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Frequency Determination Method for Cascading Grid Events

Technical Report

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Frequency Determination Method for Cascading Grid Events

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PRODUCT DESCRIPTION

On August 14, 2003, a power blackout impacted 50 million people in the U.S. Midwest, U.S. Northeast, and Ontario, Canada. A Westinghouse Owners Group review of the power outage event indicated that while emergency diesel generators performed as expected, many aspects of the event were not anticipated. Characteristics of grid events were different (e.g., typically longer recovery times) from those of plant-centered loss of off-site power (LOOP). Another aspect noted about the August 2003 event was that it did not appear to be globally applicable to all power grids and all units. A review of LOOP data indicated that grid reliability was less of a concern in areas where transmission system operators and a nuclear unit were in close contact and where the grid had considerable residual capacity. This report provides a statistical analysis of nuclear-industry and non-nuclear-industry grid disturbance reports to demonstrate the source of regional and seasonal dependencies in grid stability.

Results & Findings

This report provides a comprehensive discussion of the following key points:

- Statistically, the likelihood of a grid-induced LOOP is a strong function of the location of the plant (regional dependence) as well as the season of the year (seasonal dependence).
- While the industry uses geographic information system (GIS) software to characterize the power grid near nuclear power plants, a limited investigation of the local impact of grid networks and "islanding" of the grid around the plants was inconclusive.
- Correction factors for grid-centered LOOP frequency have been established on a regional level. Characterization of the nearby grid allows individual plants to tailor the grid-event likelihood into a plant-specific, grid-centered LOOP frequency.
- The data examined yielded average LOOP durations from three to nine hours.

Challenges & Objective(s)

LOOP event frequency is a key accident initiator found in many probabilistic risk assessment (PRA) models. The goal of this report is to provide a frequency determination method to assist PRA analysts at U.S. nuclear power plants in correctly estimating the probability of LOOP events caused by cascading grid-disturbance issues. As experience builds, the estimate(s) described in this report will statistically improve. The conclusion that the data shows regional and seasonal dependency is based on weighted combinations of three data sets, with statistical-error allowance set at 5%.

Applications, Values & Use

This report demonstrates regional and seasonal relationships and provides recommendations to nuclear utility PRA analysts in *qualitatively* and *quantitatively* considering the risk implications of power grid events on nuclear plant operation and maintenance.

EPRI Perspective

The LOOP events of August 14, 2003, have focused the industry and its regulators on what heretofore has been considered a constant, namely, the reliability of off-site power. As experience continues to build, it is apparent that grid reliability from the perspective of a nuclear power plant is a strong function of the geographic region of the country as well as season of the year. This study aims to avoid a "one-size-fits-all" assignment of grid-centered LOOP frequency and duration to each nuclear power plant PRA model. The quality of a PRA model improves when it is most realistic. An important initiator such as LOOP frequency needs to be as realistic and plant-specific as possible. As a result, this study uniquely investigates differences in the power grid that serves nuclear power plants across the United States.

Approach

Analysts compiled LOOP events and durations from different sources. They applied conventional statistical methods (such as the analysis of variance, data fitting to probability distributions, and hypothesis testing) to evaluate and derive useful insights from the collected data. To establish a statistically meaningful data set, analysts enriched grid-centered LOOP events by merging traditional LOOP events with events hypothesized to be precursors to LOOP events.

Keywords

Loss-of-Off-Site Power
LOOP Events
Initiating Event
Outage Non-Recovery Probability
Power Grid
Outage Frequency
Outage Duration
Probabilistic Risk Assessment (PRA)
Region
Season

ABSTRACT

Loss-of-offsite power (LOOP) event frequency is a key accident initiator in quantifying risk at commercial nuclear power plants. The LOOP events of August 14, 2003, focused the industry and its regulators on what heretofore has been considered a constant, namely, the reliability of off-site power grids. As experience continues to build, more evidence will support the hypothesis that the grid reliability from the perspective of a nuclear power plant is a strong function of the region of the country (i.e., regional-dependence) as well as the season of the year (seasonal-dependence). This report demonstrates these relationships and provides recommendations to the utility PSA analysts in *qualitatively* and *quantitatively* considering the risk implications of power grid events on nuclear plant operation and maintenance.

When viewed from a national perspective, the location of the nuclear power plant in the context of the North American Electric Reliability Council Regions appears to account for 40% of the variance in the mean grid-event frequency important to a nuclear power plant. Another 15% of the variance is identified by considering the season of the year (traditional solar-seasons).

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ACROYNMS

AC	alternating-current measured in amperes
ANOVA	analysis of variance
AVR	automatic voltage regulator for an AC generator
CDF	core damage frequency – PRA figure of merit
DBA	design basis event – conditions specified by regulation that the plant is intended to successfully cope with.
ECAR	NERC region on the north side of the Ohio Valley
EDG	Emergency Diesel Generator (typical on-site AC power source during LOOP)
EIA	U.S. Department of Energy's Energy Information Agency (in this report, typically refers to the data in Appendix B)
emf	electro-magnetic force
ERCOT	NERC Region in Texas
ESF	engineered safety feature(s) – systems intended to mitigate events at a nuclear power plant
FIDVR	fault-induced delayed voltage recovery
GEITF	NERC Gas/Electricity Interdependency Task Force
GIS	Geographic Information Systems -- a technology that is used to view and analyze data from a geographic perspective
kV	kilo-volt (10^3 volts)
LER	Licensee Event Report (per 10CFR§50.73)
LERF	large-early release frequency – PRA figure of merit
LOOP	Loss-of-offsite Power (no grid connection to either safety bus)
MAAC	NERC region covering the Mid-Atlantic states
MAIN	NERC region in the Mid-West
MAPP	NERC region in the upper Mid-West
MRO	NERC region in the upper Mid-West (new organization combining MAPP with others)
MVAR	See VAR

MWe	Mega-Watt electric – a unit of measure of "real power" (10^6joules/sec)
NERC	North American Electric Reliability Council
NPCC	NERC region in the U.S. Northeast (covers Ontario, Quebec, and Maritime Canada)
NPP	nuclear power plant
PF	power factor, the ratio of real power to total power in an AC circuit
PRA	Probabilistic Risk Assessment
PSA	Refers to the person or group performing PRA
PVNGS	Palo Verde Nuclear Generating Station
PWR	pressurized water reactor
SERC	NERC region in the Southeast
SPP	NERC region in the center of the U.S.
TSC	Technical Support Center (organization associated with the NPP emergency plan)
TSO	transmission system operator
UE	Unusual Event – an emergency planning action level (per 10CFR§50 Appendix E)
UVLS	under-voltage load shed
VACAR	NERC sub-region in Virginia and North Carolina
VAR	Volt-amperes reactive– a unit of measure for reactive power (also MVAR = 10^6VARs)
WECC formerly WSCC	NERC region synonymous with the Western Interconnect
WOG	Westinghouse Owners' Group

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1
INTRODUCTION

Overview

Several industry documents and conferences have pointed to the grid as a source of risk that should be factored into PRA models.

This report is intended to aid PSA analysts at American nuclear power plants by considering the effect of the grid on the PRA models and the conclusions drawn from those models. The chapters in this report cover history, some of the basic physics of grid operation, hypothetical influences on site-specific loss-of-offsite power (LOOP) frequency, statistical analysis of LOOP duration, and statistical analysis of grid events frequency. The final chapter provides mathematical detail on performing a Bayesian update of industry data with plant specific data with an eye toward LOOP frequency.

The reasons LOOP occur at a particular site can be hypothetically related to the physical position of the plant on the grid, the number of circuits to the plant, the number of nearby "MVAR providers," and the distance to industrial (inductive) loads. In a shutdown condition, the house load at nuclear plant is on the order of 20MWe. As the house load is relatively small, the nearby grid is usually able to flawlessly accommodate a sudden load shed by the nuclear power plant main generator. Because the house load is relatively small, the likelihood is quite small that the power grid *at-large* is unable to support house loads (and thus making a LOOP a rare condition). Chapter 2 examines these issues by exploring the power grid around five example plants. The chapter notes several features that hypothetically affect the stability of the grid near the plant. Unfortunately, the results are only qualitative.

Chapter 3 summarizes results of statistically estimating the <u>duration</u> of a grid outage based on industry events as well as a larger database available from the U.S. Department of Energy. The report explorers the feasibility of using a simple fraction applied to Unusual Event duration as a surrogate for a best-estimate re-connect time currently only done for a handful of events.

Chapter 4 summarizes the results of a statistical analysis looking at grid disturbances in an attempt to characterize the <u>likelihood</u> of LOOP based on the plant location (by region) and the seasonal frequency of LOOPs and hypothetical pre-cursors. The approach shows several weightings of industry data that yield a regional and seasonal dependency for grid events. The results of the study are then converted into a qualitative factor by which to adjust grid-LOOP frequency by region and by season. Finally, a procedure is provided for determining a plant-specific grid-LOOP frequency. The procedure involves counting fractions of pre-cursor events as LOOP-equivalent events.

Calculating a grid-LOOP frequency for the plant typically involves a Bayesian update of industry data (events per year) with plant specific data (events per year). The mathematical basis of this update is generally not well described in the available texts and articles. The final chapter of this report makes liberal use of notation to demonstrate a correct technique of taking a Log-normal prior, forcing it to a Gamma-distribution, performing the simple update operation, and then converting the posterior Gamma-distribution into a posterior Log-normal distribution.

Lessons Learned from the August 14, 2003, Grid Disturbance

Treatment of the August 14, 2003, loss of offsite power (LOOP) events is a difficult issue. In total 11 sites (8 sites, 9 reactors, in the United States, as well as 3 sites, 11 reactors, in Canada) lost offsite power or saw sufficient disturbances in offsite power that resulted in them disconnecting them from the grid. The key event was a run of the mill line failure that, because of high demand on distant generators with no alternate routes to serve the demand load, resulted in a cascading disturbance over hundreds of miles. Events of this magnitude have been few and far apart as shown in the tables to follow. Similar extensive grid collapses (due to inadequate system capacity) have occurred in the Eastern Seaboard only during 1965 and 1977.

It is essential to note that the massive outage on August 14, 2003, was not caused by inadequate supplies of available power generation. There are plenty of power plants to generate all the power that is currently needed for virtually all parts of the U.S. Indeed, in many large sections of the country, the so-called "reserve margins" (the excess of available “real-power” capacity over peak demand levels) is greater than 40%, indicating huge capacity surpluses that forestall the need to build more generation for several years. The issue then becomes not how many generators are available, but the locations of those generators relative to the loads on the transmission network. The August 14, 2003, transmission failure, like most outages, was caused by an inability to get the power from where it was generated to where it was being used, i.e., a transmission failure. The transmission grid – the complex pseudo-organism that continuously transfers power from hundreds of generation sources to thousands of distribution nodes ("substations") – was unable to handle a certain set of events on an otherwise fairly normal summer afternoon.[1]

As a result of the uniqueness of the August 14, 2003, transmission failure, EPRI has encountered difficulty in categorizing it, and entirely omitted the event in the LOOP database issued in April 2004 (see Reference 2). Note that Reference 2 only tabulates the last 10-years events. That cutoff excludes a July 1989 LOOP event at V.C. Summer (Reference 4), which is similar to the June 14, 2004, PVNGS event (Reference 6). The similarity was in the number of large generators tripped as a result of a grid disturbance (in this case) originating at V.C. Summer.[2] Treatment of the event in a PRA is likewise, challenging.

[1] Reference 17

[2] Per Reference 4: On July 11, 1989, a Turbine Trip/Reactor Trip occurred while operating at 100% reactor power. Technicians working inside the "Generator Stator Cooling Water" cabinet inadvertently shorted the power leads on the temperature converter causing the AC power fuse to blow. This gave a false indication of loss of generator stator cooling water which caused a Turbine Trip and a Reactor Trip due to the turbine tripping above 50% reactor power.
In addition to the aforementioned loss, three other generating stations tripped while attempting to compensate for the VARs lost on the grid with the Turbine Trip/Reactor Trip.

Grid Operation

The electric power grid associated with a nuclear power plant connects generating assets to *real power* consumers. The electric power created by the main generator flows through many devices on the way to its final usage. The generated power is split between real power and reactive power. As the geographic distance between the power-consumers and power-generation increases, the demand for *reactive power* increases. Unfortunately, reactive power production by a generator is limited by the temperature of components within the generator. Thus, there is a limit to the trade-off between real-power and reactive-power available to the TSOs.

The Role of Reactive Power

Reactive power is the component of total power that assists in maintaining proper voltages across the power grid. Sufficient voltage is maintained across the power grid with reactive power supplied from generating stations and static devices called capacitors. Lightly-loaded transmission lines also provide reactive power and help sustain system voltage. Conversely, customer loads such as motors and other electromagnetic devices consume reactive power, as do heavily loaded transmission lines.

Reactive power is when the amps and volts are not "in phase" and is, to some extent, an unavoidable by-product of producing real power. Reactive power is measured in Voltage-Ampere Reactive (VAR, or volt-amps; or many times mega-VARs – MVARs – 10^6 VARs). Reactive power is the power consumed in an AC circuit because of the expansion and collapse of magnetic (inductive) and electrostatic (capacitive) fields. It is somewhat akin to a mule pulling a barge down a canal. Not all of the energy applied by the mule translates into forward motion of the barge; some is used by the component of force perpendicular to the motion of the barge. The classic power factor (PF) is defined as the ratio of real to reactive energy. Specifically, in an AC circuit, it is the cosine of the phase angle of the current (cosine) waveform (I) compared to the voltage (sine) waveform (U). The magnetic field (and the reactive current that creates it) is effectively constant over a range of real power demands. Therefore, the variable in grid stability is the real power load on the system, the ability of the generators to support the real power load (variable), and the attendant magnetic fields (effectively constant). Harmonics caused by losses to heat, and devices that do not consume current (I) at a steady rate cause the demand for reactive power to become dynamic. Utility power plant generators are usually designed for a PF of 0.8 to 0.9. If demand-side PF were lower than the designed PF, the real power output must be limited, or the generator current (I) will rise above the equipment's rated current (e.g., raising the temperature of mechanical devices like end-bearings above design points). The following equation for a three phase system (assuming a PF of one, i.e., a voltage lag (θ) of zero) shows the relationship between mechanical power applied by the turbine to the generator and the real power and reactive power produced by the generator.

As a result of the loss of four generating stations, the offsite voltage to the Engineering Safety Feature (ESF) busses decreased below the minimum acceptable value.

$$P_{turbine} = eff * P_{generator} = \sqrt{3} * U * I * PF$$
$$where:$$
$$P = \frac{dE}{dt} \equiv watts = \frac{\Delta joules}{\Delta \sec}$$
$$eff \equiv efficiency(ratio)$$
$$U \equiv RMS - voltage - drop = \frac{\Delta joules}{coulomb}$$
$$I = RMS - current \equiv amps = \frac{coulomb}{\sec}$$
$$RMS \equiv root\_mean\_squared$$
$$PF = \cos\Theta = \frac{\operatorname{Re} alPower}{TotalApprentPower} \equiv \frac{\Delta joules}{\Delta \sec} * \frac{1}{volt - amps} = \frac{\Delta joules}{\Delta \sec} * \frac{coulomb}{\Delta joules} * \frac{\Delta \sec}{coulombs}$$
$$\Theta \equiv volt - amp\_(lead - lag)$$

The source of $P_{generator}$ is created by the turbine turning the magnetic field of the armature inside the stator coils. Rotating a magnetic field inside a coil with a potential difference (i.e., voltage potential) causes current (i.e., amperage) to flow. The generator is the amp-pump in the common analogy with piping systems.

The above equations are for idealized components. Of course, ideal components do not occur in the real world. Because a conductor above absolute zero will have resistance, there is unavoidable conversion of current into heat. Any conductor between two separate points in space will have inductance and unavoidable magnetic field energy storage. The system demands line current for real and reactive power. Some fraction of real power is lost as heat. The reactive power alternately builds up and takes down the magnetic fields in a constant back and forth between the source of power and the consumer of power. This change in the magnetic field induces an emf that is in the opposite direction of the change in current and opposite of the induced voltage. The strength of this emf is proportional to the change in current and the inductance.

The extra current consumed by reactive loads (e.g., induction motors, devices with capacitance) causes energy losses (heat) via the resistance of the conductors. The larger the cross-sectional area of the conductor, then the more electrons are available to carry the current, so the lower the resistance. The longer the conductor, the more scattering events occur in each electron's path through the material, so the higher the resistance. The motion of charges also creates the electromagnetic field around the conductor. The magnetic field exerts a mechanical radial squeezing force on the conductor. The size of that field is determined from the following equations.

$$\Phi = Li$$
$$\Phi \equiv magnetic\_field\_strength = weber = tesla * meters^2$$
$$L \equiv inductance = henry$$
$$i \equiv current = amps$$

If the rate of change of current in a circuit were one ampere per second and the resulting electromotive force had been one volt, then the inductance of the circuit equals one henry.

A conductor of a given material and volume (length x cross-sectional area) has no real limit to the current it can carry without being destroyed as long as the heat generated by the resistive loss is removed and the conductor can withstand the radial forces. This is the reason that grid-operators allow some conductors in circuits to exceed design for limited periods. Discretion is limited because the electric resistance of a typical metal conductor increases linearly with the temperature.

The electrical resistance of a material is usually defined by:

$$R = \frac{\rho \ell}{A}$$

where

ρ is the electrical resistivity (measured in ohm meters)
R is the electrical resistance of a uniform specimen of the material (measured in ohms)
l is the length of the specimen (measured in meters)
A is the cross-sectional area of the specimen (measured in square meters)

Importance of Reactive Power

Reactive power is key in the long distance transmission of real power as each stretch of transmission line consumes a certain amount of reactive power. And, as the transmission distance becomes greater (as in the deregulated market), the grid has a greater need for reactive power. The amount of current needed in a circuit to deliver power to a load follows $P=I^2R$. R increases with distance and temperature. The amperage needed to satisfy the load causes the magnetic field around the conductor to increase and causes the temperature of the conductor to increase. The amount of reactive power consumed is proportional to the size (particularly the length in transmission systems) of the conductor.

