NATIONAL INSTITUTE OF BUILDING SCIENCES

EARTHQUAKE LOSS ESTIMATION METHODS

TECHNICAL MANUAL

ELECTRIC POWER UTILITIES

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Note. This report was updated with minor editorial comments in August, 2004. The IGIS software referred herein was re-named HAZUS in 1994.

8.1 Electric Power Systems

8.1.1 Introduction

Electric power system lifelines play a vital role in modern society. Modern urban areas in the United States cannot function very well, or for very long, without electric power from the electric system lifeline.

Experience in past earthquakes has shown that electric systems include a number of important components that are vulnerable to damage or malfunction under under earthquake loadings: damage occurs, and power outages result. Experience has also shown that electric utilities often have tremendous repair capabilities, and portions of the systems can be highly interconnected and redundant. So, even if earthquake damage occurs, often the electric utility can restore electric power to customers within hours, or sometimes days.

Loss of electric power leads to a variety of losses:

1. Direct losses. These include the costs to repair the parts of the electric system that have been damaged in the earthquake.

2. Loss of electric service to other lifelines. After an earthquake, loss of electric power can adversely affect other lifelines that are dependent upon electric power. For example, lifelines that are particularly dependent upon electric power include:

    - Water Systems. Pumping plants and wells. Loss of power leads to loss of water service.

    - Light Rail. Electric trains. Loss of power leads to loss of service.

3. Economic losses. Most types of businesses cannot operate without electricity. This can lead to potentially large economic losses to the local economy.

For these reasons, a loss estimation study should consider the earthquake performance of the electric system.

8.1.1.1 Terminology Used in This Report

Although this report is not meant to be a primer on electric systems, there are certain terms that are used in the electric system methodology which need to be defined. These definitions are but a means to an end - the removal of a barrier to an accurate exchange of thought and expression.

<u>AC</u>. Alternating current.

<u>Circuit</u>. Alternating current (AC) circuits operate with three phases of electricity. This is why one typically sees three different conductors (or multiples of three) on transmission towers.

<u>Circuit Breaker</u>. A circuit breaker is a device which can close and open electrical circuits between separable contacts under load and fault conditions. The separating medium can be oil, air, gas or a vacuum. Circuit breakers are either "dead tank" (maintained at ground potential) or "live tank" (maintained at line potential and mounted high on an insulating

porcelain column). Operating mechanisms can be solenoids, motors, pneumohydraulic or pneumatic devices, motor or manually charged springs, or manual.

Conductor. A cable used in transmission lines.

Control Facilities. Control facilities include computer-assisted control centers, repair and maintenance facilities, and communication systems.

DC. Direct current.

Distribution Systems. Distribution systems include poles, pole-mounted transformers, and above ground as well as underground conductors.

kV. Thousands of volts.

Pdf. Probability density function.

Switching Substations. Switching substations (switchyards) provide circuit protection and system switching flexibility. They have switching and controlling equipment.

Transformer. A transformer is an apparatus for converting electric power in an AC system at one voltage or current into electric power at some other voltage or current without the use of rotating parts. As used in this report, transformers are sub-classified as follows:

- 500 kV or greater: very high voltage (bulk power transmission). As used in this report, 500 kV means 500 kV or greater. In California, the typical very high voltage rating is 500 kV. Outside California, even higher voltage equipment is in use (for example, 735 kV).

- 165 - 350 kV high voltage (bulk power transmission). As used in this report, 230 kV means 165 kV to 350 kV. In California, most high voltage equipment is in the 220 kV to 230 kV range. Outside California, other voltage is used (for example, 315 kV).

- 33 - 165 kV moderately high voltage (sub transmission). As used in this report, 115 kV means 33 kV to 165 kV.

- Less than 33 kV - low voltage (distribution).

A certain amount of electrical energy delivered to a transformer is transformed into heat energy, as for example due to the resistance of its windings. One of several means are provided to remove this heat:

- Self-air-cooled. Only used in transformers of very small capacity (distribution systems up to 15 kV). Also called dry-type transformers.

- Air-blast-cooled. Only used in transformers of small capacity (distribution systems, up to 35 kV).

- Liquid-immersed self-cooled. The common liquid employed is oil. Small to large sized applications. Smaller units often used in distribution pole-mounted application. Larger units have radiators.

- Liquid-immersed air-blast-cooled. Used in large applications. Many high voltage switchyard transformers are of this type. Motor-driven blowers are mounted integrally with the tank, and serve to supplement natural air convection to remove heat from the radiators.

- Gas-vapor. Sometimes used in large applications. A vaporizable liquid provides insulation and cooling during operation. Pumps are used to move the liquid through the transformer.

To step electricity to different voltage levels, either three single-phase transformers can be used, or a single three-phase transformer can be used.

- A three-phase transformer is a single piece of equipment. Damage to any part of it will cause loss of function of that circuit. A damaged three-phase transformer can be bypassed if another suitably-sized three-phase transformer (or three single-phase transformers) are available.

- A single-phase transformer is a single piece of equipment. Three single-phase transformers are needed to make a circuit. Damage to a single single-phase transformer out of the three single-phase transformers will cause loss of function of that circuit. A damaged single-phase transformer can be bypassed if another suitably-sized single-phase transformer is available.

Transmission Substations. Transmission substations reduce transmission voltage to sub-transmission voltage. They have large transformers and controlling equipment.

Transmission Lines. Transmission lines include towers and poles, insulators, conductors, and ground wires and underground cables.

8.1.2 Scope

8.1.2.1 Form of Damage Estimates

The "Level 2" loss estimation model for electric systems provides six damage estimates with the following information:

1. What hardware subcomponents (such as a transformer) of the electric system will be damaged?

2. Will damage to the hardware subcomponents cause functional failures of entire electric system stations (such as a switchyard)?

3. If system substations are damaged, will the electric utility be able to restore electricity in a short time?

4. How many customers will lose electric power after the earthquake, and where are they located?

5. How long will it take the utility to restore power to customers?

6. What will be the repair costs to fix the electric system damage?

8.1.2.2 Loss Estimation Levels

The methodology is geared towards a "Level 2" loss estimation. This means that the user will input to the model a limited description of the electric system(s) that serve the study area. The model, in turn, makes a number of inferred assumptions about the electric system.

The methodology used is a simplified version of the methods used by electric utilities to perform detailed studies of their own electric systems. Electric utility owners could use the "Level 2" methodology to get a first-order estimate of how their electric systems perform. Section 8.1.9 provides additional information as to how to expand the Level 2 methodology to perform more detailed investigations at a "Level 3" level of sophistication.

Depending upon the needs of the loss estimation exercise, the user may decide to perform a simpler electric system loss estimation effort than that described in the Level 2 approach. We have provided a "Level 1" methodology in the following section.

8.1.2.2.1 Level 1 Methodology

The Level 1 methodology is performed as follows:

1. Calculate the Peak Ground Acceleration, PGA, at each subdivision in the study area. (The subdivision will often be a zip code or census tract).

2. The probability of loss of offsite electric power is described by a damage algorithm with median PGA = 0.3g, and β of 0.5. Assuming a lognormal distribution for the fragility curve, we calculate:

   For example at a site with PGA = 0.25g:

   x = number of lognormal standard deviations below the median

   $$x = \frac{-\log_e\left(\frac{\text{Site PGA}}{A_{median}}\right)}{\beta} = 0.3646432 \qquad \text{[eq. 8.1-1]}$$

   Now integrate the normal distribution function from 0.3646432 standard deviations below the median:

   t = 1 / (1 + .2316419 * x) = 0.9221123

   $$d = 0.3989423 * \exp\left(-\frac{x^2}{2}\right) = .3732821$$

   p = 1.0 - d * t * ((((1.330274*t - 1.821256)*t + 1.781478)*t - 0.3565638)*t + 0.3193815) = .6423112 = area of pdf to the right of 0.3646432 standard deviations below the median.

   p = 64.23112 % = probability of no loss of power

   P_f (PGA = 0.25) = 1 - p = 35.76888%

or about a 36% chance of losing offsite power.

3. Sum up the probability of loss of power in each subdivision times the population in that subdivision. This is the total number of people out of power immediately after the earthquake.

4. Calculate the time to restore electric power to all customers.

    - Near field Magnitude 6 earthquake. Assume all customers have service restored in 1 day.

    - Near field Magnitude 7 earthquake. Assume all customers have service restored in 3 days.

    - Near field Magnitude 8 earthquake. Assume all customers have service restored in 10 days.

This methodology is based on judgement, and Section 8.1.6.3 of this report describes the damage algorithm. The approach will provide some information to the end user as to the locality of electric power outages, but no information as to the reasons for the loss of power and no estimates of direct physical loss.

The Level 1 analysis completely ignores the physical design of the local electric power system. Further, it describes power outages as a function of PGA at the location of the user of electricity, not at the location where electricity is produced or switched. Further, the Level 1 analysis ignores power outages due to non-hardware related reasons, such as human intervention shutdown of the electric system while gas leaks are being assessed.

For these reasons, the Level 1 methodology must be considered as only a crude approximation of what happens to electric systems after earthquakes, and may be grossly inaccurate. The Level 1 electric loss estimation methodology is a rule-based method. The rules are based on generalized observations of how electric systems have performed in past earthquakes, and take no consideration into account of how the local electric system works.

The Level 1 methodology should not be considered accurate for any particular locality. This report provides no backup justification for the Level 1 methodology.

8.1.2.2.2 Level 2 Methodology

This report is geared towards the Level 2 methodology for loss estimation for electric power utilities. The Level 2 methodology is a simplified version of the methods that can be used by electric utilities to perform detailed studies of their own electric systems.

8.1.2.2.3 Level 3 Methodology

The Level 2 methodology presented herein makes a number of simplifying assumptions. A Level 3 methodology will require additional refinement, and specialized expertise not assumed available in the performance of a regional loss estimation effort. Section 8.1.9 of the report provides the user with additional information as to how to perform a more detailed investigation at a "Level 3" level of sophistication.

8.1.3 Input Requirements

The first step in performing the electric system loss estimate is to input and locate the key parts of the electric generation and transmission systems. The Level 2 methodology uses defaults to describe the electric distribution system.

The following sections describe what input is required, and provides default data when information is not available.

8.1.3.1 Study Area

The study area is the area where the loss estimation study is being performed. The study area could represent a city, a county, a group of counties, or even multiple states, as appropriate.

In most electric systems, key parts of the system are located some distance away from the immediate area of concern in the loss estimation process. For example, Figure 8.1-1 shows that two generation facilities and two substations are outside the study area. The methodology assumes that all such parts of the electric system outside the study area are undamaged in the earthquake.

Therefore, the user must consider how big to make the study when performing the loss estimation, such that all vital parts of the electric system are included. Usually, the study area should be set to be an area that will encompass all inhabited areas with ground shaking projected to be 0.05 g or higher.

The study area should also include uninhabited areas if ground shaking exceeds 0.05 g, or if there are expected to be PGDs, if these uninhabited areas include critical parts of the electric system.

Parts of the electric system that do not need to be not explicitly located in the Level 2 methodology include:

1. Moderate voltage substations (33 kV - 100 kV). These have generally performed well in past earthquakes, and their contribution to overall system vulnerability is considered negligible. The user does not need to digitize the locations of these substations in the study area. (Note: this hypothesis is generally based on past experience of seismicially designed substations in past earthquakes. This assumption may not be completely valid for substations with unachored equipment subjected to strong ground motions).

2. Distribution circuits. Most distribution circuits have performed well in past earthquakes. However, since there are so many distribution circuits in every electric system (they extend to every customer in the system), and since occasional damage does occur, we include a method to account for distribution circuits in the Level 2 methodology. The user has some ability to override the defaults provided, but does not need to digitize the locations of these circuits in the study area.

3. High voltage (over 66 kV) transmission towers. These have generally performed well in past earthquakes, and their contribution to overall system vulnerability is considered negligible. However, the user should be aware that

some of these towers can fail, especially if they are located in landslide zones. It is considered beyond the level of detail required in a Level 2 analysis to locate all transmission towers, or to locate all landslide zones where these towers are located. This level of detail is left to a Level 3 analysis. Thus, the user does not need to digitize the locations of transmission towers in the study area.

8.1.3.1.1 Service Areas and Cells

The study area will be subdivided into smaller cells. Figure 8.1-1 shows a schematic view of these cells. For convenience, these cells are shown as a regular grid in Figure 8.1-1. In general, the cells can be any arbitrary polygon shape, and can represent zip codes or census tracts, for example.

The user will need to geo-code into the map the location of generation facilities and high voltage substations. The accuracy needed in locating these facilities is not particularly high, as long as the facility is not incorrectly placed into a soil zone that it is not actually in. The user should also be careful not to incorrectly geo-code a facility into or outside of a liquefaction or landslide zone.

The Level 2 methodology examines power outages by service areas. A service area is defined as the area served by a particular high voltage substation. Figure 8.1-1 shows these service areas delineated by thick black lines. For example, Substation 4 serves cells D-10, 11, 12; E-10, 11, 12; F-10, 11, 12; G-10, 11, 12; H-11, 12; I-11, 12; and J-11, 12.

If the user does not have access to the actual service area boundaries, a reasonable assumption is that each substation (115 kV or higher) serves a services area defined by mid-distances to the next substation.

Ideally, the cells should be shaped such that the union of a number of cells matches exactly the actual service area supported by a particular substation. In practice, if a service area actually splits two cells, there will not be significant error introduced if a reasonably weighted percentage of the complete cell is attributed completely to each substation.

A Level 3 refinement would be to digitize the cells to match the service area boundaries exactly.

Another Level 3 refinement would be to allow tracking the potential for power outages for a particular customer (such as a critical facility) which has a multiple transmission lines to two or more independent substations. Often, critical facilities such as Emergency Operations Centers, Wastewater treatment plants and the like will pay the extra cost to have this type of redundant power supply. It is suggested that owners of these critical facilities investigate this level of refinement in a Level 3 analysis.

8.1.3.2 Generating Facilities

The user must locate the power generation facilities in the study area. Figure 8.1-1 shows a schematic representation of the study area, and we will use the notation in this figure for discussion purposes.

Each generating facility is geo-coded. Geo-coding means that the generation facility is located using a map-based description of where the facility is located. Many U.S. maps are made where location is based upon longitude (usually reported positively west from 0 degrees), and latitude. Many areas of the country base their maps on different type of projections, such as eastings and northings coordinates. The IGIS (eventually re-named HAZUS) software will allow the user to enter the location of the generating facility (or any other facility) using either latitude / longitude combinations, or eastings / northings combinations. Alternately, the IGIS software will allow the user to click on a base map at the location of the facility, and the computer will internally calculate the coordinates in suitable geo-coding system.

The attributes that the user will enter for each generating facility are as follows:

1. Location (as described above)

2. Number of Units. Many power plants have multiple units (i.e., multiple separate power plants). This information is optional, but is useful for determining loss of generation capacity. The default is to assume that there is one power plant at the site.

3. Size in MWe. This is the number of Megawatts (electric) that the power plant can produce, under normal operations. The size of each unit should be provided. Alternately, if the user does not wish to examine each power plant unit, the size in MWe of the entire power plant (all units) can be input.

4. Type. The type of power plant should be described. This should be one of the following:

   - Oil fired
   - Gas fired
   - Oil / gas fired
   - Coal fired
   - Hydroelectric
   - Geothermal
   - Solar
   - Nuclear
   - Wind
   - Diesel
   - Combined Turbine / Combined Cycle
   - Gas Turbine (peak)

   The IGIS software provides default algorithms for oil, gas, and combined oil/gas power plants. The user will have to perform Level 3 analysis to consider the other types of power plants.

Based on the information provided above, default equipment lists for each power plant are set. The value of equipment is set as a function of the size of the power plant: the higher the MWe, the larger the power plant, and the more equipment involved. Table 8.1-3 provide the default values for various types of power plants. The user may override the default values with known values for each power plant.

The default equipment list for each power plant is provided in Table 8.1-4. Instead of specifying the actual number of components in a power plant, the methodology bases damage on the amount of equipment, which is set on the value of the equipment. Therefore, the percentages in Table 8.1-4 represent the percentage value of the particular type of component as a fraction of the total plant value.

Each type of equipment at a power plant is further subdivided into possible types (seismic designs). For example, a diesel generator could be either well anchored, moderately anchored (snubbed), or poorly anchored (simple vibration isolation only). Each type of equipment has its own fragility curve.

For a Level 2 analysis, it is assumed that the end user will not perform a site inspection to confirm the actual inventory of equipment in the plant, nor the style of equipment anchorages. Performing a site inventory is a critical step in a complete Level 3 seismic vulnerability analysis, the Level 2 methodology uses default equipment lists for the purposes of a regional loss estimation study.

Table 8.1-5 provides a default list of equipment and cross reference to fragility curve numbers for a typical power plant. This table provides a detailed breakdown of the default types of equipment, and how these types of equipment may vary in different parts of the country. Default data for the percentage of equipment with anchorage is based on a field inspection of naval facilities {2}.

