ratio limit. Hence, generators rescheduling executed only at G5 and G9 are sufficient to improve the damping ratio. This is in contrast with the results given by Method 3 and Method 4 indicating that G4 and G8 involved in the generators rescheduling have less significant impact on improving the damping ratio. In addition, the normalized participation factor used in Method 2 tangibly improves the cost minimization of generators rescheduling that is less than the weighted-average sensitivity used in Method 4. This signifies that the normalized participation factor used for accurate selection of critical generators in rescheduling is a crucial task so that improvement of damping ratio can be achieved more easily through a better value of ATC with the least cost minimization of generators rescheduling. In addition, the proposed method

TABLE VIII
TRANSMISSION LINE BUS DATA FOR NEW ENGLAND 39-BUS SYSTEM

From Bus	To Bus	R (p.u)	X (p.u)	B (p.u)	MVA Rating	Tap Ratio
31	2	0.0035	0.0411	0.6987	250	0
31	39	0.0010	0.025	0.7500	250	0
2	3	0.0013	0.0151	0.2572	750	0
2	25	0.0070	0.0086	0.1460	500	0
3	4	0.0013	0.0213	0.2214	250	0
3	18	0.0011	0.0133	0.2138	100	0
4	5	0.0008	0.0128	0.1342	250	0
4	14	0.0008	0.0129	0.1382	500	0
5	6	0.0002	0.0026	0.0434	1000	0
5	8	0.0008	0.0112	0.1476	500	0
6	7	0.0006	0.0092	0.1130	750	0
6	11	0.0007	0.0082	0.1389	500	0
7	8	0.0004	0.0046	0.0780	500	0
8	9	0.0023	0.0363	0.3804	250	0
9	39	0.0001	0.0250	1.2000	250	0
10	11	0.0004	0.0043	0.0729	750	0
10	13	0.0004	0.0043	0.0729	500	0
13	14	0.0009	0.0101	0.1723	500	0
14	15	0.0018	0.0217	0.3660	100	0
15	16	0.0009	0.0094	0.1710	500	0
16	17	0.0007	0.0089	0.1342	500	0
16	19	0.0016	0.0195	0.3040	1000	0
16	21	0.0008	0.0135	0.2548	500	0
16	24	0.0003	0.0059	0.0680	250	0
17	18	0.0007	0.0082	0.1319	500	0
17	27	0.0013	0.0173	0.3216	250	0
21	22	0.0008	0.0140	0.2565	1000	0
22	23	0.0006	0.0096	0.1846	250	0
23	24	0.0022	0.0350	0.3610	750	0
25	26	0.0032	0.0323	0.5130	250	0
26	27	0.0014	0.0147	0.2396	500	0
26	28	0.0043	0.0474	0.7802	250	0
26	29	0.0057	0.0625	1.0290	500	0
28	29	0.0014	0.0151	0.2490	500	0
12	11	0.0016	0.0435	0	100	1.006
12	13	0.0016	0.0435	0	100	1.006
6	1	0	0.0250	0	1000	1.070
10	32	0	0.0200	0	1000	1.070
19	33	0.0007	0.0142	0	1000	1.070
20	34	0.0009	0.0180	0	1000	1.009
22	35	0	0.0143	0	1000	1.025
23	36	0.0005	0.0272	0	1000	1.000
25	37	0.0006	0.0232	0	1000	1.025
2	30	0	0.0181	0	500	1.025
29	38	0.0008	0.0156	0	1000	1.025
19	20	0.0007	0.0138	0	250	1.060

TABLE IX
TWO-AXIS MACHINE DATA FOR NEW ENGLAND 39-BUS SYSTEM

Bus No	X_l (p.u.)	R_a	X_d (p.u)	X'_d (p.u)	T'_{do} (sec)	X_q (p.u)	X'_q (p.u)	T'_{qo} (sec)	H (sec)
1	0.0350	0	0.2950	0.070	6.56	0.282	0.170	1.50	30.3
30	0.0130	0	0.1000	0.031	10.2	0.069	0.069	0	42.0
32	0.0300	0	0.2500	0.053	5.70	0.237	0.088	1.50	35.8
33	0.0295	0	0.2620	0.044	5.69	0.258	0.166	1.50	28.6
34	0.0540	0	0.6700	0.132	5.40	0.620	0.166	0.44	26.0
35	0.0224	0	0.2540	0.050	7.30	0.241	0.081	0.40	34.8
36	0.0322	0	0.2900	0.049	5.66	0.280	0.186	1.50	26.4
37	0.0280	0	0.29000	0.057	6.70	0.280	0.091	0.41	24.3
38	0.0298	0	0.2106	0.057	4.79	0.205	0.059	1.96	34.5
39	0.0030	0	0.0200	0.0063	7.00	0.019	0.008	0.70	54.0

