Application of Game Theory in Reliability-Centered Maintenance of Electric Power Systems

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***Abstract*—As the electricity market undergoes continuous evolutions, along with the widely-recognized outdated nature of the grid, system operators would have to be able to more effectively manage the system operation expenses since waves of maintenance costs and equipment investments would be anticipated in a few years to come. Strategic implementation of cost-effective reliability-centered maintenance (RCM) approaches seems to be a key solution. This paper proposes an efficient method to assess the component criticality for system overall reliability and further maintenance focuses. A solution concept of game theory, called shapely value, is proposed that is able to fairly identify the contribution of every single equipment's to the system reliability performance once a high-order contingency occurs under different loading conditions. The identified critical components are then systematically involved in a new optimization framework for effective scheduling of RCM implementation in power systems. The suggested framework helps in realizing where investments and maintenance to be made in the grid to ensure a desirable system reliability performance. Implemented on the IEEE reliability test system, the effectiveness of the suggested framework is confirmed by comparing to conventional techniques under various scenarios.**

***Index Terms*—Contingency, critical component, failure, game theory, reliability-centered maintenance (RCM), shapely value.**

Nomenclature

I_{BB}	Set of system bus bars.
I_{GU}	Set of system-generating units.
$\mathrm{I}_{\mathrm{G}_n}$	Set of generating units of producer n.
$\mathrm{I}_{\mathrm{GU,R}}$	Set of generating units with reserve.
I_D	Set of system load points.
$\mathrm{I}_{\mathrm{off}}^{E_i}, \mathrm{I}_{\mathrm{on}}^{E_i}$	Set of the failed (offline) and online generating units in an outage event E_i.
$\mathrm{I}_{\mathrm{GU,Z}_a}$	Set of generating units in zone a.
L	Set of system transmission lines.
$C_{\mathrm{ng}}^{\mathrm{FX}}$	Fixed costs (\$/h) for generating unit g of producer n.
C_{ng}^{P}	Production cost (\$/h) of generating unit g of producer n.
$C_{\mathrm{ng}}^{\mathrm{repair},t}$	Total cost of labor and material associated with repairing generating unit g of producer n at time period t.
$C_{\mathrm{ng}}^{\mathrm{penalty},t}$	Expected security cost for generating unit g of producer n at time period t.
$C_{\mathrm{ng}}^{\mathrm{PM},t}$	Total cost of labor and material associated with preventive maintenance (PM) of generating unit g of producer n at time period t.
$E_{i,m}^{g}$	Outage event i of order m including the outage of generating unit g.
EP_{ng}^{t}	Expected profit of generating unit g of producer n at time period t.
$P_g^t, P_g^{c_i,t}$	Real power of generating unit g in normal and contingency i conditions at time t.
$P_{\mathrm{ng}}(y,m)$	Real power generated by generating unit g of producer n at time period y and subperiod m.
$P_d, P_d^{c_i}$	Real power demand d in normal and contingency i conditions.
$Q_g^t, Q_g^{c_i,t}$	Reactive power generation of generating unit g in normal and contingency i conditions at time t.
r_g^t	Reserve quantity of generating unit g at time t.
TC_i^t	Expected cost of outage event i at time t.
V_n, δ_n	Voltage magnitude and angle at bus n.
$\Psi_{g,t}^{\mathrm{Sh}}$	Contribution share of generating unit g in an outage event i at time t using the Shapley value concept.
$\Psi_{g,t}^{Sh^W}$	Contribution share of generating unit g in an outage event i at time t using the weighted Shapley value concept.
$C_{\mathrm{labor}}^{\mathrm{PM},t}$,	Cost of one working hour for performing PM and
$C_{\mathrm{labor}}^{\mathrm{repair},t}$	repair tasks at time period t.
$C_{\mathrm{material}}^{\mathrm{PM},t}$,	Cost of materials required for performing PM and
$C_{\mathrm{material}}^{\mathrm{repair},t}$	repair tasks at time period t.
d^t	Duration of a time period t (in hour).
D_{ng}	Maintenance duration of generating unit g of producer n.

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f_i^t	Frequency of outage event *i* at time *t*.
FOR_g	Forced outage rate of generating unit *g*.
K_{ng}^0	Initial value for the failure rate of generating unit *g* of producer *n*.
K_{ng}^j	*j*th stair-wise step of Weibull distribution for decoupled failure rate of generating unit *g* of producer *n*.
Labor^t	Available labor at time period *t*.
$\mathrm{Labor}_{\mathrm{ng}}^{\mathrm{repair},t}$, $\mathrm{Labor}_{\mathrm{ng}}^{\mathrm{PM},t}$	Number of labor required for repair and PM tasks of generating unit *g* of producer *n* at time period *t*.
$N(t)$	Maximum number of PM tasks in period *t*.
NI_g	Number of stair-wise failure rate intervals of generating unit *g*.
NM	Number of PM scheduling periods.
NT	Number of months at each yearly interval.
NY	Number of years in each studied period.
$P_g^{\max}, P_g^{\min}$	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*.
$r_g^{\max}$	Maximum reserve quantity of generating unit *g* at time *t*.
$R_{Z_a}^t$	Reserve requirement of zone *a* at time *t*.
$T(y,m)$	Duration (in hour) of subperiod *m* in time period *y*.
$V_n^{\max}, V_n^{\min}$	Max. and min. voltage magnitude at bus *n*.
X_{ng}^t	Maintenance status of generating unit *g* of producer *n* at time *t*.
π_i^t	Probability of outage event *i* at time *t*.
$\pi_{i,m}^{g,t}$	Probability of outage event *i* of order *m* due to the outage of generating unit *g* at time *t*.
ϑ_d^t	Load shed price of demand *d* at time *t*.
$\rho(B_g)$	Energy price at bus-bar *B* hosting generating unit *g*.
$\rho(y,m)$	Energy price for period *y* and subperiod *m*.
$\Upsilon_{g,i}^t$	Binary variable denoting the status of generating unit *g* in the outage event *i*.
$\lambda_{d,i}$	Departure rate of an outage event *i*.
μ_g, λ_g	Repair and failure rates of generating unit *g*.
$\lambda_{\mathrm{ng}}^{\mathrm{period}}(t)$	Failure probability of generating unit *g* of producer *n* over period *t*.
λ_{ng}^t	Failure rate of generating unit *g* of producer *n* at time period *t*.
$\alpha^{\mathrm{penalty}}$	Penalty parameter.
ξ_A	Expected outage duration of equipment A.
$\delta_n^{\max}, \delta_n^{\min}$	Max. and min. voltage angle at bus *n*.
Δ_g	Physical ramp rate of generating unit *g*.
$C_g(P_g^t)$, $C_g^R(r_g^t)$	Energy and reserve cost functions of generating unit *g*.
f(*v*)	Value function of *v*.
g^N	Collection of all characteristic functions.
$\mathbf{g_P}(\theta,\mathbf{V},\mathbf{P})=0$, $\mathbf{g_Q}(\theta,\mathbf{V},\mathbf{Q})=0$	Nonlinear equation of nodal real and reactive power balance.
$\mathbf{h_F}(\theta,\mathbf{V})\le 0$, $\mathbf{h_T}(\theta,\mathbf{V})\le 0$	Nonlinear function of the bus voltage angles and magnitudes for the "from" and "to" ends of each branch.
$Sh(v)$	Shapley value function of *v*.
$Sh^w(v,w)$	Weighted Shapley value function of *v* with the weight vector *w*.
v	Characteristic function of outage events.

