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Review

A survey of models and algorithms for emergency response logistics in electric distribution systems. Part I: Reliability planning with fault considerations

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ABSTRACT

Emergency response operations in electric distribution systems involve a host of decision-making problems at the reliability and contingency planning levels. Those operations include fault diagnosis, fault location, fault isolation, restoration, and repair. As the first of a two-part survey, this paper reviews optimization models and solution methodologies for reliability planning problems with fault considerations related to electric distribution operations. Contingency planning problems of emergency distribution response are discussed in the second part. The present paper surveys research on determining a distribution substation single-fault capacity, reallocating excess load, configuring distribution systems, partitioning a geographical area into service territories, and locating material stores and depots.

Contents

1. Introduction

Planning the operations of emergency distribution response involves a host of decision problems that can be solved using operations research methodologies. The importance of these problems is obvious from the impact of fault situations on customers and electric utilities. Fault situations may cause "in extremis" states where service in distribution systems is

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interrupted, thus reducing the quality of service and causing financial losses for electric utilities. These losses are difficult to quantify monetarily but can be significant in specific situations. For example, the snowstorms of January 2008 in the central-eastern-southern parts of China that brought down electricity lines and poles in several provinces affected nearly two thirds of China's total land and incurred an estimated $10-billion direct economic loss [22].

As highlighted by Ćurčić et al. [5], electric power generation and transmission system planning has long been an ideal field for the development and applications of operations research due to the complexity and challenges of the problems associated with those systems, the high investment, operating and outage costs of almost any generation or transmission plant, as well as the huge number of customers that can be affected by possible outages in these systems. However, the literature related to emergency distribution response has experienced a slow growth. This situation is somewhat surprising given that distribution systems account for up to 90% of all customer reliability problems largely due to the radial nature of most distribution systems.

In fact, the slow progress of operations research in emergency distribution response highlights the considerable difficulty of these problems. Problems faced by utility distribution planners are complex and site specific because of the difference in characteristics such as topological features of the network, operational capabilities, and applied operational devices. A previous survey by Khator and Leung [9] suggests that most early contributions in power distribution planning were dealing with simplified models either failing to address the issue of equipment failure or accounting for it by merely taking into account a safety equipment capacity. In the last two decades however, a growing body of operations research applications to emergency distribution response has appeared in the literature. The large number of components involved in distribution systems, the complexity of distribution networks, and the ever increasing capability of utilities for operating these networks all motivate the use of optimization techniques at various levels in the electric distribution utility.

Emergency response logistics in electric distribution systems presents a variety of decision-making problems that can be grouped into two important categories according to the planning horizon which is concerned [25]: reliability planning level and contingency level. The *reliability planning level* involves strategic planning decisions related to the design of reliable and robust distribution networks in which fault cases are taken into account. The planning horizon for reliability issues is usually around five years [25]. Decisions related to distribution substation capacity planning, distribution system configuration, and the establishment of service centers and service territories may be viewed as strategic. Decisions related to real-time management of the emergency response logistics resources belong to the *contingency planning level*. For example, the assignment of service calls to emergency response units and the routing of emergency response units could be termed real-time.

This paper is the first of a two-part survey of optimization models and solution algorithms for reliability and contingency planning problems related to emergency response in electric distribution systems. The aim of this paper is to provide a comprehensive survey of optimization models and solution methodologies for reliability planning problems related to emergency distribution operations. These problems include determining a distribution substation single-fault capacity, reallocating excess load, configuring distribution systems, partitioning a geographical area into service territories, and locating material stores and depots. The second part addresses emergency service restoration, repair vehicle routing, repair crew scheduling, and crew assignment models for emergency response in electric distribution systems [17].

This paper is organized as follows. Section 2 describes the operating states of electric distribution systems and the reliability planning problems with fault considerations related to electric distribution operations. Models for the determination of a distribution substation single-fault capacity and the reallocation of excess load are described in Section 3. Models that address the configuration of reliable distribution networks with fault considerations are reviewed in Section 4. Section 5 focuses on partitioning a geographical area into service territories for emergency distribution operations. Models dealing with the location of resource and material depots for emergency distribution response are presented in Section 6. Conclusions and future research paths in distribution emergency response planning are presented in the last section.

2. Electric distribution systems

Electricity is produced and delivered to consumers through generation, transmission, and distribution systems. *Generation systems* consist of generating plants that produce electrical energy from another form of energy (fossil fuels, nuclear fuels, or hydropower) and generation substations that connect generation plants to transmission lines. *Transmission systems* transport electricity over long distances from generation substations to substations that serve subtransmission or distribution systems. *Distribution systems* deliver power from bulk power systems to retail customers. To do this, distribution substations receive power from the transmission grid and step down voltages with power transformers. These transformers supply *primary distribution systems* made up of many distribution *feeders*, typically overhead distribution lines mounted on poles or underground buried or ducted cable sets that deliver power from distribution substations to *distribution transformers*. Passing through these transformers, power is lowered in voltage once again, to the final utilization voltage and routed to the *secondary system* within very close proximity to the consumer or directly to the meters of consumers. Since feeder routes must pass near every customer, each substation uses multiple feeders to cover an assigned service territory. Feeders of a substation that are not connected to other feeders are called *independent feeders*. These feeders supply power to isolated load demands. Feeders that are linked to the feeders of adjacent substations are called *connected feeders*. In emergency situations, connected feeders allow a substation's load to be transferred to adjacent substations. A simplified drawing of an overall electric power system and its generation, transmission, and distribution subsystems is shown in Fig. 1. Here, the distribution substation supplies four independent feeders to cover its service territory.

Distribution systems can be designed as radial, loop, or network systems, depending on how the distribution feeders are interconnected about a substation. The *radial system* is characterized by having only one path between each consumer and a substation. An alternative to radial feeder design is a *loop system* consisting of a distribution design with two paths between the substations and every consumer. *Network systems* have multiple electrical paths from the substation to the consumer. Radial systems are much less costly than loop or network systems and are much simpler in planning, design, and operation. However, radial systems are less reliable than the other two alternatives because the power flows exclusively away from the substation and out to the consumer along a single path. Thus, if any element along this path fails, a complete loss of power to the consumer results. The following section contains a brief description of distribution operating states of electric distribution systems. Reliability planning problems related to emergency response in electric distribution systems, which have been addressed with operations research methodologies, are then discussed.

2.1. Distribution operating states

Distribution systems must be continually monitored, adjusted, expanded, maintained, and repaired. These activities are collectively referred to as *distribution operations*. As highlighted by Gutiérrez et al. [6], distribution system operations can be grouped into five operating states: normal, alert, emergency, in extremis, and restorative states. The system is referred to as the *normal operating state* when all customers are adequately supplied within acceptable voltage tolerances, all components are operating properly, the system is configured in its usual manner and equipment loading levels are within design limits. The system is in the *alert operating state* when the system's security level is reduced, but the system is still operated within allowable limits [13]. Ćurčić et al. [5] recognize the alert state as a *pre-outage state* where the operating limits are in jeopardy. For example, a pre-outage state occurs when a piece of equipment tends to become overloaded and protection devices could take it out of service. Such a situation initiates the preventive actions required to return the system to the normal state. In the *emergency operating state*, also called the *outage state* [5], the operating limits are violated due to a short circuit, called *fault*. For example, a feeder line down, a transformer out of service, or a breaker that opens when it should not. A fault occurring on an overhead feeder component is called a *feeder fault* and a short circuit occurring on a substation component, a *substation fault*. The piece of equipment out of service cannot be returned to operation before the cause of its outage is cleared. If this can be done quickly, the system can be taken back to the normal state. If not, the system first enters in an *in extremis operating state* where the operating limits are violated and service is interrupted for one or more customers. Then, a restoration brings the system into the *restorative operating state* providing the best possible service with the remaining pieces of equipment. When the system is in the restorative state, part of the system equipment is disconnected in order to isolate the faulted section, causing customer service interruptions. Clearing the cause of outage enables the system to be returned to the normal state. Fig. 2 illustrates the possible transitions among the five operating states.

