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Identification of critical generating units for maintenance: a game theory approach

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Abstract: With the rapid evolution of electricity markets and the need for higher economic efficiency of power industry, attempts for lowering down the maintenance costs as a large portion of system operation expenses seem imperative. Recognised as a crucial step in practical implementation of modern maintenance paradigms, e.g. reliability-centred maintenance, this study proposes an efficient method to quantify the generating units' criticality on the bulk power system reliability performance. The proposed approach utilises a solution concept of game theory and evaluates the contribution of each generating unit on the overall system reliability when a higher-order contingency occurs. The suggested framework would lead to a fair identification of critical units in restructured power systems for more focused maintenance activities and also helps in recognising where investments should be made to improve the system reliability. The effectiveness of the proposed approach is confirmed through implementation on the IEEE 24-bus reliability test system.

Nomenclature

Sets

I_{BB}	set of total buses in the system
$I_{E_i}^{\mathrm{GU_{DN}}}$, $I_{E_i}^{\mathrm{GU_{UP}}}$	set of the failed and on-line generating units during outage event i
I_{GU}, I_{GU,Z_m}	set of total generating units and generating units in zone m
I_{GU}^n	set of total generating units at bus n
I_{GU_R}	set of total generating units providing reserve
I_D	set of total demands in the system

Variables

$\boldsymbol{b}_g^t$	the cost allocated to generating unit g at time t associated with an imputation vector
$\boldsymbol{B}_{i,m}^{g,t}$	imputation vector of outage event i of order m at time t including generating unit g
EOC_i^t	expected cost of outage event i at time t
P_g^t, $P_g^{c_i,t}$	real power generation of unit g in normal and contingency i conditions at time t
P_d, $P_d^{c_i}$	real power demand d in normal and contingency i conditions
P_d^n, Q_d^n	real and reactive power demand d at bus n
P_{jnm}, Q_{jnm}	real and reactive power flow of line j connecting bus n to m
Q_g^t, $Q_g^{c_i,t}$	reactive power generation of unit g in normal and contingency i conditions at time t
$r_g^{\mathrm{up},t}$, $r_g^{\mathrm{dn},t}$	upward and downward reserve quantity of generating unit g at time t
TC_i^t	total consequences of outage event i at time t
V_n, δ_n	voltage magnitude and angle at bus n
δ_{nm}	voltage angle difference between bus n and m
$\Psi_{g,i,t}^{\mathrm{Sh}}$, $\Psi_{g,i,t}^{\mathrm{Sh^W}}$, $\Psi_{g,i,t}^{\mathrm{Nu}}$, $\Psi_{g,i,t}^{\mathrm{Ba}}$	contribution of generating unit g in outage event i at time t using the Shapley value, weighted Shapely value, Nucleolus, and Banzhaf value concepts, respectively.

Parameters

$E_{i,m}^g$	outage event i of order m including generating unit g
f_i	frequency of outage event i
FOR_g	forced outage rate of generating unit g
g^N	the collection of all characteristic functions
$\boldsymbol{G}_{nm}$	element nm of the conductance matrix
k_{nm}^{sh}	shunt susceptance of the line connecting bus n to bus m
$\boldsymbol{K}_{nm}$	element nm of the susceptance matrix
$P_g^{\max}$, $P_g^{\min}$	max. and min. active generation limit for generating unit g
$Q_g^{\max}$, $Q_g^{\min}$	max. and min. reactive power limit for generating unit g
$R_{Z_m}^{\mathrm{up},t}$, $R_{Z_m}^{\mathrm{dn},t}$	upward and downward reserve requirement of zone m at time t
$r_g^{\mathrm{up,\,max}}$, $r_g^{\mathrm{dn,\,max}}$	max. upward and downward reserve of generating unit g at time t
$S_j^{\max}$	maximum apparent power flow of line j
$\mathrm{Sh}(v)$	Shapley value function of v
$\mathrm{Sh}^{\mathrm{w}}(v, \boldsymbol{w})$	weighted Shapley value function of v with the weight vector $\boldsymbol{w}$
$V_n^{\max}$, $V_n^{\min}$	max. and min. voltage magnitude at bus n
$\xi_{g,i}^t$	binary parameter denoting the status of generating unit g in the outage event i
$\lambda_{d,\ i}$	departure rate of an outage event i
η_n^t	electricity price of generation bus n hosting generating unit g at time t
$\delta_n^{\max}$, $\delta_n^{\min}$	max. and min. voltage angle at bus n
μ_g, λ_g	repair and failure rates of generating unit g

ϑ_d^t	load shed price of demand d at time t
Δ_g^{up}, Δ_g^{dn}	physical upward and downward ramp rate of generating unit g
π_i	probability of outage event i
$\pi_{i,m}^{t,g}$	probability of contingency i of order m due to the outage of generating unit g at time t
Φ	characteristic function of outage events

Functions

$C_g(P_g^t)$, $C_g^{\mathrm{R}}(r_g^t)$	energy and reserve cost functions of unit g

1 Introduction

1.1 Motivation and problem description

Reliability enhancement in power systems, although conflicting in nature with the common cost saving policies of electric utilities, needs to be ensured since customer satisfaction is closely driven by the reliable and high quality electricity. Hence, reliability assessment has always been a key requirement in the utility planning and operation practices [1]. Among the policies commonly adopted for system reliability improvement, maintenance activities are regarded as a must-do effort to maintain the equipment availability and performance over time. While maintenance costs constitute a large portion of operational expenses, frequency reduction of maintenance leads to catastrophic damages caused by increased number of forced outages.

Reliability centred maintenance (RCM) is a cost-effective maintenance paradigm where cost and reliability requirements are compromised techno-economically. RCM implementation on large-scale power transmission systems, however, is very complicated due to the system highly non-linear and complex characteristics. Quantitative assessment of the connection between equipment and system reliability has become a challenge for independent system operators (ISOs) in further decision making on the optimal operation, maintenance and investment policies [2].

In restructured power systems, taking into account the criticality of generating units in order to coordinate the generation maintenance schedules by the ISOs may have a remarkable impact on the system reliability improvement. Hence, identification of generating units' importance degree (so called criticality) for system reliability is the key. However, with increasing competition in restructured power systems, allocating costs such as unexpected outage costs in extreme events to the involved components in a reasonable way is challenging. This paper deals with fair and efficient identification of critical generating units from the system reliability standpoint, which can be used to design a payment mechanism for unexpected outages and initiate the RCM implementation in practice more systematically.

1.2 Literature review

Considerable efforts are devoted to the application of RCM, some in different industries [3–5] and some in electric domain. Among the latter category, there are some notable works on RCM implementation in power distribution systems: In [6], a sensitivity analysis approach is employed to investigate the changes in system load point reliability indices for component prioritisation. Traditional reliability indices are employed in [7] to estimate the outage consequences and schedule maintenance of equipment such as circuit breakers. A method was introduced in [8] to insert the experts' knowledge and expertise into the RCM implementation through fuzzy analytical hierarchy process. Authors in [9–11] have introduced comprehensive frameworks for practical implementation of RCM in distribution systems. Authors in [12, 13] included the expected outage costs (EOCs) in RCM evaluations for transmission networks to optimise the maintenance practices. Authors in [14] try to identify the components criticality from various perspectives in transmission grid. While there are valuable attempts in the literature for implementation of RCM in power distribution and transmission systems, application of such modern maintenance schemes in the electric generation domain is found quite scarce.

