Long-Term Maintenance Scheduling and Budgeting in Electricity Distribution Systems Equipped With Automatic Switches

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***Abstract*—Maintenance management, as a key part of the asset management practices, plays a vital role in enhancing the reliability of the electricity distribution systems (EDS) where realizing a highly reliable EDS is being attributed higher and higher criticality in today's modern society. In this paper, a new approach is proposed to improve the reliability of EDS through optimal scheduling of preventive maintenance (PM) tasks and allocation of automatic switches. The suggested objective for optimal PM schedules and switch allocation is to minimize a combination of customer-based (system average interruption duration index and system average interruption frequency index) and cost-based reliability indices. The total reliability cost includes those associated with the corrective maintenance actions, PM tasks, and automatic switch investments. The proposed approach is implemented in three different scenarios: 1) switch placement, 2) PM tasks scheduling and budget management, as well as 3) a joint switch and PM tasks decision making. The aforementioned scenarios are applied on a standard reliability test system (RBTS4) followed by multiple sensitivity analysis to further demonstrate the efficacy and performance of the proposed framework.**

***Index Terms*—Corrective maintenance (CM), distribution automation (DA), maintenance budgeting, particle swarm optimization (PSO), power system reliability, preventive maintenance (PM), switch placement.**

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Notations

Notations Used Throughout the Paper are Introduced Below for Quick Reference.

Sets

Ω^{Cl}	Set of candidate locations for automatic switch installation.
$\Omega^{\mathrm{LP}}, \Omega^{F}$	Set of network load points/feeders.
$\Omega^{l}, \Omega^{\mathrm{tr}}$	Set of network line sections/transformers.
Ω^{Py}	Set of planning years.

Constants and Parameters

$b_{lf}, b_{\mathrm{tr}f}$	Constant factor of line/transformer budget in feeder f.
C_l^{mat}	Cost of materials necessary for repair of the faulted line.
$C_{\mathrm{tr}}^{\mathrm{mat}}$	Cost of materials required for repair of the faulted transformer.
$C_l^{\mathrm{rep}}, C_{\mathrm{tr}}^{\mathrm{rep}}$	Cost of one working hour necessary for repair of the faulted line/transformer.
C^{sw}	Investment cost of each automatic switch.
$I_i^{\max}$	Maximum value of branch/bus current.
Int	Interest rate.
$\mathrm{Inv}_{\mathrm{sw}}^{\mathrm{tot}}$	Total planning investment costs for switches (k$).
KPM^{ava}	Available PM budget of the utility (k$).
$\mathrm{Labor}_l^{\mathrm{rep}}$	Number of working hours necessary for repair of the faulted line.
$\mathrm{Labor}_{\mathrm{tr}}^{\mathrm{rep}}$	Number of working hours necessary for repair of the faulted transformer.
L_f, N_f	Line length and total number of transformers in feeder f.
P_{ik}, Q_{ik}	Active/ reactive power demand of bus i at year k.
q	Annual rate of demand increase.
$\mathrm{SAIDI}_{\mathrm{opt}}$	Optimal value of the SAIDI reliability index (h./cust.yr.).
$\mathrm{SAIFI}_{\mathrm{opt}}$	Optimal value of the SAIFI reliability index (occ./cust.yr.).
$t^{\mathrm{AS}}, t^{\mathrm{MS}}$	Automatic/ Manual switching time.
$\mathrm{TRC}_{\mathrm{opt}}$	Optimal value of the total reliability cost (k$).
t_{ij}^{rep}	Repair time experienced by customers connected to load point i in contingency j that cannot be transferred to backup feeder.
$V_i^{\min/\max}$	Minimum/Maximum voltage of bus i.

Y_{in}	Element of admittance matrix between bus i and n.
ω_i	Weighting coefficient for objective function i.
θ_{in}	Angle associated with the Y-matrix element Y_{in}.
$\lambda_{lf}^{\text{new}}, \lambda_{\text{tr}f}^{\text{new}}$	Initial failure rate of line/transformer in feeder f.
$\lambda_{lf}^{yr}, \lambda_{\text{tr}f}^{yr}$	Incremental failure rate of line/transformer in feeder f.
ρ_i	Price of energy in load point i (\$/kWh).
Functions	
Inv_{sw}	Total investment cost of automatic switches (k\$).
OF	Objective function.
SAIDI	System Average Interruption Duration Index (h./cust.yr.).
SAIFI	System Average Interruption Frequency Index (occ./cust.yr.).
TCENS	Total cost of energy not supplied.
TCIC	Total customer interruption cost.
TCM	Total cost of corrective maintenance (CM).
TCML	Total cost of materials and labors required for repair.
TRC	Total reliability cost (k\$).
TPM	Total cost of preventive maintenance (PM).
Variables	
CDF_{ij}	Customer damage function of load point i in contingency j.
CENS_{ijfk}	Utility revenue loss due to unsupplied energy in load point i during contingency j in feeder f at year k (\$).
CIC_{ijfk}	Customer interruption cost of load point i during contingency j in feeder f at year k (\$).
CML_{jfk}	Total cost of materials and labors required for repair of the contingency j in feeder f at year k (\$).
I_{ijk}	Branch current for load point i during contingency j at year k.
KPM_k	Total cost of PM in year k (\$).
LTP_{ij}	Binary variable equal to one if load point i can be supplied through the backup feeder in contingency j and 0, otherwise.
PM_{jfk}	PM budget of line/transformer j in feeder f in year k (\$).
P_{ijk}^{sub}	Net active power injected at bus i in contingency state j.
Q_{ijk}^{sub}	Net reactive power injected at bus i in contingency state j.
r_{ijk}	Restoration time for bus i during contingency j at year k.
sw_i	Binary decision variable equal to 1 if an automatic switch is installed at a candidate location i and 0, otherwise.
V_{ijk}	Voltage magnitude of bus i during contingency j at year k.
π_{ij}^{AS}	Variable that is 1 when automatic switch i acts correctly in contingency j and 0, otherwise.
λ_{jfk}	Failure rate of equipment j in feeder f at year k.
δ_{ijk}	Voltage angle of bus i during contingency j at year k.

I. Introduction

NOWADAYS, the social welfare highly relies on the reliability of the electricity grid. Electricity market deregulation has increasingly imposed waves of pressure to electric utilities in order to simultaneously enhance the customer reliability and decrease the utility operation costs. The reliability of the electricity distribution systems (EDS), compared to that of generation and transmission systems, is further crucial due to its direct correlation with the customer satisfaction and, therefore, its improvement should be carefully addressed in the EDS planning practices and decision-making policies. The customer reliability performance can be generally enhanced through 1) failure rate reduction, and 2) outage time reduction, where the EDS equipment failure rates can be decreased through timely and efficient maintenance management [1], [2] and outage time can be improved by installation of remotely controlled switches (RCSs).