Some discussion of how different parts of the country are differentiated follows:

- We have provided a distinction of zones of the country based upon the usual maps provided in the Uniform Building Code, namely Zones 0, 1, 2, 3, and 4. Zone 0 has no seismic provisions, such as Florida. Zone 4 has the highest seismic provisions, such as the San Francisco Bay Area.

- We have not subdivided the country in Zones 2A (lower seismic provisions) and 2B (higher seismic provisions). We suggest that if the end user is located in a seismic Zone 2B, that the user opt to use the less rugged default inventory list associated with Zone 2, as it is likely that the existing infrastructure was built prior to the adoption of Zones 2A and 2B.

- An alternate method to subdivide the country as to seismic zones is suggested by NEHRP [[1]]. The NEHRP provisions break the country into 7 seismic zones:

    - Map Area 1. Coefficient $A_a = 0.05g$
    - Map Area 2. Coefficient $A_a = 0.05g$
    - Map Area 3. Coefficient $A_a = 0.10g$
    - Map Area 4. Coefficient $A_a = 0.15g$
    - Map Area 5. Coefficient $A_a = 0.20g$
    - Map Area 6. Coefficient $A_a = 0.30g$
    - Map Area 7. Coefficient $A_a = 0.40g$

  We use the older Zone definitions instead of the NEHRP definitions, reflecting that Zone definitions have been in use for a longer time. In the future, as the NEHRP provisions gain wider use, this will change.

  The default inventory equipment list is split into two groups for the following reasons.

    1. First, we feel that electric utilities in Zones 3 and 4 have probably installed much of their equipment with some level of seismic design, whereas electric utilities in Zones 0, 1 and 2 have probably not installed most of their equipment with as much attention to seismic design.

2. Arguably, the default inventory list could be further subdivided into 5 groups (Zones 0, 1, 2, 3 and 4) or even 7 groups (Map areas 1, 2, 3, 4, 5, 6 and 7). Given the large uncertainties in preparing default inventory lists, we do not believe that such a distinction would provide a particularly better loss estimation result.

We strongly encourage the person performing the loss estimation effort to contact the local electric utility to determine what level of seismic design has been commonly used. The user should be aware that the most current seismic design provisions may not accurately describe much of the installed infrastructure, as that infrastructure may date back decades. In any case, the user will have the ability to over-ride the default equipment lists in Table 8.1-5 to reflect the conditions that most closely represents the study area being studied.

8.1.3.3 Substations

The user will locate the very high voltage, high voltage and moderately high voltage (500 kV, 230 kV and 115 kV, respectively) substations in the study area. For a large study area with 5,000,000 people, there could be between 0 and 5 500 kV substations, 10 to 20 230 kV substations, and 20 to 40 115 kV substations.

In Zone 3 and 4 parts of the country, it is probably not necessary to include substations below 100 kV in the loss estimation study, as these substations have generally performed satisfactorily in past earthquakes. This may not be true outside of Zone 3 and 4 parts of the country subjected to strong ground motions, where lower voltage equipment may not be seismically designed.

Each substation is geo-coded. The attributes that the user will provide for each substation are as follows:

1. Location. The location does not have to be highly accurate (plus or minus a few hundred feet) as long the variability of accuracy does not incorrectly place the substation into a different geologic unit (soil versus rock) or improperly into or out of ground failure areas (liquefaction zone, landslide zone or surface faulting zone).

2. Voltage class. Some substations include multiple voltage classes. Each voltage class equipment is called a "yard". The substation as a whole is classified by the highest voltage equipment. Thus, a 500 kV substation may include 500 kV, 230 kV and 115 kV yards.

   The user inputs whether the substation has various voltage class yards, as follows:

   500 kV Substation

   - 500 kV: Options = Yes. Default = Yes.
   - 230 kV: Options = Yes, No. Default = Yes.
   - 115 kV: Options = Yes, No. Default = Yes.

   230 kV Substation

   - 500 kV: Options = No. Default = No.

- 230 kV: Options = Yes. Default = Yes.
- 115 kV: Options = Yes, No. Default = Yes.

115 kV Substation

- 500 kV: Options = No. Default = No.
- 230 kV: Options = No. Default = No.
- 115 kV: Options = Yes. Default = Yes.

3. Number of transformers. The size of a substation can be expressed as a function of the number of transformers in each voltage class at the substation. For AC power, the minimum number of transformers is 3 single-phase or 1 three-phase transformer.

   The number and voltage class of transformers (including spares), and style (single phase or three phase) is information that can be gotten from the electric power utility, by site inspection, by inference, or assumed by default. If such detail is unavailable from the electric utility, then the user can infer the number using the following guidelines:

   - Determine the number of transmission circuits entering and leaving the substation for each voltage class. An AC transmission circuit has three conductors each. Most transmission towers carry either one or two circuits. A transmission tower with 6 conductors, grouped in 3 pairs of 2 conductors, with each pair of conductors a few inches apart, is a single circuit.

     A drive-by inspection of the substation may be sufficient to count the number of circuits entering the substation. Very high voltage (500 kV+) circuits can be inferred for circuits having the longest porcelain insulators and widest separation distances between conductors. High voltage (230 kV) circuits have porcelain insulators about half the length of those for 500 kV circuits. Moderately high voltage (115 kV) circuits have porcelain circuits about half the length of 230 kV circuits.

     Alternately, some maps (such as U.S.G.S. 7.5 degree quads) will often show transmission towers and lines leading into larger substations. However, the number of circuits on each transmission tower is not usually shown. The user can easily field verify the number of circuits supported on each transmission tower.

   - The inferred number of single phase transformers for each voltage class can be estimated as follows:

     $TT = \frac{N}{2}$, rounded up to the nearest integer

     where

     N = number of circuits of each voltage class entering the substation.

     $T_{500} = (TT * 3) + 1$

This formula assumes there is one spare transformer per substation, independent of the number of circuits.

where

T_{500} = number of single phase transformers

- For example, assume that a large substation is found to have two 500 kV, eight 230 kV and twelve 115 kV circuits entering the substation. Then the inferred number of transformers is as follows:

  500 kV Class

  $TT = \frac{2}{2} = 1.0.$

  $T_{500} = (1 * 3) + 1 = 4$ 500 kV single phase transformers.

  230 kV Class

  $TT = \frac{8}{2} = 4.$ $T_{230} = (4 * 3) + 1 = 13$ 230 kV single phase transformers.

  115 kV Class

  $TT = \frac{12}{2} = 6.$ $T_{115} = (6 * 3) + 1 = 19$ 115 kV single phase transformers.

- For example, assume that a small 230 kV substation is found to have 2 230 kV circuits. then the inferred number of transformers is as follows:

  230 kV Class

  $TT = \frac{2}{2} = 1.$ $T_{230} = (1 * 3) + 1 = 4$ 230 kV transformers.

4. Number of circuit breakers. The number of circuit breakers is a function of the number of transformers and substation design practices. The user can obtain the exact number (and type) from the electric utility. Alternately, the number (and type) of circuit breakers can be inferred as follows.

   - Assume a "breaker and a half" configuration.

   - CB = T * 1.5 (rounded up to the nearest integer). [eq. 8.1-3]

5. Number of disconnect switches. The number of disconnect switches is a function of the number of substation design practices. The user can obtain the exact number from the electric utility. Alternately, the number of disconnect switches can be inferred as follows.

   - DS = CB * 2.0 [eq. 8.1-4]

6. Number of lightning arrestors.

   - LA = T (one per transformer) [eq. 8.1-5]

7. Number of current transformers.

   - CT = TT [eq. 8.1-6]

8. Number of wave traps (harmonic filters).

   - WT = 2 * TT_{500} (two per 500 kV circuit) [eq. 8.1-7]
   - WT = TT_{230} (one per 230 kV circuit) [eq. 8.1-8]
   - WT = TT_{115} (one per 115 kV circuit) [eq. 8.1-9]

9. Number of CVTS / CCVTs.

   - CCVT = N (one per circuit) (times 3 if counting by phase)

10. Control building. Most substations will include a control building. The control building includes a variety of electrical control and communication equipment. In large urban downtown areas, some control buildings will also house the large yard equipment, like transformers and circuit breakers.

    For a Level 2 loss estimation effort, it is assumed that collapse or heavy damage of the control building will put the substation out of service after the earthquake. If the control building houses only control and communication equipment, then the forced outage of the substation will be modest (about a day to three days to re-establish control with spare equipment). If the control building houses large yard equipment, then the forced outage of the substation will be long (perhaps weeks to restore electric service to the affected area). The default assumption for Level 2 loss estimation is that control buildings do not house large yard equipment. The user should perform a Level 3 loss estimation if large substations are contained within control buildings which are vulnerable to heavy damage or collapse in earthquakes.

11. Other Yard Equipment. Substation yards include a number of other pieces of equipment important for normal function.

    For purposes of a Level 2 lost estimation study, it is assumed that other yard equipment represents about 11% of the entire value of the substation. The damage loss ratio of this equipment is assumed equal to the damage loss ratio of the other components of the substation. It is further assumed that any damage to this equipment will be repaired within the same amount of time as other equipment, and thus will not control the forced outage time for the substation.

8.1.3.3.1 Seismic Design Considerations

Some types of substation equipment are vulnerable to earthquake damage even if they have been designed for earthquake loads. For example, in California Zone 4, the modest seismic design provisions in place prior to 1971 were insufficient to prevent heavy damage to the Sylmar Converter Station in the 1971 San Fernando earthquake.

Lessons learned from the 1971 San Fernando earthquake led to more rigorous seismic designs for new substations. Still, the 500 kV yard at the newly designed Devers substation suffered extensive damage in the 1986 Palm Springs earthquake. The 1994 Northridge earthquake again damaged the Sylmar Converter Station, but not nearly as severely as in the 1971 San Fernando earthquake.

With this in mind, one can make the following observations as to the state of the art in seismic design of substations, as of 1994:

- New seismic designs for 115 kV and 230 kV equipment should result in equipment that is reasonably rugged in strong ground shaking (up to about 0.5g), although occasional problems will still arise. New designs include the proper anchorage of all equipment, and the use of "dead tank" circuit breakers rather than "live tank" circuit breakers.

- New seismic designs for 500 kV equipment should result in equipment that is reasonably rugged in strong ground shaking (up to about 0.25g), although occasional problems will still arise. New designs include the proper anchorage of all equipment, and the use of "dead tank" circuit breakers rather than "live tank" circuit breakers. The industry is still developing reliable methods to design 500 kV equipment for very strong ground shaking (above 0.5g).

8.1.3.3.2 Substation Value and Default Component Inventory

The value of a substation can be specified by the user. Alternately, the following default can be used. The default value represents all station components based on the number of equivalent single phase transformer):

$$\text{Value} = (\$3{,}000{,}000 * T_{500}) + (\$2{,}000{,}000 * T_{230}) + (\$1{,}000{,}000 * T_{115}) \qquad \text{[eq. 8.1-11]}$$

If the switchyard has no transformers (switching only), the default substation value can be determined using the same calculation methodology as if there were transformers, and then multiplying the total value by 0.5.

Once the total value of the substation is determined, the breakdown of value by component can be inferred using Table 8.1-6 or supplied by the user.

The breakdown of equipment type by design practice can be input by the user, or inferred using default values in Tables 8.1-7, 8.1-8 and 8.1-9. The default percentage of substation transformers that are assumed unanchored is based upon field inspection of naval facilities [[2]].

8.1.3.4 Distribution Systems

Detailed loss estimation of electric distribution systems are generally outside the scope of a Level 2 loss study. Past loss estimation work by electric power utilities themselves focus on the transmission system rather than the distribution system, for the following reasons:

- Damage to high voltage transmission components (such as transformers) can lead to widespread power outages, possibly with long lead times necessary to fix the damage.

- Damage to distribution components (such as a pole-mounted transformers) generally leads to localized power outages, often with only short lead times necessary to fix the damage.

Experience shows that electric distribution systems have been damaged in past earthquakes, on a regular basis, and do cause localized power outages. The most common cause of damage to distribution systems has been the failure of pole-mounted or platform-mounted distribution transformers, and wire burn down. Other less common damage modes includes failure of the power poles themselves, either because of PGD effects, or because of collateral collapse to adjacent structures causing wires from these structures to pull down the distribution power pole. Collateral damage due to fire has also occurred.

8.1.3.4.1 Seismic Design Considerations

Distribution power poles are generally made of one of three materials: wood, steel or concrete. Fabricated steel towers are generally used only for high voltage transmission lines with spans of more than 350 feet.

Typical poles are generally proportioned for a 150 foot span to withstand a gale successfully, with the wind at a velocity of 70 mph and 1/2 inch of ice on the wires.

Wood poles are often designed using standardized guidelines, most often made of yellow pine in the eastern states, red or white cedar in the central states, and redwood on the west coast. Reinforced concrete poles are designed as cantilever structures, with longitudinal bars and ties needed for resistance to lateral wind loads. Steel poles are used for longer spans (250 to 350 feet) and their life span is 25 to 50 years or more, depending on the adequacy of painting and upkeep.

Guy wires are attached to poles to provide lateral resistance where there are changes in direction in the distribution circuit.

Cross arms are typically wood or steel, and are braced.

Insulators are either pin-type (above the cross arm) or suspended type (below the cross arm). Insulators are typically constructed of porcelain. The voltage rating of an insulator will depend upon manufacturer tests, but generally the longer the insulator, the higher the voltage rating.

Considering these factors, the seismic performance of distribution systems should be comparable throughout the United States, as wind, storm and guy wire load design is required throughout, and these designs are probably comparable to seismic forces.

At the Level 2 loss estimation level, we make no distinction between buried and above ground distribution circuits. Buried circuits are generally used in new developments, whereas above ground (pole) circuits remain in older communities. Although buried distribution circuits are not as vulnerable as above ground circuits to wire slapping, pole failure, or pole-mounted transformer failure, they are more vulnerable to landslide, liquefaction and and surface faulting failure. Refinement of this kind is left to a Level 3 loss estimation effort.

8.1.3.4.2 Distribution System Default Component Inventory

The following default inventory assumptions are made for distribution systems:

1. There is little difference in seismic performance of distribution systems throughout the United States. (A few utilities have seismically upgraded their distribution systems along the west coast, but as of 1994, this is the exception).

2. The distribution system is subdivided into a number of circuits. A distribution circuit includes the poles, wires, low voltage substation equipment, in-line equipment and utility-owned equipment at customer sites.

3. The number of distribution circuits leading away from a substation can be approximated from the number and type of customers served by the substation.

    - Electric Utility Customers. An electric customer is defined as the number of "meters" the utility sells electricity to. Generally speaking, there is one meter for each customer, for each structure. There are a few cases of a single customer having two or more meters (a large hotel may have two meters, for example).

      In single family residential areas, it is probable for more than 99% of cases that:

      1 Customer = 1 Meter = 1 Structure

      In industrial areas, the number of customers may not be the same as the number of structures.

    The default number of distribution circuits leading out from each substation in the study area is calculated as follows:

    - First, locate the substations. Assume all substations have distribution circuits leading to customers. (This assumption can be overridden by the user for switching substations that do not serve any customers.)

    - Second, subdivide the study area into areas served by each substation. This information is available from the electric utility. Alternately, the user may use the GIS system to assign each cell or part of a cell (census tract or zip-code) to the nearest substation. Alternately, assume that the population is equally distributed to all substations.

      Once the area is so subdivided, sum up all the population served by each substation, and assume the number of customers = population / 3.5 (residential areas) + structures (commercial / industrial areas). A more accurate count of customers is to sum up the number of structures within the area served by the substation. The most accurate count of the number of customers served by the substation is to obtain this information from the electric utility.

The number of customers served by the electric utility will be used as the measure of outages. Although it can be argued that a single industrial customer is more important than a single residential customer in an overall economic sense, the usual way power outages are described are by customer, without distinction.

- Third, the number of distribution circuits can be assumed equal to:

  Residential areas: customers / 1,000

  Commercial areas: customers / 200

  Industrial areas: customers / 100

  Alternately, the actual number of distribution circuits from each substation can be obtained from the electric utility.

Table 8.1-10 is used to define the number of seismically versus standard designs for distribution circuits. Note that even in Zones 3 and 4, few distribution circuits are "seismic" designed, as of 1994. Most electric utilities in Zones 3 and 4 install new distribution circuits as "seismic" designs, but there remains a large number of non-seismic designs.

8.1.4 Outputs

The electric lifeline module will provide the user with two forms of output: tabular and maps.

The tabular output will be in the form of a graph showing the number of customers within the service area without electric service, as a function of time after the earthquake. Example graphs are shown in Figures 8.1-2a and 8.1-2b. These graphs are explained as follows:

- There are 350,000 customers within the study area.
- Immediately after the earthquake, about 200,000 customers lose electric service.
- 3 days after the earthquake, essentially all customers have electric service restored, but some customers may have somewhat unreliable service. Unreliable service means that there will occasionally be temporary power outages of a few minutes to hours.
- 300 days after the earthquake, the electric utility will have repaired all damage to its electric system, and service will be "normal". Normal service means that the electric system will be as reliable as prior to the earthquake.