To implement the RCM in electric power generation paradigm, it is first and foremost essential to recognise the critical generating units. In restructured electric power systems, various methods for maintenance scheduling in electric power generation domain have been proposed. The maintenance outages in generation systems are typically planned based on an iterative approach between generating companies (GENCOs) and ISO and using an appropriate incentive-based and/or dis-incentive-based mechanisms [15, 16]. In another major category of research on generation system maintenance, ISO plans the maintenance schedules in accordance with some forms of 'willingness to pay' strategy announced by GENCOs and system adequacy [17, 18]. In such approaches, recognising the criticality of generating units by the ISO to set up the appropriate incentives/ dis-incentives or to maximise the collecting bids can have a significant impact on the system reliability enhancement decisions.

1.3 Highlights and contributions

With the increased complexity of network due to deregulation, providing a robust solution to recognise the system critical generating units has gained a significant importance. To the best of the authors' knowledge, there are very few applicable approaches reported in the literature to guarantee a fair identification of critical components in power systems. The reported techniques are commonly based on the conventional sensitivity analysis, whereas in dealing with the complex and highly non-linear power systems, the consequence corresponding to simultaneous outages of two components or more at a time can be far more severe than that estimated by summing individual single-order contingencies. Hence, allocation of financial consequences to system equipment based on the conventional techniques may not be accurate and effective.

Different from previous efforts, this paper proposes an economic criticality index for generating units in power systems. The main contributions of this paper are as follows:

- In conventional approaches to identify the system critical components, the impact of one component outage on the overall system reliability is considered. The performance indicators are usually highlighted by several traditional reliability indices developed based on load curtailment observations. However, the most probable first order contingencies in electric power systems usually do not impose any load interruptions. The proposed approach in this paper is on allocation of outage monetary consequences to the involved generating units in the case of all single-order and higher-order contingencies using new performance indicators.
- To evaluate the impact of generating units failure on the overall system reliability, proper modelling of market implications is imperative. In response, a criticality index reflecting the degree of importance for each generating unit is proposed where the costs from re-dispatch operations as well as the customer interruptions are taken into account in a deregulated energy and reserve market environment.
- Allocation of overall system costs due to outages to generating units in a fair and efficient mechanism is a complicated issue in the complex and non-linear electricity grid especially when it comes to higher-order contingencies. A game theoretical concept is proposed in this paper that ensures a fair and equitable solution for allocation of all the system imposed costs to the involved generating units and recognition of critical units for system reliability. By 'fair allocation', we mean a reasonable and rational distribution of the outage consequences to the generating units through which their optimum performance in electricity market would be guaranteed.

The proposed methodology is designed based on a solution concept of cooperative game theory to prioritise the generating units with respect to their criticality and outage contribution to the system reliability performance. Each contingency can be represented as a game with the system generating units as the players in which the game solution is the optimum determination of the unit shares. The criticality measure for each generating unit would be quantified by ISOs, and considered as the penalty coefficients that GENCOs would be responsible for in the case of any unexpected outage. While being generic enough to be adapted to all types of system equipment, the proposed approach would recognise the system critical generating units, which in turn, would initiate the RCM process and enhance other reinforcement decisions.

2 Recognition of critical generating units in power systems: proposed game theoretic approach

To accomplish a fair identification of critical generating units from the reliability perspective, the imposed costs to the system due to the outage of each unit is considered as the criticality index reflecting the degree of its importance for maintenance priorities. This section elaborates the analytical procedure and the proposed technique for assessment of an integrated generating unit criticality index reflecting its contribution in the cases of contingencies.

2.1 Problem formulation: single-order contingencies

In the case of single-order contingencies, the imposed cost to the system is regarded as the outage consequence of one specific equipment, i.e. the failed equipment. Generally, occurrence of an unplanned outage or an unforeseen event in the operation time frame influences some variables such as voltage magnitudes, line flows, etc. Meanwhile, ISO is responsible to maintain the system security by generation re-dispatch, purchase of energy from the specified reserve sources, or initiating load shedding actions to migrate the system to a new operating state ensuring a safe and economic performance. In a competitive electricity market environment, ancillary services are provided to maintain system reliability and security which can be dispatched together with the energy either simultaneously or sequentially. In this paper, the simultaneous forms of auctions, frequently used in integrated power systems, are considered. To determine the amount of energy and reserve for each generating unit, as well as the locational marginal prices (LMP) at each bus, the ISO optimises the social welfare by minimising the total cost of energy and reserve while satisfying power flow, ancillary service requirements, and transmission operating constraints [19]. While DC power flow is frequently approached by the ISOs due to simplicity and computational efficiency, AC formulations are adopted in this paper for more accuracy. The ISO optimisation objective function is formulated below

$$\min_{\theta,V,P,Q,r} \sum_{g\in I_{GU}} C_g(P_g^t) + \sum_{g\in I_{GU_R}} C_g^R(r_g^{\mathrm{up},t}) + \sum_{g\in I_{GU_R}} C_g^{\mathrm{R}}(r_g^{\mathrm{dn},t}) \tag{1}$$

Subject to

$$\sum_{g\in I_{GU}^n} P_g^t - \sum_m V_n V_m(\boldsymbol{G}_{nm}\cos\delta_{nm} + \boldsymbol{K}_{nm}\sin\delta_{nm}) - P_d^n = 0, \quad \forall n \quad (\eta_n^t) \tag{2a}$$

$$\sum_{g\in I_{GU}^n} Q_g^t - \sum_m V_n V_m(\boldsymbol{G}_{nm}\sin\delta_{nm} - \boldsymbol{K}_{nm}\cos\delta_{nm}) - Q_d^n = 0, \quad \forall n \tag{2b}$$

$$P_{jnm} = V_n V_m(\boldsymbol{G}_{nm}\cos\delta_{nm} + \boldsymbol{K}_{nm}\sin\delta_{nm}) - \boldsymbol{G}_{nm}V_n^2, \quad \forall j \tag{2c}$$

$$Q_{jnm} = V_n V_m(\boldsymbol{G}_{nm}\sin\delta_{nm} - \boldsymbol{K}_{nm}\cos\delta_{nm}) + V_n^2(\boldsymbol{K}_{nm} - k_{nm}^{\mathrm{sh}}), \quad \forall j \tag{2d}$$

$$P_{jnm}^2 + Q_{jnm}^2 \le (S_j^{\max})^2, \quad \forall j \tag{2e}$$

$$\delta_n^{\min} \le \delta_n \le \delta_n^{\max}, \quad \forall n \in I_{BB} \tag{2f}$$

$$V_n^{\min} \le V_n \le V_n^{\max}, \quad \forall n \in I_{BB} \tag{2g}$$

$$P_g^{\min} \le P_g^t \le P_g^{\max}, \quad \forall g \in I_{\mathrm{GU}} \tag{2h}$$

$$Q_g^{\min} \le Q_g^t \le Q_g^{\max}, \quad \forall g \in I_{GU} \tag{2i}$$

$$0 \le r_g^{\mathrm{up},t} \le \min(r_g^{\mathrm{up,\,max}}, \Delta_g^{\mathrm{up}}), \quad \forall g \in I_{\mathrm{GU_R}} \tag{2j}$$

$$0 \le r_g^{\mathrm{dn},t} \le \min(r_g^{\mathrm{dn,\,max}}, \Delta_g^{\mathrm{dn}}), \quad \forall g \in I_{\mathrm{GU_R}} \tag{2k}$$

$$P_g^t + r_g^{\mathrm{up},t} \le P_g^{\max}, \quad \forall g \in I_{\mathrm{GU_R}} \tag{2l}$$

$$P_g^{\min} \le P_g^t - r_g^{\mathrm{dn},t}, \quad \forall g \in I_{\mathrm{GU_R}} \tag{2m}$$

$$\sum_{g\in I_{\mathrm{GU},Z_m}} r_g^{\mathrm{up},t} \ge R_{Z_m}^{\mathrm{up},t}, \quad \forall m \tag{2n}$$

$$\sum_{g\in I_{\mathrm{GU},Z_m}} r_g^{\mathrm{dn},t} \ge R_{Z_m}^{\mathrm{dn},t}, \quad \forall m \tag{2o}$$

