A Multi-Objective Distribution System Expansion Planning Incorporating Customer Choices on Reliability

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***Abstract*—This paper proposes a new multi-objective framework for primary distribution system planning (DSP). Further consideration is devoted to early DSP formulations in order to assess the risk imposed by probabilistic customer choices on reliability (CCOR). The CCOR is a buy/sell strategy that permits customers to pay the electricity price equiponderant to the reliability level provided by the distribution utility over the contract period. A Monte Carlo-based simulation is carried out to examine the effects of the probability of a customer's interest in adopting the CCOR on profit-at-risk. Furthermore, the DSP was conducted to simultaneously minimize both total planning cost and profit-at-risk. The resultant optimization problem is solved through the non-dominated sorting genetic algorithm (NSGA-II) accompanied by a fuzzy decision making method to select the best result among the obtained Pareto optimal set of solutions. The developed method is applied to an actual large-scale distribution system with about 140 000 customers, followed by a discussion on results.**

***Index Terms*—Customer choices on reliability (CCOR), distribution system planning (DSP), Monte Carlo simulation, non-dominated sorting genetic algorithm (NSGA-II), power system reliability, profit-at-risk.**

NOTATION

The notation used throughout this paper is reproduced below for quick reference.

Sets:

Ω^l	Set of load points (electrical domains).
Ω^n	Set of network nodes.
Ω^s	Set of existing and candidate substations.
Ω^b	Set of existing and candidate branches.
Ω^c	Set of conductor types.
Ω_{ss}	Set of selected substations (existing and proposed).
Ω_{sb}	Set of selected branches (existing and proposed).
Ω_{sc}	Set of selected cross-connections.
Ω_i^n	Set of nodes that can connect directly to node i.
$\Omega_{s,i}^{tr}$	Set of allowed standard-size transformers in substation i.
$\Omega_{l,i}^b$	Set of branches in which the fault leads to supply interruption at load point i.
$\Omega_{l,i}^s$	Set of substations in which the fault leads to supply interruption at load point i.

Constants:

C_h^l	Per unit cost of energy loss at year h ($/kWh).
C^{sw}	Total cost of installing a switch ($).
C_h^{se}, C_h^{SI}	Electricity selling price/cost of supply interruption at year h at a load point uninterested in CCOR.
n_y	Number of years in planning period (year).
PW	Present worth factor.
Ifr, Itr	Inflation/interest rate.
$\underline{\psi}, \overline{\psi}$	Minimum/maximum permissible loading percentage of substations.
α	Number of hours in a year (8760).
γ	Loss factor.
κ	Load factor.
d_{ij}	Distance between nodes i and j (km).
λ_{ij}	Failure rate in branch $i-j$ (fail/km/year).
τ_{ij}	Average repair time in branch $i-j$ (h).
$P_{ih}^D, Q_{ih}^D, S_{ih}^D$	Expected active/reactive/total load demand at node i at year h (MW/MVAr/MVA).
$\Delta V_{\max}$	Maximum allowed voltage drop.
V_0	Nominal voltage magnitude (V).

Functions:

Γ_{DSP}	Profit of the DSP within the planning horizon ($).
P_{ijh}^{loss}	Copper losses of feeder located between nodes i and j at year h (kW).
C_{DSP}^{inv}	Total DSP cost ($).
C_{DEP}	Total DSP cost while $\xi_i = 0$ for all customers ($).
C_{ih}^{sell}	Electricity selling price at load point i at year h.

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C_{ih}^{SI}	Cost of supply interruption at load point i at year h ($).
$CROS_i$	Customer reliability of service at load point i.
$CUOS_i$	Customer unreliability of service at load point i.
$f(.), g(.)$	Variation of C_i^{sell}/C_i^{SI} due to CCOR service.

Variables:

C_i^S	Total expansion and maintenance costs of substation i within the planning horizon ($).
$C_{ij}^F(\rho_k)$	Construction/reinforcement cost of feeder located between nodes $i-j$ by conductor ρ_k ($/km).
$I_{\rho_k}^{\max}$	Maximum allowed current of feeder of type ρ_k (A).
r_{ij}	Resistance per length of feeder constructed between nodes $i-j$ (Ω/km).
B_{ij}, G_{ij}	Nodal susceptance/conductance matrix elements.
P_i^{cu}	Copper losses of substation i at the rated loading (kW).
P_i^{iron}	Iron losses of substation i (kW).
P_{ih}, Q_{ih}	Active/reactive power calculated at node i at year h.
$P_{ih}^s, Q_{ih}^s, S_{ih}^s$	Active/reactive/total power provided by substation at node i at year h (MVA).
I_{ijh}	Current flows through branch $i-j$ at year h (A).
CS_i	Selected capacity of substation i (MVA).
u_i^s	Average outage time of substation i (h).
ζ_{ij}	Binary decision variable that is equal to 1 if substation i supplies load point j in normal operation period, 0 otherwise.
ξ_i	Binary decision variable that is equal to 1 if load point i is interested in adopting the CCOR option, 0 otherwise.

I. Introduction

DISTRIBUTION systems are facing many challenges as the rate of load growth increases and operational constraints reach hazardous limits [1]. Distribution utilities are obliged to expand and operate their networks in a timely and efficient manner so as to keep customers satisfied.

Since network expansion is costly, utilities need to seek out bank lending, sale participation papers, and so on, which leads to new obligations being placed on the utility. Furthermore, the Union of Consumer Rights and the Power System Regulatory Commission are imposing stricter conditions on the delivered services [2]. Under such conditions, distribution expansion planning needs to take several considerations into account, including economic, environmental, and social welfare issues, while being efficient with respect to recent technologies.

The aim of comprehensive distribution system expansion planning is to provide the basis for delivering energy from the HV level to end users [3]. As reported in the literature, distribution system planning (DSP) problem is aimed at establishing the main infrastructure of the distribution system by sitting and sizing the HV/MV substations and determining the optimal feeder routing [4]. In order to do so, several cost indices, including equipment installation, network losses, and supply interruption costs, should be considered. Technical constraints that have to be satisfied are supplying all loads, adhering to the maximum allowed voltage drops at load points, not exceeding the maximum permissible loading of substations, ensuring network radiality, and respecting the feeders' maximum current limits. According to the scope of the utility, the planning horizon may vary from one year to decades, classified into short-, mid-, and long-term planning periods [5].