The user will also be able to request the output in the form of a map. For example, the map in Figure 8.1-3 shows the parts of the study area with various levels of electric power outage, immediately after the earthquake.

8.1.5 General Form of Damage Algorithms

Damage algorithms for electric system facilities and equipment are expressed as a ground shaking parameter, peak ground acceleration, PGA, or spectral acceleration parameter, SA, or permanent ground deformation parameter, PGD.

Damage algorithms are expressed as lognormal distributions described by a median ground motion and a dispersion . These damage algorithms are related to PGAs, and PGDs. In some cases, where the fundamental frequency of the damage mode is important, and where suitable fragility data was available, damage algorithms are expressed in terms of spectral accelerations (SAs) instead of PGAs.

Each equipment item has at least one damage state and associated damage factor and functionality code. The damage state is a description of the type of damage expected for the particular piece of equipment. The damage factor is the ratio of the repair cost of the equipment and its replacement value. The functionality code describes whether the equipment is functional; should the damage state occur.

8.1.6 Damage Algorithms

This section of the report describes the damage algorithms for each component of the electric system. Since electric systems use many of the same components as other lifelines, some electric system component damage algorithms are described in the sections for these other lifelines. No duplicate descriptions are made for these components, and the user is referred to the appropriate sections for those components.

8.1.6.1. Electric Power Facility Performance in Past Earthquakes

The development of damage algorithms for substation components is currently (1994) based upon empirical evidence strongly tempered with engineering judgement.

There are currently no known publicly available databases of damage algorithms for major substation equipment. Given this limitation, the algorithms presented in this report must therefore be considered as a best estimate circa 1994.

Additional research work in this area is recommended. The authors of this report welcome suggestions for improvements. Any interested parties with documented empirical or test table data as to substation component damage states and/or damage algorithms are encouraged to forward their information to the authors.

<u>Kern County Earthquake, 1952</u>

The Kern County magnitude 7.7 earthquake of 1952 caused extensive damage at substations and also caused 800 pole-mounted transformers in distribution systems to fall [3]. Equipment installed up to this time did not meet the seismic design provisions in place today in California.

<u>San Fernando Earthquake, 1971</u>

The San Fernando magnitude 6.5 earthquake of 1971 caused severe damage to a limited number of components in high voltage substations.

Certain critical components of the Sylmar Converter station (500 kV DC) were severely damaged with an estimated $22,000,000 loss, or 40 percent of the total value [4]. The adjacent Olive View substation was out of service.

The distribution system performance included damage to 285 transformers (mostly pole mounted), and 30 wood poles.

Seismic design practices for substation components up to this time tended to use building code-style practices, such as an equivalent static lateral force coefficient of about 20% times the weight of the component. The lessons learned in this earthquake suggested that this level of seismic design did not produce good seismic performance. After this earthquake, new seismic design standards were adopted by California electric utilities to design new substation components using a response spectrum method, anchored to a PGA of 0.5g for substations (220 kV and above) exposed to high seismic hazards.

Managua, Nicaragua Earthquake, 1972

The Managua magnitude 6.25 earthquake of 1972 damaged some electric power facilities in the city of Managua. The following damage descriptions are adapted from an early reconnaissance effort [5].

Three small electric steam power plants in the epicentral area were shut down, although overall damage was slight. Estimated PGA was 0.40g - 0.60g. It was reported these facilities had been designed for lateral forces of 10% of gravity.

The distribution system in downtown Managua was severely damaged by fire and debris from damaged and collapsed buildings.

Morgan Hill Earthquake, 1984

This magnitude 6.2 earthquake damaged a 500 kV substation with local site accelerations estimated at 0.06g [6]. Distribution power lines had some wire slapping and burndown.

Palm Springs Earthquake, 1986

This magnitude 5.9 earthquake caused extensive damage to the Devers substation. The Devers substation includes 500 kV, 220 kV and 110 kV yards. The epicenter was located 4.5 miles from the substation. Ground motions recorded at the Devers substation were 0.97g, 0.72g and 0.48g (two horizontal and the vertical directions, respectively). Very strong ground motions (exceeding 0.5g) lasted 3 seconds.

The Devers substation (500 kV yard) had been designed using a target response spectra anchored to 0.5g. However, not all equipment was actually qualified by test to this level. The site acceleration was measured at about 0.97g, representing a higher seismic demand than the design basis; however, the extent of the damage still exceeded the typical levels of damage seen in ductile structures for similar overloads.

There was heavy damage in the 500 kV yard, modest damage in the 220 kV yard, and little damage in the 115 kV yard.

80,000 customers were out of power for 5 hours. The cost to repair the substation was estimated to be $3,200,000. Repair time was about 10 days using 300 repair crew working up to 16 hour shifts.

San Salvador Earthquake, 1986

This magnitude 5.4 earthquake affected two substations near the epicenter.

One 115 kV substation was located near the epicenter, and experienced ground motions of about 0.50g [7]. Another 115 kV substation experienced ground motions between 0.25 and 0.50g. Live tank circuit breakers failed at both substations.

Whittier Narrows, 1987

This magnitude 6.1 earthquake had strong ground shaking of about 5 seconds.

The Commerce Waste-to-Energy 10 MWe facility was located about 6 miles from the epicenter. Ground motions at the site were over 0.30g (horizontal). Post earthquake inspections showed that all well anchored equipment had no significant damage. The following exceptions were noted: a small bore threaded pipe coupling leaked; a 3 inch pipe impacted a rod hanger without loss of pressure integrity; a HVAC diffuser was dislodged. Large bore pipe was designed for dead load only.

The Glendale Power Plant experienced ground motions of about 0.15g (horizontal) and 0.06g (vertical). The plant has eight units. Post earthquake inspections showed that all well anchored equipment had no significant damage. Large bore pipe had no damage. Small bore pipe had three breaks: two lines with threaded couplings; and one branch line (corroded) between a large bore pipe and a wall penetration.

Tejon Ranch Earthquake, 1988

This magnitude 5.2 earthquake severely damaged a 230 kV substation, with local site accelerations estimated at 0.08g [8]. The time to partially restore power was 4 days, and it was estimated to take 6 to 8 weeks to repair the damage.

Saguenay Earthquake, 1988

This magnitude 6.5 earthquake occurred in northern Quebec province [9]. Four substations were damaged (three with major damage) located between 80 miles and 130 miles from the epicenter, with estimated PGAs of between 0.10 g and 0.15 g. Typical components having total or heavy damage included 230 kV - 315 kV circuit breakers, switches and lightning arrestors.

Power outages in Quebec City (90 miles from the epicenter) occurred. Power restoration in Quebec City began 15 minutes after the earthquake, and complete power restoration occurred 9 hours after the earthquake.

Loma Prieta Earthquake, 1989

This magnitude 7.1 earthquake caused severe damage to substations [10]. Electricity was lost to about 1,400,000 customers.

The San Mateo substation is located 42 miles north of the epicenter. The closest strong motion recording was 2 miles away, and registered 0.16g. The substation is on fill, but there was no evidence of liquefaction or lateral spreading. The San Mateo substation includes 230 kV and 115 kV yards. The 230 kV yard had major damage.

The Metcalf substation is located 16 miles northeast of the epicenter. Two nearby recordings, located 7 miles southeast and 7 miles west of the substation, registered 0.28g and 0.19g, respectively. Metcalf has a 500 kV yard, a 230 kV yard, and a 115 kV yard. There was heavy damage to the 500 kV yard. The 230 kV and 115 kV yards were basically undamaged.

A review of the available strong motion recordings and damage near the Moss Landing power plant and substation suggests that the site motions were in the 0.25g to 0.30g range (horizontal) and 0.15g to 0.25g range (vertical). The 500 kV yard was destroyed (70% of elements requiring replacement), the 230 kV yard was severely damaged, and the 115 kV yard was undamaged.

The Moss Landing power plants include seven oil and gas fired units with a total generating capacity over 2000 MWe. One 750 MWe unit was operating at the time of the earthquake. The facility is generally founded on compacted soil. When the earthquake hit, the one operating unit tripped off-line due to high voltage resulting from loss of the 500 kV switchyard. Inspections found damage to main steam pipe supports in every unit; no damage to rotating equipment. Restoration efforts were concentrated on the smaller units, as the 500 kV switchyard was damaged beyond rapid repair. About 12 hours after the earthquake, offsite power was restored to the plant. Two small units were brought on-line about 30 hours after the earthquake. One more unit was brought on-line 72 hours after the earthquake. One more unit was brought on line 5 days after the earthquake. There was no evidence of damage to well anchored equipment. Small bore piping in the two largest units suffered no damage. Some lateral restraints on large bore piping were damaged. Moderately to heavily loaded cable trays had no damage. HVAC ducts had no observed damage. None of the tanks (partially full) in the fuel oil storage tank farm were damaged. Four distilled water tanks were damaged (broken pipe connections). One large at-grade steel water tank ruptured at the bottom plate weld. The tank also had shell buckling in its upper course.

The Monte Vista substation is located 11 miles north of the epicenter. The closest strong motion recording was 6 miles away, and registered 0.34g. The substation includes 230 kV and 115 kV yards. Moderate damage occurred in he 230 kV yard. There was no significant damage in the 115 kV yard.

Distribution System Damage. Many aerial conductors were downed in epicentral area. Thousands of fuses were blown. Some pole mounted transformers fell. About 50 to 75 transformers were damaged. Cross arms broke on some poles. Several poles fell over due to rotten bases, and some sound poles broke. Many poles were lost in landslides. Buried distribution lines and equipment did well, except in areas of liquefaction. Overall level of damage to the distribution was characterized as typical to that in a severe storm expected once per year.

<u>Northridge Earthquake, 1994</u>

This magnitude 6.8 earthquake caused extensive damage to substation equipment. A cursory discussion of electric system damage is provided below.

Power outages in Los Angeles were estimated as follows [[11]]:

- 2,000,000 customers immediately after the earthquake
- 1,100,000 customers 16 hours after the earthquake
- 72,500 customers 44 hours after the earthquake
- 7,500 customers 76 hours after the earthquake

An additional 600,000 customers in nearby cities also lost power. Virtually all customers regained power 9 days after the earthquake [12].

One generating plant (PGA greater than 0.40g) which was not on-line at the time of the earthquake had minor damage, and was brought on line several hours after the earthquake. Seven other generating plants, in the areas with shaking above 0.05g, had minor damage, and were brought on-line several hours after the earthquake.

Southern California Edison's Pardee and Vincent substations had significant damage to both 230 kV and 500 kV equipment. 500 kV equipment damaged included capacitor banks, circuit breakers, disconnect switches. Of interest is that one 500 kV circuit breaker (modern dead tank design) was almost damaged due to collapse of adjacent disconnect switches.

All 8 230 kV live tank circuit breakers at Pardee substation failed, whereas none of the dead tank circuit breakers failed.

L.A. Department of Water and Power's Sylmar Converter Station suffered extensive damage (site PGA over 0.4g). Equipment damaged included transformer bushings, lightning arrestors, disconnect switches, circuit switchers, bus supports, and potential-measuring devices. The high voltage DC equipment (500 kV) will probably be out of service for an extended period of time, perhaps as long as a year. Many 230 kV circuit switchers were damaged, although none were damaged in the 1971 San Fernando earthquake which produced lower ground motions at the site. Most of the capacitor banks were damaged in the 1971 San Fernando earthquake, but the replacement capacitor banks designed to higher seismic standards did not fail in the 1994 Northridge earthquake.

Four other LADWP substations (Rinaldi, RS-J, RS-U and RS-E) were also damaged.

Damage at Rinaldi (horizontal PGA of 0.8g, vertical acceleration of 1.4g) included collapse of 230 kV rigid buses, and damage to 34.5 kV reactors. None of the 230 kV dead tank circuit breakers (several dozen) were damaged.

A few transmission towers were damaged, and some collapsed. Collapsed towers included bolted lattice structures carrying 66 kV and 230 kV. Tower collapses may have been triggered by high acceleration at ridge tops and foundation distress.

ASCE Dynamic Analysis Committee

ASCE's Dynamic Analysis Committee put together a 1987 report on the earthquake performance of electric power facilities [13]. This report was augmented by Yokel [14]. Six of the twelve earthquakes occurred outside the United States (Kanto 1923, Managua, 1972, Miyagi-ken-oki 1978, Corinth Greece 1981, San Salvador 1986, New Zealand 1987). Incomplete damage statistics are available from all earthquakes, but the following general trends are noted:

- Transmission tower failures are rare (especially when considering the large population of towers, and the few instances when towers are damaged).
- Distribution system damage (pole mounted transformers, wire slapping) seems to be limited (but may be under-reported).
- Damage to low voltage substation equipment (switchgear, electrical cabinets, batteries) is not uncommon.

- At least some damage to transformers, circuit breakers and various porcelain components is expected in earthquakes.

- Transformer failures included toppling (inadequate anchorage), core damage, bushing damage, gasket leaks, radiator damage.

- Disconnect switches become dysfunctional either due to burned contacts or misalignment caused by accidental opening.

General Observations

The performance of certain types of high voltage substation equipment has been less than satisfactory in past earthquakes. In response to this performance, electric utilities in California have been upgrading their seismic design practices. A good description of these design practices is provided by Schiff [15]. The evolution of these seismic design practices is still evolving (1994), and will likely change again based upon the lessons learned in the 1994 Northridge earthquake.

Some general trends in seismic design of substation equipment include the following:

- Seismic design following the provisions in local area building codes (such as lateral forces of 20% of the equipment weight) do not result in good seismic performance of certain types of high voltage (220 kV and above) substation equipment.

- Seismic design by analysis using response spectra anchored to relatively high PGAs (0.5g) do not result in reliable seismic performance of very high voltage (500 kV) equipment due to intense shaking (> 0.5g).

- At this point in time, shake table testing of substation equipment appears to be a necessary step in reliable seismic qualification of substation equipment. At this point in time, we do not have the ability to reliably design substation equipment solely by analysis.

Some observations as to substation vulnerabilities outside California:

- Earthquake design practices for substation equipment outside of California (Zone 4) vary from utility to utility, depending upon the perception of earthquake hazards in each region. While all electric utilities have emergency response procedures that are routinely exercised by often occurring emergencies, such as wind and ice storms, earthquakes outside of Zone 4 may provide a set of conditions not rigorously incorporated into these plans.

- The nature of earthquakes outside of California (attenuation issues) may cause high levels of damage over wider areas than common in California. This could possibly leading to loss of electric system redundancy for utilities outside of California. This redundancy has been a factor as to why post-earthquake power outages in California are relatively modest in duration.

- The source of low voltage substation emergency power (needed to operate equipment at the substation) may be vulnerable to earthquake damage. For example, station batteries can be lost if they are not anchored. Seismic design practices of this equipment outside Zone 4 may not be given adequate attention.

- California electric utilities have recognized the particular vulnerability of high voltage live tank circuit breakers. These components are rapidly being phased out in California, and being replaced with dead tank circuit breakers. Utilities outside California may not be following this trend.

- Unreinforced masonry control buildings are probably in use outside of California. These are particularly vulnerably to earthquake damage.

8.1.6.2 Substation Component Damage Algorithms

Based on the empirical evidence of damage in substations to date, and using engineering judgement, Table 8.1-11 is developed.

The PGAs provided in Table 8.1-11 represent approximately where the onset of a significant ratio of the equipment can be expected to be seriously damaged. These PGAs are considered below the median for each component type.

With the exception of live tank circuit breakers, there is relatively little evidence of serious damage to 115 kV equipment. Therefore, the PGAs values in Table 8.1-11 are high.

It is recognized that different brands of substation equipment will have different designs, and hence different fragility curves. For the purpose of a Level 2 loss estimation effort, it is not expected that the planner will obtain actual manufacturer model numbers or detailed substation configurations. Tables 8.1-6 through 8.1-9 represent a possible configuration. This report does not make any recommendations as to the seismic ruggedness of any particular manufacturer's equipment, or ways to configure substations. A Level 3 loss estimation effort would be required to refine the equipment damage algorithms for particular manufacturer's equipment, and consider actual substation configuration.

Figures 8.1-4 through 8.1-9 provide the empirical data for functional damage to 500 kV and 230 kV substation equipment. The earthquakes represented include Morgan Hill (1984), Palm Springs (1986), Tejon Ranch (1988), Saguenay (1988), Loma Prieta (1989) and Northridge (1994, partial data). The following trends are seen:

- 500 kV equipment is more vulnerable than 230 kV equipment.

- 500 kV dead tank circuit breakers are relatively rugged.

- 230 kV dead tank circuit breakers classes are very rugged.