Constraints (2a) and (2b) represent two sets of N_b non-linear nodal active and reactive power balancing equations. The LMP, denoted by (η_n^t), is corresponding to Lagrange multiplier associated with the power balance constraint (2a). Network constraints (2c) and (2d) represent branch active and reactive power flow limits measured at bus n in direction towards bus m. The inequality constraints (2e) consist of two sets of N_l apparent power flow limits corresponding to the 'from' and 'to' ends of each branch. Constraints (2f) and (2g) reflect equality upper and lower limits on all bus voltage phase angles and magnitudes. Supply constraints are presented in (2h)and (2i); and (2j)–(2o) are capacity reserve constraints. Constraints (2j) and (2k) reflect the reserve for each generating unit that must be positive and limited above by a reserve offer quantity as well as the physical ramp rate of the unit (Δg). For the sake of simplicity, a set of fixed zonal spinning (or synchronised) reserve constraints is considered in this work as ancillary service requirements. Constraint (2l) and (2m) enforce that the total amount of energy plus upward reserve of the generating unit does not exceed its capacity and the amount of energy minus downward reserve of the generating unit is limited to its minimum capacity. Constraint (2n) and (2o) are enforced to ensure that enough amount of capacity is procured according to the reserve requirements in each region [19]. The assisting reserve capacities in other zones can be considered by applying the equivalent assisting unit approach described in [20], where the assistance reserves from another zone scan be represented by an equivalent multi-state unit which describes the potential ability of one zone to accommodate capacity deficiencies in the other. The assisting reserve types of the equivalent unit can be categorised according to their required deployment response time in multi-zone power systems [21, 22]. This paper is primarily focused on the energy and spinning reserve market environment. Note that the proposed framework is generic enough to be equipped with the other types of operating reserves such as rapid start units, hot reserve units, interruptible loads and assistance reserve from other zones.

To evaluate a true and more realistic financial consequences following a generating unit contingency, both the customer interruption cost that the utility is responsible for [23, 24] and the cost of energy purchases from the reserve sources in the deregulated environment are considered as the consequence imposed to the system. In restructured power systems, demands can also offer prices which is called 'demand reduction bid' in demand response programs to control their loads [25], and the accepted offers for each load point can be considered as the customer interruption cost. For each contingency, ISO tries to

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minimise the following objective

$$\min \mathrm{TC}_i^t = \mathrm{EPPC}_i^t + \mathrm{ELSC}_i^t = \sum_{g \in I_{\mathrm{GU}}} \left(\eta_n^t \left(P_g^{c_i,t} - P_g^t \right) \right) + \sum_{d \in I_D} \left(\vartheta_d^t \left(P_d^t - P_d^{c_i,t} \right) \right) \quad (3)$$

The set of constraints for this optimisation are (2a)–(2g) as well as the following constraints

$$Q_g^{\min} \xi_{g,i}^t \le Q_g^{c_i,t} \le Q_g^{\max} \xi_{g,i}^t \quad (4a)$$

$$\left(P_g^t - r_g^{\mathrm{dn},t} \right) \xi_{g,i}^t \le P_g^{c_i,t} \le \left(P_g^t + r_g^{\mathrm{up},t} \right) \xi_{g,i}^t \quad (4b)$$

Outage of generating units in an outage event i is modelled through a vector of binary parameters, $\xi_{g,i}^t$, with 1 denoting the availability of components and 0 otherwise. Constraints (4a) and (4b) enforce the output of generating unit g to zero if it is failed in the outage event i. If generating unit g is available, the changes of its active power output are limited to the predetermined reserve margins. If in case of a contingency, one or several constraints including branch apparent power flow, voltage phase angles and magnitudes, and generating units' capacity violates its desired limit, a violation penalty is added to the objective function.

Having the above optimisation model solved in face of an outage, the reliability indices can be calculated as follows [20, 26]

$$\mathrm{EOC}_i^t = \pi_i \times \mathrm{TC}_i^t \quad (5a)$$

$$\pi_i = \prod_{g \in I_{E_i}^{\mathrm{GUDN}}} \frac{\lambda_g}{\left(\mu_g + \lambda_g \right)} \times \prod_{g \in I_{E_i}^{\mathrm{GUUP}}} \frac{\mu_g}{\left(\mu_g + \lambda_g \right)} \quad (5b)$$

In (5a), the imposed EOC to the system due to contingency i is assessed by multiplying the occurrence probability and consequence of the outage event [see (3)]. Using the common two-state Markov model with independent component failure, the probability of each contingency is calculated in (5b) considering the availability of online components and unavailability of the failed ones. Note that in systems where the $N-1$ reliability criterion is ensured, load shedding is not allowed for a single-order contingency and high-order contingencies are consequently of more significance; however, contracted loads can be interrupted and, hence, single-order outage analysis is still important.

2.2 Problem formulation: higher-order contingencies

In case of higher-order contingencies, where several components are involved in an imposed financial consequence, the optimisation problem with the objective function in (3) is solved to re-dispatch the generating units economically while maintaining the system security. The proposed approach in this paper employs the state enumeration technique for the reliability assessment of power system. The monetary contribution of each component corresponding to each higher-order contingency is identified by utilising the concept of cooperative games. When a critical higher order contingency occurs, this situation can be better represented as a transferable utility (TU) cooperative game with generating units as the players through which a finite set of units impose certain amounts of costs. There are numerous methods for cost allocation among the players to determine how to divide the joint costs resulted from the cooperation. The paper idea is founded based on the concepts of cooperative game approaches including Shapley value game theory (SVGT), weighted Shapley value game theory (WSVGT), Nucleolus game theory, and Banzhaf game theory.

We first introduce the proposed cooperative concepts of game theory for recognition of critical generating units. Let $n_E \ge 2$ denote the number of failed generating units in a high-order contingency E, and let N_E denote the set of such components. Each outage event involving a generating unit of set N_E can be defined as a coalition, S_E, which is a subset of N_E. Φ_E is a consequence function from the set of all subsets of contingency E to $R(\Phi_E{:}2^N \to R)$ that can be represented as a characteristic function such that $\Phi_E(\phi) = 0$. Consequence function, $\Phi_E(S_E)$, gives the maximum cost incurred by the outage event S_E, which is equal to TC_{S_E} and is obtained using (3). The cost allocation vector $\boldsymbol{B}^E = (b_1^E, \ldots, b_n^E)$ is actually a distribution of the costs which is grand and individually rational, and any allocation vector that satisfies group rationality lies in the core of the game. Indeed, the core may be empty especially in the electric power network cost allocation problem as conditions may not be rationality satisfied [27]. Accordingly, we are dealing, in this paper, with the game approaches based on the concept of a value.

