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AUTOMATED UTILITY SERVICE AREA ASSESSMENT UNDER EMERGENCY CONDITIONS [1]

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ABSTRACT

All electric utilities serve power to their customers through a variety of functional levels, notably substations. The majority of these components consist of distribution substations operating at lower voltages while a small fraction are transmission substations. There is an associated geographical area that encompasses customers who are served, defined as the service area. Analysis of substation service areas is greatly complicated by several factors: distribution networks are often highly interconnected which allows a multitude of possible switching operations; also, utilities dynamically alter the network topology in order to respond to emergency events. As a result, the service area for a substation can change radically. A utility will generally attempt to minimize the number of customers outaged by switching effected loads to alternate substations. In this manner, all or a portion of a disabled substation's load may be served by one or more adjacent substations. This paper describes a suite of analytical tools developed at Los Alamos National Laboratory (LANL), which address the problem of determining how a utility might respond to such emergency events. The estimated outage areas derived using the tools are overlaid onto other geographical and electrical layers in a geographic information system (GIS) software application. The effects of a power outage on a population, other infrastructures, or other physical features, can be inferred by the proximity of these features to the estimated outage area.

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FEATURES OF THE ELECTRIC DISTRIBUTION SYSTEM

Major components

A typical distribution substation will have one, two or three transformers. In general, transformers serve as connections between higher- and lower-voltage portions of the electrical network. Because single-transformer substations are subject to single contingency failure (the loss of the one transformer causes the loss of the entire substation), utility planners will normally limit their size. When a one-transformer substation approaches 80% to 85% of capacity then planners are likely to add a second identical transformer. The second transformer adds a small amount of additional capacity to the substation, but provides a large increase in substation reliability.

For two- and three-transformer substations, the first contingency outage rule applies. It avoids service interruptions to customers due to the loss of a single facility in the system. In practice, a two-transformer substation is operated to the full emergency rating of the smaller of the two transformers. This corresponds to the substation's loadability rating. Loadability for a three-transformer substation is the combined emergency rating of the two smallest transformers. Normally planners will design the substation so that each of the transformers at a substation has the same capability. Because of the much higher reliability of multi-transformer substations, utility planners can make them much larger than single-transformer substations. Typically, the upper limit on substation capability is the ability to obtain inexpensive and aesthetically acceptable distribution feeder exits out of the substation property.

A distribution feeder is a radial connection (only one source of supply) from the distribution substation to its

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many customers. A small one-transformer substation will typically have from two to four feeders. In larger substations each transformer will serve a distribution bus. Each distribution bus will have from three to six feeders.

Service and outage areas

Distribution systems can be characterized by an associated geographic area that encompasses customers who are served, defined as the service area. Under normal operating conditions, the feeder network is configured to deliver power to customers who are located within tightly meshed corridors, typically along roads or within compact developments such as malls. Distribution feeders cannot extend beyond the physical constraints of acceptable voltages or currents and this feature usually limits the service area boundary. A distinction is often made between "direct" and "total" service area. In the former case, only the geographic area encompassing actual feeder corridors is included. However, in the process of constructing networks along available corridors, many service areas capture unused (and electrically unserved) areas adjacent to the feeder. In some instances, 40 percent or more of the service area is unused but within reach of the feeder to allow for future development. Estimates of direct plus unserved therefore comprise the feeder's total service area. In this paper, the authors are discussing only methods, which estimate total service area.

Two difficulties arise when attempting to estimate service areas for substations with multiple feeders. First, deregulation and the resulting increase in competition for customers in the utility industry have created a more secretive business climate. Utilities are often reluctant to provide important details such as distribution maps, schematic diagrams, and especially descriptive information about their customers' loads. Another difficulty results from the fact that distribution networks are highly interconnected and offer a multitude of possible switching operations. A utility can dynamically alter the network topology in order to maintain service during emergencies. As a result, substation service areas are time-dependant and can change substantially over short periods of time.