A. Maintenance Scheduling and Management in EDS

Maintenance scheduling is regarded as an important part of the midterm asset management practices. Maintaining and modernizing the grid existing infrastructure are being seriously considered at the moment, with the expectations of maintenance investment waives be twice as much in the next two decades, majorly due to obsolete and aging infrastructure of the grid's [3], [4]. Timely maintenance management focuses on decreasing the equipment failure rate, which in turn, improves the equipment availability over time and enhances EDS reliability through reduction of outage frequencies [5]–[7]. Reliability-centered maintenance (RCM) has been proven as one of the interesting strategies balancing the maintenance cost and reliability of the EDS. The RCM was initially proposed and implemented in the manufacturing industries, followed by successful implementations in electrical networks, e.g., power plants, transmission, and distribution systems [8], [9]. RCM has been also implemented specifically on some types of electric equipment, e.g., on transmission lines [10]–[12], cable systems [13], and power transformers [14], [15], just to name a few. Focusing on power distribution systems, key factors for recognizing the EDS critical infrastructure for RCM implementation are specified in [16] and the list of critical equipment in both low voltage (LV) and medium voltage (MV) levels for maintenance priorities is presented. A comprehensive framework for practical implementation of RCM in EDS is suggested in [17] and [18]. Moreover, a maintenance program based on RCM principles for EDS reliability enhancement is developed by an Algerian electric company in [19]. Maintenance prioritization of EDS feeder sections is accomplished in [20], where the proposed algorithm is applied in EDS with significant deployment of distributed generation units.

In principle, RCM incorporates a cost-benefit analysis where corrective maintenance (CM) and preventive maintenance (PM) plans are optimally allocated to the system equipment [21]. Assigning appropriate time intervals between maintenance actions and recognizing the equipment priorities for maintenance activities has been always a significant challenge in EDS planning, budgeting, and operation decision makings [22], [23]. Several research efforts have been so far devoted for proposing new ideas in tackling the aforementioned challenge [22]–[27]. In [22], an approach based on the fuzzy analytical hierarchical process has been utilized in order to solve the multiobjective maintenance problem including reliability and cost objectives constrained by the available budget for maintenance. A method for maintenance budgeting of EDS utilities is introduced in [23], where the total outage cost is reduced through optimal allocation of available resources. In [24], Aravinthan and Jewell proposed an approach to minimize the EDS maintenance costs, while maintaining the desirable system reliability performance. A multiobjective optimization problem is solved in [25] in which both PM and CM activities are coordinated considering the customer interruption costs and available maintenance budgets. In [26], the critical outage causes are determined through fuzzy analysis, for which the maintenance budget is optimized accordingly. A failure rate model for overhead lines is introduced in [27] based on a failure mode analysis. A decoupled risk model in conjunction with state transition framework based on the decision tree concept is suggested in [28], which provides an accurate and significantly simplified model for maintenance scheduling problem in EDS and dynamic programming is then employed to evaluate the optimal maintenance scenarios. A mixed-integer programming model is proposed in [29] to schedule maintenance activities on overhead transmission lines.

B. Automatic Switch Placement in EDS

Once a fault occurs in electric networks, it should be quickly recognized and located. The sectionalizing switches are supposed to promptly isolate the faulted zones in distribution systems. Thus, there should be a plethora of sectionalizing switches available in the network to isolate the faulted segments in case of possible contingencies and enhance the EDS reliability performance. Wide deployment of automatic switches, however, mandates additional investments; hence, a tradeoff should be well thought between the system reliability and additional costs [30]. Indeed, such an approach aims at distribution automation resulting in a sharp decrease of the customer interruption frequency and duration. A number of studies have been yet conducted to explore the optimal placement of automatic switches in EDS [31]–[34]. A greedy search algorithm has been employed in [31] for optimal allocation of RCS. Abiri-Jahromi *et al.* in [32] introduced a new optimization approach for deciding on the optimal location of RCS with the intent of minimizing the total cost including customer interruption costs, investments, as well as annual operation and maintenance costs associated with the automatic switches. Optimal allocation of both manual and automated switches has been simultaneously taken into account in [33] and [34] through a probabilistic analysis of control strategies in all possible contingency scenarios.

C. Highlights and Contributions

This paper proposes a coordinated framework considering both maintenance budgeting and automatic switch placement in EDS. It is observed that simultaneous consideration of maintenance budgeting and switch placement leads to an emerging

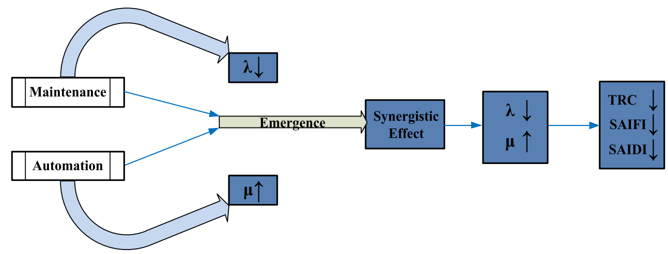

Fig. 1. Conceptual framework for integrated maintenance and automation in EDS.

improvement in reliability cost and reliability indices, comparing to that of a separate consideration. Conceptual framework of the paper idea is shown in Fig. 1. This concept shows the synergistic effect of maintenance and automation to reduce reliability cost and improve the reliability indices. The suggested objective function is to minimize the system total reliability cost (TRC), system average interruption duration index (SAIDI), and system average interruption frequency index (SAIFI). The TRC is suggested to include those associated with the CM and PM plans as well as the automatic switch investments. CM cost consists of the customer interruption costs, energy not supplied costs, and that associated with the required labor and material for repair. The proposed procedure is framed in three different scenarios:

1) automatic switch placement alone;
2) PM budgeting planning with presence of automatic switches found in the former scenario; and
3) the simultaneous maintenance budget allocation and switch placement.

Multiple sensitivity analyses are conducted to further complement the optimal solutions. The remainder of this paper is structured as follows: Section II introduces the problem formulations and the solution approach is presented in Section III. Numerical case studies are extensively conducted through three different scenarios in Section IV. Discussions and sensitivity analysis are provided in Section V and finally comes the conclusions in Section VI.

II. Problem Formulation

Providing the customers with highly reliable electricity has been always a key concern for electric utilities that has brought about some inevitable challenges in adopting efficient practices for ensuring a continuous delivery of electricity to customers. In this paper, EDS reliability is improved through maintenance activities scheduling as well as optimal allocation of sectionalizing switches.

A. Objective Function

The objective function of the presumed problem is to minimize a combined customer-based (SAIFI and SAIDI) and cost-based (TRC) reliability index. Indeed, the objective function is to minimize (1), where TRC is the TRC considering all investments, PM, and CM expenses as defined in (2) and (3). Besides, $\mathrm{Inv}_{\mathrm{sw}}$ is the investment cost of switches that should be optimally located in the EDS. The TCM is calculated in (3), where it includes the total customer interruption cost (TCIC), total cost of energy not supplied (TCENS), and the total cost of materials and labor required for repair (TCML). The optimal value for each term of the objective function is calculated when another is not included. Moreover, the normalized values of indices are weighted through coefficients ω_1, ω_2, and ω_3, which could be defined based on practical considerations and EDS operator preferences.

