J. Webster (ed.), *Wiley Encyclopedia of Electrical and Electronics Engineering*

POWER SUBSTATION MODELING

An electric power system generally includes a generating system, a transmission system, and a distribution system, as shown in Fig. 1. This article is concerned with distribution system planning. The objective of distribution system planning is to meet the growing demand for electricity by expansion of the distribution system in an economically and technically desirable manner. The loads must be served, but at maximum cost-effectiveness by minimizing operating and construction costs.

An important task in distribution system management is the planning of substation capacity. A substation houses transformers that convert high-voltage power to low-voltage power. The low-voltage power is then delivered to customers via a network of power lines called feeders. Commonly, the feeders of several substations are integrated, thus forming a larger power distribution network. The amount and locations of substations depend on the load density, power availability, geographical factors, and so on.

In a distribution substation, there are four major types of equipment: transformers, breakers, regulators, and capacitor banks. The majority of capital investment goes to the purchase of transformers, which, for large utilities, may have an average price of around $450,000 (see Table 1). The types of transformers commonly used by large utilities are shown in Table 2.

The maximum amount of power that a transformer can convert in a normal (nonemergency) situation is defined as its *nameplate capacity.* The sum total of the nameplate capacities of a substation's transformers is referred to as the *normal substation capacity.* The sum total of a substation's feeder capacities is the substation's *distribution capacity.* Feeders can be radial with no connections or be linked via feeder ties to adjacent substations. During emergency (transformer failure), sections of a feeder can be temporarily switched to those of adjacent substations, thus allowing load of neighbor substations to be shared. The amount of emergency power through a feeder is limited by the feeder's *transfer capacity,* which is feeder capacity minus existing load on the feeder.

Distribution planners must ensure that there is adequate substation capacity and distribution capacity to meet load forecasts. If capacity is found to be insufficient, alternatives such as procuring transformers and building new feeders and new substations need be evaluated carefully. In general, the decisions in the planning of power distribution system include

- Optimal location of a substation
- Optimal routes of feeders
- Optimal individual feeder design
- Optimal allocation of load
- Optimal allocation of substation capacity
- Optimal mix of transformer by substation

The relevant factors in the decision environment include

- Kirchhoff's current law
- Kirchhoff's voltage law

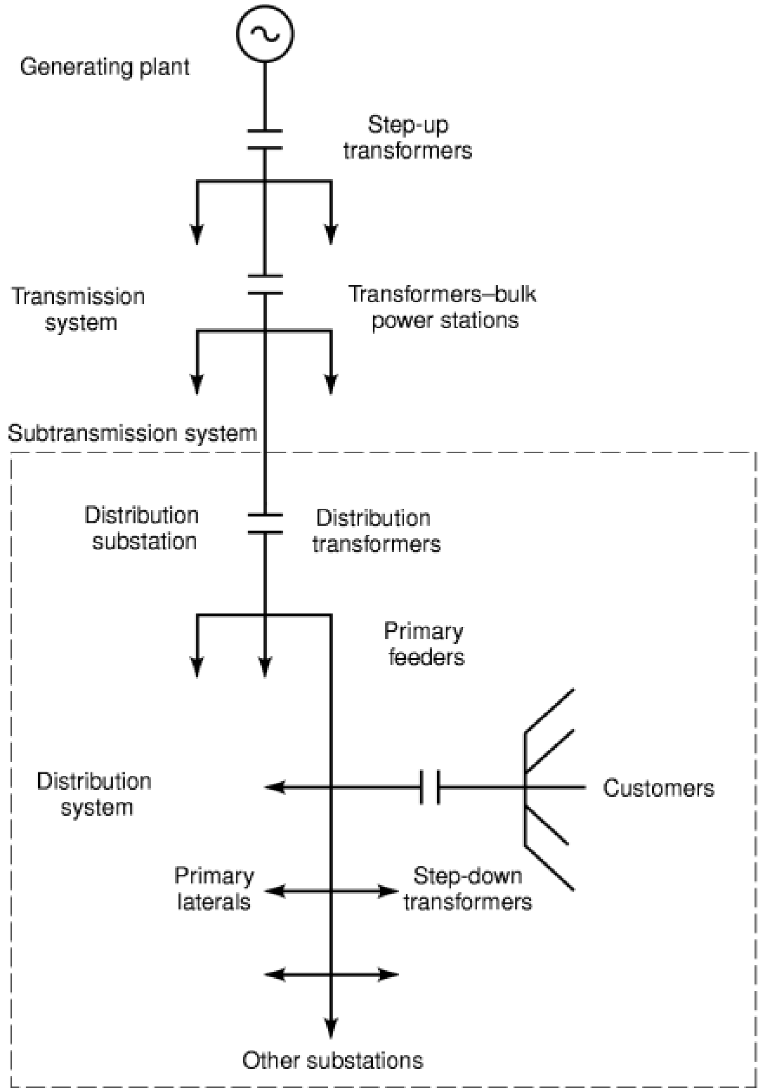

Fig. 1. Line diagram of an electric power system showing a generating, a transmission, and a distribution system.

