Chapter 8
Switch Deployment in Distribution Networks

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Abstract This chapter presents the optimal switch deployment in distribution systems. First, an explanation regarding different types of switches and their functionality is introduced. Then, a fundamental description of fault management procedure in distribution networks is presented. Thereafter, the mathematical formulation of optimal fault management process is described. Optimal switch deployment problem is formulated in the format of mixed integer programming (MIP). The impact of remote controlled switch (RCS) and manual switch (MS) is scrutinized on the interruption cost once they are installed either individually or simultaneously. The concept of switch malfunctions is explained and the influence of this issue on the optimal solution of the problem is discussed. Finally, the effect of uncertain parameters such as failure rate and repair time on the solution of switch deployment problem is investigated. It was shown that the uncertainty imposes a significant risk on distribution companies (DisCos).

Keywords Distribution networks · Fault management · Remote controlled switch
Manual switch · Network automation · Malfunction · Financial risk

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8.1 Introduction

Nowadays, the tight dependency of social life to electricity makes the users much further desire to receive electrical services with high level of reliability, appropriate service quality, and enough safety and security. Since a great share of interruptions in power systems is originated from faults in distribution networks, improving the service reliability in distribution level has motivated distribution planners to establish different strategies. To this end, various methods have been proposed, among them deploying monitoring and control devices has caught more attention of distribution companies (DisCos). Sectionalizing switches (SSs), both in remote controlled switch (RCS) and manual switch (MS) types, play a fundamental role in the improvement of service reliability in distribution systems. SSs enable network reconfiguration in both normal and abnormal conditions. In normal conditions, network reconfiguration done through SSs can be applied to enhance network efficiency, while in abnormal conditions, prompt network reconfiguration is conducted to mitigate violations in operational constraints and to restore service to interrupted customers. The principle benefit of the switches corresponds to their ability for the reduction in interruption duration of affected customers. Although both of the switch types are effective in fault management process, RCSs outdo MSs in much faster restoration. Remote switching actions performed by RCSs take few minutes, which is mainly needed for detecting the fault location and making a decision for suitable maneuvers. On the other hand, MSs just can be used for field switching actions, which may take several minutes. From fault management point of view, once a fault occurs in an electric distribution network, field crews can determine the location of the fault by patrolling the suspicious fault zone. Once the fault is located, the customers whose connection point is out of the fault zone are restored by switching RCSs and MSs. The rest of customers should remain interrupted until the fault section is repaired. Although applying SSs brings numerous advantages to DisCos, they impose some costs comprising of investment costs, installation costs, and maintenance costs. In addition, issues such as budget limits prevent the wide deployment of these devices in distribution networks. Also, it is neither necessary nor financially justifiable to fully equip a network with such devices. Hence, cost/benefit analyses are required to determine the optimal number and location of SSs. In the literature, the switch deployment problem was attacked via several optimization approaches including classical optimization methods like mixed integer programming (MIP) and heuristic methods like genetic algorithm, simulated annealing algorithm, particle swarm optimization algorithm, and cooperative agent algorithm.

In addition, there are numerous significant parameters with considerable impacts on the optimal solution of the switch deployment problem such as the interruption cost function of each customer, the switch malfunction probability, and the stochastic nature of contingency events in distribution systems. Customer damage function (CDF) plays an important role in the number of installed SSs such that DisCos are enthusiastic to install more devices when CDF is increased. In case of high value of CDF, the benefits of SSs installation justify the relevant switch costs. The second parameter concerns with switch reliability, assuming the full reliable of SSs is not rational. Hence, considering the impact of SSs malfunction can tamper the cost/benefit analysis of switch deployment problem and leads to change in the final solution of the problem. The last but not least parameter is uncertainties with high volatility in distribution networks. The uncertain behavior of contingencies in practical systems such as stochastic nature of contingency events, uncertain repair time, and failure time impose remarkable financial risk and detract from the worth of SSs installation. Therefore, a risk-averse or a risk-taker behavior of the planners can change the final optimal solution of the problem. To consider this issue, the financial risk evaluation of SS in distribution networks is presented.

8.2 Switching Devices and Types

The most common used switching devices in distribution networks include circuit breaker, automatic recloser, sectionalizing switch, and counter sectionalizer. The explanations regarding their characteristics and functionality are described in the following subsections.

8.2.1 Circuit Breaker (CB)

A circuit breaker (CB) is designed to immediately isolate the faulted feeder from the rest of network. CBs are usually installed inside the distribution substation where transmission high voltage is converted to distribution medium voltage. CB may be equipped with various protective relays such as overcurrent and earth fault relays which send signals to CB in order to operate properly. This may cause a considerable interruption in the feeder since customers who are located in downstream of the CB are de-energized.

8.2.2 Automatic Recloser (AR)

Automatic recloser (AR) acts as CB and is also able to distinguish and clear transient faults in addition to permanent faults. According to field observations and experiences, a bulk portion of fault occurrences in distribution systems are related to transient faults which are originated from assorted sources such as temporary tree contact, flashover initiating from lighting strike, conductor clashing, and bird contact, to name just a few. AR is able to interrupt the electric power for a short duration, and then to restore electrical energy. This process can be done for several times and the interruption duration is increased consecutively in order to make sure that the interruption duration is enough to clear the transient fault [1]. For instance, once a fault occurs at the downstream of an AR in an electric distribution network, the AR operates after a short delay in order to check if the fault is transient or permanent. This step is known as the first operation. The AR remains open for a specific duration (i.e., near 0.2 s) and is closed for a predetermined duration again. If the fault current still flows, the AR would disconnect the electric distribution network, which is known as the second open-action (i.e., near 2 s). The described process is iterated for specific number of open-close actions (most of the time at most three iterations are sufficient). In case the AR clears the fault before reaching the maximum number of iterations, the fault is determined as a transient fault, otherwise the fault is permanent and the AR isolates the electric distribution network. Since substantial share of faults in distribution systems are transient, installing AR would play a prominent role in reducing the interruption duration due to transient contingencies and consequently, enhancing the service reliability of distribution networks.

8.2.3 Sectionalizing Switch (SS)

Sectionalizing switches (SSs), both in RCS and MS types, enable network reconfiguration in both normal and abnormal conditions. In normal conditions, network reconfiguration can be applied to enhance network efficiency, while in abnormal conditions, prompt network reconfiguration is conducted to mitigate violations in operational constraints and to restore service to interrupted customers. The principle benefit of SSs corresponds to their ability in isolating healthy zones from faulted section and consequently, shortening interruption duration of affected customers. It is worth mentioning that SSs cannot operate under the excess current like short circuit fault current. Although both types of SS are effective in fault management process, RCSs outdo MSs in much faster restoration. Remote switching actions performed by RCSs take few minutes, which is mainly needed for detecting the fault location and making a decision for suitable maneuvers. On the other hand, MSs just can be used as field switching actions, which may take several minutes.

8.2.4 Counter Sectionalizer (CS)

Counter sectionalizers (CSs) are installed downstream of ARs. They cannot operate under fault or load currents. Rather, they are equipped with a fault counter device in order to count the number of current interruptions made by the upstream AR. These switches are opened once the AR operates and the counter reaches a predefined value. Appropriate coordination of ARs and CSs can limit fault consequences if the fault is permanent and occurs downstream of the CS. When a fault occurs in an electric distribution network, the AR iterates reclosing process and CS counts the number of interruptions. If the fault is permanent, the CS is opened once the counter reaches the preset value. If the fault is located downstream of the CS, the AR does not sense the fault current anymore. So, the customers downstream the CS are interrupted while the upstream customers are isolated from the fault. If the fault is located upstream of the CS, the AR operates and all customers are interrupted.

8.3 Fault Management Process

Fault management process is defined as the set of actions conducted in order to alleviate the consequences of an unexpected fault. Fault management includes several sequential processes including fault occurrence notification, locating the faulted section, isolating the fault from the healthy sections, and remedial actions to restore the interrupted customers. In this regard, the flowchart of fault management process is shown in Fig. 8.1.

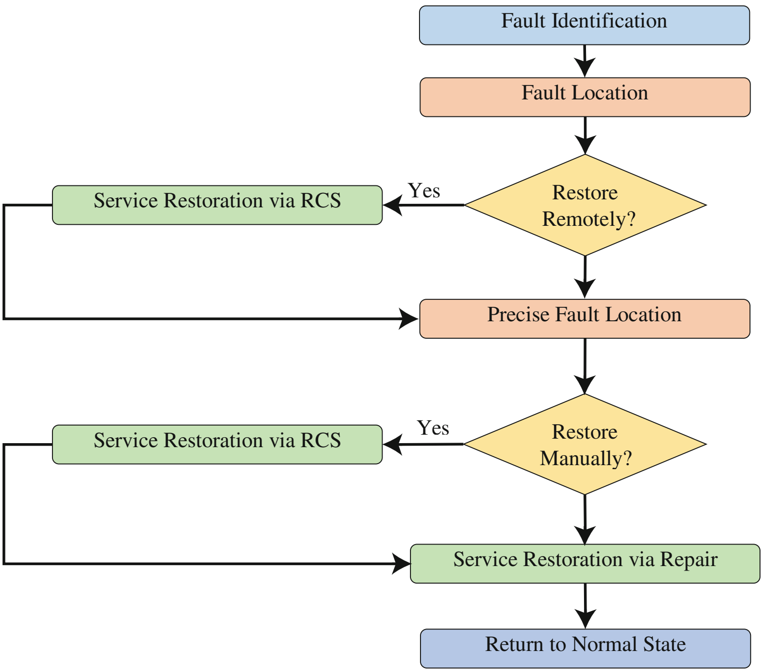

Fig. 8.1 Fault management process flowchart

8.3.1 Step 1: Fault Notification

The first step in fault management process is to notice that a fault occurred in the system. The following indications enable operators to become aware of fault in distribution systems:

- Customers contact
  One of the typical ways to identify fault occurrence is contacts from customers whose services are interrupted. In this regard, a system is established in distribution control center to receive information of interruption events that are provided by customers. The contacts can be in different types such as calls, email services, and web-based event recorders.
- Status change of protection devices
  Distribution operator can check the status of the system-wide protection and control devices through monitoring systems [2–4]. Once the status of a switching device changes, the first point bears in mind is that a fault has occurred somewhere downstream the device.
- Condition change in network operation
  Any significant deviation in network operation can be considered as an indication of fault occurrence [5]. As an example, an abrupt change in loading of a feeder points that a protection device within the feeder is opened following a downstream fault.
- Receiving notification from monitoring devices
  Modern distribution networks are equipped with different monitoring devices such as line sensors. These devices send signals to the control center whenever predefined conditions such as overload are sensed. Fault indicators are among line sensors which are particularly designed for fault identification.
- State-of-art system monitoring
  Distribution systems are going to become further equipped with sophisticated devices such as smart meter. These devices are able to record the interruption and provide prompt notification for the operator. In addition, because of the great benefit of system monitoring through synchronized measurements, the distribution systems intend to become equipped with Phasor Measurement Units (PMUs) [6]. These devices monitor the system in time-series manner and give insight regarding the abnormal event in the system.

8.3.2 Step 2: Fault Location

After the operator recognized that a fault is occurred somewhere in the system, it is necessary to determine the fault location suspiciously. There are various fault location approaches as follows:

- Customers contact
  Once an interrupted customer reports an interruption event, the distribution operator can estimate the likely location of the fault. Although this is a typical way to identify the suspicious location of fault, it is not an effective and accurate way.
- Fault distance estimation
  There exist different methods for fault location identification based on fault distance estimation. Broadly speaking, the existing methods to identify fault locations at distribution grid can be categorized into two main groups: impedance based methods and wide-area monitoring. The former class of methods work based on calculating the line impedance between the fault location and sensor location. These methods usually come up with multiple possible locations for the fault. The second group of methods, e.g., the wide-area monitoring, work based on the fact that voltages and currents along the feeder fluctuate following fault events. In this regard, these methods use the pre-event and post-event states of the grid to identify the exact location of the fault [7, 8].
- Fault indicator
  Fault indicator is among line sensors which provide substantial chance to estimate the fault location. Fault indicators which are equipped with communication module, send signals once fault current is sensed. Hence, the operator recognizes that the fault is somewhere downstream the fault indicator whose signals are received. Fault indicators without communication modules are equipped with light bulbs whose blinking lets the field crews understand that the fault is somewhere downstream of the device. This information usually limits suspicious fault area and thus, eases fault location process [9].
- Advanced metering infrastructure (AMI)
  By propagating AMIs in distribution system, DisCos are of great interest to take benefits of these state-of-art infrastructures. One of the most advantages of AMIs is their ability in assisting in fault management process. AMIs installed at the customer level are able to capture the interruptions and immediately report them. Control center collects all the reported interruptions and determine the likely zone of the fault. In particular, an especial type of these devices can provide the voltage sag initiated by a fault. The collected voltage sages can be used in various fault location methods to identify the precise fault location.

Although the above-mentioned approaches provide utmost effect in finding the suspicious location of fault, neither determines the precise location. So, it is always necessary to employ field crews to patrol the suspicious area in order to determine the exact location of fault.

8.3.3 Step 3: Service Restoration

Once the fault is detected and its location is determined, different remedial actions are accomplished to reduce the interruption duration of affected customers. In this situation, the distribution operator should make his/her best decision in order to restore the customers as soon as possible. The interrupted customers can be divided into two main groups. The first group contains the customers whose connection point can be isolated from the faulted area. The second group contains customers who are directly connected to the faulted area. The following steps should be conducted for restoring service to the interrupted customers.

8.3.3.1 Step 3-1: Remote Switching Action

After determining the approximate location of the fault, field crews start patrolling the suspicious area. However, since finding the precise location may take considerable time, it makes sense to remotely change the status of available RCSs adjacent to the faulted section. By doing so, some customers would be restored in a short duration. These customers experience interruption duration required for RCS switching action.

8.3.3.2 Step 3-2: Precise Fault Location

By restoring some customers via installed RCSs, field crews should find the precise fault location. This process also extends the fault location duration. Finding the precise location depends on several factors such as the geographical location of the electric distribution network (i.e., mountain or residential area, harsh or soft valley, etc.), types of the feeder (i.e., overhead or underground), the number of field crews, and other possible factors which might vary from one distribution system to another.

8.3.3.3 Step 3-3: Manual Switching Action

Once the faulted section is located, some customers whose connection points are out of the faulted area can be manually restored through available MSs. To do so, field crews determine boundary MSs and change their status. The customers restored via MSs experience interruption with longer duration that is needed for manual switching action and fault location.

8.3.3.4 Step 3-4: Repair Action

After finding the faulted equipment and restoring service to customers out of the faulted area, repair crews repair the faulted section. The time takes to repair a system element depends on various factors such as the type of the element (e.g., transformer, switch, and line), the number of repair crews, the required tools for repairing, etc. The customers in the faulted area should remain de-energized until the faulted section is repaired. These customers experience the interruption duration associated with the repair time and fault location time.

8.3.3.5 Step 3-5: Returning to the Initial State

Conducting various remedial actions alters the network operation from the optimal condition. So, it is necessary to return the status of switches to their normal condition. To do so, depending on the switches, the customers who were previously restored via appropriate switching actions may be de-energized for a short duration again.

Example 8.1 The interruption duration of load points fed through a typical feeder following a fault are determined here. The feeder and other required information are shown in Fig. 8.2.