As real power (volts*amps) demand increases, the network increases the demand for current from all of the generators and transformers at ties to other systems (the voltage-drop to ground is effectively constant on the grid network). Reactive power is used by nearly all of the other devices connected to the grid, e.g., transformers, underground cables. These devices consume reactive power to maintain their own magnetic field. The transmission system itself presents a dynamic reactive load. Furthermore, as line loads rise (i.e., increased current), the amount of reactive power the line absorbs rises even faster. Reactive power cannot travel long distances because it meets considerable resistance over the transmission lines. Thus, it is preferred to add power relatively near to the reactive loads and minimize the reactive power consumed by the circuit conductors.

Under Loaded Grid Versus Over-Loaded Grid

Transmission lines are highly capacitive when not loaded, voltages can easily become excessive. In low-voltage conditions, generators and reactors are used to hold voltages down. Unfortunately, generators are less stable when they *absorb* large amounts of reactive power than when they *produce* reactive power.

Limits on Reactive Power Creation

Within reasonable bounds, the grid-operators can control the amount of reactive power added to the grid network. From a national perspective, there are more than enough generators on the grid to provide the real power demanded by the economy at any given time. The limiting parameter for the grid-operators becomes balancing the available reactive power with the dynamic demand for reactive power (which is a function of the amps sent through the network).

Excitation (i.e., the magnetic field created with the armature) controls the current and reactive power produced in the stator coils. Stator coils are connected by phase bus ducts to the main output transformer of the plant. "Under normal conditions the terminal voltages of generators are maintained constant."[3]

The automatic voltage regulator (AVR) of the generator attempts to control the terminal voltage and reactive power whilst also ensuring proper sharing of the reactive power amongst parallel connected generators. Generators are nonlinear systems that are continuously subjected to load variations. The AVR design must cope with both normal load and fault conditions of operation.[4]

Generators <u>create</u> reactive power when they are "over excited" and <u>absorb</u> reactive power when they are "under excited." The amount of reactive power controllable by the generator is limited by the stator current, armature current, and stator end-region heating (i.e., maximum temperature as well as rate of temperature change). The generator field current is automatically limited by an over-excitation limiter. On most generators, the armature current limit is realized manually by operators responding to alarms. The operator reduces reactive or real power output to bring the armature current within safe limits. On some generators, armature current limitation is automatic (indirectly) via the AVR trying to control reactive power.[5] Turbo-generators at newer stations tend to have less iron and less copper than prior vintages. That lack of iron and copper mass affects the amount of VARs those generators can produce. In addition for financial reasons, power generators often have little or no incentive to produce reactive power because they are paid primarily for producing real power.

Root Cause of Widespread Grid Failures

Grid networks allow wide discretion in connecting a power source with a power load. Wide spread transmission failures are almost always a result of a MVAR deficit.

[3] Reference 3, Chapter 14.1.2.
[4] Reference 18.
[5] Reference 3, Chapter 14.1.2.

One of the characteristics of the August 14, 2003, blackout was an apparent "voltage collapse" that occurred on portions of the transmission system surrounding and within the northern Ohio and eastern Michigan load centers. Transmission system voltage is needed to transfer electric power from the generation stations to the load centers, and is somewhat similar in function to water main pressure. As transmission line loads increase, they consume more of the reactive power needed to maintain proper transmission voltage.

When heavily loaded transmission lines disconnect, the lines that remain in service automatically pick up portions of flow formerly moving through the disconnected line, which increases the reactive power consumed by the still in-service lines. When reactive supply is limited, the increased loading will cause a voltage drop along the line. If reactive supply is not provided at the end of the line, the voltage could fall precipitously. At that point, the transmission system can no longer transfer electric power from distant generation to energy users in load centers.

As would be expected, the likelihood of a transmission failure (a mismatch of generation, transmission paths, and major loads) creating a LOOP at a NPP depends upon several factors including: (a) location of the NPP, i.e., its regional grid – see Chapter 4, (b) grid capabilities and demands i.e., margin, which is a hypothetical function of season – see Chapter 4, (c) location[6] of the plant on the particular grid relative to other plants and major load centers – see Chapter 2, and (d) likelihood of advance notice, i.e., communication between plant operators and TSOs.

August 14, 2003, in Particular

The August 14, 2003, transmission failure was the quintessential grid event propagating across several grids, causing reactor trips at 20 plants and effective loss of offsite power at 7 sites (Canadian and US units) in and near the area highlighted on Figure 1-1. In addition, the grid collapse occurred while grid voltage and other margins were very low[7] as opposed to a direct weather event. Figure 1-1 shows the extent of the August 14, 2003, outage and provides some insight as to why some NPPs in NY did not lose every off-site power circuit, while restoration of off-site power at other plants took much longer. Note that plants in the midst of the outage experienced off-site problems for over eight hours while those on the periphery of the outage lasted two to four hours and had recovery steps more typical of plant-centered LOOPs. Estimating the duration of LOOP events is the subject of Chapter 3.

[6] That is location as a function of distance to other generators and major loads.
[7] The need to produce real-power limited the ability of the TSOs to create enough VARs to transmit that power.

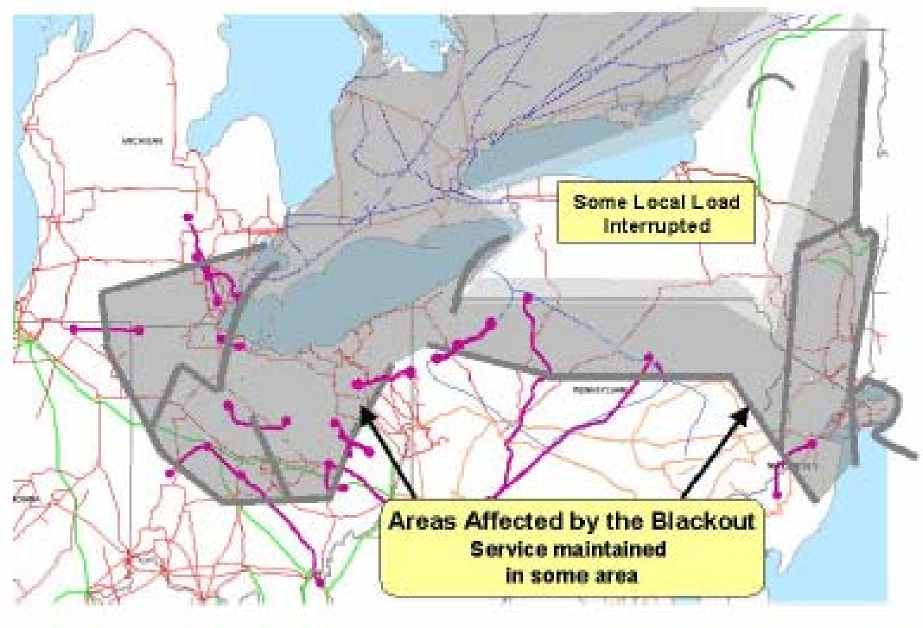

Figure 1-1
Extent of the August 14, 2003, Transmission Failure

2
GRID CHARACTERISTICS AROUND PLANTS

This chapter discusses a statistical hypothesis that the configuration of the NPP within the grid is important in determining whether or not a grid disturbance will cascade into a LOOP event at the plant. The discussion focuses on the grid equipment within ~50 miles of the NPP. The high voltage equipment that the NPP generator feeds is part of a broader grid that in turns is a sub-set of three large and relatively independent national electric grids.

The national grid is a complex machine made of three large sub-systems: the Eastern Interconnect, the Western Interconnect, and the Texas grid. It also can be thought of in parts as small as the 750kV to 13.8kV distribution systems of each of the utility companies in the U.S., Canada, and parts of Mexico.

The future reliability of the grid near the NPPs will be a function of timely completion of planned capacity additions, including the ability to construct the required associated transmission facilities; ability to obtain necessary zoning and environmental permits; ability to obtain financial backing; price and supply of fuel; and political and regulatory actions. Generating capacity fulfills the real power needs of customers and the infrastructure needs of the transmission equipment (i.e., reactive power). Lack of reactive power at key points in the network is a threat to grid stability.

In areas of North America with a restructured electric industry, the addition of new generating capacity depends on several factors: (1) basic economics of supply and demand, (2) traditional planning reserve margin requirements and other resource adequacy criteria established by industry, utility, and regulatory groups, and (3) the response of power plant owners/operators to relevant market signals. In these areas, capacity margins will likely fluctuate, similar to normal business cycles experienced in other industries. In areas that have not undergone restructuring, new capacity will be constructed primarily in response to resource adequacy criteria established by individual utilities or their regulators.

For example, at the time this report was written, deliveries of western coal from the Powder River Basin (Wyoming) were being curtailed due to rail track maintenance. The response to this curtailment of coal deliveries will vary by region and degree of reliance on coal generation. NERC established the Gas/Electricity Interdependency Task Force (GEITF) to identify the magnitude of the fuel delivery problem and recommend a proper course of action. The GEITF issued the report Gas/Electricity Interdependencies and Recommendations in June 2004, which evaluated the interdependency between gas pipeline operation and planning, and electric system operation and planning reliability over the next ten years.

Characterizing a Region

The power system near the NPPs (as it is everywhere) is designed to ensure that when conditions on the grid (excessive or inadequate voltage, apparent impedance or frequency) threaten the safe operation of the transmission lines and/or power plants, the impacted equipment automatically separates from the network to protect itself from a potential physical damage. If such physical damage were allowed to occur, it would render restoration efforts more difficult and much more expensive.

In some instances, the reactive power demand within an area is too great for the local generating units to supply. In those cases, the units can trip (automatic separation or shut-down), because of reactive power overload, or because the system voltage has become too low to provide power to the generators' own auxiliary equipment, such as fans, coal pulverizers (in the case of a coal-fired power plant), and pumps.

Fault-induced delayed voltage recovery (FIDVR) is a transient short-term voltage condition in which the system voltage stays at low levels for several seconds after a transmission fault has been cleared, and may be accompanied by loss of load and even generation. Heavily loaded induction motors subjected to low voltages tend to slow down and increase their reactive power consumption (e.g., air conditioning equipment); thus, aggravating the low voltages created by the initial fault activity. Low voltage is a particular problem in power systems because it can lead to excessive current flows that overheat transmission. In a worst-case scenario, FIDVR may even evolve into short-term voltage instability.

During periods of high demand, traditional operational assessments may indicate that the system is secure. TSOs employ "contingency studies" as a means of identifying network vulnerabilities. The contingency studies comprise a long list of initial conditions for the grid and then serially introduce faults in an effort to expose real weakness. It is akin to a nuclear plant single-failure analysis, but the grid is a network that allows for a large number of success paths in comparison to the two assumed in most nuclear plant design basis studies. The contingency study may identify a single contingency scenario, or credible multi-contingency fault scenarios, which could cause a FIDVR event. Some FIDVRs can cascade into local or wide-area loss of load and generation.

Aggregating non-coincident demand forecasts can cause the total forecast to be too high because the actual peak demand in individual regions will not occur simultaneously. On the other hand, the regional forecasts (by the organizations that make up the NERC) are assumed to occur during normal or average weather conditions. Actual weather conditions can vary significantly from region to region and from year to year – see discussion in Chapter 4. If temperatures were above average in multiple regions over the summer, an aggregated forecast based on average weather conditions will tend to be too low. Real-life experiences expose features of the grid that ought to be changed to maintain high voltage-availability for customers, i.e., *necessity is the mother of invention* as discussed below.

Known Issues in Various Regions

As might be expected, unique conditions in the region of the various power grids associated with unusually high demands and transmission constraints may impact the ability of a power grid to accommodate disturbances. Reference 11 describes the following (recent) regional-specific issues that can affect the probability of a grid disturbance.

ERCOT is noted to have a primary dependence on natural gas-fueled generation units. Consequently, the adequacy of natural gas supply during extended periods of cold weather is a concern. A number of new 345kV and 138kV lines are under construction in the Dallas-Fort Worth area, western, central and southern Texas that will provide relief for these constrained areas and will allow ERCOT to exit costly RMR contracts (that keep otherwise old generators on-line). These improvements are also planned to eliminate most of the existing remedial action plans and special protection systems that have been put in place to temporarily reduce redispatch for congestion management.

MRO — System stability operating guides involving the transmission facilities connecting Minneapolis-St. Paul to the Iowa and Wisconsin areas continue to manage congestion by limiting energy transfers from northern MRO to Iowa and Wisconsin.

Large and variable loop flows are expected to impact transfer capabilities on a number of interfaces within SERC and between SERC and other regions. The SERC-MAIN and SERC-ECAR regional interfaces, and the Southern-TVA, Entergy-Southern, and Southern-VACAR subregional interfaces are affected by these loop flows. The proposed significant increases in merchant plant capacity over the next few years lead to increasing uncertainty in flow patterns on the transmission system. Unexpected flow patterns can also significantly impact transfer capability.

In response to the NERC blackout recommendations, First Energy installed an under-voltage load shed (UVLS) scheme (operational in June 1, 2005), in the northern Ohio and western Pennsylvania area. This scheme has the capability to shed a total of about 1,300 MW and is capable of providing an effective method to prevent uncontrolled cascading following extreme equipment outages.

WECC covers a large geographic area and experiences considerable weather diversity. Under normal weather conditions, this weather diversity with the northern portion of the region experiencing winter peaking and the southern portion experiencing summer peaking. This feature allows an area experiencing extreme weather to call on neighboring areas for emergency support. However, a widespread heat wave may result in multiple areas experiencing simultaneous high peak demands, diminishing emergency support capability.

In California, since the brownouts of summer 2001, over 12,000MWe have come online in via ~25 new generating plants. One key north-south transmission corridor has added a third transmission line, easing distribution state-wide like an extra lane on a freeway. Brownouts (a rather extreme method to stabilize the grid) in response to high demands are controlled and by themselves do not make the grid more vulnerable to grid events.

All of these projects are intended to reduce congestion, increase capacity, and in general increase the reliability of the power grid.

Graphical Characterization of the Grid Near the Plant

Nuclear power plants generate electricity as well as consume part of it for in-house electric loads. In a four reactor coolant pump (RCPs) PWR, ~20MWe is needed to run those pumps. The circulating water pumps are typically just as large and just as numerous. The 1000MWe class of nuclear plants almost exclusively uses 4160-volt pumps for tasks like component cooling water and service water. Some of the plants have electric-motor-driven (MD) main feedwater pumps. All together, a nuclear power plant operating at rated power could itself consume on the order of 50MWe. That load is colloquially referred to as the "house load." As it is evident from this discussion, after a nuclear plant trips many of its large normally operating pumps no longer are needed. An off-line plant uses one or two reactor coolant pumps, maybe one circulating water pump for shutdown cooling (i.e., residual heat removal). Component cooling water and service water demands typically increase during shutdowns, so those loads remain. In a shutdown condition, the house load at nuclear plant is on the order of 20MWe. As the house load is relatively small, the nearby grid is usually able to flawlessly accommodate a sudden load shed by the NPP main generator. Because the house load is relatively small, the likelihood is quite small that the power grid *at-large* is unable to support house loads (and, thus, making a LOOP event a rare condition).

Examination of the reported LOOP events (where the grid fails to supply both safety-buses) revealed that some plants have never had a LOOP event whereas others have had several. This report discusses the hypothesis that the nearby grid has enough resources to carry house loads even in the face of a wide spread grid outage. For example, during the August 14, 2003, event, Nine Mile Point Unit 2 had available a 115kV circuit throughout the duration of its Unusual Event (UE). It should be possible to identify characteristics of a grid that make it less likely to drop the house loads of a nuclear power plant.

Generally, the more high-voltage connections to the switchyard and the more large generators in the vicinity, the less likely it is that a LOOP condition develops at the plant. Using a software program called PowerMap, the authors constructed the figures in this chapter to help identify vulnerability to a grid-disturbance. PowerMap also identifies the high-voltage circuits which are considered constricted according to the North American Electric Reliability Council (NERC). In general, *constricted* means that the capacity of the transmission network is limited by available equipment. For example, three 500kV circuits connect node A with node B, but only two 500kV circuits connect node B with node C. Five example maps were created with PowerMap. The plants were selected as representative of plants with numerous high-voltage circuits, plants that are relatively isolated from large loads and other generators, and plants with numerous nearby large generators.