Because of the importance of this issue, considerable research has been devoted to the DSP problem. In a recent study, [6] proposes an optimal power flow approach for DSP incorporating distributed generations (DGs); this approach considers various cost indices, including network upgrade, operation, maintenance, and losses, but does not address reliability issues. On the other hand, [7] presents an integrated DSP to simultaneously solve HV/MV substation and DG expansion planning, optimal feeder routing, and the definition of the cross-connections, thereby maximizing system reliability. In addition, a new heuristic approach based on a back-propagation algorithm combined with a cost-benefit analysis is carried out in [8] to solve the comprehensive multi-year DSP problem. Reference [9] introduces a balanced genetic algorithm (GA) with data envelopment in order to solve the multistage DSP problem. In this approach, the overall performance of the proposed algorithm is assessed by considering different uncertainties under the Greenfield condition; however, reliability is not modeled through the objective function.

Moreover, integer programming has been widely used for DSP [10], [11]. In [10], a reliability-based approach is employed to solve the DSP problem. Mixed integer linear programming (MILP) is used for the optimization process. Since the radiality constraint is guaranteed by forcing the algorithm to select only one feeding path for each load node, it is difficult to model DGs through the proposed method. A constructive heuristic algorithm is proposed for DSP in [11]; a local improvement phase and branching technique are implemented in the solution process in order to improve the obtained results. Besides these, several heuristic and meta-heuristic algorithms have been proposed to separately solve substation expansion planning (SEP) or optimal feeder routing. Solving these problems separately can decrease the computational burden of DSP, yet the optimality of the solutions is affected [12]–[14].

Despite aforementioned literature, some researchers have studied the DSP problem with conflicting objectives using multi-objective approaches [15]–[19]. In [15]–[17], the application of a multi-objective tabu search algorithm for DSP is evaluated; while the total planning costs and reliability are considered as objectives in [15] and [16], the objectives of [17] are modeled using fuzzy sets, including fuzzy economic cost, level of fuzzy reliability, and exposure. The strength of [15] over the other two is that it allocates both sectionalizing switches and the construction of tie lines. In [18], a dynamic programming approach for multi-objective optimal feeder routing is presented; the objectives are to simultaneously minimize total installation and operational costs, as well as interruption cost. In [19], a weakly meshed DSP is conducted considering load demand uncertainties; a contingency load-loss index is assumed to be an objective function, and a multi-objective particle swarm-based algorithm is employed for the optimization process.

As it can be deduced from previous studies, while system reliability indices have been widely used for DSP, load point indices have not been explicitly considered. However, it seems to be useful to study load point reliability indices along with distribution system restructuring in order to keep specific customers satisfied. Moreover, as a matter of fact, distribution system faults have different impacts on different customers [20], and the value of uninterrupted service varies from one customer to the next. Each has a unique supply interruption damage function [21]. Hence, some customers are willing to pay more for the electricity price in order to ensure better reliability. To meet such demands, customer choice on reliability (CCOR) might be presented by utilities as a new option [22]. CCOR may be defined as a bilateral strategy between customers and the distribution utility over the contract period. CCOR permits customers to pay the electricity price equal to the reliability level of the delivered services.

This paper reports a multi-objective DSP incorporating CCOR strategy. First, a prevalent DSP problem formulation is developed to collaborate with the load point reliability indices. As the most noteworthy contribution of this paper, profit-at-risk is formulated and applied to DSP as a new objective function. Then, a non-dominated sorting genetic algorithm is employed to simultaneously minimize both total planning cost and profit-at-risk. In addition, a Monte Carlo simulation is conducted on the obtained results in order to examine the uncertainties inherent in CCOR. The planning cost includes costs associated with substation expansion, feeder reinforcement, sectionalizing switches, and cross-connections, while respecting several technical constraints. Finally, the developed method is applied to an actual large-scale distribution system, followed by presenting the results and comparing them to those of previous research.

II. Problem Formulation of DSP

A. Mathematical Modeling

The aim of the static DSP reported in this paper is to find a set of decision variables, including substation locations and sizes, optimal feeder and cross-connection routing, conductor selection, and switch locations. These objectives must be fulfilled while incurring minimum expansion costs and respecting technical constraints [11]–[13]. In this paper, total planning cost and technical constraints are modeled through (1)–(16) as follows:

$$\begin{aligned} C_{DSP}^{inv} = &\sum_{i\in\Omega_{SS}} C_i^S + \sum_{i\in\Omega_{sw}} C_i^{sw} + \sum_{(ij)\in\{\Omega_{sb},\Omega_{sc}\}} C_{ij}^F(\rho_k).d_{ij} \\ &+\sum_{h=1}^{n_y} PW^h.\sum_{(ij)\in\Omega_{sb}} \alpha.\gamma.C_h^l.P_{ijh}^{loss} \\ &+\sum_{h=1}^{n_y} PW^h.\sum_{i\in\Omega_{ss}} \alpha.C_h^l\left[P_i^{iron}+P_i^{cu}.\gamma\left(\frac{S_{ih}^s}{CS_i}\right)^2\right] \\ &+\sum_{h=1}^{n_y} PW^h.\sum_{i\in\Omega_l} \alpha.\kappa.CUOS_i.C_{ih}^{SI}.S_{ih}^D \end{aligned} \quad (1)$$

where

$$PW = \frac{1+Ifr}{1+Itr} \quad (2)$$

$$P_{ijh}^{loss} = r_{ij}.I_{ijh}^2, \qquad \forall\, ij\in\Omega_{sb} \quad (3)$$

$$CUOS_i = \underbrace{\left[\bigcup_{(kj)\in\Omega_{l,i}^b}\left(\frac{\lambda_{kj}.\tau_{kj}.d_{kj}}{\alpha}\right)\right]}_{feeder\ outage} \cup \underbrace{\left[\bigcup_{k\in\Omega_{l,i}^b}\left(\frac{u_k^s}{\alpha}\right)\right]}_{substation\ outage} \quad (4)$$

$$C_{ih}^{SI} = \begin{cases} g(CROS_i), & \xi_i = 1 \\ C_h^{SI}, & \xi_i = 0 \end{cases}, \qquad \forall\, i\in\Omega_l \quad (5)$$

$$CROS_i = 1 - CUOS_i. \quad (6)$$

subject to

$$P_{ih} - P_{ih}^S + P_{ih}^D = 0, \quad \forall\, i\in\Omega^n, h=\{1,\ldots,ny\} \quad (7)$$

$$Q_{ih} - Q_{ih}^S + Q_{ih}^D = 0, \quad \forall\, i\in\Omega^n, h=\{1,\ldots,ny\} \quad (8)$$

$$P_{ih} = V_{ih}\sum_{j\in\Omega^n} V_{jh}.[G_{ij}.\cos\theta_{ij} + B_{ij}.\sin\theta_{ij}],\ \forall i\in\Omega^n \quad (9)$$

$$Q_{ih} = V_{ih}\sum_{j\in\Omega^n} V_{jh}.[G_{ij}.\sin\theta_{ij} - B_{ij}.\cos\theta_{ij}],\ \forall i\in\Omega^n \quad (10)$$