Assumptions The feeder is equipped with a CB at the beginning and a tie switch (TS) at the end. Without loss of generality, it is presumed that the time takes to change the status of CB and TS is trivial. The time takes for fault location is assumed to be 20 min. Also, the switching times associated with RCS and MS are considered to be 5 and 60 min, respectively. It takes 180 min to repair the faulted section. Also, it is assumed that operators can recognize the suspicious fault section and consequently, the suspicious fault location duration is neglected. The locations of MS and RCS are determined with circuit and square, respectively.

CASE I This case provides information regarding the feeder not equipped with any SS. This case is a comparison benchmark to show the effectiveness of SS deployment.

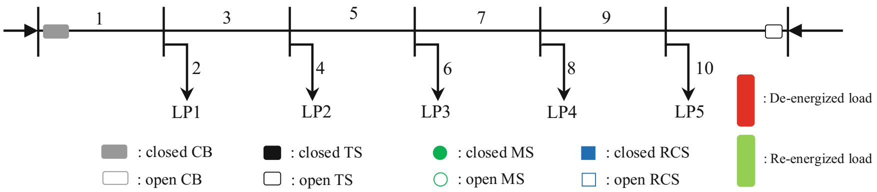

Fig. 8.2 Representative feeder of Example 8.1

Step I: The operators recognize that a fault has occurred somewhere in the network by the information obtained from either of the above-mentioned ways (e.g., customers contact).

Step II: The operators recognize that the fault has happened in the illustrated feeder. In this way, the approximate fault location is determined by the above-mentioned approaches, e.g., fault indicator, (Fig. 8.3).

Step III: The repair crews patrol the suspicious area in order to identify the faulted section (Fig. 8.4).

Step IV: The repair crews start repairing the faulted section. The repair action takes 180 min (Fig. 8.5).

Step V: After repairing section 3, the CB is closed to restore all customers. Therefore, the customers who are fed through this feeder remain interrupted for 200 (= 20 + 180) min (Fig. 8.6).

The restoration times for the load points are represented in Table 8.1.

CASE II In this case, just MS deployment is considered and the allocation of RCSs is ignored. The configuration of the feeder is depicted in Fig. 8.7. The fault management steps are as follows:

Table 8.1 Restoration time and mode of the load points in CASE I of Example 8.1

Load point no.	Restoration time (min)	Restoration type
1	200	Fault location + repair action
2	200	Fault location + repair action
3	200	Fault location + repair action
4	200	Fault location + repair action
5	200	Fault location + repair action

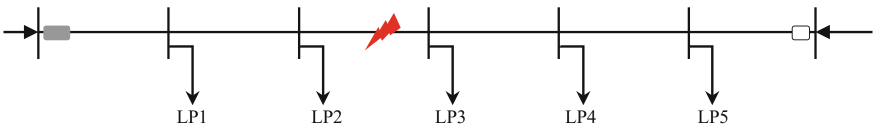

Fig. 8.3 Representative feeder of Example 8.1 in CASE I

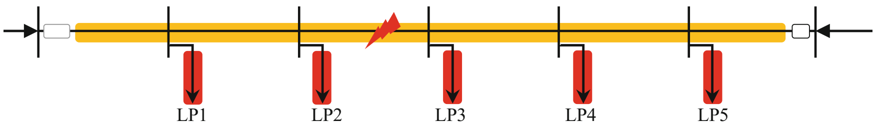

Fig. 8.4 Representative feeder of Example 8.1 in CASE I-step II

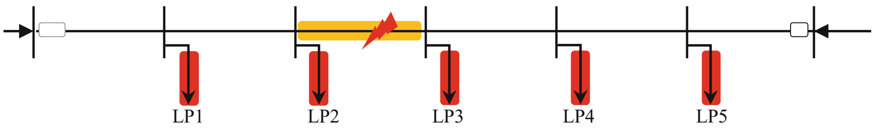

Fig. 8.5 Representative feeder of Example 8.1 in CASE I-step III

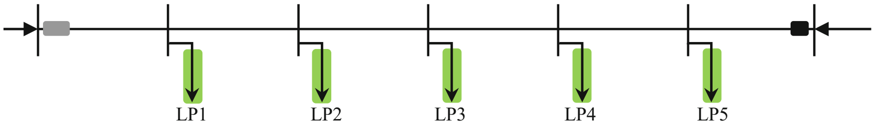

Fig. 8.6 Representative feeder of Example 8.1 in CASE I-step V

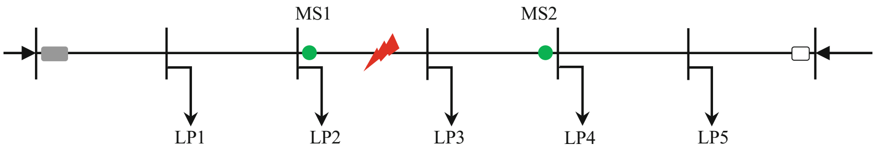

Fig. 8.7 Representative feeder of Example 8.1 in CASE II

Step I: The operators recognize that a fault has occurred somewhere in the network by the information achieved from the above-mentioned ways (e.g., customers contact).

Step II: They identify that the fault has happened somewhere in the feeder below. In this way, they are able to determine the approximate faulted zone by the above-mentioned approaches, e.g., fault indicator, (Fig. 8.8).

Step III: The repair crews patrol the suspicious area in order to identify the faulted section. By doing so, the crews determine the faulted section (Fig. 8.9).

Step IV: The repair crews manually open MS1 and MS2. Then, CB and TS are closed in order to restore load points 1, 2, 4, and 5. Since the time to arrive the MS location and change its state takes 60 min, the load points remain interrupted for 80 (= 20 + 60) min. Hence, the interruption duration of load points 1, 2, 4, and 5 is equal to 80 min (Fig. 8.10).

Step V: The repair crews commence repairing the faulted equipment. This process takes 180 min.

Step VI: Since load point 3 cannot be restored prior to repair action, it should remain interrupted until section 3 is repaired. So, the customers connected to this load point experience 200 (= 20 + 180) min of interruption (Fig. 8.11).

The restoration times for the load points are represented in Table 8.2.

Table 8.2 Restoration time and mode of the load points in CASE II of Example 8.1

Load point no.	Restoration time (min)	Restoration type
1	80	Fault location + manual switching
2	80	Fault location + manual switching
3	200	Fault location + repair action
4	80	Fault location + manual switching
5	80	Fault location + manual switching

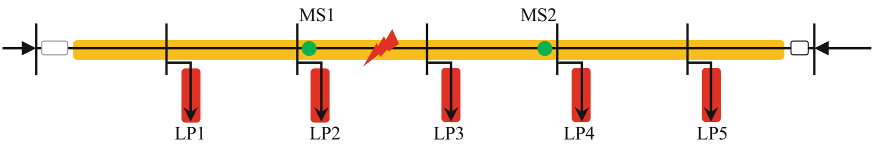

Fig. 8.8 Representative feeder of Example 8.1 in CASE II-step II

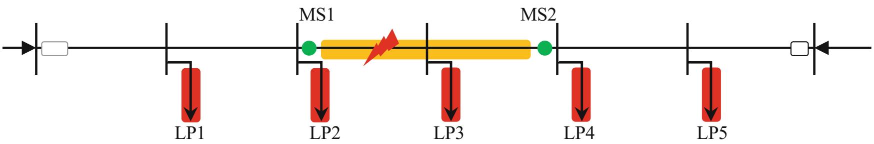

Fig. 8.9 Representative feeder of Example 8.1 in CASE II-step III

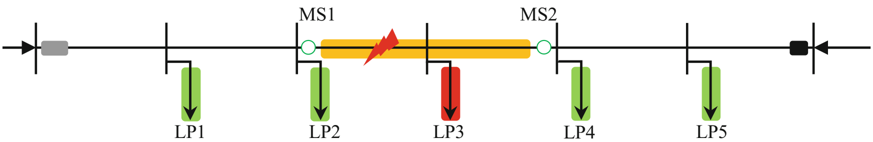

Fig. 8.10 Representative feeder of Example 8.1 in CASE II-step IV

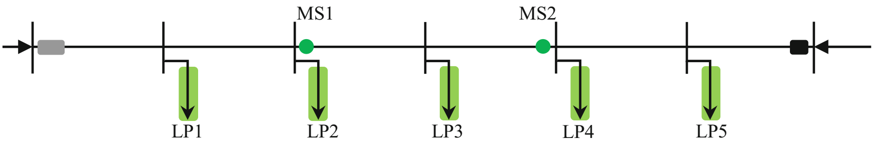

Fig. 8.11 Representative feeder of Example 8.1 in CASE II-step VI

CASE III In this case, just RCS deployment is considered and the allocation of MSs is ignored. The feeder is portrayed in Fig. 8.12. The fault management steps are as follows.

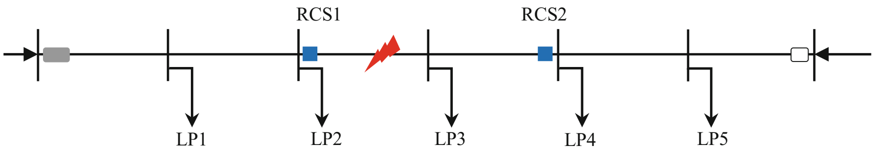

Fig. 8.12 Representative feeder of Example 8.1 in CASE III

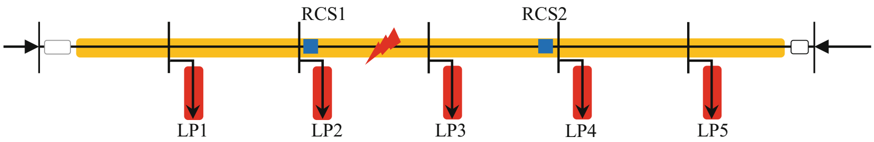

Fig. 8.13 Representative feeder of Example 8.1 in CASE III-step II

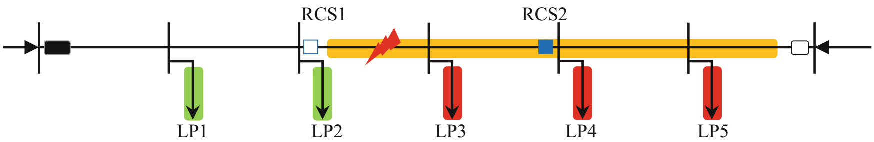

Fig. 8.14 Representative feeder of Example 8.1 in CASE III-step III

Step I: The operators diagnose a fault occurrence in the network by the information obtained from the above-discussed approaches (e.g., customers contact).

Step II: The operators recognize that the fault has happened in the shown feeder. In this way, they are able to determine the fault zone by the above-mentioned approaches, e.g., fault indicator, (Fig. 8.13).

Step III: The operators may use trial and error approach to determine the suspicious area. To do so, they first open RCS1 remotely and close the CB. In this situation, since the fault has occurred downstream of RCS1, the CB does not operate. Hence, the operators recognize that the fault is somewhere after RCS1. This circumstance is shown in Fig. 8.14.

The next trial is to close RCS1, open RCS2, and close the CB. By doing so, the CB operates. Therefore, the operators recognize that the fault is somewhere between RCS1 and RCS2. This circumstance is shown in Fig. 8.15. The trial and error approach does not take considerable time which is neglected here.

Now, load points 1, 2, 4, and 5 can be restored remotely via the RCSs. This process takes 5 min. So, the customers whose connection points are

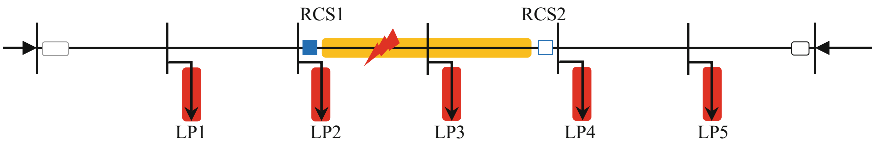

Fig. 8.15 Representative feeder of Example 8.1 in CASE III-step III

Table 8.3 Restoration time and mode of the load points in CASE III of Example 8.1

Load point no.	Restoration time (min)	Restoration type
1	5	Remote switching
2	5	Remote switching
3	200	Fault location + repair action
4	5	Remote switching
5	5	Remote switching

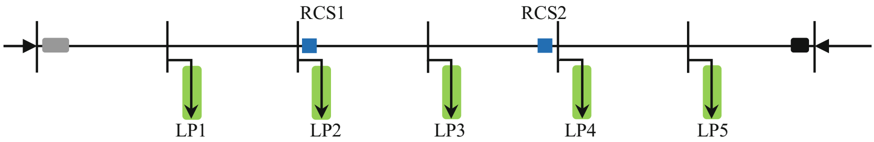

Fig. 8.16 Representative feeder of Example 8.1 in CASE III-step VI

upstream of RCS1 and downstream of RCS2 experience 5 min interruption.

Step IV: The repair crews precisely patrol the suspicious area. By doing so, the crews determine the faulted section. This process takes 20 min.

Step V: The crews repair the faulted equipment which takes 180 min.

Step VI: Load point 3 should remain interrupted during the repair action. So, by taking into account the previous remedial actions, load point 3 retains interrupted for 200 (= 20 + 180) min. Finally, the network returns to the normal condition (Fig. 8.16).

The restoration times for the load points are represented in Table 8.3.

CASE IV In this case, both RCS and MS deployment is considered. The feeder is depicted in Fig. 8.17. The fault management steps are as follows:

Step I: The operators recognize that a fault has occurred somewhere in the network by the information obtained from the above-mentioned ways (e.g., customers contact).

Step II: The operators figure out that the fault has happened in the illustrated feeder. In this way, they are able to determine the fault zone by the above-mentioned approaches (e.g., fault indicator) (Fig. 8.18).

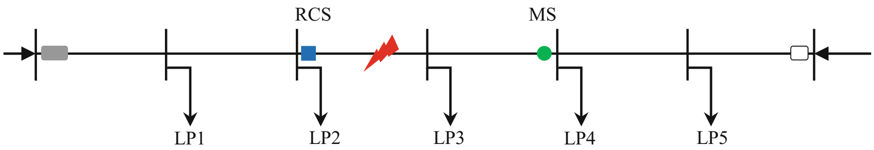

Fig. 8.17 Representative feeder of Example 8.1 in CASE IV

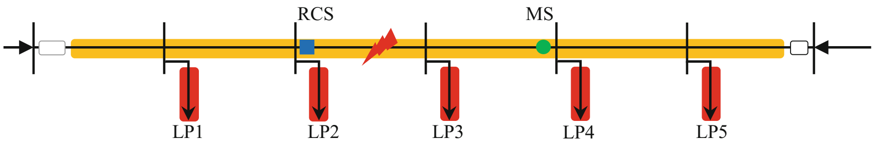

Fig. 8.18 Representative feeder of Example 8.1 in CASE IV-step II

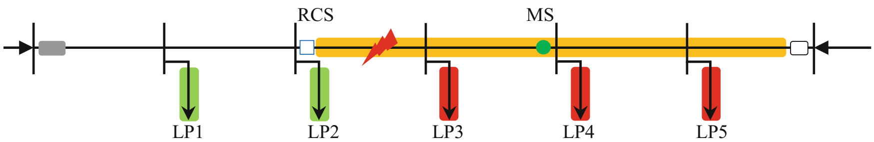

Fig. 8.19 Representative feeder of Example 8.1 in CASE IV-step III

Step III: The operators apply trial and error approach to determine the suspicious area. To do this, the operators send a signal to RCS to be opened and close the CB. In this condition, the CB does not operate and load points 1 and 2 are re-energized, which means that the fault has originated from sections downstream the RCS. So, the RCS capability enables the operators to reduce the suspicious area and consequently to decrease the fault location duration. This circumstance is shown in Fig. 8.19.
Load points 1 and 2 are restored via remote switching action which takes 5 min. So, the customers whose connection points are upstream of the RCS experience 5 min interruption.