2.2. Reliability planning problems with fault considerations

At the most basic level, reliability strategies dealing with faults address the determination of distribution substation single-fault capacity and the reallocation of excess load demand to substations (Section 3). In many large electric utilities, a substation's capacity is determined based on the maximum load it can handle during emergencies. One emergency policy widely used among large electric utilities, called the *single-fault policy*, allows a single transformer fault among the substations of a service area at any given time. More involved reliability strategies, in which fault cases are considered, concern the reconfiguration of the system by addition of new feeders, substation transformers or substations (Section 4). Reliability plans with fault considerations can also help to partition a geographical area into emergency repair districts (Section 5). Given the large dispersed geographic extent of most emergency distribution operations, a utility generally partitions its service area into subareas, called *districts*. All districts are treated simultaneously by separate crews to facilitate the organization of the emergency repair operations and thus reduce the duration of electric power interruptions. The *district design problem* consists of partitioning a large service area into non-overlapping small districts according to several criteria such as contiguity, size, and workload. A district is contiguous if every pair of its basic units is connected. Basic units are the units of analysis used to partition the service area into districts and are defined as small geographic entities. Also, districts are balanced in workload if they are approximately the same size and are assigned equivalent resources. The design of emergency repair districts is similar to the electrical power districting problem studied by Bergey et al. [1] in the context of deregulated marketplaces with competitive business units responsible for transmission and distribution functions. The design of emergency repair districts also shares several characteristics with districting problems for arc routing applications such as the arc partitioning problem studied by Bodin and Levy [2] in the context of postal delivery and the design of sectors for refuse collection [14,19,7]. Finally, reliability plans with fault considerations can help to locate resource depots (Section 6). A resource depot is a place where resources for restoring the electric power in a locality are stored. These resources include repair crews, vehicles, poles, and transformers. The depots may be different, i.e., the types of the resources and the amount of each type of resources in each depot may be different. The *resource depot location problem* consists of simultaneously selecting the proper sites to allocate different depots with resource capacities, and determining the amounts of the resources shipped from the depots to various geographically scattered locations or customers in order to satisfy the demands of the customers, while minimizing the total transportation cost for the power restoration.

3. Distribution substation single-fault capacity and load reallocation models

Leung et al. [11] proposed a linear programming formulation for the problem of determining a substation's single-fault capacity. Let S be the set of the substations within the service area (including substation k, the substation being evaluated). The sum of the capacities of a substation's transformers is referred to as the *normal substation capacity*, i.e., the load a substation can handle under normal conditions. When a transformer fails at a substation, the load of the failed transformer can be transferred to the remaining in-service transformers operating at an above 100% emergency rate for a short period of time until the transformer is repaired. The sum of the capacities of the substation's in-service transformers operating beyond design limits is called the *emergency substation capacity*. For every substation $i \in S$, let UD_i be a

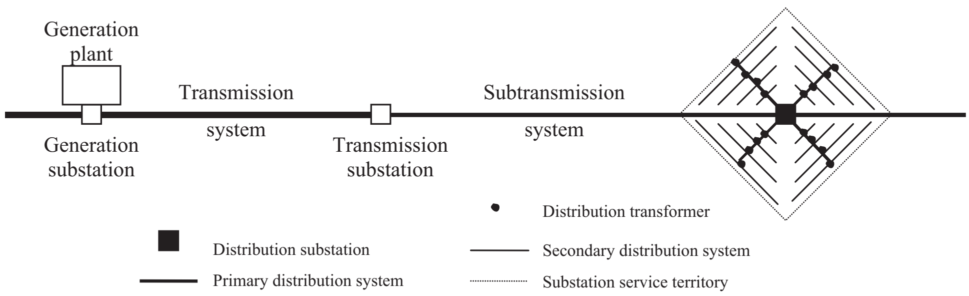

Fig. 1. A power system and its subsystems (adapted from [21]).

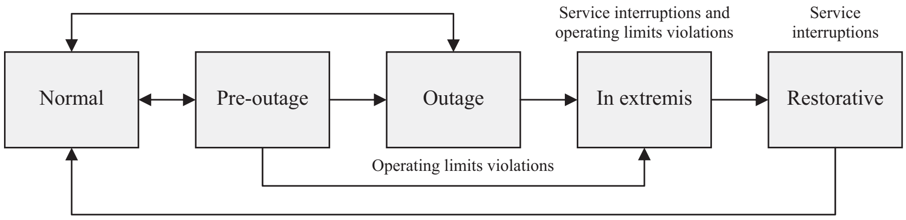

Fig. 2. Operating states of a distribution system (adapted from [5]).

nonnegative real variable representing the unsatisfied demand of substation i, and define NC_i, EC_i, LD_i, and FC_i as the normal capacity, the emergency capacity, the load demand and the feeder transfer capacity of substation i, respectively. The *transfer capacity* of a substation, given its load demand satisfied, is the excess feeder capacity of the substation. Let $S_i \subset S$ be the set of the adjacent substations to substation i, $i \in S$. For every substation $i \in S$ and for every adjacent substation $j \in S_i$, let P_{ij} be a nonnegative real variable representing the amount of power transferred from substation j to substation i via connected feeders when substation i is under emergency, and let AFC_{ij} represent the aggregate capacity of the feeders connecting substation j to substation i. Define also M as the total power transfer limit. We present here an equivalent nonlinear version of the Leung et al. [11] formulation for the substation single-fault capacity problem (we eliminate the additional constraints and variable introduced by Leung et al. [11] to linearize the model).

$$\text{Maximize}\left[\min_{i \in S_k}\left\{EC_k+\sum_{i \in S_k}\alpha_{ki}P_{ki}; NC_k-P_{ik}\right\}-(1+\delta)\sum_{i \in S_k}UD_i\right] \quad (3.1)$$

subject to

$$\sum_{j \in S_i}\alpha_{ij}P_{ij}+EC_i \geq LD_i-UD_i \quad (i \in S_k) \quad (3.2)$$

$$\min_{i \in S_k}\left\{EC_k+\sum_{i \in S_k}\alpha_{ki}P_{ki}; NC_k-P_{ik}\right\} \geq LD_k-UD_k \quad (3.3)$$

$$P_{ij} \leq FC_j-LD_j \quad (i \in S, j \in S_i) \quad (3.4)$$

$$P_{ij} \leq \min\{AFC_{ij}, AFC_{ji}\} \quad (i \in S, j \in S_i) \quad (3.5)$$

$$P_{ij} \leq NC_j-LD_j \quad (i \in S_j \backslash \{k\}, j \in S_k) \quad (3.6)$$

$$\sum_{j \in S_i}\alpha_{ij}P_{ij} \leq M \quad (i \in S) \quad (3.7)$$

$$P_{ij} \geq 0 \quad (i \in S, j \in S_i) \quad (3.8)$$

$$UD_i \geq 0 \quad (i \in S) \quad (3.9)$$

The objective function (3.1) maximizes the load that substation k can handle under the single-fault policy. When the largest transformer of substation k fails, the single-fault capacity of substation k corresponds to the first term which is the sum of its emergency load capacity and the power it receives via feeder from adjacent substations. The parameter α_{ki} is a discounting factor to take into account voltage drop in feeders. Voltage drops in distribution systems are permitted to reduce system demand. When the largest transformer of an adjacent substation to substation k fails, the single-fault capacity of substation k corresponds to the second term which is the remaining capacity of the substation, after supplying power to the adjacent substation. The minimum of the two capacities is the maximum load the substation can handle under the single-fault policy. The parameter δ is a very small penalty value for unsatisfied demand. Constraints (3.2) and (3.3) guarantee that the load demand of the service area is satisfied if a transformer fault occurs. Constraints (3.4)–(3.6) assure that the power transfer limits imposed by distribution capacities, substation normal capacities and forecasted load demands are respected. The distribution capacity of a substation is the sum of the capacities of the feeders supplied by the substation. Constraints (3.4) and (3.5) assume that the load for a substation can be redistributed among its transformers during emergency. However, if load redistribution within a substation is not possible, then these constraints must be replaced by the following constraints.

$$P_{ij} \leq \min\left\{AFC_{ij}-FL_{ij}, \frac{FL_{ij}}{\alpha_{ij}}\right\} \quad (i \in S, j \in S_i) \quad (3.10)$$

For every substation $i \in S$ and for every adjacent substation $j \in S_i$, let FL_{ij} be the load on the feeders connecting i to j. Then, constraints (3.10) ensure that the power transfer limits imposed by either the connecting feeder's transfer capacity or the load on its neighboring station's feeders are respected. The limit on the total power transferred to any substation under emergency from all its adjacent substations is respected via constraint set (3.7). Model (3.1)–(3.9) is repeated for each substation in the service area.