The damage algorithms for various types of substation equipment are provided in Appendix B, Tables S500, S230 and S115. The median acceleration values are chosen with consideration of the data in Table 8.1-11 and experience in past earthquakes. The beta (dispersion) values are chosen with consideration of randomness of 0.50 for ground motions, and 0.50 for uncertainty. Therefore, beta is:

$$\beta_{min} = \sqrt{\beta_r^2 + \beta_u^2} = \sqrt{0.5^2 + 0.5^2} = 0.707 \text{ (say 0.70).}$$

8.1.6.3 Loss of Power (Level 1) Damage Algorithms

The "Level 1" methodology for loss estimation of electric power was described in Section 8.1.2.2.1. The simplified damage algorithm presented is described by a damage algorithm with median PGA = 0.3g, and β of 0.5.

The basis of this damage algorithm is it simplicity. There is no particular damage associated with this damage algorithm to substations. The damage algorithm is based on the ground motions located at the location of the estimate (say a particular census tract), and not at the location of where the vulnerable equipment is actually located (the substation). The algorithm makes no differentiation of whether an area is served by 500 kV, 230 kV or 115 kV substations.

Therefore, the algorithm is fundamentally incorrect. Without knowledge of the actual electric system configuration for the study area, there can be no estimate of the error associated with the level 1 damage algorithm. If one goes to the effort to collect the actual electric system configuration (in order to estimate the error), one should use the Level 2 methodology.

8.1.6.4 Generating Facilities

As a rule, damage to generating facilities has been light. This is due to a number of factors:

- Most generating plants that have experienced strong earthquake motions have been designed to fairly rigorous seismic standards. For example, most California electric utilities design generating facilities to seismic loads higher than those required in UBC provisions for Zone 4. While the earlier versions of the UBC called for lateral loads of 13% of the weight of the building, the usual design practice was to use 20% of the weight of the building.

- Many types of mechanical equipment in generating plants are inherently seismically rugged.

- Many types of equipment in generating plants undergo high loading in the course of normal operations. For example, rotating machinery (pumps) need to be well anchored just to make sure they are not damaged under normal loading; and this anchorage is more than adequate for the additional loading imposed during earthquakes.

[Absent from the California database of generating stations are coal fired power plants. There are some researchers who are concerned that such power plants may be somewhat less seismically rugged, owing to complex coal handling equipment. A coal power plant was damaged in the Peru 2001 earthquake]

Whereas the Level 2 loss estimation methodology specifically excludes analysis of nuclear power plants, the methodology borrows from the extensive work in probabilistic analysis that has already been performed for nuclear power plants. For this project, we use the "Handbook of Nuclear Power Plant Seismic Fragilities [16]" as a source of power plant fragility curves for components which are similar to both nuclear and non-nuclear power plants. The fragility curves were developed using a variety of sources:

> "The sources of data and the methods used [to compute fragilities] are the best sources available at the time [1985] when this work was done. In many instances, where data were inadequate or absent, decisions were made to construct fragility curves based on the best professional judgement of the [staff preparing the Handbook]. ... The work presented here represents a significant step forward in the quantification of component ... fragilities."

The fragility curves developed for mechanical and electrical components were derived from a number of sources. Experimental data was assigned a higher weight as compared to analysis or judgement. Expert opinion surveys were also used. The experimental data comes from the U.S. Army Corps of Engineers' SAFEGUARD program, an effort in support of missile-hardening. Tests were done using off-the-shelf components including electrical and mechanical equipment.

Component fragility curves include their supports to the point of interface with the building structure. Assemblies such as valves and pumps include the complete assemblies normally furnished by component suppliers.

Fragility curves for the following components are adapted from the Handbook for this project:

<u>Large Vertical Storage Vessels with Formed Heads</u>. This category includes accumulator tanks and volume control tanks. These vessels are typically low pressure, with thin wall construction supported by skirts. (E2.1)

<u>Large Horizontal Vessels</u>. This category includes large storage tanks, heat exchangers and diesel oil storage tanks. The designs are usually low pressure, thin wall cylindrical tanks mounted with the cylinder axis in the horizontal position. The tanks are usually supported by two saddles mounted to the floor. (E2.3)

<u>Small to Medium Vessels and Heat Exchangers</u>. These are typically cylindrical in shape, although spherical tanks are sometimes used. Cylindrical vessels are either horizontally or vertically mounted. Supports are usually legs or saddles welded directly to the pressure boundary and bolted to the floor. (E2.4)

<u>Large Vertical Pumps</u>. These type of pumps include those in the intake structure and are often used as service water pumps and fire pumps. They are typically supported at a flange located at the pump-motor interface and have lengths several times the pump diameter such that they respond to seismic excitation as a flexible cantilever beam. (E2.5)

<u>Motor Driven Pumps</u>. These small to medium pumps and compressors find widespread use in power plants. These pumps are generally mounted separately from their drive motors and the pumps and drive motor set are mounted on a single skid or directly to the floor. Drive motors are generally in line with the pump shaft. (E2.6)

<u>Large Motor Operated Valves</u>. These remotely actuated valves find widespread use in power plants. They are characterized by a rugged body with an extended yoke structure that supports a motor-gearbox operator assembly. (E2.8)

<u>Large Hydraulic and Air Actuated Valves</u>. These valves find occasional use in power plants. These valves do not have the extended structures as a motor operated valve, and hence are more seismically rugged. (E2.9)

Large Relief and Check Valves. These valves find widespread use in power plants. They are characterized as compact, rugged assemblies that should not be as susceptible to seismic loading as motor operated valves. (E2.10)

Small Motor Operated Valves. These remotely actuated valves find widespread use in power plants. They are similar to large motor operated valves but are for piping 4 inches and smaller. (E2.11)

Diesel Generators. These are large diesel-powered generators used to provide standby AC power (4 kV) to the generating station. The engines and alternators are not considered susceptible to seismic failure. The most likely failure modes are from failure of ancillary equipment, such as air supply, fuel and oil lines, filter brackets, local controls and instrumentation. (E1.1)

Batteries and Battery Racks. Batteries provide emergency DC power and are kept charged by a static charger system. The batteries themselves are usually mounted on large metal racks. Well anchored batteries have been proven very reliable when subjected to severe shock loading. (E1.2)

Switchgear. Switchgear are complex electrical systems consisting of active and passive electrical devices housed in a structural assembly. Included are small transformers, relays, breakers, capacitors and buses. The switchgear fragility curve is not that associated with the switchyard. (E1.3)

Control and Instrument Panels and Racks. These categories of electrical equipment include lightweight electrical equipment mounted in panels or racks. They often have a large number of individual electrical items. (E1.4)

Auxiliary Relay Cabinets, Motor Control Centers and Circuit Breakers. These cabinets house electrical relay and switching gear, some transformers, and circuit breakers. (E1.6)

Turbines. Turbines are designed to trip if thee are unbalanced loads. Earthquakes trigger devices which sould normally shutdown the turbine. (E1.7)

Inverters. These are passive devices that convert DC power to AC power. Well anchored units are seismically rugged.

Cable Trays. Cable trays (raceways) are used throughout power plants to support power, lighting and communication cables. The fragility curve provided is for failure of the wires. (E3.1)

Air Handling Equipment. This includes cooling fan systems.

HVAC Ducting. This includes ductwork for moving cooling air and exhaust. (E3.2).

The following fragility curves are based on engineering judgement and empirical evidence, as noted.

Boilers and Steam Generators. These vessels are usually designed following the ASME Boiler and Pressure Vessel Code. They operate at high temperatures and pressures. They include various internal structures. They are usually nozzle supported or (sometimes) skirt supported. Since the rigor of manufacture and design for nuclear power applications is probably higher than in non-nuclear applications, the fragility curve from nuclear application is not considered appropriate for non-nuclear application. The fragility curve provided is geared to provide about a 2% chance of failure at a PGA of 0.30g: it is developed by engineering judgement, and may not be accurate for particular applications. The user should always apply Level 3 analysis for plant-specific assessment of boilers and steam generators. (E2.2)

Piping. The fragility curve for non-nuclear power plant piping is based upon the experience of such piping in 29 earthquakes from 1923 through 1985. Detailed description of this damage is provided by the Electric Power Research Institute [17] and summarized by Stevenson [18]. The summary is provided in Table 8.1-12. The statistics in this table suggest that less than 0.01% of all power plant piping and supports subjected to peak ground accelerations of 0.2g to 0.5g failed as a result of the earthquake.

This low failure rate suggests that only localized weaknesses leave rise to significant chance of piping failure. Considering that the database power plants have about the same weaknesses, on average, as power plants subject to the loss estimation study, and allowing that the 141 combined failures and damages were on a total of 1,200,000 feet of pipe, we arrive at an above ground piping repair rate of:

$$n = \frac{141}{1200} = 0.12 \text{ repairs per thousand feet, with PGA} = 0.20\text{g to } 0.50\text{g.}$$

Next, allowing that support and miscellaneous pipe damage (internal equipment includes boiler tubes, condenser pipes and the like) totalled 74, then:

$$k = \frac{74}{141} * n$$

$$= 0.52 * n = 0.06 \text{ per thousand feet, with PGA} = 0.20\text{g to } 0.50\text{g.}$$

The piping loss estimate, therefore, for a complete power plant for a site larger than 0.20g PGA requires only an estimate of the number of feet of pipe in the power plant. This can be user supplied, but a "ballpark" estimate is as follows:

L = 30,000 feet of pipe per 100 MWe power plant

$$\text{Total Pipes Damaged} = 0.12 * \frac{\text{MWe}}{100} * 30 \qquad \text{[eq. 8.1-12]}$$

$$\text{Total Pipe Supports + Misc. Items Damaged} = 0.06 * \frac{\text{MWe}}{100} * 30 \qquad \text{[eq. 8.1-13]}$$

Assuming the direct cost to repair each pipe is $6,000 and $3,000 for each pipe support or misc. damage, the total pipe loss is $32,400 per 100 MWe. The repair costs may be on the high side, but the overall error is probably small in terms of the complete loss estimate.

8.1.6.5 Distribution Circuits

The probability that a distribution circuit will be damaged is a function of the intensity of ground shaking (possibly damaging poles and pole mounted transformers), the extent of ground failures (landslides will damage poles and buried lines), and collateral damage (collapsed buildings will pull down conductors and poles; fires will burn down conductors and poles).

The number of distribution circuits served by each substation is input by the user, or based on default information, as described in Section 8.1.3.4.2.

Two damage algorithms are provided for distribution circuits: "standard" and "seismic". The seismic damage algorithm should be used in areas where essentially all pole and platform mounted transformers have been anchored. It is assumed that 25% of all distribution circuits in Zone 3 and 4 have be so-upgraded (some Zone 3 and 4 utilities have done this, some have not).

It should be noted that the damage algorithms assume a damage "cost" instead of a damage "factor". The cost represents the cost to repair a single distribution circuit. Although there will be variance in damage to each circuit, the loss of accuracy is not significant for a Level 2 loss estimation effort. In general, only a very few items along the distribution circuit (usually under 1% of the total installed value) will actually be damaged. The $3,000 cost assumes that some circuits will need only a few hours of labor to repair, and some will require replacements of poles, transformers or other hardware. A Level 3 analysis should be performed if the user needs more refined loss estimates.

8.1.7 Post - Earthquake Electric Service and Restoration

8.1.7.1 Level 1 Methodology

For purposes of a Level 1 analysis, a rule-based system restoration method is provided:

- Near field Magnitude 6 earthquake. Assume essentially all customers have service restored in 1 day.
- Near field Magnitude 7 earthquake. Assume essentially all customers have service restored in 3 days.
- Near field Magnitude 8 earthquake. Assume essentially all customers have service restored in 10 days.

8.1.7.2 Level 2 Methodology

The Level 2 restoration analysis methodology is based on experience of electric utilities after earthquakes, and judgement. The restoration times should be considered as reasonable estimates, and can vary substantially.

Substations

For purposes of a Level 2 analysis, the time needed to restore electric power to customers is a function of the level of damage induced to substations and distribution systems. The following assumptions are made in calculating the extent and duration of outages at substations:

1. Substations can experience considerable damage and still remain functional. In the event that damage reaches a degree where function is lost, substations can be

re-configured with undamaged components and again be functional (although not as reliable).

2. Substation restoration times assume the following:

    - Weather permits

    - Spare parts are available (may be borrowed from other substations)

    - There are sufficient experienced crews in the area

    - Power demand after an earthquake will not exceed the substation's capacity. Experience shows that power demand drops after an earthquake (due to concurrent damage to the general building stock). We assume that once a substation can restore a single circuit, independent of voltage class, then that single circuit can support the demand. We further assume that as demand picks up after the earthquake, that the substation's additional circuits are repaired in tandem. A Level 3 analysis would be required to refine this assumption.

3. Forced power outages (not hardware related), such as by human decision to shut off power to particular areas of the study area, such as those with gas leaks, are not considered.

The substation can be in one of six damage states (meeting any of the conditions causes the damage state). The damage states are ranked from least severe to most severe.

1. Substation is functional (no transformers damaged, less than 2% of other equipment, by value, is damaged).

2. Substation outage will be brief (assume 15 minutes) if:

    - There remains at least 3 undamaged transformers (of a single voltage class) that are undamaged.

    - Less than 5% of disconnect switches are damaged.

    - Less than 5% of circuit breakers are damaged.

3. Substation outage will be < 8 hours (assume 8 hours) if:

    - There remains at least 3 undamaged transformers (of a single voltage class) that are undamaged.

    - Less than 20% of disconnect switches are damaged.

    - Less than 20% of circuit breakers are damaged.

4. Substation outage will be < 24 hours (assume 24 hours) if:

    - There remains at least 3 undamaged transformers (of a single voltage class) that are undamaged.

    - Less than 40% of disconnect switches are damaged.

- Less than 40% of circuit breakers are damaged.
- Less than 40% of current transformers are damaged.
- The control building internal equipment is damaged.

5. Substation outage will be < 72 hours (assume 72 hours) if:

    - There remains at least 2 undamaged transformers (of a single voltage class) that are undamaged. (It is assumed that the third damaged transformer requires minor repairs).
    - Less than 70% of disconnect switches are damaged.
    - Less than 70% of circuit breakers are damaged.
    - Less than 70% of current transformers are damaged.
    - The control building collapses or is heavily damaged.

6. Substation outage will be about 3 weeks (assume 3 weeks) if:

    - There are 0 or 1 undamaged transformers.
    - The control building collapses or is heavily damaged and it houses large yard equipment.

<u>Distribution</u>

Distribution system outages will depend upon the extent of distribution system damage. The time needed to restore essentially all distribution circuits is assumed to be:

1. 4 hours (< 1% of all distribution circuits damaged)
2. 8 hours (1% - 3% of all distribution circuits damaged)
3. 16 hours (3% - 6% of all distribution circuits damaged)
4. 24 hours (6% - 12% of all distribution circuits damaged)
5. 48 hours (12% - 25% of all distribution circuits damaged)
6. 72 hours (25% - 50% of all distribution circuits damaged)
7. 96 hours (50% - 75% of all distribution circuits damaged)
8. 1 week (>75% of all distribution circuits damaged)

Distribution circuits in areas subject to collateral damage (fire, severe liquefaction, severe landslides etc.) may be restored on a longer interval. Distribution circuits in remote areas may take longer times to repair.

The probability that a particular distribution circuit will be repaired at a given time after the earthquake can be estimated using the following example assuming 4% of all distribution circuits are damaged. Using the above rules, it will take 16 hours to repair all distribution circuits. Then:

1. At time 0 hours, 4% of distribution circuits are damaged.

2. At time 4 hours, 3% of distribution circuits remain damaged (4/16, or 25%, are repaired)

3. At time 8 hours, 2% of distribution circuits remain damaged (8/16, or 50%, are repaired)

4. At time 12 hours, 1% of distribution circuits remain damaged (12/16, or 75%, are repaired)

5. At time 16 hours, 0% of distribution circuits remain damaged (16/16, or 100%, are repaired)

<u>Generation</u>

In past earthquakes in California, damage to generating facilities has been modest. This is in part due to the high level of seismic design which is incorporated. Further, electric utilities in California are large, and have multiple generating facilities and interties to other electric utilities. Thus, it has been the experience in California that damage to generating facilities do not cause long power outages.

There is not as much earthquake experience for power plants in the United States outside California. However, considering the worldwide performance of power plants designed for at least nominal earthquake loads, restoration times for power plants have been modest (a few days in most cases), and outage times based on substation and distribution system performance will probably control the restoration curve.

In the case where a power plant has been designed for zero earthquake loads, and it experiences a large earthquake, we make the following assumptions:

1. Most items in the power plant will not be damaged. They are rugged by industrial design purposes.

2. Some items in the power plant may be damaged. Most of these items can be repaired in a few days.

3. The building will most likely not be heavily damaged. However, in the case where a building (or critical non-redundant component) collapses or is heavily damaged, there will be a long term (months to years) outage for that particular generating plant. In these cases, it is assumed that generating capacity from a distant undamaged power plant will be available. In the case where many generating plants collapse, and there is insufficient transmission capacity to bring in power from distant locations, local power outages will be lengthy, and severe power rationing will be required. If a Level 2 loss estimation predicts that more than 60% or 3,000 MWe generation capacity (whichever is smaller) is lost for long duration time in a study area, it is recommended that the user consult

with the local electric utilities to perform a Level 3 loss estimation in order to better quantify damage and outage times.