Step IV: The repair crews determine the faulted section by patrolling the suspicious area.

Step V: The crews restored load points 4 and 5 through opening the MS and closing the TS at the end of the feeder. In this situation, the load points experience 80 (= 20 + 60) min interruption (Fig. 8.20).

Step VI: The repair crews repair the faulted equipment, which takes 180 min.

Step VII: Finally, the network should return to its normal state. By doing so, load point 3 remains interrupted for 200 (= 20 + 180) min (Fig. 8.21).

Table 8.4 Restoration time and mode of the load points in CASE IV of Example 8.1

Load point no.	Restoration time (min)	Restoration type
1	5	Remote switching
2	5	Remote switching
3	200	Fault location + repair action
4	80	Fault location + manual switching
5	80	Fault location + manual switching

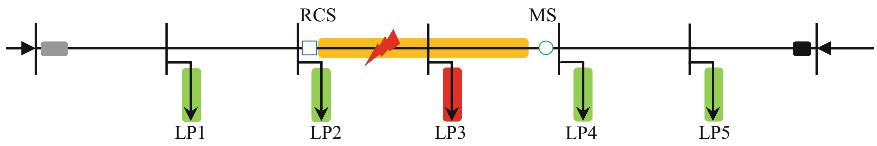

Fig. 8.20 Representative feeder of Example 8.1 in CASE IV-step V

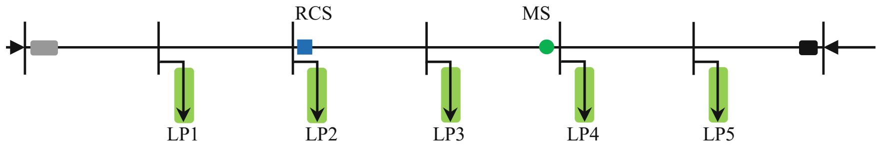

Fig. 8.21 Representative feeder of Example 8.1 in CASE IV-step VII

The restoration times for the load points are represented in Table 8.4.

Table 8.5 summarizes the simulated cases. As can be seen, all customers should stay de-energized for a long duration in CASE I. In CASE II, the customers should be interrupted for shorter interval compared to the customers in CASE I. However, load point 3 experiences the same interruption duration in all of the cases. According to the results, the customer interruption duration of load points 1, 2, 3, and 4 is diminished by 120 min by installing MSs in CASE II. While, in CASE III where RCSs are employed in the feeder, the interruption duration of customers out

Table 8.5 Customer interruption duration of CASE I–CASE IV in Example 8.1

Load point no.	Customer interruption duration (min)			
	CASE I	CASE II	CASE III	CASE IV
1	200	80	5	5
2	200	80	5	5
3	200	200	200	200
4	200	80	5	80
5	200	80	5	80

of the faulted section is reduced by 195 min. Also, in CASE IV, the same situation happens for load points 1 and 2 due to the capability of RCS by isolating these load points from the faulted section. Nevertheless, the customers who are fed through load points 4 and 5 should experience longer interruption time. More accurately, 75 min increment in interruption duration of these customers is the penalty of exploiting MS instead of RCS. The results of CASE I–CASE IV clearly demonstrate the significant impact of deploying RCS and MS on interruption duration decrement.

8.4 Switch Deployment Model

In the previous section, the impact of employing RCS and MS on customer interruption duration was explained. The purpose of this section is to present a mathematical model for SS deployment in distribution networks. SSs bring great benefits in diminishing system interruption costs through reducing customer interruption duration and decreasing the fault location time. However, deployment of SSs imposes considerable costs such as capital investment costs, installation costs, and maintenance costs. In this regard, employing of SSs in all possible locations in the system is neither essential nor cost-effective. In this regard, it is necessary to consider a trade-off between the benefits and costs of SS deployment. To do so, various heuristic and mathematical approaches have been developed in the literature. Most of the proposed methods try to minimize the system costs including interruption and SS deployment costs. In [10], the fuzzy decision approach was applied to solve the problem. In [11–13], heuristic optimization techniques such as genetic algorithm, simulated annealing algorithm, and ant colony algorithm were used to find the number and location of SSs. In [14], the authors extended the previous models by taking into account CBs in the problem. The relocation problem was proposed in [15] to locate SSs in a system. Reference [16] divided the candidate SS locations into several independent sets and the problem was solved for each set separately. The bellmen's principle was taken into account in [17] to determine the place of RCSs. Besides, the mathematical approaches were used in the format of MIP in [18–20]. In [18], authors determined the optimal number and location of RCSs by minimizing aggregated system costs. In addition, by extending the proposed model in [18], the impact of earth faults was taken into account in [19]. Furthermore, the budgetary limitation was considered in [20] by proposing a multi-stage planning model to determine the location of RCSs in each year. In addition, the joint RCS and MS placement is considered as reported in [20, 21]. The optimal number and location of SSs in switch placement problem are defined such that the overall system costs comprising of system interruption costs and related SS costs are reduced as [21]:

$$\text{Minimize}\, Cost^{int} + Cost^{SS} \tag{8.1}$$

where $Cost^{int}$ and $Cost^{SS}$ are respectively system interruption and SS costs, which are explained as follows.

8.4.1 Customer Interruption Costs

The customers' interruption costs depend on various parameters such as element failure rate, average customers' demands, and customers' damage function. Customers' damage function relies on the type of affected customers and the interruption duration. So, the system interruption costs are formulated as

$$Cost^{int} = \sum_{t\in T}\sum_{f\in F}\sum_{i\in I}\sum_{j\in J}\sum_{k\in K}\frac{(1+q_{\lg})^{t-1}}{(1+q_{dr})^{t}}\lambda_{f,i}L_{f,j,k}CDF_{f,i,j,k}(d^{int}_{f,i,j,k}) \tag{8.2}$$

where $\lambda_{f,i}$ is the failure rate of an element at location i in feeder f. $L_{f,j,k}$ is the average demand of customers with type k at location j in feeder f. The CDF is represented with $CDF_{f,i,j,k}$ which indicates the damage costs of customers with type k who are connected to load point at location j in feeder f when section i is failed. $d^{int}_{f,i,j,k}$ is the interruption duration of customers with type k at load point j of feeder f during failure in section i. The annual discount rate (q_{dr}) is deemed here to consider the present value of investment. In addition, without loss of generality, a constant load growth rate $(q_{\lg})$ is assumed here. In (8.2), the reliability data of network equipment and load data are assumed to be predetermined parameters. However, interruption duration and hence, CDF are function of the restoration mode. So, the relation between the location of the installed SSs and load points plays a fundamental role in determining CDF. Figure 8.22 shows a representative feeder for the developed mathematical model. As shown, CB is installed at the beginning and end of the feeder. Also, both sides of sections are candidate locations for SSs.

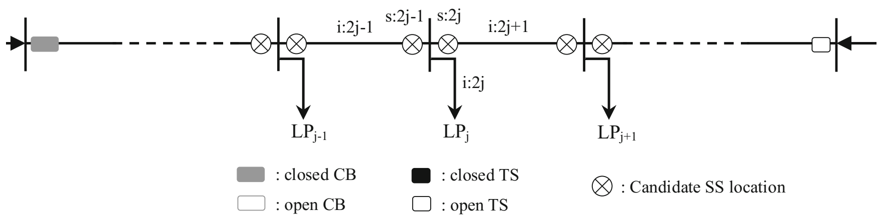

Fig. 8.22 Sample feeder to illustrate the impact of switch location on interruption duration

According to the fault and customer locations in the system as well as the deployed SSs in the system, affected customers can be categorized into three groups. In case of existing any RCS between customers and the fault, they can be promptly isolated from the fault and re-energized through remote switching actions in a few minutes, while other customers would stay for fault location process. After locating the faulted section, other customers who can be isolated from the fault through MSs can be restored by proper switching actions. The rest of customers ought to tolerate interruption duration associated with repair time of the faulted section. Therefore, interruption duration of customers can be calculated based on the configuration of the SSs as

$$d^{int}_{f,i,j,k} \geq TTS^{RCS}_{f,s}; \quad \forall f \in F, \forall i \in I, \forall j \in J, \forall k \in K \tag{8.3}$$

$$d^{int}_{f,i,j,k} \geq \left(TTL_{f,i} + TTS^{MS}_{f,s}\right)\left[1 - \sum_{s=2j}^{i-1} X^{RCS}_{f,s}\right]; \quad \forall f \in F, \forall i \in I, \forall 2j < i, \forall k \in K \tag{8.4}$$

$$d^{int}_{f,i,j,k} \geq \left(TTL_{f,i} + TTS^{MS}_{f,s}\right)\left[1 - \sum_{s=i}^{2j-1} X^{RCS}_{f,s}\right]; \quad \forall f \in F, \forall i \in I, \forall 2j > i, \forall k \in K \tag{8.5}$$

$$d^{int}_{f,i,j,k} \geq \left(TTL_{f,i} + TTR_{f,i}\right)\left[1 - \sum_{s=2j}^{i-1} X^{RCS}_{f,s} - \sum_{s=2j}^{i-1} X^{MS}_{f,s}\right]; \quad \forall f \in F, \forall i \in I, \forall 2j < i, \forall k \in K \tag{8.6}$$

$$d^{int}_{f,i,j,k} \geq \left(TTL_{f,i} + TTR_{f,i}\right)\left[1 - \sum_{s=i}^{2j-1} X^{RCS}_{f,s} - \sum_{s=i}^{2j-1} X^{MS}_{f,s}\right]; \quad \forall f \in F, \forall i \in I, \forall 2j > i, \forall k \in K \tag{8.7}$$

$$d^{int}_{f,i,j,k} \geq TTL_{f,i} + TTR_{f,i}; \quad \forall f \in F, \forall i \in I, \forall 2j = i, \forall k \in K \tag{8.8}$$

where $X^{RCS}_{f,s}$ and $X^{MS}_{f,s}$ are the binary variables associated with existence of RCS and MS in location s in feeder f. In case MS or RCS is installed in a location, the relevant binary variable will be set equal to 1, otherwise it takes the value of zero. In the above formulations, $TTS^{RCS}_{f,s}$, $TTS^{MS}_{f,s}$, $TTL_{f,i}$, and $TTR_{f,i}$ are respectively related to remote switching, manual switching, fault location, and repair time for interrupted customers restoration. Formulation (8.3) belongs to customers who can be isolated through remote switching action. The interruption duration of customers who can be isolated from fault point by manual switching is determined through expressions (8.4) and (8.5). These two formulations are respectively related to the customers whose location is upstream and downstream of the faulted section.

Constraints (8.6) and (8.7) are associated with customers who cannot be isolated from the faulted section through RCS and MS and should remain interrupted until the repair action is carried out. In addition, constraint (8.8) is related to faults occur in customers sections, thereby making sure that the customers are interrupted subsequent to repair time.

8.4.2 SS Costs

SS costs consist of capital investment, installation, and maintenance costs of deployed MSs and RCSs, which is expressed as

$$Cost^{SS} = CI + IC + MC \tag{8.9}$$

$$CI = \sum_{f \in F} \sum_{s \in S} \left(X_{f,s}^{RCS} CI_{f,s}^{RCS} + X_{f,s}^{MS} CI_{f,s}^{MS} \right) \tag{8.10}$$

$$IC = \sum_{f \in F} \sum_{s \in S} \left(X_{f,s}^{RCS} IC_{f,s}^{RCS} + X_{f,s}^{MS} IC_{f,s}^{MS} \right) \tag{8.11}$$

$$MC = \sum_{t \in T} \sum_{f \in F} \sum_{s \in S} \frac{1}{\left(1 + q_{dr}\right)^t} \left(X_{f,s}^{RCS} MC_{f,s}^{RCS} + X_{f,s}^{MS} MC_{f,s}^{MS} \right) \tag{8.12}$$

where $CI_{f,s}^{RCS}$, $IC_{f,s}^{RCS}$, and $MC_{f,s}^{RCS}$ are the capital investment cost, installation cost, and annual maintenance cost of a RCS, respectively. $CI_{f,s}^{MS}$, $IC_{f,s}^{MS}$, and $MC_{f,s}^{MS}$ are the capital investment cost, installation cost, and annual maintenance cost of a MS. The mentioned SSs cost can vary for different locations. The capital costs can highly depend on the types of line (i.e., overhead or underground). Also, the installation costs are related to factors such as the geographical location (i.e., mountain region) and the types of the line. Moreover, RCS requires specific communication facilities to be controlled remotely from control center, thereby raising the RCS installation cost as the distance between the RCS location and control center increases.

8.4.3 Problem Constraints

DisCos own limited financial sources for equipping their system with SS. So, budget limitation plays a fundamental role in the optimal solution of the deployment problem. In this regard, to alleviate the DisCo's concerns regarding the financial restriction, some constraints are considered as

$$\sum_{f \in F} \sum_{s \in S} X_{f,s}^{RCS} \leq N_{RCS}^{\max} \tag{8.13}$$

$$\sum_{f \in F} \sum_{s \in S} X_{f,s}^{MS} \leq N_{MS}^{\max} \tag{8.14}$$

$$CI + IC \leq budget \tag{8.15}$$

$$\sum_{f \in F} \sum_{i \in I} \sum_{j \in J} \sum_{k \in K} \frac{N_{j,k} \lambda_{f,i} d_{f,i,j,k}^{int}}{N^{total}} \leq SAIDI \tag{8.16}$$

$$\sum_{f \in F} \sum_{i \in I} \sum_{j \in J} \sum_{k \in K} \frac{N_{j,k} \lambda_{f,i} L_{f,j,k} d_{f,i,j,k}^{int}}{N^{total}} \leq AENS \tag{8.17}$$

where the first and the second constraints define the maximum number of allocated RCSs $(N_{RCS}^{\max})$ and MSs $(N_{MS}^{\max})$ in the system, and the third one limits the investment cost, including capital investment and installation costs, to the company budget limitation $(budget)$. In addition, the last two constraints consider the system reliability requirements. Broadly speaking, the system reliability indices serve to appraise the efficiency of a grid in emergency situations, e.g., fault occurrence, and DisCos are concerned to keep these indices below a defined level to avoid getting fined. In this regard, constraint (8.16) is associated with the SAIDI index. This index determines the expected value of customer interruption duration per year. $N_{j,k}$ denotes the number of customers in load point j with type k, and N^{total} represents the total number of customers in the network. Also, the expected value of energy not served by customers per year, defined as AENS, is regarded in constraint (8.17).

Example 8.2 In this example, the proposed method is applied to Roy Billinton Test System (RBTS) bus 4, shown in Fig. 8.23, which has been broadly used for SS deployment problem [18–22]. This system consists of 7 feeders which feed 38 load points. The required data associated with load points, failure rates, and feeders' configuration are given in [23]. In addition, three types of customers including residential, small-user, and commercial are accommodated into this system. The CDF and other related information regarding the customers are provided in [24].