In the same paper, Leung et al. [11] proposed a linear programming formulation for the reallocation of excess load demand to substations so that certain loads can be restored after a fault occurs. When a transformer fails at a substation, the adjacent substations can *temporarily* meet part of the failed substation's demand load by transferring power to it via connected feeders. However, when a substation's forecasted load demand exceeds the maximum load of the substation, utility planners can *permanently* reallocate the excess load to adjacent substations without necessitating new capital investments such as building feeders, purchasing transformers, or constructing new substations. For every substation $i \in S$ and for every adjacent substation $j \in S_i$, let R_{ij} be a nonnegative real variable representing the amount of load reallocated from substation j to adjacent substation i, and let V_{ij} represent the maximum load that can be reallocated with respect to the voltage ratings of the feeders from substation j toward substation i.

$$\text{Minimize} \sum_{i \in S}\sum_{j \in S_i}R_{ji} \quad (3.11)$$

subject to

$$EC_i+\sum_{j \in S_i}\alpha_{ij}P_{ij} \geq LD_i+\sum_{j \in S_i}(R_{ij}-R_{ji}) \quad (i \in S) \quad (3.12)$$

$$NC_i-P_{ji} \geq LD_i+\sum_{j \in S_i}(R_{ij}-R_{ji}) \quad (i \in S, j \in S_i) \quad (3.13)$$

$$P_{ij} \leq FC_j-\left(LD_j+\sum_{k \in S_j}R_{jk}-\sum_{k \in S_j}R_{kj}\right) \quad (i \in S, j \in S_i) \quad (3.14)$$

$$P_{ij} \leq \min\{AFC_{ij}, AFC_{ji}\} \quad (i \in S, j \in S_i) \quad (3.15)$$

$$\sum_{j\in S_i}\alpha_{ij}P_{ij}\le M \quad (i\in S) \tag{3.16}$$

$$R_{ij}\le \min\{V_{ij},V_{ji}\} \quad (i\in S, j\in S_i) \tag{3.17}$$

$$P_{ij},R_{ij}\ge 0 \quad (i\in S, j\in S_i) \tag{3.18}$$

The objective function (3.11) minimizes the total load reallocated to adjacent substations. Constraints (3.12) and (3.13) ensure that load demand requirements are met after load reallocation under the single-fault emergency situation when a substation or an adjacent substation is under emergency, respectively. Constraints (3.14)–(3.16) ensure that feeder capacity limits are respected. Voltage rating limits of the feeders connecting all pairs of adjacent substations are respected via constraints (3.17). Leung et al. used the MPS mathematical programming package to solve the two models (3.1)–(3.9) and (3.11)–(3.18) with a set of data from the substation network of the Fort Myers District of Florida containing 12 substations connected via feeders.

4. System configuration models with fault considerations

More involved reliability strategies, in which fault cases are considered, concern the reconfiguration of the system by addition of new feeders, substation transformers, or substations.

4.1. Feeder configuration models

The following linear MIP model, proposed by Sarada et al. [18], provides a multi-year plan which determines the period-to-period installation times and locations of new feeders for a network of substations. For every substation $j\in S$, define VR_j, NF_j, and NTR_j as the increase in feeder capacity of substation j obtained by adding a feeder, the number of existing feeders at substation j, and the number of transformers available at substation j, respectively. For every substation $j\in S$ and for every adjacent substation $k\in S_j$, let d_{jk} be the distance from substation k to the junction of feeders from substation j. Let T be the set of time periods, expressed in years. For every substation $j\in S$ and for every time period $t\in T$, define LD_{jt} as the forecast load demand of substation j for time period t and T_{jm} as the percentage change, due to load growth, in the load at substation j between the time period $m-1$ to m, $m<t$. Let D be the set of new load demand locations. Fig. 3, taken from Sarada et al. [18], illustrates connected existing feeders (solid lines) and potential feeders (dotted lines) between substations j and k, and the new load demand location i at the junction of potential feeders.

For every new load demand location $i\in D$ and for every time period $t\in T$, define L_{it} as the forecast load demand at new load location i for time period t. For every new load demand location $i\in D$, for every substation $j\in S$ and for every time period $t\in T$, let y_{ijt} be a binary variable equal to 1 if and only if a new independent or connected feeder is to be installed from substation j toward new load location i in time period t, and let NLT_{ijt} be a nonnegative real variable representing the amount of load at new location i assigned to substation j in time period t. For every substation $j\in S$, for every adjacent substation $k\in S_j$, and for every time period $t\in T$, let x_{jkt} be a binary variable equal to 1 if and only if a new connected feeder is to be installed from substation k toward substation j in time period t, let P_{jkt} be a nonnegative real variable representing the amount of power transferred from substation k to substation j via connected feeders when substation j is under emergency in time period t, let R_{jkt} be a nonnegative real variable representing the amount of load reallocated from substation k to adjacent substation j in time period t and let CF_{jkt} be the cost of adding a feeder of unit length from substation k toward substation j in period t. For every new load demand location $i\in D$, for every substation $j\in S$, for every adjacent substation $k\in S_j$ and for every time period $t\in T$, let NFC_{ijkt} be a binary variable equal to 1 if and only an increase in connecting feeder capacity occurs in time period t when both substations j and k are connected via new load location i. Finally, define $numf$ as the maximum number of feeders (both existing and new) per transformer in any time period at a substation and PR as the penalty cost for reallocating a unit of load. All other operational parameters are defined as in Section 3. The formulation is given next.

$$\text{Minimize}\sum_{j\in S}\sum_{k\in S_j}\sum_{t\in T}(CF_{jkt}d_{jk}x_{jkt})+\sum_{i\in D}\sum_{j\in S}\sum_{t\in T}(CF_{ijt}d_{ij}y_{ijt})+\sum_{j\in S}\sum_{k\in S_j}\sum_{t\in T}(PR\times R_{jkt}) \tag{4.1}$$

subject to

$$EC_j+\sum_{k\in S_j}P_{jkt}\ge LD_{jt}+TR_{jt}+\sum_{i\in D}NLT_{ijt} \quad (j\in S, t\in T) \tag{4.2}$$

$$NC_j-P_{kjt}\ge LD_{jt}+TR_{jt}+\sum_{i\in D}NLT_{ijt} \quad (j\in S, k\in S_j, t\in T) \tag{4.3}$$

$$R_{jkt}\le \min\{V_{jk},V_{kj}\} \quad (j\in S, k\in S_j, t\in T) \tag{4.4}$$

$$NLT_{ijt}\le VR_j\sum_{m=1}^{t}y_{ijm} \quad (i\in D, j\in S, t\in T) \tag{4.5}$$