Short term loss of power plants due to relay trips, unbalanced loads and the like, will cause plants to go off-line. Operator action to reset the plant may take a few minutes to a few hours. Such sudden loss of power to the transmission grid may cause widespread outages, even if there is no other damage to the transmission and distribution systems. The power outage model in the Level 2 methodology assumes that substation and distribution outages controls.

Transmission Towers

Loss estimation for transmission towers is not included in the Level 2 methodology. In the case where key non-redundant transmission towers collapse, lengthy power outages may ensue. This has not been the experience in past earthquakes. The user should perform a Level 3 loss estimation iif the user wishes to explore the possible effects of transmission tower failures.

Normal Service

The time needed to repair the electric system to its pre-earthquake level of "normal" reliability will depend upon the total damage sustained, and the total effort applied to repairing all the damage. Due to long lead times needed for acquisition of some types of components, long term repair times can be substantial. A rough rule of thumb is as follows:

1. Calculate total major system damage ($). This is the sum of losses to generation and transmission systems.

2. Calculate the system loss ratio (= damage / value).

3. For large electric utilities (serving over 2,000,000 population), if the system loss ratio is less than 0.5%, assume 3 months
   0.5 to 2%, assume 9 months
   2 to 10%, assume 2 years
   > 10%, assume > 2 years.

4. For small electric utilities, where loss of major facility occurs (such as single power plant), the time to rebuild may be several years.

8.1.7.2.1 Calculation Procedure

1. Calculate the ground motions at each substation facility.

2. Calculate the financial losses for generation, substation and distribution hardware.

3. Calculate the percentage of distribution circuits leading from each substation i which are damaged. Say there are n distribution circuits at substation i. Then, the probability of power loss to customers served by substation i, due to distribution circuit damage, at time 0 is:

$$P_{f(\text{distribution}_i)} = \frac{\text{Number of damaged distribution circuits @ i}}{n}$$

[eq. 8.1-14]

4. Calculate the number and probability of damaged transformers, circuit breakers, disconnect switches, current transformers at each substation. Calculate the probability of failure of the control building.

   Determine the probability that the substation will be in a particular damage state, using the rules provided in Section 8.1.7.2. This is usually done using Monte Carlo simulation techniques. Alternately, the user could query the damage algorithms directly to determine the best estimate of each component damage state.

   $$P_{f(\text{substation}_i)} = \sum_{j=2}^{6} P_f[\text{Damage State}_j] \qquad \text{[eq. 8.1-15]}$$

   Note that the summation is over damage states 2 through 6, as damage state 1 means there is insufficient damage at the substation to cause a power outage.

5. Calculate the number of customers C_i served by substation i with power after the earthquake.

   $$C_{power} = C_i \ * \ (1 - P_{f(\text{substation}_i)}) \ * \ (1 - P_{f(\text{distribution}_i)}) \qquad \text{[eq. 8.1-16]}$$

   Similarly, the number of customers without power is:

   $$C_{no\ power} = C_i \ - \ C_{power} \qquad \text{[eq. 8.1-17]}$$

6. Calculate the number of customers in the entire study area with no power following step 5, summing up over all substation i. (Note: this analysis ignores that circuits may be lost between substations. This assumption can be relaxed in a Level 3 loss estimation effort).

7. Repeat steps 5 and 6 at four hour intervals. In this manner, the power restoration curve of Figures 8.1-2a and 8.1-2b can be developed for the study area as a whole.

   Similarly, the map showing areas with power outages, as in Figure 8.1-3 can be developed at time 0 (immediately after the earthquake). These maps can be generated for various times after the earthquake, depending upon how one assumes that the electric utility allocates repair crews. A simple assumption (probably not correct) would be that repair crews are allocated proportional to the level of damage. In such a case, one can compute the areas of the study area with power restored using the same rules as described above. In reality, the electric utility will allocate repair resources based upon system importance and other factors. This level of detail could be accommodated in a Level 3 loss estimation effort.

8.1.8 Benchmarks

Many of the damage algorithms provided in this report for electric systems are based on limited empirical evidence from past earthquakes, and engineering judgement. Where available, benchmarks of the damage algorithms are provided in Section 8.1.6.

It is recognized that additional and refined empirical and analytical damage algorithms for electric system components will be developed in the future. The mathematical format for the algorithms presented in this report is probably robust enough to accommodate most of these refinements, and the user can simply over-ride the older algorithms with the refined ones.

8.1.9 Level 3

Although the model described in this report treats many of the key components in an electric system, there are a number of refinements that could be made in order to provide a more thorough analysis, or a so-called "Level 3" analysis.

There are several areas that could be refined:

1. Inventory. The Level 2 model provides default inventory for most electric system hardware. The loss estimation effort can be significantly improved by collecting an accurate inventory of the electric.

   The following improvements will give significantly more confident results:

   - Actual component lists for substations
   - Actual component lists for generating facilities
   - Whether large substation yard equipment is housed within the control building

   Other improvements include:

   - Geo-coding transmission towers
   - Geo-coding buried circuits (transmission or distribution) in soil liquefaction, landslide or surface faulty zones.

2. Network models. The simplified power outage model provided in section 8.1.7 neglects how substations are interconnected. The Level 2 model implicitly assumes that power will be available to all substations. Clearly, if an undamaged substation gets its power only from another substation which is damaged, then the undamaged substation will have no power. Therefore, the Level 2 loss estimation effort will tend to underestimate power outages.

   A simple refinement to the Level 2 model would include a network analysis of substations. This has been performed using consultant - proprietary electric lifeline computer codes.

A more detailed network model would incorporate transmission line limitations, outages at generating plants, load imbalances, etc. This level of refinement will require significant input from the electric utility.

3. Site Inspections. Many vulnerabilities of electric system equipment can be best found by site inspection (expert walkdown). Equipment anchorage and seismic interactions are two vulnerabilities which usually cannot be treated strictly using design drawing documentation.

4. Refined Damage Algorithms. Damage algorithms can be developed for specific components of an electric system. In particular, different brands of substation equipment have significantly different seismic performance characteristics.

   This level of refinement is almost always performed by electric utilities. It requires a review of each component's design basis and site investigation to confirm installation.

   The effect of conductor slack should be incorporated into the substation component damage algorithms. Conductor slack can be best found with site inspection.

5. Operations Review. The loss estimation model provided in this report makes number of assumptions about how the electric system operates. The best people who really know how an individual electric system works are the people that operate the system on a daily basis. It is strongly recommended that electric utility operations staff be involved with the inputs to the model, and interpretation of results.

6. The user could perform more extensive geotechnical investigations. This would allow study of transmission towers, buried transmission lines, and improved study of individual substation sites.

The results from a Level 3 analysis will include all those from the Level 2 analysis, plus the following:

1. What pre-earthquake mitigation hardware improvements can the electric utility perform to improve post-earthquake service levels?

2. What number of spare parts (like transformers) should the electric utility keep in inventory to minimize post-earthquake service outages? The Level 2 analysis assumes that spare parts will not be a limiting factor in the post-earthquake restoration effort.

8.1.10 References

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Electric Generation Facilities	Components
Oil Power Plants	Buildings
Gas Power Plants	Buried Pipe
Coal Power Plants	Elevated Pipe
	Boilers
	Turbines
	Steam Generators
	Coal Handling Structures and Equipment
	Coal Pulverizers
	Flat Bottom Tanks
	Large horizontal tanks
	Small to medium horizontal tanks
	Vertical pumps
	Horizontal pumps
	Large motor operated valves
	Large hydraulic and air actuated valves
	Large relief, manual and check valves
	Small valves
	Diesel Generators
	Batteries
	Low voltage switchgear
	Instrument racks and panels
	Motor control centers
	Inverters
	Cable trays and conduits
	HVAC ducting
	HVAC equipment
	Low voltage circuit breakers
	Substation (see transmission)

Table 8.1-1 Electric Generation Facilities - Components

Facility	Components

Substations
High Voltage
(Over 110 kV)
	Transformers
	Live Tank Circuit Breakers
	Dead Tank Circuit Breakers
	Disconnect Switches
	Lightning Arrestors
	Coupling Capacitor Voltage Transformers
	Current Transformers
	Wave Traps
	Bus Structures
	Control Building
	    Relay and Control Panels
	    Station Batteries
	    Emergency Generators
	Other yard equipment
	    Circuit Switchers
	    Series Capacitors
	    Potential Transformers
	    Insulator Posts
	    Other

Distribution	Low voltage distribution circuit - looped Low voltage distribution circuit - string

Table 8.1-2 Electric Switchyards - Components

Generation Facility	Size (MWe)	Value per MWe
Coal Fired	0 - 200	$1,250,000
	200 - 500	$1,500,000
	500 +	$1,750,000
Gas Fired	0 - 50	$1,000,000
	50 - 200	$1,500,000
	200 - 500	$1,750,000
	500 +	$1,750,000
Oil Fired	0 - 50	$1,250,000
	50 - 200	$1,500,000
	200 - 500	$1,750,000
	500 +	$1,750,000
Nuclear	All	$2,500,000

Table 8.1-3 Generation Facilities - Default Values

Note: value is represented in $1994 dollars. Substantial variation in value of different power plants of the same power output exist throughout the country. The user may override the default value for individual power plants using actual plant values.

Equipment / Component	Fraction of Total Plant Value (%)
Boiler Building	10
Turbine Building	8
Administration Building	2
Buried Pipe*	1
Elevated Pipe**	12
Boilers + Steam Generators	11
Turbines	5
Flat Bottom Tanks	3
Large Horizontal Tanks	4
Small to medium hz. tanks	4
Vertical pumps	2
Horizontal pumps	3
Large motor operated valves	3
Large hydraulic, air valves	1
Large relief, manual and relief valves	1
Small valves	1
Diesel Generators	2
Batteries	2
Instrument racks and panels	1
Control Panels	1
Switchgear	1
Motor control centers	3
Inverters	1
Cable trays and raceways	3
HVAC ducting	1
HVAC equipment	2
Switchyard	n.a.
Miscellaneous	12
Total	100 %

Table 8.1-4 Generation Facilities - Default Component Values

* Assumed 6,000 feet per 100 MWe power plant.

* * Assumed 40,000 feet per 100 MWe power plant.

Equipment / Component	Zone 3 / 4	Zone 0 / 1 / 2	Frag. Curve
Boiler Building	Braced Steel Frame (80%) Moment Resist Frame (20%)	Braced Steel Frame (80%) Moment Resist Frame (20%)	
Turbine Building	Braced Steel Frame (40%) Moment Resist Frame (30%) R.C. Shear Wall (28%) Steel Frame / URM (2%)	Braced Steel Frame (30%) Moment Resist Frame (45%) R.C. Shear Wall (15%) Steel Frame / URM (10%)	
Administration Building	Lowrise Steel (40%) Lowrise RC (40%) Trailers (20%)	Lowrise Steel (40%) Lowrise RC (40%) Trailers (20%)	
Buried Pipe	Large Diam. Cast Iron (50%) L. Diam. Welded Steel (40%) Small Diam. Cast Iron (10%)	L. Diam. Cast Iron (50%) L. Dm. Welded Steel (40%) Sm. Diam. Cast Iron (10%)	Eq. 8.2-1 Eq. 8.2-2 Eq. 8.2-3
Elevated Pipe	Piping (50%) Supports (50%)	Piping (50%) Supports (50%)	Eq. 8.1-12 Eq. 8.1-13
Boilers + Steam Generators	Well Anchored (90%) Moderately Anchored (10%)	Well Anchored (75%) Moderately Anchored (25%)	E2.1
Turbine Generator	Standard (100%)	Standard (100%)	E1.7
Flat Bottom Tanks	Steel - Anchored (40%) Steel - Unanchored (40%) Concrete - Anchored (10%) Concrete - Unanchored (10%)	Steel - Anchored (20%) Steel - Unanchored (60%) Concrete - Anchored (2%) Concrete - Unanch. (18%)	TK5 TK3 TK8 TK2
Large Horizontal Tanks	Anchored (90%) Unanchored (10%)	Anchored (70%) Unanchored (30%)	E2.3
Small to medium Horizontal Tanks	Anchored (90%) Unanchored (10%)	Anchored (70%) Unanchored (30%)	E2.4
Vertical Pumps	Standard	Standard	W3.2
Horizontal Pumps	Standard	Standard	W3.3

Table 8.1-5 Generation Facilities - Default Component Types (Part 1)

Equipment / Component	Zone 3 / 4	Zone 0 / 1 / 2	Frag. Curve
Large MOVs	Standard	Standard	E2.8
Large Hydraulic, Air Valves	Standard	Standard	E2.9
Large Manual, Relief Valves	Standard	Standard	E2.10
Misc. Small Valves	Standard	Standard	E2.11
Diesel Generators	Anchored (60%) Snubbed Anchored (30%) Unanchored (10%)	Anchored (30%) Snubbed Anchored (40%) Unanchored (30%)	W2.1 W2.2 W2.3
Battery Racks	Well Anchored (70%) Moderately Anchored (10%) Unanchored (20%)	Well Anchored (25%) Moderately Anchored (25%) Unanchored (50%)	E1.2 W2.5 W2.8
Instrument Panels and Racks	Well Anchored (70%) Moderately Anchored (10%) Unanchored (20%)	Well Anchored (25%) Moderately Anchored (25%) Unanchored (50%)	E1.4 W5.2 W5.3
Control Panels	Well Anchored (70%) Moderately Anchored (10%) Unanchored (20%)	Well Anchored (25%) Moderately Anchored (25%) Unanchored (50%)	E1.5 W5.2 W5.3
Switchgear	Well Anchored (70%) Moderately Anchored (10%) Unanchored (20%)	Well Anchored (25%) Moderately Anchored (25%) Unanchored (50%)	E1.3 W5.2 W5.3
Motor Control Centers	Well Anchored (70%) Moderately Anchored (10%) Unanchored (20%)	Well Anchored (25%) Moderately Anchored (25%) Unanchored (50%)	E1.6 W5.2 W5.3
Inverters	Well Anchored (70%) Moderately Anchored (10%) Unanchored (20%)	Well Anchored (25%) Moderately Anchored (25%) Unanchored (50%)	E1.6 W5.2 W5.3
Cable Trays and Raceways	Seismic Design (20%) Industrial Design (80%)	Seismic Design (0%) Industrial Design (100%)	E3.1
HVAC Ducting	Seismic Design (20%) Industrial Design (80%)	Seismic Design (0%) Industrial Design (100%)	E3.2
HVAC Equipment	Seismic Design (20%) Industrial Design (80%)	Seismic Design (0%) Industrial Design (100%)	E3.3
Miscellaneous	Standard	Standard	

Table 8.1-5 Generation Facilities - Default Component Types (Part 2)

Component	Fraction of Total Substation Value
Transformers	40 %
Circuit Breakers	15
Disconnect Switches	2
Lightning (Surge) Arrestors	1
CCVTs	1
Current Transformers	2
Wave Traps	1
Bus Structures	7
Control Building	10
Batteries	1
Electrical Control Equipment	9
Other Yard Equipment	11
Total	100 %

Table 8.1-6 Substation Facilities - Default Component Values

Component	Zone 3 / 4	Zone 0 / 1 / 2	Frag. Curve
Transformers	Anchored (90%) Unanchored (10%)	Anchored (25%) Unanchored (75%)	S500-1 S500-2
Circuit Breakers	Live Tank Seismic (5%) Live Tank Standard (15%) Dead Tank (80%)	Live Tank Seismic (0%) Live Tank Standard (50%) Dead Tank (50%)	S500-4 S500-3 S500-5
Disconnect Switches	Rigid Bus (50%) Flexible Bus (50%)	Rigid Bus (50%) Flexible Bus (50%)	S500-6 S500-7
Lightning Arrestors	Standard (100%)	Standard (100%)	S500-8
CCVTs	Cantilevered (50%) Suspended (50%)	Cantilevered (50%) Suspended (50%)	S500-9 S500-10
Current Transformers	Gasketed (50%) Flanged (50%)	Gasketed (50%) Flanged (50%)	S500-11 S500-12
Wave Traps	Cantilevered (50%) Suspended (50%)	Cantilevered (50%) Suspended (50%)	S500-13 S500-14
Bus Structures	Rigid Bus (50%) Flexible Bus (50%)	Rigid Bus (50%) Flexible Bus (50%)	S500-15 S500-16
Control Building	Reinforced Concrete (30%) Reinforced Masonry (30%) Steel (30%) Tiltup (10%)	Reinforced Concrete (30%) Reinforced Masonry (30%) Steel (30%) Tiltup (8%) Unreinforced Masonry (2%)	
Batteries	Anchored (25%) Unanchored (75%)	Anchored (25%) Unanchored (75%)	W5.5 W5.8
Electrical Equipment	Anchored (35%) Nominally Anchored (35%) Unanchored (30%)	Anchored (15%) Nominally Anchored (25%) Unanchored (60%)	W5.1 W5.2 W5.3
Other Yard Equipment	Standard (100%)	Standard (100%)	S500-17