I. Introduction

EMERGENCE of the electricity markets has commanded the utilities for further improvements in reliability of power systems and availability of the constituent components to be able to keep the pace in this competitive environment. Reliability improvements in power systems, although seems contradictory to the current cost-drop policies in utilities, need to be approached and somehow strictly guaranteed since the customer satisfaction is closely driven by the reliable and high-quality electricity. Hence, reliability and risk assessments are always a critical concern for the utilities worldwide [1].

Among the main activities power utilities utilize for system reliability improvement, maintenance strategies are regarded as the must-do efforts to maintain the equipment availability and enhance the system overall reliability performance over time. While maintenance costs constitute a large portion of system operational expenses, reducing maintenance actions on system equipment leads to higher damages caused by the increased number of forced outages. Reliability-centered maintenance (RCM) is a cost-effective strategy, where the cost and reliability requirements are compromised techno economically [2].

Interesting efforts have been recently dedicated to the application of RCM, some of which in different industrial fields [3]–[5] and some in the electric domain. Among the latter category, RCM implementation in power distribution systems is widely explored. In [6], Bertling *et al.* have employed the conventional sensitivity analysis and investigated the changes in the system load point reliability indices to prioritize the system equipment. In [7], a new method is introduced to determine the criticality of distribution equipment types by incorporating the experts' knowledge and expertize into the analysis trough fuzzy analytical hierarchical process. Dehghanian *et al.* [8]–[12] introduced an all-inclusive framework for practical implementation of RCM in power distribution systems. Attempt has been made in [13] to schedule the most profitable maintenance practices through outage cost optimization. Traditional reliability indices have been employed in [14]–[17] to calculate malfunction consequences and schedule maintenance of circuit breakers. RCM implementation in switching substations has been studied in [18]. Heo *et al.* [19]–[23] introduce executable RCM approaches in large-scale transmission systems. The authors have defined the indices representing the importance of each system equipment's from different perspectives and prioritized them accordingly. Additionally, RCM applications in power plants and generation stations are studied in [24] and [25].

To the best of the authors' knowledge, no applicable method can be found in the literature that can fairly identify the system critical components regarding their contribution on the imposed consequences not only in the cases of single outages, but also when a high-order contingency occurs. Conventional sensitivity analysis is frequently approached to evaluate the equipment criticality on system reliability. However, sensitivity analysis is majorly involved with the effect of one component outage at a time on the system performance. In dealing with the complex highly nonlinear power systems, the consequence associated with simultaneous outages can be extremely different from that estimated by summing individual single-order contingencies and, as a result, make it a more complicated problem to identify the criticality of the equipment involved in outages for more concentrated maintenance activities. Additionally, the electricity grid is supposed to be $(N-1)$ secured and, hence, single failure of the equipment in transmission and generation levels would not result in an electricity interruption. As a result, traditional performance indices might not be accurate and effective in deciding the system critical equipment, and proper performance indices need to be developed considering realistic electricity market implications. Considering the above shortcomings, this paper ties to accomplish the following contributions.

1) A new methodology for fair allocation of outage consequences to the involved equipment in the case of higher order contingencies is proposed. The proposed methodology employs a solution concept of game theory, namely shapely value, which helps in the prioritization of equipment according to their contribution to the system reliability performance.
2) The performance of the suggested technique is extensively compared against conventional approaches to prove its effectiveness and efficiency in real-world scenarios under various loading conditions. While being generic enough to be adapted to all types of system equipment, this paper is primarily focused on generating units and their criticality for system reliability.
3) The criticality measure for each generating unit will be quantified and considered as the penalty coefficients that generation companies (GENCOs) would be responsible for in the case of any unexpected outage. A new optimization framework is suggested for GENCOs to find the optimal maintenance plan on generating units and pursue the RCM implementation in practice.

The rest of this paper is organized as follows. The analytical procedure for reliability evaluation of power systems in dealing with contingencies is briefly presented in Section II. Section III introduces the proof of concept of shapely value game theory (SVGT) and the corresponding mathematical background as well as a detailed description of the proposed methodology to determine the criticality and importance of the network equipment. Section IV introduces a new optimization framework for realizing the RCM advantages in power systems by GENCOs. Numerical case studies are presented in Section V following by the concluding remarks in Section VI.

II. Reliability Evaluation of Electric Power Systems

The main goal of reliability evaluation in power systems is fundamentally to investigate the system capability to handle its desirable performance majorly in the cases of outages. This involves failure impact assessment of various equipment on the system overall performance; as a result, a comprehensive model of the system and the associated components is critical. On the other hand, electricity markets mandates considering the economic aspects of system operation in such decision makings. Hence, system modeling for reliability evaluation needs to be integrated with the electricity market requirements and related issues. Here, in this paper, a reliability model of the system is focused taking into account the system physical constraints, market performance, and the response from operators in different system operating conditions [26].

Reliability evaluation of large-scale power systems is a complicated task and commonly requires many calculations with considerable computational burden. Two practical methods of Monte–Carlo simulations and state enumeration are frequently approached to model the outages in a bulk power system. Either of these methods has both advantages and disadvantages depending on the application conditions. Monte–Carlo simulation is divided into sequential and nonsequential categories. The sequential or state duration sampling approach is accomplished by sampling the probability distribution of the component state duration, while the nonsequential approach is done by sampling the probability that the component appears in that state. After each equipment state is determined, the system state can be obtained by the combination of all equipment states [26]. State enumeration approach comprises of two independent parts namely statistical analysis and consequence evaluation. In this approach, the possible contingencies are selected first, and probability and frequency of their occurrence are determined in the statistical analysis stage. In the consequence evaluation stage, the impact of each outage event on the system overall performance is evaluated. The reliability indices are calculated at the third stage by combining the results of the first two steps. In this method, usually a limited number of simultaneous outages are considered as the possible list of contingency. A state enumeration technique is more suitable compared to the Monte–Carlo approach for a system of equipment with low failure probabilities since the probability and frequency of contingency decreases very rapidly as the number of equipment outages increases [26]. Furthermore, this approach provides the advantage of applying parallel processing techniques due to independent behavior of components. Therefore, the proposed method benefits from the state enumeration approach for reliability and risk assessments.