Minimize

$$\mathrm{OF} = \left\{\omega_1 \times \frac{\mathrm{TRC} - \mathrm{TRC}_{\mathrm{opt}}}{\mathrm{TRC}_{\mathrm{opt}}} + \omega_2 \times \frac{\mathrm{SAIDI} - \mathrm{SAIDI}_{\mathrm{opt}}}{\mathrm{SAIDI}_{\mathrm{opt}}} + \omega_3 \times \frac{\mathrm{SAIFI} - \mathrm{SAIFI}_{\mathrm{opt}}}{\mathrm{SAIFI}_{\mathrm{opt}}}\right\} \quad (1)$$

$$\mathrm{TRC} = \mathrm{TCM} + \mathrm{TPM} + \mathrm{Inv}_{\mathrm{sw}} \quad (2)$$

$$\mathrm{TCM} = \mathrm{TCIC} + \mathrm{TCENS} + \mathrm{TCML}. \quad (3)$$

Further, the TCIC is a sizeable chunk of the cost during outages that the EDS utilities are plagued with as follows:

$$\mathrm{TCIC} = \sum_{k\in\Omega^{\mathrm{Py}}} \left(\frac{1}{1+\mathrm{Int}}\right)^{k} .(1+q)^{k-1} . \left[\sum_{f\in\Omega^F} \sum_{j\in\{\Omega^l\cup\Omega^{\mathrm{tr}}\}} \sum_{i\in\Omega^{\mathrm{LP}}} \mathrm{CIC}_{ijfk}\right] \quad (4)$$

$$\mathrm{TCENS} = \sum_{k\in\Omega^{\mathrm{Py}}} \left(\frac{1}{1+\mathrm{Int}}\right)^{k} .(1+q)^{k-1} . \left[\sum_{f\in\Omega^F} \sum_{j\in\{\Omega^l\cup\Omega^{\mathrm{tr}}\}} \sum_{i\in\Omega^{\mathrm{LP}}} \mathrm{CENS}_{ijfk}\right]. \quad (5)$$

In (4), the total interruption cost is calculated considering all possible contingency scenarios resulting in interruptions of the EDS load points. Herein, the CIC_{ijfk} is the customer interruption cost in the contingency j provided that the load point i cannot be restored in feeder f in year k. In (5), the CENS_{ijfk} is the revenue loss of the utility due to the unsupplied energy during contingency j provided that the load point i cannot be restored in feeder f in year k. Also, the interest rate is assumed to be constant during the planning period and the load increase rate $(1+q)^{t-1}$ has been also taken into account in (4) and (5)

$$\mathrm{CIC}_{ijfk} = \lambda_{jfk}.L_f.P_{ik}.\mathrm{CDF}_{ij}(r_{ijk}) \;\; \forall i \in \Omega_f^{\mathrm{LP}}, \forall j \in \Omega_f^l, \forall f \in \Omega^F, \forall k \in \Omega^{\mathrm{Py}} \quad (6)$$

$$\mathrm{CIC}_{ijfk} = \lambda_{jfk}.P_{ik}.\mathrm{CDF}_{ij}(r_{ijk}) \quad \forall i \in \Omega_f^{\mathrm{LP}}, \forall j \in \Omega_f^{\mathrm{tr}}, \forall f \in \Omega^F, \forall k \in \Omega^{\mathrm{Py}} \quad (7)$$

$$\mathrm{CENS}_{ijfk} = \lambda_{jfk}.L_f.P_{ik}.r_{ijk}.\rho_{ik} \quad \forall i \in \Omega_f^{\mathrm{LP}}, \forall j \in \Omega_f^l, \forall f \in \Omega^F, \forall k \in \Omega^{\mathrm{Py}} \quad (8)$$

$$\mathrm{CENS}_{ijfk} = \lambda_{jfk}.P_{ik}.r_{ijk}.\rho_{ik} \quad \forall i \in \Omega_f^{\mathrm{LP}}, \forall j \in \Omega_f^{\mathrm{tr}}, \forall f \in \Omega^F, \forall k \in \Omega^{\mathrm{Py}} \quad (9)$$

$$\lambda_{jfk} = (\lambda_{jf(k-1)} + \lambda_{lf}^{yr}).e^{b_{lf}.\mathrm{PM}_{jfk}} \quad \forall j \in \Omega_f^l, \forall f \in \Omega^F, \forall k \in \Omega^{\mathrm{Py}} \quad (10)$$

$$\lambda_{jfk} = (\lambda_{jf(k-1)} + \lambda_{\mathrm{tr}f}^{yr}).e^{b_{\mathrm{tr}f}.\mathrm{PM}_{jfk}} \quad \forall j \in \Omega_f^{\mathrm{tr}}, \forall f \in \Omega^F, \forall k \in \Omega^{\mathrm{Py}} \quad (11)$$

$$r_{ijk} = \mathrm{LTP}_{ijk}.(t^{\mathrm{AS}}.\pi_{ij}^{\mathrm{AS}} + t^{\mathrm{MS}}.(1-\pi_{ij}^{\mathrm{AS}})) + (1-\mathrm{LTP}_{ijk}).t_{ij}^{\mathrm{rep}} \quad \forall i \in \Omega_f^{\mathrm{LP}}, \forall j \in \{\Omega_f^l \cup \Omega_f^{\mathrm{tr}}\}, \forall k \in \Omega^{\mathrm{Py}}. \quad (12)$$

CIC_{ijfk} and CENS_{ijfk} are calculated in (6)–(9) for all line and transformer contingencies, with the required parameters defined in (10) and (11). r_{ijk} is the restoration time for bus i in case of contingency j, which is calculated in (12) where LTP_{ijk} denotes the load transfer possibility determined through load flow analysis. Moreover, π_{ij}^{AS} is the probability of accurate automatic switching for load point i in case of contingency j. Indeed, the restoration time for load point i in case of contingency j is equal to the automatic switching time (t^{AS}), if load point i can be automatically transferred to the backup feeder (i.e., $\pi_{ij}^{\mathrm{AS}} = 1$ and $\mathrm{LTP}_{ijk} = 1$). Similarly, the restoration time for load point i in contingency j will be equal to manual switching time (t^{MS}), if this load point can be transferred to the backup feeder, while the automatic switching is infeasible due to failure of an automatic control, i.e., through failure of automatic switches and/or the communication network (i.e., $\pi_{ij}^{\mathrm{AS}} = 0$ and $\mathrm{LTP}_{ijk} = 1$). Furthermore, the restoration time of the load point i in contingency j will be equal to the repair time of the defected equipment, if this load point cannot be transferred to a backup feeder ($\mathrm{LTP}_{ijk} = 0$).

Equipment outages can happen due to either random or deteriorating failures. Random failures are modeled through exponential probability distributions with constant failure rates, while deteriorating failures are modeled through Weibull or normal probability distributions [29]. Since the failure rate is typically considered constant for random failures, maintenance activities cannot prevent such random failures. However, failure rates originated from deterioration (i.e., aging) are time-varying and, hence, planned maintenance activities will bring about significant improvements over time [see (10), (11)] [9].