Power outages introduce additional complexity. An outage is created by the loss of adequate feeder capacity, usually due to failed lines or transformers. The associated outage area encloses customers who have lost connectivity to the substation source. During outages, a utility will generally attempt to minimize the number of customers without power. This may be achieved through the use of switches and operating procedures that allow customers to be served from alternate substations and feeders which interconnect at transfer points. In this manner, all or a portion of a disabled substation's load may be served by one or more adjacent substations.

THE CELLULAR AUTOMATA METHOD

Los Alamos National Laboratory has previously developed software models and related analysis [1,2,3] to estimate service and outage areas for electric-power substations. Commercial GIS applications have been used in concert with these models to process and render geographic data and areal results. The approach described in this paper uses cellular automata (CA) based algorithms that can be applied to a variety of situations requiring advanced planning under emergency electrical conditions.

Figure 1 highlights the major functions of this analysis in which key processes are labeled A, B, and C. Each process is described next in more detail.

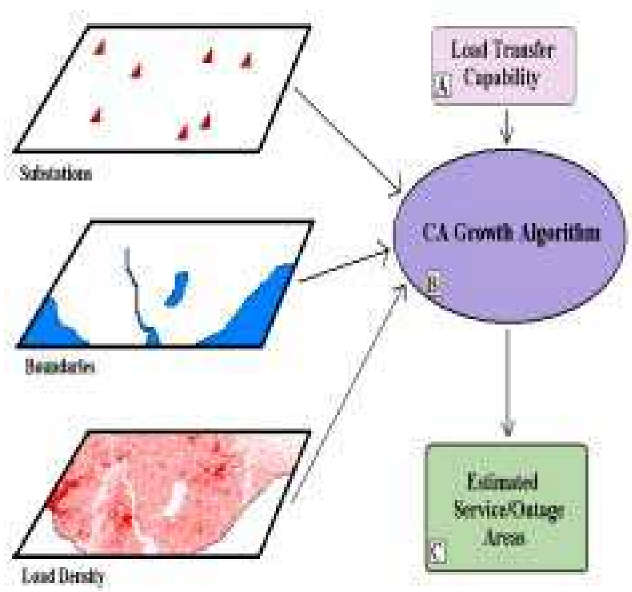

Figure 1. Overview of data sources and processes utilized

A. Load Transfer Capability

This process' function is to estimate the gross characteristics of a distribution network. The resulting network parameters in turn can be used to calculate the capacity of interconnections to adjacent service areas, assuming the loss of the network's associated substation. Due to a considerable degree of generalization, only three inputs are required; they are:

- Substation capacity
- Delivery voltage

- Network service type

The third item is problematic in most analyses. It represents a crude estimate of the embedded feeder topology, based on observations of road networks, population density, and other related data. Assignment of service type classifies distribution networks into one of four categories: downtown, urban, suburban and rural. Because differing load densities and connectivity characterize service types, it is possible to model unique features of the network with acceptable accuracy. Many operating parameters can be estimated on this basis such as delivery voltage, current, and reserve capacity available under abnormal conditions.

Key modeling features are shown graphically in Figure 2.

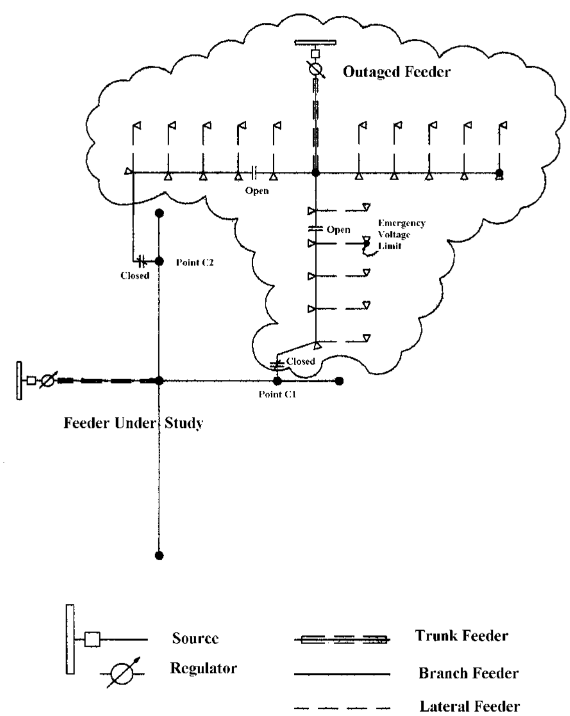

Figure 2. Features of the Load Transfer Capability model.