A. *Stage I: Statistical Analysis*

The first stage deals with the evaluation of the probability and frequency of contingencies. Using Markov model and considering an independent nature for equipment failures, the probability, departure rate, and frequency of each contingency are calculated as follows:

$$\pi_i^t = \prod_{g \in \mathrm{I}_{\mathrm{off}}^{E_i}} \frac{\lambda_g}{(\mu_g + \lambda_g)} \times \prod_{g \in \mathrm{I}_{\mathrm{on}}^{E_i}} \frac{\mu_g}{(\mu_g + \lambda_g)} \quad (1)$$

$$\lambda_{d,i} = \sum_{g \in \mathrm{I}_{\mathrm{off}}^{E_i}} \mu_g + \sum_{g \in \mathrm{I}_{\mathrm{on}}^{E_i}} \lambda_g \quad (2)$$

$$f_i^t = \pi_i^t \times \lambda_{d,i}. \quad (3)$$

Equation (1) calculates the probability of contingency by multiplying the availability of online equipment and unavailability of the failed ones. Departure rate of a contingency is obtained in (2) by summing the failure rate and repair rate of the online and failed components, respectively. Equation (3) represents the frequency of a contingency.

B. Stage II: Consequence Analysis

Once the system is thoroughly modeled, its overall reliability performance in different operating conditions can be evaluated. For this purpose, the system operational performance in normal conditions and in response to unplanned outages should be studied. In a competitive electricity market, the Independent System Operator's (ISO's) main responsibility is to ensure the system economic efficiency, while maintaining the system reliability and security by providing ancillary services that can be either dispatched with energy dispatch simultaneously or sequentially. Here, the simultaneous forms of auctions are considered.

The objective of dispatching the energy and reserves is to optimize the social welfare, which can be maximized by minimizing the total payment or the total cost of energy and reserves, while satisfying ac power flow equations, ancillary services, transmission, and operating constraints [26], [27]. Mathematically, the objective for ISO is formulated as

$$\min_{\theta,V,P,Q} \quad \sum_{g\in I_{\mathrm{GU}}} C_g({P_g}^t) + \sum_{g\in I_{GU,R}} C_g^R({r_g}^t) \tag{4}$$

s.t.

$$\mathbf{g_P}\left(\theta,\mathbf{V},\mathbf{P}\right) = 0 \tag{5}$$

$$\mathbf{g_Q}\left(\theta,\mathbf{V},\mathbf{Q}\right) = 0 \tag{6}$$

$$\mathbf{h_F}\left(\theta,\mathbf{V}\right) \le 0 \tag{7}$$

$$\mathbf{h_T}\left(\theta,\mathbf{V}\right) \le 0 \tag{8}$$

$$\delta_n^{\min} \le \delta_n \le \delta_n^{\max} \quad \forall n \in I_{\mathrm{BB}} \tag{9}$$

$$V_n^{\min} \le V_n \le V_n^{\max} \quad \forall n \in I_{\mathrm{BB}} \tag{10}$$

$$P_g^{\min} \le P_g^t \le P_g^{\max} \; \forall g \in I_{\mathrm{GU}} \tag{11}$$

$$Q_g^{\min} \le Q_g^t \le Q_g^{\max} \; \forall g \in I_{\mathrm{GU}} \tag{12}$$

$$0 \le r_g^t \le \min(r_g^{\max}, \Delta_g) \;\; \forall g \in \; I_{GU_R} \tag{13}$$

$$P_g^t + r_g^t \le P_g^{\max} \; \forall g \in I_{GU_R} \tag{14}$$

$$\sum_{g\in I_{\mathrm{GU},\mathrm{Z}_a}} r_g^t \ge R_{Z_a}^t \;\; \forall a. \tag{15}$$

Constraints (5), (6) give two sets of N_b nonlinear nodal active and reactive balancing equations. Network constraints (7), (8) represent two sets of N_l branch flow limits, one for the *from* end and one for the *to* end of each branch, which are nonlinear functions of the bus voltage angles and magnitudes. Constraints (9), (10) represent the limits on bus voltage phase angle and magnitude. Constraints (11), (12) are supply constraints and (13)–(15) are capacity reserve constraints. Constraint (13) ensures that the reserve for each generating unit must be positive and is bounded above by a reserve offer while respecting the physical ramping limitation. Constraint (14) enforces that the total amount of energy plus reserve of the unit is limited above by its capacity. Constraint (15) represents the spinning reserve requirements in each region. The locational marginal prices (LMP) are determined by an ac optimal power flow function in terms of Lagrange multipliers. After this optimization, ISO determines the amount of energy and reserve of each generating unit as well as the LMP at each bus.

In a general case, the occurrence of an unplanned outage or unforeseen event at the operation time frame influences the system parameters, such as bus voltages, branch flows, etc. Meanwhile, according to the ISO's responsibility to maintain the system security, by purchasing energy from the specified reserve or load shedding actions, system transits to a new operating state and, as a result, safe and economic performance are guaranteed in this condition.

Here, the cost of purchasing energy from the reserve sources and the cost of total load shedding are added to the operating cost and can be considered as the contingency consequences imposed to the system. Demands in restructured power systems can also offer prices to reduce the load and the interruption cost can be calculated from the accepted offers. The ISO minimizes the total interruption costs. For each contingency, the ISO tries to minimize the following:

$$\begin{aligned}\min\, TC_i^t = & \sum_{g\in \mathrm{I_{GU}}} \left(\rho(B_g)\left(P_g^{c_i,t} - P_g^t\right)\right) \\ & + \sum_{d\in \mathrm{I}_D} \left(\vartheta_d^t\left(P_d^t - P_d^{c_i,t}\right)\right).\end{aligned} \tag{16}$$

The set of constraints for this optimization formulation are (5)–(10) explained earlier, as well as the following constraints:

$$Q_g^{\min}\Upsilon_{g,i}^t \le \; Q_g^{c_i,t} \le Q_g^{\max}\Upsilon_{g,i}^t \tag{17}$$

$$P_g^t\Upsilon_{g,i}^t \le \; P_g^{c_i,t} \le \left(P_g^t + r_g^t\right)\Upsilon_{g,i}^t. \tag{18}$$

Failure of generating units in an outage event i can be represented via a vector of binary variables $\Upsilon_{g,i}^t$ with 1 denoting the availability of components and 0 otherwise. Constraints (17), (18) enforce the output of the generating unit g to zero if it is failed in the outage event i. If generating unit g is available, its increased active power output should not exceed the predetermined reserve margins.

C. Stage III: Reliability Indices Calculation

Once the statistical and consequence evaluations are accomplished considering all possible contingencies, the reliability index is calculated by combining the results of the aforementioned two modules as follows:

$$EOC_i^t = \pi_i^t \times TC_i^t. \tag{19}$$

In which the expected outage cost imposed to the system due to contingency i is obtained by multiplying the probability and consequence of its occurrence.