The other monetary term of the suggested objective function is the labor and material costs for repairing the distribution overhead lines and transformers. The average number of working hours and the amount of materials needed to repair such failures are simply prespecified; thus, the total cost of repair can be quantified in (13)–(15). In (14) and (15), the cost of repair materials and labors for overhead lines and transformers is quantified [29]. Moreover, the total cost of PM activities is assessed in (16) and (17). In (17), the first term refers to the total budget available for maintenance of the network lines while the second term denotes that of the network transformers

$$\mathrm{TCML} = \sum_{k\in\Omega^{\mathrm{Py}}} \left(\frac{1}{1+\mathrm{Int}}\right)^{k} . \left[\sum_{f\in\Omega^F} \sum_{j\in\{\Omega^l\cup\Omega^{\mathrm{tr}}\}} \mathrm{CML}_{jfk}\right] \quad (13)$$

$$\mathrm{CML}_{jfk} = \lambda_{jfk}.L_f.(C_l^{\mathrm{rep}} \times \mathrm{Labor}_l^{\mathrm{rep}} + C_l^{\mathrm{mat}}) \quad \forall j \in \Omega_f^l, \forall f \in \Omega^F, \forall k \in \Omega^{\mathrm{Py}} \tag{14}$$

$$\mathrm{CML}_{jfk} = \lambda_{jfk}.N_f.(C_{\mathrm{tr}}^{\mathrm{rep}} \times \mathrm{Labor}_{\mathrm{tr}}^{\mathrm{rep}} + C_{\mathrm{tr}}^{\mathrm{mat}}) \quad \forall j \in \Omega_f^{\mathrm{tr}}, \forall f \in \Omega^F, \forall k \in \Omega^{\mathrm{Py}} \tag{15}$$

$$\mathrm{TPM} = \sum_{k\in\Omega^{\mathrm{Py}}} \left(\frac{1}{1+\mathrm{Int}}\right)^k .\mathrm{KPM}_k \tag{16}$$

$$\mathrm{KPM}_k = \sum_{f\in\Omega^F}\sum_{j\in\Omega^l} \mathrm{PM}_{jfk}.L_f + \sum_{f\in\Omega^F}\sum_{j\in\Omega^{\mathrm{tr}}} \mathrm{PM}_{jfk}.N_f \quad \forall k \in \Omega^{\mathrm{Py}}. \tag{17}$$

The investment cost of automatic switches is evaluated in (18), where Ω^{Cl} is the total number of feasible candidate locations for installation of automatic switches. The candidate locations include both upstream and downstream sections of the buses located at the main feeder, excluding the fixed locations for normally open tie switches

$$\mathrm{Inv}_{\mathrm{sw}} = \sum_{s\in\Omega^{\mathrm{Cl}}} \mathrm{sw}_s.C^{\mathrm{sw}}. \tag{18}$$

B. Optimization Constraints

The proposed optimization problem is subject to several technical and economic constraints introduced below.

1) Power Balance Constraints: Active and reactive power balance at each bus must be fulfilled under all possible contingency scenarios. The forward–backward sweep method is employed in this paper to consider the power balance constraints defined as follows:

$$P_{ijk}^{\mathrm{sub}} - P_{ijk} = \sum_{n\in\Omega^{\mathrm{LP}}} Y_{in}.V_{ijk}.V_{njk}.\cos(\delta_{ijk} - \delta_{njk} + \theta_{in}) \quad \forall i \in \Omega_f^{\mathrm{LP}}, \forall j \in \{\Omega_f^l \cup \Omega_f^{\mathrm{tr}}\}, k \in \Omega^{\mathrm{Py}} \tag{19}$$

$$Q_{ijk}^{\mathrm{sub}} - Q_{ijk} = \sum_{n\in\Omega^{\mathrm{LP}}} Y_{in}.V_{ijk}.V_{njk}.sin(\delta_{ijk} - \delta_{njk} + \theta_{in}) \quad \forall i \in \Omega_f^{\mathrm{LP}}, \forall j \in \{\Omega_f^l \cup \Omega_f^{\mathrm{tr}}\}, k \in \Omega^{\mathrm{Py}}. \tag{20}$$

2) Total PM Cost Constraints: From the economic point of view, the available budget for EDS maintenance is typically restricted and scarce. The optimization problem tries to optimally allocate the available maintenance budget to equipment needing it the most in order to improve the overall system reliability performance. Accordingly, the maintenance budget constraint is enforced in the following equation:

$$\mathrm{KPM}_k \le \mathrm{KPM}^{\mathrm{ava}} \qquad k \in \Omega^{\mathrm{Py}}. \tag{21}$$

3) Automatic Switch Investment Cost Constraints: The limited budget of distribution automation confines the number of automatic switches to be installed, as dictated in the following equation:

$$\mathrm{Inv}_{\mathrm{sw}} \le \mathrm{Inv}_{\mathrm{sw}}^{\mathrm{tot}}. \tag{22}$$

4) Network Configuration Constraints: From an operational perspective, the distribution network should maintain its radial configuration, both in normal and restoration states.

5) Voltage Constraints: According to the following equation, the voltage magnitude at each bus should remain within a standard predefined range, as follows:

$$V_i^{\min} \le V_{ijk} \le V_i^{\max} \quad \forall i \in \Omega_f^{\mathrm{LP}}, \forall j \in \{\Omega_f^l \cup \Omega_f^{\mathrm{tr}}\}, k \in \Omega^{\mathrm{Py}}. \tag{23}$$

6) Line Flow Constraints: As defined in the following equation, the line thermal capacity restricts the maximum current that can be carried through each feeder conductors without damaging the feeder cables:

$$I_{ijk} \le I_i^{\max} \quad \forall i \in \Omega_f^{\mathrm{LP}}, \forall j \in \{\Omega_f^l \cup \Omega_f^{\mathrm{tr}}\}, k \in \Omega^{\mathrm{Py}}. \tag{24}$$

III. Solution Approach

Meta-heuristic algorithms are commonly employed to solve various types of optimization problems, among which the particle swarm optimization (PSO) algorithm has well demonstrated its accuracy and effectiveness in different fields of engineering. The PSO algorithm performs simultaneous search locally and globally to find the optimum solution. This method, introduced in 1995 [36], employs initial vectors in the form of X_i, called particles. A speed vector (V_i) is assigned to each particle to lead it toward the best-known local and global particles. The formulation for updating the particles in a given optimization problem is as follows:

$$X_j^{k+1} = X_j^k + \lfloor V_j^k \rfloor \tag{25}$$

$$V_j^{k+1} = \omega^k \times V_j^k + c_1 \times r_1 \times (P\mathrm{best}_j^k - X_j^k) + c_2 \times r_2 \times (G\mathrm{best}_j^k - X_j^k) \tag{26}$$

where ω^k is an inertia weight that tries to maintain previous speed of each particle; $P\mathrm{best}_j^k$ is the best record of particle j until iteration k; $G\mathrm{best}^k$ is the best record of all particles until iteration k; c_1 and c_2 are local and global optimization parameters, respectively; and r_1 and r_2 are random numbers in the range of [0, 1].