The source icon represents an electrical interface between adjacent transmission and distribution networks, functionally equivalent to a distribution substation. Exiting each source. is a single feeder element, the trunk feeder, which connects to three branch feeder elements. Each branch serves additional feeder elements, the lateral feeders, which in turn connect directly to end-users. While typical of many systems, this topology is only conceptual. The Load Transfer Capability model will frequently estimate different branch/trunk or lateral/branch ratios, depending on values input by the user, in order to approximate the number of feeder elements actually in operation.

An adjacent outaged feeder is also highlighted in Figure 2. Sections adjacent to the source are assumed to be de-energized due to the loss of source. Transfer points are schematically shown, which connect an energized feeder with the outaged branch elements.

B. Cellular Automata Growth

The CA-based approach uses geographic data in a lattice or grid format where each cell can contain a numeric value. The geographic grid layers include barriers or boundaries, such as lakes and mountains, and load density. The load density grid is a composite of residential,
commercial, and industrial load data, each with a known, aggregated or estimated geographic component. Substation properties including geographic location, and load transfer capacity are considered by the CA growth algorithm. The algorithm uses these input data to enable substations to claim cells in the grid and simulate power delivery to customers in assigned areas. Each claimed cell is aggregated with the corresponding substation's pool of claimed cells. The growth algorithm abides by boundaries and enables substations to claims cells and their accompanying load density as long as the total accumulated load for the substation does not exceed its transformer capacity. However, not all of the growth algorithms use the load density grid to limit substation growth by capacity.

Several variations of the CA based algorithm have been developed to explore the effects produced by using differing growth rule sets. These are:

- Equal Area
- Weighted Growth by Capacity
- Weighted, Limited Growth by Capacity

Cellular growth rate is a critical variable in the algorithm. Algorithms exist that allow substations to claim cells at an equivalent rate or at varying rates based on substation capacity. The Equal Area algorithm implements the non-advantaged approach, so that each substation accumulates cells at an equivalent rate. The Weighted Growth by Capacity approach allows substations with larger capacity to claim cells at an accelerated rate. Similarly, the Weighted, Limited Growth by Capacity algorithm allows larger load-bearing substations to claim cells at a faster rate, but also limits each substation's accumulation of load by its capacity.

Through development and calibration efforts, the algorithms can be enhanced and refined to produce more accurate estimates when compared with actual utility data collected during emergency conditions.

C. Service/Outage Areas

In this process, the estimated service and outage areas are derived using the CA based algorithm. The resulting areal features are polygons with a one-to-one correspondence to load-bearing substations. In some cases, a utility engineer may provide details on known substation service areas. These details can be incorporated into the boundary data source to enable the growth algorithm to limit and shape cellular growth patterns for specified adjacent substations. More generally, by using a variety of predefined grid cell values coupled with the implementation of algorithmic logic, additional information on how substations acquire area and load can be included in this methodology.

The CA algorithm outputs estimated areas in a grid format. Commercial GIS tools are used to convert from grid to vector formats. The vector format represents geographic data using a Cartesian coordinate system, so that point features have x and y coordinates, line features are comprised of a series of x and y values, and polygons are comprised of a series of x and y values that begin and end at the same point to form an areal feature. The specific vector format for these estimated areas is a polygon feature.

SAMPLE RESULTS

Figure 3 displays the estimated service areas for a cluster of adjacent substations and the estimated outage area resulting from the loss of one substation (labeled as the Event sub). Two adjacent substations (labeled as Transfer subs 1 and 2) are capable of serving only a fraction of the load associated with the event substation's normal service area. The substation icons portray distribution substations, with each icon scaled in size by its load value. Larger icons correspond to larger values of load being served.