III. Critical Component Identification in Power Systems: Proposed Methodology

A. SVGT Algorithm: Theoretical Background

In the case of higher order contingencies, the optimization problem with the objective function in (5) would be solved to redispatch the generating units economically while maintaining the system security. The problem is not as easy as it seems when it comes to higher order contingencies where several components are involved in an outage and the imposed financial consequence.

There are numerous approaches for cost allocation among the players of transferable utility (TU) cooperative games, which specify how to share the joint costs among participants. This study is based on the concepts of Shapley value providing *fair* and *stable* models for embedded cost allocation of power networks to avoid any interest for players to secede the system that otherwise leads to an unoptimal situation [28].

Let $n \geq 2$ denote the number of players in the game, and let $N = 1, 2, \ldots, n$ denote the set of players. A coalition S is defined to be a subset of N that coordinate together and $v : 2^N \rightarrow R$ is a characteristic function defined on the set 2^N of all coalitions (subsets of N) such that $v(\emptyset) = 0$. Characteristic value $v(S)$ gives the maximum cost or payoff incurred by coalition S. Since we take the set of players N to be fixed, the collection of all characteristic functions on N is denoted by g^N. A solution for TU-game is a function which assigns an $|N|$-dimensional real vector to every TU-game. This payoff vector $X = (x_1, x_2, \ldots, x_n)$ is seen as a distribution of the payoffs with the understanding that player i is to receive x_i. An imputation is a pay-off vector that is grand and individually rational and any imputation that satisfies group rationality lies in the core of the game. The core concept is useful as a measure of stability without distinguishing one point of a set of imputations as preferable to another [29]. Since the core may be empty particularly in the power network cost allocation problem as rationality conditions may not be satisfied, the game approaches based on the concept of a value are considered in this paper [40].

A famous solution for TU-game is the Shapley Value (SVGT). A value function is assigned to each possible characteristic function v, an n-tuple $f(v) = (f_1(v), f_2(v), \ldots, f_n(v))$. The Shapley value is the function $sh : g^N \rightarrow R^N$ given by

$$Sh_i(v) = \sum_{i \in S} \frac{\Delta_v(S)}{|S|} \quad \forall i \in N. \tag{20}$$

With dividends of

$$\Delta_v(s) = \sum_{T \subset S} (-1)^{|S|-|T|} v(T) \ \ \forall S \subset N. \tag{21}$$

The most important characteristics of this function are satisfactory efficiency, symmetry, the null property, additivity, and fairness property as follows:

$$\sum_{i \in N} Sh_i(v) = v(N) \tag{22.a}$$

$$v(S \cup \{i\}) = v(S \cup \{j\}) \ \ \forall S \subset N \backslash \{i, j\} \Rightarrow Sh_i(v) = Sh_j(v) \tag{22.b}$$

$$v(S) = v(S \backslash \{i\}) \ \ \forall S \subset N \Rightarrow Sh_i(v) = 0 \tag{22.c}$$

$$Sh(v + u) = Sh(v) + Sh(u) \ \ \forall v, u \in g^N. \tag{22.d}$$

Axiom (22.a) represents the efficiency property denoting that the total value of the players is the value of the grand coalition. Second axiom (22.b) implies that the Shapley value solution satisfies the symmetry property. If $i,\ j \in N$ are symmetric players in $v \in g^N$, their assigned values are equal. Third axiom (22.c) assigns zero value to the dummy player which neither helps nor harms any coalition. The last axiom (22.d) reflects the property that the value of two games played at the same time should be equal to the sum of the values of the games if they are played at different times.

It is easily verifiable that a solution which follows the symmetry and additivity properties will also satisfy the fairness property. As demonstrated in (23), fairness property states that if a game is added to a game in which two players are symmetric, then their allocations would change by the same amount [28]–[30]

$$Sh_i(v + u) - Sh_i(v) = Sh_j(v + u) - Sh_j(v) \ \ \forall v, u \in g^N. \tag{23}$$

It is notable that a theorem exists stating that a solution for TU-game is equal to Shapley value if and only if it satisfies these axioms [29], [30]. However, the symmetry axiom can be used only when the parameters of the game are completely symmetric for the players, which make it sometimes unrealistic in practice.

Another value functions that obey the Shapley's axioms except the symmetry axiom are weighted Shapley values (SVGT). An example of such a weighted Shapley value is the function $sh^w : g^N \times R_+^N \rightarrow R^N$ given by

$$Sh_i^w(v, w) = \sum_{i \in S} \left(\frac{w_i}{\sum_{j \in S} w_j} \right) \Delta_v(S) \quad \forall i \in N \tag{24}$$

where $w = (w_1, w_2, \ldots, w_n)$ is a weighting vector that assigns different positive weights to the players [28]. Compared to the Shapley value function, a share of the joint costs assigned to the player in this function is proportional to its weight additional to its marginal contribution.

B. Application of Game Theory for Recognition of System Critical Components

To determine the system critical equipment (here generating units) for more focused maintenance attention, the imposed cost due to all possible outage scenarios should be evaluated. A high-order contingency can be represented as a game with generating units being players, and characteristic values associated with coalitions are the consequences. In (25) and (26), the contribution of the component j in the total outage cost is calculated by employing the Shapley value and weighted Shapley value concepts, respectively. Such contributions could be then summed up to achieve the total monetary index of each equipment's over many outage scenarios

$$\Psi_{g,t}^{Sh} = \sum_{m}\sum_{i}\pi_{i,m}^{g,t} \times \left[\sum_{S\subset E_{i,m}^{g}}\sum_{T\subset S}\frac{(-1)^{|S|-|T|}TC_{T}^{t}}{|S|}\right] \quad (25)$$

$$\Psi_{g,t}^{Sh^{W}} = \sum_{m}\sum_{i}\pi_{i,m}^{g,t} \times \left[\sum_{S\subset E_{i,m}^{g}}\frac{\mathrm{FOR}_{g}}{\sum_{k\in S}\mathrm{FOR}_{k}}\sum_{T\subset S}(-1)^{|S|-|T|}TC_{T}^{t}\right]. \quad (26)$$

IV. Optimization Framework for Implementation of RCM on Power-Generating Units

RCM is an efficient analytical approach to recognize the intrinsic relationship between maintenance process, aging of generating units, system reliability, and system operation cost. This section proposes an optimization framework for GENCOs to implement the RCM process on the generating units considering their criticality factors. In centralized frameworks, maintenance scheduling and its implementation are accomplished by ISOs to create an appropriate balance between system reliability and maintenance costs [31]–[33]. In deregulated power systems, however, maintenance scheduling is optimized individually by independent power producers to decrease their operating costs or profit loss. Furthermore, in a deregulated environment, GENCOs would be responsible for any penalty cost as a consequence of the outages. Appropriate determination of such penalty costs due to unexpected outages helps in preventing the failure conditions of generating units by allocating the available resources to their maintenance. Therefore, in order to have a reliable and fair competition, the share of each generating unit in single or higher order outages has to be specified, and the generating units with higher intense impacts on the imposed costs to system should be assigned higher penalty coefficients.