Table 1. Example –Annual Distribution Substation Equipment Expenditure

Equipment	Annual Investment (in Million $)	Number of Units	Average Unit Cost
Transformers	6.75	15	450,000
Breakers	4.20	175	24,000
Regulators	2.75	250	11,000
Capacitor banks	0.06	10	6,000
Miscellaneous	6.60	–	–

Table 2. Transformer Types (x = Available)

Voltage Rating (kV) HV	LV	Capacity (MVA) 30	45	55	80	Voltage Rating (kV) HV	LV	Capacity (MVA) 30	45	55	80
69	13.8	x	x	x		138	13.8	x	x	x	
	24.0	x		x			24.0	x		x	x
115	13.8	x	x	x		230	13.8	x	x	x	
	24.0	x	x	x			24.0	x		x	x

- Concave variable cost in feeders
- Radiality of feeders
- Voltage drop on feeders
- Substation normal capacity
- Substation distribution capacity
- Substation emergency capacity
- Feeder emergency capacity

This article provides an overview of problems and selected models related to the planning of substation and/or feeder distribution. Our discussion is organized under two major categories: planning under normal conditions, and planning for emergency. The former does not explicitly consider transformer and/or feeder failures; here, a safety capacity is implicitly factored into the analysis. The latter explicitly considers contingency planning, where the supply of power is examined within the context of when failure of transformers occur. It should be pointed out that the issue of network reliability is not included in this article. Reliability is about the *likelihood* of a failure occurring in the system (versus contingency, which is about the actions *when* a failure occurs). It is indeed an important aspect of power distribution planning. However, we believe it is a topic in its own right and thus it will not be addressed here.

Distribution Planning: Normal Conditions

A power distribution system can be viewed as a network of nodes and arcs, where the nodes represent substations and arcs represent feeders. An example of a small substation network in the Fort Myers district of Florida consisting of 12 substations connected via feeders is shown in Fig. 2. Such a network framework, with its objectives and constraints, can often be formulated within a mathematical programming context: linear programming, mixed 0-1 linear programming, and nonlinear programming.

Except for linear programs (*LP*s), which can be solved easily using standard commercially available LP software, the other types of mathematical programs are generally not so easy to solve. Coupled with the fact that the dimension of a typical real-life problem is large in that there are a large number of 0-1 variables and constraints, it may be unrealistic to solve these models within a reasonable time. In such cases, decision makers may accept a good solution in lieu of the optimal one. There exist quite a number of heuristic-based approaches as well as antificial intelligence (*AI*) approaches. In this section, the modeling framework is organized according to their approaches toward solutions: optimization models, heuristic and algorithms, and AI/expert system approaches. Under optimization models, we have two further classifications: single-period models and multiperiod models (Fig. 3).

Optimization Models.

Single-Period Models. Single-period models assume that the load demand would not change during the horizon. Here the load growth factor is not considered, and there is no need to relate installations of

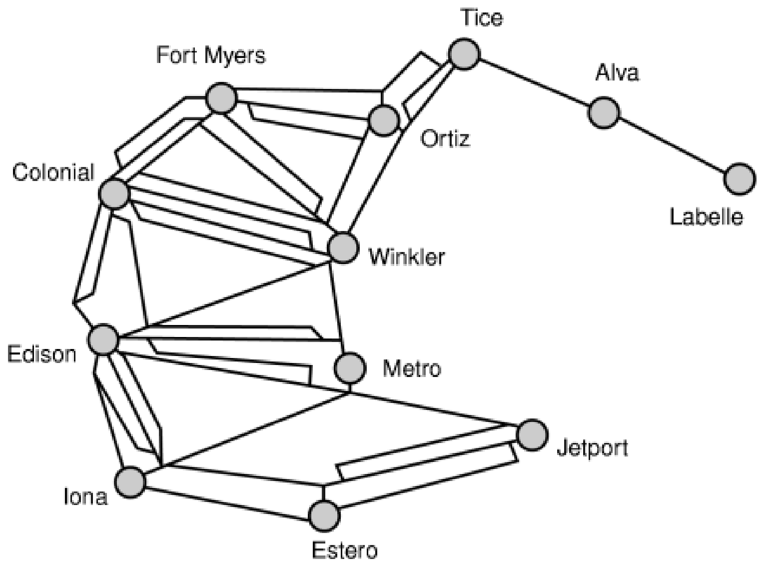

Fig. 2. A schematic of a small substation network in the Fort Myers district of Florida consisting of 12 substations connected via feeders. The nodes in this network represent substations, and arcs indicate feeders.

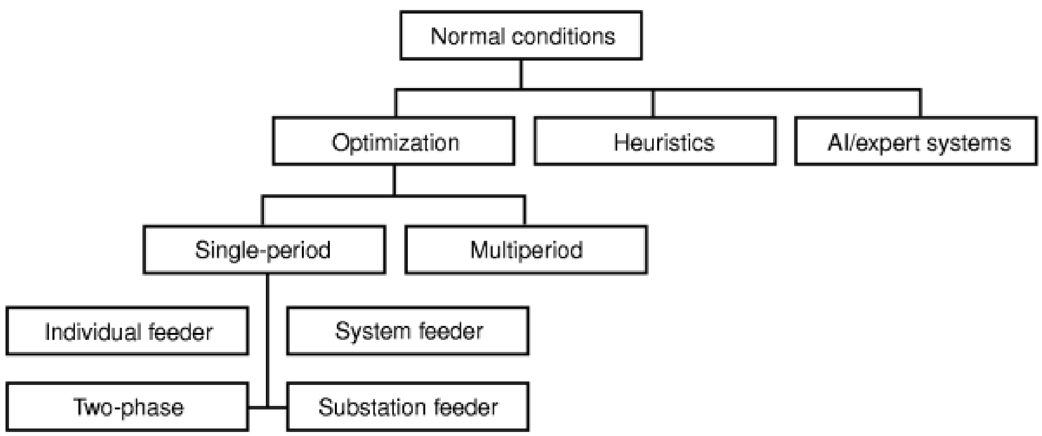

Fig. 3. Classification of models for distribution planning under normal conditions. The first-level classification is based on the solution approach used. The optimization models are further subdivided as single-period and multiperiod models. Feeder configurations provide the further breakdown of single-period models.

substations and feeders in one year to the next. In general, such optimization models can be categorized into four subgroups: individual feeder models, system-feeders models, two-phase substation-then-feeder model, and substation-feeder models.