$$|\Omega_{sb}| = |\Omega_l| \quad (11)$$

$$\sum_{i\in\Omega_{ss}} \zeta_{ij} = 1, \qquad \forall\, i\in\Omega^l \quad (12)$$

$$\underline{\psi} \le \frac{S_{ih}^S}{CS_i} \le \overline{\psi}, \qquad \forall\, i\in\Omega_{ss}, h=\{1,\ldots,ny\} \quad (13)$$

$$|V_{ih} - V_0| \le \Delta V_{\max}, \qquad \forall\, i\in\Omega^n, h=\{1,\ldots,ny\} \quad (14)$$

$$|I_{ijh}| \le I_{\rho_k}^{\max}, \qquad \forall\, ij\in\Omega_{sb}, h=\{1,\ldots,ny\} \quad (15)$$

$$\underline{CROS_i} \le CROS_i \le \overline{CROS_i}. \quad (16)$$

B. Description of the Terms Employed

Total DSP costs of a selected layout are calculated in (1), where the first term represents total expansion and maintenance costs of substations [11]. The second and third terms consider the total required costs for installing/expanding switches and medium voltage feeders, respectively [12]. In this term, $C_{ij}^F(\rho_k)$ is a variable that indicates the total construction/reinforcement cost of a branch located between nodes $i-j$ by conductor ρ_k. The fourth term accompanying (3) computes feeder losses, while total no-load and loading losses of substations are aggregated in the fifth term [13]. In these terms, PW stands for present worth factor and is calculated through (2).

Finally, the last term of (1) considers total penalties imposed on the distribution utility because of undelivered services [12]. It is assumed that supply interruptions are caused by feeder and substation outages, which are calculated through (4). $CUOS_i$ represents the unreliability of service to the customer at load point i, where $\lambda_{kj}.\tau_{kj}.d_{kj}/\alpha$ shows the probability of supply interruption at load point i caused by a failure within branch kj. Moreover, the effects of an outage in substation k on the nodal reliability index are modeled via u_k^s/α. The symbol $\cup$ in (4) stands for union operator; as the aforementioned events are independent, the union of probabilities provides the total probability of supply interruption at each load point [12]. It should be noted that while imperfect switching is not considered in this study, the network may be reinforced with a detailed model of protections without loss of generality by calculating τ_{kj} through each contingency [23]. Since CCOR is considered in this paper, the cost of supply interruption is proportional to the reliability of service to the customer as reported in (5) and (6). Equation (5) reveals that if a customer is interested in using the CCOR option, the restitution of supply interruption will be paid according to the contract $(g(.))$; otherwise, it is a single value.

DSP constraints are guaranteed using (7)–(16); (7)–(10) represent the conventional equations of load balance which are also insured within load flow studies [11], [24]. As distribution systems mostly operate in radial structure, the obtained layout should meet (11) and (12) [12]. Considering the technical requirements, the loading of substations must fall within an acceptable margin as shown in (13). Moreover, (14) and (15) ensure that electric consumers receive the proper supply with permissible voltage drop at load points and allowed thermal capacity limit in network branches [13]. Finally, (16) ensures that service reliability to each customer meets the minimum $(\underline{CROS_i})$ and maximum $(\overline{CROS_i})$ permissible values.

III. Mathematical Formulation of Profit-at-Risk

Incorporating CCOR in the DSP changes the optimal layout, cost indices, and earnings of the distribution utility. Hence, it would be helpful to designate the utility profit as the measure by which to decide among several feasible layouts. The total profit of the DSP within the planning horizon can be found with (17), where the first term represents the total revenue obtained by selling electricity to the end users:

$$\Gamma_{DSP} = \left[\sum_{h=1}^{n_y} PW^h \cdot \sum_{i\in\Omega_l} \alpha \cdot \kappa \cdot [C_{ih}^{sell} - C_h^l] \cdot S_i^D\right] - C_{DEP}^{inv} \tag{17}$$

$$C_{ih}^{sell} = \begin{cases} f(CROS_i), & \xi_i = 1 \\ C_h^{se}, & \xi_i = 0 \end{cases}, \qquad \forall\, i \in \Omega_l. \tag{18}$$

As seen in (18), the price of selling electricity to a customer may be proportional to the customer reliability of service (CROS). It should be noted that ignoring the CCOR in the DSP will result in a similar C_{ih}^{sell} for all customers, making the first term of (17) equal to a constant value. Therefore, the DSP is conducted via (1) in non-deregulated distribution systems as investigated in the specialized literature.

Once a distribution utility decides to implement the CCOR option in its DSP, it may have to install more substations, redundant transformers, more switches, shorter feeders, and so on relative to the existing DSP. In fact, with the aim of increasing profits, the utility should increase the reliability levels at nodes were customers might be the most eager to adopt the CCOR. Such a strategy will increase the total expansion investment of the DSP. Despite greater investment, however, the utility may gain less profit than from the existing DSP, since the customers' interest in adopting the CCOR involves several uncertainties. In other words, the utility may not gain the expected profit relative to its investment value. In this case, the utility investment has encountered risk in terms of its profitability.

Considering the above comments, when the DSP is solved for a planning horizon, there are several uncertainties that affect the utility's, especially when CCOR is considered. The probability of a customer's interest in adopting CCOR is an important issue because it introduces risk to the distribution utility. To account for such uncertainties, it is assumed that the probability function of each uncertainty, accompanied by its minimum and maximum permissible values, is available. This assumption is reasonable since distribution utilities have adequate knowledge regarding the minimum/maximum values of its load growth, electricity pricing, expansion costs, and so on. Furthermore, the statistics/Gaussian distribution suitably fits the probability function of the uncertainties [25]. Utilities can also employ field studies and polls, and draw on several other social/economic resources, in order to gather information regarding the minimum/maximum probability of a customer's interest in adopting the CCOR option at a given geographical position.

Considering these issues, a Monte Carlo simulation can generate enough data to calculate profit-at-risk. Once a layout is proposed for the DSP, a probabilistic evaluation of its profitability against the uncertainties raised by CCOR is conducted via a general procedure as follows:

Step 1) Form a normal probability function for each customer considering the customer's minimum/maximum interest in employing the CCOR;

Step 2) Define the decision variable ξ_i for each customer with respect to a number randomly generated by the normal probability function formed in Step 1. If the random number is greater than 0.5, then $\xi_i = 1$, 0 otherwise;

Step 3) Steps 1–2 are repeated until decision variable ξ_i is set for all load points;

Step 4) Total profit of the DSP is calculated via (17) with respect to the values obtained in Step 3;

Step 5) Steps 1–4 are repeated until the Γ_{DSP} converges.