$$\sum_{j\in S}NLT_{ijt}=L_{it} \quad (i\in D, t\in T) \tag{4.6}$$

$$P_{kjt}\le EFC_{jt} \quad (j\in S, k\in S_j, t\in T) \tag{4.7}$$

$$P_{kjt}\le AFC_{jk}+VR_k\sum_{m=1}^{t}x_{jkm}+VR_k\sum_{i\in D}\sum_{m=1}^{t}NFC_{ijkm} \quad (j\in S, k\in S_j, t\in T) \tag{4.8}$$

$$P_{kjt}\le AFC_{kj}+VR_j\sum_{m=1}^{t}x_{kjm}+VR_j\sum_{i\in D}\sum_{m=1}^{t}NFC_{ikjm} \quad (j\in S, k\in S_j, t\in T) \tag{4.9}$$

$$2NFC_{ijkt}\le y_{ijt}+y_{ikt}\le 1+NFC_{ijkt} \quad (i\in D, j\in S, k\in S_j, t\in T) \tag{4.10}$$

$$2NFC_{ijkt}\le y_{ijt}+y_{ikm}\le 1+NFC_{ijkt} \quad (i\in D, j\in S, k\in S_j, t,m\in T, m<t) \tag{4.11}$$

$$2NFC_{ijkt}\le y_{ijm}+y_{ikt}\le 1+NFC_{ijkt} \quad (i\in D, j\in S, k\in S_j, t,m\in T, m<t) \tag{4.12}$$

$$\sum_{k\in S_j}P_{jkt}\le M \quad (j\in S, t\in T) \tag{4.13}$$

$$NF_j+\sum_{m=1}^{t}\left(\sum_{k\in S_j}x_{kjm}+\sum_{i\in D}y_{ijm}\right)\le numf\times NTR_j \quad (j\in S, t\in T) \tag{4.14}$$

$$x_{jkt},y_{ijt},NFC_{ijkt}\in\{0,1\} \quad (i\in D, j\in S, k\in S_j, t\in T) \tag{4.15}$$

$$R_{jkt},P_{jkt},NLT_{ijt}\ge 0 \quad (i\in D, j\in S, k\in S_j, t\in T) \tag{4.16}$$

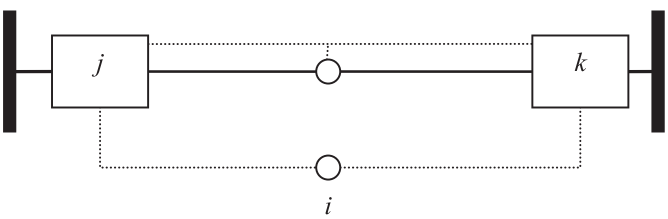

Fig. 3. Existing feeders, potential feeders, and new load location [18].

where, for every substation $j \in S$ and for every time period $t \in T$,

$$TR_{jt} = \sum_{m=1}^{t} \left(\sum_{k \in S_j} R_{jkm} - \sum_{k \in S_j} R_{kjm} \right) + \sum_{m=2}^{t} \left(\sum_{k \in S_j} T_{km} R_{jkm-1} - \sum_{k \in S_j} T_{jm} R_{kjm-1} \right)$$

and

$$EFC_{jt} = FC_j + VR_j \left(\sum_{m=1}^{t} \sum_{k \in S_j} x_{kjm} \right) + VR_j \left(\sum_{m=1}^{t} \sum_{i \in D} y_{ijm} \right) - \left(LD_{jt} + \sum_{i \in D} NLT_{ijt} + TR_{jt} \right)$$

are two intermediary nonnegative real variables representing the total load reallocated to substation j in time period t and the excess feeder capacity of substation j in time period t, respectively. The total load reallocated to a substation in a given time period is the difference between the sum of the loads it receives from its adjacent substations and the loads it reallocates to them up to that time period. The excess feeder capacity of a substation is the difference between its total feeder capacity and its net load. The objective function (4.1) minimizes the total costs of new feeders. The first term corresponds to the total installation cost of new connected feeders. The second term is the total installation cost of feeders along new routes required to meet loads at new locations. The final term is the penalty cost assigned to load reallocations to prevent unnecessary redistribution of loads. Constraint sets (4.2)–(4.4) are similar to their respective counterparts (3.12), (3.13), and (3.17) of the model (3.11)–(3.18). Constraint set (4.5) imposes a limit on the amount of load, at each new location, that can be assigned to an adjacent substation in a given time period. Constraint set (4.6) ensures that the load demand at each new location is satisfied for each time period. Constraint sets (4.7) and (4.8)–(4.9) impose upper bounds on the power transferred by each substation to an adjacent substation under emergency for each time period. Constraint sets (4.10)–(4.12) link new feeder locations and feeder capacity increase. They ensure an increase in interconnecting feeder capacity between each pair of adjacent substations only when new feeders are installed from both substations via a new load location. Constraint set (4.13) is similar to its counterpart (3.16) of the model (3.11)–(3.18). Finally, a limit on the total number of feeders, both existing and new, at every substation for each time period is imposed by constraint set (4.14). Again, the model was applied to the Fort Myers District of Florida for a planning horizon of two time periods and solved by the branch-and-bound algorithm of the MPS package. As mentioned by Sarada et al. [18], the problem size may be reduced by exploiting the spatial nature of the problem. Theoretically, each substation can be connected to all other substations in the distribution network via new feeders. However, given the high cost of installing new feeders over long distances, it is practical to consider new feeders only to the substations in the vicinity. This reduces the size of the problem considerably. The authors also emphasizes that the model can be extended to include decisions related to expansion of the substation capacities such as upgrading existing transformers or adding new transformers.

Recently, Cárcamo-Gallardo et al. [4] proposed a two-stage greedy algorithm for the problem of reconfiguring distribution feeders. The objective considered is to minimize the energy not supplied, which is formulated as a function of the network topology and the reliability parameters associated to the feeders. The authors showed that minimizing the energy not supplied in a network is equivalent to the problem of finding a minimum spanning tree of a graph, where the edge weights are unfixed and the objective is to minimize the energy not supplied. In the first stage of the algorithm, a Prim-based algorithm is used to construct a minimum spanning tree by adding loads at every iteration. To reduce the amount of computing time, the authors exploited the fact that distribution networks usually comprise an important number of leaf nodes that can be clustered with their corresponding distribution nodes. Tests showed that the algorithm is efficient in terms of the computing-time taken to achieve the minimal energy not supplied in radial configurations. For the cases of small distribution networks, the algorithm was able to achieve the optimal solutions.

4.2. Substation transformer configuration models

When the addition of feeders does not ensure that load demand requirements are met, transformer configuration must be considered. For a network of substations, Leung et al. [12] proposed a 0–1 linear programming model to identify the optimal transformer configuration. Let I_1 and I_2 be two sets of transformer destinations. The set I_1 denotes substations where new transformers may be added or substations for which transformers may be upgraded. The set I_2 denotes transformer storage locations. The decision of moving a transformer to a storage location implicitly involves relocating the transformer to another service area for subsequent use. For every destination substation $i \in I_1$, define NC_i, EC_i, MT_i, and M_i as the normal capacity of substation i, the emergency load capacity of substation i, the maximum number of transformers that substation i can take on, considering physical or other constraints, and the maximum amount of power that can be received by substation i during emergency conditions, respectively. For every destination substation $i \in I_1$, let N_i be the set of substations adjacent to substation i. For every destination substation $i \in I_1$ and for every adjacent substation $n \in N_i$, let P_{in} be a nonnegative real variable representing the amount of power transferred from substation n to adjacent substation i via connected feeders when substation i is under emergency, and define FC_n, LD_n, and AFC_{in} as the feeder transfer capacity of substation n, the load demand at substation n, and the aggregate capacity of the feeders connecting substation n to substation i, respectively. Let J be the set of transformer sources (vendors, transformer storage locations or substations where transformers may be removed or downgraded). For every source of transformers $j \in J$, let K_j be the set of transformers in source j. For every transformer source $j \in J$ and for every transformer $k \in K_j$, define c_{jk} as the capacity of transformer k of source j. For every transformer destination $i \in I_1 \cup I_2$, for every transformer source $j \in J$ and for every transformer $k \in K_j$, let x_{ijk} be a binary variable equal to 1 if and only if transformer k of source j is allocated to destination i, and define pc_{ijk} as the procurement cost of moving transformer k from source j to destination i. Depending on the corresponding source and destination of a transformer, the procurement cost may include purchase cost, transportation cost, disassembly cost, installation cost, savings of subsequently utilizing in another district a transformer moved to a storage location, cost of using a storage unit, etc. The formulation for the configuration of substation transformers under the single-fault policy can be stated as follows:

$$\text{Minimize } \delta \sum_{i \in I_1} \sum_{\substack{j \in J \\ j \neq i}} \sum_{k \in K_j} c_{jk} x_{ijk} + \sum_{i \in I_1 \cup I_2} \sum_{j \in J} \sum_{k \in K_j} pc_{ijk} x_{ijk} \tag{4.17}$$

subject to

$$NC_i = \sum_{j \in J} \sum_{k \in K_j} c_{jk} x_{ijk} \quad (i \in I_1) \tag{4.18}$$

$$P_{in} \leq FC_n - LD_n \quad (i \in I_1, n \in N_i) \tag{4.19}$$

$$P_{in} \leq \min\{AFC_{in}, AFC_{ni}\} \quad (i \in I_1, n \in N_i) \tag{4.20}$$

$$EC_i + \sum_{n \in N_i} \alpha_{in} P_{in} \geq LD_i \quad (i \in I_1) \tag{4.21}$$

$$NC_i - P_{ni} \geq LD_i \quad (i \in I_1, n \in N_i) \tag{4.22}$$

$$EC_i \leq \beta(NC_i - c_{jk}x_{ijk}) \quad (i \in I_1, j \in J, k \in K_j) \tag{4.23}$$

$$\sum_{n \in N_i} \alpha_{in} P_{in} \leq M_i \quad (i \in I_1) \tag{4.24}$$

$$\sum_{i \in I_1} x_{ijk} \leq 1 \quad (j \in J, k \in K_j) \tag{4.25}$$

$$\sum_{j \in J} \sum_{k \in K_j} x_{ijk} \leq MT_i \quad (i \in I_1) \tag{4.26}$$

$$x_{ijk} \in \{0,1\} \quad (i \in I_1 \cup I_2, j \in J, k \in K_j) \tag{4.27}$$

$$P_{in} \geq 0 \quad (i \in I_1, n \in N_i) \tag{4.28}$$

where δ is the opportunity cost per unit capacity. The objective function (4.17) minimizes the sum of opportunity cost and procurement cost. Constraints (4.18) define the normal capacity of every substation. Constraints (4.19)–(4.22) are very similar to their respective counterparts (3.4), (3.5), (3.2), and (3.6) of the model (3.1)–(3.9). Note that for situations where a substation's load cannot be redistributed among its transformers during emergency, constraints (4.19) and (4.20) must be replaced by the following constraints.

$$P_{in} \leq \min\left\{AFC_{in} - FL_{in}, \frac{FL_{in}}{\alpha_{in}}\right\} \quad (i \in I_1, n \in N_i) \tag{4.29}$$

Constraints (4.21) and (4.22) assure that load demand requirements are satisfied when a fault occurs to either the largest transformer of each destination substation or the largest transformer of each substation adjacent to a destination substation, respectively. Constraints (4.23) state that the emergency capacity of each destination substation must be computed from the worst scenario, i.e., fault of the substation's largest transformer. The parameter β is the emergency rate of the remaining substation's in-service transformers operating under emergency conditions. The maximum amount of power that each destination substation can receive during emergency conditions is respected via constraint set (4.24). Constraints (4.25) require each transformer to be assigned to at most one destination. Finally, constraints (4.26) impose a limit on the number of transformers within each destination substation. Computational tests using MPS mathematical programming package were performed on data from the substation network of the Fort Myers District of Florida containing 12 substations connected via feeders and between one and three transformers for each substation. The model was also used to analyze a variety of scenarios for extensions to the basic model, including maximization of single-fault capacity and allocation of transformers over a multi-period horizon.

4.3. *Compound feeder, transformer and substation configuration models*

As highlighted by Khator and Leung [8], the installation of new feeders is closely linked to the addition or upgrading of transformers. However, these interdependent problems are most often solved separately. Typically, when a substation's forecast load demand exceeds its single-fault capacity and reallocation of load is not possible due to insufficient distribution capacity, the cheapest alternative is to first install new feeders. When the substation's load cannot still be met, its capacity may then be increased by either replacing the existing units with transformers of higher capacity or adding transformers to the substation. Should that fails to overcome the capacity shortage, the last and most expansive alternative is to build a new substation. Obviously, this sequential approach may lead to suboptimal decisions.

Nara et al. [16] proposed a linear mixed integer programming formulation for the combined feeder, transformer and substation configuration problem in which faults are taken into consideration. The formulation is based on a previous multi-period expansion planning model developed by Nara et al. [15]. Fig. 4, adapted from Nara et al. [16], provides an example of a distribution network described through a graph with one source node (transmission substation), three substation nodes, six transformer nodes, and 11 load demand nodes. A link between two load points represents an existing or potential feeder. New installation facility candidates include substations, transformers, and feeders.

Let I and J be the sets of nodes and links, respectively. For each link $j \in J$, let w_j be a binary variable equal to 1 if and only if link j is installed, and let also c_j be the installation cost of link j ($c_j = 0$ for existing links). The cost of a link between a source node and a substation node corresponds to the cost of building the substation; the cost of installing a feeder between a substation node and a transformer node corresponds to the cost of installing the transformer; the cost of a link between a transformer node and a load point corresponds to the fixed cost of installing a feeder section between the two nodes; the cost of a link between two load points corresponds to the variable feeder cost. For each link $j \in J$, define LC_j, and R_j as the loading capacity and impedance of link j. Impedances are series of resistances and reactances that determine ohmic losses and voltage drops. Resistance is influenced by feeder material, conductor temperature, and current waveform frequency. Reactance is primarily determined by construction geometry, with compact designs having a smaller reactance than designs with large phase conductor separation. Let T be the set of predetermined fault cases. For each link $j \in J$ and for each fault $t \in T$, let y_{jt} be a binary variable equal to 1 if and only if link j is used in fault case t, and let also x_{jt}^+ and x_{jt}^- be the forward and inverse direction power flows in link j in fault case t, respectively, as shown in Fig. 5. For each node $i \in I$ and for each fault case $t \in T$, let v_{it} be a nonnegative real variable representing the voltage at node i in fault case t. For each load demand node $i \in I$ and for each fault case $t \in T$, define d_{it} as the load demand at node i

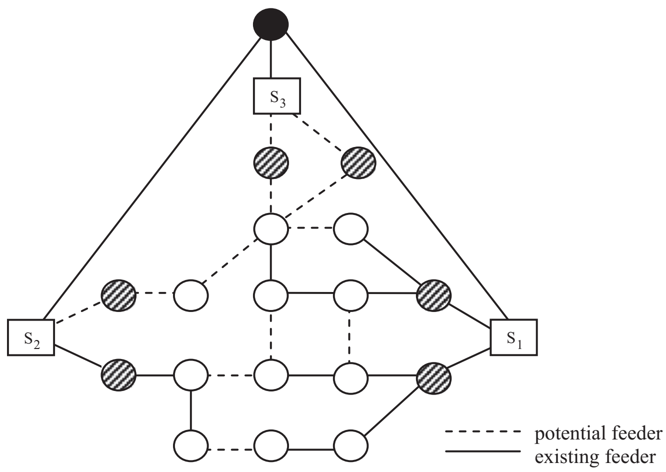

Fig. 4. Example of a distribution network (adapted from [16]).