In this example, the capital investment and installation costs of RCS and MS are considered to be US k$4700 and US $500, respectively. The annual maintenance costs of RCS and MS are supposed to be 2% of capital and installation costs (i.e., US k$94 and US $10). The annual load growth rate and discount rate are set equal to 3 and 8% for a 15-year study horizon. In addition, remote and manual switching actions are assumed to take 5 and 60 min. The fault location time is deemed to be 20 min. Without loss of generality, it is presumed that TS, located at the end of the feeders, immediately operates whenever it is necessary. Also, the repair action for

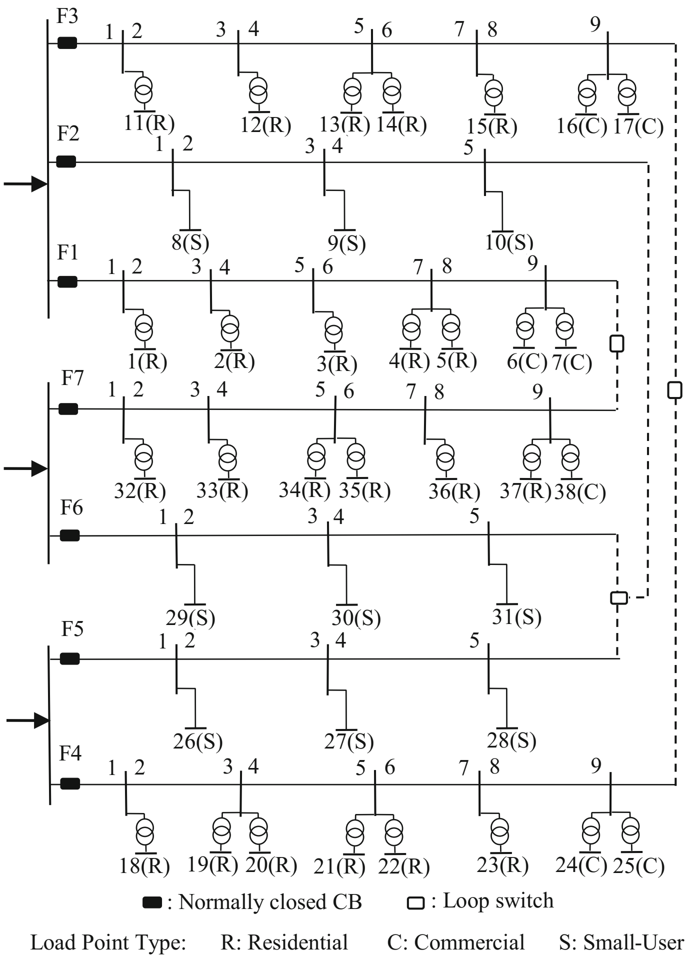

Fig. 8.23 Single line diagram of RBTS-Bus4

each section takes 3 h. According to the test system shown in Fig. 8.23, the total number of candidate places for SSs is equal to 51.

CASE I This case provides information regarding original network not equipped with any SS. This case is a comparison benchmark to show the effectiveness of the developed model for SS deployment.

CASE II The optimal number and location of MSs in the network are determined. In this case, just MS deployment is considered and the allocation of RCSs is ignored. The results are represented in Table 8.6. As can be seen, 5 MSs are allocated to feeders 2, 5, and 6 where small-user customers are fed. In other words, MSs are installed in all possible locations. However, 4 MSs are deployed in other

Table 8.6 Optimal location of MSs in CASE II

Feeder	MSs location
1	3,5,7,9
2	1,2,3,4,5
3	3,5,6,9
4	3,4,6,9
5	1,2,3,4,5
6	1,2,3,4,5
7	3,5,6,9
Total	31

Table 8.7 Optimal location of RCSs in CASE III

Feeder	RCSs location
1	5,9
2	1,2,3,4
3	5,9
4	4,9
5	1,3,4,5
6	1,2,3,4,5
7	5,9
Total	21

feeders where both residential and commercial customers present. In these feeders, MSs are installed with approximately uniform distribution.

CASE III The optimal number and location of RCSs in the network are determined. In this case, the simulation is iterated to find the number and location of only RCSs without considering MSs. The results are provided in Table 8.7. As can be seen, 2 RCSs are installed in feeders 1, 3, 4, and 7 such that one of them is located in middle of the feeders and the other one is located at the end of the feeders where commercial customers are fed. However, at least 4 RCSs are utilized in feeders with small-user customers.

CASE IV The simultaneous placement of RCS and MS is simulated in this case. Table 8.8 gives the location of RCSs and MSs in each feeder. According to the table, 3 MSs are installed in each feeder. In feeders 1, 3, and 4, the first MS is installed in location 3 where the total load and CDF are higher than other feeders. However, the first MS is deployed in location 1 in other feeders. Regarding the RCS location, RCS is employed at the end of feeders 1, 3, 4, and 7 (location 9) where the commercial customers are fed.

The system costs including system interruption cost and switch costs are provided in Table 8.9. As can be seen, employing SSs in CASE II and CASE III leads to US k$459.58 and US k$721.62 reduction in system interruption costs (by 50.41 and 79.15%), respectively. Based on the results, using RCS provides higher achievements in system interruption costs instead of MS installation due to its

Table 8.8 Optimal location of RCSs and MSs in CASE IV

Feeder	MSs location	RCSs location
1	3,5,7	9
2	1,2,5	3,4
3	2,5,6	9
4	3,4,6	9
5	1,3,4	2,5
6	1,2,4	3,5
7	1,5,6	9
Total	21	10

Table 8.9 System costs (US k$) in CASE I–CASE IV of Example 8.2

CASE	Equipment				Interruption (US k$)	Total (US k$)
	Number of MSs	Number of RCSs	MSs (US k$)	RCSs (US k$)		
I	–	–	–	–	911.72	911.72
II	31	–	18.37	–	452.14	470.51
III	–	21	–	118.11	190.10	308.21
IV	21	10	12.44	56.25	208.10	276.79

significant capability in prompt isolating the healthy part from the faulted section. Applying simultaneously RCS and MS reduces the interruption cost from US k$911.72 to US k$208.10 by 77.18% saving in total interruption costs. Furthermore, although the system interruption costs in CASE III and CASE IV are roughly equal, the equipment costs in CASE IV are US k$49.42 smaller than that of CASE III. Hence, the DisCo can reduce system interruption costs by installing MS coupled with RCS without any increment in investment costs.

8.5 Affecting Parameters and Sensitivity Analyses

According to the SS deployment method, explained in the previous section, various parameters may affect the solution of SS deployment problem. This section intends to investigate the impact of key parameters on the SS deployment problem. To do so, the simulation is repeated to find the impact of different prominent parameters including CDF, failure rate and repair time of elements, financial constraints associated with number of allowable SS, and budget limitations.

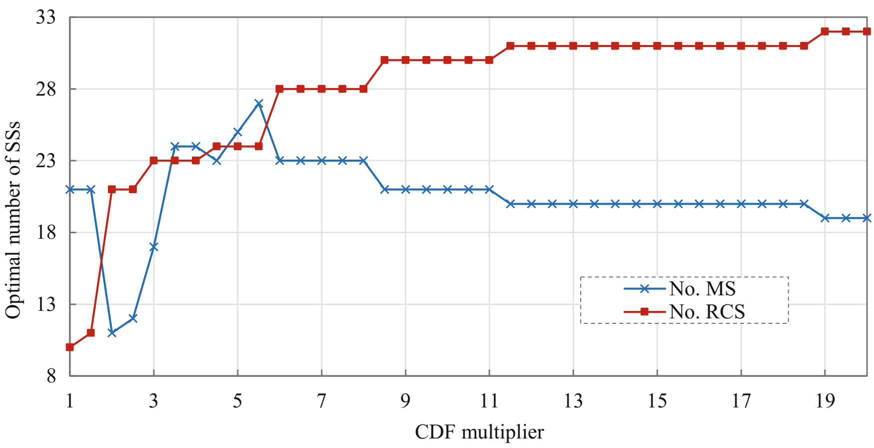

Fig. 8.24 Optimal number of SSs versus different CDFs

8.5.1 Customer Damage Function (CDF)

Here, the effect of CDF on the optimal solution of SS placement problem is scrutinized. In this regard, the simulations are conducted for different CDFs by considering a multiplier varying from 1 to 10. The optimal numbers of RCSs and MSs are depicted in Fig. 8.24. As can be seen, the number of RCSs increases as the CDF rises, thereby diminishing the customer interruption costs. However, the number of MSs does not follow the same pattern, because the number of MSs has a close relation with the number and location of RCSs. As the number of RCSs increases, the number of MSs decreases.

8.5.2 Failure Rate

Elements in distribution networks are not exposed to failure with the same probability, such that sections with higher failure rates are more likely to undergo a fault. In this regard, it is valuable to investigate the impact of different failure rates on the solution of the problem. Also, according to the previous section, SSs are more likely to be installed in locations where the majority of customers can be isolated from sections with higher failure rate. With this in mind, the presented model of switch placement is simulated for different failure rates. The optimal numbers of RCSs and MSs are illustrated in Fig. 8.25. As can be seen, the number of RCSs is generally increased as the failure rate rises. Also, the more RCSs considerably restrict the suspicious fault area and thereby reducing the customer interruption time for customers whose connection point can be isolated prior to repair action. However, the number of installed MSs relies on the number and

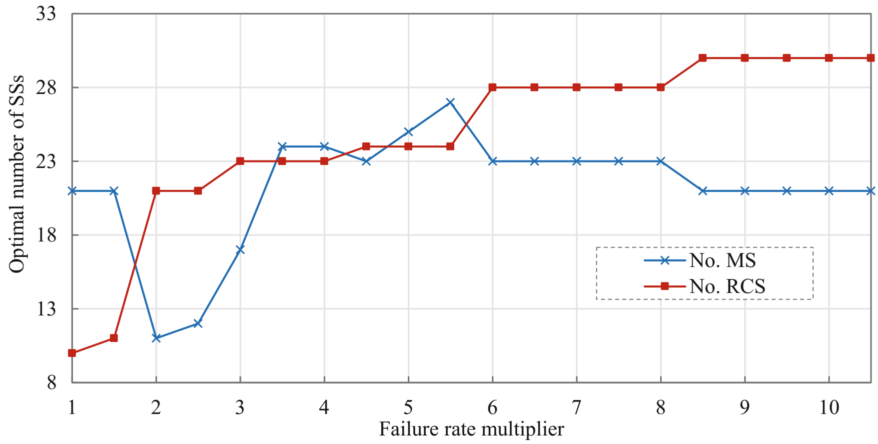

Fig. 8.25 Optimal number of SSs versus different failure rate multiplier

location of RCSs such that as the failure rate is doubled, the number of MSs is extremely reduced while the number of RCSs is increased.

8.5.3 Repair Time

According to several out of control factors such as geographical location (i.e., mountain regions and snow areas), the type of line (i.e., overhead and underground), and the number of repair crews, the repair time can varies in different systems. Therefore, as an affective parameter in SS deployment problem, the impact of repair time should be investigated on the SS allocation. In this regard, the simulation is repeated for different repair times. The numbers of allocated RCSs and MSs are depicted in Fig. 8.26. As can be seen, the optimal number of MSs is increased while the number of RCSs is constant as the repair time increases. In this regard, deploying more MSs remarkably reduces interruption duration of customers whose connection point cannot be restored via manual switching action. Hence, the customer interruption costs significantly waned when the repair time waxed.

8.5.4 Limited Number of SSs

Although employing optimal number of SSs provides the cost effective solution, most DisCos may not be able to equip the system at the beginning of the planning due to the considerable expenses of switches. In this regard, they are interested to understand the extent to which their system efficiency increases as a limited number

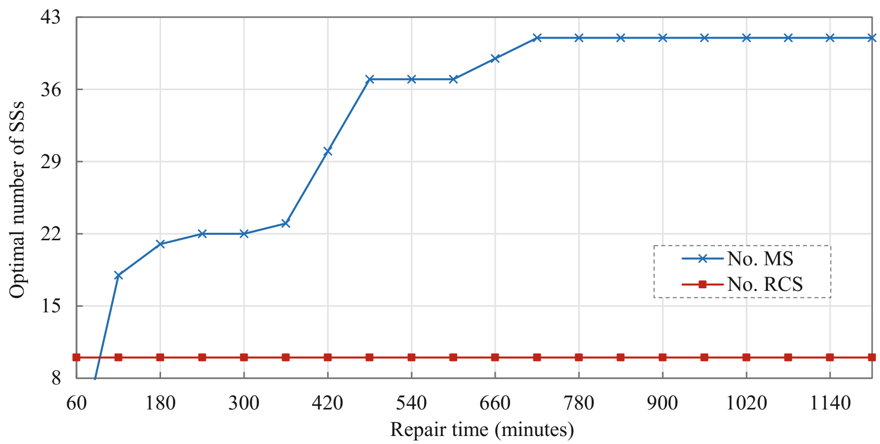

Fig. 8.26 Optimal number of SSs versus different repair time

of SSs getting installed in the system. To this end, the SS deployment problem is run by restricting the number of available MSs and RCSs separately as shown in Figs. 8.27 and 8.28. The maximum number of SSs, i.e., RCSs or MSs, is gradually increased from 0 to 51. According to Fig. 8.27, installing the first MS leads to considerable reduction in customer interruption costs while the reduction is gradually declined when the solution converges to the optimal solution. As was mentioned in CASE II of Example 8.2, the optimal number of MSs is equal to 31, which is shown in the figure. Figure 8.28 represents the impact of the maximum number of RCSs on the system costs. As can be seen, the system interruption cost significantly decreases when the first RCS is installed. The problem is converged when

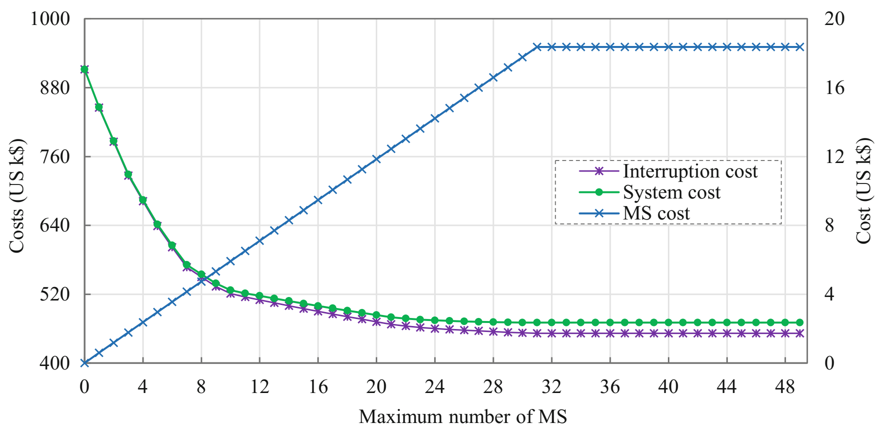

Fig. 8.27 Impact of the maximum number of MS on the system costs

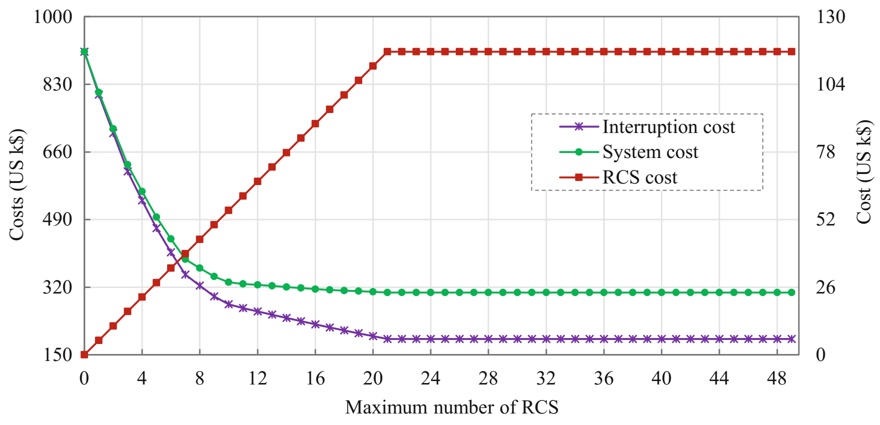

Fig. 8.28 Impact of the maximum number of RCS on the system costs

the optimal solution reaches. According to the results, the optimal solution in this case is equal to 21 as was calculated in CASE III of Example 8.2.