Beaver Valley

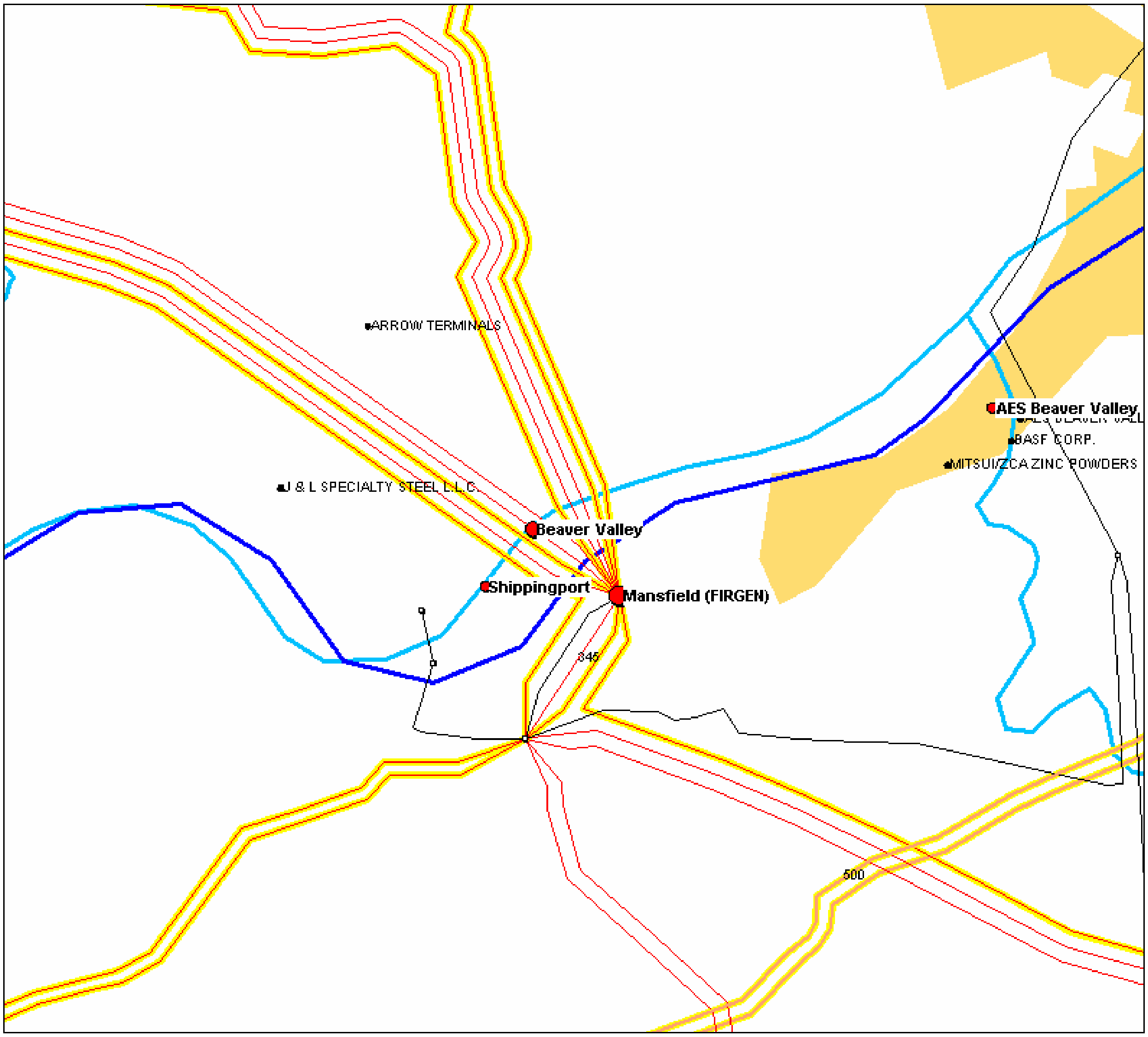

Figure 2-1
Grid in the Vicinity of Beaver Valley

The PowerMap generated power line mapping in the vicinity of Beaver Valley is illustrated in Figure 2-1. Beaver Valley is part of the grid controlled by the MAAC. Beaver Valley is of interest because it did not trip on August 14, 2003, even though its corporate owner/operator was the focus of much attention in the wake of the event.

To enable a plant to remain operating through a grid disturbance, the power sources in the vicinity of the plant must be able to accommodate and redistribute the power resulting from the loss of off-site sources. The Beaver Valley site clearly has a large number of available circuits, any one of which could handle the house loads at the site.

It should be noted that many lines in the vicinity of the plant are considered constrained by the NERC. Thus, these lines would not be effective in redistributing power disturbances. There is a large fossil fired unit immediately adjacent to the owner controlled area. On the other hand, there is one notable reactive power consumer within a few miles of Beaver Valley. Nevertheless, the EPRI LOOP data base has no LOOP events of any type listed for Beaver Valley reactors in Reference 2. Furthermore, there are no trips associated with grid events (see Appendix A).

Fort Calhoun Station

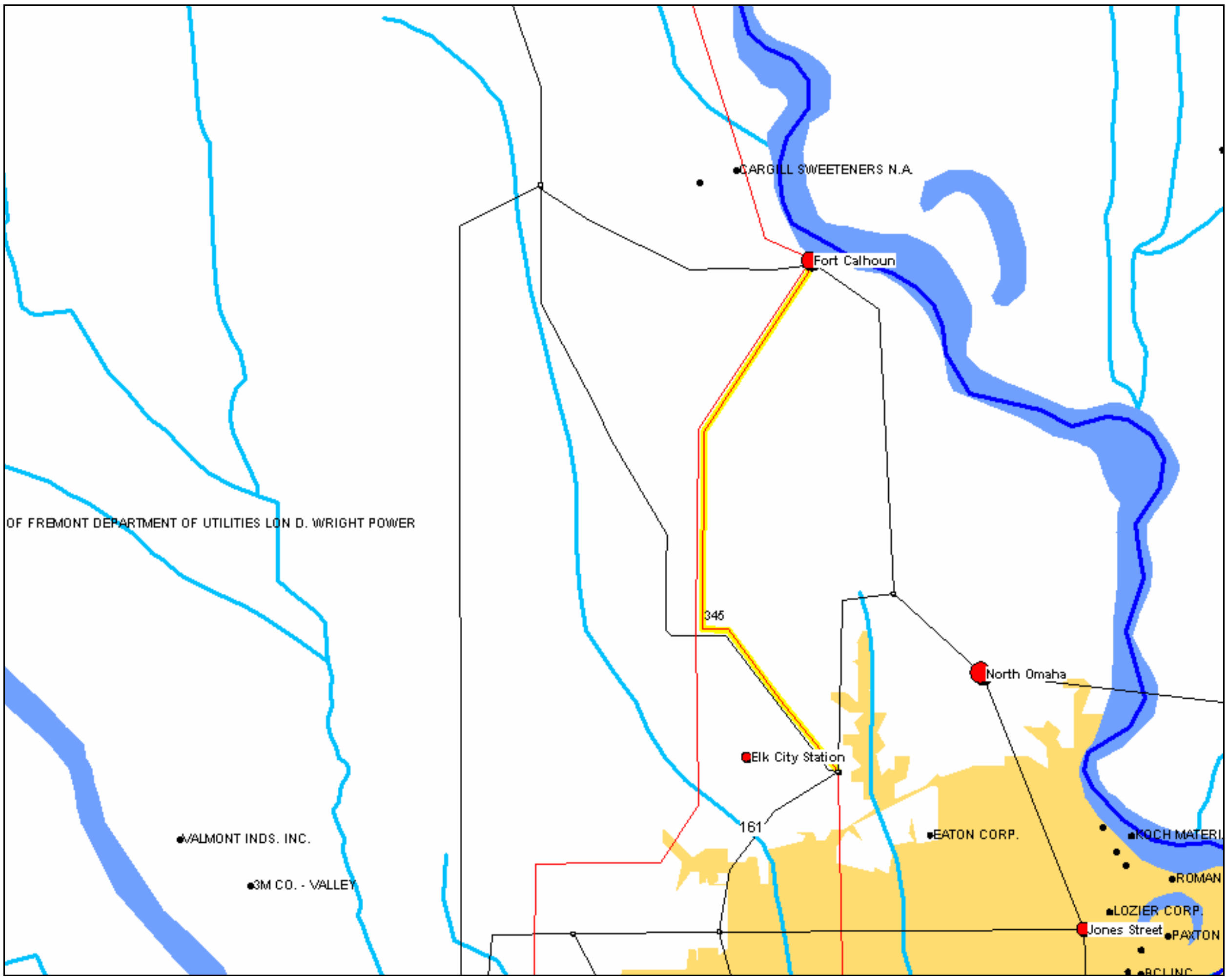

Figure 2-2
Grid in the Vicinity of Fort Calhoun Station

Fort Calhoun Station is of interest because it is relatively far from its principal loads south-south-east of the plant with one exception. The PowerMap generated Figure 2-2 that shows high-voltage circuits and loads in the vicinity of Fort Calhoun Station. The plant is notable in that it is designed with electric-driven main feedwater pumps. The pump motors at Fort Calhoun are relatively small, e.g., the four reactor coolant pumps (RCPs) have 4160V motors. As a result of the relatively low power output of the plant, the house loads for Fort Calhoun are relatively small compared to other NPPs during shutdown conditions.

A review of local area also indicates that there is one large reactive load consuming customer within a few miles of the plant. The next nearest large generator is in Omaha proper, approximately 20 miles away.

Three 345kV lines connect Fort Calhoun to the grid, the one circuit to Omaha is considered constrained by the NERC. Similar to the Cooper Station (also in Nebraska), OPPD makes clever use of a 165kV circuit in the event the 345kV circuits become unavailable. No grid or weather related events resulted in a LOOP (Reference 2) or grid-induced trip (Appendix A) at Fort Calhoun. Small house loads and two different high-voltage systems are believed to decrease the likelihood of LOOP at Fort Calhoun.

Seabrook

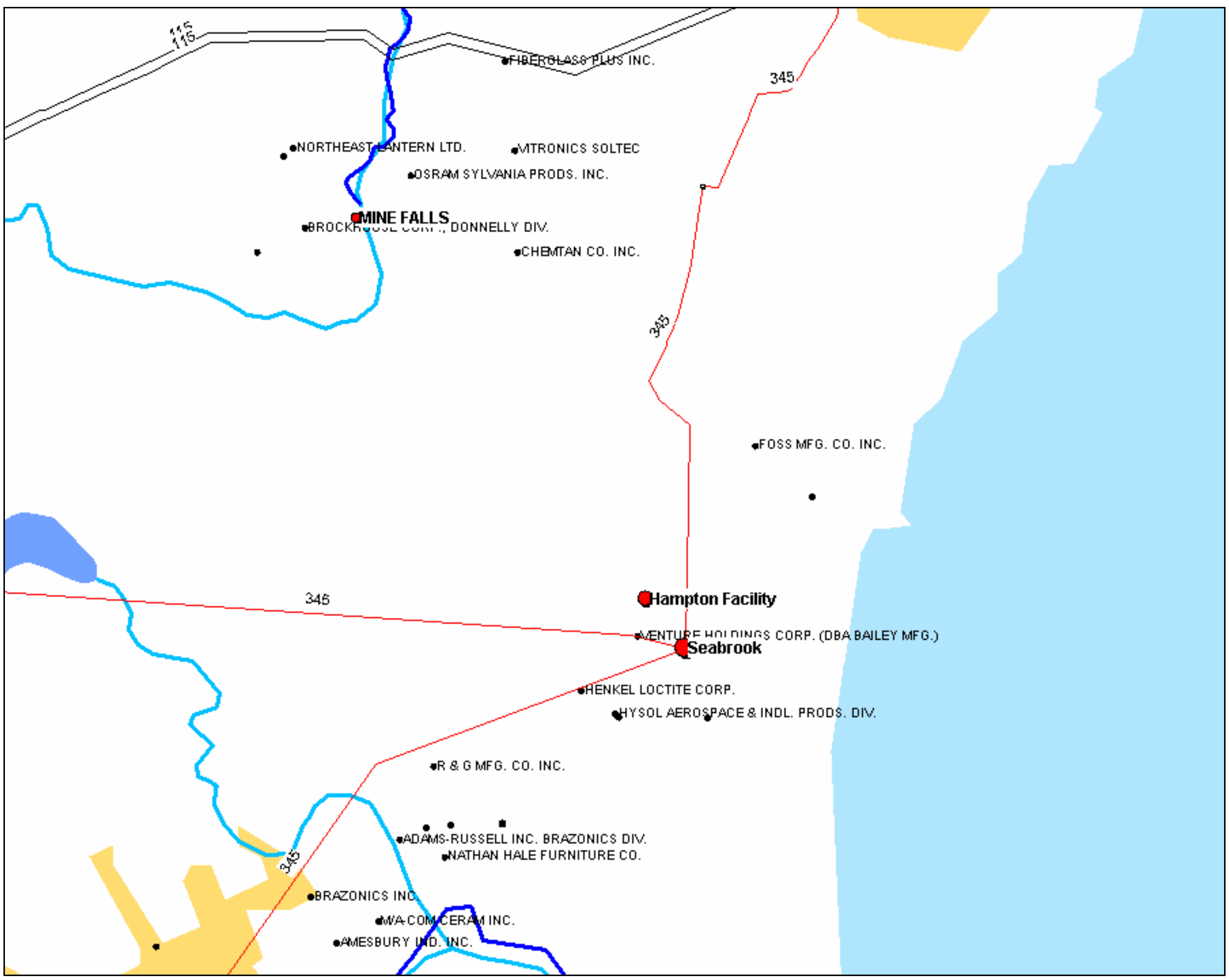

Figure 2-3
Grid in the Vicinity of Seabrook

The PowerMap output for the vicinity of Seabrook is illustrated in Figure 2-3. Seabrook is of interest because there are relatively few circuits available.

Seabrook is considered to be in an "end of the grid" configuration with three 345kV lines coming from different areas. Seabrook has numerous large reactive power consumers near by in addition to the large load in the Boston area. All of the circuits are considered unconstrained. There is one other large generating plant nearby. The Hampton Facility is a fossil-fired unit owned by a non-utility entity. Seabrook is relatively modern and has typical house loads.

Reference 2 and Appendix A indicate that no grid-centered or weather-related events resulted in a LOOP or grid-induced trip at Seabrook. The ability of the three lines to support a stable operating environment was seen in April 1997, when while at 100% power, two of the three 345 kV transmission lines became unavailable during a severe regional storm. Despite this problem, off-site power was never lost. On another occasion, March 5, 2001, during a severe snow and wind storm, Seabrook tripped from 100% power when the main generator became separated from all three 345 kV lines that connect the plant to the grid. Prior to the plant trip, wind and wet snow caused multiple flashovers across 345kV bushings in the switchyard. Various transmission line trips and reclosings left only one of the three 345kV transmission lines in service. However the pattern of open and closed 345kV switchyard breakers was such that the main generator was isolated from the grid. At the same time the pattern was such that the reserve auxiliary transformers continued to be energized from off-site power throughout the event.

Waterford

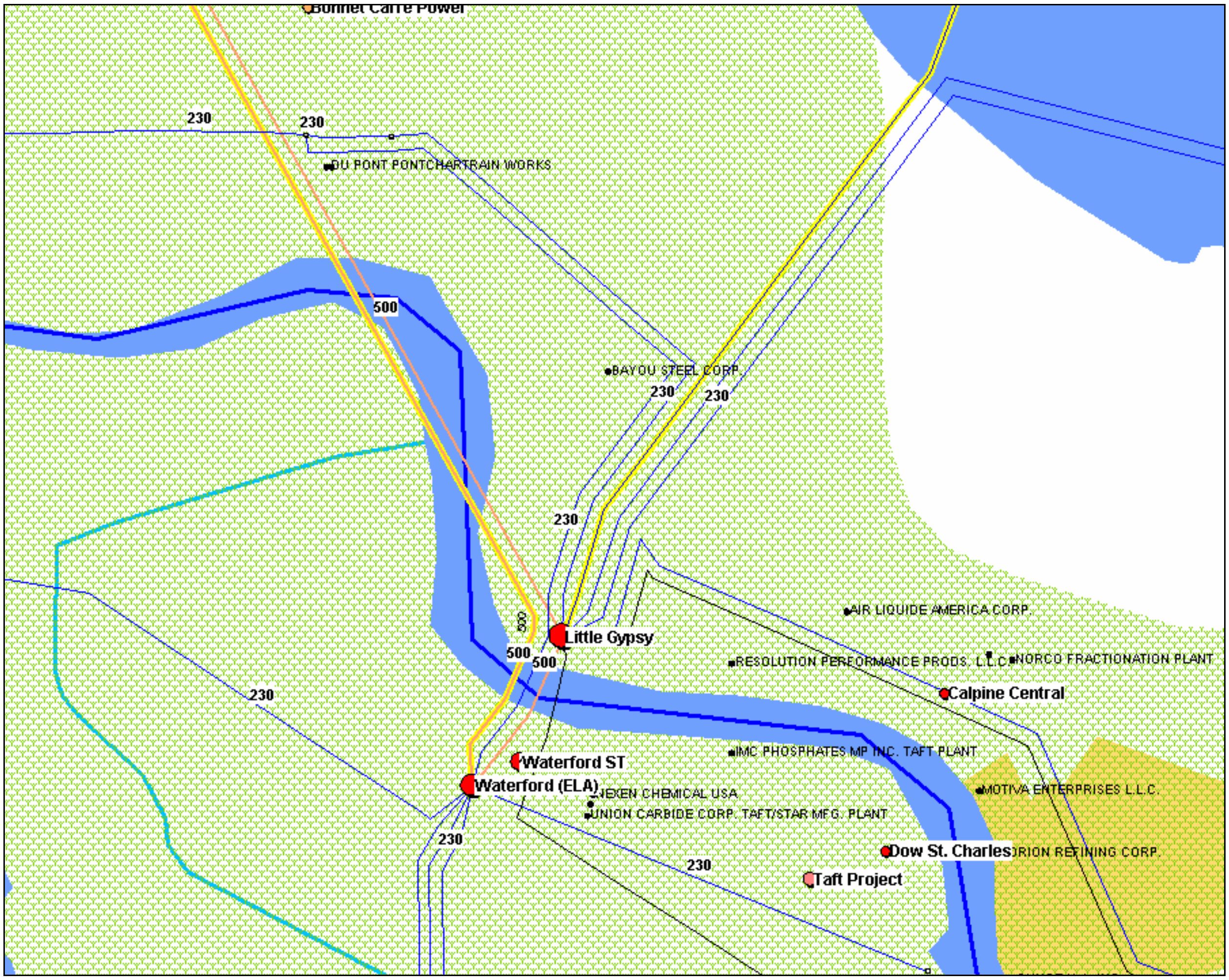

Figure 2-4
Grid in the Vicinity of Waterford

The PowerMap generated output for the vicinity of Waterford is illustrated in Figure 2-4. Waterford was selected because it is in the midst of numerous large generators. There is significant industrial activity downriver of Waterford in St. Charles Parish. There are additional large fossil fired generators just off the Southeast corner of this map. Bayou Steel is a particularly large reactive power consumer. This situation should contribute to high grid availability to the house loads, which seems to be borne out in recent history.

No grid or weather related events resulted in a LOOP or grid-induced trip at Waterford from 1997 to 2004. Of course, Hurricane Katrina (2005) resulted in a LOOP and an extended period of grid instability (because of low voltage conditions).