Table 8.1-7 500 kV Substation Facilities - Default Component Types

Component	Zone 3 / 4	Zone 0 / 1 / 2	Frag. Curve
Transformers	Anchored (90%) Unanchored (10%)	Anchored (25%) Unanchored (75%)	S230-1 S230-2
Circuit Breakers	Live Tank Seismic (5%) Live Tank Standard (15%) Dead Tank (80%)	Live Tank Seismic (0%) Live Tank Standard (50%) Dead Tank (50%)	S230-4 S230-3 S230-5
Disconnect Switches	Rigid Bus (50%) Flexible Bus (50%)	Rigid Bus (50%) Flexible Bus (50%)	S230-6 S230-7
Lightning Arrestors	Standard (100%)	Standard (100%)	S230-8
CCVTs	Standard (100%)	Standard (100%)	S230-9
Current Transformers	Standard (100%)	Standard (100%)	S230-10
Wave Traps	Cantilevered (50%) Suspended (50%)	Cantilevered (50%) Suspended (50%)	S230-11 S230-12
Bus Structures	Rigid Bus (50%) Flexible Bus (50%)	Rigid Bus (50%) Flexible Bus (50%)	S230-13 S230-14
Control Building	Reinforced Concrete (30%) Reinforced Masonry (30%) Steel (30%) Tiltup (10%)	Reinforced Concrete (30%) Reinforced Masonry (30%) Steel (30%) Tiltup (8%) Unreinforced Masonry (2%)	
Batteries	Anchored (25%) Unanchored (75%)	Anchored (25%) Unanchored (75%)	W5.5 W5.8
Electrical Equipment	Anchored (35%) Nominally Anchored (35%) Unanchored (30%)	Anchored (15%) Nominally Anchored (25%) Unanchored (60%)	W5.1 W5.2 W5.3
Other Yard Equipment	Standard (100%)	Standard (100%)	S230-15

Table 8.1-8 230 kV Substation Facilities - Default Component Types

Component	Zone 3 / 4	Zone 0 / 1 / 2	Frag. Curve
Transformers	Anchored (90%) Unanchored (10%)	Anchored (25%) Unanchored (75%)	S115-1 S115-2
Circuit Breakers	Live Tank Seismic (5%) Live Tank Standard (15%) Dead Tank (80%)	Live Tank Seismic (0%) Live Tank Standard (50%) Dead Tank (50%)	S115-4 S115-3 S115-5
Disconnect Switches	Rigid Bus (50%) Flexible Bus (50%)	Rigid Bus (50%) Flexible Bus (50%)	S115-6 S115-7
Lightning Arrestors	Standard (100%)	Standard (100%)	S115-8
CCVTs	Standard (100%)	Standard (100%)	S115-9
Current Transformers	Standard (100%)	Standard (100%)	S115-10
Wave Traps	Cantilevered (50%) Suspended (50%)	Cantilevered (50%) Suspended (50%)	S115-11 S115-12
Bus Structures	Rigid Bus (50%) Flexible Bus (50%)	Rigid Bus (50%) Flexible Bus (50%)	S115-13 S115-14
Control Building	Reinforced Concrete (30%) Reinforced Masonry (30%) Steel (30%) Tiltup (10%)	Reinforced Concrete (30%) Reinforced Masonry (30%) Steel (30%) Tiltup (8%) Unreinforced Masonry (2%)	
Batteries	Anchored (25%) Unanchored (75%)	Anchored (25%) Unanchored (75%)	W5.5 W5.8
Electrical Equipment	Anchored (35%) Nominally Anchored (35%) Unanchored (30%)	Anchored (15%) Nominally Anchored (25%) Unanchored (60%)	W5.1 W5.2 W5.3
Other Yard Equipment	Standard (100%)	Standard (100%)	S115-15

Table 8.1-9 115 kV Substation Facilities - Default Component Types

Component	Zone 3 / 4	Zone 0 / 1 / 2	Frag. Curve
Circuit	Standard (75%) Seismic (25%)	Standard (100%) Seismic (0%)	D1-1 D1-2

Table 8.1-10 Distribution Systems - Default Component Types

Components	500 kV	230 kV	115 kV
Transformers	0.20	0.25	0.50
Live Tank Circuit Breakers	0.05 - 0.10	0.05 - 0.20	0.20 - 0.30
Dead Tank Circuit Breakers	0.40 - 0.50	>0.50	>0.70
Disconnect Switches	0.20	0.20	0.60
Lightning Arrestors	0.20	0.20- 0.35	0.75
CCVTs	0.20	0.20- 0.35	0.75
Current Transformers	0.10 - 0.20	0.10- 0.35	0.50
Wave Traps - Cantilevered	0.30	0.25- 0.40	0.75
Rigid Bus Structures	0.20	0.20- 0.35	0.75

Table 8.1-11 Electric Switchyards - Damaging PGAs - Anchored Equipment
(Onset of Significant Risk of Serious Damage)

Category	Failures	Damaged
Piping (Above Ground)		
Seismic Anchor Movement	15	0
Corrosion	7	0
Interaction	3	60
Non-welded Joints	36	10
Pipe Supports	11	29
Internal Equipment	15	19

Table 8.1-12 Piping Damage and Failure in Power Plants
Based on Worldwide Survey of 29 Earthquakes

Estimated total amount of piping at risk: 1,200,000 feet
Estimated total number of supports at risk: 100,000

E1: ELECTRIC POWER PLANT EQUIPMENT - Electrical Components - Well Anchored										
			Ground Shaking			Ground Failure				
Hazard	Damage State	Damage Factor	Median A (g)	Beta	Freq. (Hz)	Median PGD (inch)	Beta	Functionality Code	Item Code
Ground Shaking	Diesel Generators	0.00	0.65	0.40	22			0	1
Ground Shaking	Battery Racks - failure of batteries	0.05	2.29	0.50	33			0	2
Ground Shaking	Switchgear - spurious actuation of relays	0.00	2.33	0.81	6			0	3
Ground Shaking	Instrument Racks and Panels - relay chatter	0.00	1.15	0.82	5			0	4
Ground Shaking	Control Panels - mulfunctioning equipment	0.05	11.50	0.88	5			0	5
Ground Shaking	Aux. Relay Cabinets/ MCCs / Circuit Breakers - relay or breaker trip	0.00	7.63	0.88	5			0	6
Ground Shaking	Turbine Trip	0.00	0.30	0.40	33*			0	7

Notes: (a) Damage Factor is ratio of repair cost of subcomponent / replacement value of component.
(b) Functionality Code: 0 means not functional; 1 means functional.
(c) Item Codes: For each Item Code for which demand exceeds capacity, the damage state occurs.
(d) 33* indicates use of PGA and does not mean the equipment's frequency is 33 Hz

E2: ELECTRICAL POWER PLANT EQUIPMENT - Mechanical Equipment - Well Anchored										
			Ground Shaking			Ground Failure			
Hazard	Damage State	Damage Factor	Median A (g)	Beta	Freq. (Hz)	Median PGD (inch)	Beta	Functionality Code	Item Code
Ground Shaking	Large vertical vessels with formed heads	0.25	1.46	0.40	7			0	1
Ground Shaking	Boilers and Pressure Vessels	0.40	1.30	0.70	10			0	2
Ground Shaking	Large horizontal vessels	0.25	3.91	0.61	15			0	3
Ground Shaking	Small to medium horizontal vessels	0.25	1.84	0.51	15			0	4
Ground Shaking	Large vertical pumps	0.50	2.21	0.39	5			0	5
Ground Shaking	Motor Driven pumps	0.50	3.19	0.34	7			0	6
Ground Shaking								0	
Ground Shaking	Large Motor Operated Valves	0.25	4.83	0.65	15			0	8
Ground Shaking	Large Hydraulic and Air Actuated Valves	0.25	7.61	0.46	33			0	9
Ground Shaking	Large Relief, Manual and Check Valves	0.25	8.90	0.40	33			0	10
Ground Shaking	Small Motor Operated Valves	0.25	9.84	0.65	20			0	11
								0	12

Notes: (a) Damage Factor is ratio of repair cost of subcomponent / replacement value of component.
(b) Functionality Code: 0 means not functional; 1 means functional.
(c) Item Codes: For each Item Code for which demand exceeds capacity, the damage state occurs.

E3: ELECTRICAL POWER PLANT EQUIPMENT - Other Equipment									
			Ground Shaking			Ground Failure			
Hazard	Damage State	Damage Factor	Median A (g)	Beta	Freq. (Hz)	Median PGD (inch)	Beta	Functionality Code	Item Code
Ground Shaking	Cable Trays	0.25	2.23	0.39	33*			0	1
Ground Shaking	HVAC Ducting - Support system failure	0.12	3.97	0.54	8			0	2
Ground Shaking	HVAC Equipment - Fans	0.25	2.24	0.34	4			0	3
Ground Shaking								0	4
Ground Shaking								0	5
Ground Failure								0	6

Notes: (a) Damage Factor is ratio of repair cost of subcomponent / replacement value of component.
(b) Functionality Code: 0 means not functional; 1 means functional.
(c) Logic Codes: For each Logic Code, only one Damage State can occur. For each Logic Code for which demand exceeds

S230. Substation High Voltage Components (165 kV - 350 kV)

Hazard	Damage State	Damage Factor	Ground Shaking Median A (g)	Beta	Freq. (Hz)	Ground Failure Median PGD (inch)	Beta	Functionality Code	Item Code
Ground Shaking	Transformer - Anchored	0.40	0.60	0.70	33*			0	1
Ground Shaking	Transformer - Unanchored	0.60	0.30	0.70	33*			0	2
Ground Shaking	Live Tank Circuit Breaker - Standard	0.60	0.50	0.70	33*			0	3
Ground Shaking	Live Tank Circuit Breaker - Seismic	0.10	0.70	0.70	33*			0	4
Ground Shaking	Dead Tank Circuit Breaker - Standard	0.40	1.60	0.70	33*			0	5
Ground Shaking	Disconnect Switch - Rigid Bus	0.50	0.50	0.70	33*			0	6
Ground Shaking	Disconnect Switch - Flexible Bus	0.10	0.75	0.70	33*			0	7
Ground Shaking	Lightning Arrestor	1.00	0.60	0.70	33*			0	8
Ground Shaking	CCVT	1.00	0.60	0.70	33*			0	9
Ground Shaking	Current Transformer (gasketed)	0.50	0.50	0.70	33*			0	10
Ground Shaking	Wave Trap - Cantilevered	1.00	0.60	0.70	33*			0	11
Ground Shaking	Wave Trap - Suspended	0.50	1.40	0.60	33*			0	12
Ground Shaking	Bus Structure - Rigid	0.15	0.60	0.70	33*			0	13
Ground Shaking	Bus Structure - Flexible	0.05	2.00	0.70	33*			0	14
Ground Shaking	Other Yard Equipment	0.50	0.60	0.70	33*			0	15
Ground Failure	Any Piece of Yard Equipment	1.00				6	1.00	0	16

Notes: (a) Damage Factor is ratio of repair cost of component / replacement value of component.
(b) Functionality Code: 0 means not functional; 1 means functional.
(c) Frequency: 33* indicates that damage algoriuthm is keyed to PGA, and does not indicate actual fundamental frequency of the component

S115. Substation Moderately High Voltage Components (100 kV - 165 kV)

Hazard	Damage State	Damage Factor	Ground Shaking Median A (g)	Ground Shaking Beta	Ground Shaking Freq. (Hz)	Ground Failure Median PGD (inch)	Ground Failure Beta	Functionality Code	Item Code
Ground Shaking	Transformer - Anchored	0.40	0.75	0.70	33*			0	1
Ground Shaking	Transformer - Unanchored	0.60	0.50	0.70	33*			0	2
Ground Shaking	Live Tank Circuit Breaker - Standard	0.60	0.60	0.70	33*			0	3
Ground Shaking	Live Tank Circuit Breaker - Seismic	0.10	1.00	0.70	33*			0	4
Ground Shaking	Dead Tank Circuit Breaker - Standard	0.40	2.00	0.70	33*			0	5
Ground Shaking	Disconnect Switch - Rigid Bus	0.50	0.90	0.70	33*			0	6
Ground Shaking	Disconnect Switch - Flexible Bus	0.10	1.20	0.70	33*			0	7
Ground Shaking	Lightning Arrestor	1.00	1.00	0.70	33*			0	8
Ground Shaking	CCVT	1.00	1.00	0.70	33*			0	9
Ground Shaking	Current Transformer (gasketed)	0.50	0.75	0.70	33*			0	10
Ground Shaking	Wave Trap - Cantilevered	1.00	1.00	0.70	33*			0	11
Ground Shaking	Wave Trap - Suspended	0.50	1.60	0.60	33*			0	12
Ground Shaking	Bus Structure - Rigid	0.15	1.00	0.70	33*			0	13
Ground Shaking	Bus Structure - Flexible	0.05	2.00	0.70	33*			0	14
Ground Shaking	Other Yard Equipment	0.50	1.00	0.70	33*			0	15
Ground Failure	Any Piece of Yard Equipment	1.00				6	1.00	0	16

Notes: (a) Damage Factor is ratio of repair cost of component / replacement value of component.
(b) Functionality Code: 0 means not functional; 1 means functional.
(c) Frequency: 33* indicates that damage algoriuthm is keyed to PGA, and does not indicate actual fundamental frequency of the component

S500. Substation Very High Voltage Components (500 kV and Higher)									
			Ground Shaking			Ground Failure			
Hazard	Damage State	Damage Factor	Median A (g)	Beta	Freq. (Hz)	Median PGD (inch)	Beta	Functionality Code	Item Code
Ground Shaking	Transformer - Anchored	0.40	0.40	0.70	33*			0	1
Ground Shaking	Transformer - Unanchored	0.60	0.25	0.70	33*			0	2
Ground Shaking	Live Tank Circuit Breaker - Standard	0.60	0.30	0.70	33*			0	3
Ground Shaking	Live Tank Circuit Breaker - Seismic	0.10	0.40	0.70	33*			0	4
Ground Shaking	Dead Tank Circuit Breaker - Standard	0.40	0.70	0.70	33*			0	5
Ground Shaking	Disconnect Switch - Rigid Bus	0.50	0.40	0.70	33*			0	6
Ground Shaking	Disconnect Switch - Flexible Bus	0.10	0.60	0.70	33*			0	7
Ground Shaking	Lightning Arrestor	1.00	0.40	0.70	33*			0	8
Ground Shaking	CCVT - Cantilevered	1.00	0.90	0.60	33*	check this		0	9
Ground Shaking	CCVT - Suspended	1.00	0.30	0.70	33*	check this		0	10
Ground Shaking	Current Transformer (gasketed)	0.60	0.30	0.70	33*			0	11
Ground Shaking	Current Tranformer (flanged)	0.40	0.80	0.70	33*			0	12
Ground Shaking	Wave Trap - Cantilevered	1.00	0.50	0.70	33*			0	13
Ground Shaking	Wave Trap - Suspended	0.50	1.30	0.60	33*			0	14
Ground Shaking	Bus Structure - Rigid	0.15	0.40	0.70	33*			0	15
Ground Shaking	Bus Structure - Flexible	0.05	2.00	0.70	33*			0	16
Ground Shaking	Other Yard Equipment	0.50	0.40	0.70	33*			0	17
Ground Failure	Any Piece of Yard Equipment	1.00				6	1.00	0	18

Notes: (a) Damage Factor is ratio of repair cost of component / replacement value of component.
(b) Functionality Code: 0 means not functional; 1 means functional.
(c) Frequency: 33* indicates that damage algoriuthm is keyed to PGA, and does not indicate actual fundamental frequency of the component

D1. Distribution Circuits									
			Ground Shaking			Ground Failure			
Hazard	Damage State	Damage Cost	Median A (g)	Beta	Freq. (Hz)	Median PGD (inch)	Beta	Functionality Code	Item Code
Ground Shaking	Standard Circuit Fails	$3	0.60	0.50	33*			0	1
Ground Shaking	Seismic Circuit Fails	$3	0.75	0.50	33*			0	2

Notes: (a) Damage Cost is typical repair cost per circuit (in thousands)
(b) Functionality Code: 0 means not functional; 1 means functional.
(c) Frequency: 33* indicates that damage algoriuthm is keyed to PGA, and does not indicate actual fundamental frequency of the component