8.5.5 *Restricted Budget*

Budget holds an utmost key in economic planning, such that most of companies are concerned about their financial resources for equipping their system. In this regard, in order to investigate the impact of budget limitation on the SS deployment problem, the economic constraint associated with a range of budget limitation is taken into account. The relevant results are shown in Fig. 8.29. As can be seen,

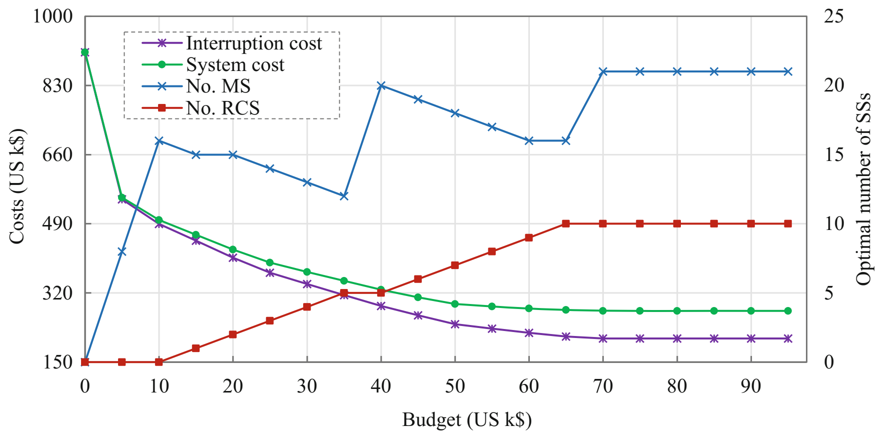

Fig. 8.29 Impact of budget limitation on SS placement solution

only MSs are deployed in the system once allocated budget is less that US k$10. However, by allocating higher budget for equipping system with SS, the number of RCSs gradually increases, while the number of MSs does not follow a regular pattern. Broadly speaking, RCSs, due their quick operation for restoring customers, have greater ability than MS in decreasing customer interruption cost. However, they are more expensive than MSs, which might restrict their allocation in the system. In some cases, it might be more profitable to allocate several MSs than a few number of RCSs to improve the system reliability. As shown in Fig. 8.29, for some cases, by rising in the budget, the number of RCSs does not change, while more MSs are deployed in the system.

8.6 Switch Malfunction

Heretofore, it was assumed that SSs always operate properly. However, sometimes, SSs are not able to function as they are expected, which is referred to as SS malfunction. SS malfunction may degrade the SS worth for fault isolation procedure and consequently affects the optimal solution of the SS deployment problem. Various types of malfunction can be considered for SSs. Isolation capability malfunction of MS and RCS is referred to as their inability in isolating the faulted zone from the rest of system. In addition, the RCS may not respond to the signals sent by control center, referred to as remote controllability malfunction. In this type of malfunction, although RCS is not capable of operating remotely, the switching action can be done manually by the repair crews, treated as a MS. This section is aimed at considering the impact of the SS malfunctions on switch deployment problem. First, the impact of SS malfunction on the SS deployment problem is illustrated by an example. Then, the SS deployment problem, explained in Sect. 8.4, is reformulated by considering SS malfunctions. Finally, the relevant results are presented.

Example 8.3 This example intends to describe the impact of various SS malfunctions, including MS and RCS isolation capability as well as RCS remote controllability malfunction, on the SS deployment problem explained in CASE IV of Example 8.1 (Fig. 8.30).

CASE I: MS isolation capability malfunction.

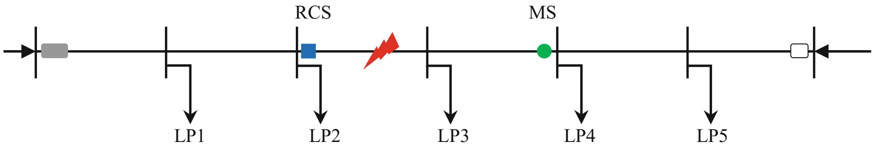

Fig. 8.30 Representative feeder in Example 8.3

Table 8.10 Restoration time and mode of the load points in CASE I of Example 8.3

Load point no.	Restoration time (min)	Restoration type
1	5	Remote switching
2	5	Remote switching
3	200	Fault location + repair action
4	200	Fault location + repair action
5	200	Fault location + repair action

In this case, it is assumed that the MS is not able to isolate the faulted section, while RCS operates properly. Since RCS can function successfully, steps from I to IV in this example are the same as those in Example 8.1. Therefore, the customers connected to load points 1 and 2 are assumed to be restored after remote switching action. However, after the field crews find the faulted section, load points 4 and 5 cannot be disconnected from the faulted section due to the failure in MS isolation capability. Hence, these load points should be kept interrupted during the repair action similar to load point 3. The restoration times for the load points are provided in Table 8.10.

As shown in Table 8.10, MS isolation capability malfunction leads to 120 min increment in customer interruption duration of load points 4 and 5. Hence, in this case, considering the MS malfunction can be interpreted as the absence of MS in the feeder. In addition, the interruption time of load points 1 and 2 does not change due to the successful operation of RCS between the load points and the faulted section. Also, the MS malfunction does not affect the interruption duration of load point 3 which already tolerates repair time without considering MS malfunction.

CASE II RCS isolation capability malfunction.

In this type of RCS malfunction, the RCS is not able to isolate faulted section. Therefore, it can be presumed that the RCS does not exist. In this regard, load points 1 and 2 cannot be isolated from the faulted section, and should remain interrupted subsequent to clearing the fault. However, the malfunction of RCS does not affect load points 4 and 5, and they can be disconnected from section 3 through the MS and restored from the adjacent feeder. With this in mind, Table 8.11 summarizes the interruption times of the load points.

As can be seen, the isolation capability malfunction of RCS increases the interruption duration of load points 1 and 2 by about 200 min. Accordingly, the

Table 8.11 Restoration time and mode of the load points in CASE II of Example 8.3

Load point no.	Restoration time (min)	Restoration type
1	200	Fault location + repair action
2	200	Fault location + repair action
3	200	Fault location + repair action
4	80	Fault location + manual switching
5	80	Fault location + manual switching

Table 8.12 Restoration time and mode of the load points in CASE III of Example 8.3

Load point no.	Restoration time (min)	Restoration type
1	80	Fault location + manual switching
2	80	Fault location + manual switching
3	200	Fault location + repair action
4	80	Fault location + manual switching
5	80	Fault location + manual switching

RCS isolation capability malfunction highly increases the interruption duration of customers whose connection points are supposed to be restored quickly, which results to a costly interruption.

CASE III RCS remote capability malfunction.

In this type of malfunction, it is assumed that the RCS cannot operate remotely, while it can isolate the fault manually, acting like a MS. Here, due to this type of malfunction, the RCS cannot receive the remote control signals, and the operator cannot limit the suspicious fault area. So, the field crews have to patrol all the feeder sections in order to find the faulted element. After determining the faulted section, the field crews open RCS and MS manually in order to restore load points 1, 2, 4, and 5 through manual switching actions. At the end, load point 3 is re-energized after that the faulted section is repaired. Table 8.12 gives the results in this case.

According to the table, due to the RCS remote controllability malfunction, the interruption duration of load points 1 and 2 increases by about 80 min. Although this growth in interruption duration is less than that of isolation capability case, i.e., 200 min, it is still much greater than remote restoration time, i.e., 5 min. Accordingly, RCS remote controllability malfunction can burden system with higher interruption costs.

By taking into account the results of the example, all types of SS malfunctions cause the interruption durations of some customers increase, thereby resulting in higher customer interruption costs. Therefore, malfunctions degrade SSs worth for reducing interruption cost and enhancing system reliability.

8.6.1 Switch Placement Model Considering Malfunctions

As discussed in previous section, malfunctions detract from the SS worth in customer interruption cost reduction and improving service reliability. The effect of SS malfunctions on the system reliability and operation has been investigated in several literatures. The effect of devices failure in distribution networks was taken into account in [25]. In [26], the effect of malfunction of protective and automatic apparatuses in fault indicator deployment problem was deemed. The impact of SS malfunction on service reliability and SSs benefit was reported in [27].

As explained earlier, SS malfunction could rise the interruption duration of some customers which might result in higher interruption costs. Therefore, considering SS malfunctions can change the solution of SS deployment problem as it affects the interruption costs. To extend the SS deployment problem for considering SS malfunctions, the effect of different types of SS malfunctions on customers' interruption duration should be modeled. Here, three types of SS malfunctions including MS isolation capability malfunction, RCS isolation capability malfunction, and RCS remote controllability malfunction are considered. The impact of each type of malfunction on customers' interruption duration is expressed as follows.

8.6.1.1 MS Isolation Capability Malfunction

As mentioned earlier, in MS isolation capability malfunction, the MS is not able to isolate the faulted section from the rest of the feeder. With this in mind, the following formulations calculate the customer interruption duration in case of MS isolation capability malfunction.

$$d^{int,m-MS}_{f,i,j,k} = \sum_{s' \in S} X^{MS}_{f,s'} d^{int}_{f,i,j,k,s'}; \quad \forall f \in F, \forall i \in I, \forall j \in J, \forall k \in K \tag{8.18}$$

$$d^{int}_{f,i,j,k,s'} \geq TTS^{RCS}_{f,s}; \quad \forall f \in F, \forall i \in I, \forall j \in J, \forall k \in K \tag{8.19}$$

$$d^{int}_{f,i,j,k,s'} \geq \left(TTL_{f,i} + TTS^{MS}_{f,s}\right)\left[1 - \sum_{s=2j}^{i-1} X^{RCS}_{f,s}\right]; \quad \forall f \in F, \forall i \in I, \forall 2j < i, \forall k \in K \tag{8.20}$$

$$d^{int}_{f,i,j,k,s'} \geq \left(TTL_{f,i} + TTS^{MS}_{f,s}\right)\left[1 - \sum_{s=i}^{2j-1} X^{RCS}_{f,s}\right]; \quad \forall f \in F, \forall i \in I, \forall 2j > i, \forall k \in K \tag{8.21}$$

$$d^{int}_{f,i,j,k,s'} \geq \left(TTL_{f,i} + TTR_{f,i}\right)\left[1 - \sum_{s=2j}^{i-1} X^{RCS}_{f,s} - \sum_{\substack{s = 2j \\ s \neq s'}}^{i-1} X^{MS}_{f,s}\right]; \quad \forall f \in F, \forall i \in I, \forall 2j < i, \forall k \in K \tag{8.22}$$

$$d^{int}_{f,i,j,k,s'} \geq \left(TTL_{f,i} + TTR_{f,i}\right)\left[1 - \sum_{s=i}^{2j-1} X^{RCS}_{f,s} - \sum_{\substack{s = i \\ s \neq s'}}^{2j-1} X^{MS}_{f,s}\right]; \quad \forall f \in F, \forall i \in I, \forall 2j > i, \forall k \in K \tag{8.23}$$

$$d_{f,i,j,k,s'}^{int} \geq TTL_{f,i} + TTR_{f,i}; \quad \forall f \in F, \forall i \in I, \forall 2j = i, \forall k \in K \tag{8.24}$$

where $d_{f,i,j,k,s'}^{int}$ represents customer interruption duration when SS in location s' encounters isolation capability malfunction. Also, $d_{f,i,j,k,s'}^{int,m-MS}$ is total customer interruption duration with considering all MSs malfunction in feeder f. The MS malfunction indicates that the MS cannot be able to disconnect customers from faulted section before repair action. Hence, for this type of malfunction, it can be assumed that the MS is not installed. So, to consider the malfunction of MS in location s', $X_{f,s'}^{MS}$ is supposed to be excluded from (8.22) and (8.23).

8.6.1.2 RCS Isolation Capability Malfunction

Similar to the MS isolation capability malfunction, the impact of RCS isolation capability malfunction on the interruption duration can be formulated as

$$d_{f,i,j,k}^{int,mI-RCS} = \sum_{s' \in S} X_{f,s'}^{RCS} d_{f,i,j,k,s'}^{int}; \quad \forall f \in F, \forall i \in I, \forall j \in J, \forall k \in K \tag{8.25}$$

$$d_{f,i,j,k,s'}^{int} \geq TTS_{f,s}^{RCS}; \quad \forall f \in F, \forall i \in I, \forall j \in J, \forall k \in K \tag{8.26}$$

$$d_{f,i,j,k,s'}^{int} \geq \left(TTL_{f,i} + TTS_{f,s}^{MS}\right)\left[1 - \sum_{\substack{s = 2j \\ s \neq s'}}^{i-1} X_{f,s}^{RCS}\right]; \quad \forall f \in F, \forall i \in I, \forall 2j < i, \forall k \in K \tag{8.27}$$

$$d_{f,i,j,k,s'}^{int} \geq \left(TTL_{f,i} + TTS_{f,s}^{MS}\right)\left[1 - \sum_{\substack{s = i \\ s \neq s'}}^{2j-1} X_{f,s}^{RCS}\right]; \quad \forall f \in F, \forall i \in I, \forall 2j > i, \forall k \in K \tag{8.28}$$

$$d_{f,i,j,k,s'}^{int} \geq \left(TTL_{f,i} + TTS_{f,s}^{MS}\right)\left[1 - \sum_{\substack{s=2j \\ s \neq s'}}^{i-1} X_{f,s}^{RCS} - \sum_{s=2j}^{i-1} X_{f,s}^{MS}\right]; \quad \forall f \in F, \forall i \in I, \forall 2j < i, \forall k \in K \tag{8.29}$$

$$d^{int}_{f,i,j,k,s'} \geq \left(TTL_{f,i} + TTR_{f,i}\right)\left[1 - \sum_{\substack{s=i \\ s \neq s'}}^{2j-1} X^{RCS}_{f,s} - \sum_{s=i}^{2j-1} X^{MS}_{f,s}\right]; \tag{8.30}$$
$$\forall f \in F, \forall i \in I, \forall 2j > i, \forall k \in K$$

$$d^{int}_{f,i,j,k,s'} \geq TTL_{f,i} + TTR_{f,i}; \quad \forall f \in F, \forall i \in I, \forall 2j = i, \forall k \in K \tag{8.31}$$

In (8.25), $d^{int,mI-RCS}_{f,i,j,k,s'}$ represents customer interruption duration with considering RCS isolation capability malfunction. In this type of malfunction, RCS is not able to disconnect fault, so it can be presumed that RCS does not exist. Therefore, to consider the malfunction of RCS in location s', $X^{RCS}_{f,s'}$ should be removed from the RCS summation as shown in constraints (8.27)–(8.30).