Nine Mile Point and Fitzpatrick

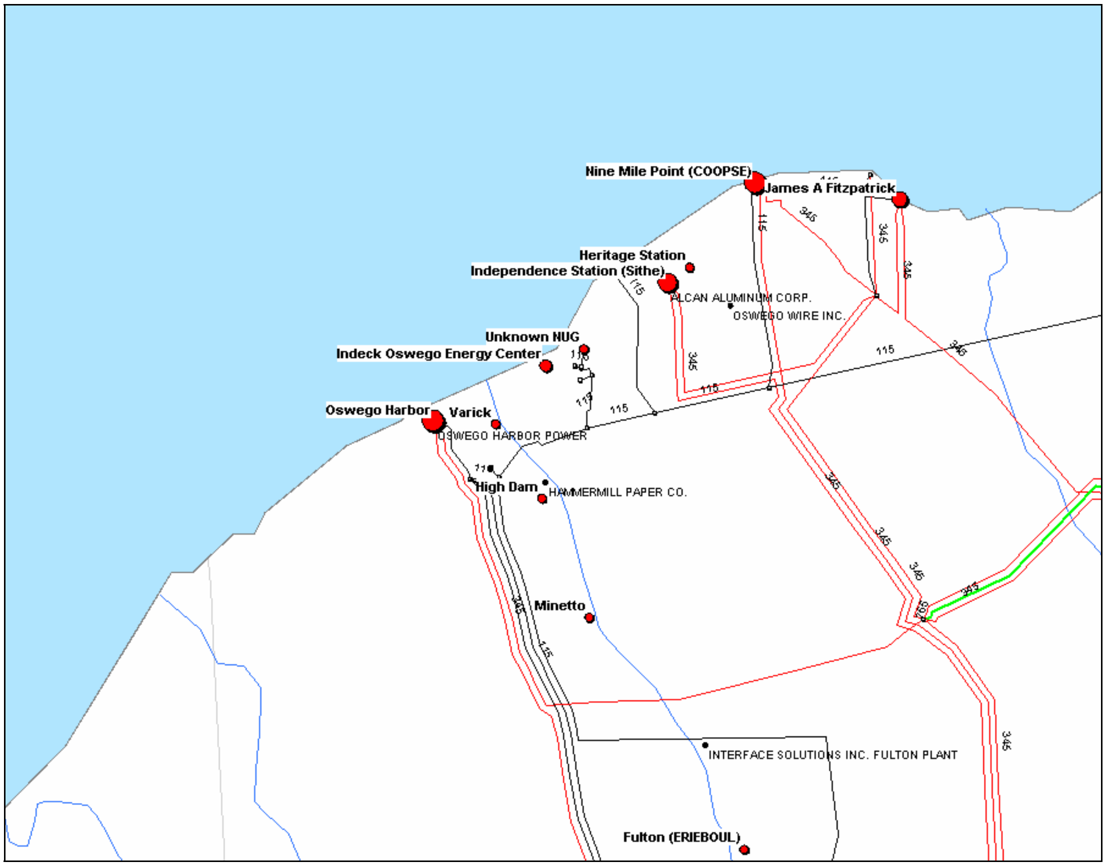

Figure 2-5
Grid in the Vicinity of Nine Mile Point

Figure 2-6
Arial View of Nine Mile Unit 1, Nine Mile Unit 2, and J. A. Fitzpatrick and Independence Station in the Lower Left

The PowerMap generated output for the vicinity of Nine Mile Point and J. A. Fitzpatrick is illustrated in Figure 2-5 and Figure 2-7. Nine-Mile & Fitzpatrick were chosen for reasons similar to Waterford. There are many large generators nearby. In close proximity is one large reactive power consumer (an aluminum plant). Many circuits connect the site to the south. This site has many of the good characteristics that would point to high grid availability for the safety busses.

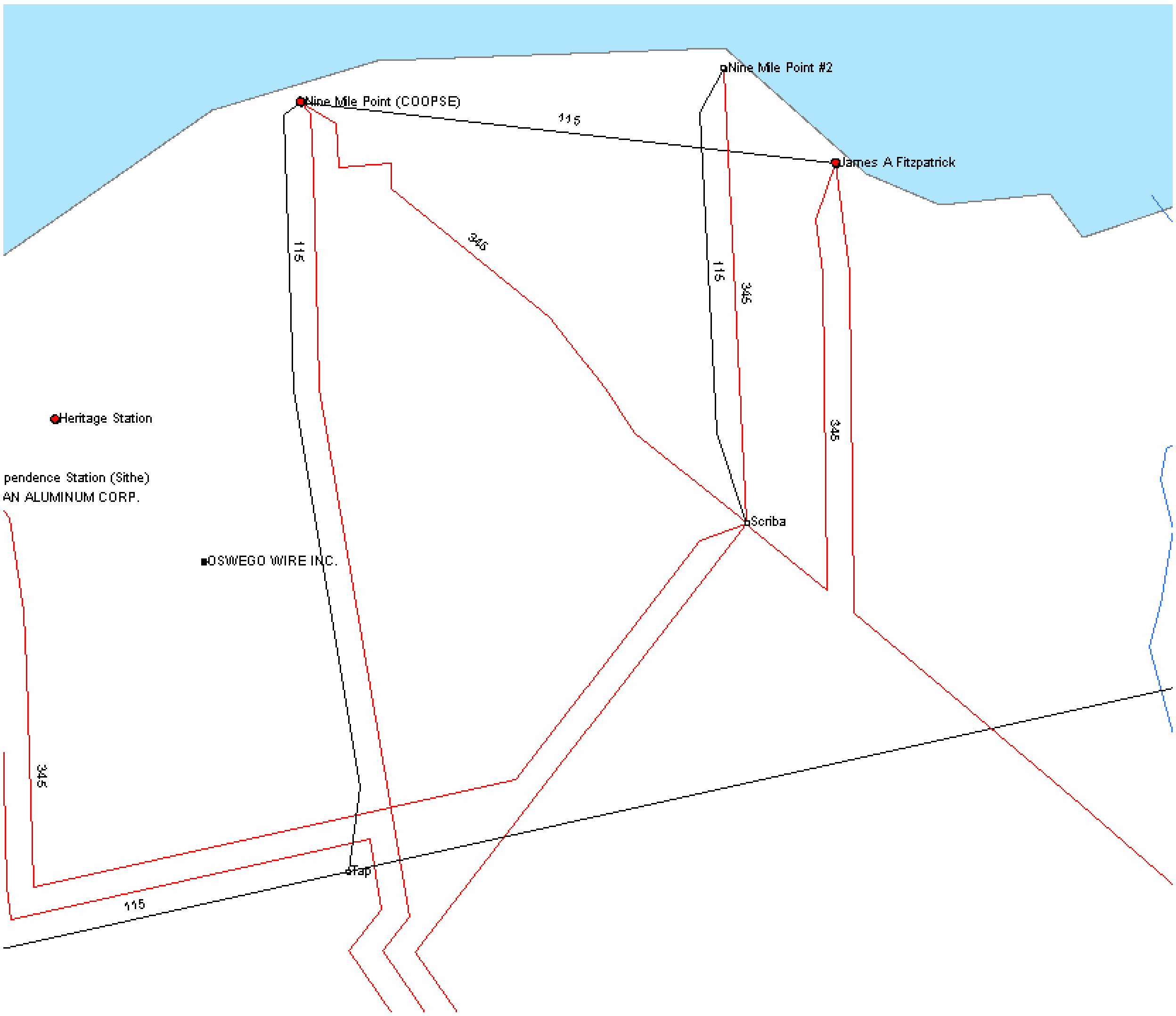

Figure 2-7
Close-Up of Nine Mile and Fitzpatrick High-Voltage Circuits

The power requirements for Nine Mile Point Unit 1 are supplied by two 115 kV lines, Line 1 and Line 4 which can be seen in the figure above. On November 1, 2002, Line 2, which shares common line structures with Line 1 (going to the Nine Mile Unit 2 switchyard), suffered storm damage and was removed from service for emergency repairs. As part of the recovery operation, Line 1 was removed from service to facilitate repair work. Shortly thereafter the state estimator computer program signaled a low voltage contingency alarm. This alarm alerted operators that with these two lines out of service, off-site voltage at the plant might be below prescribed levels if there were an event involving a loss of coolant accident, plant trip and operation of major safety loads. Plant personnel transferred the safety buses to the emergency diesel generators. Line 1 was returned to service, and the limited condition for operation (LCO) ACTION was cancelled after about eight hours. The unit remained on line and at power throughout this event.

Both Nine Mile units as well as Fitzpatrick experienced a grid-induced loss of load trip on August 14, 2003. Those two plants and Fitzpatrick went on to implement parts of their emergency plan related to a LOOP condition shortly thereafter. However, both 115kV lines to the Nine Mile Unit 2 switchyard remained energized (although considered unreliable at the time) throughout the entire event. The only other event considered a LOOP by EPRI (category IIb) was the one in November 2002.

Applying Qualitative Analysis to Grid-Centered LOOP Frequency

Tools such as PowerMap can help visualize the grid arrangement around a specific plant. With this information the PSA analyst can consider plant specific features within the large NERC grid regions discussed in other chapters of this report. Once the regional-seasonal values for LOOP frequency are established, the local impact may be adjusted according to the qualitative factors on Table 2-1. At present, the factors are only qualitative. More detailed assessments over time may be lead to quantifying the tabled factors. Consideration of the impact of the local grid arrangement will help avoid penalizing well situated plants with raw data from plants in less favorable configurations.

A follow-up to this report can map each nuclear plant site and include a list of pertinent grid-events. For now, the evidence is that most features observable from the PowerMap information do not help predict LOOPs and grid-induced trips. However, the large number of plants in the vicinity of Beaver Valley and Waterford leads to a hypothesis that LOOPs are less likely for those plants. Beaver Valley avoided a trip (and LOOP) on August 14, 2003. Likewise, Waterford experienced many severe storm events from 1997 through 2004 without subsequent LOOP.

Table 2-1
Qualitative Factors for Plant-Specific Grid-Centered LOOP Events

Nearby Grid Feature	Effect on Grid-Centered LOOP Frequency	Comment
Other large generators within 10 miles	Decrease	Nearby sources of reactive power can support NPP house-loads post trip. When one of the nearby generators has “black start” capability, the duration of an outage should be relatively short (see Chapter 3).
More than one high voltage system available to supply safety busses (e.g., 345kV and 115kV).	Decrease	TSOs have increased flexibility to keep house loads on line. Systems at different voltage levels available to the plant switchyard are somewhat independent.
The plant switchyard supplied by the main turbo-generator is separate from the switchyard supplying the house loads.	Decrease	Disturbances affecting generation are somewhat isolated from equipment supplying house loads.
Control room real-time predictive state estimator or frequent and formalized communication with the TSOs. Having an active switchyard oversight committee for work package and switchyard activity control. It is typically composed of plant and TSO personnel regularly involved in making operating decisions.	Decrease for effective formalized communication Increase for poor or infrequent communication	INPO has cited inadequate interface between NPPs and the power TSO as a contributor to events[8] even though written agreements between the organizations are in place. Nuclear Plants in organizations which own their plants and are also the TSO are expected to have better communication as well as increased stability. Such utilities include Southern Nuclear Company, a subsidiary of Southern Company since 1990. Southern Company is also the TSO via Southern Company’s five regulated retail electric utilities: Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric. The plant operators become aware over time of the local grid behavior just as they do core-damage risk after implementing configuration risk monitors. They are less likely to make major load changes or perform tasks on high-voltage equipment in relatively vulnerable periods.

[8] INPO OEs 20280 (22Dec2004), 19968 (31Dec2004), 20249 (10Feb2005), 20333 (11Feb2005), 20168 (11Feb2005), 20446 (14Feb2005), 20459 (22Feb2005), 20369 (23Feb2005), 20367 (27Feb2005), 20524 (1Mar2005), 20171 (11Mar2005), 20575 (1Apr2005), 20427 (6Apr2005), as well as EN 41646 (28Apr2005), and EN 41692 (12May2005).

Nearby Grid Feature	Effect on Grid-Centered LOOP Frequency	Comment
Station design basis events (DBA) are in the set of contingencies run by the TSO. The TSO model conservatively predicts swing voltage and absolute voltage values. In addition, it triggers alarms based on various NPP bus configurations.	Decrease	Evaluation of potential NPP challenges and providing that information to the NPP is important to controlling grid related risks. Without such evaluations the power TSOs are less likely to compensate for unexpected grid activity with steps detrimental to the NPP.
Preponderance of gas-fired large generators nearby that seasonally adjusts operations to accommodate expected fuel supply disruptions. Unavailability of natural gas supplies in regions where power production is dominated by that fuel.	Increase	Power production will shift to units further away or to off-grid purchases.
Large industrial loads nearby (MVAR consumers)	Increase	Other large consumers of reactive power compete with the house-loads at the NPP.
Exposed to large bodies of water	Increase	Weather events (e.g., lake-effect snow, sea spray) are more likely at these plants. Physical layout of plant may also physically restrict areas from which power can be supplied.
Urbanized community are within 10 miles (MVAR consumers)	Increase	Other large consumers of reactive power compete with the house-loads at the NPP. The urban centers tend to be farther than industrial customers relative to the NPP location.
Facilities for a large nearby industrial customer are under construction testing.	Increase	During various tests, load and grid balance can change suddenly. Unless the transmission system is being upgraded at the same time, the intuition and expectations regarding local grid behavior will be based on outdated experience.
NERC rated ‘constrained’ high-voltage circuit connected to the NPP switchyard(s).	Increase	Constrained lines fractionally limit the number of circuits available to supply NPP house-loads. Note that NPP house loads are not the only user of the grid power. Constrained loads reduce margin in the transmission lines and complicates the job of the TSO in accommodating large fluctuations in power supply.

3
ENHANCING LOOP DURATION DATA

The non-recovery probability associated with grid-centered LOOPs is directly related to the LOOP-condition duration.

There is very little research that measures the “best estimate reconnect time” following a LOOP. The exact time off-site power is reconnected to the safety buses has been a function of subjective judgment by plant management. Off-site power does not automatically bring the plant house-loads back on to the grid. Other EPRI reports rigorously determine the “best estimate reconnect time” for the classic LOOP events (see excellent work in Reference 2). Unfortunately, partial LOOPs in this list are not so rigorously treated. Because many of the LOOP events engender an “Unusual Event” the time that management stands-down the “Unusual Event” may be used as a surrogate for the end of the LOOP condition. This possibility is the subject of the current chapter.

The Energy Information Agency (EIA) requires utilities to document the duration of the events in EIA-417 reports. However, in those events there is no clear conditions such as “restored power to the first safety-bus” to formally set an end to the outage. Fortunately, there are many events reported to the EIA and the statistical law of large numbers can be applied to establish a statistically valid distribution of outage duration.

The traditional source of LOOP data has been provided by EPRI (latest version is Reference 2). It covers the past ten years of operating experience and LOOP events in that time. LOOPs are based on licensee event reports (LERs) submitted by the plants. The events are categorized as shown in Table 3-1.

Table 3-1
All EPRI LOOP Categories and Descriptions

Ia	No off-site power available for 30 minutes or longer to the safety buses.
Ib	No off-site power available for less than 30 minutes to the safety buses.
IIa	With the unit on-line, the startup/shutdown sources of off-site power for the safety buses become deenergized. The main generator remains on-line (connected to the off-site grid) and power for the safety buses is available from a unit auxiliary transformer.
IIb	With the unit on-line, the startup/shutdown sources of off-site power for the safety buses remain energized but in question. There is low or unstable grid voltage, or there might be if the unit trips, or trips along with a LOCA and emergency safety feature actuation. The main generator remains on-line (connected to the off-site grid) and power for the safety buses is available from a unit auxiliary transformer.
III	The unit auxiliary source of power for the safety buses becomes deenergized or unavailable, but off-site power for the safety buses remains available, or can be made available, from a startup/shutdown source. Utilization of this source may require a fast or slow automatic transfer, or manual switching from the control room. A loss of unit auxiliary power that is the result of a unit trip is not a Category III event. To be a Category III event the loss of power from the unit auxiliary source must be the initiating event and precede the unit trip. Most problems that trip the unit off-line are not Category III events. A Category III event is more properly associated with a failure of main electrical power hardware that makes near term availability of the unit auxiliary source of power for the safety buses unlikely.
IV	No off-site power available during cold shutdown because of special maintenance conditions that does not occur during or immediately following operations.
None	Event of interest

The author (of Reference 2) expends most of his time trying to establish the “best-estimate” duration of the most serious LOOPs. That work is done by studying plant electrical design and interviewing staff at the plant. The durations are only established for Type Ia and Ib LOOP events.

The same LERs provide an additional data point not available in Reference 2. Each of these more modern LERs consistently describes the start and stop time of the emergency plan “Unusual Event Declaration.” This has the advantage of being (1) easy to find and (2) regulations compelling near uniform agreement on when LOOP Unusual Events start and can be exited. Because of industry benchmarking, Unusual Events (UE) are typically exited as soon as practical. Appendix C provides a summary of the Unusual Event durations taken strictly from the LERs that described the listed events.

The United States Department of Energy, Energy Information Agency (EIA), keeps track of electric public-utility outages via compulsory EIA-417 reports. See Appendix B. The advantage of this data is that qualifying outages happen on the order of a dozen times in a month. And each report includes event duration. The number of reports makes the data amenable to standard statistical analysis. Unfortunately, the duration measure is based on a less specific start and end time (as compared to “Unusual Event”). However, the sheer number of these events should reveal a reliable distribution of durations.

As there is little data to choose from, there is no attempt to estimate regional or seasonal factors involved in LOOP duration. The data is treated in two groups as summarized in this chapter. One group is the LOOP duration found in earlier EPRI reports. The other group comes from the EIA data reproduced in the appendix of this report. Surprisingly, both sets of data generate a similar probability distribution shape, both with high R-values.

A Brief History of Wide Spread Grid Outages (1965 to 1998)

The largest instance of such a widespread event was the famous New York City blackout of Tuesday, November 9th around 5:30 in the afternoon, which knocked out power for up to 13 hours and affected 30 million people in eight States and Canada.