A bold line encircles the event substation and represents its pre-outage service area. The shaded areas encroaching into the service area boundary indicate areas where loads normally served by the event substation have been transferred to one of the two adjacent substations. In this example, adequate transfer capacity exists to re-energize 33% of the customer load that would otherwise be lost without transfers. The white area shown within the bold boundary indicates areas, which are likely to be left unserved following transfer switching. The lighter-shaded region represents water which functions as a boundary that limits CA growth.

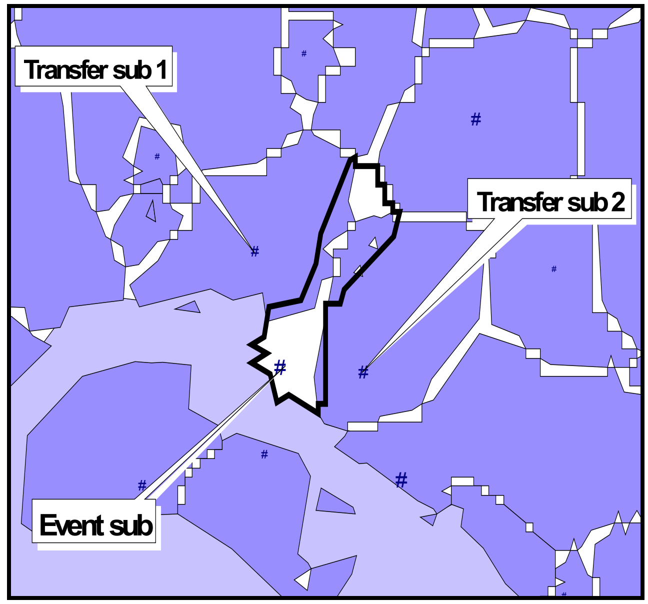

Figure 3. Estimated outage area during emergency event

The underlying load grid is comprised of 500-foot square cells. Between each service area polygon, Figure 3 displays a series of border cells, which are unserved; this result is an artifact of the CA algorithm, which is designed to isolate those cells claimed by more than one substation.

POSSIBLE APPLICATIONS OF THE TOOL SUITE

The ability to quickly estimate utility service and outage areas, especially in terms of multiple event scenarios, suggests a variety of potential uses for the tool suite being described. An application of particular interest was suggested to the authors by an operating utility in the southeastern U.S. and is discussed briefly below.

The host utility serves nearly 500,000 electric customers in a 16,000-square-mile service area. It has been historically vulnerable to severe system damage from hurricanes. Following such damage, its ability to restore service to outaged customers has been limited by the availability of line crews, both internal and external to its system. This problem can be addressed, in large measure, by combining the CA tool suite with a wind damage assessment model. Such results provide a basis for informed management decisions related to allocating crews in the event actual damage occurs. Ultimately, the utility's goal is to significantly shorten customer outage durations and also to minimize crew costs through more efficient allocations.

A wind damage assessment model would be created for the host utility. It includes a variety of factors such as engineering standards used in system design, materials specifications and the subsequent failure of conductors, buswork and supporting poles or towers under a range of varying wind conditions. Further calibration would require damage data from a recent storm, which significantly impacted the utility's service area such as Hurricane Floyd (1999).

In actual use, a variety of possible storm tracks and wind contour scenarios would serve as input to the wind damage assessment model. Features of the embedded distribution network would be estimated and service areas identified graphically. Then, a time-sequenced cluster of substation outages would be simulated as the storm track moves through the utility system. Using Monte-Carlo simulations, a range of outage areas would be determined. The authors estimate that it is possible to achieve a 60-70% accuracy of prediction of total service area interruptions (as measured by pole-miles and/or load impacted).

References

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Biography

G. LOREN TOOLE serves as a Team Leader in the Infrastructure Assurance Program for Los Alamos National Laboratory, Los Alamos, NM. Mr. Toole received his B.S. and M.S.(Power Systems) degrees in Electrical Engineering from Georgia Tech. His industrial experience includes over 20 years in the promotion of utility-related projects. His technical interests include electric distribution planning and demand/supply integration.

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