The mean and variance of the Γ_{DSP} can be found using sample values obtained through the Monte Carlo simulation as follows [25]:

$$\overline{\Gamma_{DSP}} = \frac{1}{NS} \cdot \sum_{i=1}^{NS} \Gamma_{DSP}(i) \tag{19}$$

$$var(\Gamma_{DSP}) = \frac{1}{NS} \cdot \sum_{i=1}^{NS} (\Gamma_{DSP}(i) - \overline{\Gamma_{DSP}})^2 \tag{20}$$

where $\Gamma_{DSP}(i)$ represents the total revenue at the ith iteration and NS shows the total number of iterations. The stopping criteria for the Monte Carlo simulation are shown in (21), where σ is assumed to be equal to 0.002 in this paper [25]:

$$\frac{\sqrt{var(\Gamma_{DSP})}}{\sqrt{NS \cdot \overline{\Gamma_{DSP}}}} \leq \sigma. \tag{21}$$

The probability distribution of the profitability of a selected layout can reveal noteworthy information about the generalizability of that solution. To do so, the results obtained from the Monte Carlo simulation are divided into several sections of equal width, and the probability of each range is calculated through (22) [26]:

$$Prob(i) = \frac{N_i}{NS} \tag{22}$$

where N_i represents the total number of iterations that settle on range i. As the Monte Carlo simulation provides a range of values for Γ_{DSP}, the risk of each layout, its profit-at-risk, can be calculated as follows [26], [27]:

$$Risk(\Gamma_T) = \frac{1}{NS}. \sum_{\Gamma_{DSP}<\Gamma_T} \left(\frac{\Gamma_T - \Gamma_{DSP}}{\Gamma_T} \right) \tag{23}$$

where Γ_T is the expected profit of the DSP expressed by the distribution utility; any value lower than this amount is considered to be risk [27]. As seen in (23), the risk of not achieving the desired profit value is proportional to the decrease in profit. Therefore, if decreasing expansion costs lead to reliability attenuation, utility profit decreases and profit-at-risk increases. Similarly, if the utility mistakenly over-expands its network to achieve the most probable income from the CCOR strategy, expansion costs increase significantly and Γ_{DSP} decreases, which leads to profit-at-risk intensification. However, as the profit-at-risk and expansion costs are not consistent, the simultaneous optimization of these objectives should be conducted via a multi-objective optimization method.

IV. Solution Approach

A. Optimization Algorithm and Problem Codification

In recent years, population-based algorithms, such as GA, have been widely used to solve multi-objective optimization problems. Such algorithms are able to generate a Pareto-optimal set of solutions in a single run. Meanwhile, single-objective optimization algorithms need several independent runs to achieve the same set of solutions [28]. A multi-objective problem with various conflicting objectives usually has no single optimal solution. Hence, decision makers that handle compromises are employed in order to select one solution from a finite set of Pareto-optimal solutions [29].

The non-dominated sorting genetic algorithm (NSGA-II) is a multi-objective evolutionary optimization algorithm, which is an extension of GA. The NSGA-II tries to improve the adaptive fit of a population of candidate solutions to a Pareto front constrained according to a set of objective functions. The algorithm employs an evolutionary process with deputies for evolutionary operators, including selection, genetic crossover, and genetic mutation. The population is sorted into a hierarchy of sub-populations based on the order of Pareto dominance. The similarity between members of each sub-group is evaluated on the Pareto front, and the resulting groups and similarity measures are applied to construct a diverse front of non-dominated solutions. A comprehensive explanation of this algorithm can be found in [29].

This paper employs NSGA-II for its optimization process; its performance has been demonstrated in several problems [30]. The DSP codification is presented in (24), where $\boldsymbol{U}$ represents the substations' capacity vector and u_i is a gene that shows the capacity of substation i at the planning horizon. According to (25), if $u_i = 0$, the ith substation is not selected. Moreover, $\boldsymbol{V}$ is the feeder/cross-connection routing vector so that v_i can select "0", meaning no feeder/cross-connection, "1", which identifies a selected/existing feeder, or "2", which represents a cross-connection. As seen in (27) and (28), the conductor selection and switch placement are determined by vectors $\boldsymbol{W}$ and $\boldsymbol{X}$, respectively. See (24)–(28) at the bottom of the page.

As (29) and (30) show, the distribution utility is interested in achieving a DSP layout that simultaneously minimizes investment costs and the risks associated with the CCOR strategy. It should be mentioned that C_{DEP} represents the total DSP investment cost, while $\xi_i = 0$ for all customers. In other words, C_{DEP} denotes the expansion costs of the distribution system without considering CCOR, as reported in the literature:

$$Min\ f_1 = C_{DEP} \tag{29}$$

$$Min\ f_2 = Risk. \tag{30}$$

The overall process of the proposed multi-objective DSP is as follows:

Step 1) Technical and economic information is obtained;

Step 2) Initial populations are generated; while a heuristic method (proposed in [12]) is used for the initialization of $\boldsymbol{U}$, the minimum spanning tree concept (reported in [31]) is employed to generate the initial

$$\vartheta_i = [\boldsymbol{U}, \boldsymbol{V}, \boldsymbol{W}, \boldsymbol{X}] = \left[\underbrace{u_1, \ldots, u_{|\Omega^s|}}_{Substation\ Sizing}, \underbrace{v_1, \ldots, v_{|\Omega^b|}}_{Feeder\ Routing}, \underbrace{w_1, \ldots, w_{|\Omega^b|}}_{Conductor\ Selection}, \underbrace{x_1, \ldots, x_{|\Omega^b|}}_{Switch\ Placement} \right] \tag{24}$$

$$u_i = \{0, 1, \ldots, |\Omega^{tr}_{s,i}|\}, \quad \forall i = 1, \ldots, |\Omega^s| \tag{25}$$

$$v_i = \{0, 1, 2\}, \quad \forall i = 1, \ldots, |\Omega^b| \tag{26}$$

$$w_i = \{0, 1, \ldots, |\Omega^c|\}, \quad \forall i = 1, \ldots, |\Omega^b| \tag{27}$$

$$x_i = \{0, 1\}, \quad \forall i = 1, \ldots, |\Omega^b| \tag{28}$$

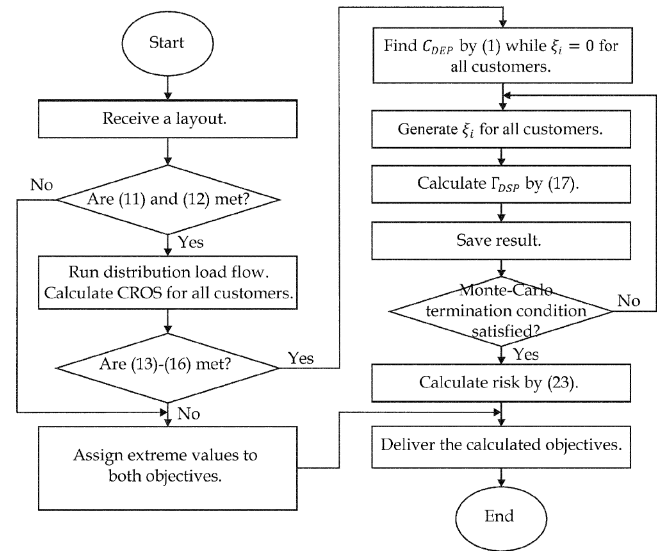

Fig. 1. Overall process of evaluating objective functions for a layout.