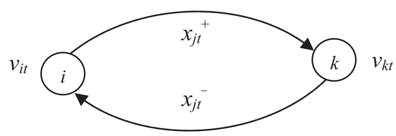

Fig. 5. Feeder between two nodes.

in fault case t ($d_{it}=0$ if load point i is an element of the faulted section in fault case t). Let $I_D \subset I$ be the set of load demand nodes. For each load demand node $i \in I_D$, let J_i be the set of links incident to load point i. For each load demand node $i \in I_D$, for each link $j \in J_i$, and for each fault case $t \in T$, define the binary constant a_{ijt} equal to 1 if and only if load point i can be supplied via incident link j in fault case t ($a_{ijt}=0$ if link j is an element of the faulted section in fault case t). Finally, define n as the number of nodes, including the source node and v as the allowable voltage drop.

The formulation is given next.

$$\text{Minimize} \sum_{j \in J} c_j w_j \tag{4.30}$$

subject to

$$y_{jt} \le w_j \quad (j \in J, t \in T) \tag{4.31}$$

$$\sum_{j \in J} y_{jt} = n-1 \text{ and the graph is connected} \quad (t \in T) \tag{4.32}$$

$$x_{jt}^{+} \le M y_{jt} \quad (j \in J, t \in T) \tag{4.33}$$

$$x_{jt}^{-} \le M y_{jt} \quad (j \in J, t \in T) \tag{4.34}$$

$$\sum_{j \in J_i} a_{ijt}(x_{jt}^{+} - x_{jt}^{-}) = d_{it} \quad (i \in I_D, t \in T) \tag{4.35}$$

$$(v_{it} - v_{kt}) - R_j(x_{jt}^{+} - x_{jt}^{-}) + s_{jt}^{+}(1-y_{jt}) - s_{jt}^{-}(1-y_{jt}) = 0 \quad (j \in J, t \in T) \tag{4.36}$$

$$x_{jt}^{+} \le LC_j \quad (j \in J, t \in T) \tag{4.37}$$

$$x_{jt}^{-} \le LC_j \quad (j \in J, t \in T) \tag{4.38}$$

$$v_{it} \ge \underline{v} \quad (i \in I, t \in T) \tag{4.39}$$

$$w_j \in \{0,1\} \quad (j \in J) \tag{4.40}$$

$$y_{jt} \in \{0,1\} \quad (j \in J, t \in T) \tag{4.41}$$

$$x_{jt}^{+}, x_{jt}^{-}, s_{jt}^{+}, s_{jt}^{-} \ge 0 \quad (j \in J, t \in T) \tag{4.42}$$

$$v_{it} \ge 0 \quad (i \in I, t \in T) \tag{4.43}$$

The objective function (4.30) minimizes the sum of the installation costs for all the predetermined fault cases. Constraint set (4.31) guarantees that each link can be used as a part of a post-fault configuration of the distribution feeder in each fault case only if this link is installed. Constraint set (4.32) assures that a radial configuration, i.e., a spanning tree, is defined for each fault case. The linking constraint sets (4.33) and (4.34) ensure that the forward or inverse power flow of a given link in a given fault case is positive if the link is used in this fault case. M is a sufficiently large positive number. Constraint set (4.35) requires that the load demand is satisfied for each load point in each fault case. For each link $j \in J$ and for each fault $t \in T$, the difference ($x_{jt}^{+} - x_{jt}^{-}$) denotes the power flow in link j in fault case t. For every link where an existing or potential feeder exists as shown in Fig. 5, constraint set (4.36) must be satisfied. If a link is used, then this set assures that the line voltage drop relation holds. Otherwise, the voltage difference between two nodes can be absorbed by either s_{jt}^{+} or s_{jt}^{-} according to the sign of the voltage difference. The variables s_{jt}^{+} and s_{jt}^{-} are two nonnegative real slack variables. Constraint sets (4.37)–(4.38) ensure that the power flow limits imposed by current capacities are respected in each fault case. Constraint set (4.39) imposes a lower voltage bound on the voltage at every node for each fault case. This model is solved with a three-phase composite heuristic. 1) Given a set of installed facilities, the first phase constructs, for each fault case, an initial tree configuration that satisfies all the constraints except current capacity limits and voltage drop constraints. 2) Then, in the second phase, the initial set of tree configurations is made feasible by applying five procedures successively. In the first procedure, a sequence of link exchanges is performed for each fault case. A link exchange first constructs a cycle by adding one link in an initial tree configuration, and then removes another link along the cycle to form a new tree configuration. A candidate link, to add or to delete for the exchange, is chosen so as to minimize both installation cost and constraint violations. When capacity limits are respected, the candidate link is chosen so as to both minimize installation cost and maximize voltage (maximize voltage implicitly means to reduce operating cost or losses as much as possible). The search ends when no candidate link can improve the tree configurations. The second procedure still attempts to eliminate constraint violations by applying link exchanges for each fault case. However, tree configurations violating current capacity limits and voltage drop constraints are allowed during the search process. The third, fourth, and fifth procedures try to eliminate constraint violations by adding one, two or even all candidate facilities to the existing system, respectively. To do this, link exchanges are independently carried out for the fault cases for each procedure. 3) When a procedure terminates, if no constraint violations exist, the last phase attempts to reduce the installation cost by removing unnecessary installed facilities or by replacing costly facilities with cheaper ones, provided that these link exchange operations do not cause any constraint violations. The five improvement procedures and the last phase are applied to several initial sets of tree configurations and the best system configuration plan is selected. The authors also proposed a simplified version of the heuristic where a feasible tree configuration is determined for each fault case independently. Results on two problems involving 59 nodes, 69 links, and 6 fault cases indicated that the three-phase composite heuristic allows installation cost savings of up to 73.39% over the tree configurations produced by the simplified method with computing times less than 8 minutes.

4.4. Compound substation capacity, load reallocation, and system configuration models

Largely due to the nature of the single-fault policy, there are strong interactions between the determination of substation load capacity, the permanent reallocation of excess load, the installation of new feeders, and the addition of substation transformers. In an effort to integrate these closely interrelated decisions into a single decision scheme, Khator and Leung [8] proposed a heuristic approach for the combined problem of substation single-fault capacity planning, load reallocation, feeder configuration, and transformer configuration over a multi-year planning horizon. The approach, which is based on the three models proposed by Leung et al. [11], Sarada et al. [18] and Leung et al. [12], also integrates a substation transformer configuration model with no fault consideration developed by Leung and Khator [10]. Fig. 6, taken from Khator and Leung [8], depicts the heuristic algorithm for the combined problem. The decision scheme was applied to the Fort Myers District of Florida for a planning horizon of ten years.

5. District design models

Zografos et al. [23] proposed a solution method to design contiguous and balanced districts for emergency distribution operations. The objective is to minimize the service restoration time following a power interruption, while providing uniform level of service to customers. The number of districts to be designed equals the number of emergency repair vehicles that should be available per shift. The emergency repair vehicles are mobile servers that can be located anywhere in a designated district at the time of dispatch.