2.2.1 Shapley value game theory approach:

A value function H is a (single valued) solution which assigns an $|N|$ dimensional real vector in the form of $H(\Phi_E) = [h_1(\Phi_E), \ldots, h_n(\Phi_E)]$ to each possible consequence of an n-order contingency, where H represents the share of failed generating units in a contingency E. A famous solution for a TU-game is the Shapley value which can be obtained by axioms consisting the efficiency, symmetry, null player and additivity properties for $H(\Phi_E)$. More information on the aforementioned properties is provided on a note in [28]. Let us consider the special consequence function $u_{S_E}(T_E)$ for all the $T_E \subset N_E$ as follows

$$u_{S_E}(T_E) = \begin{cases} 1 & \text{if } S_E \subset T_E \\ 0 & \text{otherwise} \end{cases} \quad (6)$$

From null player property, it can be concluded that the share of generating unit i, $h_i(u_{S_E})$ is zero if this unit is available and online during the outage event S_E. From symmetry axiom, $h_i(u_{S_E}) = h_j(u_{S_E})$ if both generating units i and j are involved in S_E and efficiency axiom results $h_i(u_{S_E}) = 1/|S_E|$ for all $i \in S_E$. It can be proved that every consequence $\Phi_E \in g^N$ can be expressed as below in (7) [28]

$$\Phi_E = \sum_{S_E \subset N_E} \Delta\Phi_{S_E} u_{S_E} \quad (7)$$

where the dividends are as follows

$$\Delta\Phi_{S_E} = \sum_{T_E \subset S_E} (-1)^{|S_E| - |T_E|} \Phi_E(T_E) \quad (8)$$

By applying additivity axiom, it can be shown that if a value function exists, it must be in the following form

$$Sh_i(\Phi_E) = \sum_{i \in S_E} \frac{\Delta\Phi_{S_E}}{|S_E|} \quad \forall i \in N_E \quad (9)$$

However, one of the axioms that characterises the Shapley value is the symmetry axiom; it can be used only when the parameters of the game for the generating units are completely symmetric which makes it sometimes unrealistic in practice. The parameter that has a significant impact on an outage event is the forced outage rates of generating units and may be different for even generating units of the same size and location. The impact of such parameters can be well considered in weighted Shapley value approach which will be described next.

2.2.2 Weighted Shapley value game theory approach:

Among the other value functions that do not need to be symmetric, but obeying the other axioms of Shapley, is the WSVGT. An example use of such a weighted Shapley value is the function $\mathrm{Sh}^{\mathrm{w}}: g^{N_E} \times R_+^{N_E} \to R^{N_E}$ given by:

$$\mathrm{Sh}_i^{\mathrm{w}}(\Phi_E, w) = \sum_{i \in S} \left(\frac{\mathrm{FOR}_i}{\sum_{j \in S} \mathrm{FOR}_j} \right) \Delta\Phi_{S_E} \quad \forall i \in N_E \tag{10}$$

where, $\boldsymbol{FOR} = [\mathrm{FOR}_1, \ldots, \mathrm{FOR}_n]$ is a weighting vector that assigns different positive weights to generating units. The main difference between this function and that in SVGT approach is that a share of the joint costs assigned to the generating units is proportional to its weight additional to its marginal contribution.

2.2.3 Nucleolus value game theory (NVGT) approach: The other value function is the NVTG, concept of which was introduced in 1969 [27]. The idea behind this approach is to find an imputation $\boldsymbol{B}^E = (b_1^E, \ldots, b_n^E)$ that minimises the worst inequity instead of applying a general axiomatisation of fairness to a value function defined over set of all characteristic functions. As a measure of $\boldsymbol{B}^E$ for an outage event S_E, the excess is defined as

$$e_{\Phi_E}(\boldsymbol{B}^E, S_E) = \sum_{i \in S_E} b_i^E - \Phi_E(S_E) \tag{11}$$

This excess gives an indication of how dissatisfied outage event S_E is with the proposed imputation $\boldsymbol{B}^E$; that is, it measures the amount by which an outage event surpasses its maximum potential $\Phi_E(S_E)$, in the allocation $\boldsymbol{B}^E$. The Nucleolus is calculated as a solution with fairness by minimising the maximum excess; whenever the core is non-empty, the nucleolus belongs to the core. In this procedure for a fixed allocation $\boldsymbol{B}^E$, the outage event with the largest excess is found and $\boldsymbol{B}^E$ is adjusted to make this largest excess smaller [27].

2.2.4 Banzhaf value game theory (BVGT) approach: Banzhaf value, similar to the SVGT, assigns an expected marginal allocation to generating units. It ensures that every generating unit is equally likely to be involved in any outage event whereas the Shapley value assumes that every generating unit is equally likely to join any outage event of the same order and all coalitions with the same order are equally likely to exist. Given that $\beta: g^{N_E} \to R^{N_E}$, we will have

$$\beta_i(\Phi_E) = \frac{1}{2^{|N_E|-1}} \sum_{i \in S_E} \left(\Phi(S_E) - \Phi(S_E \backslash \{i\}) \right) \quad \forall i \in N_E \tag{12}$$

First part of the above equation gives the probability of any generating unit jointing to a particular outage event and the difference part gives the marginal contribution that any particular generating unit makes to the outage event [29]. The Banzhaf player satisfies the null player as well as the fairness properties while does not meet the efficiency condition.

2.3 Overall contributions of generating units to system outages

Having calculated the contribution of each generating unit in all possible contingencies, the contributions could be summed up and the total monetary index for each generating unit can be assessed through (13a)–(13d).

$$\Psi_{g,i,t}^{\mathrm{Sh}} = \sum_m \sum_i \pi_{i,m}^{g,t} \left[\sum_{S \subset E_{i,m}^g} \sum_{T \subset S} \frac{(-1)^{|S|-|T|} \mathrm{TC}_T^t}{|S|} \right] \tag{13a}$$

$$\Psi_{g,i,t}^{\mathrm{Sh^W}} = \sum_m \sum_i \pi_{i,m}^{g,t} \left[\sum_{S \subset E_{i,m}^g} \frac{\mathrm{FOR}_g}{\sum_{k \in S} \mathrm{FOR}_k} \sum_{T \subset S} (-1)^{|S|-|T|} \mathrm{TC}_T^t \right] \tag{13b}$$

$$\Psi_{g,i,t}^{\mathrm{Nu}} = \sum_m \sum_i \pi_{i,m}^{g,t} \times \boldsymbol{b}_g^t, \quad \boldsymbol{b}_g^t \in \boldsymbol{B}_{i,m}^{g,t} \tag{13c}$$

$$\Psi_{g,i,t}^{\beta} = \sum_m \sum_i \pi_{i,m}^{g,t} \left[\frac{1}{2^{\left|E_{i,m}^g\right|}} \sum_{S \subset E_{i,m}^g} [\mathrm{TC}_S^t - \mathrm{TC}_{S \backslash \{g\}}^t] \right] \tag{13d}$$

Equations (13a)–(13d) represent the contribution of system generating units in the total imposed costs of outages, calculated via the suggested SVGT, WSVGT, NVGT, and BVGT concepts, respectively. Equation (13a) is derived from the concept of Shapley value which satisfies the Shapley axioms. Equation (13c) utilises the Nucleolus concept by minimising the worst inequity and obtaining the optimal imputation. In (13a), (13c) and (13d), the probability of outage events is considered as a driving factor while in (13b), the forced outage rate of generating units is, instead, considered as the most important factor. The criticality degree of generating units may vary over time due to the changes in system topology, load, and operating characteristics. The general framework proposed to identify the critical generating units for system reliability is presented in Fig. 1.

3 Numerical case study

The IEEE RTS 24-bus test system is selected as the test bed in this paper for case studies. This system is composed of 32 generating units, 20 load points, 24 buses, and 38 transmission lines, with the maximum generation capacity of 3405 MW serving total demand of 2850 MW [30]. The suggested framework is applied to determine the criticality degree of generating units from the reliability perspective in a monthly time horizon taking into account the system peak load profiles in a one-year period. Other data such as bidding strategies in energy and reserve markets and economic variables are presented in [31]. All the system load points are assumed to be composed of 20% dispatchable load which is offered in 2.5% of value of lost load (VOLL) per MW and 80% non-dispatchable load that is offered in VOLL price per MW. Generating unit output and energy reserves, load demand, LMPs are initially obtained from the energy and reserve market simulations in the system normal operating condition [32, 33]. The reserve requirement is considered equal to the capacity of the largest generating unit of the system. The studied non-linear optimisation problem and the required simulations are conducted in MATLAB environment using Matpower operating toolset [32]. We selected the default option provided in Matpower employing the primal-dual interior point solver called MIPS, for MATLAB Interior Point Solver. MIPS is a port of the primal dual interior point method solver for which the algorithm is extensively explored in [33, 34].