The flowchart of the proposed algorithm is demonstrated in Fig. 2. As shown in this figure, while the entire contingencies are being analyzed in the proposed optimization problem, the reliability indices and fitness functions are evaluated for the generated PM budget and switch locations decisions. New switch locations and budgeting decisions are then updated and the process is repeated until the termination criterion is met. The termination condition is here considered to be the maximum number of iterations.

IV. Case Study and Numerical Analysis

A standard test case, the bus number 4 of the Roy Billinton Test System (RBTS), is employed in this paper to demonstrate the effectiveness of the proposed framework. The test system is illustrated in Fig. 3, for which all the system and equipment data including failure rates, repair times, demand types, etc.

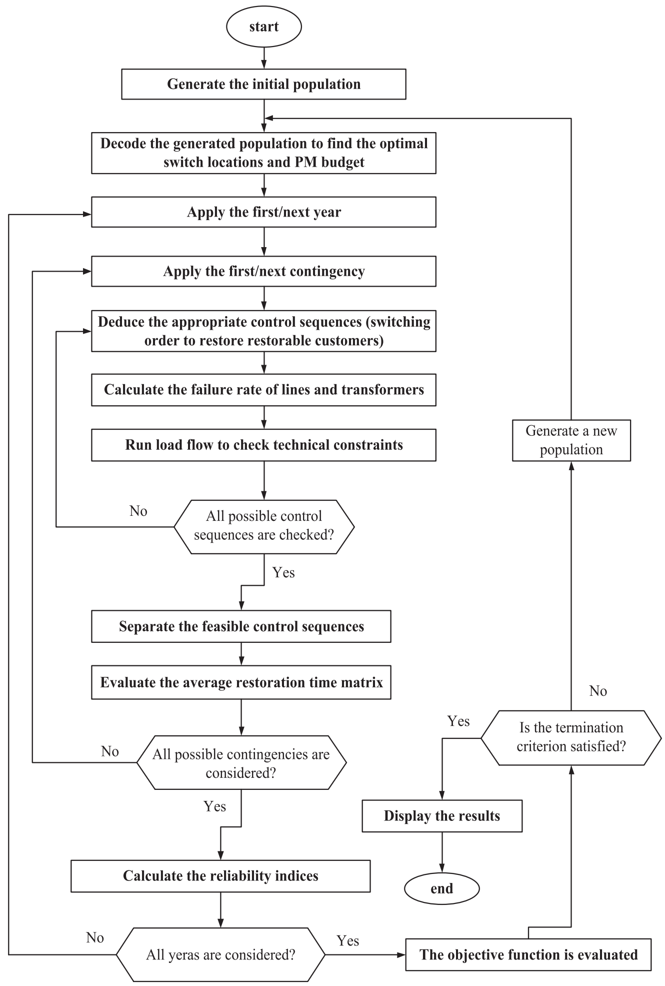

Fig. 2. Flowchart of the proposed optimization algorithm.

can be found in [37]. Furthermore, the network parameters are borrowed from [38] and simulation data including the customer interruption costs for different types of customers and the energy price of different load points are provided in Fig. 4 and Table I, respectively [27], [35], [39].

The overhead line failure rates are derived from the Weibull probability distributions in [29] and the transformer failure rates are calculated from the Weibull probability distributions in [35]. Herein, it is assumed that the RCM planning is conducted for an EDS where the equipment is installed ten years ago. Thus, the equipment failure rates at the beginning of the planning horizon are considered equal to that of ten years working equipment. The planning horizon is considered 5 years, and the interest rate (Int) and annual demand increase rate (q) during the planning horizon are assumed equal to 6% and 3%, respectively. The available budget of the utility to invest in automatic switches and annual PM tasks are considered to be 450 and 100 k$, respectively. The installation cost of each automatic switch and charging station is assumed 21 k$ [33]. Maximum and minimum voltage at each bus should be $1.05^{\mathrm{p.u}}$ and $0.9^{\mathrm{p.u}}$, respectively [40]. The weighting parameters ω_1, ω_2, and ω_3 are supposed to be equal to 0.7, 0.15, and 0.15, respectively. Further, b_{lf} and $b_{\mathrm{tr}f}$ have been extracted from the historical data of the Greater Tehran Electricity Distribution Company through an exponential curve fitting technique and are found equal to –0.0001 and –0.00022, respectively [26]. $\lambda_{lf}^{\mathrm{new}}$ and $\lambda_{\mathrm{tr}f}^{\mathrm{new}}$ are assumed equal to 0.065 and 0.015 occ./fault per year per kilometer, respectively [37]. Furthermore, the repairing time for lines and transformers are 3 and 5 h, respectively [41]–[43]. Also, the required labor hours, labor cost, and material cost for repair tasks are all provided in Table II.

The TRC, SAIDI, and SAIFI indices are first calculated for the existing system reflecting the base case condition, where no automatic switches exist and no PM tasks are scheduled in the distribution system. The base case TRC, SAIDI, and SAIFI indices are calculated as 3749.514 (k$), 10.2535 (h./cust.yr.), and 2.9497 (occ./cust.yr.), respectively. The optimization problem is then solved through three different scenarios. In the first scenario, automatic sectionalizing switches are optimally allocated in the EDS. The optimal values of TRC, SAIDI, and SAIFI indices [used in (1)] in the first scenario are calculated as 1557.968 k$, 3.4943 (h./cust.yr.), 2.9497 (occ./cust.yr.), respectively. According to the results presented in Table III, 20 automatic switches are located within the EDS; as a result, the distribution automation cost is found to be 420 k$, and the TRC in this scenario is equal to 1572.054 k$. Also, the SAIDI index of reliability has decreased from 10.2535 to 4.1164 (h./cust.yr.), while the SAIFI index of reliability has remained unchanged.