values of $\boldsymbol{V}$. Furthermore, w_i is set to $|\Omega^c|$ if v_1 is "1" in the initialization process;

Step 3) Objective values are evaluated, as represented in Fig. 1;

Step 4) Solutions are sorted based on their non-dominated rank;

Step 5) Parents are selected based on their non-dominated ranks and crowding distances;

Step 6) The simulated binary crossover, polynomial mutation, and tournament selection between each two individuals are employed to generate a new population [28], [30];

Step 7) Steps 3–6 are repeated until the termination condition is satisfied;

Step 8) Pareto-optimal solutions are generated;

Step 9) Fuzzy decision making method is used to select the final plan.

B. Fuzzy Decision Making

The fuzzy decision making method is held to be an effective approach to selecting the final solution from a set of non-dominated partially ordered solutions [23]. Since the Pareto-optimal set of solutions obtained using the NSGA-II includes several solutions, the fuzzy decision making method is employed to select a solution that provides acceptable performance with respect to all objectives.

According to the fuzzy set theory, each objective function can be normalized using a linear membership function as (31) [32]–[34]:

$$\mu_i^k = \frac{[f_i^{\max} - f_i^k]}{[f_i^{\max} - f_i^{\min}]}, i = 1, \ldots, n; k = 1, \ldots, m \quad (31)$$

$$\mu_i^k = \frac{\sum_{i=1}^{n} \mu_i^k}{\sum_{k=1}^{m} \sum_{i=1}^{n} \mu_i^k} \quad (32)$$

where $f_i^{\max}$ represents the absolute maximum of objective i within the non-dominated set of solutions, and $f_i^{\min}$ shows the minimum values of objective i that are satisfactory to the decision-maker. For each non-dominated solution, the membership function is then normalized through (32). The result associated with the maximum normalized membership value is employed as the best non-dominated solution [23], [32]–[34].

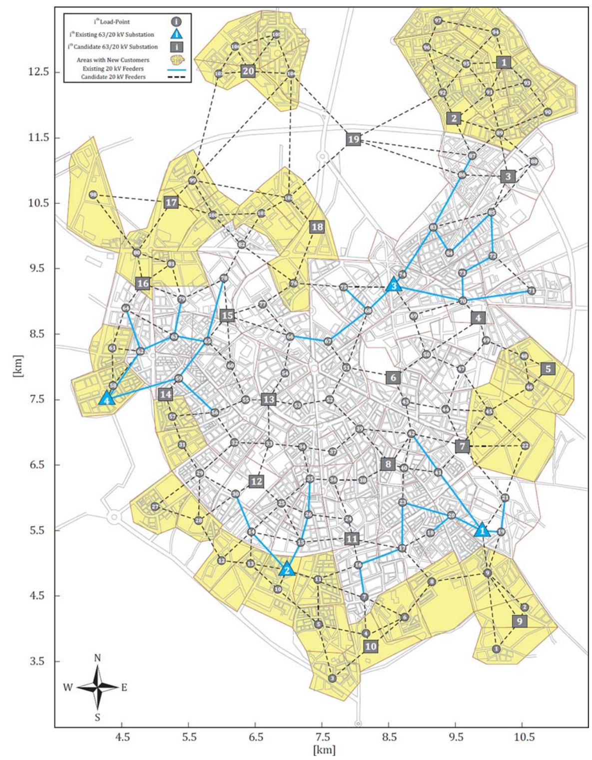

Fig. 2. Planning zone, city of Hamedan, Iran.

V. Tests and Results

With the aim of analyzing the effects of CCOR, the DSP was solved for the city of Hamedan in the center of Hamedan province in Iran [12]. The planning zone, including the existing and candidate branches, is shown in Fig. 2, while the complete data can be found in [12] and [35]. It is assumed that the sets of installable conductors are similar in all branches, taken from [36]; switch costs and repair times are given in [23]. The computer used for the simulations had Intel 2.53-GHz CPU with 4 GB of RAM.

In this section, the main contribution of this paper is quantitatively studied in two scenarios. While the first scenario investigates the single-objective DSP, the purpose of the second scenario is to illustrate the performance of the proposed DSP considering the CCOR strategy.

A. First Scenario

The single-objective DSP was solved for Hamedan in order to analyze the performance of the developed algorithm on a real-life, large-scale network. It is useful to mention that the SEP was solved for this network in [12] in which optimal feeder routes were neglected. The electrical plant consisted of 106 medium voltage load buses. Candidate/exiting substations and feeder

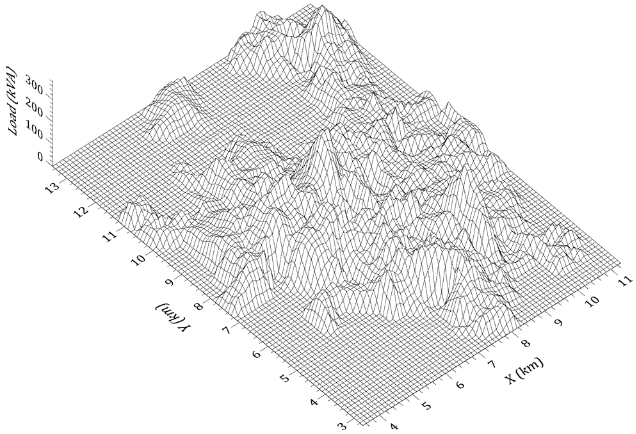

Fig. 3. Approximate electrical energy consumption for the planning zone [12].

routes are depicted in Fig. 2, while maximum load demand for the planning period is shown in Fig. 3.