Individual Feeder Models. This class of problem deals with the design of individual feeders. Here, the task is to design optimally the configuration of each individual feeder by deciding on the length, conductor size, and gradation, and by addressing the economic trade-off between fixed and operating costs.

System Feeder Models. Given a network of substations with demand points and supply points, the objective here is to determine the best way to connect the substations such that the demands are met at minimum cost. The models, in general, take on the following mixed 0-1 LP form:

$$\begin{aligned} \text{Min:}\quad & \text{Fixed cost} + \text{Variable cost} \\ \text{st.}\quad & \text{Flow distribution} = \text{Demand} \\ & \text{Individual flow} \le \text{Capacity} \end{aligned}$$

Mathematically, this can be expressed as

$$\begin{aligned} \text{Min:}\quad & \boldsymbol{c}_{\mathrm{f}}\boldsymbol{x} + \boldsymbol{c}_{\mathrm{v}}\boldsymbol{p} \\ \text{st.}\quad & A\boldsymbol{p} = \boldsymbol{d}, \\ & \boldsymbol{p} \le M\boldsymbol{x},\ \boldsymbol{x} \in (0,1),\ \boldsymbol{p} \ge 0 \end{aligned}$$

where

$\boldsymbol{x}$ = the decision vector for individual feeder connections
$\boldsymbol{p}$ = the quantity of flow vector
$\boldsymbol{c}_{\mathrm{f}}$ = the vector for the fixed charges of the connections
$\boldsymbol{c}_{\mathrm{v}}$ = the vector for variable cost per unit power flow
A = the flow matrix
$\boldsymbol{d}$ = the demand/supply vector
M = the capacity matrix of the connection

There are two cost components: the fixed cost and the variable cost of power flow for a particular connection. Linearization of the concave variable cost c_{v} would be a realistic approach to model cost functions that are nonlinear. General branch and bound techniques are plausible solution approaches.

Two-Phase Models. The simultaneous determination of optimal substation and feeder installation is a computationally difficult task since a large number of integer variables are involved. The problem may be approximated by breaking the planning task into two sequential problems. Solving the distribution planning problem in this fashion is referred as the two-phase method. The first phase (0-1 LP model) determined the substation decisions, with consideration on redistribution of load. The second phase used a transportation model, with substation capacity from the first phase, to determine the optimal power flow for the feeders. In general, the two phases can be described as follows:

$$\begin{aligned} \text{First phase:}\quad & \text{Min:}\quad && \boldsymbol{c}_{\mathrm{F}}\,\boldsymbol{y} \\ & \text{st.} && R\boldsymbol{y} \ge l, \boldsymbol{e}\boldsymbol{y}_{\mathrm{i}} \le 1 \forall i, \boldsymbol{y} \in (0,1) \\ \text{Second phase:}\quad & \text{Min:} && \boldsymbol{c}_{\mathrm{v}}\boldsymbol{p} \\ & \text{st.} && S\boldsymbol{p} = \boldsymbol{R}^{*}, D\boldsymbol{p} = \boldsymbol{l}, \boldsymbol{p} \ge 0 \end{aligned}$$

where

$\boldsymbol{y}$ = the substation decision vector consisting of a series of $\boldsymbol{y}_1, \boldsymbol{y}_2, \ldots, \boldsymbol{y}_i$
$\boldsymbol{y}_{\mathrm{i}}$ = the capacity options vector for individual substation
$\boldsymbol{e}$ = a unit row vector (to sum all elements in $\boldsymbol{y}_{\mathrm{i}}$
$\boldsymbol{e}\boldsymbol{y}_{\mathrm{i}} \le 1$ = ensures that no more than one capacity type is chosen per substation
R = the capacity choice matrix
$\boldsymbol{l}$ = the load vector
S = the supply flow matrix
D = the demand flow matrix
$R*$ = the resulting capacity vector from phase one

The first phase model is a 0-1 linear program that can be solved using branch-and-bound or other implicit enumeration algorithms. The second phase is a linear program that can be easily solved. Again, nonlinear variable power cost and voltage drop can be incorporated into the second-phase model, and linearization of the nonlinear function will be needed.

Substation-Feeder Models. This class of problem simultaneously determines the decisions of substation and feeder installation, the feeder flow, and substation load. Added to the system feeder formulation are 0-1 variables (new substation installations) along with the variable cost component based on the sum power flow for the individual substations. The formulation has the following framework:

$$\begin{aligned} \text{Min:}\quad & \text{Fixed} + \text{Variable cost (For both substations and feeders)} \\ \text{st.}\quad & \text{Distribution flow} = \text{Demand} \\ & \text{Feeder flow} \leq \text{Feeder capacity} \\ & \text{Sum feeder flow per substation} \leq \text{Substation capacity} \end{aligned}$$

Mathematically, it is a mixed 0-1 linear program:

$$\begin{aligned} \text{Min:}\quad & \boldsymbol{c}_{\mathrm{F}}\boldsymbol{y} + \boldsymbol{c}_{\mathrm{v}}\boldsymbol{P} + \boldsymbol{c}_{\mathrm{f}}\boldsymbol{x} + \boldsymbol{c}_{\mathrm{v}}\boldsymbol{p} \\ \text{st.}\quad & A\boldsymbol{p} = \boldsymbol{d} \\ & \boldsymbol{p} \leq M\boldsymbol{x} \\ & \boldsymbol{P} \leq R\boldsymbol{y} \qquad \boldsymbol{x}, \boldsymbol{y} \in (0, 1),\ \boldsymbol{p} \geq 0 \end{aligned}$$

where

$\boldsymbol{c}_{\mathrm{F}}$ = the substation fixed cost vector
$\boldsymbol{c}_{\mathrm{V}}$ = the substation variable cost vector
$\boldsymbol{P}$ = Σp, the sum-flow vector to individual substations
R = the flow matrix for substations

A branch-and-bound algorithm has been proposed to solved this problem. Here, two major bounding criteria are (1) minimum incremental cost bound, and (2) shortest path customer assignment. The first bounding criteria assumes that the fixed costs of all potential substations to be zeros, and the power flow problem is then solved, thus giving the lowest incremental cost of power flow. This incremental cost plus the actual fixed costs of the potential substation provided a lower bound cost. For the second bounding criteria, the flow problem to a specific demand point from a specific potential substation is solved with all existing substation open and all other potential substations closed. This gives the marginal cost of a particular flow. Enumerating all other potential sources resulted in the lower bound cost of serving a particular demand point.