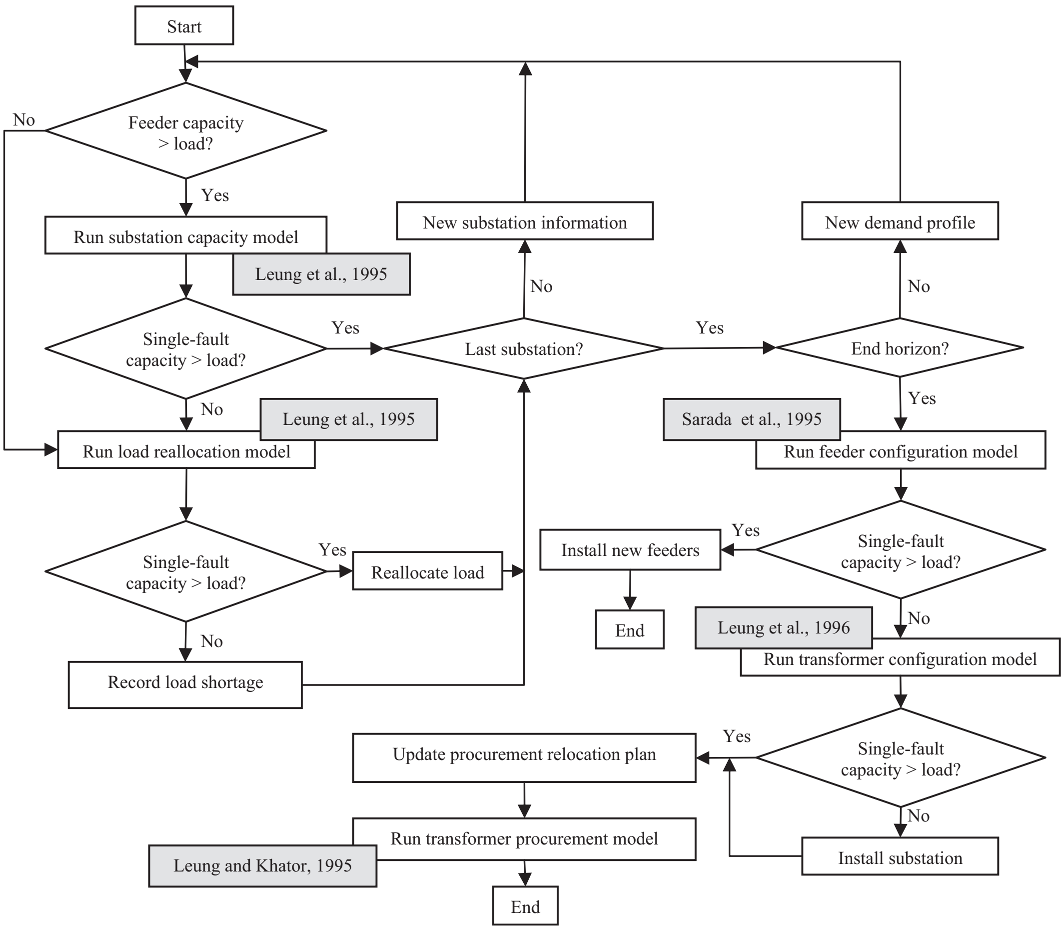

Fig. 6. Heuristic for the combined substation capacity planning, load reallocation, and system configuration problem [8].

Furthermore, the district design process is performed in the plane. The authors proposed a three-phase heuristic that builds all districts simultaneously by assigning basic units, representing small geographic entities, to the repair vehicles. Let J be the set of repair vehicles. 1) In the first phase, the heuristic starts by selecting $|J|$ basic units to serve as seed districts for the $|J|$ repair vehicles. 2) In the second phase, basic units are first allocated to the vehicles through the solution of a linear program. Let I be the set of basic units to agglomerate into districts. For every basic unit $i \in I$, let P_i, and A_i represent the workload of basic unit i and the area of basic unit i, respectively. The workload of a basic unit is calculated as the product of the number of customers' calls originating from this basic entity to report service unavailability and the average repair time of each call. For every basic unit $i \in I$ and for every vehicle $j \in J$, let x_{ij} be a nonnegative variable representing the amount of workload of basic unit i assigned to vehicle j, and let t_{ij} be the travel time from the centroid of basic unit i to the centroid of the seed district associated with vehicle j. Finally, define $\overline{P}$ and $\bar{A}$ as the average district workload and the average district area, respectively. Then the problem of assigning basic units to the vehicles can be formulated as follows.

$$\text{Minimize} \sum_{i \in I}\sum_{j \in J} t_{ij}x_{ij} \tag{5.1}$$

subject to

$$\sum_{j \in J} x_{ij} = P_i \quad (i \in I) \tag{5.2}$$

$$(1+\alpha_1)\overline{P} \le \sum_{i \in I} x_{ij} \le (1+\alpha_1)\overline{P} \quad (j \in J) \tag{5.3}$$

$$(1-\alpha_2)\bar{A} \le \sum_{i \in I} A_i \frac{x_{ij}}{P_i} \le (1-\alpha_2)\bar{A} \quad (j \in J) \tag{5.4}$$

$$x_{ij} \ge 0 \quad (i \in I, j \in J) \tag{5.5}$$

The objective function (5.1) minimizes the total demand-weighted travel time. Constraints (5.2) require that the total workload demand generated at each basic unit is satisfied. These constraints allow each basic unit to be split into more than one part, each part being assigned to a different district. Constraints (5.3) ensure that the total workload assigned to each district is within a given threshold value from the average workload of the entire geographical area. Similarly, constraints (5.4) assure that the size of each district is within a given threshold value from the average. 3) The third phase then finds the centroid that minimizes the weighted travel cost within each district resulting from the second phase. Model (5.1)–(5.5) allows non-contiguous districts. If there is an enclave (portion of a district which is entirely surrounded by the territory of a neighbouring district), the second and the third phases are repeated by solving model (5.2)–(5.5) with the following objective function until each district is composed of a contiguous set of basic units:

$$\text{Minimize} \sum_{i \in I}\sum_{j \in J} M_{ij}t_{ij}x_{ij} \tag{5.6}$$

where M_{ij} is a very large positive number if basic unit i belongs to an enclave and district j is not the neighbouring area of the enclave, and 0 otherwise. When all districts are contiguous, the heuristic terminates if the summation of the difference of the centroid coordinates and the positions of all the centroids between two successive iterations do not differ more than predetermined small values. Otherwise, the algorithm returns to the second phase. The heuristic was tested on a real geographic area of approximately 65 mi^2. Basic units having an area of 1 mi^2 were used as the unit of analysis. The quality of the configuration of the districts was evaluated on the basis of the performance of the emergency repair operations simulated within each district produced by the heuristic. The heuristic uses the IMSL library for the solution of the linear program. Details on the simulation model are given in the paper by Zografos et al. [24]. Tests performed showed a 70% reduction in total service restoration time over the existing district configuration. The heuristic and the simulation model were embedded in a decision support system to assist planners of a large electric utility in the southeast United States in establishing districts and assigning service calls to repair crews for emergency distribution operations [25].

6. Resource and material depot location models

Wang et al. [20] proposed a non-linear mixed integer programming model for the strategic resource depot location problem. Let I be the set of depots and J be the set of customer locations. For every pair of customer locations $j, k \in J, j \neq k$, let d_{jk} represent the distance between the depot located at customer location j and customer k. For every depot $i \in I$ and for every customer location $j \in J$, let y_{ij} be a binary variable equal to 1 if and only if depot i is located at customer location j. Let R be the set of resource types. For every depot $i \in I$, for every customer location $j \in J$ and for every resource type $r \in R$, let x_{rij} be a nonnegative variable representing the quantity of resources r transported from depot i to customer location j, and define C_r, A_{ir}, and D_{jr} as the unit transportation cost of resource r, the capacity of depot i for resource r, and the demand of customer j for resource r, respectively. The formulation is given next.