In the IEEE 24-bus RTS, transmission lines are assigned relatively high power flow limits compared with the power injected to the branches in normal condition. Therefore, it can be proved that only upward reserves would be mostly active if needed. Since the LMP is simply the sensitivity of overall objective function to a change in the load at a given bus and the Lagrangian can be taken for non-convex problems, the Lagrangian multiplier of (2a) is equal to the LMP [33]. Of course this is valid at the problem solution, which, in a non-convex problem, is not guaranteed to be a global solution; however, by deploying this solver, a local optimal solution is achieved [34–36].

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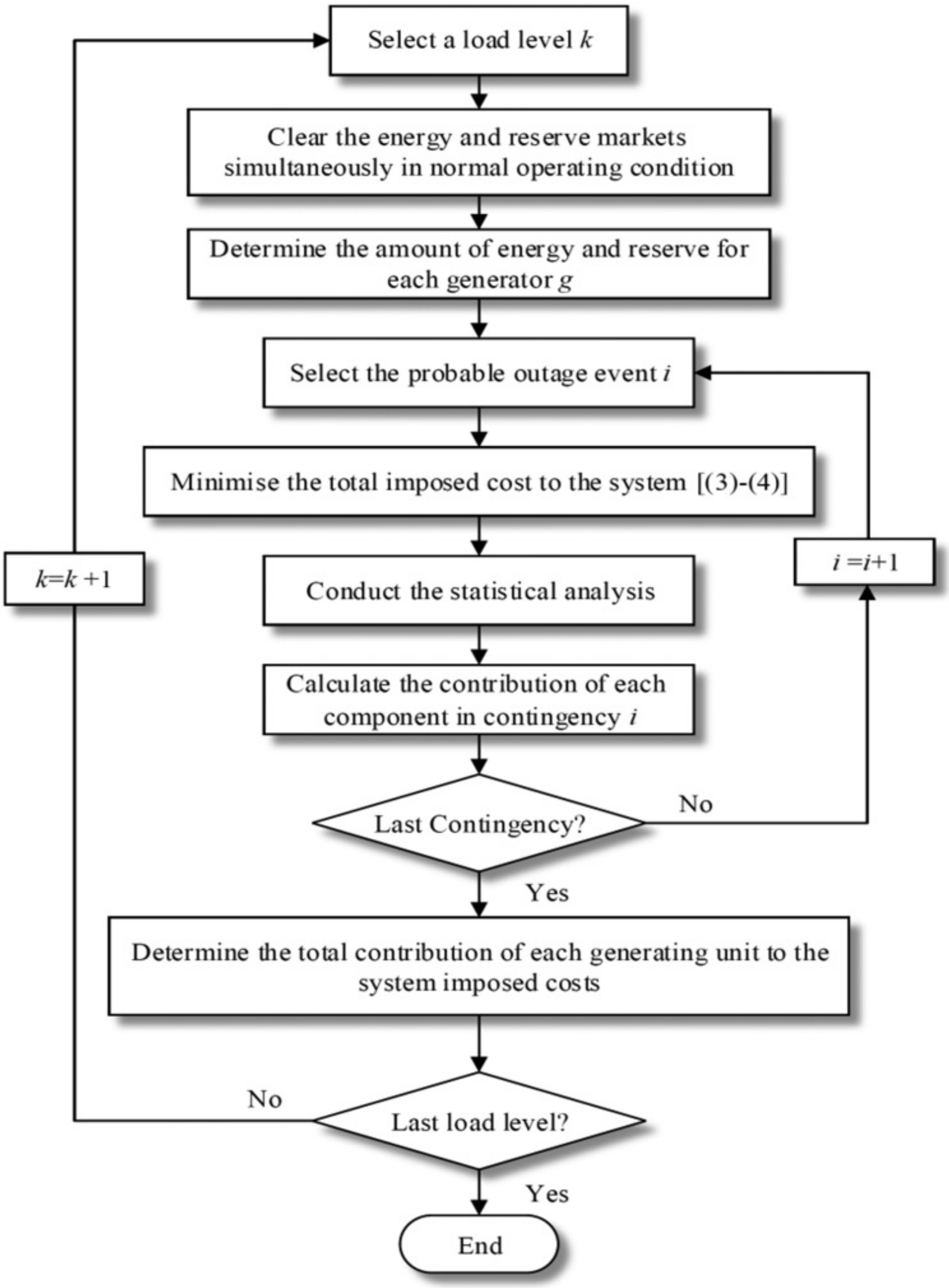

Fig. 1 *Flowchart of the proposed algorithm*

By simulating and analysis of all the possible outage events up to the fourth order of contingencies, the monthly reliability risk indices including loss of load probability (LOLP), expected demand not served (EDNS) both for individual load points and the overall system, and also the proposed criticality index are calculated. The LOLP and the EDNS calculated for the system delivery points during the studied 12 months are depicted in Fig. 2. The load point indices are highly dependent on the system load priority order. It can be seen that bus-bars 9, 12, 13, and 16 are assigned higher risk indices than the others, majorly due to their higher customer interruption costs. It can be also observed that system reliability performance varies over time depending on the system generation schedules and load patterns in different months.

Fig. 3 illustrates, through several indices of interests, the financial risk imposed to the system in the studied time horizon. The proposed indices can represent the total expected purchased power cost (EPPC) from the existing reserve in addition to the expected load shedding cost (ELSC) and also the EOC. It can be seen from this figure that the financial risk escalates with the increase in the system peak load (the peak load percentages are demonstrated by the horizontal axis corresponding to each month) and as a result, the criticality of generating units varies over time. One can also observe in Fig. 3 that the share of ELSC has higher impact on the system overall risk at each month than that of the EPPC. Having calculated the above financial risk indices imposed to the system at each month, the contribution of each generating unit to the imposed cost is determined by utilising the concept of cooperative games introduced earlier in Section 2. The contribution of each generating unit corresponding to the system critical buses (i.e. 9, 13, and 16) on the overall system LOLP and EDNS are quantified using the SVGT, WSVGT, BVGT, and NVGT concepts and are demonstrated in Figs. 4*a* and *b*, respectively. The proposed criticality measures, i.e. TC_i^t, corresponding to different generating units are also calculated and illustrated in Fig. 4*c* for the 100% load scenario and by employing the cooperative game concepts.