Multiperiod Models. A multiperiod planning problem should not be approached as if it is solving a series of single-period problems. However, it is not uncommon to have a multiperiod problem broken down into a sequence of period-to-period expansion situation. In such cases, each preceding period's decisions will form the basis for each following period's decisions, and so on until the end of the planning horizon. While this way of partitioning the problem into solving a series of smaller problems will be computationally much more easier than solving the entire n-period problem, the resulted solution might not be an overall optimum as current solutions are not influenced by future decisions during the optimization process.

Moreover, extending single-period models by the mere time subscripting of time-dynamic variables and parameters is not adequate. In multiperiod problems, explicit modeling of correlated time-dynamic decisions must be formulated. These decisions include only one installation at a location, conjunctive or mutually exclusive installations, and radiality consideration over time. Using 0-1 variables, these considerations can be modelled as logical constraints. The general framework is

```
Min: Present value of fixed and variable cost (substation + feeder) st. All single-
period conditions for each period in the horizon with accumulated capacities Plus Only
one installation at a location Conjunctive or mutually exclusive installations Radiality
consideration over time
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The general mathematical formulation is

$$\begin{aligned}
\text{Min:} \quad & \textstyle\sum_t \{\boldsymbol{c}_{\mathrm{Ft}}\,\boldsymbol{y}_t + \boldsymbol{c}_{\mathrm{vt}}\boldsymbol{P}_t + \boldsymbol{c}_{\mathrm{ft}}\,\boldsymbol{x}_t + \boldsymbol{c}_{\mathrm{vt}}\boldsymbol{p}_t\} \\
\text{st.} \quad & A_t\boldsymbol{p}_t = \boldsymbol{d}_t, \quad \boldsymbol{p}_t \le (M_1\boldsymbol{x}_1 + \cdots + M_t\boldsymbol{x}_t) \\
& \boldsymbol{P}_t = \boldsymbol{e}_t\,\boldsymbol{p}_t, \quad \boldsymbol{P}_t \le (R_1\boldsymbol{y}_1 + \cdots + R_t\,\boldsymbol{y}_t) \\
& \boldsymbol{e}_t\,\boldsymbol{y}_t \le \mathbf{1} \\
& \boldsymbol{e}_t\,\boldsymbol{x}_t \le \mathbf{1} \\
& G(\boldsymbol{x}_1, \ldots, \boldsymbol{x}_t : \boldsymbol{y}_1, \ldots, \boldsymbol{y}_t) = 0 \\
& \boldsymbol{x}_t, \boldsymbol{y}_t \in (0, 1), \quad \boldsymbol{p}_t \ge 0, \qquad \forall t = 1, \ldots, n
\end{aligned}$$

where all cost factors are in terms of present value, n is the planning horizon, constraint sets $\boldsymbol{e}_t\boldsymbol{y}_t \le 1$ and $\boldsymbol{e}_t\boldsymbol{x}_t \le 1$ ensure one installation per site, and $G(\boldsymbol{x}_1, \ldots, \boldsymbol{x}_t; \boldsymbol{y}_1, \ldots, \boldsymbol{y}_t) = 0$ is a system of logic constraints representing additional correlated time-dynamic installation logic, which is usually situation specific.

Note that the fixed installation costs (modeled using 0-1 variables) are incurred only once, while variable costs would be accounted for throughout the equipment's life. Also, the capacities of previously installations must be accumulated to the succeeding periods. Refinement to the model includes modeling of concave variable costs (linearization) and characterization of voltage drop in feeders using stepwise functions of power flow.

A Two-Phase Method. Again, because a real-life problem would typically consist of a large number of 0-1 variables, a suboptimal but simpler solution procedure might prove to be more desirable. One such procedure utilizes the fixed-charge-transshipment framework of earlier single-period models to develop a procedure to solve the multiperiod distribution problem. This procedure consists of two phases. The first phase solves essentially a static base problem where decisions for substations and flow are first determined. Based on this initial configuration, new inputs (growth and new demand locations) for the next period are incorporated to determine the optimal installation and flow of that period. In turn, the base configuration plus the added configuration then become the basis for the following year's decision, and so on until the end of the planning horizon. This procedure would not guarantee that an overall optimal solution would be obtained since current decisions are not related to future ones.

Heuristic and Algorithms. When using branch-and-bound to solve the mixed 0-1 LP, the user may stop the solution process if a certain feasible as well as acceptable solution (although suboptimal) has been reached. Another alternative is to simplify the problem by relaxing certain assumptions such that it may be computationally manageable. However, there is no guarantee that the optimal solution to the simplified or relaxed problem will be optimal to the original problem. The two-phase methods are simplifying approaches to reduce the dynamic problem into a static one, thus allowing the problems to be solved more efficiently at the expense of getting an optimal solution. Several algorithms are discussed in the following subsections.

Single-Period Branch-Exchange Algorithm. This algorithm is applicable for single-period distribution planning and works as follows:

- Start with a feasible configuration, and add a route to form a loop.
- Then, to gain feasibility, a route (with either high installation cost or constraint violation) is removed. If this exchange resulted in an improvement, retain the exchange; otherwise, abandon the exchange.
- Repeat this procedure iteratively until the objective function cannot be improved further.

The determination of the most sensitive exchange is selected from the information provided by the simplex tableau (LP) of the power flow problem.

Multiperiod Branch-Exchange Algorithm. The algorithm works as follows:

- Forward Path At period t, using the branch-exchange method, the approximate optimal expansion plan for $t = t + 1$ is determined. This one-period expansion plan determination is termed the forward path.