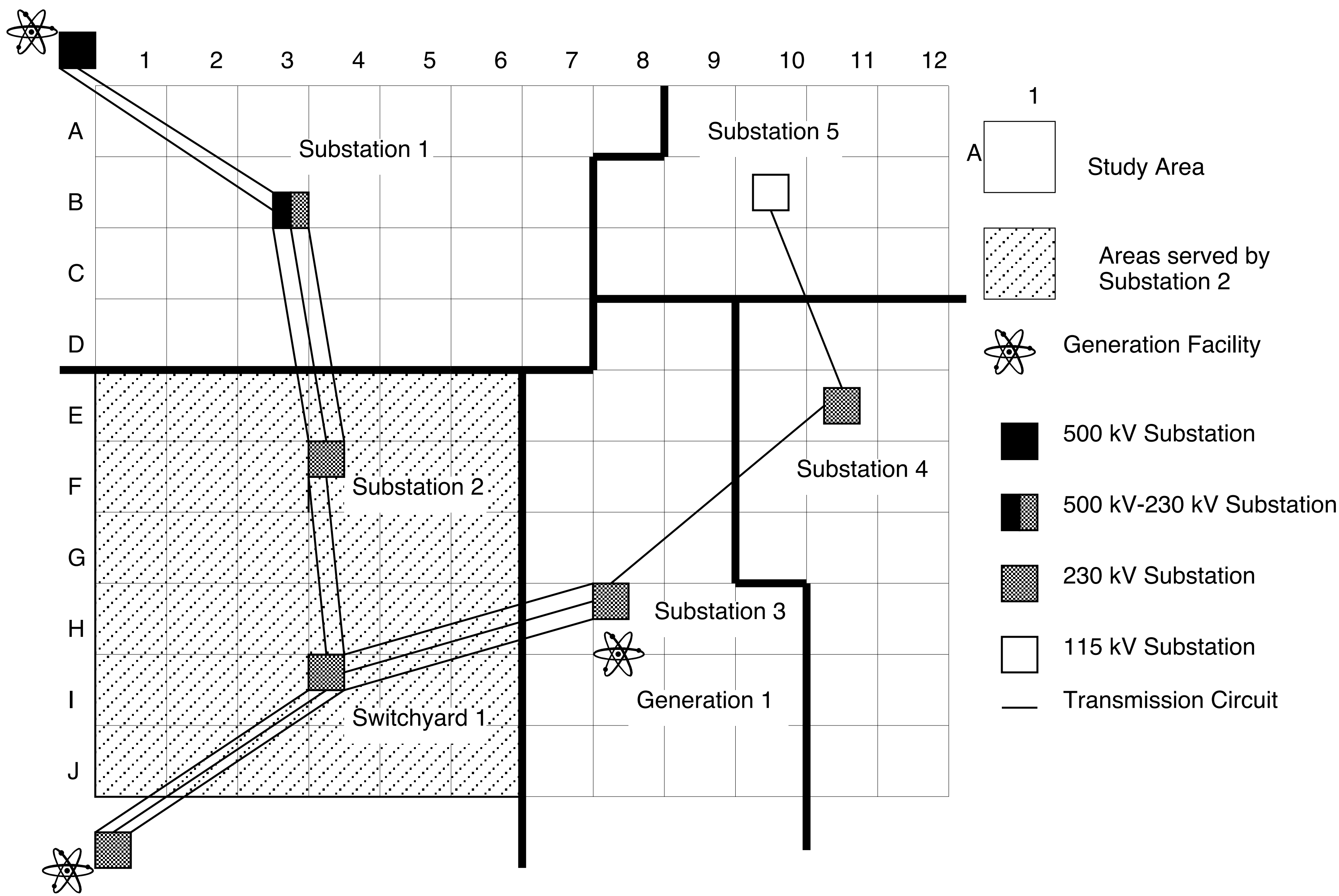

Fig. 8.1-1 GENERATION FACILITIES AND SUBSTATIONS

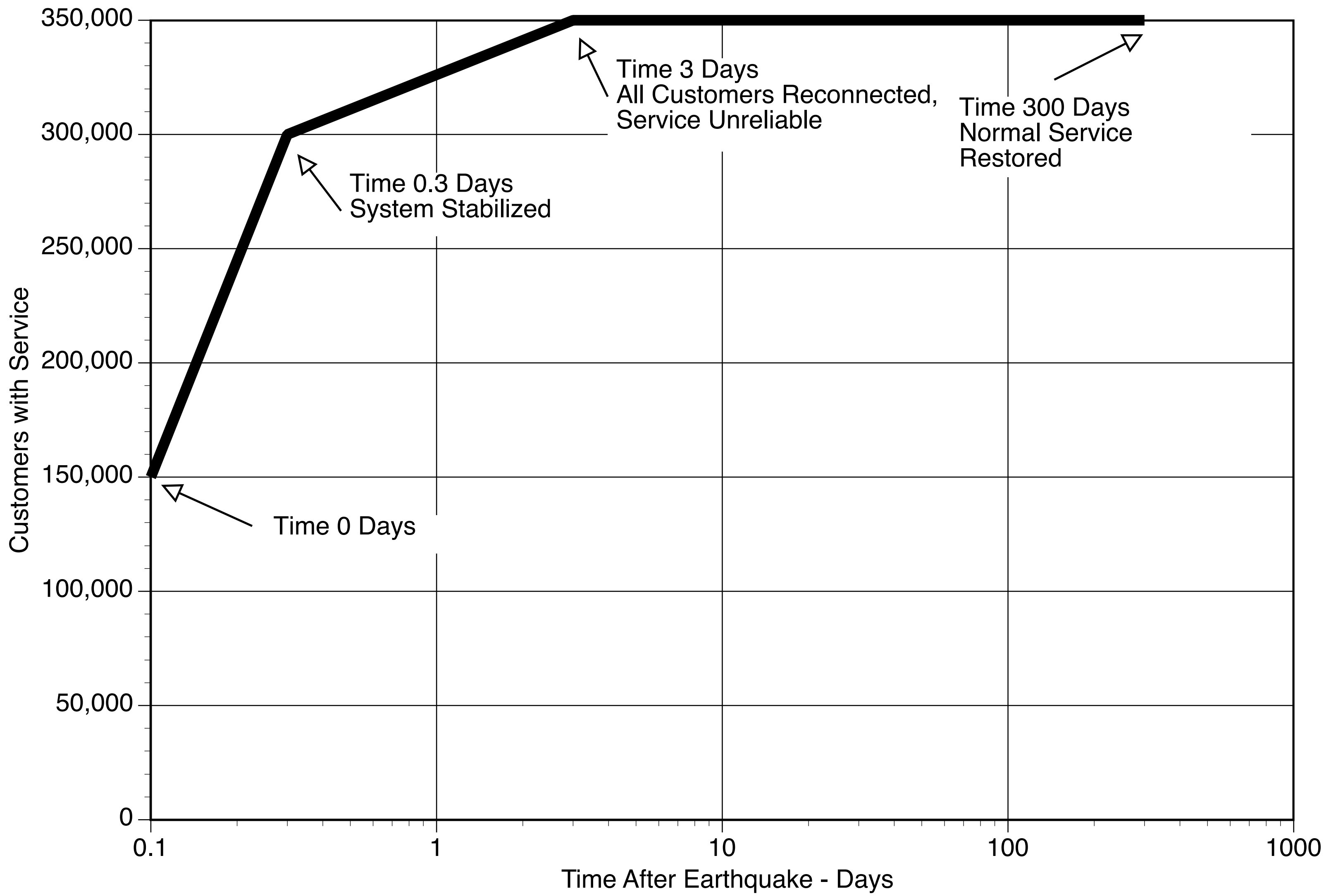

Figure 8.1-2a. Service Restoration Curve (Customers with Service)

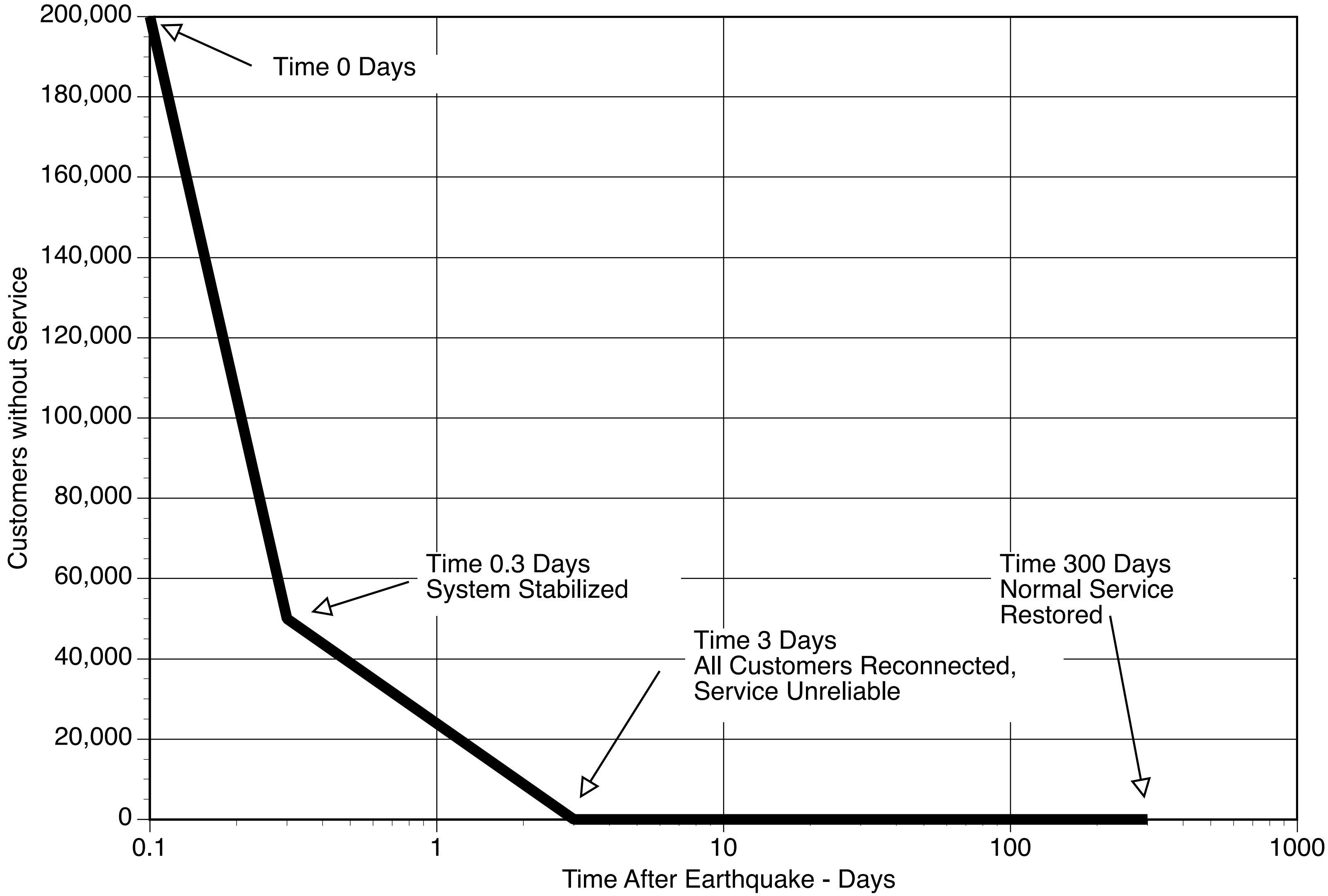

Figure 8.1-2b. Service Outage Curve (Customers without Service)

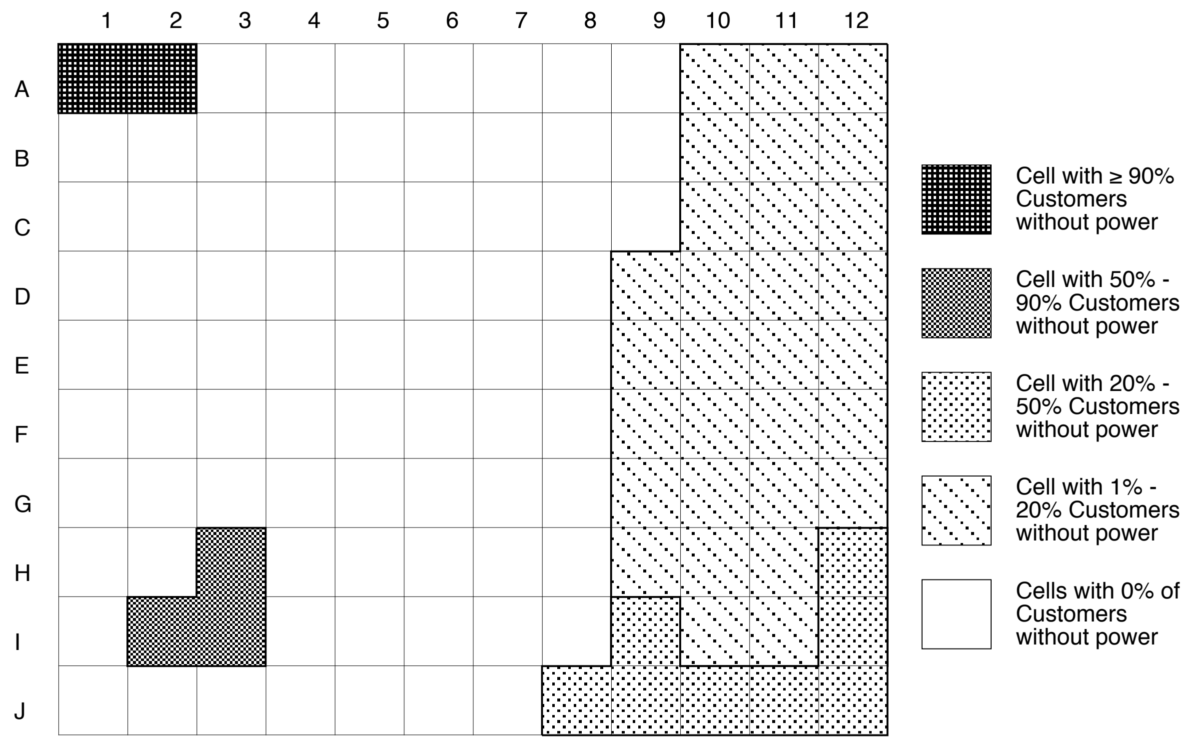

FIGURE 8.1-3. ELECTRIC OUTAGE MAP - TIME 0

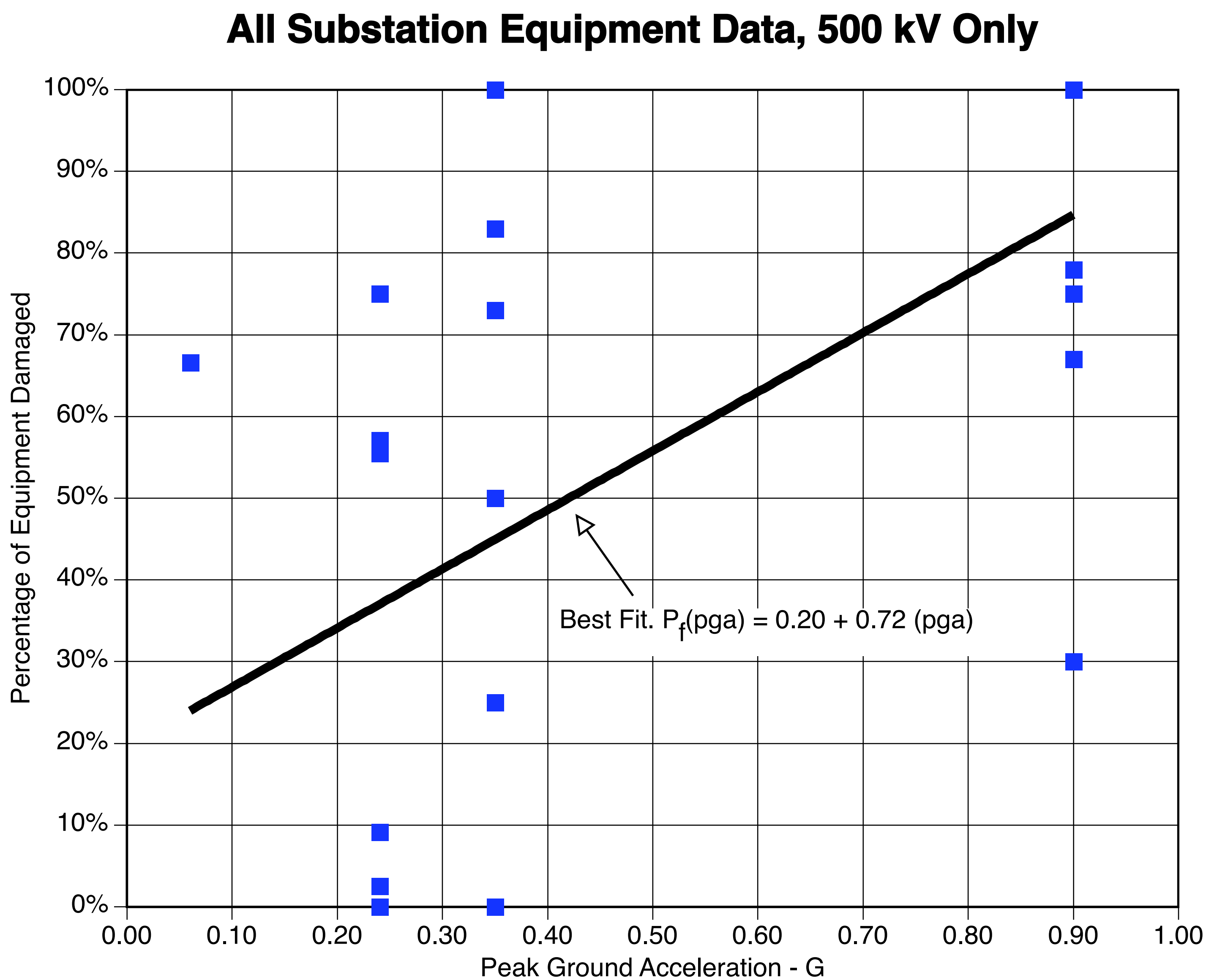
All Substation Equipment Data, 500 kV Only
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percentage of Equipment Damaged
Best Fit. P_f(pga) = 0.20 + 0.72 (pga)
0.00
0.10
0.20
0.30
0.40
0.50
0.60
0.70
0.80
0.90
1.00
Peak Ground Acceleration - G