From the obtained results, it can be seen that the two 400 MW nuclear steam units located at buses 22 and 23 can impose more costs to the system due to the high capacity and the maximum

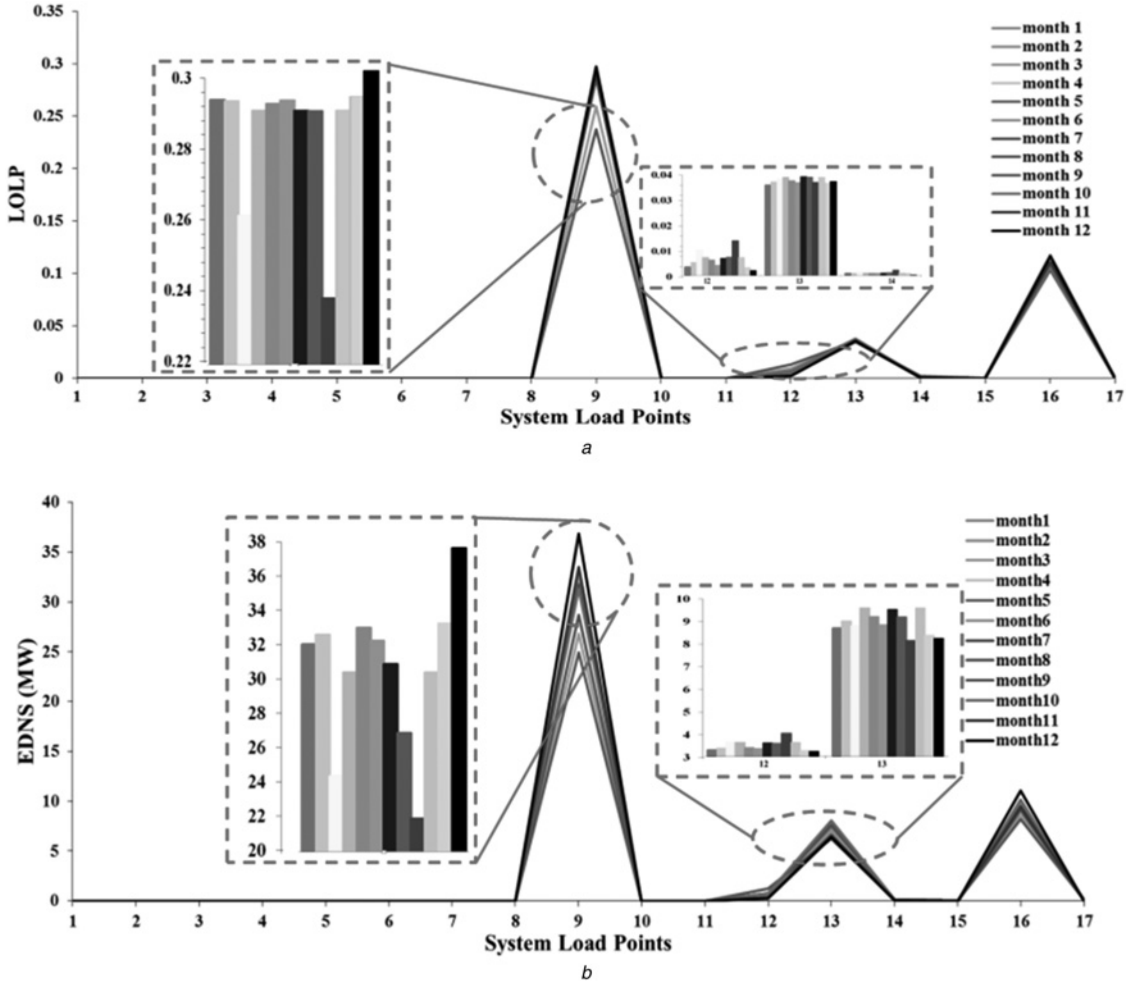

Fig. 2 *LOLP and the EDNS indices of system load points during the studied 12*
a LOLP
b EDNS

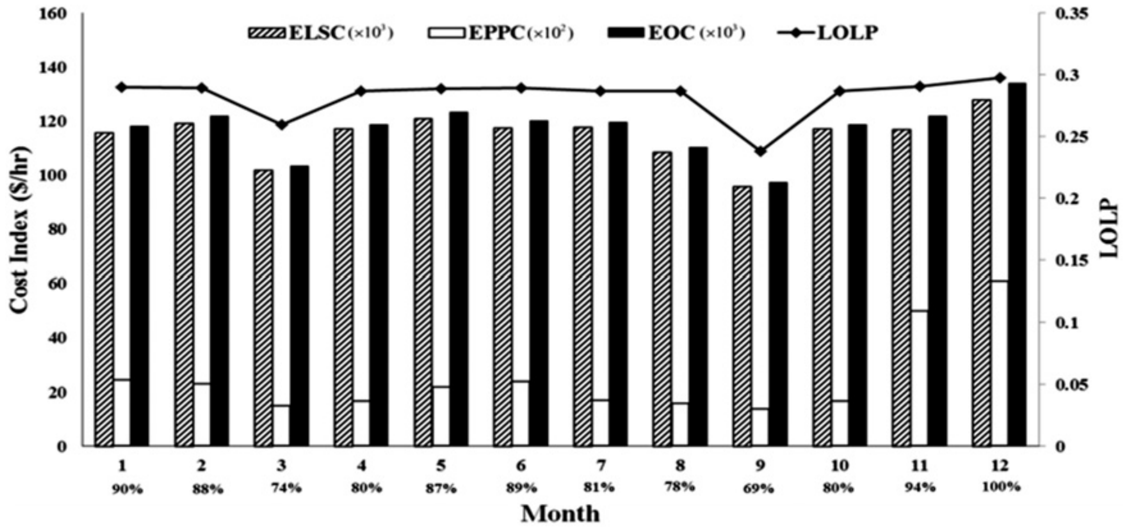

Fig. 3 *Financial risk and reliability criterion of the system in a one-year period: 100% load scenario*

utilisation factor in normal operating conditions and, hence, are identified as the most critical generating units of the system. From the results, it is also clear that the criticality of generating units majorly depends on the location and failure rate of the units in addition to their capacity. For instance, the criticality measure calculated for the 50 MW hydro unit at bus 22 is less than that for the combustion turbine units of 20 MW at buses 1 and 2, not only due to the lower failure rates, but also their position in the north of

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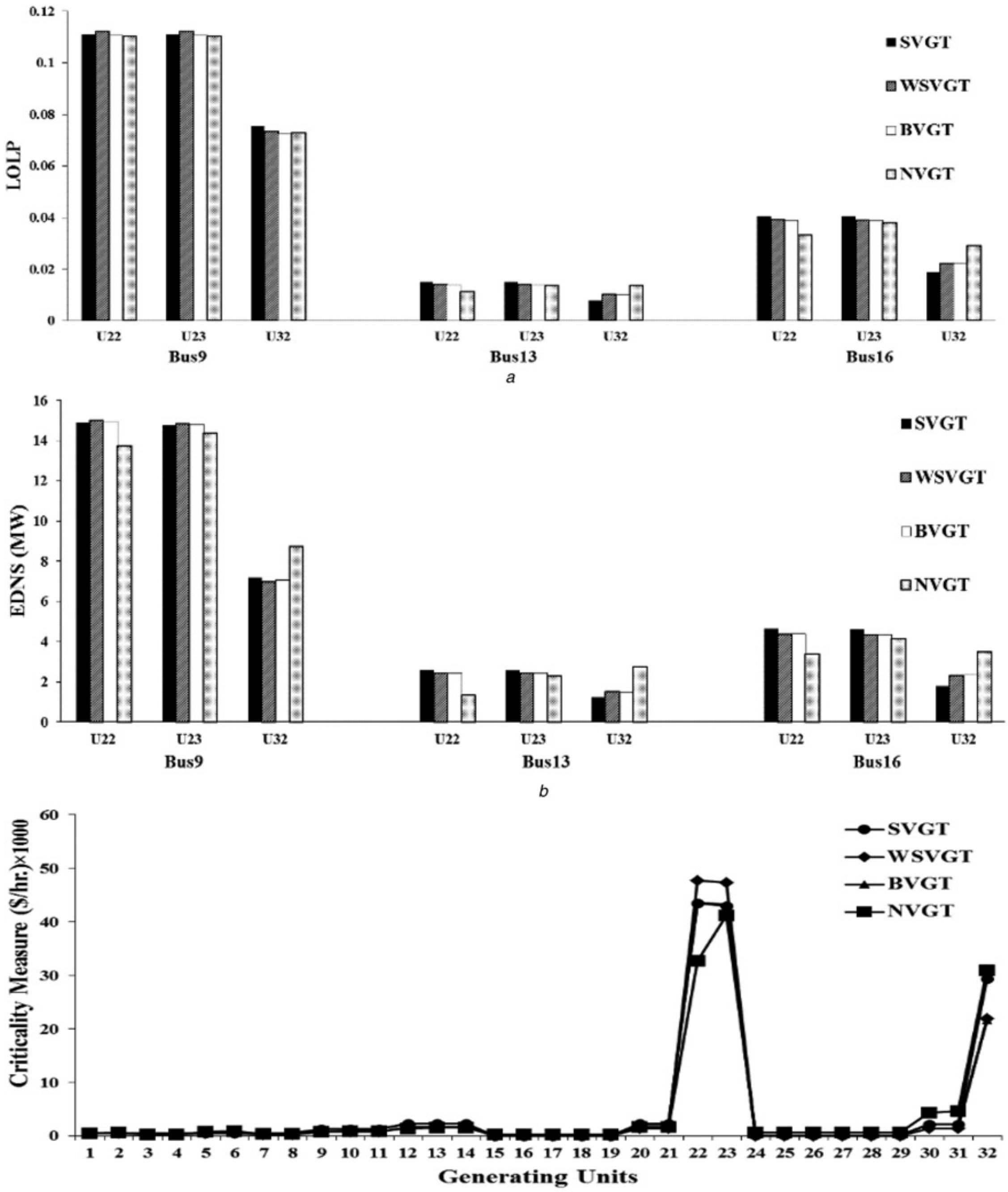