A. Determining Penalty Factors for System-Generating Units: Proposed Application of Game Theory

In order to ensure the system reliability in restructured power systems, ISOs should determine the impact of unexpected or planned outages of generating units on system reliability. In case of reliability violations, they should set up penalties for each period and subperiod to encourage producers to modify their schedules. In the proposed procedure, ISO sets up penalty factors based on the criticality degrees of generating units to encourage producers to take their aging into account in their maintenance schedules. The criticality index, calculated based on SVGT and WSVGT as explained in Section III, is used to prioritize the generating units with respect to their contribution to system reliability performance. The penalty factors of generating units are dynamic and depend on time, location, their maximum capacity, and network configuration.

B. Optimization Formulation for RCM Scheduling of System-Generating Units

In the restructured environment of electric industry and competitions in energy markets, power producers seek to maximize their profits by optimizing their maintenance schedules over time. Hence, it is essential for GENCOs to consider the impact of unexpected outages of their generating units on the maintenance schedules. Various cost functions are considered in the suggested optimization model [34]:

1) Expected Energy-Sale Profits: The profits of producer *n* obtained by generating unit *i* is calculated as the difference between the revenue of energy sale in electricity market and production costs. In order to quantify the impact of an unexpected outage of a generating unit, the profit is weighted by the probability of equipment failure over the time period *t*. The unique property of the following formulation is the embodiment of the aging momentum of generating unit *k* in terms of $\lambda_{ng}^{\mathrm{period}}(t)$

$$EP_{\mathrm{ng}}^{t} = \sum_{y=1}^{\mathrm{NY}}\sum_{m=1}^{\mathrm{NM}}\left[\rho(y,m)P_{\mathrm{ng}}(y,m) - C_{\mathrm{ng}}^{P}P_{\mathrm{ng}}(y,m) - C_{\mathrm{ng}}^{\mathrm{FX}}\right] \times T(y,m) \times \lambda_{ng}^{\mathrm{period}}(t) \quad (27)$$

$$\lambda_{ng}^{\mathrm{period}}(t) = \lambda_{\mathrm{ng}}^{t} \times d^{t}. \quad (28)$$

2) Expected Labor and Material Cost for Outage Repair: The other expense term that would be imposed to GENCOs in case of an outage is the repair cost of equipment. Since the average amount of materials and number of hours required for failures are typically known, the expected repair cost can be quantified as follows:

$$C_{\mathrm{ng}}^{\mathrm{repair},t} = \lambda_{ng}^{\mathrm{period}}(t) \times \left(C_{\mathrm{labor}}^{\mathrm{repair},t} \times \mathrm{Labor}_{\mathrm{ng}}^{\mathrm{repair},t} + C_{\mathrm{material}}^{\mathrm{repair},t}\right). \quad (29)$$

In order to consider the unknowable nature of failure events, the labor and material costs are multiplied by the failure probability of generating units over time period *t* [34].

3) Expected Security Cost of Generating Unit Failure: After quantifying the criticality measure and penalty factors for each generating unit, GENCOs should consider such coefficients in their scheduling programs. Each GENCO has to pay a penalty cost for its unexpected outage events, which can be formulated below:

$$C_{\mathrm{ng}}^{\mathrm{penalty},t} = \lambda_{\mathrm{ng}}^{\mathrm{period}}(t) \times \left(\Psi_{ng,t}^{Sh^{w}} \times \alpha^{\mathrm{penalty}}\right). \quad (30)$$

4) Labor and Material Cost for Preventive Maintenance (PM): The other cost factor is associated with facilities and crew required to perform PM tasks. Generally, the average number of hours and materials required to perform PM tasks are predetermined. Therefore, such costs can be obtained as follows [34]:

$$C_{\mathrm{ng}}^{\mathrm{PM},t} = C_{\mathrm{labor}}^{\mathrm{PM},t} \times \mathrm{Labor}_{\mathrm{ng}}^{\mathrm{PM},t} + C_{\mathrm{material}}^{\mathrm{PM},t}. \quad (31)$$

5) Objective Functions and Constraints: The proposed RCM scheduling problem for each GENCO to maximize its own profit is mathematically formulated as follows:

$$\max \sum_{t=1}^{\mathrm{NT}} \sum_{g \in G_n} \begin{bmatrix} (EP_{\mathrm{ng}}^t - C_{\mathrm{ng}}^{\mathrm{repair},t} - C_{\mathrm{ng}}^{\mathrm{Penalty},t}) \times \\ (1 - X_{\mathrm{ng}}^t) - C_{\mathrm{ng}}^{\mathrm{PM},t} \times X_{\mathrm{ng}}^t \end{bmatrix} \quad (32)$$

s.t.

$$\sum_{t=1}^{\mathrm{NT}} X_{\mathrm{ng}}^t = D_{\mathrm{ng}} \ \ \forall g \in G_n \quad (33)$$

$$X_{\mathrm{ng}}^t - X_{\mathrm{ng}}^{t-1} \leq X_{\mathrm{ng}}^{t+D_{\mathrm{ng}}-1} \ \ \forall g \in G_n \ \ \forall t \quad (34)$$

$$\sum_{g \in G_n} X_{\mathrm{ng}}^t \leq N(t) \ \ \forall t \quad (35)$$

$$\sum_{g \in G_n} \left[\mathrm{Labor}_{\mathrm{ng}}^{\mathrm{PM}} \times X_{\mathrm{ng}}^t + \lambda_{\mathrm{ng}}^t \times \mathrm{Labor}_{\mathrm{ng}}^{\mathrm{repair},t} \right] \leq \mathrm{Labor}^t \ \ \forall t. \quad (36)$$

where EP_{ng}^t reflects the expected energy sale profits. $C_{\mathrm{ng}}^{\mathrm{repair},t}$ and $C_{\mathrm{ng}}^{\mathrm{Penalty},t}$ represent the costs associated with failure of generating units over the scheduling time horizon. $C_{\mathrm{ng}}^{\mathrm{PM},t}$ reflects the PM cost multiplied by the corresponding decision binary variable X_{ng}^t. Constraint (33) ensures that each generating unit is maintained in a required number of time periods and (34) enforces that the maintenance task for any generating unit would be completed once it begins. Constraint (35) restricts the maximum number of simultaneous maintenance actions in each time period. Constraint (36) addresses labor requirements. Note that λ_{ng}^t depends on the last time the corresponding maintenance task was performed. The constraints below link the failure rate variables to PM tasks

$$\lambda_{\mathrm{ng}}(t) \geq K_{\mathrm{ng}}^0 \times X_{\mathrm{ng}}^t \quad (37)$$

$$\lambda_{\mathrm{ng}}^t \geq K_{\mathrm{ng}}^j \times \left[1 - \sum_{\tau=0}^{j} X_{\mathrm{ng}}^{t-\tau} \right] \quad \forall g \in G_n \ \ \forall t \ \ \forall j = 0, ..., NI_g. \quad (38)$$

Constraints (37), (38) enforce that the unit's failure rate is tied to the last time maintenance activity performed and stair-wise Weibull distribution [34].