Figure 8.1-4

Substation Equipment Data, 500 kV Only, Excluding Dead Tank Circuit Breakers and Transformers

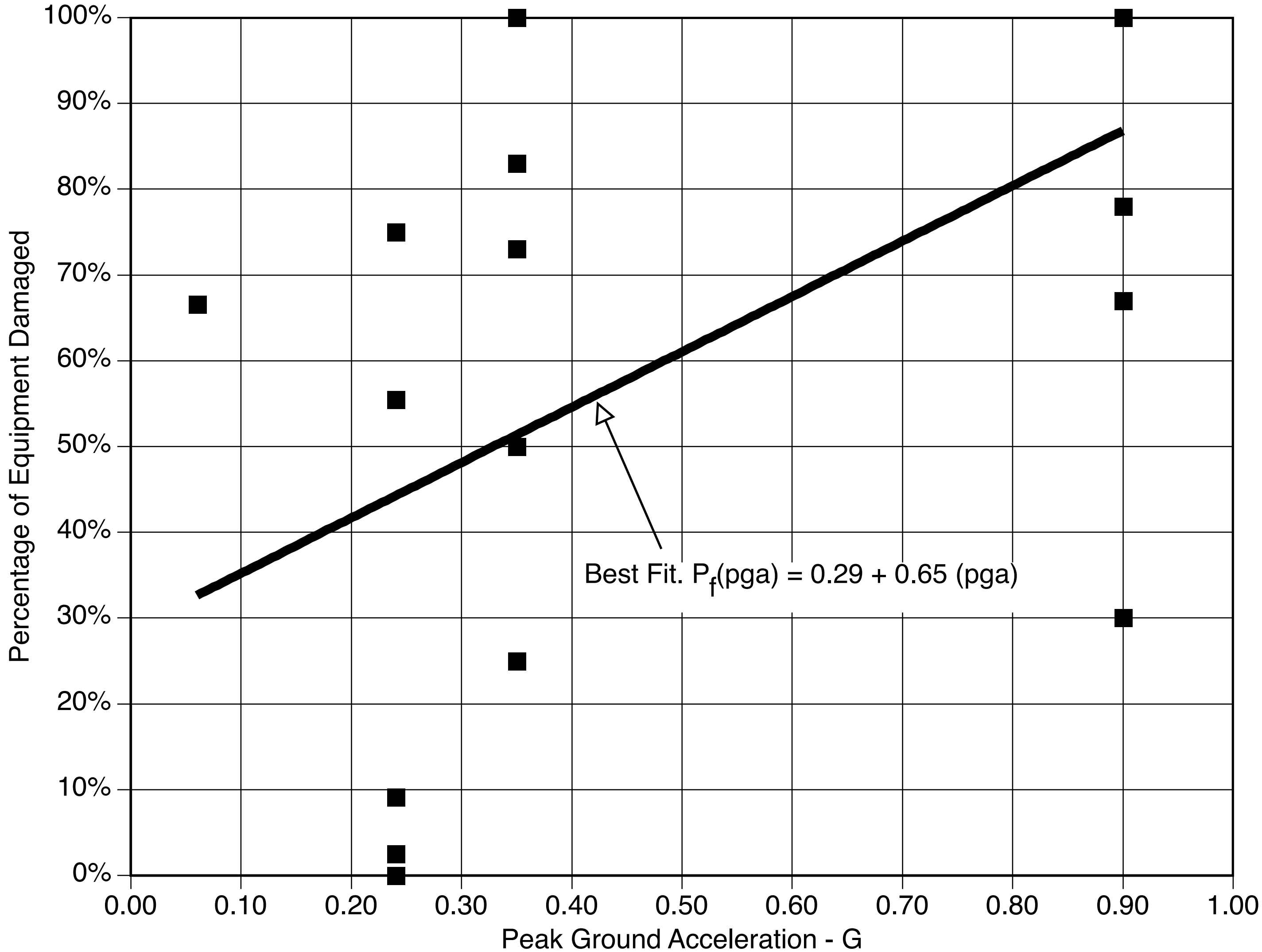

Figure 8.1-5

All Substation Equipment Data, 500 kV Anchored Transformers and Dead Tank Circuit Breakers

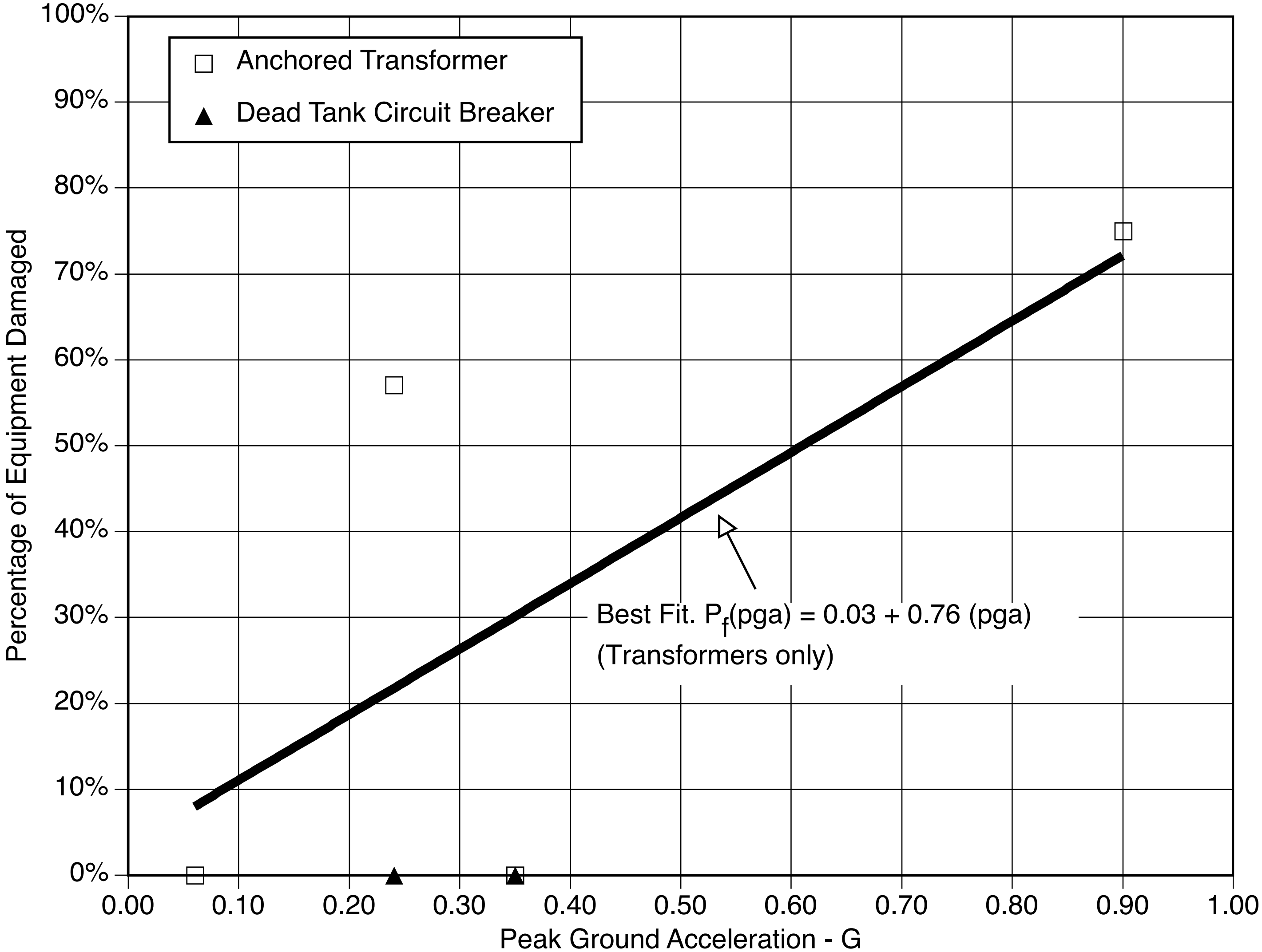

Figure 8.1-6

Substation Equipment Data, 230 kV Only, Excluding Dead Tank Circuit Breakers and Transformers

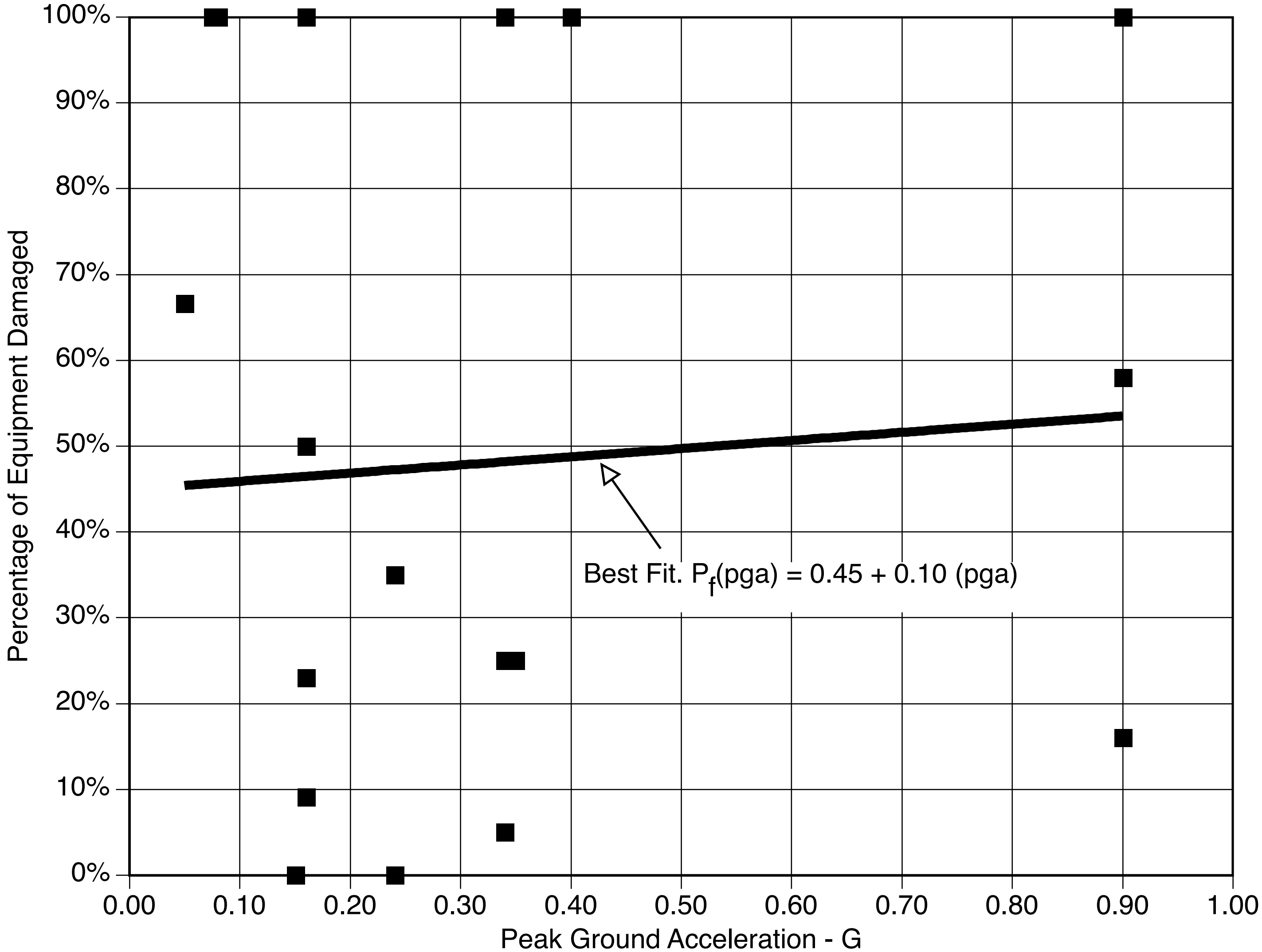

Figure 8.1-7

Substation Equipment Data, 230 kV Anchored Transformers and Dead Tank Circuit Breakers

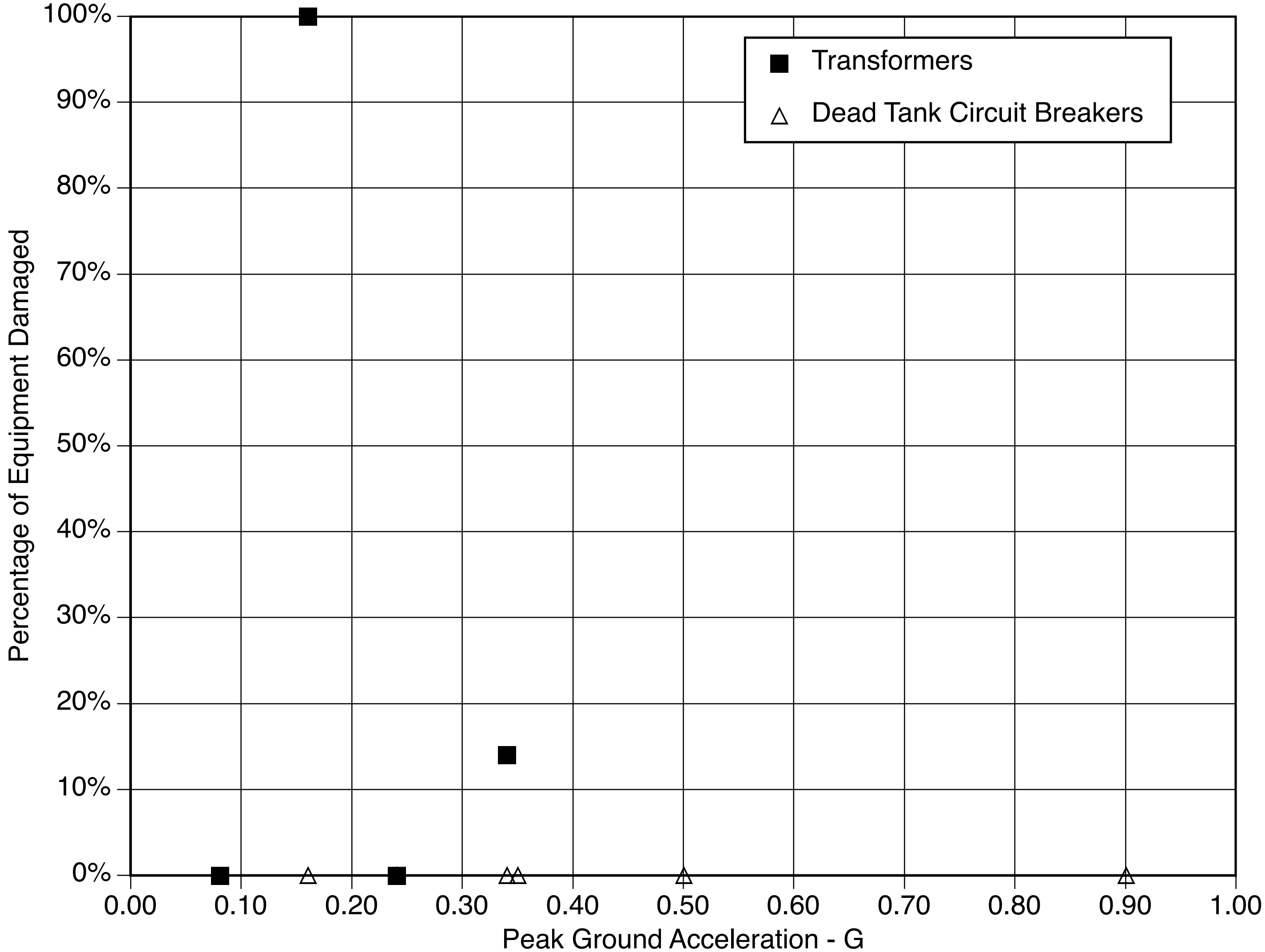

Figure 8.1-8