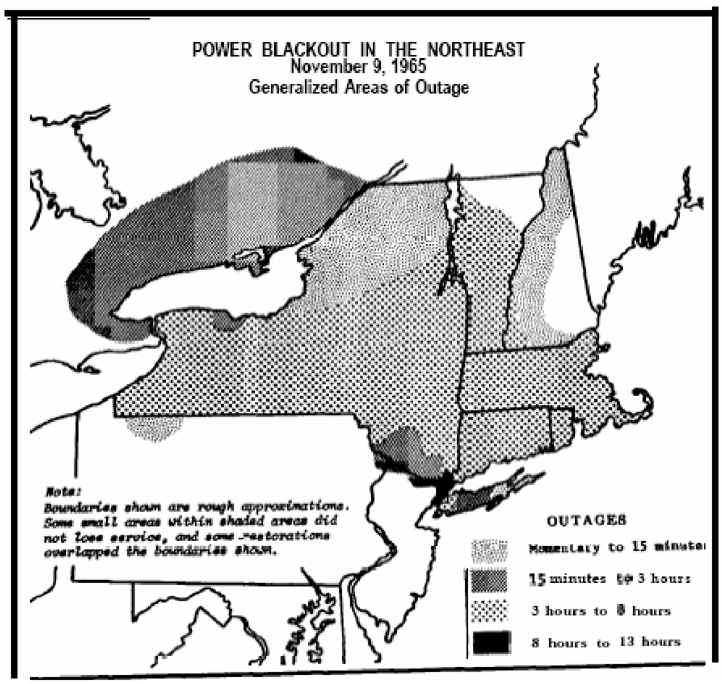

Figure 3-1
Extent of the November 1965 Northeast Blackout

EXHIBIT 1-B
Power Service Outages, Northeastern United States & Ontario, Canada, November 9 and 10, 1965

Utility	Time of Outage	Time Service Restored[x]	
		Partial[x]	Completed[x]
Niagara Mohawk Power Corp	5:16 p.m.	5:37 p.m.	10:30 p.m.
Rochester Gas & Electric Corp	5:16 p.m.	7:45 p.m.	11:44 p.m.
PASNY [x]---Moses-Niagara	5:16 p.m.	....	6:10 p.m.
PASNY [x]---Moses-St. Lawrence	5:16 p.m.	....	....
New York State Electric & Gas Corp.	5:16 p.m.	5:38 p.m.	11:14 p.m.
Central Hudson Gas & Electric Corp.	5:22 p.m.	7:30 p.m.	10:00 p.m.
Consolidated Edison Co.	5:28 p.m.	10:36 p.m.	7:00 a.m.
Long Island Lighting Co.	5:30 p.m.	7:09 p.m.	1:00 a.m.
Orange & Rockland Utilities	5:20 p.m.	5:20:30 p.m.	9:12 p.m.
Hydro-Electric Power Commission, Ontario	5:16 p.m.	....	8:30 p.m.
CONVEX [x]	5:17 p.m.	5:30 p.m.	11:15 p.m.
Vermont Electric Power Co., Inc.	[x]5:18 p.m.	6:16 p.m.	7:20 p.m.
New England Electric System	5:17 p.m.	6:03 p.m.	10:00 p.m.
Public Service Co. of New Hampshire	5:21 p.m.	([x])	5:25 p.m.
Boston Edison Co	5:21 p.m.	8:14 p.m.	1:00 a.m.
Central Vermont Public Service Co.	5:16 p.m.	5:33 p.m.	7:58 p.m.
Pa.-N.J.-Md. Interconnection	([x])	....	([x])
Detroit Edison Co.	0	....	....
Consumers Power Co.	0	....	....
Central Maine Power Co.	0	....	....

[x]Power Authority State of New York
[x]Wholesale supplier. [x]
[x]Power interrupted in the W-, Pa. area for about 15 minutes.
[x]Loss of service generally in southwestern New Hampshire area.
[x]Connecticut Light and Power Co., Hartford Electric Light Co., United Illuminating Co., Western Massachusetts Electric Co.

Figure 3-2
Tabulation of the November 1965 Outage Durations

The 1977 New York blackout of the Consolidated Edison (ConEd) Grid occurred on Wednesday, July 13 just after 9:30 in the evening in the midst of an unusually severe heat-wave and severe weather.

Large blackouts unrelated to storms occurred in Pennsylvania, New Jersey, and Maryland on June 5, 1967 (affecting 4 million people); Miami on May 17, 1977 (1 million); New York on July 17, 1977 (9 million); Idaho, Utah, and Wyoming on January 1, 1981 (1 million); four western states on March 27, 1982 (1 million); California and five other western states on December 14, 1994 (2 million).

More recent blackouts unrelated to storms occurred on July 2, 1996 (2 million) – a cascading power failure in the Western Interconnect region affected 2 million customers in 14 States, Canada, and Mexico. Most customers had power restored within 30 minutes, but some did not regain service for over six hours. This situation was repeated on August 10, 1996[9] (7.5 million), when all major transmission lines between Oregon and California were dropped. This outage affected 5.6 million users for up to 16 hours in ten western States (see Figure 3-4).

[9] Reference 13

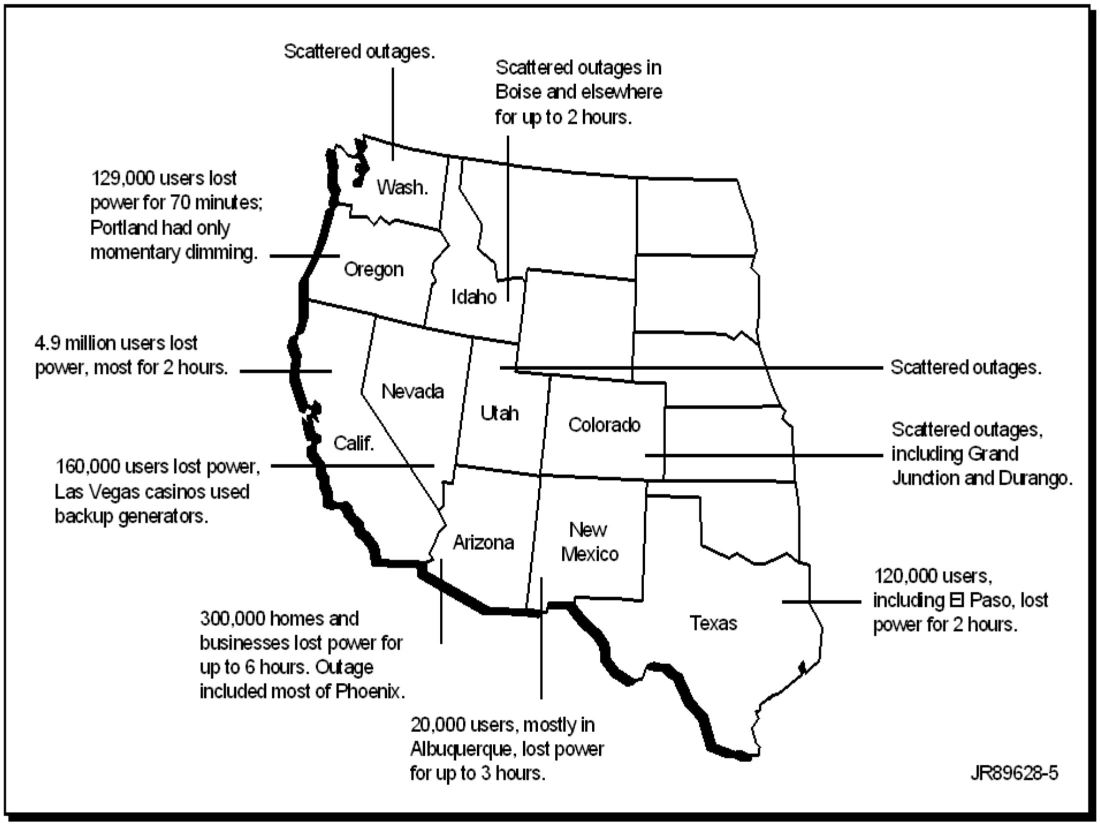

Figure 3-3
July 1996 Widespread Grid Event

Another occurred in San Francisco on December 8, 1998 (0.5 million), and in Los Angles on September 13, 2005 (2.0 million) for roughly two-and-one-half hours.[10]

LOOP Duration and Recovery

Power grids were not designed to fail completely and be started-up all at once. The basic problem is that it takes energy to produce energy. Hydroelectric, steam, and nuclear power plants all require energy to start up. Steam and nuclear plants require enough energy to convert a large amount of water to steam before operation can begin. Hydroelectric (hydropower) plants need power to open massive valves which when opened manually normally take 300 turns. Hydroelectric plants are the easiest to start from blackout conditions. However, during the black-out of the Hydro Quebec power grid in March 1989, it took 9 hours to restore 90% of the system even though it is based on hydroelectric power plants.

Most plants do not have "Black Start" capability[11] - they depend on grid power to start the fans, pumps, and controls needed to fire up the boilers, roll the turbines and synchronize the

[10] Reference 19
[11] A black start unit is defined as a generating unit that is able to start without an outside electricity supply or demonstrated ability of a base unit to remain operating, at reduced levels, when automatically disconnected from

generators to the grid. Steam may or may not be available at the proper pressures for a restart, but that is only part of the problem with an area wide grid outage.

Each plant can only supply a portion of the grid load. It can supply a small "island" when engineers can be assured that: (a) the required transmission lines are intact, and (b) the generator won't be overloaded at the second it is synced to the local grid. That takes verification by engineers that the total connected load for the circuits to be recovered is less than the capacity of the generator(s) to be reconnected. Then it must be verified that only those circuits are connected and not any others - sometimes that requires a visual inspection of the breakers at the local substation. Somebody has to go out and look. Usually, this happens in foul weather, so that isn't the easiest thing to do.

Recovery of widespread grid outages is far from routine, even if the utility has procedures for performing the required actions. Obviously the first time performing a task takes longer than if it the same task is performed routinely. The last time a cascading grid event like August 14, 2003, occurred was in 1973. It is reasonable to assume that anyone involved in the recovery from that grid outage has retired. The implication is the current employees will proceed cautiously.

Plants and systems along the edge of the grid outage area usually are the first to recover as they can connect to an operating system on the other side of that edge to borrow power to start those pumps and fans required for boiler/turbine restart. Of course, that's once the necessary transmission lines have been verified as operable.[12]

The NERC operating manual table of contents includes Policy Number 5. The policy refers to emergency operations, and its "item E" called system restoration. "When you're restoring the system from some system collapse or an outage (such as what happened in the Western Systems Coordinating Council on August 10, 1996) there are five steps under the requirements. The fifth step in this process is off-site supply for nuclear plants. This is the first thing that happens after the system is brought back together, resynchronized and judged to be functioning. This is before we bring back any other loads or generating plants."[13] "Besides, since the NPPs are connected to a backbone … in any restoration of the system, you begin with the black-start plants and go right to the backbone. So NPPs naturally receive priority to restore the system because the operators must restore its backbone."[14]

Data capturing the minimum time for power recovery indicated considerable uncertainties. This is, in part, due to the definition of "power available." In several LOOPs, power was believed to be available to the busses long before the Unusual Events (UEs) ended. Delays in reconnecting the plant to the grid and fully exiting the UE occurred for several reasons including the following.

- Need for multiple plants to be reconnected caused UEs to be longer than what would be expected for a LOOP that affected a single unit.

the energy grid. A black start plant is a power plant that includes one or more black start units. While black start units are not used often, they are an integral part of a system's contingency plans in the event of a system blackout.

[12] Reference 16

[13] Reference 12

[14] Ibid.

- The plant staff conservatively felt that continued EDG operation was acceptable. This may be due to potential grid parameter fluctuations or the need to assess the impact of the event before starting the reconnection procedure.

LOOP Duration from Various Data Sources

Using Reference 20 and Reference 21, the following statistical distribution figures (3-5 through 3-10) summarize the duration data (i.e., Reference 2 and Appendix B) and their characteristics.

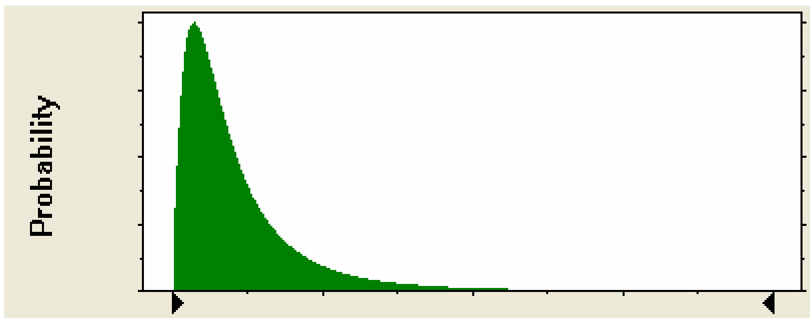

Figure 3-4
Distribution of LOOP Duration (minutes) Measured by Unusual-Event Duration – Lognormal
Jan. 1, 1997 to Dec. 31, 2004

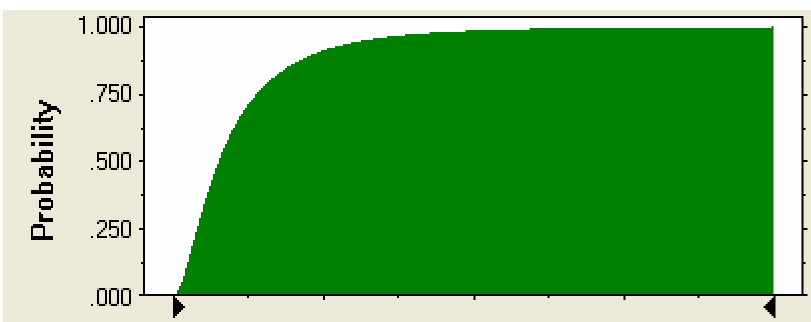

Figure 3-5
Distribution of LOOP Duration (minutes) Measured by Unusual-Event Duration – Cumulative
Jan. 1, 1997 to Dec. 31, 2004

(Based on Lognormal Distribution)

Table 3-2
Lognormal Parameters of Unusual Event Duration Distributions

Statistics	U E Duration (minutes)	U E Duration (hours)
Mean	731.48	12.19
Median (50th percentile)	538.21	8.97
Upper Bound (95th percentile)	2,027.51	33.79
Lower Bound (5th percentile)	132.86	2.21

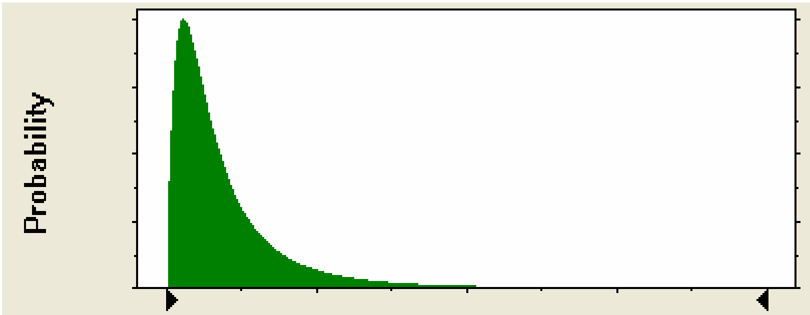

Figure 3-6
Distribution of LOOP Duration (minutes) Measured by Best-Estimate Reconnect Time – Lognormal
Jan. 1, 1997 to Dec. 31, 2004

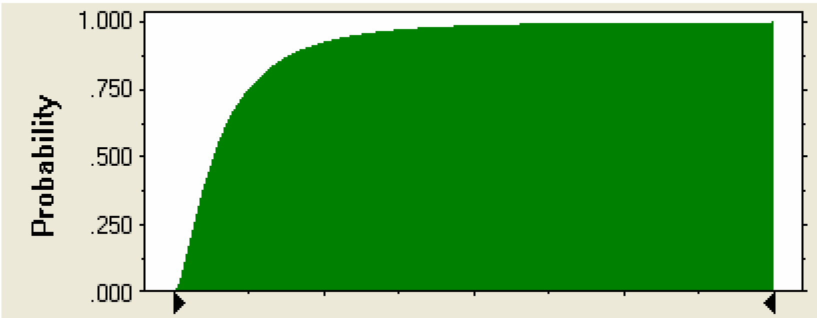

Figure 3-7
Distribution of LOOP Duration (minutes) Measured by Best-Estimate Reconnect Time – Cumulative
Jan. 1, 1997 to Dec. 31, 2004

(Based on Lognormal Distribution)

Table 3-3
Lognormal Parameters of Best-Estimate LOOP Duration Distributions

Statistics	LOOP Duration (minutes)	LOOP Duration (hours)
Mean	489.00	8.15
Median (50th percentile)	332.60	5.54
Upper Bound (95th percentile)	1,412.43	23.54
Lower Bound (5th percentile)	77.97	1.30

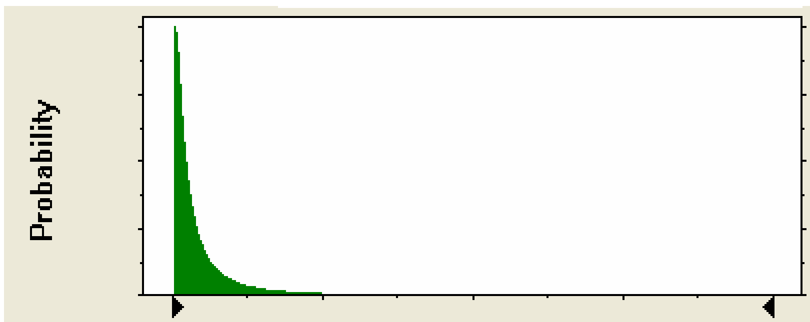

Figure 3-8
Distribution of EIA Outage Duration (hours, Equipment Only) – Lognormal
Jan. 1, 1999 to Dec. 31, 2004

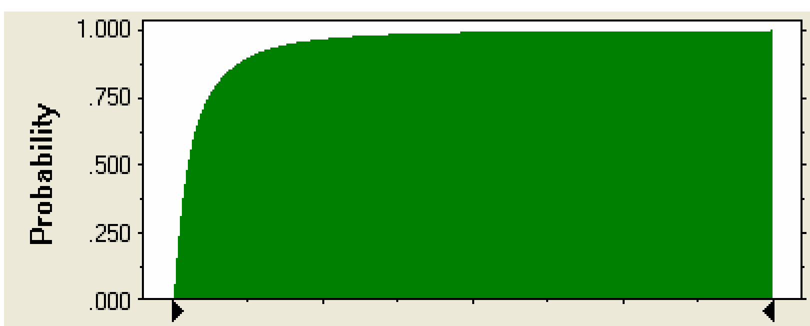

Figure 3-9
Distribution of EIA Outage Duration (hours, Equipment Only) – Cumulative
Jan. 1, 1999 to Dec. 31, 2004

Table 3-4
Lognormal Parameters of EIA Outage Duration Distributions

Statistic	Outage Duration (minutes)	Outage Duration (hours)
Mean	450.6	7.51
Median (50th percentile)	192.6	3.21
Upper Bound (95th percentile)	1855.8	30.93
Lower Bound (5th percentile)	30.6	0.51

Interpretation of data: As an example, the statistical data shown in Figures 3-9 and 3-10 can be stated as follows:

There is 5% probability that the outage duration is less than or equal to 30 minutes.