8.6.1.3 RCS Remote Controllability Malfunction

The impact of RCS isolation controllability malfunction on the interruption duration can be calculated as

$$d^{int,mR-RCS}_{f,i,j,k} = \sum_{s' \in S} X^{RCS}_{f,s'} d^{int}_{f,i,j,k,s'}; \quad \forall f \in F, \forall i \in I, \forall j \in J, \forall k \in K \tag{8.32}$$

$$d^{int}_{f,i,j,k,s'} \geq TTS^{RCS}_{f,s}; \quad \forall f \in F, \forall i \in I, \forall j \in J, \forall k \in K \tag{8.33}$$

$$d^{int}_{f,i,j,k,s'} \geq \left(TTL_{f,i} + TTS^{MS}_{f,s}\right)\left[1 - \sum_{\substack{s=2j \\ s \neq s'}}^{i-1} X^{RCS}_{f,s}\right]; \quad \forall f \in F, \forall i \in I, \forall 2j < i, \forall k \in K \tag{8.34}$$

$$d^{int}_{f,i,j,k,s'} \geq \left(TTL_{f,i} + TTS^{MS}_{f,s}\right)\left[1 - \sum_{\substack{s=i \\ s \neq s'}}^{2j-1} X^{RCS}_{f,s}\right]; \quad \forall f \in F, \forall i \in I, \forall 2j > i, \forall k \in K \tag{8.35}$$

$$d_{f,i,j,k,s'}^{int} \geq \left(TTL_{f,i} + TTR_{f,i}\right)\left[1 - \sum_{s=2j}^{i-1} X_{f,s}^{RCS} - \sum_{s=2j}^{i-1} X_{f,s}^{MS}\right]; \quad \forall f \in F, \forall i \in I, \forall 2j < i, \forall k \in K \tag{8.36}$$

$$d_{f,i,j,k,s'}^{int} \geq \left(TTL_{f,i} + TTR_{f,i}\right)\left[1 - \sum_{s=i}^{2j-1} X_{f,s}^{RCS} - \sum_{s=i}^{2j-1} X_{f,s}^{MS}\right]; \quad \forall f \in F, \forall i \in I, \forall 2j > i, \forall k \in K \tag{8.37}$$

$$d_{f,i,j,k,s'}^{int} \geq TTL_{f,i} + TTR_{f,i}; \quad \forall f \in F, \forall i \in I, \forall 2j = i, \forall k \in K \tag{8.38}$$

where $d_{f,i,j,k,s'}^{int,mR-RCS}$ is designed as customer interruption duration corresponding to consider RCS remote controllability malfunction in location s'. In this type of malfunction, the RCS fails to remotely isolate by the control signal from the control center. Hence, the customers who were supposed to be isolated through remote switching actions should remain interrupted until manual switching actions are done by the field crews. With this in mind, in order to consider the RCS with remote controllability malfunction in location s', $X_{f,s'}^{RCS}$ should be excluded from the RCS summation as shown in (8.34) and (8.35). It is worth mentioning that the RCS which is not able to be isolated remotely should be included in RCS summation in constraints (8.36) and (8.37) since they can be opened manually and isolate the faulted section.

8.6.1.4 Total Interruption Duration

So far, the customer interruption duration associated with all types of SS malfunctions was calculated. By considering the malfunction probability of the mentioned malfunctions, the following equation determines the total customer interruption duration.

$$\begin{aligned} d_{f,i,j,k}^{tot-int} = {} & (1 - P_f^{m-MS})(1 - P_f^{mI-RCS} - P_f^{mR-RCS}) d_{f,i,j,k}^{int} \\ & + P_f^{m-MS}(1 - P_f^{mI-RCS} - P_f^{mR-RCS}) d_{f,i,j,k}^{int,m-MS} \\ & + (1 - P_f^{m-MS}) P_f^{mI-RCS} d_{f,i,j,k}^{int,mI-RCS} \\ & + (1 - P_f^{m-MS}) P_f^{mR-RCS} d_{f,i,j,k}^{int,mR-RCS} \end{aligned} \tag{8.39}$$

where P_f^{m-MS}, P_f^{mI-RCS}, and P_f^{mR-RCS} represent the probability of MS isolation capability malfunction, RCS isolation capability malfunction, and RCS remote controllability malfunction, respectively. According to (8.39), the total customer interruption duration is the summation of four terms. The first term relates to the mode that no SS malfunction is considered, referred to Sect. 8.4. The second term is associated with MS isolation capability malfunction. Also, the third and fourth terms belong to RCS isolation capability and RCS remote controllability malfunction, respectively. Accordingly, the SS deployment problem can be extended to consider SS malfunction through considering the calculated customers interruption duration in (8.39).

To find the optimal number and location of SSs, it is necessary to minimize the system cost comprising of system interruption cost and SSs cost is minimized as

$$\text{Minimize } Cost^{int} + Cost^{SS} \tag{8.40}$$

where $Cost^{SS}$ is calculated according to (8.9)–(8.12). $Cost^{int}$ is determined as

$$Cost^{int} = \sum_{t\in T}\sum_{f\in F}\sum_{i\in I}\sum_{j\in J}\sum_{k\in K}\frac{(1+q_{\lg})^{t-1}}{(1+q_{dr})^{t}}\lambda_{f,i}L_{f,j,k}CDF_{f,i,j,k}(d_{f,i,j,k}^{tot-int}) \tag{8.41}$$

Above expression is similar to (8.2) except that the total interruption duration $(d_{f,i,j,k}^{tot-int})$ by considering the impact of SSs malfunction is taken into account.

Example 8.4 In this example, the effect of SS malfunction on the SS deployment problem in RBTS-Bus4 is investigated using the extended model.

CASE I This case has to do with MS deployment problem by considering the MS isolation capability malfunction. The probability of MS malfunction is assumed to be 0.05. The optimal location of MSs is provided in Table 8.13. As can be seen, the number of installed MSs is reduced from 31, referred to CASE II of Example 8.2, to 21 in this case. Therefore, it can be concluded that considering MS malfunction causes the number of allocated MS in the system declines.

CASE II In this case, the optimal deployment of RCSs with considering RCS malfunctions is examined. The probabilities of RCS isolation capability malfunction and isolation controllability malfunction are considered to be equal to 0.015 and 0.02, respectively. The optimal location of RCSs is given in Table 8.14. According to the results, when RCSs fail to isolate the faulted section remotely or manually, the optimal number of RCSs does not change and is equal to the number of RCSs when they are able to operate properly.

Table 8.13 Optimal location of MSs in CASE I of Example 8.4

Feeder	MSs location
1	7,9
2	1,2,3,4
3	5,9
4	5,9
5	1,2,4,5
6	1,2,3,4,5
7	5,9
Total	21

Table 8.14 Optimal location of RCSs in CASE II of Example 8.4

Feeder	RCSs location
1	5,9
2	1,2,3,4
3	5,9
4	5,9
5	1,2,4,5
6	1,2,3,4,5
7	5,9
Total	21

Table 8.15 Optimal location of RCSs and MSs in CASE III of Example 8.4

Feeder	MSs location	RCSs location
1	5	9
2	1,2,5	3,4
3	5	9
4	5	9
5	1,2,5	3,4
6	1,2,4	3,5
7	5	9
Total	13	10

CASE III In this case, the optimal number and location of MSs and RCSs are determined with considering all types of SS malfunction. The malfunction probabilities of MS and RCS are considered the same as in previous cases. Here, the optimal placement of RCS and MS is taken into account and the optimal solution is presented in Table 8.15. As can be seen, the optimal number of MSs is decreased from 21 to 13, while the optimal number of RCSs does not change and is equal to the number of RCSs when they operate properly.

Tables 8.16 and 8.17 summarize the number of SSs and system costs for the cases of considering and not considering SS malfunctions in SS deployment problem. By comparing the results, it can be noticed that considering the SSs malfunction reduces the number of deployed SSs and increases the customer interruption costs. Also, according to expression (8.39), the SSs benefit for enhancing system reliability relies on the malfunction probability of SSs and has

Table 8.16 System costs (US k$) in CASE I–CASE III of Example 8.4

CASE	Equipment				Interruption (US k$)	Total (US k$)
	Number of MSs	Number of RCSs	MSs (US k$)	RCSs (US k$)		
I	21	–	12.44	–	472.04	484.48
II	–	21	–	118.11	197.59	315.70
III	13	10	7.70	56.25	225.55	289.50

Table 8.17 System costs (US k$) in CASE I–CASE IV of Example 8.2

CASE	Equipment				Interruption (US k$)	Total (US k$)
	Number of MSs	Number of RCSs	MSs (US k$)	RCSs (US k$)		
I	–	–	–	–	911.72	911.72
II	31	–	18.37	–	452.14	470.51
III	–	21	–	118.11	190.10	308.21
IV	21	10	12.44	56.25	208.10	276.79

significant impact on the number of SSs. So, the SSs benefits wane as the malfunction probability is increased and consequently the allocated SSs are reduced.

8.7 Uncertainty and Financial Risk

In previous sections, the optimal solution of switch placement was determined by comparing the expected interruption costs and switch costs. The initial investment is known before the deployment of SSs while the system interruption costs rely on several parameters which are a function of uncertain parameters. The uncertainties alter the benefits of SSs in reducing the customer interruption costs which interprets that they impose undeniable financial risk on the investor as a private company. The purpose of this section is to assess the financial risk when the SSs are utilized in the network. To do so, the step by step algorithm is presented in the following sections. At the beginning, the main sources of uncertainties are defined which have direct correlation with the system interruption cost. Then, several scenarios are generated representing the status of selected uncertain parameters. Next, the optimal fault management, similar to optimal switch placement except that here, the location of SSs is known, is applied to each of the scenarios in order to calculate the system interruption cost. Finally, the final indices including DisCo profit and risk are reported. The financial risk is calculated through a pragmatic index which is commonly used in risky situations. The proposed approach is thoroughly discussed in the following subsections.

8.7.1 Uncertain Parameters

The uncertainties in distribution systems are originated from various sources like the load forecast error, uncertain characteristic of renewable energy resources, stochastic nature of fault occurrence, and variable duration of repair actions. Among the proposed factors, stochastic nature of contingencies as well as repair time hold a substantial impact on the SSs achievements. In order to take into account the uncertainties, several approaches like mathematical and scenario based model, to name just a few, were presented. The mathematical approaches take the advantages of fuzzy concept or probability density function. The fuzzy approach is used when the values of uncertain parameters are not accessible. While, the other one considers the probability density function for each uncertain parameter in order to achieve the probability density function of the objective. The scenario based approach utilizes a set of scenarios that represent the status of uncertain parameters. Although the mathematical methods provide more precise solutions, their complexity leads to significant computation impediments. To avoid this issue, the scenario based approach is taken into account in this section. Also, the enough number of scenarios are generated to assure the accuracy of the method. It is worth mentioning that scenario reduction techniques can decline the number of generated scenarios with negligible impact on the accuracy of the final solution. In order to keep the reduced scenarios close to the original scenarios, they are determined based on the probability distance concept. The most common probability distance is the Kantorovich distance which is defined between two probability distributions. In [28], two scenario reduction techniques based on the Kantorovich distance were proposed. Among them, fast forward selection algorithm is taken into account in this chapter. The algorithm is a repetitive process where, at each iteration, one scenario is selected such that the Kantorovich distance between the original and the selected scenario sets is minimized. The algorithm is terminated when the number of selected scenarios reaches a predefined number. Finally, probability of the non-selected scenarios is transferred to the selected scenarios [29].

8.7.2 *Financial Risk Indices*

As was mentioned heretofore, the uncertain parameters alter the RCS profit from the expected value and thus, induce financial risk. In this regard, various risk measures have been introduced to evaluate the financial risk [29]. The most common risk indices are volatility index (VolIn), shortfall probability (SP), expected shortage (ES), value at risk (VaR), and conditional value at risk (CVaR) to name just a few. The description and formulation of the mentioned indices are presented hereinafter.

8.7.2.1 Volatility Index (VolIn)

VolIn represents the variance of the profit from the expected value. In order to determine the VolIn, the expected value of the difference between the profit and the expected profit should be calculated. By assuming as the profit of each scenario, VolIn is formulated as

$$\mathrm{VolIn} = \varepsilon\left\{ (\mathrm{Profit}_{\omega} - \varepsilon\{\mathrm{Profit}_{\omega}\})^2 \right\} \tag{8.42}$$

where ε is the expected value calculator and $\varepsilon\{\mathrm{Profit}_{\omega}\}$ is the expected profit. According to the definition of the index, the situation is more risky when VolIn value is higher.

8.7.2.2 Shortfall Probability (SP)

SP represents the cumulative probability of profit smaller than a predefined profit. By considering the predefined value of profit as η, the mathematical formulation of SP can be expressed as

$$\mathrm{SP}_{\eta} = P(\omega|\mathrm{Profit}_{\omega} < \eta); \quad \forall \eta \in R \tag{8.43}$$

where P is the cumulative probability of profit. As can be observed from the above formula, the situation is more risky when SP converges to 1. However, if SP value is near 0, the situation is less risky. Hence, the higher the index, the more risky is the situation.

8.7.2.3 Expected Shortage (ES)

ES measures the expected profit for the scenarios with the profit less than a predefined value. In other words, ES is similar to SP, except that it calculates the expected profit while SP measures the probability. The formulation of ES is shown as

$$\mathrm{ES}_{\eta} = \varepsilon\{\mathrm{Profit}_{\omega}|\mathrm{Profit}_{\omega} < \eta\}; \quad \forall \eta \in R \tag{8.44}$$

According to the above formula, it is clear that the situation is less risky when ES value is higher.

8.7.2.4 Value at Risk (VaR)

VaR indicates the maximum value of profit within a predefined percent of the worst scenarios. The worst scenarios have the least values of profit. VaR can be formulated as

$$\mathrm{VaR}_{\alpha} = \sup\{\eta|P(\omega|\mathrm{Profit}_{\omega} < \eta) \leq 1 - \alpha\}; \quad \forall \alpha \in (0, 1) \tag{8.45}$$

where sup and α are the supreme value of a set and the predefined percent, respectively. VaR formulation reveals that the situation is less risky when its value is higher.

8.7.2.5 Conditional Value at Risk (CVaR)

CVaR donates the expected value of profit in a predefined percent of the worst scenarios. CVaR can be expressed mathematically as

$$C\text{VaR}_\alpha = \varepsilon\{\text{Profit}_\omega|\text{Profit}_\omega < VaR_\alpha\}; \quad \forall\alpha \in (0,1) \tag{8.46}$$

As can be expected, the financial risk decreases when CVaR value is increased.

By taking into account the above explanations, both SP and ES are calculated based on predefined values of profit while VaR and CVaR measure the risk based on predefined values of probability. Since determining the predefined value of profit is difficult, it is logical to consider a predefined percent of the most severe scenarios. Also, making decision based on the expected value is more comparative than the maximum value. So, the financial risk is represented with CVaR in this chapter.

8.7.3 Scenario Generation

Here, the introduced uncertainties, i.e., fault occurrence and repair time, are considered to compose the situation of the system in each scenario. Then, several scenarios are generated by iterating the method presented in this subsection. A scenario represents the up/down status of elements in the system. Once a component fails to operate properly, its status changes from up to down. The time that the element fails has a direct correlation with the probability distribution function of the element failure. Various probability distribution functions have been employed to calculate the time to failure such as exponential, gamma, lognormal, and passion. Without loss of generality, the exponential distribution function is taken into account here. The Monte Carlo Simulation (MCS) is taken in use to generate scenarios. To do so, the following steps represent this approach [30].

Step 1: Time to failure of an element located in section i and feeder f is as

$$TTF_{f,i} = -MTTF_{f,i} \times \ln(u) \tag{8.47}$$

where $MTTF_{f,i}$ is the mean time to failure of the element and u is a random variable with standard distribution. Time to failure indicates the time that the element fails to work properly. In other word, the status of the element changes from up state to down state.