$$\text{Minimize} \sum_{r \in R} C_r \sum_{i \in I} \sum_{j \in J} y_{ij} \sum_{k \in J} d_{jk} x_{rik} \tag{6.1}$$

subject to

$$\sum_{j \in J} x_{rij} \leq A_{ir} \quad (i \in I, r \in R) \tag{6.2}$$

$$\sum_{i \in I} x_{rij} \geq D_{jr} \quad (j \in J, r \in R) \tag{6.3}$$

$$\sum_{j \in J} y_{ij} = 1 \quad (i \in I) \tag{6.4}$$

$$\sum_{i \in I} y_{ij} \leq 1 \quad (j \in J) \tag{6.5}$$

$$x_{rij} \geq 0 \quad (i \in I, j \in J, r \in R) \tag{6.6}$$

$$y_{ij} \in \{0,1\} \quad (i \in I, j \in J) \tag{6.7}$$

The objective function (6.1) seeks to minimize the total cost of transportation. Constraints (6.2) guarantee that the amount of resource shipped from an individual depot does not exceed its capacity. Constraints (6.3) require that the demand of each customer is satisfied. Constraints (6.4) guarantee that each depot be located in exactly one customer location, and constraints (6.5) guarantee that each customer location contains only one depot. Model (6.1)–(6.7) is converted into an equivalent integer linear programming problem by introducing a nonnegative variable $P_{rijk} = y_{ij} x_{rik}$ representing the amount of resource r transported from depot i located at customer location j to customer location k and by adding the following constraints to the resulting model:

$$P_{rijk} + M(1 - y_{ij}) \geq x_{rik} \quad (i \in I, j \in J, k \in J, r \in R) \tag{6.8}$$

where M is a large positive number. Although the optimal solution for a relatively large size integer linear programming problem was obtained by using LINDO software, the size remained small with respect to a realistic problem. When $|J| > 12$, $|I| > 3$, and $|R| > 3$, the computation became intractable. The authors thus developed a two-phase heuristic for the depot location. In the first phase, an assignment cost table, that shows every possible assignment of a depot to a customer location and its associated cost based on the depot capacity, is used to assign the depots to customer locations. The customer location corresponding to the smallest value in row i $i \in I$ is chosen as a reasonably good candidate location for depot i. However, to avoid violations of constraints (6.4) and (6.8), after each depot obtains its candidate location, overlapping candidates must be identified and be avoided. In the second phase, a shipment cost table, that shows every possible shipment of a depot and its associated cost based on the customer demand, is used to determine the amount of different resources shipped from the appropriate depots. The depot corresponding to the smallest value in column $j \in J$ is chosen as the priority depot to serve customer j. However, if the capacity of the depot located at customer location j is less than the demand of customer j, the depot with the second smallest value is chosen and the depot located at customer location j serves the remainder, and so on, until the demand of customer j is satisfied. Computational experiments were performed on instances with up to 25 depots, 200 customer locations, and 30 resource types. For small instances with $2 \leq |I| \leq 3$, $5 \leq |J| \leq 16$, and $|R| = 3$, the two-phase heuristic produced optimal solutions in most cases almost instantly (the relative difference ratio is within 5%), while using LINDO software to optimally solve the linear mixed integer programming model required a few minutes. Larger instances could be solved heuristically within 27.7 seconds.

In the same paper, Wang et al. [20] described an optimization tool to assist utility distribution planners in analyzing the location of additional resource depots to account for existing resource shortage. The problem is to determine how many new depots to be allocated and where to locate them. The objective is to minimize the total costs that include shipping cost, fixed cost, and the cost of building new depots. Let I denote the set of existing and new depots. The new resource depot location problem reduces to a resource assignment problem that can be obtained by fixing the location variables y_{ij} for the existing depots in the original formulation (6.1)–(6.7). The number of additional depots is determined by trial and comparison of the total costs of the cases before and after adding new depots. When the demand is less than the capacity of existing depots, the authors used the following rule to determine whether or not it is necessary to locate new depots: if the total cost of the resource assignment problem is less than the total cost of adding one depot, then no new depot is necessary.

7. Conclusions

This paper is the first of a two-part survey of optimization models and solution algorithms for emergency response problems related to electric distribution operations. (The second part of the survey discusses contingency planning problems of emergency distribution response.) This paper addresses distribution substation single-fault capacity, load reallocation, system configuration, district design, and resource and material depot location models with fault considerations. Table 1 summarizes the characteristics of the reliability planning models related to emergency distribution operations.

Most reliability planning models that have been proposed typically consider the single-fault policy for systems operated with a radial topology. However, if two or more faults occur at the same time, these models may have poor reliability. Also, although radial

Table 1
Characteristics of reliability planning models with fault considerations.

Articles	Problem type	Problem characteristics	Objective function	Model structure	Solution method
Leung et al. [11]	Substation single-fault capacity	Single-fault policy, load demand requirements, power transfer limits, equipment overloading, and voltage dropping	Max substation load and total demand supplied	Linear P	MPS mathematical programming
Leung et al. [11]	Substation load reallocation	Single-fault policy, load demand requirements, power transfer limits, load reallocation limits, and voltage rating limits	Min total load reallocated	Linear P	MPS mathematical programming
Sarada et al. [18]	Feeder configuration	Single-fault policy, load demand requirements, voltage rating limits, and equipment loading limits	Min feeder costs and load transfer costs	Linear MIP	Branch-and-bound
Cárcamo-Gallardo et al. [4]	Feeder configuration	Radiality	Min energy not supplied	Minimum spanning tree	Heuristic
Leung et al. [12]	Substation transformer configuration	Single-fault policy, voltage drop limits, and equipment overloading limits	Min transformer capacity requirement and transformer procurement cost	Linear 0–1 IP	MPS mathematical programming
Nara et al. [16]	Compound feeder, transformer and substation configuration	Radiality, load demand requirements, line voltage relations, voltage drop limits, and loading limits	Min installation costs	Linear MIP	Composite heuristic
Khator and Leung [8]	Compound substation capacity, load reallocation, and system configuration	Single-fault policy, load demand requirements, power transfer limits, equipment overloading limits, load reallocation limits, and voltage drop limits	Min cost expansion planning	–	Heuristic
Zografos et al. [23]	District design	Contiguity, balanced districts, maximum district size, basic units, and fixed number of districts	Min total demand-weighted travel time	Linear P	Heuristic
Wang et al. [20]	Resource depot location	Different depots, multiple resources, depot capacities, and customer demands	Min transport costs	Nonlinear MIP	Heuristic

systems are applicable to most primary distribution systems in the US, many distribution substation and secondary distribution systems may not operate according to a radial structure [3]. Further, many primary distribution systems in Europe are operated in closed loop or more complicated network topologies. Future research directions in distribution reliability with fault considerations should thus be oriented towards the development of new mathematical formulations that integrate the simultaneous failure of multiple components in radial, loop or network systems.

The resource and material depot location model is closely linked to the routing of repair vehicles. However, the location of resource and material depots is most commonly treated as a separate problem. Very frequently, resource and material depots are located by assuming that each repair vehicle is dispatched to one customer from a fixed depot. After repairing the fault at a single customer location, the repair vehicle returns to a depot, and so on, until all faults are repaired. Wang et al. [20] used this approach for locating resource and material depots for emergency distribution operations. Since the time for returning to a depot after repairing a fault can be significant, this approach obviously leads to suboptimal decisions. As mentioned by Wang et al. [20], a better approach could consist of simultaneously locating resource and material depots and establishing repair vehicle routes by assuming that a vehicle returns to the depot after repairing multiple faults.

As mentioned in Section 4.3, when a substation's forecast load demand cannot be satisfied under the single-fault policy, specific reliability planning decisions can be established to overcome the capacity shortage. These decisions include, in incremental expenditure, reallocation of excess load, installation of new feeders, addition or upgrading of transformers, and construction of new substations. These decisions are interrelated and hence require an integrative approach. However, they are most often treated separately. Therefore, another direction worth pursuing involves the further development of models that address the integration of substation capacity planning with other decisions related to system configuration with fault considerations. The compound models proposed by Nara et al. [16] and Khator and Leung [8] are good examples of integrated models.

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