There is 95% probability that the outage duration is less than or equal to 31 hours.

LOOP Duration Findings

Based on a review of Figure 3-5 through Figure 3-10, the approximate durations of grid events can be estimated. Table 3-5 summarizes the key statistical parameters of the distributions illustrated above. The raw data for these distributions is provided in the appendices to this report.

Table 3-5
Lognormal Parameters of Duration Distributions (in minutes)

Data Source	Mean	Median	95%	5%	Error Factor
Unusual Event Duration (minutes)	731.48	538.21 (~9.0hrs)	2,027.51	132.86	3.8
Best-Estimate Duration (minutes)	489	332.6 (~5.5hrs)	1,412.43	77.97	4.2
EIA Event Duration (minutes)	450.6	192.6 (~3.0hrs)	1855.8	30.6	9.6

Table 3-5 compares the statistical characteristics of large grid loop durations established from three data sets. The Best-Estimate and Unusual-Event data measure the duration of LOOPs of various causes including plant-centered causes. This data is obtained from Reference 2 as well as based on discussions between the authors of this work and knowledgeable plant personnel. The EIA duration data is most closely related to the grid-centered data traditionally used at the plants. Note that with a Log-normal distribution, the best estimate for the value being investigated is the median (50^{th} percentile in the cumulative probability distribution).

The paucity of LOOP events (i.e., actual dual-safety-bus failure) puts the authors in a position of combining LOOPs at the plants with grid problems associated with equipment. The authors did notice that grid events caused by weather and those caused by equipment issues had a similar distribution. It is interesting to note that both the UE Duration and the Best-Estimate Duration have typical nuclear industry PRA model error factors. Exiting an Unusual Event is somewhat of a judgment call by the plant management.[15] The Emergency Planning (or Technical Support Center, TSC) leader needs to be convinced by his staff of the readiness of the plant to reconnect to the off-site source and the readiness of the TSO to accept the NPP house loads – the reconnect is not automatic. Although the "emergency action level" is fairly clear, reconnecting to the grid has to be authorized. The plant staff is likely to only obtain this authorization to reconnect from the plant senior management, which could be a non-trivial time, after they have verified that the TSO can reliably handle the NPP house loads.

The grid is a network of equipment. The advantage of a network design is that there are numerous success paths for transmitting power from where it is generated to where it is consumed. A plausible hypothesis for the distribution of durations is for them to be skewed to short-durations with a long-tail representing extensive outages like August 14, 2003. The high error factor for EIA data (compared to the LOOP data) is indicative of a situation where there is a high probability of an extensive outage even though a typical outage is only three hours long. Because the EIA events in this group are "equipment related" only, it is fair to hypothesize that there is no regional or seasonal dependency in this duration data. There is little diversity in the fundamental design, function, or capacity of high voltage equipment used across the country.

The three ways of measuring LOOP duration discussed here are related but are not expected to be equivalent. The rules for Unusual Event duration are relatively rigorous (plant conditions meet a prescribed "emergency action level). The best-estimate durations established for nuclear power plants appear to be most realistic, although realism is achieved at a greater cost. The EIA event durations also appear to be easy to gather, but the method of determining duration on EIA-417 has the least incentive for rigor. The greater uncertainty in the duration is a function of the large variability in the extent of the power outages and the size of the geographical area to be restored. Note that EIA durations include outages below the size of the house loads of a typical NPP to some that took thousands of customers off-line.

At the outset of this project, it was hoped that the *easy to obtain* Unusual Event duration could be used as a surrogate for actual LOOP duration. At the conclusion of this analysis, that hope is forlorn. For the PSA analyst to make effective use of future LOOP data, future reports of LOOP events at the plants should make an explicit best-estimate reconnect[16] time to the industry, if not in the formal (regulatory) licensee event report itself. Increasing the number of LOOP duration data points attributable to plant, grid, and weather LOOP events (of all types listed in Table 3-1) will allow a more conclusive set of statistics to be created leading to a better estimate of LOOP duration.

It should be noted that in compiling the above data, no distinction is made between large grid events and events at multiple unit sites. In considering large grid events there are physical

[15] Furthermore, the Unusual Event can be triggered by more than one "emergency action level," not just the one related to LOOP.
[16] Connection to the first safety-bus (in a dual safety-bus LOOP) or the affected safety-bus

factors that control the time of recovery. Plants on the periphery of the blackout region would typically recover sooner, as available power sources are redistributed to support that part of the grid. Plants in the deep interior of the blackout will take longer. NPPs near plants designated by the utility as their "black-start" plant are also more likely to reconnect house loads to the power grid. Thus, the data used do not entirely represent independent events.

Similarly, multiple unit sites will also bias the data for an individual unit, as the units are brought on line sequentially. The PVNGS units were reconnected to the grid in-series following the single grid disturbance (see Reference 1 and Reference 5). Thus, timings for the second (and third unit) would necessarily be longer than the recovery of the first unit. These issues will persist until the size of the event-duration database increases.

4

MERGING LOOP DATA, TRIP DATA, AND GRID-OUTAGE DATA

This section discusses the statistical methods used to predict whether or not the grid-events can be fairly characterized by seasonal and regional factors. The events underlying these figures are provided in the appendices.

Data Source Descriptions

To gather a statistically significant sample of LOOP initiators by region for this study, the national grid is subdivided into the major North American Electric Reliability Council regions as shown on Figure 4-1. This grouping keeps events at "remote plants" from skewing the LOOP frequency estimate of any particular plant, i.e., events at Diablo Canyon from skewing the LOOP frequency estimate of any particular plant; for example, events at Diablo Canyon will not skew the non-recovery estimate for St. Lucie. The regions selected do reflect the significant amount of bulk electric sales among utility companies that affects the frequency of LOOP events at each NPP. Increasing the number of sub-regions thins the available data so much that the usefulness of the data becomes fuzzy. Thus, this entire report focuses on the ten major grid-organizations as a basis for parsing the data. As will be demonstrated in this chapter, focusing on the ten major grid-organizations yields interesting findings that meet the intuition described in Chapter 1. That is, the grid characteristics differ across the country.

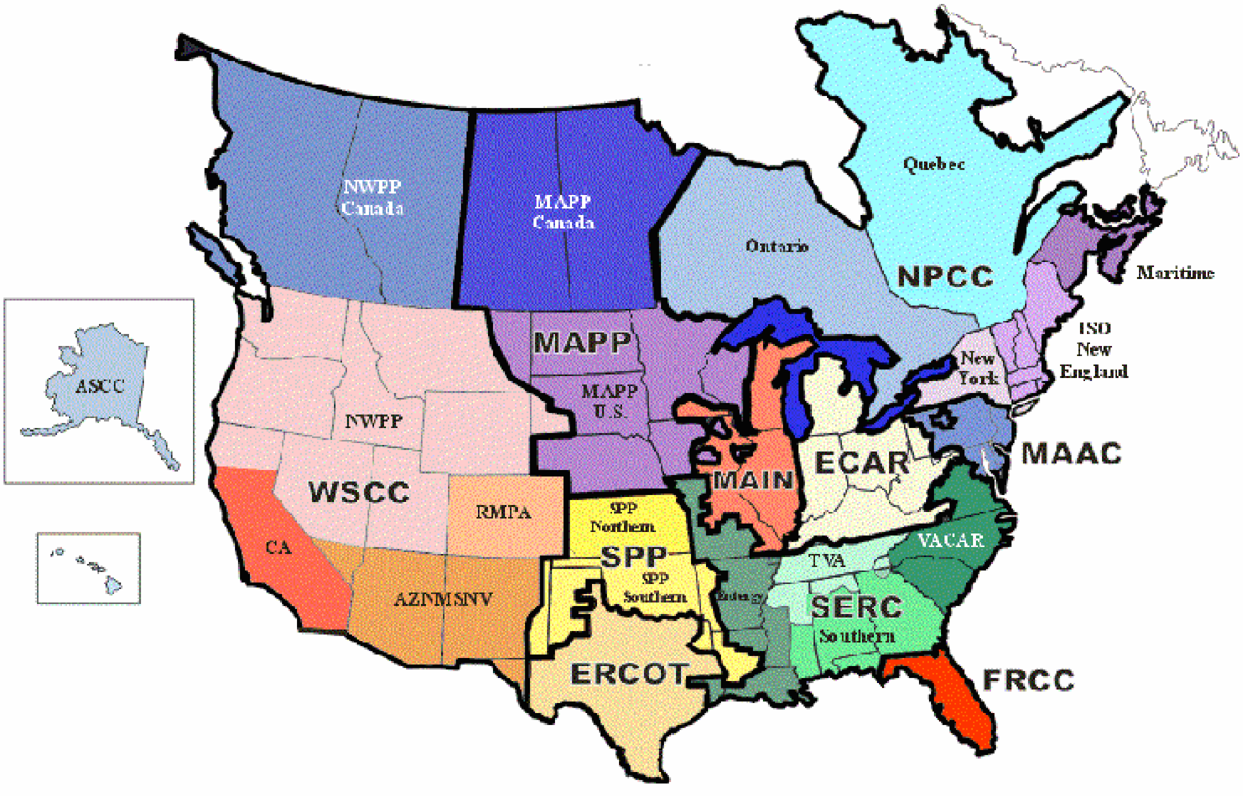

Figure 4-1
North American Reliability Council Regions

EPRI LOOP Events (Reference 2)

The traditional source of LOOP data has been provided by EPRI (latest version is Reference 2). It covers the past ten years of operating experience and LOOP events in that time. LOOPs are based on LERs submitted by the plants. The events are categorized according to the following table. As industry performance has improved, the number of Type Ia and Type Ib LOOP events has decreased so that the current ten year list is dominated by the LOOP events on August 14, 2003, and June 14, 2004.

Table 4-1
All EPRI LOOP Categories and Descriptions

Ia	No off-site power available for 30 minutes or longer to the safety buses.
Ib	No off-site power available for less than 30 minutes to the safety buses.
IIa	With the unit on-line, the startup/shutdown sources of off-site power for the safety buses become deenergized. The main generator remains on-line (connected to the off-site grid) and power for the safety buses is available from a unit auxiliary transformer.
IIb	With the unit on-line, the startup/shutdown sources of off-site power for the safety buses remain energized but in question. There is low or unstable grid voltage, or there might be if the unit trips, or trips along with a LOCA and emergency safety feature actuation. The main generator remains on-line (connected to the off-site grid) and power for the safety buses is available from a unit auxiliary transformer.
III	The unit auxiliary source of power for the safety buses becomes deenergized or unavailable, but off-site power for the safety buses remains available, or can be made available, from a startup/shutdown source. Utilization of this source may require a fast or slow automatic transfer, or manual switching from the control room. A loss of unit auxiliary power that is the result of a unit trip is not a Category III event. To be a Category III event the loss of power from the unit auxiliary source must be the initiating event and precede the unit trip. Most problems that trip the unit off-line are not Category III events. A Category III event is more properly associated with a failure of main electrical power hardware that makes near term availability of the unit auxiliary source of power for the safety buses unlikely.
IV	No off-site power available during cold shutdown because of special maintenance conditions that does not occur during or immediately following operations.
None	Event of interest

EPRI Grid Trip Events (Appendix A)

EPRI compiles plant trip information. A subset shows nuclear plant trips resulting from grid-centered events. The events are listed in Appendix A. The advantage of this source of data is that there are many events compared to the LOOP data.

The August 14, 2003, transmission failure distinguished itself from other recent LOOP events in that the event was widespread, affected more than one site and that the key initiating-event occurred well away from any nuclear plant. A review of the EPRI data base and associated event LERs for non-weather related LOOPs indicates that in the past 10 years four grid-type events impacted more than one site. Three of these events occurred on the WSCC grid and were noted on December 14, 1994, August 10, 1996, and June 14, 2004. Of these, two of the three events (December 14, 1994 and August 10, 1996) resulted in transmission failures and trips at multiple plants, but no loss of offsite power occurred at any of the nuclear plants.

> The western transmission failure of August 10, 1996 marked a hot day in Los Angeles. Relatively inexpensive hydropower was available from the northwest. Large amounts of power were flowing southward when voltage problems in the northwest became evident. A line sagged into a tree at Oregon. Lines tripped; generating plants tripped. The system separated into four islands. Frequency in the Northern-California-island dropped. All five sets of load shedding relays actuated causing about 50 percent of Northern California

> load to be shed. Many power plants tripped, including Diablo Canyon units 1 and 2. Southern California, Arizona and New Mexico were part of the southern island. Frequency dropped there also, triggering load shedding. Palo Verde units 1 and 3[17] in the southern island tripped. Neither nuclear site (i.e., Diablo, PVNGS) lost all off-site power as a result of the event. A transient resulted in tripping of 190 generating units. [18]

The more recent "bird" event affecting PVNGS on June 14, 2004 isolated all the Palo Verde units from the grid and also propagated the transmission failure to the San Onofre site (although no significant impact[19] on San Onofre operation was noted).

EIA Events (Appendix B)

The Energy Information Agency requires utilities to report the duration of the events reported on EIA-417. See Appendix B. The advantage of this source is that there are many events reported to the EIA and the statistical law of large numbers can be applied to establish a statistically valid event frequency. Appendix B details the federally mandated reporting requirements for the grid-operators.

Statistical Analysis of Combined Data

A common solution to the issue of comparing three or more groups is a statistical test known as analysis of variance or ANOVA. It addresses the question of whether there are differences between the means of the groups. It does not, however, identify which of the groups differ from one another. It is important to remember that a significance test only indicates that some or all of the group means are different. As we do not know which of the means are different, further analyses known as post hoc comparisons must be performed to determine how the groups differ from one another.

[17] Reference 7: On August 10, 1996, Palo Verde Units 1 and 3 were operating at approximately 100 percent power, when both reactors tripped on low Departure from Nucleate Boiling Ratio (DNBR) following a major grid perturbation. The grid perturbation was characterized by an initial substantial load decrease followed by a significant load demand increase. The reactor trip was generated due to power exceeding the Variable Over Power Trip (VOPT) setpoint within the Core Protection Calculators (CPC). Power exceeded the VOPT setpoint when Steam Bypass Control System (SBCS) Valves (SBCV) opened in response to turbine load fluctuations induced by the grid perturbation. The Unit 1 and Unit 3 shift supervisors classified the events as uncomplicated reactor trips. There were no ESF actuations and none were required. Required plant equipment and safety systems responded to the event as designed in each unit. Unit 2 survived the transmission failure because it had a less negative moderator temperature than the other units, which were nearer end-of-life. Both units started up the following day.

[18] Reference 12 – discussion of Slide 11.

[19] A voluntary LER by SCE reported a frequency fluctuation. San Onofre and Columbia experienced frequency oscillations, but remained operating throughout the event. See Reference 6.

ANOVA makes three assumptions.

1. First, the observations are assumed to be normally distributed. If this is not the case, the data must first be transformed to a normal distribution or a non-parametric multiple comparisons method must be utilized. One option for dealing with non-normally distributed data is to perform a non-parametric ANOVA. The non-parametric equivalent of a two-way ANOVA is the Friedman two-way ANOVA by ranks.

2. The second ANOVA assumption is that the population variance is assumed to be the same in each group. The importance of this assumption is lessened when the sample sizes are equal.

3. Third, the observations in each group must be independent and cannot affect the values of observations in another group. As with any statistical analysis, the raw data should be examined initially to determine whether these assumptions are met.

ANOVA begins by calculating the mean of each group of data. It then combines the data from each group into a single group and calculates the grand mean of the grouped data. ANOVA uses these means to ask two questions:

1. Is there a difference between the groups (i.e., between-groups variance)?

   If the group means were similar to the grand mean of all of the data, then the variance of the observations within the groups will be small and the groups will likely be very similar.

2. How much variability exists between the observations and their respective group means (the within-groups variance)?

   If the variability between the groups were similar to the variability within the groups, then they are likely from the same population.

With repeated measures ANOVA, there are three sources of variability: between columns (treatments), between rows (individuals) and random (residuals). The ANOVA table partitions the total sum-of-squares into those three components. It then adjusts for the number of groups and number of subjects (expressed as degrees of freedom) to compute two F-ratios. The main F-ratio tests the null hypothesis (H_0) that the column means are identical. The other F-ratio tests the null hypothesis that the row means are identical (this is the test for effective matching). In each case, the F-ratio is expected to be near 1.0 if the null hypothesis were true. If F were found to be large, then the P-value would be small.

Selection of Data Source Weighting

Various experiments were run on these data sets to determine the individual characteristics of each.

The traditional LOOP event data is dominated by the 2003 Northeast blackout and the 2004 Palo Verde event. The data consists almost entirely of events in the Spring and Summer (traditional solar seasons). Given the typical weather in Arizona, the June 14, 2004, event can easily be considered a summertime event, but to retain consistency this seasonal grouping is strictly by calendar seasons. The number of NERC regions involved in the Reference 2 list is broad, but because of the small number of events (14 grid-centered LOOPs), it has neither statistically significant regional nor seasonal dependencies.