The optimal values of the TRC, SAIDI, and SAIFI indices [used in (1)] in the second scenario are found to be 1405.886 k$, 2.3902 (h./cust.yr.), and 1.7497 (occ./cust.yr.), respectively, while they are 1384.964 k$, 2.0659 (h./cust.yr.), and 1.7497 (occ./cust.yr.), in the third scenario. According to the results presented in Table III, the optimal PM tasks for lines and transformers as well as the PM budget for each feeder have changed in the third scenario in comparison to those in the second one, since in the former, the PM tasks and budgets are optimally allocated with respect to the automatic switch locations which should be optimally determined too. In fact, in the last scenario, the number of automatic switches decreased and the participation of PM tasks and budget increased. This, in turn, results in a change in the location of the required automatic switches and PM tasks to decrease the TRC and SAIDI indices. Parts of the system where the PM tasks are scheduled and the required budget for lines and transformers of feeders are shown in Table III. In this table, 1(1-2-3-4) reflects the PM task to be performed on line of feeder 1 in first, second, third, and fourth year, with the associated PM budget represented in the next column. Moreover, in the second scenario, locations of switches are fixed according to the results obtained in the first scenario, and the PM tasks are accomplished in the earlier years compared to decisions in the third scenario. Hence, the PM tasks in the third scenario tend to be allocated in more recent years. Conversely, in the last scenario, as the switch locations and PM tasks are determined simultaneously, switches can be allocated in the middle of the zones. Hence, a considerable proportion of the load points in the affected zones could be restored through the backup feeders, as a result of which PM tasks are no longer forced to be

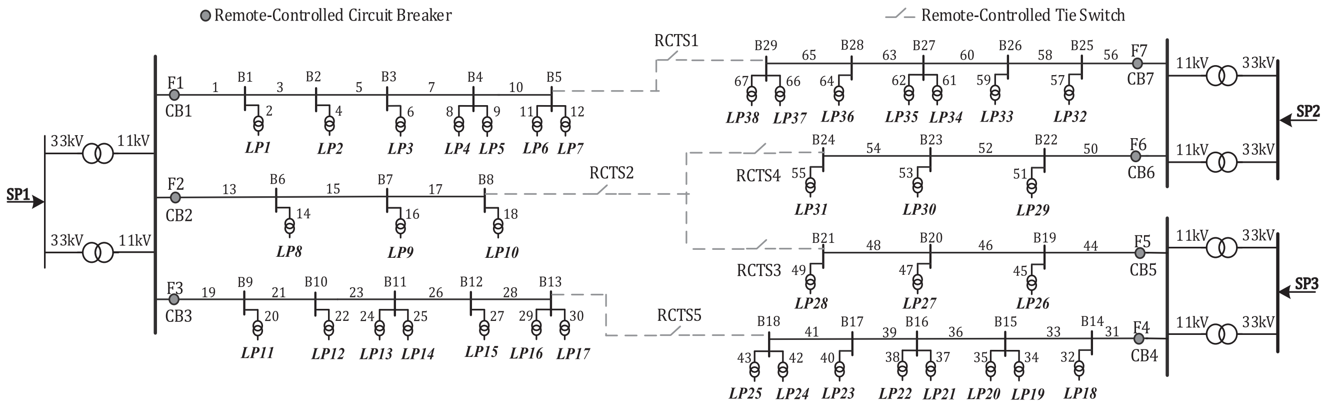

Fig. 3. Studied test system: the bus number 4 of RBTS [37].

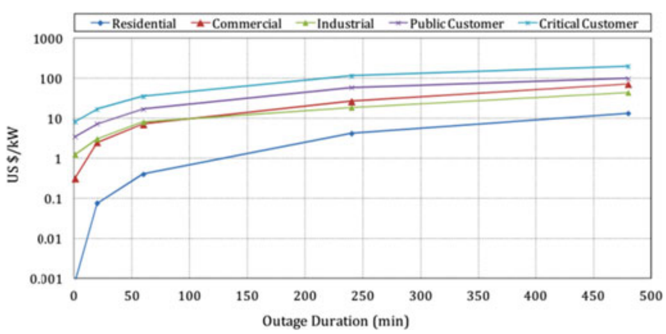

Fig. 4. Interruption cost for different types of customers [39].

TABLE I
PRICE OF ENERGY FOR DIFFERENT TYPES OF CUSTOMERS [27]

Customer Category	Residential	Commercial	Industrial
Price of Energy ($/kWh)	0.05	0.12	0.12

TABLE II
REQUIRED LABOR HOURS, LABOR COST, AND MATERIAL COST FOR REPAIR TASKS [35]

Equipment	$C^{\text{rep}}\,[\$/\text{h}]$	$\text{Labor}^{\text{rep}}\,[\text{h}]$	$C^{\text{mat}}\,[\$]$
Lines	19.7218	10	65.7328
Transformers	54.7745	60	230.065

allocated in early years and are distributed during the planning years.

As illustrated in Fig. 5, CIC of most load points in the last scenario is the same as that in the second scenario, despite the fact that the CIC for some load points have an insignificant increase. However, this increase is much more than the CIC reduction in other load points; accordingly, the CIC in aggregation has increased in the last scenario but the TRC has generally decreased. Moreover, load point restoration time during the entire planning period is demonstrated in Fig. 6, where the restoration time for most load points in the last scenario has decreased compared to the other scenarios, while the restoration time for some load points have an insignificant increase. Again, this increase in restoration time is much less than the reduction in other load points; accordingly, the SAIDI in aggregation has declined in the last scenario.

V. DISCUSSIONS

While the effectiveness of the proposed framework has been demonstrated earlier in Section IV, several parameters such as objective function weighting coefficients as well as the time when the EDS is planned to be equipped with RCSs and PM task schedules might affect the optimal decision on automatic switch placement and PM task schedules and budgets. Accordingly, sensitivity analysis is pursued in this section to evaluate the consequence of such adjustments on the performance of the proposed framework.

A. Sensitivity Analysis on the Choice of Reliability Index

As noted earlier, the SAIFI, SAIDI, and TRC indices are considered in the proposed objective function. The priority of SAIFI, SAIDI, and TRC indices are defined by weighting coefficients ω_1, ω_2, and ω_3, respectively. If one weighting coefficient is set equal to one, the problem is solved to minimize the related function and the other weights would be set to zero. Thus, to evaluate the impact of changes in the SAIFI and SAIDI as the customer welfare indices and the TRC as the total cost of the system, sensitivity analysis is performed on the associated weighting coefficients. To this end, the proposed formulation is tested in scenario III with respect to ten different cases and the results are shown in Table IV. One can see, from Table IV, that when the objective function is solely assumed to be minimizing the SAIFI index of reliability, the system total cost and the SAIDI indices would increase. The same trend is observed when minimizing the SAIDI index is the only objective of the problem. However, load points with the higher values of interruption cost possess higher priorities, when the TRC index is assumed as the only term in the objective function, as a result of which both the SAIFI and SAIDI indices increase.