The optimal DSP layout is depicted in Fig. 4 and in Tables I and II. As seen in Table I, the three existing substations were expanded, and four new ones were constructed. Total substation capacities were 210 MVA, and average loading percentage was 62.68%. Compared to the SEP results reported in [12], substation locations were significantly changed. Such differences show the effects of optimal feeder routing and switch placement on the DSP results. Table II illustrates that feeder costs made up almost 48% of the expansion costs. Moreover, it reveals that the total feeder cost associated with the DSP layout was about 50% more than that of the SEP reported in [12]. In addition, as shown in Table II, there was a significant difference between the supply interruption cost of the DSP and that of the SEP due to the exact calculation of energy not supplied when feeder routes were considered. It should be noted that while the planning zone was split into 64 electrical domains in [12], it has been divided into 106 load points for this study in order to determine a more accurate layout. Therefore, total number of feeders, and associated contingencies also increased.

The above descriptions and discrepancies clearly show that utility planners should avoid dividing the DSP into two subproblems, namely SEP and optimal feeder routing, as it may substantially change the layout obtained. The SEP should be conducted by implementing more constraints for feeder routing, especially those countries where sub-transmission substations are operated by the regional electrical companies.

The simulations run for this scenario show that the developed routines satisfy the engineering requirements for the single-objective DSP and can be expanded into multi-objective frameworks, ensuring that it will result in feasible solutions.

B. Second Scenario

This scenario investigated the effects of incorporating CCOR into the DSP solution. To this end, the DSP was carried out via a multi-objective approach to simultaneously minimize both total planning costs and profit-at-risk. Since some customers may not be eager to adopt the CCOR option, the distribution utility should conduct some field studies and polls and examine several social/economic contexts in order to obtain the initial estimates

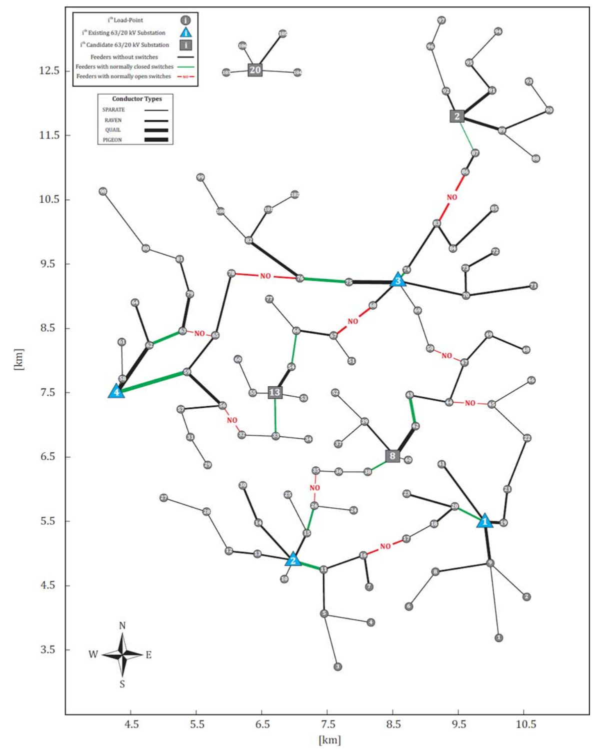

Fig. 4. Proposed single-objective DSP for the planning zone.

TABLE I
SUBSTATION LAYOUT OBTAINED BY DSP OF FIG. 4

No	Existing capacity (MVA)	Load (MVA)	New capacity (MVA)	Loading (%)
Existing 01	30	15.421	30	51.40
Existing 02	15	19.889	2×15	66.29
Existing 03	15	20.106	2×15	67.02
Existing 04	30	26.452	15+30	58.78
Candidate 02	--	11.217	15	74.78
Candidate 08	--	21.790	2×15	72.63
Candidate 13	--	10.969	15	73.12
Candidate 20	--	5.623	15	37.48

TABLE II
DETAILED COST INDICES OF DSP FOR FIG. 4 (MILLION $)

	Substation	Feeders and switches	Total expansion	Total supply interruption	C_{DEP}
DSP	3.53857	3.83085	7.36942	1.37058	8.74000
SEP [12]	3.25248	2.49717	5.74965	0.27600	6.02565

of the minimum/maximum probability of a customer's interest in employing the CCOR strategy. However, in this study, those values were estimated according to some social contexts, the geographic location, and the number of customers supplied in each electrical domain; the minimum and maximum probability values are shown in Fig. 5 [35].

To simply model the CCOR strategy, the electricity selling price of customer i who desires to use the CCOR option is calculated according to the reliability of the delivered service to node i $(CROS_i)$ as shown in Fig. 6. For example, a customer who is faced with a total of 7 h blackout in a year has a CROS equal to $(8760-7)/8760 = 0.999201$. As shown in Fig. 6, this customer should pay 0.063 ($/kWh) for the electricity if he or she has adopted the CROS strategy; otherwise, the price is 0.07

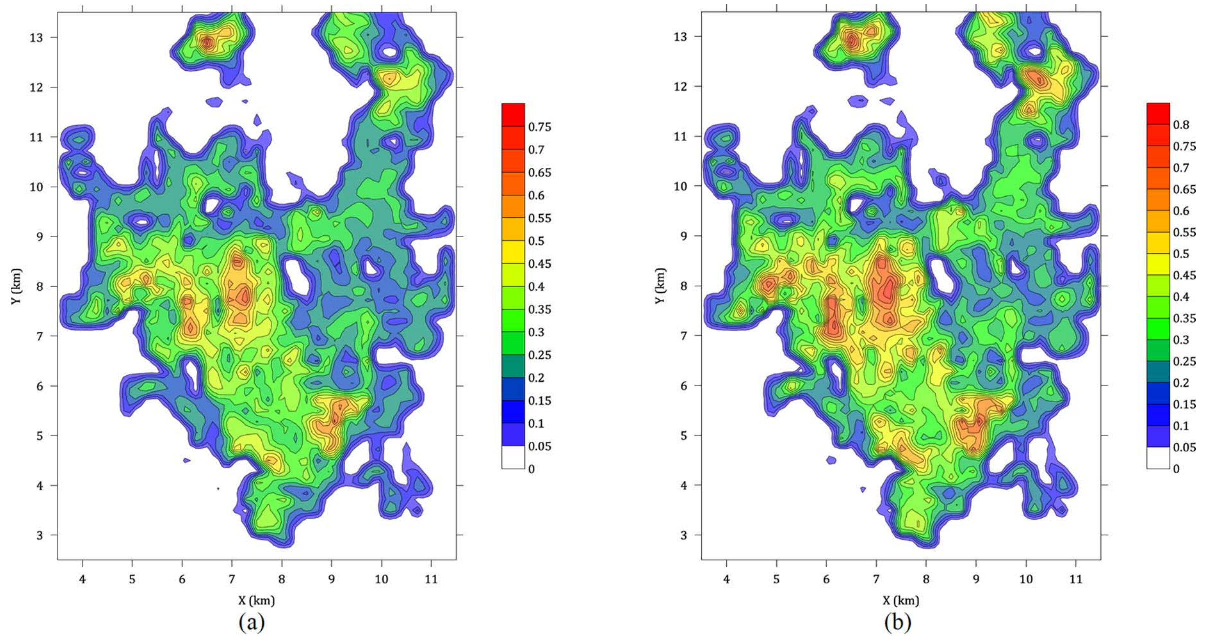

Fig. 5. Predicted probability of customer's interests to employ the CCOR strategy. a) Minimum of probability. b) Maximum of probability.