- Backward Path Unlike the two-phase method, which proceeds period-by-period into the future, the proposed algorithm would do a backward path after each forward path. The backward path is to return to the preceding period to see if the expansion plan P_0, found up to that period, is indeed the best that could be achieved via branch exchange. This is done by removing, one preceding period at a time, the period's facilities that are not utilized and by performing branch exchange on the resulted configuration.
- Backward/Forward Path If at any period the plan from backward path is not an improvement, the backward process would stop and the forward process would resume with the previous forward path plan (P_0). If the backward process is able to reach the starting period (resulting in a plan P_1), then the algorithm would restart at $t = 1$ with the new period 1 plan as the basis for the next forward path; the subsequently developed plan P_2 would be compared to the previously determined backward plan P_1, with the better plan to replace P_0 for the next forward path at $t = t + 2$.

Two Stages: Clustering and Forecasting and Planning. In stage 1, the problem of load growth is solved in two phases. The first phase divides the service area into smaller subareas with the demand points in each subarea summed to form a single demand node; the second phase assesses the demand forecast per demand node. In stage 2, the planning problem is again divided into two phases. The first-phase problem is to determine the overall installations required (without knowing when to install) by solving the problem of meeting projected demand at the horizon year. In the second phase, for each intermediate year between the base and the horizon year, an optimal intermediate system is determined using only the equipment set from the static optimum problem. This would determine the schedule of the installations and the year-to-year expansion plan. The optimization model of the subproblem is a constrained nonlinear formulation.

AI/Expert System Approaches. A set-theory-based expert system formulation can be built for load allocation in distribution substation and can be implemented on a PC using PROLOG. It would first generate all hypothetical solutions. An evaluator routine then discards the invalid solutions, and finally a tester would select the best solution that honors the station as well as distribution network constraints.

A rule-based expert system can also be developed for load reallocation in the case of distribution expansion planning. The system's inference engine can consist of two algorithms, one to minimize power and the other to minimize investment cost. The system may also incorporate heuristic rules. Rule-based expert systems may also be applied to designing substation locations and feeder configuration of a distribution system. They can be designed to minimize feeder losses and to support the inference engine. Physical constraints on substation locations, feeders, and right of way can also be included as well.

It has been assessed that the knowledge-based methods complement the pure algorithmic methods without being part of the algorithm, and that the knowledge-based systems provide the flexibility needed for analyzing complex distribution networks.

Distribution Planning for Emergency

In the preceding section, the issue of equipment failure is not addressed. Although failure is not a common phenomenon, transformers and feeders do fail and the cost of power outage is significant. However, to account for equipment failure by merely factoring in a safety capacity is not adequate due to the synergistic nature of power distribution. During emergency, sections of a feeder can be switched to feeders of adjacent substations,

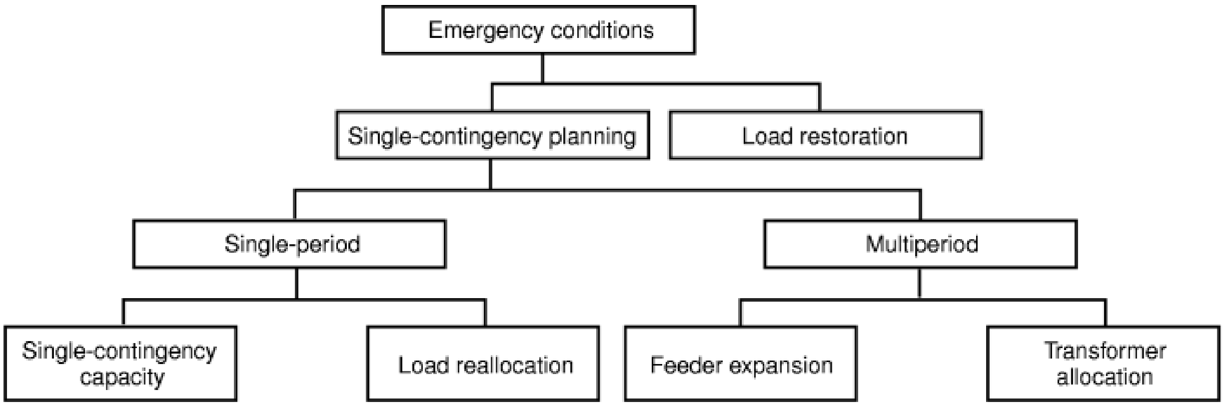

Fig. 4. Classification of models for distribution planning under emergency conditions. Single-contingency models deal with the failure of a single transformer among substations of a service area while the load restoration models work at the feeder level. Approaches developed to meet with the unsatisfied demand with increasing cost impact under single-period and multiperiod models form the final level of the classification scheme.

thus allowing the load of the emergency substation (transformer failure) or that of the emergency feeder to be shared. This special feature implies that a substation's capacity is not an absolute value but a relative one depending on such factors as adjacent substation's transfer capacity, feeder capacity, and so on. In this section, we divide the emergency models into two subcategories (Fig. 4). The first consists of problems in contingency planning where the environment is generally at the substation level. The second consists of problems in load restoration and load balance, both of which are at the feeder level.

Single-Contingency Capacity. In many large electric utilities, a substation's capacity is not assessed according to its normal capacity. Instead, it is based on the maximum load it can handle during emergency. One emergency policy, widely used among electric utilities, is the *single-contingency* policy. The policy permits a single transformer failure among the substations of a service area at any given time; all load in the area must be met during that time. In essence, the single-contingency capacity becomes the real capacity of a substation.

Under single contingency, the working principle is that the load of the service area must be met if failure occurs to either the largest transformer at the substation being evaluated or one of its adjacent substation's largest transformer (not necessarily the largest transformer of *all* the adjacent substations). The capacity of a substation is the load it can take on when failure occurs to either the largest transformer of the substation or one of its adjacent substation's largest transformer. In the former case, it is the sum capacity of the in-service transformers (operating under emergency rates) plus maximum power received from adjacent substations. In the latter, it is the nameplate (normal) capacity of the substation minus the emergency transfer to its adjacent substation. The lesser of the two load situations will be the single-contingency capacity of the substation. Within a mathematical programming context, the problem is as follows:

```
Max: Single-Contingency Capacity of a Substation
st.   Usable capacity, which must cover load demand Load coverage when largest trans-
former of the substation fails Load coverage when largest transformer of an adjacent
substation fails Emergency transfer limits
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This problem of determining a substation's single-contingency capacity, assuming a given substation-load assignment, can be formulated as the following LP model:

$$
\begin{aligned}
\text{Max:}\quad & C_k \\
\text{st.}\quad & C_k \geq L_k \\
& C_k \leq E_k + \textstyle\sum_i \alpha_{ik} P_{ik} \\
& C_k \leq N_k - P_{ki} \forall i \\
& E_j + \textstyle\sum_j \alpha_{ij} P_{ij} \geq L_j \\
& N_j - P_{ji} \geq L_j, P_{ij} \leq F_{ij} \qquad C_k \text{ and } P_{ij} \geq 0\ \forall i, j
\end{aligned}
$$

where

C_k = the substation's single contingency capacity
L_k = its load demand
E_k = its emergency capacity
$\Sigma_i P_{ik} \alpha_{ik}$ = the emergency power transfer from its neighbors (each discounted by α_{ik}, the voltage drop factor)
N_k = its normal capacity
P_{ki} = the emergency power out to its ith neighbor
E_j = the emergency capacity of the jth substation (adjacent to k)
$\Sigma_j \alpha_{ij} P_{ij}$ = the sum emergency flow to the jth substation
N_j = the normal capacity of substation j
P_{ji} = the emergency power out to j's neighbor i
F_{ij} = the transfer capacity of the feeders connecting substations i and j

Load Reallocation. The overall capacity plan is the result of capacity assessments at individual substation networks within the utility. For each network, the principal goal is to ensure that load forecast for each substation can be met under single contingency. When a substation's forecast exceeds its single-contingency capacity, the cheapest alternative is to reallocate permanently part of its load to adjacent substations.

A load reallocation model seeks to reallocate unsatisfied load under the single-contingency environment. There exists considerable synergistic behavior in a power distribution system, such that adding capacity to a substation could provide relief to its multiple neighbors and adding capacity to the shortage substation might not be the most economical. For a network of substations, the framework is as follows:

```
Min: Total load each substation can reallocate to adjacent substations. st. When a sub-
station is under emergency When an adjacent substation is under emergency Feeder capacity
limitation Total emergency power allowed kVA rating limitation
```

Multiperiod Feeder Expansion. When load reallocation fails to overcome the unsatisfied load, one capacity enhancement measure is to construct new feeders to facilitate further load reallocation. Such multiperiod feeder expansion with contingency planning can be modeled as a mixed 0-1 LP formulation that would prescribe the least-cost feeder expansion plan. The model determines the installation schedule as well as sites of new feeders, while concurrently calculating the optimal load reallocation to meet load demand. Figure 5 is a real-life example of multiperiod feeder expansion, determined using a mixed 0-1 LP, which can be described as follows:

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Min: Cost of new feeders st. Feeder capacity requirement during emergency Voltage rating
of load reallocation Load reallocation possibilities Emergency power transfer for dif-
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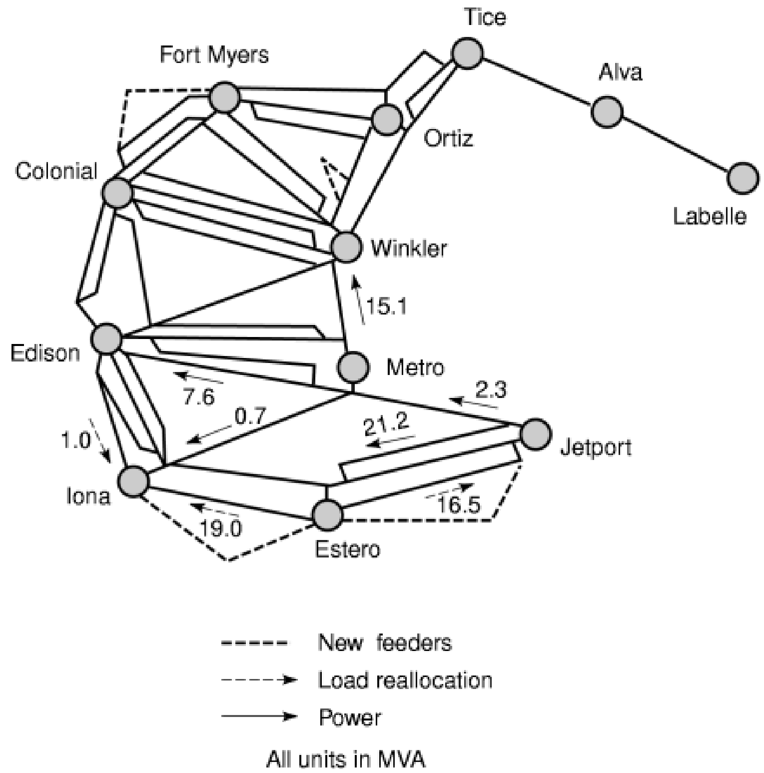