Table 4-2
All EPRI Grid-Centered LOOP Events by Region and Season
Jan 1997 to Dec 2004

Grid	Spring	Summer	Fall	Winter
ECAR		3		
ERCOT				
FRCC				
MAAC				
MAIN		1		1
MAPP				
NPCC		6		
SERC				
SPP				
WSCC	3			

Table 4-3
All EPRI Grid-Centered LOOP Events Jan 1997 to Dec 2004

Region	Date	Reactor Name
ECAR	08/14/03	Davis Besse
ECAR	08/14/03	Fermi 2
ECAR	08/14/03	Perry
ECAR	08/14/03	Palisades
MAAC	08/14/03	Oyster Creek
MAIN	01/06/99	Clinton
MAIN	08/12/99	Callaway
NPCC	08/14/03	Nine Mile Point 1
NPCC	08/14/03	Nine Mile Point 2
NPCC	08/14/03	Fitzpatrick
NPCC	08/14/03	Indian Point 2
NPCC	08/14/03	Indian Point 3
NPCC	08/14/03	Ginna
WSCC	06/14/04	Palo Verde 3
WSCC	06/14/04	Palo Verde 1
WSCC	06/14/04	Palo Verde 2

EPRI created a list of plant trips caused by grid-related issues (reproduced in Appendix A of this report). This list has 19 events that do not overlap the LOOP event list cited above. It shows neither statistically significant regional nor seasonal dependencies.

Table 4-4
All EPRI Grid-Centered Trip Events by Region and Season
Jan 1997 to Dec 2004

Grid	Spring	Summer	Fall	Winter
ECAR				
ERCOT	2			1
FRCC		1	1	
MAAC		3		
MAIN		1		
MAPP				
NPCC		2		1
SERC	2	3		1
SPP				
WSCC				1

The large list of EIA events (reproduced in Appendix B) has 51 events that involved a loss of five or more MWe because of “equipment problems” as categorized by the authors (the entire database is a list of 158 weather and equipment events). Equipment problems include failures of lighting ballasts and industrial motor controls. This type of equipment is designed and installed to minimize the size of grid disturbances. That is, lightning induced problems is assigned to the “equipment category” because the system (by empirical evidence) routinely handles lightning strikes without incident. If lightning were to cause a significant event, evidently the equipment or network design is inadequate. The EIA data shows a significant regional and seasonal dependency. The shear number of events makes the EIA data the best of the three databases for characterizing the grid at-large. But clearly, a large fraction of events in this database do not correspond to a nuclear plant trip or a LOOP.

Table 4-5
All EIA "Equipment" Events by Region and Season
Jan 1999 to Dec 2004

Grid	Spring	Summer	Fall	Winter
ECAR	1	4		
ERCOT	3			1
FRCC	1	1		
MAAC		3		1
MAIN		3		
MAPP				
NPCC	2	2		3
SERC	1	2		
SPP		1		
WSCC	5	11		6

The balance of this portion of the project was to determine a fair weighting of the events.

An assortment of weightings results in significant regional and seasonal dependencies. The most appropriate weighting should reflect one fundamental objective of this analysis, namely, a fair estimate of how often off-site grid events will result in LOOP to both safety-buses at a nuclear plant. The following chart (Figure 4-2) shows example weightings of the data sets that demonstrate regional and seasonal dependencies. Because the EIA events have weak correlation to LOOPs, it appears to be best for purposes of nuclear power plant PRAs to choose a high weighting for LOOP events.

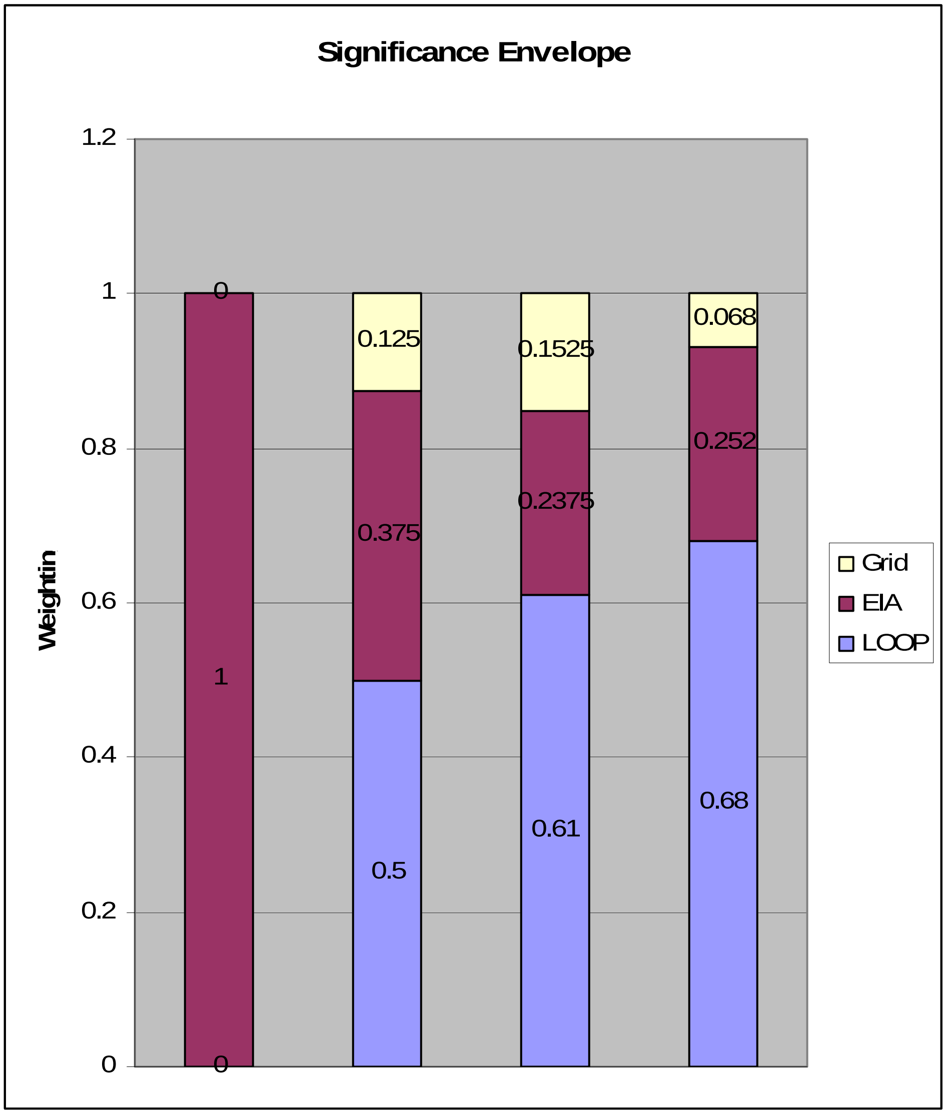

Figure 4-2
Database Weighting Cases Resulting in Regional-Seasonal Dependency

Depending on how well the analyst believes that the grid-induced trips are pre-cursors to LOOP events, three weightings of LOOP events result in a dataset with both regional and seasonal dependency. When a weighting of 0.500, 0.375, and 0.125 are used for the LOOP, EIA, and Grid-Trip databases respectively, the weighted number of events in each region-season is as follows on the next table. This weighting results in a total number of events for each region being at least one-point-zero, except for MAPP and SPP. For perspective, the number of Type Ia and Type Ib Grid-LOOPs reported by Reference 2 are listed in the right-most column. The implication is that there are site-specific grid features that prevent off-site disturbances from propagating to the plant safety busses (See Chapter 2.0 of this report).

The following chart is a surrogate for the probability of the frequency of LOOPs being higher in a given season than the average for that region.

Table 4-6
A Weighted Matrix of Grid-Centered Events by Region and Season Over Ten Years

Grid	Spring	Summer	Fall	Winter	*EPRI Ia & Ib Grid-LOOPs*
ECAR	0.38	3.00	-	-	*3*
ERCOT	1.38	-	-	0.50	*None*
FRCC	0.38	0.50	0.13	-	*None*
MAAC	-	1.50	-	0.38	*None*
MAIN	-	1.75	-	0.50	*2*
MAPP	-	-	-	-	*None*
NPCC	0.75	4.00	-	1.25	*6*
SERC	0.63	1.13	-	0.13	*None*
SPP	-	0.38	-	-	*None*
WSCC	3.38	4.13	-	2.38	*3*

The factors in Table 4-7 below are to be applied to plant-specific grid-LOOP frequencies for configuration-risk assessments. The value is based on the z-value associated with the region-season cell (see the previous Table 4-6) versus the average for each region. The study shows that grid events in the Fall are highly unlikely in all regions of the country. Summer tends have the greatest potential for grid related events. The importance of Spring and Winter varies based on the region. Furthermore, MAPP has *no* events identified in any of the three data sets and appears not susceptible to equipment related grid events. Likewise, SPP has only one summertime event in the three data sets. SPP LOOP data is different from the other regions in that there is only one reactor in the region. Future work may show that SPP is most similar to ERCOT in terms of peak load seasons, and that (for purposes of LOOP studies) the two regions can be lumped together.

Table 4-7
Grid-LOOP Adjustment Factor

Grid	Likelihood of exceeding the average in Spring	Likelihood of exceeding the average in Summer	Likelihood of exceeding the average in Fall	Likelihood of exceeding the average in Winter	Reactors in Region[20]
ECAR	L	H	L	L	8
ERCOT	H	L	L	M	4
FRCC	H	H	L	L	5
MAAC	L	H	L	M	13
MAIN	L	H	L	M	16
MAPP	L	L	L	L	6
NPCC	L	H	L	L	12
SERC	H	H	L	L	33
SPP	L	H	L	L	1
WSCC	H	H	L	M	8

Maintenance programs at the plants should consider the regional and seasonal dependencies of Table 4-7 and Table 2-1.

LOOP Frequency Findings

Based on this discussion it is recommended that a grid event be treated as a "site level" event. The nature of the August 14, 2003, transmission failure as well as others mentioned in this report point to seasonal and regional factors as part of considering to what degree nuclear power plants (NPPs) are vulnerable to widespread transmission failures. The plants that tripped on August 14, 2003, and June 14, 2004, ought to count events on those days as a valid full-LOOP (typically referred to as a Category Ia LOOP – see Table 4-1). Furthermore, while several plants in the large North American Electric Reliability Council regions recorded fluctuations in off-site power parameters but did not trip, those NPPs were nevertheless vulnerable as evidenced by their control room indications of grid frequency changes during the first minutes of the August 14, 2003, event. Therefore, plants in the regions where other NPPs did experience a grid-induced trip on August 14, 2003, should count a partial LOOP events based on seasonal and grid system related factors. Because of the regional nature of events like that of August 14, 2003, plants outside of North American Electric Reliability Council Regions: NPCC, MAIN, and ECAR (see Figure 4-1) may exclude the August 14, 2003, transmission failure from the list of LOOPs considered in the plant specific LOOP frequency. Specific recommendations follow (see Table 4-8) for including the events like August 14, 2003, event in the LOOP frequencies for PRA models of U.S. NPPs.

[20] Includes some plants that were permanently shutdown sometime during the period studied.

Applying the general principles of Table 4-8 to the June 14, 2004, event would mean that the PVNGS "average annual" PRA model would count the June 14, 2004, event as one LOOP event. Columbia, Diablo Canyon, and San Onofre (also on the WSCC grid) would count the summertime[21] June 14, 2004, event as a fractional LOOP. A factor of at least 0.10 (out of a range from 0.10 to 0.35) is proposed as a bounding value for the partial/fractional LOOP based on the weightings described in Figure 4-2. The fractional-LOOP is intended to account for low grid-operating margin more *typically* found in the summer months during one-fourth of the year, i.e., a low enough margin that a NPP was forced to trip. The range from 0.10 to 0.35 is a reasonable value between zero and one and reflects the fact that continued plant operation throughout the grid event was not certain. It does not seem prudent to say that LOOP events have no bearing on other plants in the same grid region, and thus a value of zero was excluded. It would be unrealistic to assume that any LOOP caused by any grid disturbance in the region can be counted as a LOOP at all of the plants in that region. Thus a value of one was excluded. Given the small number of multiple LOOPs across a wide region (except for the August 14, 2003, event) it is fair to assume that a grid-induced trip of one NPP will affect a second (somewhat distant) plant less than half of the time. Regional and seasonal effects are notable when non-traditional grid events are equated to be at least 30%-LOOP to 50%-LOOP. Of 31 grid-induced trips reported by EPRI from April 1997 to September 2004, twelve became LOOP events (~40%).[22] Many other plants were likely potentially affected, but not reported via LERs. Assuming that the grid event could potentially affect plants in the region, the grid-induced trips to LOOP factor would fall to about 10%. Viewing this factor from another perspective, one hundred sixty EIA events were matched to two LOOP events (~1%). Plant specific margin estimates considering additional information provided in Chapter 2 may also be used to select a reasonable fractional-LOOP value between 0.10 and 0.35.

For maintenance rule risk applications (i.e., 10CFR§50.65(a)(4)), during periods of "low-operating-margin" on the NPCC, ECAR, MAIN grids, <u>all</u> NPPs in those regions should consider the August 14, 2003, transmission failure as a full-LOOP (i.e., EPRI Category Ia). It is expected that the seasonal LOOP weighting factor (see Table 4-7) will off-set the extra LOOP frequency by this method of counting (see the second half of Table 4-8). Note that there is no seasonal adjustment in the annual average CDF calculation as there should be for a Maintenance Rule risk assessment. Using the factors suggested in Table 4-7 fairly considers the regional and seasonal nature of the event and highlights decreased plant LOOP risks during certain seasons.

The proposed inclusion of widespread grid events into the PRA model LOOP frequency is summarized in Table 4-8.

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[21] Per the NRC definition in NUREG-1784 (Reference 10).

[22] 12/31 = 0.387 rounded off

Table 4-8
Proposed Method for Including Grid-Centered Events in the LOOP Frequency

For annual-average (base-case) CDF and LERF:
Narrow the count to the grid events that happened in my grid region.
The event caused a LOOP (count 1 LOOP). If the grid event did not trip my plant, but it tripped another NPP in the same grid then count at least 0.10 LOOP to 0.35 LOOP (based on a plant specific assessment similar to that in Chapter 2). The “tripped another NPP in my region” conditional characterizes the grid disturbance as significant. Grid trips for the site under consideration are already in other initiating events in the model (e.g., turbine-trip).
Increase (or decrease) the frequency by a small fraction (e.g., ±5%) to account for the location of the plant on the grid (see Table 2-1).
For (a)(4) planning purposes:
Narrow the count to the grid events that happened in my grid region.
Regardless of the season in which it occurred, if the grid event caused a LOOP or tripped any NPP in my grid region count at least 0.10 LOOP to 0.35 LOOP (based on a plant specific assessment similar to that in Chapter 2). The “tripped any NPP in my region” conditional characterizes the grid disturbance as significant. Of course, all LOOP events that had an effect on-site are counted as full-events. Grid trips for the site under consideration are already in other initiating events in the model (e.g., turbine-trip).
Adjust the grid-centered LOOP frequency by an appropriate weighting factor chosen according to the current season and location of the plant (see Table 4-7).

5
COMBINING LOOP EXPERIENCE AT OTHER PLANTS

This section covers generating a LOOP frequency for a specific plant by Bayesian updating of regional data with plant specific data. The method is to create a prior distribution of LOOP frequency for the region using the Log-normal probability distribution function. Next, the Log-normal distribution is converted into a Gamma-distribution because it is mathematically simple to include plant specific information into a more general prior. The α and β Gamma parameters are incremented with the plant specific (linear) values of number-of-events and the time over which those events have occurred, e.g., two events in eleven years. The updated Gamma is then converted back to the equivalent Log-normal for use in the PRA model.

The remainder of this section provides the mathematical basis for the method described above. The detail provided below is unavailable in any other published reference.

Bayesian Update of Hourly Failure Rates

The Bayesian parameter estimation begins with a prior distribution about a parameter, quantifying uncertainties about possible values of the parameter, observing new data, and finally generating a posterior distribution (p.d.f.) of the parameter.

Hourly failure rates (λ) can be updated using the Gamma distribution and the Poisson distribution functions to apply Bayes' Theorem. From Appendix 10.1, P. 10.21 of Reference 14,

$$P(\lambda \mid k,T) = \frac{P(k,T \mid \lambda) * P(\lambda \mid \alpha,\beta)}{P(k,T)} = \frac{P(k,T \mid \lambda) * P(\lambda \mid \alpha,\beta)}{P(\bar{\lambda})P(k,T \mid \bar{\lambda}) + P(\lambda)P(k,T \mid \lambda)} \qquad \textbf{(5-1)}$$

Where:

$P(\lambda \mid \alpha,\beta)$ is a Gamma distribution used to represent the <u>prior</u> distribution (e.g., generic data distribution).

$P(k,T \mid \lambda)$ is a Poisson distribution used to represent the new information likelihood distribution (e.g., plant-specific data distribution).

Hence, the numerator of Eq. (5-1) is the product of the likelihood times the prior probability distribution of λ. To obtain the full posterior probability, we divide every such product by the sum of all such products. This makes the posterior probabilities add up to unity.

The denominator $P(k,T)$ in Equation (5-1) is a normalizing factor (constant) that is the integral of the product of the Poisson distribution and the Gamma distribution over all values of λ from 0 to infinity. Also calculated as $P(\bar{\lambda})P(k,T \mid \bar{\lambda}) + P(\lambda)P(k,T \mid \lambda)$. The $P(k,T)$ normalizing constant[23] ensures the posterior distribution $P(\lambda \mid k,T)$, really is a proper[24] probability distribution.

$P(\lambda \mid k,T)$ is the resulting Gamma distribution used to represent the posterior distribution (e.g., the updated data distribution).