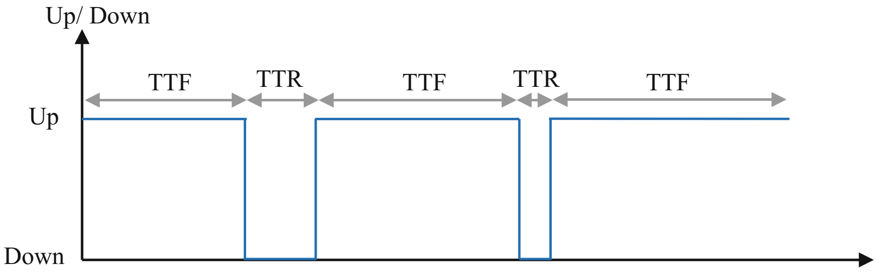

Fig. 8.31 Up/down status of sample element

Step 2: After calculating time to failure of the faulted element, the time to repair of the element is calculated as

$$TTR_{f,i} = -MTTR_{f,i} \times \ln(u) \tag{8.48}$$

where $MTTR_{f,i}$ refers to mean time to repair of the element.

Step 3: Steps 1 and 2 are iterated for a period equal to or greater than the length of horizon study. Then, the up/down status of each element during the study horizon is determined. As an example, Fig. 8.31 shows the up/down status of a sample element.

Step 4: Steps 1–3 are repeated for all elements in the networks.

Step 5: In this step, the up/down status of elements is compared together to determine the up/down status of the network. By doing this, the location of faulted sections, time to failure as well as time to repair of them can be obtained from the up/down status of system.

Step 6: Steps 1–5 are repeated for specific number of scenarios.

The following example clarifies the scenario generation to product a scenario.

Example 8.5 The up/down status of the feeder shown in Fig. 8.32 within a 15-year horizon is determined. Assume that time to failure and time to repair of the elements are 5 years and 3 h, respectively. To avoid complexity of the solution, it is

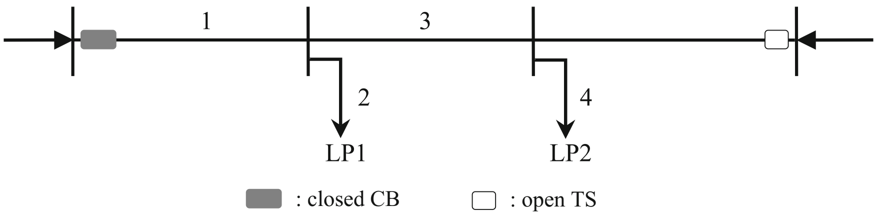

Fig. 8.32 Representative feeder for scenario generation in Example 8.5

Table 8.18 Time to failure and time to repair (h) of sections in the sample feeder in Example 8.5

Section	Time to failure	Time to repair	Time to failure	Time to repair	Time to failure	Time to repair
1	43,800	5	87,600	1	–	–
2	61,320	3	43,800	2	70,080	2
3	175,200	1	–	–	–	–
4	78,840	2	52,560	3	–	–

presumed that the random values are calculated and the corresponding time durations are determined.

To diminish the complexity of the MCS procedure, steps 1 to 3 of MCS is summarize in this example. So, random numbers are generated for each section and time to failure and time to repair for sections 1–4 are calculated. Since the length of study horizon is 15 years, the up/down status of elements should be calculated until the total time of each section reaches 15 years. Table 8.18 represents the up/down information of the sections.

According to the table, the first fault in section 1 occurs in time 43,800 h. The section requires 5 h to be repaired. Since the second fault in this section happens in time 131,405 h (= 43,800 + 5 + 87,600) which is larger than the length of the study horizon (131,400 h), just the first fault is considered in the up/down status of this section. In section 2, the first and the second fault occur in time 61,320 and 105,123 h (= 61,320 + 3 + 43,800), respectively. In section 3, since the first fault occurs after the length of study horizon, the status of the section remain up state during the study horizon. Finally, only one fault happens in section 4 which is in time 78,840 h and it takes 2 h to be repaired. By taking into account aforementioned points regarding the up/down status of sections, the up/down status of the sample system can be determined. In this regard, the first fault occurs in section 1 at time 43,800 h and the repair action takes 5 h long. The second one happens in section 2 at time 61,320 h and the repair action takes 3 h long. The third fault occurs in section 4 at time 78,840 h and 2 h is required to be repaired. The forth and the final fault happens in section 2 at time 105,123 h which 2 h is required to be repaired.

According to the example, generating time to failure and time to repair is based on the random values. So, it is possible that different scenarios have different numbers of fault. In order to achieve the proper accuracy in financial risk assessment, it is necessary to generate enough number of scenarios. When a fault occurs in the system, the fault management process should be conducted to reduce the consequences of fault occurrence. Hence, the next section presents the optimum fault management problem once a contingency occurs.

8.7.4 Optimum Fault Management Problem

By taking into account the points in Sect. 8.3, the aim of fault management process is to reduce the interruption duration of the customers once a contingency happens in the system. Also, the reduction in customer interruption duration is translated to reduction in customer interruption cost. In this regard, it is necessary to minimize the customer interruption cost when a contingency occurs in the system [31]. The optimum fault management problem for each contingency is as

$$\mathrm{Cost}_c^{int} = \sum_{f\in F}\sum_{i\in I}\sum_{j\in J}\sum_{k\in K}\frac{(1+q_{\mathrm{lg}})^{t_c-1}}{(1+q_{dr})^{t_c}}L_{f,j,k}CDF_{f,i,j,k}(d_{f,i,j,k}^{int}) \tag{8.49}$$

As can be seen in (8.49), the minimization of customers interruption cost is solved for each contingency. The costumer interruption cost depends on the average load of customers and the CDF. The average load is constant except that it grows with a predefined growth rate. However, the CDF relies on the customer interruption duration. The interruption duration depends on the correlation between the faulted section and the load point that feeds the customer. In case any RCS is present between the two, the customers can be isolated from the faulted equipment via remote switching actions. In this situation, the interruption duration is equal to remote switching action time. Other customers who can be isolated through manual switching actions will remain interrupted after locating the precise location of fault and prior repairing the faulted section. So, the interruption duration for these customers is longer than the customers whose service is restored remotely. Finally, the other customers who cannot be isolated from the faulted section should be kept interrupted until the faulted equipment is repaired. So, the customers can be restored in three ways as formulated in the following:

$$d_{f,i,j,k}^{int} \geq TTS_{f,s}^{RCS}; \quad \forall f\in F, \forall i\in I, \forall j\in J, \forall k\in K \tag{8.50}$$

$$d_{f,i,j,k}^{int} \geq \left(TTL_{f,i} + TTS_{f,s}^{MS}\right)\left[1-\sum_{s=2j}^{i-1}X_{f,s}^{RCS}\right]; \quad \forall f\in F, \forall i\in I, \forall\, 2j<i, \forall k\in K \tag{8.51}$$

$$d_{f,i,j,k}^{int} \geq \left(TTL_{f,i} + TTS_{f,s}^{MS}\right)\left[1-\sum_{s=i}^{2j-1}X_{f,s}^{RCS}\right]; \quad \forall f\in F, \forall i\in I, \forall\, 2j>i, \forall k\in K \tag{8.52}$$

$$d_{f,i,j,k}^{int} \geq \left(TTL_{f,i} + TTR_{f,i}\right)\left[1-\sum_{s=2j}^{i-1}X_{f,s}^{RCS}-\sum_{s=2j}^{i-1}X_{f,s}^{MS}\right]; \quad \forall f\in F, \forall i\in I, \forall 2j<i, \forall k\in K \tag{8.53}$$

$$d_{f,i,j,k}^{int} \geq \left(TTL_{f,i} + TTR_{f,i}\right)\left[1 - \sum_{s=i}^{2j-1} X_{f,s}^{RCS} - \sum_{s=i}^{2j-1} X_{f,s}^{MS}\right]; \qquad (8.54)$$
$$\forall f \in F, \forall i \in I, \forall 2j > i, \forall k \in K$$

$$d_{f,i,j,k}^{int} \geq TTL_{f,i} + TTR_{f,i}; \quad \forall f \in F, \forall i \in I, \forall 2j = i, \forall k \in K \qquad (8.55)$$

The above expressions have the same meaning as (8.3)–(8.8) in Sect. 8.4. In this regard, to avoid repetition of what was discussed, the explanation of these equations is avoided. It is worth mentioning that $X_{f,s}^{RCS}$ and $X_{f,s}^{MS}$ are among known parameters whose values are obtained from the optimal SS placement problem in Sect. 8.4. By solving the fault management problem, the customer interruption cost is determined for each contingency. Then, the system interruption cost is calculated by summing up the customer interruption costs of contingencies within the scenario. Heretofore, scenario generation and interruption cost calculation methods were introduced. In the following, an approach is presented to achieve financial risk.

8.7.5 *Financial Risk Evaluation Approach*

In order to evaluate the imposed financial risk on a DisCo, it is necessary to obtain the probability density function of its profit. To do so, the profit of SS deployment is defined as the reduction in system interruption cost before and after SS deployment minus the SS costs. The step by step framework for deriving PDF of system interruption cost is shown in Fig. 8.33 [31]. The approach to calculate financial risk is as follows.

8.7.5.1 Step 1: Preparing Input Data

The first step is to prepare input data including network data, study horizon, financial assumptions, and CDFs. The network data consists of failure rate and repair time of equipments, number and types of customers, the average load of customers, and the location of MSs and RCSs in the network. The location of SSs is known and it is determined from the optimal SS placement problem presented in Sect. 8.4. Study horizon is the time that the benefit of SS deployment is studied. Financial assumptions consist of switch costs, discount rate, and load growth rate. CDFs for different types of customers as function of interruption duration should be prepared in this step.

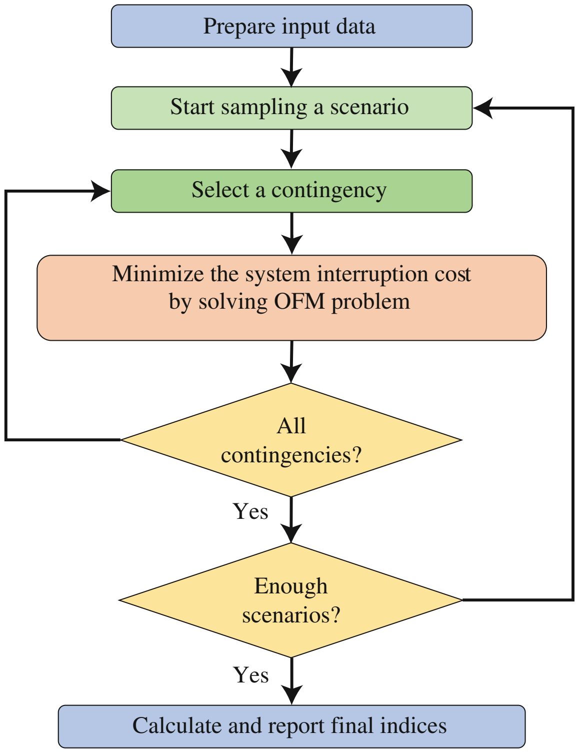

Fig. 8.33 The proposed algorithm to calculate the financial risk under power system uncertainty

8.7.5.2 Step 2: Scenario Selection

In this step, a scenario is selected from the generated scenarios. The scenario selection is iterated until the number of sampled scenarios reaches the maximum number of scenarios.

8.7.5.3 Step 3: Contingency Selection

After a scenario is selected in previous step, a contingency within the sampled scenario is selected. According to the selected contingency, the location and the time to repair the faulted section are determined.

8.7.5.4 Step 4: Optimum Fault Management Problem

Once the location and repair time of the faulted section are determined, the fault management problem is solved in order to minimize the system interruption cost. To do so, the proposed model of fault management is applied. It is worth mentioning that customers interruption duration and interruption costs are outputs of the problem.

8.7.5.5 Step 5: Determining Probability Density Function

As mentioned heretofore, each scenario comprises of several contingencies within the study horizon. To calculate the system interruption costs, Steps 3–4 should be repeated for all contingencies within the sampled scenario. The system interruption cost for each scenario is the combination of interruption costs. Then, the process continues from Step 2 to iterate over all generated scenarios. Doing so, the probability density function of system interruption cost is obtained.

8.7.5.6 Step 6: Calculation of Profit and Financial Risk Index

The previous steps should be conducted before and after installing SSs. The difference of the two PDFs is the PDF of gross profit of SS deployment. The PDF of net profit is calculated by subtracting SS costs from the gross profit. Then, the financial risk of SS placement can be calculated by taking into account the obtained PDF.

Example 8.6 PDF of RCS profit for the network considered in Example 8.2 is determined here. To do so, 10,000 scenarios are generated to guarantee accuracy of the results. It is assumed that α in CVaR index calculation is equal to 0.99. Also, the location of RCS is determined based on the results of Example 8.2 as represented in Fig. 8.34.

Applying the presented approach for financial risk assessment, PDF of the profit is calculated and represented in Fig. 8.35. As can be seen, although the expected profit is US k$496.64, the profit varies from US k-21 to US k$1800. The wide range of the profit variation imposes a significant risk which should be taken into account in decision making.

The cumulative density function of the SS profit is depicted in Fig. 8.36. As can be seen, in 0.22% of the scenarios (i.e., 22 out of 10,000 generated scenarios), installing RCS leads to negative profits which means that the DisCo is confronted to loss.

The results associated with system costs with and without RCS deployment, RCS profit as well as risk index are provided in Table 8.19. As can be seen, the expected profit is 4.2 times the RCS cost. Also, the CVaR is 90% smaller than the expected profit which indicates the RCS deployment strategy as a risky investment plan.