Fig. 5. Sample results obtained by running the multiperiod feeder expansion model. The outcome of the model indicates the new feeders to be installed. The load reallocation and power transfer decisions under single-contingency are also indicated.

ferent feeder combinations Total emergency power limit by substation Limit on the total number of feeders by substation

The mixed 0-1 model is as follows:

$$\begin{aligned} \text{Min:}\quad & \textstyle\sum_t \boldsymbol{c}_{\mathrm{ft}} \boldsymbol{x}_t \\ \text{st.}\quad & A_t \boldsymbol{l}_t + B_t \boldsymbol{p}_t = \boldsymbol{d}_t \\ & \boldsymbol{l}_t + \boldsymbol{p}_t \le M \boldsymbol{x}_t \\ & G(\boldsymbol{x}_1, \ldots, \boldsymbol{x}_t) = 0 \\ & \boldsymbol{x} \in (0, 1), \boldsymbol{l}_t, \boldsymbol{p}_t \ge 0,\ \forall t = 1, \ldots, n \end{aligned}$$

where

$\boldsymbol{x}_t$ = the decision vector for individual connections
$\boldsymbol{c}_{\mathrm{ft}}$ = the present value fixed charge of the connection
A_t = the load assignment matrix
B_t = the single-contingency matrix
$\boldsymbol{l}_t$ = the substation-load decision vector
$\boldsymbol{p}_t$ = the quantity of emergency flow vector
$\boldsymbol{d}_t$ = the load demand/supply vector
M = the capacity of the connection
$G(x_1, \ldots, x_t)$ = represents the constraint set for radiality and correlated feeder installation decisions

Multiperiod Transformer Allocation. When improvements to the distribution feeder network do not resolve load demand needs, the capacity of a substation may be increased by either replacing the existing transformers with units of a higher MVA capacity or adding transformers to the substation (adding transformers to adjacent substations may also resolve the problem). Should that fail, building a substation would be the last alternative.

Essentially, the single-contingency requires that a substation capacity be planned at the transformer level. Hence, when the addition of feeders would not resolve the demand shortfall, transformer procurement must be considered. A multiperiod allocation and procurement of transformers under single contingency can be formulated as a mixed 0-1 LP model that evaluates such procurement alternatives as additions via purchase, relocations from a transformer storage, and relocation within the service network. The optimal mix of transformer (type and quantity) for substations within a service network can then be determined. The model also concurrently determines the reallocation of load (if needed). The model will ensure that all loads in the network be met under single contingency. Since there are quite a few planning issues worth investigating, the model can take on one of the following alternative objective functions:

- Minimization of capacity requirement
- Minimization of procurement cost
- Minimization of opportunity cost and procurement cost

Considerations are as follows:

- Emergency power transfer
- Normal capacity combinations
- Emergency load capacity
- Maximum power supplied
- Availability of transformers
- Maximum number of transformers by substation
- Intertemporal relocation of transformer

$$\begin{array}{ll} \text{Min:} & \sum_t \boldsymbol{c}_{\text{ft}} \boldsymbol{z}_t \\ \text{st.} & A_t \boldsymbol{l}_t + B_t \boldsymbol{p}_t = C\boldsymbol{z}_t + \boldsymbol{d}_t \\ & \boldsymbol{l}_t + \boldsymbol{p}_t \leq M \\ & Q(\boldsymbol{z}_1, \ldots, \boldsymbol{z}_t) = 0 \\ & \boldsymbol{z}_t \in (0, 1), \boldsymbol{l}_t, \boldsymbol{p}_t \geq 0, \forall t = 1, \ldots, n \end{array}$$

where

$\boldsymbol{z}_t$ = the transformer decision vector (purchase, spares, etc.)

C = the capacity matrix of the transformers candidates

$Q(z_1, \ldots, z_t)$ are = logic constraints for correlated transformer procurement decisions

Single-Contingency Planning Scheme. In sum, there are several ways to overcome the capacity shortage. In incremental expenditure, these options are (1) permanent reallocation of excess load, (2) installation of new feeder ties, (3) addition or upgrading of transformers, and (4) construction of new substations. These options are interrelated. Figure 6 is a decision scheme that holistically and systematically tackles these important planning decisions. The scheme systematically utilizes the single contingency capacity model, load reallocation model, multiperiod feeders expansion model, and multiperiod transformer allocation model.

Load Restoration and Balance. Other than models that address the single-contingency situation, there are research works that explore planning situations with fault considerations. Service restoration after a fault, also referred to as emergency service restoration, is concerned with the speedy restoration of the emergency load (deenergized load) when a fault or failure occurs by using the sectionalizing switches. This amounts to a process of switching emergency load to feeders with excess capacity and is not a simple task. Essentially, this means the reconfiguration of the whole network, which is a large-scale combinatorial problem. Further, when load is transferred, operating constraints such as radiality of the system, voltage drop limit, transformer capacity limit, and so on, must be satisfied.