Fig. 4 *The contribution of each generating unit in LOLP, EDNS and criticality measure using the SVGT, WSVGT, BVGT, and NVGT concepts*

a LOLP of system critical load points
b EDNS of system critical load points
c Criticality measure of generating units on system overall reliability (all cases are studied in a %100 loading scenario)

the system attached to a less important bus-bar. The discussions presented next will further provide details on (i) comparison of the results using traditional reliability indices (EDNS and LOLP) and the proposed criticality index, and (ii) performance of various suggested cooperative game concepts.

4 Discussions

4.1 Performance of the suggested criticality measure

In this section, performance of the suggested criticality measure over the conventional LOLP-based and EDNS-based importance degrees for system generating units is compared. Fig. 5 demonstrates the impact of single outage of each generating unit on the overall system LOLP and EDNS reliability indices which is a common practice in former studies. If all the generating units are online, the overall system LOLP and EDNS indices in the base case condition are 0.2936 and 52.8755 MW, respectively. According to Fig. 5, outage of generating unit 32 has less impact on the LOLP index compared with the outage of generating units 12, 13, and 14. This observation is in contrast with that obtained previously in Fig. 4*c* using the proposed criticality degree. Similar conclusion is also valid when solely using the EDNS index: the EDNS-based criticality factors for generating units 20 and 21 are calculated higher than those for generating units 12, 13, and 14, while the former generating units have less capacity than the latter. Such observations highlight the fact that the impact of unit capacity cannot be considered accurately when solely using the conventional LOLP-and EDNS-based indices as a decisive factor. Fig. 6

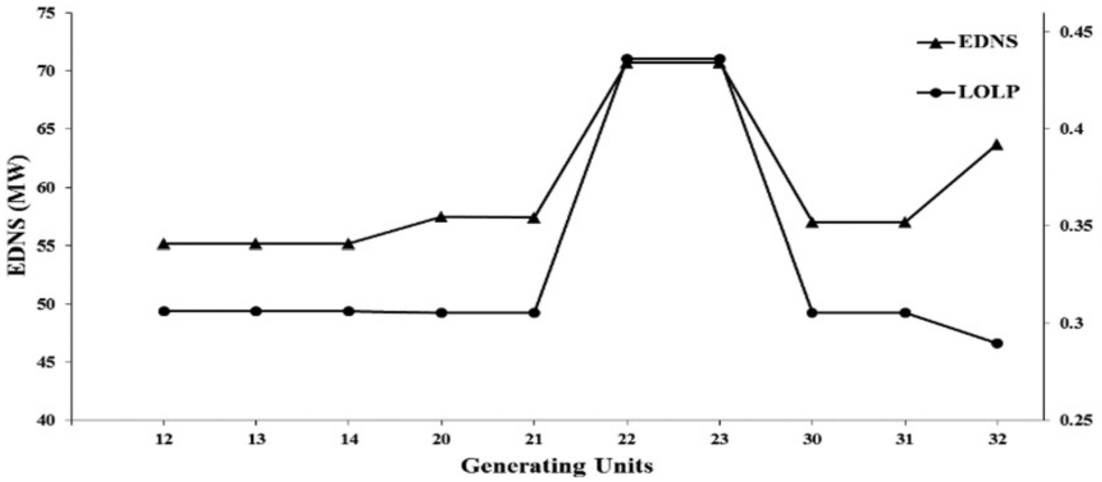

Fig. 5 *Traditional criticality of generating units based on LOLP and EDNS indices of reliability*

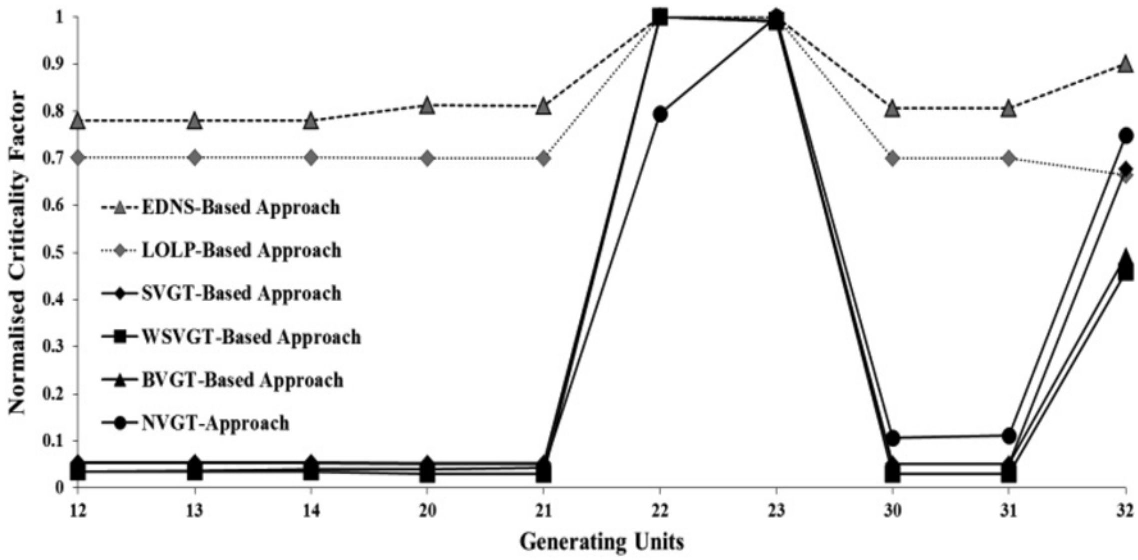

Fig. 6 *Comparison of traditional and the proposed criticality evaluation techniques for generating units*

demonstrates the criticality degrees of the selected generating units in a normalised manner with respect to the maximum criticality degree obtained through the corresponding evaluation approach. As it can be seen in this figure, if using the traditional EDNS- and LOLP-based indices as a measure of unit criticality, the criticality difference among generating units 22 and 23 compared with the others are much lower than those calculated via the suggested game concepts. Moreover, the traditional LOLP- and EDNS-based techniques conservatively assign a high level of criticality degrees to the selected generating units while the proposed game solutions can well differentiate the highly critical generating units over the non-critical ones, make it easier to make cost-effective maintenance and reinforcement decisions in power systems. The reason for this observation lies in the fact that the simultaneous outages involving generating units 22 and 23 with others cannot be reflected when using the traditional LOLP- and EDNS-based sensitivity analysis while it is well reflected using the proposed approach.