As was mentioned, installing RCS reduces the interruption costs when a contingency occurs in the system. In this regard, it can be anticipated that the higher interruption costs prior to RCS installation, the more RCS profit is achieved. Besides, the interruption cost chiefly depends on several factors such as the number

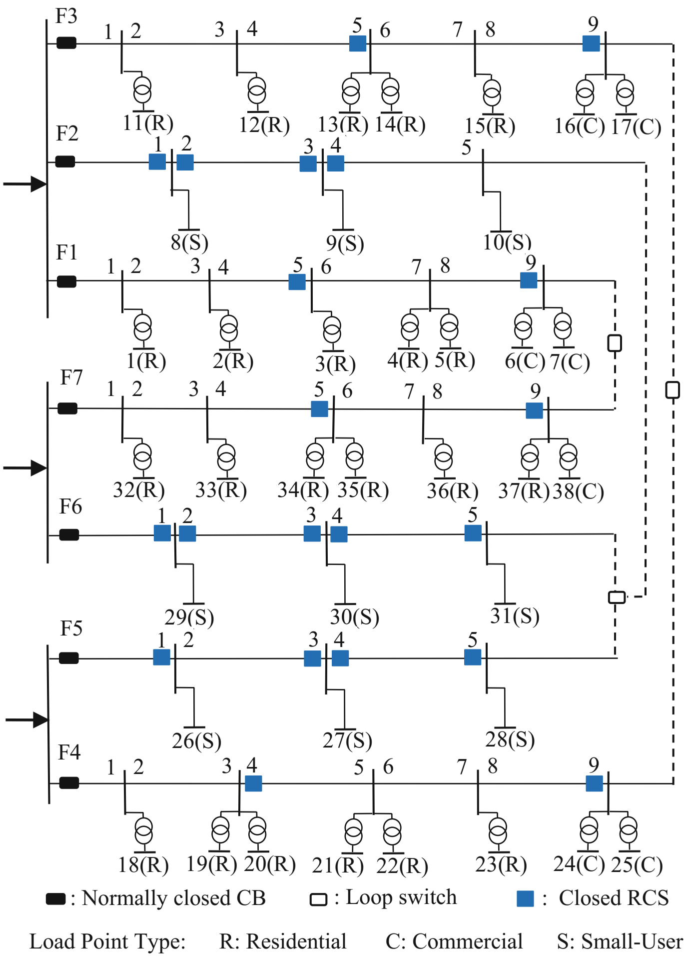

Fig. 8.34 Location of installed RCSs in RBTS-Bus4

of fault occurrences, the repair action duration, and the energy curtailment. In this regard, the impact of the mentioned factors on the RCS profit is scrutinized and the results are shown in Fig. 8.37. As can be seen, the expected profit is near US k$340 when 16 faults occur or the interruption duration is about 48 h. Also, the profit is almost US k$650 when 26 faults occur or the interruption duration lasts 77 h. Furthermore, when the energy curtailment and interruption costs are 185 kWh and US k$520, respectively, the profit is near US k$270. Also, when the energy curtailment and interruption costs are 385 kWh and US k$1025, respectively, the net profit is near US k$700. Hence, the finding results indicate the positive relationship between the mentioned factors and RCS profit. It is worth pointing that although the RCS installation provides considerable profit, it is possible that the DisCo

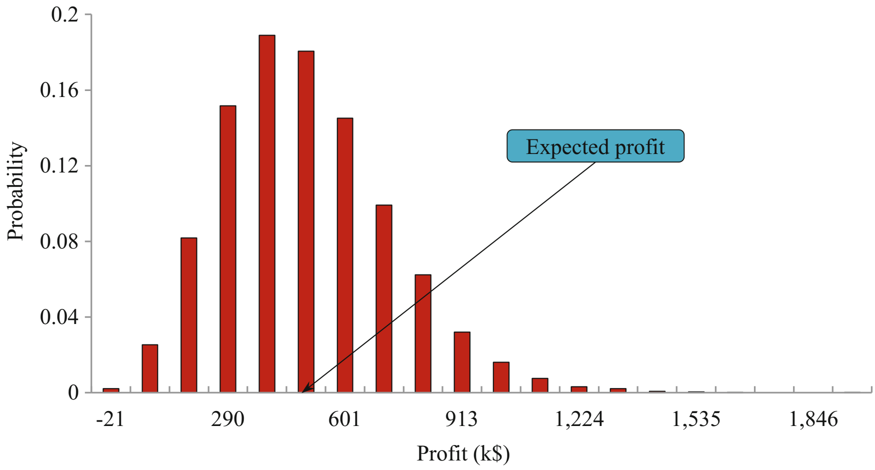

Fig. 8.35 Individual probability of RCS deployment profit

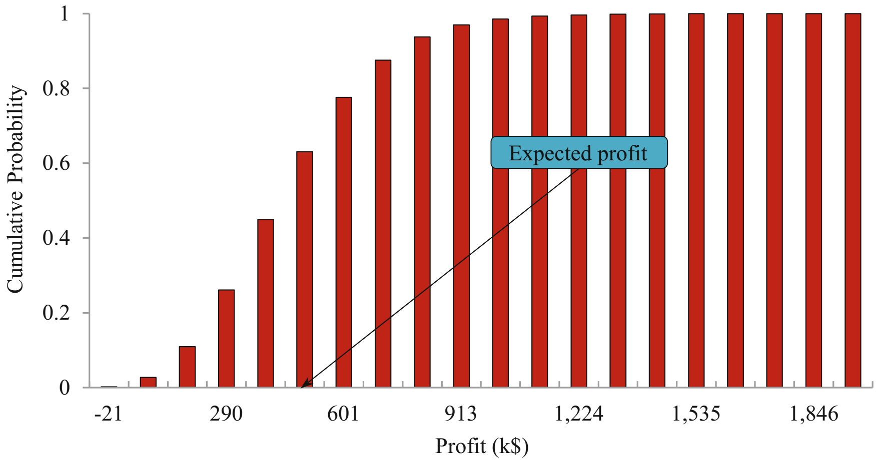

Fig. 8.36 Cumulative density function of RCS deployment profit

Table 8.19 Financial results (US k$) with and without RCS installation

Costs without RCS			Costs with RCS			Expected profit	CVaR
RCS	Interruption	Total	RCS	Interruption	Total		
–	779.72	779.72	118.11	164.96	283.07	496.64	47.69

encounters with undeniable negative profit (loss). For example, the profit is negative when the number of faults is less than 7, system remains interrupted for less than 11 h, total energy curtailment is smaller than 40 kWh, or the interruption cost

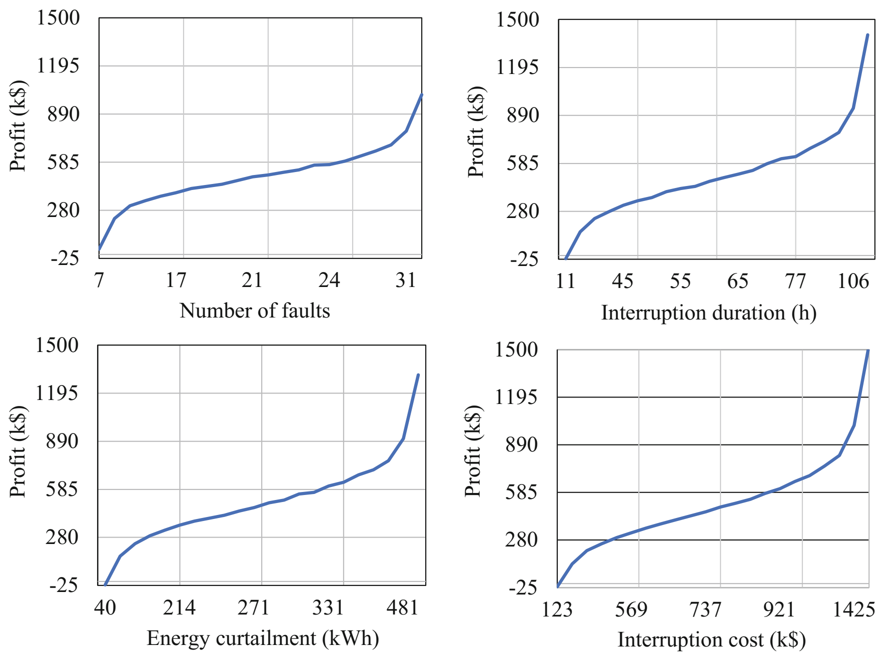

Fig. 8.37 RCS deployment profit versus number of faults, interruption duration, energy curtailment, and interruption cost

is less than US k$118 (i.e., RCS costs). So, the results reveal that several factors should be considered for making decision regarding RCS placement.

8.7.6 Sensitivity Analyses

Heretofore, it was revealed that installing RCS imposes significant risk on the DisCo. Here, the impact of key parameters such as the number of installed RCSs, length of study horizon, system size, RCS costs, CDF failure rate and repair time of equipments on the expected profit and financial risk is scrutinized.

8.7.6.1 Number of Installed RCSs

In previous simulations, it was assumed that 21 RCSs are allocated to the system. Here, in order to study the impact of the number of RCSs, the simulation is repeated for different number of RCSs. To do so, the number of RCSs is increased from 1 to 30 according to the priority order developed in Sect. 8.4. The expected profit and

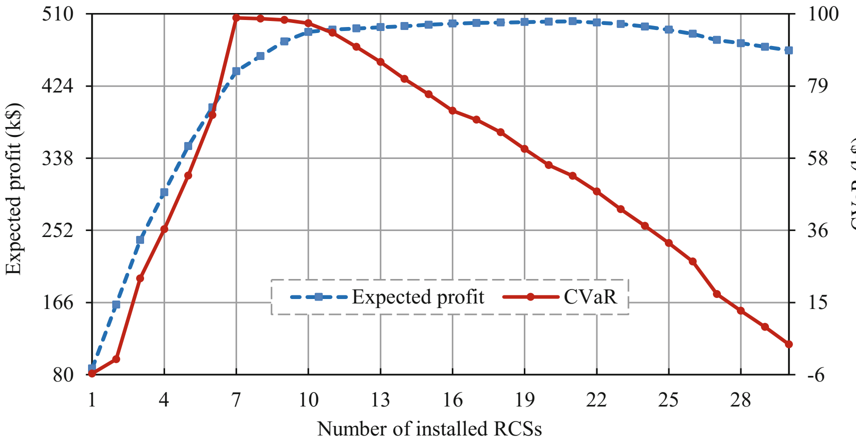

Fig. 8.38 Expected profit and CVaR versus the number of installed RCSs

CVaR versus the number of embedded RCSs are depicted in Fig. 8.38. As can be seen, the maximum expected profit and CVaR are obtained when 21 and 7 RCSs are installed in the network, respectively. The maximum value of CVaR indicates the minimum value of financial risk. In this regard, the risk-taker DisCo prefers to install 21 RCSs in order to achieve the highest profit. However, the risk-averse DisCo allocates 7 RCSs in order to decline the imposed financial risk. So, the compromiser DisCo equips the system with any number of RCSs from 7 to 21 in order to achieve a tradeoff between the profit and risk. So, the DisCos with different risk awareness may make different decisions to equip their system.

8.7.6.2 Length of Study Horizon

In order to determine the impact of the length of study horizon, the simulation is repeated by increasing the study horizon duration. To do so, a set of scenarios is produced for 45 years and the impact of study horizon is observed from 15 to 45 years. For example, in case of study horizon equal to 30 years, the simulation is accomplished for contingencies occur before the 30th year and other contingencies are missed. The expected profit and CVaR for different lengths of study horizon are provided in Table 8.20. According to the results, the expected profit and CVaR are increased as the study horizon is extended since more contingencies are likely to occur for longer study horizons. Also, the value of CVaR is more sensitive to the study horizon than the expected profit. For example, when the study horizon is increased from 15 to 30 years by 2 times, the expected profit and CVaR are augmented by almost 1.6 and 5.4 times. So, considering financial risk in RCS deployment planning is essential in studies for short study horizons.

Table 8.20 Impact of study horizon on financial results

Planning horizon (year)	RCS cost (US k$)	Interruption cost (US k$)		Expected profit (US k$)	CVaR (US k$)
		Without RCS	With RCS		
15	118.11	779.72	164.96	496.64	47.69
20	120.97	940.14	198.15	621.01	134.20
25	122.91	1061.96	223.99	715.06	205.38
30	124.23	1155.56	243.78	787.5	257.21
35	125.13	1229.05	259.34	844.58	305.69
40	126.75	1286.89	270.61	889.53	346.40
45	127.16	1331.82	280.16	924.51	376.63

8.7.6.3 System Size

Since the size of typical networks is much larger than the size of the network used in this simulation, the effect of system size on the result of SS deployment is studied. To do so, a few RBTS-Bus4 networks are connected together to achieve larger networks. It is worth mentioning that the number and location of RCSs in each of them are based on the presented configuration of RCS in a single RBTS-Bus4. For example, 42 RCSs are installed in a system comprised of 2 RBTS-Bus4 networks. So, the investment costs of RCS is directly increased as the size of system is increased. In this regard, the simulation is repeated by increasing the system size and the results are provided in Table 8.21. As can be seen, the expected profit and CVaR wane as the system size wax. So, considering the financial risk is critical in small distribution systems while it is negligible in practical systems which have larger size (in several orders of magnitude). More accurately, when the system size is 2 times larger than the test system, the expected profit and CVaR are about 2 and 6.6 times, respectively. Also, when 4 RBTS-Bus4 networks are joined together, the expected profit and CVaR are near 4 and 20 times, respectively. Hence, the CVaR is more sensitive than the expected profit to the size of the system.

Table 8.21 Impact of system size on financial results

Number of connected systems	RCS cost (US k$)	Interruption cost (US k$)		Expected profit (US k$)	CVaR (US k$)
		Without RCS	With RCS		
1	118.11	779.72	164.96	496.64	47.69
2	236.22	1560.01	325.94	997.85	315.63
3	354.33	2339.10	482.87	1501.90	625.41
4	472.45	3118.81	642.87	2004.31	954.86
5	590.5	3898.58	800.99	2507.02	1345.10

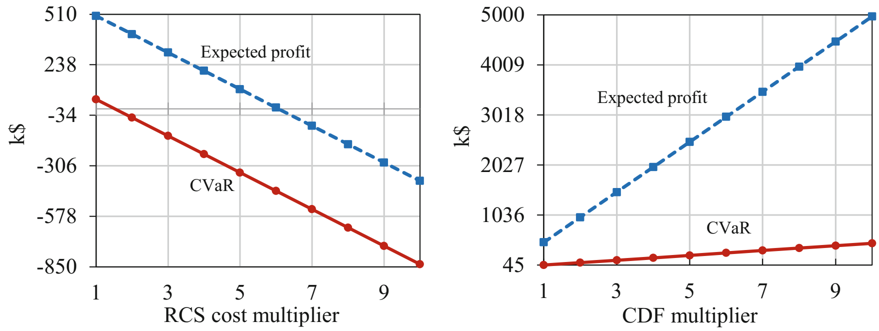

Fig. 8.39 Profit and CVaR versus RCS costs and CDF multipliers

8.7.6.4 RCS Costs

In order to scrutinize the impact of RCS costs, the simulation is iterated for different RCS costs and the results are shown in Fig. 8.39. As can be seen, the expected profit and CVaR are decreased when the RCS costs are increased. This means that the financial risk is less critical in future since the trend of RCS costs is decreasing.

8.7.6.5 Customer Damage Function (CDF)

Here, the impact of CDF on the result of the simulation is studied. The results are depicted in Fig. 8.39 by increasing the CDF. As can be expected, higher CDF increases the expected profit and decreases the financial risk. According to Fig. 8.39, the expected profit is changed dramatically compared to CVaR. So, it is necessary to consider the financial risk in the system with less sensitive customers to interruption events.

8.7.6.6 Failure Rate and Repair Time

There are several factors which have positive influence on the failure rate and repair time such as geographical conditions and type of lines used in the system, to name just a few. In this regard, the impacts of failure rate and repair time are individually studied in this subsection and the results are provided in Fig. 8.40. As can be seen, the expected profit is increased and financial risk is decreased when the failure rate and repair time are increased individually. So, considering financial risk is less important in system which is difficult to access the sections (e.g., mountain) or difficult to repair the equipments (e.g., underground system). In the other hand, considering risk in the network with smaller failure rate and repair time is critical.

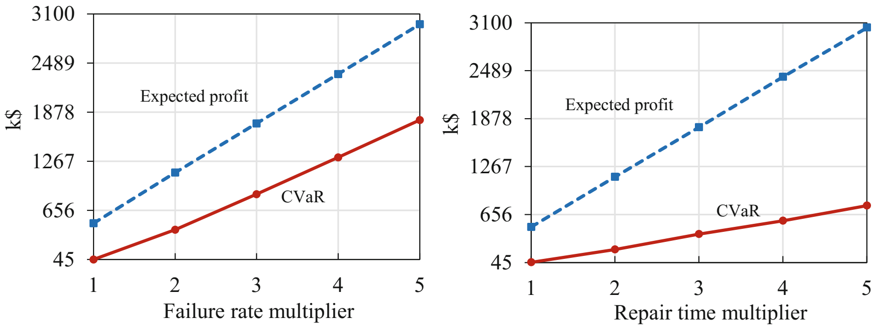

Fig. 8.40 Profit and CVaR versus failure rate and repair time multipliers

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