The following is a load restoration algorithm that quickly restores the emergency loads in a distribution system:

- Connect emergency loads in an isolated area to an adjacent feeder (main feeders) by opening sectionalizing switches. If main feeders violate constraints, they are referred to as violation feeders and proceed. Otherwise stop.
- For feeders that have violated constraints, an effective way of transferring load can be performed as follows. Transfer excess loads from violation feeders to other feeders (first-stage support feeders) in descending quantity of $h_j/\alpha_j(H_j + \beta)$, where h_j is the effective length of violation withdrawal, H_j the effective length of remaining violations, α_j the priority of support, and β a constant. Repeat this process until all violations are eliminated or until no more load can be successfully transferred without causing new violations in the first-stage feeders. In the latter case, proceed to the next step (the second stage).

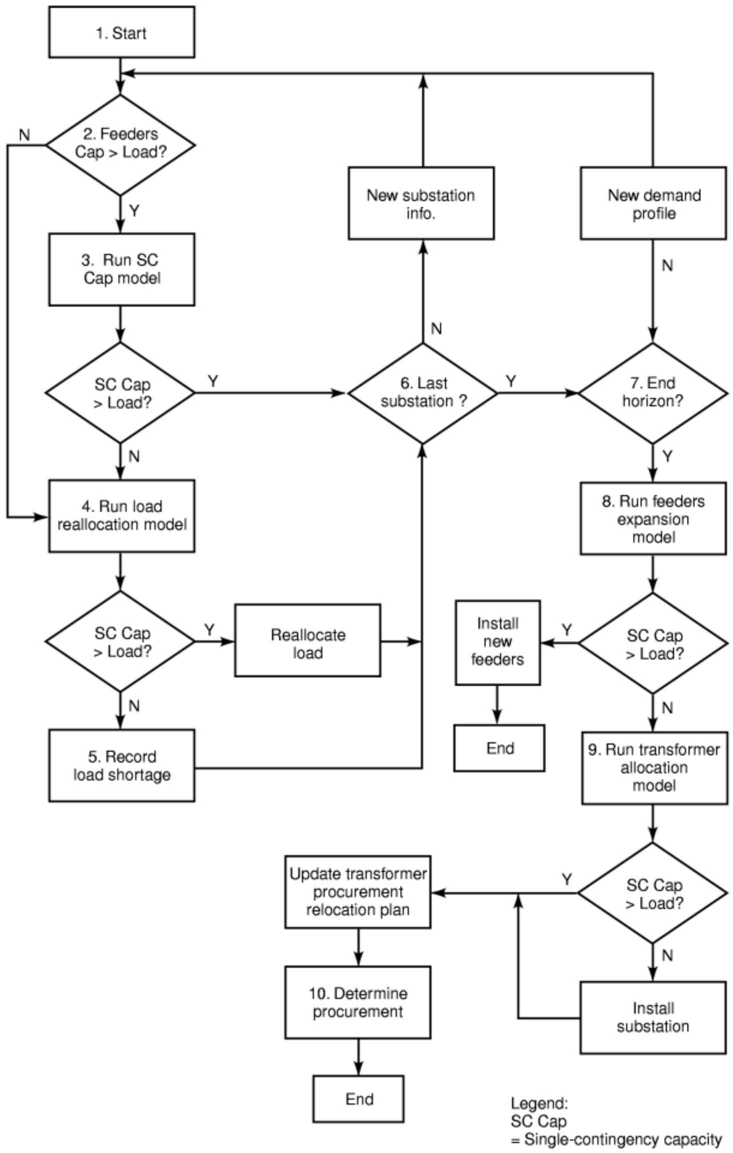

Fig. 6. A single-contingency decision scheme for substation planning. The scheme outlines various options on incremental expenditure basis. The single-contingency capacity model (step 3) is run to find a substation's capacity. The load reallocation model (step 4) reallocates load on permanent basis. The feeder expansion model (step 8) will attempt to solve the capacity shortage problem through feeder expansion while the transformer allocation model (step 9) can be used to overcome the capacity shortage by upgrading/adding transformers.

- In the second stage, a tolerance of violations in the first-stage feeders is first generated as follows. Determine max: $[h_j/\alpha_j(a_j + \beta)]$ for each switch, where a_j is the magnitude of section load that can be transferred via cut switch j. Then, the violations are eliminated by transferring load to the second-stage feeders from the first-stage feeders with which they are connected. Return to preceding step for first-stage support.

Other variants of this algorithm include the following:

- Deciding the open positions of switches in order to achieve load balancing of transformers and feeders while subject to their capacity limits
- Determining rules to balance two transformers at a time systematically until approximate balance is achieved to all transformers
- Determining the open/closed states of the tie and sectionalizing switches to reduce power losses in distribution feeders via feeder reconfiguration

The issue of protective device coordination can be incorporated in a feeder reconfiguration algorithm. The algorithm would first identify a set of switchable regions in which switch operations are allowed. The protective devices may be designed such that proper coordination could be attained during load balancing and load reduction, where switches are assessed per on/off states.

Incorporating faults consideration issues into multiyear distribution planning, the problem can be formulated as a mixed 0-1 LP model. The model may be solved by an algorithm that first decomposes the planning problem into subproblems according to the predetermined fault cases; the subproblems can then be solved using branch exchange. Further improvements would be conducted via iterative use of the branch-exchange method.

Conclusion

Substation capacity and distribution planning is an important as well as a complex endeavor. It provides the map for power delivery to customers in the most cost-effective fashion. It also forms the basis for many logistics activities, such as capital budget requirement, equipment requirement planning, maintenance management, and management of installation activities. The effectiveness of substation capacity and distribution planning depends on both the supply of accurate information and the application of appropriate decision support systems.

In this article, we have provided many modeling approaches as well as frameworks within which power distribution planning can be applied. We believe effective decision support systems can be designed based on these concepts and models. For more detail expositions of the specific approaches, readers are referred to the research papers where these models and concepts first appeared. In that connection, a comprehensive bibliography organized according to the framework of this article is included.

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