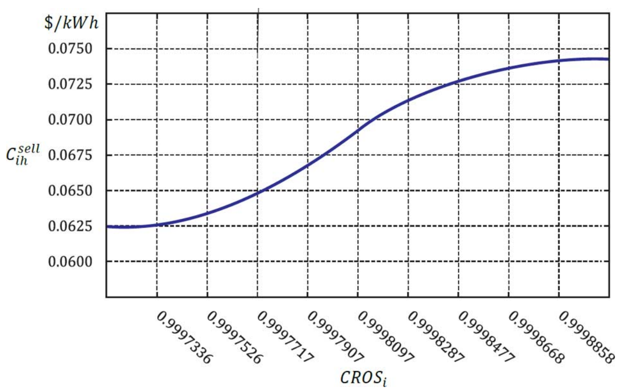

Fig. 6. Electricity selling price versus CROS.

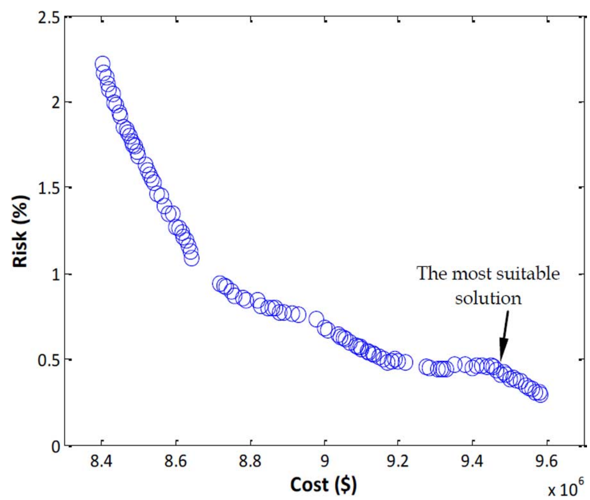

Fig. 7. Pareto front of the DSP for the planning zone.

(\$/kWh), as assumed in the single-objective DSP. Since the distribution utility must provide a minimum reliability level at each node, the $CROS_i$ of customers cannot be less than a minimum value. Similarly, since it is not technically possible to provide perfect reliability at each node, the $CROS_i$ of customers cannot be greater than a maximum value. At the same time, the utility cannot sell the electricity at less than a permissible value, nor would customers be interested in paying more than a reasonable price. As a result, the curve has limited ends. It should be mentioned that the proposed multi-objective approach can be carried out with any curve of electricity selling price versus reliability, without loss of generality.

The multi-objective DSP was investigated as reported in Sections III and IV and the expected profit of the DSP (Γ_T) was set as equal to the profit obtained by the utility in the single-objective layout in Fig. 4. The distribution indices of mutation and crossover were all set to 20; the population size and the total number of iterations were assumed to be 400 and 2500, respectively. The NSGA-II-based algorithm was conducted and the Pareto-front was obtained after approximately 8.8 h of computation. The Pareto-front is represented in Fig. 7. Details associated with the minimum costs, minimum risks, and most suitable solutions are reported in Table III. As Table III shows, while the total expansion costs associated with the most suitable solution were almost \$ 1.14 million (14.5%) more than the layout with the least cost (Fig. 4), the distribution utility's profit increased by \$ 1.89 million (10.5%). The most suitable DSP scheme is shown in Fig. 8; there were six new substations, and the selected locations were substantially different than those shown in Fig. 4. Two existing substations were expanded, and the average loading of the substations was about 55%, which shows that there is more free capacity available in the network that can be used for contingencies.

As reported in Table III, the total feeder length found in Fig. 8 was 65.76 km., which was 3.7% greater than in Fig. 4, where the network feeders were shortened, and the maximum

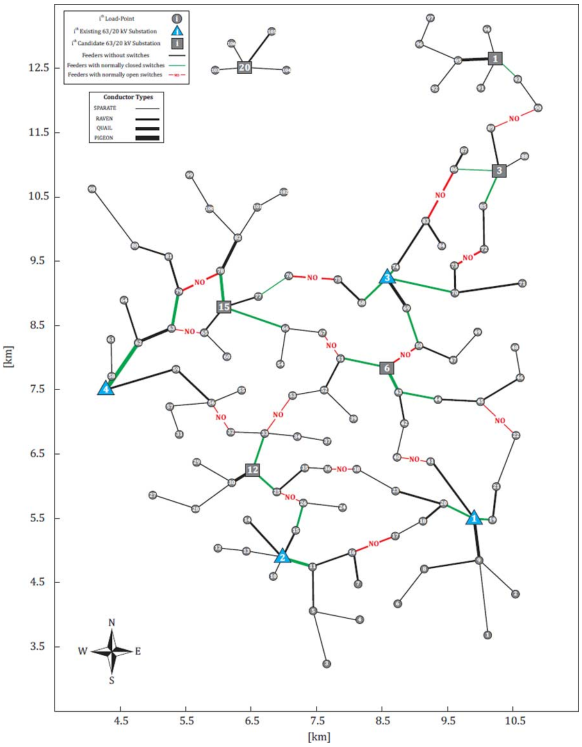

Fig. 8. Proposed multi-objective DSP for the planning zone.