TABLE X
IEEE TYPE DC-1 EXCITER DATA FOR NEW ENGLAND 39-BUS SYSTEM

Gen. No.	K_A	T_A	K_F	T_F	Vr_{max} (p.u.)	Vr_{min} (p.u.)	K_E	T_E	$S_{E,1}$	$S_{E,2}$	$E_{fd,1}^*$	$E_{fd,2}^*$
39	5	0.06	0.1	1	1	-1	0	0.46	0.1	0.33	2.3	3.1
32	6	0.06	0.1	1	1	-1	0	0.46	0.1	0.33	2.3	3.1
33	5	0.06	0.1	1	1	-1	0	0.46	0.1	0.33	2.3	3.1
34	5	0.06	0.1	1	1	-1	0	0.46	0.1	0.33	2.3	3.1
35	40	0.02	0.1	1	1	-1	0	0.46	0.1	0.33	2.3	3.1
36	40	0.02	0.1	1	1	-1	0	0.46	0.1	0.33	2.3	3.1
37	40	0.02	0.1	1	1	-1	0	0.46	0.1	0.33	2.3	3.1
38	5	0.02	0.1	1	1	-1	0	0.46	0.1	0.33	2.3	3.1
30	40	0.02	0.1	1	1	-1	0	0.46	0.1	0.33	2.3	3.1

provides a straightforward solution to select the best critical generators which will be a useful and cost-effective approach for rescheduling process especially involving a large interconnected system.

The transient response of δ_g for all generators can be observed in Fig. 4 until Fig. 6, respectively. The attainment of transient stability subsequent to generators rescheduling using Methods 1, 2, 3 and 4 can be perceived through $\Delta\delta_g^{COI}$ that is the difference between relative rotor angles with respect to the centre of inertia (COI).

VII. CONCLUSION

This paper has presented on the importance of small signal stability analysis required for the damping stability improvements with the aid from a new ATC determined by rescheduling the critical generator that takes into account the outage of critical line. A straightforward explanation on the concept of small-signal stability has clarified on the issues related to the derivation of system matrix or eigenvalue required for developing the formulations of normalized participation factor and damping ratio. The utilization of inter-area oscillation in normalized participation factor can be considered as an novel, ominous and cost-effective approach for selecting the best critical generators which endeavour in enhancing robustness of the proposed rescheduling technique to determine the maximum permissible amount of ATC while retaining the stability of damping ratio during the outage of critical line. In addition, comparison with the other techniques have proven that the proposed rescheduling technique gives a larger value of new ATC and the damping ratio is still retained slightly above its specified limit.

APPENDIX

Table VI lists the bus data for a New England 39-bus system. Table VII lists the additional and opportunity cost coefficients of each generator for energy bidding. Table VIII lists the transmission line bus data for a New England 39-bus system. Table IX lists the transmission line bus data for a New England 39-bus system. Table X lists the IEEE Type DC-1 Exciter Data for a New England 39-bus system.

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Muhammad Murtadha Othman (M'05) received the B.Eng. (Hons) degree from Staffordshire University, U.K., in 1998, the M.Sc. degree from Universiti Putra Malaysia in 2000, and the Ph.D. degree from Universiti Kebangsaan Malaysia in 2006.

He is currently an Associate Professor at the Faculty of Electrical Engineering, Universiti Teknologi Mara, Malaysia. His areas of research interests are artificial intelligence, energy efficiency, transfer capability assessment, demand side management, power system stability, and reliability studies in a deregulated power system.

Stendley Busan received the B.Eng. (Hons.) and M.Sc. degrees in electrical engineering from Universiti Teknologi Mara, Malaysia, in 2009 and 2012, respectively.

He is a Project Engineer at the Thermal and Renewable Division, Mott MacDonald (M) Sdn Bhd, Kuching, Sarawak. His responsibility is to provide professional services to the clients for a few projects in terms of its deliverables, internal procedures, and contract management preparation tasks. In addition to that, he also is involved with the preparation of Technical and Commercial for tender proposal purposes. His areas of research interests are transfer capability assessment and stability studies in a deregulated power system.