V. Numerical Case Studies and Discussions

The proposed approach for criticality evaluation of generating units on the power system overall reliability performance is applied to the IEEE reliability test system (IEEE-RTS) [35]. This system is composed of 32 generating units, 20 load points, 24 buses, and 38 transmission lines with generation capacity of 2859 MW. All the system load points are assumed to be dispatchable and can be reduced in emergency scenarios according to their offers given in [36] and [37]. The criticality degree of generating units is determined per month according to the system peak load.

In order to evaluate the proposed framework for criticality assessment of generating units and its application for RCM implementation, two cases are studied. Former, the criticality degree and priority of generating units are determined and the performance of the proposed approach is compared against the conventional methods. Latter, how to consider the proposed criticality measure as a cost penalty factor is examined to clarify the RCM implementation procedure. The proposed methodology is implemented in the MATLAB environment using the MATPOWER operating toolset employing the primal-dual interior point solver called MIPS [38]. In order to handle the nonlinearity and mixed-integer nature of the RCM optimization problem from the GENCO's standpoint, the discrete binary version of the particle swarm optimization (PSO) is implemented in this paper.

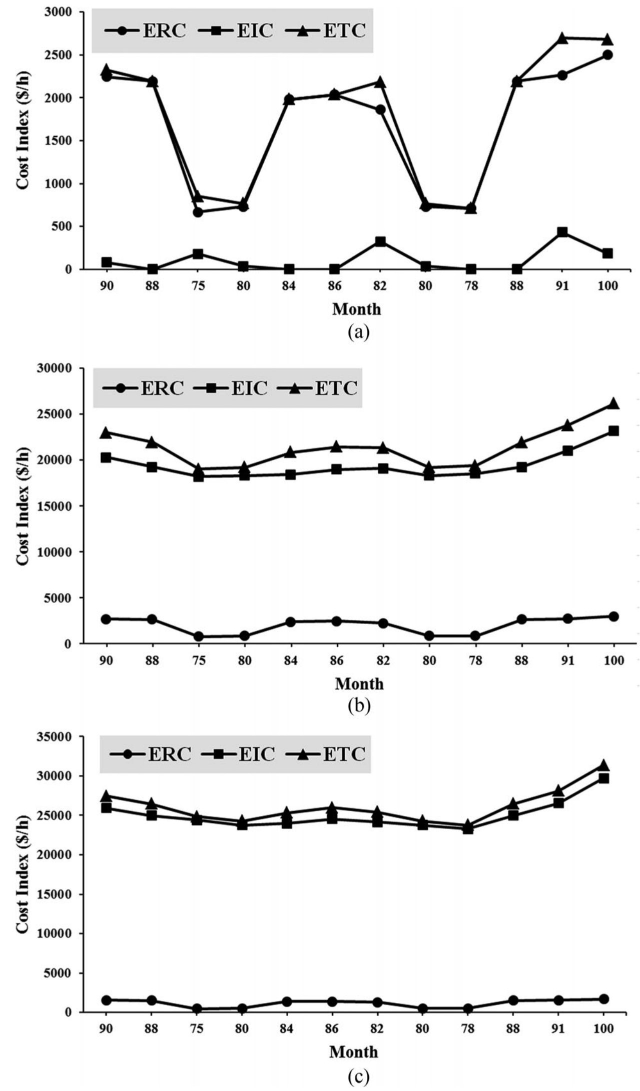

Fig. 1. Risk index of the system in (a) single-order, (b) second-order, and (c) third-order outage events in the studied yearly time frame: IEEE-RTS.

A. Identifying System-Critical-Generating Units

The criticality degree of generating units is determined per month according to the system peak load. The system active and reactive power of generating units, load demand, spinning reserve of generating units, and LMPs are initially obtained from the energy and reserve market simulations in the system normal operating condition. The reserve requirement is considered equal to the capacity of the largest generating unit.

TABLE I
COMPARISON OF OUTAGE CONSEQUENCES IN DIFFERENT LOAD SCENARIOS

Load Level (%)	Active Power (MW)	Outage of U23	No Outage	Outage of U22
75	Supplied Load	2135.7	2137.5	2136.9
	Generation	2172.8	2172.8	2172.8
	Loss	37.10	35.28	35.91
80	Supplied Load	2279.5	2280	2280
	Generation	2316.7	2319.6	2315.8
	Loss	37.14	39.63	35.82

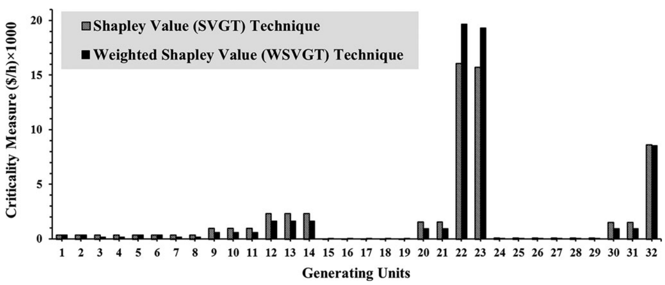

Fig. 2. Criticality degree of generating units for system reliability: IEEE-RTS.

Having calculated the consequences of all outage events up to the third order, the risk imposed to the system corresponding to each order of outages for each month is evaluated, as demonstrated in Fig. 1. It can be seen that in case of single-order outages, the share of expected redispatch cost (ERC) has a bigger contribution in the expected total cost (ETC) compared to that of expected interruption cost (EIC). The reason lies in the fact that in most single-order outage events of units with low capacities, there is enough available generation in the system to cover the outages (considering the 400-MW available reserve), and, hence, load shedding actions are not needed. However, in case of multiple-order outage events, the load shedding actions become of importance and such conclusion is not valid. In addition, it can be seen that in case of single-order outages, the risk imposed to the system does not necessarily increase when the system peak load increases. For instance, consider the system in 75% loading scenario: the EIC is higher than that at 80% loading scenario due to the interruption of load point 9 with 131.25-MW demand in some outage scenarios. Moreover, in case of 75% loading scenario, outage of units of 400-MW capacity at buses 18 and 21 (U22 and U23), which has higher impact on the system reliability, would result in a higher amount of loss compared to the case in 80% loading scenario (see Table I). Therefore, the outage impact of generating units U22 and U23 is higher in case of 75% loading scenario compared to that at 80%. Fig. 1(b) and (c) also shows that in case of multiple-order contingencies, the imposed risk to the system increases as the load level grows.