4.2 Performance comparison of the utilised game concepts

This section provides more details on the performance of each of the introduced cooperative game concepts in the assessment of system reliability and criticality measures of generating units. The results on the cost contribution of different generating units when the higher order contingencies occur are demonstrated in Figs. 7*a–d* employing the SVGT, WSVGT, BVGT, and NVGT techniques, respectively. As it can be seen in these figures, the two sets of generating units [12–14] or [29, 30], which have the same capacity and location in the system, are assigned an equal total contributions in the system costs that reflects the symmetry property of the SVGT, WSVGT and BVGT techniques. Comparisons of the results obtained via the four approaches reveals that the WSVGT method allocates a higher share to the generating units with higher probability of failure in each outage event which makes it more suitable in applications where the game players (here generating units) contribute to a system down state. In other words, in contrast with the other game theoretic approaches, the WSVGT approach can well differentiate the generating units with the same capacity and location, but different failure rates.

Comparing the results in Figs. 7*a* and *b*, it can be concluded that when employing the SVGT and WSVGT approaches, the sum of the total contributions of generating units in higher order outage events is equal to the total costs imposed to the system at month 12 which in second, third and fourth order contingencies are 47,147, 44,400 and 23,559 \$/h, respectively. This highlights the efficiency property of these two methods discussed earlier in the paper. Moreover, from the total contribution of generating units using different techniques, it can be observed that the sum of the EPPC and ELSC indices is always equal to the EOC in each higher order

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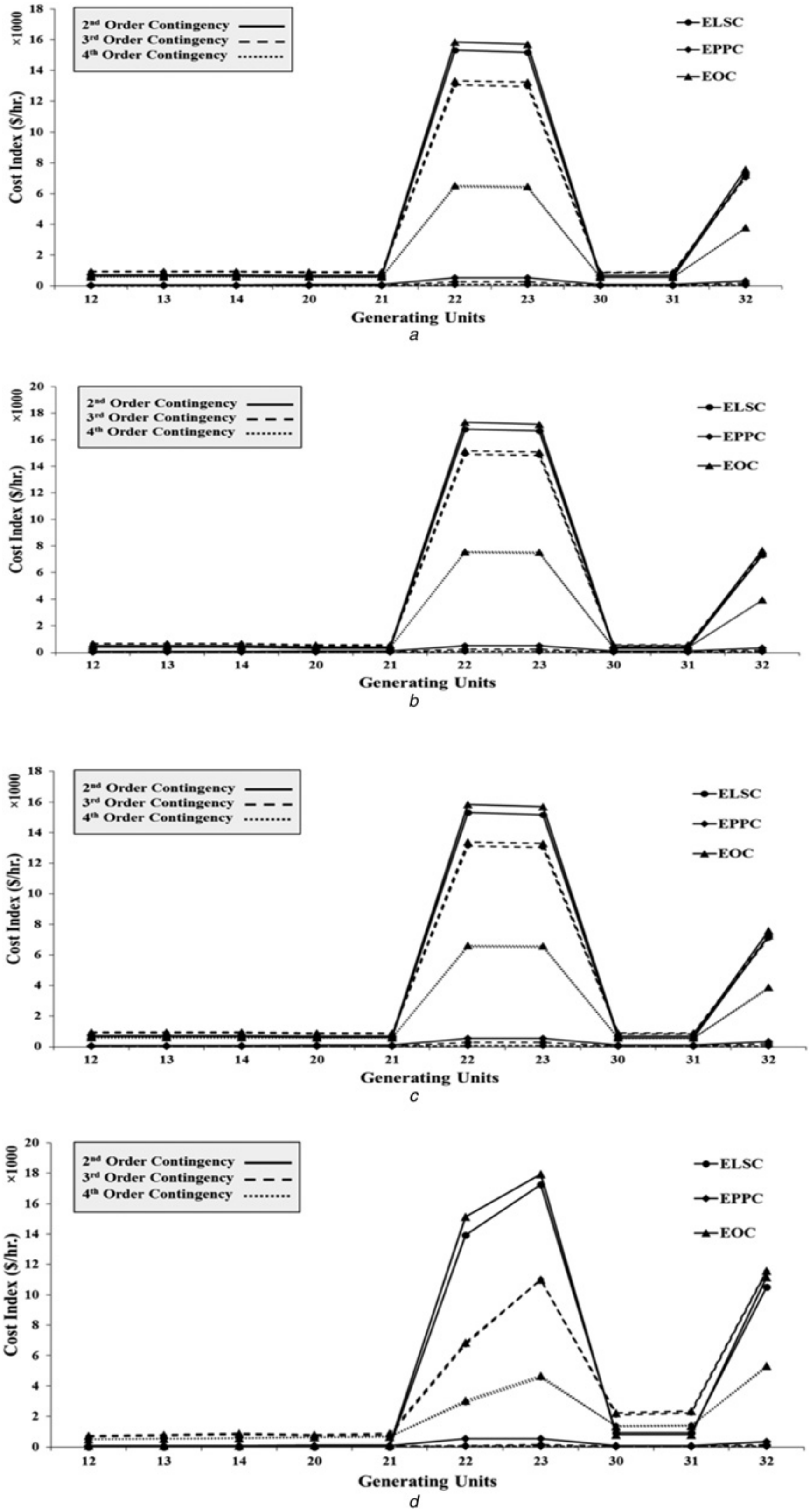

Fig. 7 *Contribution of system generating units in financial consequences of higher order contingencies*

a SVGT
b WSVGT
c BVGT
d NVGT approaches

outage ensuring the additivity property of the suggested techniques. From Figs. 7*a* and *b*, one can conclude that the WSVGT approach is more suitable compared with the other proposed methods due to the critical features of efficiency and additivity. Besides, this approach is well able to highlight the impact of failure rate and other parameters of generating units through certain assigned weights which will be reflected in the cost allocation process. This will eventually lead to an efficient and fair allocation of outage financial consequences to the involved equipment for further maintenance and investment decisions.

5 Conclusions

This paper proposed an efficient formulation to prioritise the system generating units based on their contributions to system reliability. Effective use of game theoretic concepts is pursued to evaluate the criticality of each system generating unit. The criticality measures are linked to the financial risk imposed to the system due to the failure of system generating units and also their contributions in high-order contingencies. Application of the proposed methodology was demonstrated through simulations on the IEEE-RTS 24-bus case study. According to the presented results, the proposed approach is well able to fairly map the failure consequences in the case of higher order contingencies to the involved components and could successfully recognise the critical generating units from the viewpoint of system reliability. Performance comparisons with the traditional EDNS- and LOLP-based sensitivity techniques reveal the efficiency and superiority of the suggested solution for the criticality evaluation of generating units. The results can be utilised in further implementation of modern maintenance approaches such as RCM and re-enforcement decisions in bulk electric power systems.

The focus of this work was to primarily propose a general model and practical framework to fairly recognise the system critical generating units by the ISO. Future extension of this work can be realised through implementation of the RCM process in integrated power generation and transmission systems considering market interactions. Development of probabilistic models to deal with the existent uncertainties in electricity price, forced outage rate of units, as well as operational conditions through the robust probabilistic techniques (such as point estimation method) is suggested for future works. Another interesting extension would be on the maintenance plans and scheduling optimisation of generating units by GENCOs based on the security/safety operational considerations and types of units. Investigating the impact of non-spinning reserves, switching operations, demand response, storage, postponable outages and assistance reserve from other zones on calculating the monetary consequences of contingencies and determining critical generating units for system reliability can be also focused in the future works.

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