TABLE III
DETAILED COST INDICES OF DSP WITHIN THE SECOND SCENARIO (MILLION $)

Detailes			Minimum Cost (Fig. 4)	Minimum Risk	Layout of Fig. 8
Substations	Existing or Expanded	Capacity (MVA)	135	105	120
		Cost	1.46581	0.64039	1.07624
	New	Capacity (MVA)	75	180	135
		Cost	2.07276	4.93871	3.68981
	Total	Capacity (MVA)	210	270	255
		Cost	3.53857	5.58910	4.76605
Feeders and cross-connections	Length (km)		63.41	58.25	65.76
	Construction cost		1.19022	0.99356	1.19683
	Loss cost		2.51436	2.19931	2.33694
	Total cost		3.70485	3.19287	3.53377
Switches	Normally open		9	20	15
	Normally closed		12	27	21
	Total cost		0.12600	0.28200	0.21600
Total expansion cost			7.36942	9.06397	8.51582
Total supply interuption cost			1.37058	0.52260	0.91471
C_{DEP}			8.74000	9.58624	**9.43053**
Risk (%)			2.22	0.297	0.547
Total income of selling electricity without considering the CCOR option			16. 51224	16.51224	16.51224
Total income of selling electricity considering the CCOR option			16.36267	18.09340	**18.25394**
Γ_{DSP} without considering the CCOR option			8.11047	6.92601	7.08171
Mean of Γ_{DSP} considering the CCOR option			8.01516	8.50718	**8.82341**

voltage drop was reduced to 3.87%. The total number of installed switches increased by about 71%, while the total supply interruption cost decreased by $ 0.46 million. However, there are some valuable lessons embedded in these values. Table IV reports some statistical indices of the CROS and the customers' interruption times from Figs. 4 and 8. As shown in Table IV, the average total customer interruption time in Fig. 8 was about 18 min (23%) less than that in Fig. 4. This difference is due to the fact that while Fig. 8 contains more substations, it has shorter feeders and has more switches. The implication is that, according to the proposed multi-objective DSP framework, utility planners should try to improve the reliability of the service at those load points where customers might be more eager to adopt the CCOR strategy. Although overall system reliability will increase regardless, focusing primarily on those areas with a greater probability of customers adopting the CCOR option will be more profitable for the utility. Conversely, as seen in Table III, the total utility income generated by selling electricity to customers in Fig. 4 is reduced by $0.15 million when the CCOR option is considered. In other words, the statistical distribution of the load-point reliability indices in Fig. 4 changes so that the customers who might have eagerly adopted the CCOR might not adopt it due to high reliability levels. Table IV also reports the standard deviation of CROSs and interruption times. It can be seen that the standard deviation of customers' interruption times in Fig. 4 is almost 41% greater than that in Fig. 8 which reveals the high dispersed distribution of load-point reliabilities in Fig. 4.

TABLE IV
STATISTICAL INDICES OF CROSS AND CUSTOMERS'INTERRUPTION TIMES IN DSP LAYOUT SHOWN IN FIGS. 3 AND 7 (ST.D STANDS FOR STANDARD DEVIATION)

Details	Fig. 4	Fig. 8
Average of CROSs	0.9998194	0.9998537
Average of total customer's interruption times (min)	94.92	76.9
St.D of CROSs	7.70456×10^{-5}	5.44879×10^{-5}
St.D of total customer's interruption times (min)	40.49	28.64

Considering the above results and observations, the proposed CCOR strategy along with the developed multi-objective framework not only results in a new DSP layout, but also increases the profit for the utility. Furthermore, since the CCOR is a voluntary bilateral strategy, customers are free to adopt it or not. At the same time, the distribution utility is forced to achieve service reliability for every customer through (16). Customers who require more reliability may adopt the CCOR strategy.

In order to demonstrate the effects of uncertainties when employing the CCOR strategy, the Monte Carlo simulation was repeated for the layout of Fig. 8 using the data reported in Fig. 5. The probabilistic distribution of the utility profit is shown in Fig. 9 and Table V. As seen in Fig. 9, there is an over 83% potential for the utility to gain a profit of more than $ 8.11 million with the single-objective DSP layout in Fig. 4. However, as represented in Table III, the utility may select any other scheme with lower risk levels up to 0.297—which is the minimum value—in order to earn the aforementioned profit with more security.

VI. DISCUSSION

Considering CCOR option in the DSP may raise reasonable criticisms. Some of these are discussed in this section.

As numerically reported in the previous section, the development of a distribution system that incorporates a CCOR strategy increases the total cost of expansion. Since the extra expansion costs will not be paid by all customers, the irrational judgment of those customers who might adopt the CCOR strategy could lead to profit losses compared to the single-objective layout. Although the proposed multi-objective framework may increase

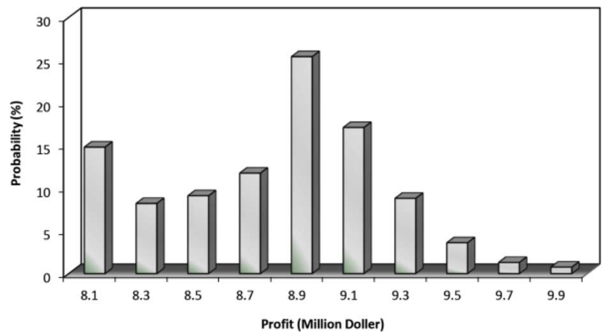

Fig. 9. Probabilistic distribution of Γ_{DSP} for Fig. 8.

TABLE V
STATISTICAL INDICES OF Γ_{DSP} FOR THE LAYOUT SHOWN IN FIG. 8 (MILLION $)

Final mean value	Variation Range	Standard deviation
8.82341	1.94726	0.46488

overall system reliability in terms of planning, the distribution system operator (DSO) must observe the requested reliability level at every node in terms of operation. In other words, the DSO should have a priority list of the customers who have adopted the CCOR strategy and take it these priorities into account when carrying out conventional activities such as feeder reconfiguration, restoration, maintenance, and so on. Therefore, it is the DSO that guarantees the reliability of these customers, while honestly deals those customers who do not pay for greater reliability.

Therefore, the CCOR option is a redundant service provided by the distribution utility; it may decrease its profitability if uncertainties and risk are not properly assessed. In other words, the proposed multi-objective framework may be used as a DSP procedure in deregulated environment, since non-deregulated distribution companies should not implement ancillary services that might endanger their expected levels of profitability.

In addition, there might be some concerns regarding the applicability of the CCOR strategy in terms of its computational effort and the consideration of customers supplied through secondary distribution network. Since the DSP usually deals with electrical domains instead of single load point, an electrical domain may contain customers supplied through both primary and secondary networks. However, this paper solves the DSP for the primary network as it includes a greater number of customers who need higher reliability for their services. Therefore, the same process may be carried for the secondary DSP without loss of generality, except for the greater uncertainties that will impact the DSP.

VII. CONCLUSION

A new multi-objective DSP approach aimed at incorporating CCOR strategy was presented in this paper. The CCOR option is a bilateral strategy between customers and the distribution utility that can not only emphasize the customer's rights, but also increase the total profit of the utility. Despite these benefits, incorporating the CCOR option has some disadvantages, and adds greater uncertainty and more complexity to the DSP problem. In order to tackle such issues, a Monte Carlo simulation including risk analysis was employed. The developed algorithm was successfully tested on a real-life distribution system composed of highly sophisticated data. The results revealed that the proposed approach can be used as an effective tool for the DSP of a practical network under several conditions.

Further research may be conducted to evaluate the effects of the CCOR strategy on other distribution planning/operation problems such as optimal switch placement, distribution system reconfiguration, and so on.

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