The contribution of each generating unit is determined by utilizing the concepts of SVGT and WSVGT functions, as illustrated in Fig. 2. It can be seen that two nuclear steam units of 400 MW located at buses 18 and 21 are identified as the most critical components of the system. The reason is the fact that the generating units U22 and U23 impose higher costs to the

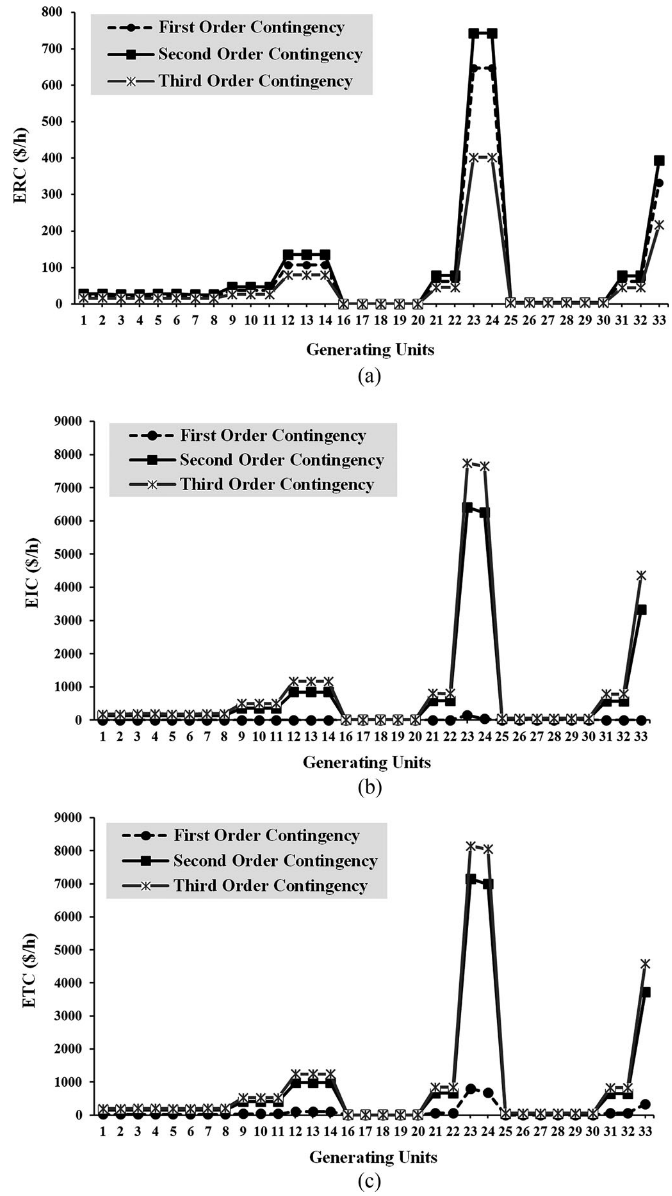

Fig. 3. Contribution of generating units in (a) ERC, (b) EIC, and (c) ETC.

system due to the high capacity and their maximum utilization factor in normal operating condition.

Fig. 3 demonstrates the contribution of each generating unit on various system outage consequences (ERC, EIC, ETC) separately in the cases of single-order, second-order, and third-order outage events and considering the 100% loading condition. From the obtained results in Figs. 2 and 3, it can be realized that the criticality of generating units majorly depends on the capacity and failure rate of the units in addition to where they are located in the system. For instance, the importance of the hydrounits of 50 MW is less than that of the combustion turbine units of 20 MW, not only due to a lower failure rate, but also since they are located on the north parts of the system attached to a less important bus bar. In addition, it can be seen that the units of the same capacity and location have the same total contribution that well reflects the symmetry property of the SVGT

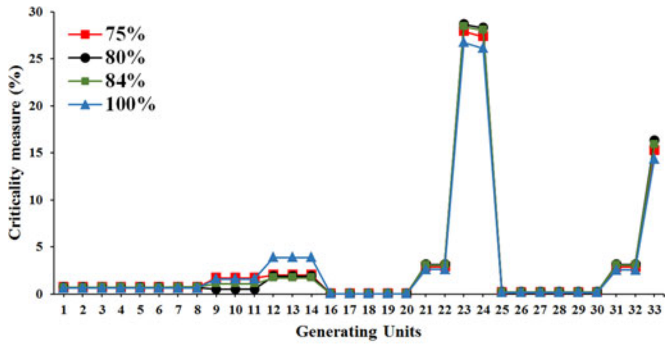

Fig. 4. Contribution of generating units under different loading scenarios.

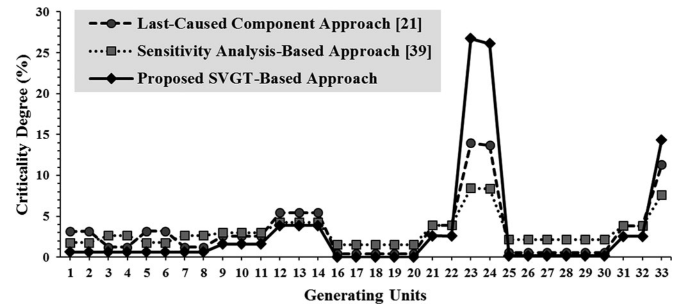

Fig. 5. Comparison of traditional and the proposed criticality evaluation approaches for generating units: IEEE-RTS.

and WSVGT methods. Comparisons of the results obtained via these two methods, it can be observed that the WSVGT method allocates a higher share to the units with higher probability of failure in each outage event which makes it more suitable and attractive in cases where the players (here equipment) may involve in system down states. As can be seen in Figs. 1 and 3, the sum of generating units' contributions in each outage order is equal to the costs imposed to the system, which indicates that the proposed method can efficiently manage a fair allocation of the entire outage costs to the involved equipment. Fig. 3 also shows that the contribution of generating units in ERC for first-order outages is higher than that in third-order outage events. Moreover, EIC has shown a higher contribution in the total imposed costs when considering the third-order contingencies compared to the rest [40].

B. Discussions

1) Performance of the Suggested Criticality Measure Under Different System Loading Scenarios: Fig. 4 illustrates the criticality measure of the system-generating units under different loading scenarios. In order to compare the results, they are demonstrated in percentages. It can be seen that the criticality degree of generating units 23 and 24 at loading scenario 75% is lower than that in all other loading scenarios. Also, the generating units 12, 13, and 14 are more critical than the others under 100% loading scenario. Therefore, it can be concluded, from this figure, that the criticality degree of some generating units can decrease in higher loading scenarios and some others maybe more critical for system reliability due to their higher contributions to the outage consequences. Such observations confirm the fact that the criticality measure is dynamic, varies over time, and depends on the topology of the system and loading conditions.