TABLE III
PLANNING RESULTS FOR SWITCH LOCATIONS AND PM TASKS SCHEDULES

Case	Optimal Locations of Automatic Switches	Optimal PM Schedule for Line of Feeder (yr.)	Optimal PM Budget for Line of Feeder (k$/km)	Optimal PM Schedule for Transformer of Feeder (yr.)	Optimal PM Budget for Transformer of Feeder (k$/transformer)	SAIFI (occ./cust.yr.)	SAIDI (h./cust.yr.)	TRC (k$)	TPM (k$)	TCM (k$)
Existing System	–	–	–	–	–	2.9497	10.2535	3749.514	0	3749.514
Scenario I	3U-7U-10U-15U-17D-17U-23D-26U-28U-36D-39U-41U-46U-48U-52D-52U-54U-60D-63U-65U	–	–	–	–	2.9497	4.1164	1572.054	0	1152.054
Scenario II	3U-7U-10U-15U-17D-17U-23D-26U-28U-36D-39U-41U-46U-48U-52D-52U-54U-60D-63U-65U	1(1-2-3-4), 2(1-2-3), 3(1-2-3-4), 4(1-2-3-4), 5(1-2-3-4), 6(1-3-4), 7(1-2-3-4)	0.4-0.4-1.2-2-0.5-1.6-2.7-0.7-1.4-1.2-1.4-1.1-2.2-0.2-3.1-0.2-2.8-2.3-0.1-2.9-0.8-0.5-0.7-2.6-0.6-1.6	1(1-3-4), 2(1-2-3-4), 3(1-2-3-4), 4(1-2-3-4), 5(1-3), 6(1-2-3-4), 7(1-2-3-4)	1.8-1.2-0.2-0.9-2.1-1.6-0.7-0.8-0.8-1.2-0.4-1.9-0.4-1.1-1-2.8-2.8-1.7-1.1-0.9-1.5-1.3-0.6-0.8-0.8	2.0637	2.8219	1525.325	345.838	759.486
Scenario III	5D-7U-10U-15U-17U-23D-26U-28U-36D-39U-41U-46U-48U-52U-54U-60D-63U-65U	1(1-2-3-4), 2(1-2-3-4), 3(1-2-3-4), 4(1-2-3-4), 5(1-2-3), 6(1-2-3-4), 7(1-2-3-4)	0.4-0.4-1.2-1.5-0.5-1.6-2.7-1.5-0.7-1.4-1.2-1.3-1.1-2.2-0.2-3.1-0.2-2.7-2.3-2.9-0.1-0.8-1.8-0.7-2.6-0.6-1.5	1(1-3-4), 2(1-2-3-4), 3(1-2-3-4), 4(1-2-3-4), 5(1-3), 6(1-2-3-4), 7(1-2-3-4-5)	1.8-1.2-0.1-0.9-2.1-1.6-0.5-0.8-0.8-1.5-0.3-1.9-0.4-1.1-0.9-2.8-2.8-1.7-1.1-0.9-1.3-1.3-0.6-0.5-0.6-0.9	2.075	2.795	1515.928	351.176	786.751

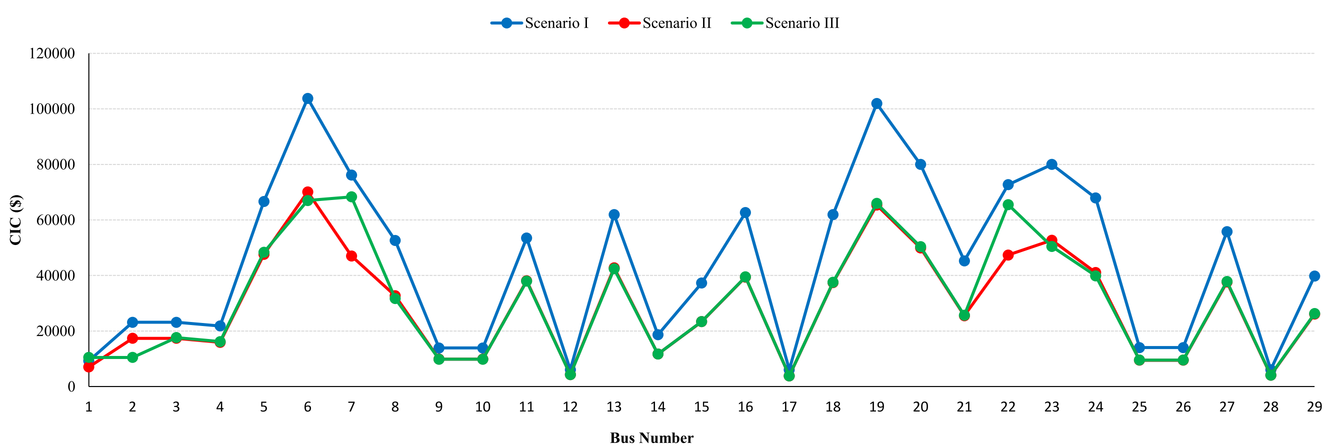

Fig. 5. CIC for the network load points.

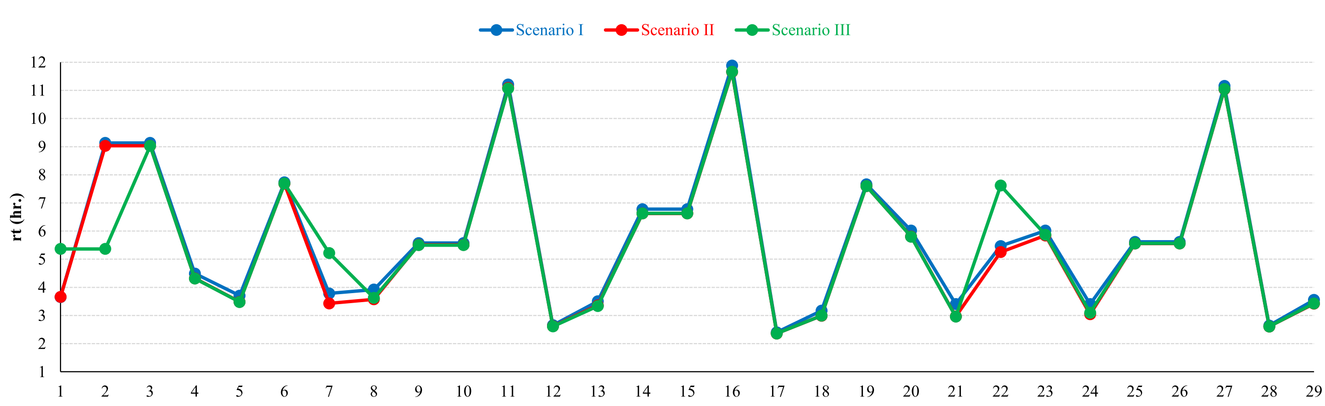

Fig. 6. Restoration time for different load points of the studied network.

TABLE IV
SENSITIVITY ANALYSIS RESULTS ON SCENARIO III

ω_1	ω_2	ω_3	SAIFI (occ./cust.yr.)	SAIDI (h./cust.yr.)	TRC (k$)	TPM (k$)	TCM (k$)
0.7	0.15	0.15	2.075	2.795	1515.928	351.176	786.751
0.15	0.7	0.15	1.8276	2.1398	2389.838	421.133	1548.705
0.15	0.15	0.7	1.7779	2.3966	1795.353	421.019	954.333
0	0	1	1.7490	3.7220	2717.696	421.043	1918.652
0.25	0.25	0.5	1.7583	2.3074	1767.533	421.118	926.415
0	1	0	1.8227	2.0659	2941.083	420.758	2100.325
0.25	0.5	0.25	1.7720	2.3566	1796.768	421.107	955.661
1	0	0	2.7387	4.1321	1384.964	222.199	826.765
0.5	0.25	0.25	1.8238	2.3588	1727.196	356.597	950.598
0.33	0.33	0.33	1.7736	2.3176	1811.935	421.056	970.879