2) Comparisons With Conventional Criticality Measures: Relatively a little work has been published to link the equipment availability to the system reliability and quantify their criticality for system-wide reliability. In [21], single- and multiple-order component outages are considered to prioritize the transmission system equipment through three separate importance indices: 1) based on their expected outage rate; 2) based on their impact on transmission security margins; and 3) based on their impact on the interruption of the connection to load supply and generating units. In this approach, the entire outage consequence is solely allocated to the last component triggered the final consequence and the other equipment involved in the outage is not assigned any share of the consequence. In other words, the contingency consequence of an outage in component B followed by an outage in component A is entirely allocated to component A, which is not a fair solution. The suggested technique in our paper takes into account the outage event of $A + B$ and the contribution of each A and B individually. Additionally, not only the first- and second-order contingencies are studied as in [21], the suggested technique also includes the third-order contingencies. The following equations show the expected unavailability indices for the single-order, second-order, and third-order outage events where the final caused outage trigger is equipment A. These equations are used to calculate the outage probabilities

$$U_{\{A\}} = \lambda_A \xi_A \tag{39}$$

$$U_{\{B+A\}} = \lambda_A (\lambda_B \xi_B) \frac{\xi_A \xi_B}{\xi_A + \xi_B} \tag{40}$$

$$\lambda_{\{C+B+A\}} = \lambda_B \lambda_C \xi_C \lambda_A \frac{\xi_B \xi_C}{\xi_B + \xi_C} + \lambda_C \lambda_B \xi_B \lambda_A \frac{\xi_C \xi_B}{\xi_C + \xi_B} \tag{41}$$

$$\xi_{\{A+B+C\}} = \frac{\xi_A \xi_B \xi_C}{\xi_A + \xi_B + \xi_C} \tag{42}$$

$$U_{\{A+B+C\}} = \lambda_{\{A+B+C\}} \xi_{\{A+B+C\}}. \tag{43}$$

Another common practice in former studies to quantify the criticality degree of equipment is the sensitivity analysis approach. Sensitivity analysis is carried out to determine the impact of changes in some system parameters and indices on the equipment priority. In this conventional approach to recognize the critical-generating units, the impact of only one generating unit outage at a time on the overall system reliability is considered, and, hence, the impacts of simultaneous outages (higher order contingencies) are neglected [39].

In this section, a comparison of the proposed SVGT-based technique for identification of critical-generating units with the aforementioned two approaches (presented approach in [21] based on the last-caused component and sensitivity analysis [39]) is presented. Fig. 5 demonstrates the contribution of generating units in the total imposed costs using the three methods. Comparing the results, it can be concluded that when

TABLE II
CRITICALITY FACTORS OF GENERATING UNITS U7, U21, U33: IEEE-RTS

Month	Peak load (%)	Criticality Factor ($/h)			Peak load (%)	Criticality Factor ($/h)		
		U7	U21	U33		U7	U21	U33
1	90	632	4990	36718	82	235	4601	35202
2	88	627	4873	37161	80	150	4521	34852
3	75	120	3184	22059	78	123	4035	27593
4	80	150	4521	34852	88	627	4873	37161
5	84	473	4639	35870	91	667	5137	37595
6	86	639	4826	37245	100	1158	6923	49728

TABLE III
COMPARISONS OF TWO MAINTENANCE STRATEGIES WITH AND WITHOUT PENALTY COSTS: IEEE-RTS

Generating Units		Profit ($) ($\times 10^6$)	Revenue ($)($\times 10^6$)	PM* Cost ($)	CM* Cost ($)	X*	Y*
With consideration of penalty cost	U7	2.6403	2.7371	85576	11248	4	4
	U21	5.6612	5.7115	21695	28675	5	5
	U33	13.144	13.159	25539	25900	3	2
No consideration of penalty cost	U7	2.6044	2.6154	11091	0	6	0
	U21	5.2147	5.2389	24254	0	7	0
	U33	13.07	13.1072	37208	0	5	0

*Preventive Maintenance: **PM**. *Corrective Maintenance: **CM**.
*Number of Maintenance Tasks: **X**. *Number of Unexpected Outages: **Y**.

employing the SVGT approach, the contributions of generating units 23 and 24 are much higher, while that of the other generating units is lower compared to the cases where the other methods are employed. In the suggested SVGT-based approach, the criticality difference among generating units 23 and 24 and the other generating units is much higher than those calculated via the other techniques. The criticality difference is also higher in the final-caused component approach compared to that using the sensitivity analysis. Such observations highlight the fact that the multiple-outage events including the outage of generating units 23 and 24 with other units cannot be reflected well when using the traditional sensitivity analysis. Also, the impact of unit capacity and its location can be well incorporated when using the suggested SVGT-based approach for simultaneous outages.

C. RCM Implementation and GENCO's Optimizations

The main purpose of maintenance scheduling is to mitigate the system-wide impacts of outage events. Therefore, the outage events caused by the failure of critical generating units with high impacts on the system reliability should be prevented particularly under heavier loading conditions. Once the criticality degree of each generating unit on system reliability is evaluated, the ISO can determine the penalty coefficients such that GENCOs would be responsible for any unexpected outages. To confirm the effectiveness of the proposed approach, a GENCO having three generating units including units 7, 21, and 33 is considered. The simulations of the maintenance scheduler optimization are performed via using PSO and Monte–Carlo Simulation in MATLAB environment.

Table II shows the criticality factors obtained via the SVGT-based approach. The goal is to demonstrate the impact of the penalty costs on RCM schedules and profit of the producers. Table III summarizes the profit, revenue, preventive and corrective maintenance costs, number of unexpected outages, and number of tasks in two maintenance strategies. Table III shows that the producers' profit decreases and the number of maintenance tasks and PM costs increases if considering penalty costs for units to prevent their unplanned outages. Another advantage of the proposed method is considering the aging momentum of generating units. As shown in Table II, generating unit U21 is scheduled for maintenance more than others due to its higher aging momentum.

VI. CONCLUSION

An efficient formulation to prioritize the system components, specifically generating units, based on their failure impacts on system reliability is proposed. Employing a solution concept of game theory (SVGT), the criticality of each network equipment was linked to the risk imposed to the system due to its failure and also contribution in high-order contingencies. Example application of the proposed framework was illustrated through simulations on the IEEE-RTS case study with extensive discussions. According to the results, the proposed approach was well able to fairly map the outage consequences in case of higher order contingencies to the involved components. The suggested technique could successfully identify the system critical components from the reliability viewpoint for further maintenance focuses. It was shown that the suggested SVGT-based technique outperforms the conventional methods and has a higher accuracy and efficiency under various loading scenarios of the system.

An efficient analytical approach to recognize the intrinsic relationship between maintenance process, aging of generating units, system reliability, and system operation cost was also formulated. The proposed optimization framework for GENCOs to implement the RCM process on the generating units considering their criticality factors was implemented on several generating units and its effectiveness was confirmed. It was concluded that consideration of the penalty factors based on the unit's criticality degree is essential to realize a higher profit, lower unexpected outages, and risks to system reliability.

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