TABLE V
SENSITIVITY ANALYSIS ON THE SCHEDULES OF THE PLANNED ACTIONS

year	Optimal Location of Automatic Switches	Optimal PM Schedule for Line of Feeder (yr.)	Optimal PM Budget for Line of Feeder (k$/km)	Optimal PM Schedule for Transformer of Feeder (yr.)	Optimal PM Budget for Transformer of Feeder (k$/transformer)	SAIFI (occ./cust.yr.)	SAIDI (h./cust.yr.)	TRC (k$)	TPM (k$)	TCM (k$)
1–5	5D-7U-10U-15U-17U-21U-26U-33D-36D-39U-52U-54U-60D-63U-65U	1(4), 2(5), 3(2,5), 4(2-3), 5(2-3-4), 6(4), 7(2-3)	1.3-2.9-1.4-0.5-1-0.8-2.1-2.5-0.8-0.1-2.2-1.3	1(3), 3(2), 4(3-4-5), 5(2-3-4), 6(2), 7(3)	0.2-1.8-1.9-1.4-1.4-1.1-2.4-0.7-0.1-0.3	0.9654	1.3487	848.335	148.308	385.026
6–10	5D-7U-10U-15U-17U-23D-26U-28U-36D-39U-41U-46U-48U-52U-54U-60D-63U-65U	1(1-2-3), 2(1-2-3), 3(1-2-3), 4(1-2-3), 5(1-2), 6 (1-2), 7(1-2-3)	1.4-0.7-0.2-0.6-1.1-1.3-0.3-0.7-2-2.2-1-2.5-1.5-1.7-2.2-0.7-1.3-0.8-2.6	1(1-2-3), 2(1-2-3-4), 3(1-2-3), 4(1-2-3), 5(1-2), 6(1-2-3), 7(1-2)	1.5-0.1-0.7-1.6-0.5-0.7-1.2-0.5-1.3-0.8-1.3-0.9-1.5-0.3-3.4-0.9-1.8-1.7-0.3-3.2	1.4851	2.0042	1163.838	270.039	515.799
11–15	5D-7U-10U-15U-17U-23D-26U-28U-36D-39U-41U-46U-48U-52U-54U-60D-63U-65U	1(1-2-3-4), 2(1-2-3-4), 3(1-2-3-4), 4(1-2-3-4), 5(1-2-3), 6(1-2-3-4), 7(1-2-3-4)	0.4-0.4-1.2-1.5-0.5-1.6-2.7-1.5-0.7-1.4-1.2-1.3-1.1-2.2-0.2-3.1-0.2-2.7-2.3-2.9-0.1-0.8-1.8-0.7-2.6-0.6-1.5	1(1-3-4), 2(1-2-3-4), 3(1-2-3-4), 4(1-2-3-4), 5(1-3), 6(1-2-3-4), 7(1-2-3-4-5)	1.8-1.2-0.1-0.9-2.1-1.6-0.5-0.8-0.8-1.5-0.3-1.9-0.4-1.1-0.9-2.8-2.8-1.7-1.1-0.9-1.3-1.3-0.6-0.5-0.6-0.9	2.075	2.795	1515.928	351.176	786.751
16–20	7U-10U-15D-15U-17U-23D-26U-28U-36D-39U-41U-44U-46U-48D-48U-52U-54U-60D-63U-65U	1(1-2-3-4), 2(1-2), 3(1-2-3-4), 4(1-2-3-4), 5(1-2-4), 6(1-2-4), 7(1-3-4)	0.4-0.3-2-1.8-3.9-2.2-0.3-0.8-2.8-0.1-0.2-0.3-1.1-4.4-2-2-0.6-4.1-2.4-0.2-0.8-3.2-0.8	1(1-2-3-4), 2(1-2-3-4), 3(1-2-3-4), 4(1-2-3-4), 5(1-2-4), 6(1-2-4-5), 7(1-2-3-4)	0.6-2.5-0.1-0.3-3.1-0.5-0.3-2-0.9-0.6-0.8-1.8-1.1-1.1-0.9-0.9-1.6-2.7-0.3-2.6-2.4-0.1-0.7-0.1-1.7-0.9-0.4	2.8506	4.0381	1864.668	347.885	1096.782

B. Sensitivity Analysis on the Schedule of the Planned Actions

A sensitivity analysis is conducted to consider the effect of the time schedules for planning the PM tasks and RCS installations on the reliability and cost performance of the studied EDS. For this purpose, four time horizons are considered as shown in Table V. Failure rate of the lines and transformers in each scenario are calculated from the Weibull probability distributions. In the first year of the 20-year planning period, the equipment failure rate is considered equal to that of its new condition while increasing as time goes on. The results are shown in Table V. It can be seen, in Table V, that if one plans the EDS in the initial years of the studied horizon, the optimal number of RCSs is lower than that if considering the planning in the last years. Maintenance frequency in each year is shown in Fig. 7. In this state, the maintenance frequency (the number of maintenance tasks) decreases in the initial years while it increases in the last years of the planning horizon. From the first to forth cases, the TRC has increased due to the increase in the equipment failure rates. Moreover, the SAIDI and SAIFI indices have increased together with the number of the RCSs and maintenance frequency.

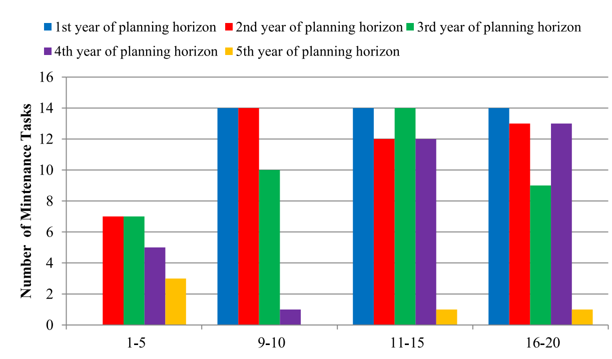

Fig. 7. Maintenance frequency.

Thus, it is more appropriate to plan the EDS in the initial years of the planning horizon than in the recent years.

VI. Conclusion

In this paper, a joint optimization problem to optimally allocate the PM task schedules and automatic switches is formulated and solved. The objective function is to minimize a combined customer-based and system-based performance indices: SAIDI, SAIFI, and the system total cost, considering the CM and PM costs as well as the automatic switch investments. Maintenance plans affect the failure rates of the overhead lines and transformers, and RCS implementations have an impact on fast and timely restoration of the system following to possible disruptions. The results revealed that when simultaneous PM tasks schedules and switch placement is implemented in an EDS, both the SAIDI index and system total costs are far less than those in case of either switch placement or PM tasks scheduling optimizations. In addition, the optimal number of the required RCSs has decreased and PM task schedules are more decentralized during the planning time horizon. Sensitivity analyses were also conducted to evaluate the objective function weighting coefficients and the time schedules of the planned actions on the performance of the proposed approach. Results revealed that when the problem is solved in initial years of the planning period, PM task schedules and the number of RCSs has been significantly reduced.

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