Poisson Likelihood Distribution in the Bayesian Equation

From Section 5.5.2.4.1 of Reference 8, the Poisson distribution (representing the new information) can be used to represent hourly failure probabilities when k is large and λ is small as follows:

$$P(k,T \mid \lambda) = \frac{(\lambda T)^k e^{-\lambda T}}{k!} \tag{5-2}$$

Where:
λ = failure rate per unit time
T = Time units
k = Number of failures in time T

Gamma Prior Distribution, Gamma ($\lambda \mid \alpha_{prior}, \beta_{prior}$), in the Bayesian Equation

From Section 5.5.2.2.8 of Reference 8, the Log-normal distribution is frequently used as a prior distribution, $P(\lambda \mid \alpha, \beta)$, for failure probability. The Log-normal distribution equations described later in this Chapter are used to transform the initial Log-normal distribution to an equivalent Gamma distribution. The Gamma distribution is like a Gaussian distribution, except that the Gaussian goes from -∞ to +∞, whereas Gamma distributions go from 0 to +∞. Just as the Gaussian distribution has two parameters $\bar{x}$ and σ which control the mean and width of the distribution, the Gamma distribution has two parameters, alpha (α) and beta (β). The mean values and confidence limits of the two distributions are constrained to be the same by the analyst.

The values of y in (x,y) are Log-normal when the plot of (ln(x),y) has a normal-curve shape (y-axis as linear values of the frequency and x-axis as logarithmic values of the data points) with a mean of μ and a variance of σ^2. Note that the typical application of this process starts with a Log-normal approximation of the prior; generally, only the mean and confidence limits are known. The process is more complex when the prior is a collection of raw data points (x,y).

[23] often not known, but an exact value (constant) can be worked out mathematically
[24] Proper distributions must either sum or integrate to 1, depending on whether they are discrete or continuous, respectively.

Gamma distributions are based on the gamma function, which is sometimes known as the generalized factorial function. Like exponential distributions, they are often used for times to complete a task, such as service time. Gamma functions have a smaller variance than exponential functions and they also have two shape parameters, which give more control over their shape than exponential distributions.

The Gamma distribution can be parameterized in terms of a shape parameter α and an inverse scale parameter $\beta = 1 / \theta$, called a rate parameter, sometimes called the *inverted*-Gamma distribution. This alternate (*inverted*) Gamma distribution can be used to describe the probability that α events will occur within a period β. [Contrast it with the exponential distribution, which describes the probability that one event will occur.] The remainder of this section will refer to this inverted-gamma as simply the gamma (in order to make comparison to reference material simpler).

From Appendix 10.3 of Reference 15, the Gamma distribution function of interest in LOOP frequency calculations (the *inverted* form) can be represented as follows.[25] The (inverted) form chosen in this work is convenient for updating initiating event frequencies and demand failure probabilities demonstrated later.

$$P(\lambda \mid \alpha, \beta) = \frac{\beta^{\alpha} (\lambda)^{\alpha - 1} e^{-\beta\lambda}}{(\alpha - 1)!} \tag{5-3}$$

Where:

λ = failure rate (i.e., number of failures per unit time)

Distributions of λ that can be written in this pattern have a mean for $\lambda = \alpha/\beta$

Distributions of λ that can be written in this pattern have a variance for $\lambda = \alpha/\beta^2$

The α and β parameters of the Gamma distribution function can be made to match a priori distribution with Log-normal-mean ($\mu_{\text{Log-normal}}$) and priori Log-normal-variance ($\sigma_{\text{Log-normal}}^2$) as follows:

β = Log-normal-mean / Log-normal-variance

α = (Log-normal-mean)^2 / Log-normal-variance

The complexity in the method comes in determining the "Log-normal mean" and "Log-normal variance" when starting with the mean and the confidence limits of the prior.

---

[25] The non-inverted form of the gamma is $P(\lambda \mid \alpha, \beta) = \frac{(\lambda)^{\alpha - 1} e^{-\lambda/\beta}}{\beta^{\alpha} (\alpha - 1)!}$

The Log-normal parameters needed to build a Gamma approximation of the given Log-normal are calculated using the parameters assumed in the Log-normal as follows.

The Log-normal percentiles (confidence limits) need to be converted into the equivalent raw values. That is, the input is the mean and confidence limits assumed for (ln(x),y). For this process to work-out mathematically correct, the analyst needs the confidence limits of the raw data (x,y) instead. By definition, the mean of the prior must be the same regardless of the distribution. That is $\mu_{raw} = \mu_{Log\text{-}normal}$ in this process. Thus, the term $\mu_{Log\text{-}normal}$ (used below) can be considered over-specified.

$\lambda_{95\%\text{-}raw}=\exp(\lambda_{95\%\text{-}Log\text{-}normal})$; in the work described by this document, $\lambda_{95\%\text{-}Log\text{-}normal}$ is a given.

$\lambda_{5\%\text{-}raw}=\exp(\lambda_{5\%\text{-}Log\text{-}normal})$; in the work described by this document, $\lambda_{5\%\text{-}Log\text{-}normal}$ is a given.

The error factor for a Log-normal distribution is defined as the ratio of the 95th percentile to the median, or equivalently, the ratio of the median to the 5th percentile. Physically, the square of EF represents the width of a 90% confidence interval with the median at its mid-point.

Error Factor (EF) = $(\lambda_{95\%\text{-}raw}/\lambda_{5\%\text{-}raw})^{1/2.}$

The standard deviation of the raw data is $\sigma_{raw} = \frac{\ln(ErrorFactor)}{1.645}$ when using the 5-to-95% confidence interval. That is, in a normal (Gaussian) distribution 95% probability is reached when the value on the x-axis is the mean plus 1.645 times the standard deviation.

To correctly assign the α and β for the gamma approximation of the prior, the analyst needs to calculate the variance associated with the (ln(x),y) prior, using the Error Factor (EF) and standard-deviation (σ^2_{raw}) calculated above.

$$\sigma^2_{\log normal} = \left(e^{[2*\ln(ErrorFactor)]} + \sigma^2_{raw}\right)*\left(e^{\sigma^2_{raw}} - 1\right) \tag{5-4}$$

In the form of the Gamma distribution used in this work[26], the mean and variance of the Gamma are (in general) as follows.

$Mean_{gamma} = \alpha / \beta$

$Variance_{gamma} = \alpha / \beta^2$

To build a Gamma distribution that has the mean and variances of the prior, the Gamma parameters for the prior approximation (i.e., α and β) are determined directly from the $\mu_{Log\text{-}normal}$ and $\sigma^2_{Log\text{-}normal}$.

$\beta = \mu_{Log\text{-}normal} / \sigma_{Log\text{-}normal}^{2}$

[26] An alternate and popular form of the Gamma uses mean = α * β and variance = α * β².

$\alpha = \mu_{Log\text{-}normal}^2 / \sigma_{Log\text{-}normal}^2$

Posterior Gamma Distribution, Gamma($\lambda | \alpha_{posterior}$, $\beta_{posterior}$), in the Bayesian Equation

When a Gamma distribution with parameters α and β is considered to be the prior distribution for λ, then the posterior distribution for λ will also be a Gamma distribution, with parameters α + k and β + t, where k failures are observed during t total time on test ($t = \sum t_i$ and t_i is the time on test for the i^{th} test unit).

$$\alpha_{posterior} = \alpha_{prior} + k \tag{5-5}$$

$$\beta_{posterior} = \beta_{prior} + \sum t_i \tag{5-6}$$

Where $\sum t_i$ is summation of times related to observing k failures.

See Reference 9, Section 6.2.2.7.2. The correctness of this approach can be verified by comparing the “coefficient of variance” of the gamma prior with the coefficient of variance of the Log-normal prior – by definition, they must be the same[27]. The usefulness of this (*inverted*) arrangement in a Bayesian update derives from the fact that the two parameters of the Gamma distribution, α and β, are sometimes referred to as the pseudo failures and pseudo total test time, respectively.

Now, the relationship between the prior gamma and the posterior gamma can be formulated. Recall the following mathematical relationships:

$$P(\lambda | k,T) = \frac{P(k,T|\lambda) * P(\lambda|\alpha,\beta)}{P(\bar{\lambda})P(k,T|\bar{\lambda}) + P(\lambda)P(k,T|\lambda)} \tag{5-7}$$

The normalizing factor, denominator, $P(\bar{\lambda})P(k,T|\bar{\lambda}) + P(\lambda)P(k,T|\lambda)$ is:

$$K = P(\bar{\lambda})P(k,T|\bar{\lambda}) + P(\lambda)P(k,T|\lambda)$$

$$K = \int P(k,T|\lambda) * P(\lambda|\alpha,\beta) d\lambda(k)$$

$$K = \int \frac{(\lambda T)^k e^{-\lambda T}}{k!} * \frac{\beta^\alpha (\lambda)^{\alpha-1} e^{-\beta\lambda}}{(\alpha-1)!} d\lambda(k) \tag{5-8a, b, c, d}$$

$$K = \frac{T^k \beta^\alpha}{k!(\alpha-1)!} \int \lambda^{\alpha+k-1} e^{-\lambda(T+\beta)} d\lambda(k)$$

The integral in the expression for K here is quite complex. Reference 9, Section 6.2.2.3 avoids this integral by replacing the equality in the Bayesian update formula with a proportionality sign. However, because the form of the posterior is known and must also have the form of a Gamma

[27] The coefficient of variance for the Gamma distribution is 1/SQRT(alpha),
for the lognormal: coefficient of variance is standard deviation / mean of the raw data

distribution, the value of the integral can be inferred. The values for α, k, β and T must be positive integers to satisfy the solution of the integrals shown next.

$$
\begin{aligned}
&use\\
&\int x^n e^{-bx} dx = b^{-n-1}\Gamma(n+1)\\
&and\\
&\Gamma(n+1) = \int x^n e^{-x} dx = (n)\Gamma(n) = (n)!\\
&n \sim \alpha + k - 1,\\
&b \sim \mathrm{T} + \beta,\\
&x \sim \lambda\\
&simplifies\\
&\int \lambda^{\alpha+k-1} e^{-\lambda(T+\beta)} d\lambda(k) = \frac{(\alpha+k-1)!}{(\beta+\mathrm{T})^{\alpha+k}}\\
&so\\
&K = \frac{T^k\beta^\alpha}{k!(\alpha-1)!}\frac{(\alpha+k-1)!}{(\beta+\mathrm{T})^{\alpha+k}} = \frac{(\alpha+k-1)!}{k!(\alpha-1)!}\left(\frac{T}{\beta+T}\right)^k\left(\frac{\beta}{\beta+T}\right)^\alpha
\end{aligned}
\tag{5-9}
$$

The value of K represents the normalizing factor in the Bayesian update equation. K is a function of only constants, and thus is a constant itself – as expected. Using K for $P(k,T)$ in the Bayesian update equation, the quantity $P(\lambda \mid k,T)$, i.e., the posterior Gamma distribution is:

$$
\begin{aligned}
&P(\lambda \mid k,T) = K^{-1} * \frac{(\lambda T)^k e^{-\lambda T}}{k!} * \frac{\beta^\alpha(\lambda)^{\alpha-1}e^{-\beta\lambda}}{(\alpha-1)!}\\
&P(\lambda \mid k,T) = \left(\frac{k!(\alpha-1)!}{(\alpha+k-1)!}\left(\frac{\beta+\mathrm{T}}{T}\right)^k\left(\frac{\beta+\mathrm{T}}{\beta}\right)^\alpha\right) * \frac{(\lambda T)^k e^{-\lambda T}}{k!} * \frac{\beta^\alpha(\lambda)^{\alpha-1}e^{-\beta\lambda}}{(\alpha-1)!}\\
&P(\lambda \mid k,T) = \frac{(\beta+\mathrm{T})^{\alpha+k}}{(\alpha+k-1)!}(\lambda)^{\alpha+k-1}e^{-(\beta+T)\lambda}\\
&Where:\\
&mean = \frac{(\alpha+k)}{(\beta+T)}\\
&\mathrm{var} = \frac{(\alpha+k)}{(\beta+T)^2}
\end{aligned}
\tag{5-10a, b, c, d, e}
$$

because the inverse Gamma function follows the Gamma-distribution pattern from which the mean and variance (describe earlier) can be identified.

For the posterior gamma, the equation has α+k instead of α, and β+T instead of β.

$$P(\lambda \mid \alpha, \beta) = \frac{\beta^{\alpha} (\lambda)^{\alpha-1} e^{-\beta\lambda}}{(\alpha-1)!} = \frac{\beta^{\alpha}}{(\alpha-1)!} (\lambda)^{\alpha-1} e^{-\beta\lambda} \qquad \textbf{(5-11)}$$

This shows how the prior gamma parameters are related to the posterior Gamma parameters. The α parameter becomes $\alpha+k$. The β parameter becomes $\beta+T$. Thus the formulas for the posterior mean and variance are nearly as simple as those for the prior.

Finally, the posterior Gamma distribution is then transformed to an equivalent posterior Log-normal distribution using the Log-normal equations provided in the next section. As in the previous transformation, the mean values and confidence limits are forced to be the same for gamma and Log-normal distributions. As may be expected, the prior mean differs from the posterior mean. The Log-normal parameters are calculated using the Gamma mean (μ) and variance (σ^2) as follows:

$$\mu_{posterior} = \frac{\alpha + k}{\beta + T}$$

$$\sigma^2_{posterior-gamma} = \frac{\alpha + k}{(\beta + T)^2}$$

$$\sigma_{posterior-\log normal} = \sqrt{\ln\left(\frac{\sigma^2_{posterior-gamma}}{\mu^2_{posterior-gamma}} + 1\right)}$$

$$ErrorFactor = e^{[\sigma_{posterior-\log normal} * 1.645]} \qquad \textbf{(5-12a, b, c, d, e, f, g)}$$

$$median = \frac{\mu_{posterior}}{\exp\left(\frac{\sigma^2_{posterior-\log normal}}{2}\right)}$$

$$\lambda_{5\%-posteriorLogNormal} = median / ErrorFactor$$

$$\lambda_{95\%-posteriorLogNormal} = median * ErrorFactor$$

Log-normal Distribution

In general terms, a non-negative random variable (x) is said to have a Log-normal distribution when dependent measure (plotted on the y-axis) together with the transformed random variable ln(x) (plotted on the x-axis) has a normal distribution (μ, σ^2).

In PRA applications, the probability (dependent variable P) of a particular (independent-random variable) value of λ follows a Log-normal when the P is plotted against ln(λ) and takes on a normal-curve shape (probability, P, on the y-axis, ln(x) on the x-axis). A Log-normal distribution results when the variable is the product of a large number of independent, identically-distributed variables. The likelihood, P, of random (dependent) variable λ having a particular value (along the x-axis) can be thought of as <u>Log-normally</u> distributed in terms the parameters: geometric mean (μ_{λ}) and standard deviation (σ_{λ}). Likewise ln(x) (transformed independent-random variable) can be thought of as <u>normally</u> distributed in terms of its mean (μ_y)

and its standard deviation (σ_f). From hereon, the variable 'f' will represent ln(x), i.e., f=ln(x). The parameters (μ_λ,σ_λ) and (μ_f, σ_f) can be related to each other via the following formulation (see Reference 9, Appendix A.7.3).

$$\ln(\lambda \mid \mu_\lambda, \sigma_\lambda) = \frac{1}{\sigma_f \lambda (2\pi)^{1/2}} * e^{\frac{-(\ln(\lambda)-\mu_f)^2}{2\sigma_f^2}} \quad \textbf{(5-13)}$$

Where
$\lambda \geq 0$

$-\infty < \mu_f < \infty$

$\sigma_f \geq 0$

Variables with a log-normal distribution are of interest in PRA model quantification because products and quotients of Log-normal random variables also have Log-normal distributions (think about the cutset line items generated from fault tree quantification). From Section 5.5.2.4.4 of Reference 8, the Log-normal distribution[28] is frequently used as a prior distribution for failure rates (λ). Log-normal distributions are typically specified in one of two ways. One way is to specify the mean and standard deviation of the underlying normal distribution (μ_λ and σ_λ). The other way is to specify the distribution using the mean of the Log-normal distribution itself (μ_f) and a term called the error factor (EF). The error factor for a Log-normal distribution is defined as the ratio of the 95th percentile to the median, or equivalently, the ratio of the median to the 5th percentile. Physically, the square of EF represents the width of a 90% confidence interval with the median at its mid-point. The other terms in 5.5.2.4.4 are as described in 5.5.2.2.8 of Reference 8, as summarized below.

$\lambda_{5\%\text{-raw}}$ = 5% confidence limit associated with λ, failure rate

$\lambda_{95\%\text{-raw}}$ = 95% confidence limit associated with λ, failure rate

Error Factor (EF) = $(\lambda_{95\%\text{-raw}}/\lambda_{5\%\text{-raw}})^{1/2}$ = exp(1.645 σ_f) using a 5-to-95% confidence interval[29]

When data describes rates of change or when the data follows an exponential distribution, the correct way to calculate mean is using the geometric-mean technique[30] rather than the arithmetic-average. In a normal (Gaussian, bell-shaped curve), the values of mean and median are identical values because the curve is symmetrical around the mean (i.e., the distribution of sample values is not skewed). In general, the limits are as follows.

$\lambda_{5\%}$ = median of λ divided by the error factor (EF) **(5-14)**
$\lambda_{95\%}$ = median of λ times the error factor (EF) **(5-15)**

[28] Reference 8 has an extra parenthetical in 5.5.2.4.4, which is corrected here. Reference 9, Appendix A.7.3 has the correct equation. For clarity, this work added subscripts (which appears in neither reference) to help the reader understand when the data is raw or transformed by LN().
[29] The z-value of a normal distribution is 1.64485 when the probability that the value is less than z is 95%. This equation is on page 5-45 of Reference 8.

[30] The geometric mean of a sequence of values ($a_1, a_2, a_3, \ldots, a_n$) is found from $(\Pi(a_1, a_2, a_3, \ldots, a_n))^{1/n}$

standard deviation σ_f = ln(error factor derived from $\lambda_{95\%\text{-raw}}$ and $\lambda_{5\%\text{-raw}}$) / 1.645 **(5-16)**
using a 5-to-95% confidence interval

The <u>geometric mean</u> (GM) of a set of positive random values (e.g., a set that is normally distributed) is the same as taking the <u>exponent of the mean of the log transformation</u> of the same positive random values. When λ_i (all positive) follows a Log-normal shape, the geometric-mean of λ is the same as applying the exponential function to the arithmetic-mean of f (where f=ln(λ)).

$GM[\lambda_1, \lambda_2, \lambda_3, \ldots \lambda_n] = \exp(\text{mean}_f)$ When λ_i (all positive) and $f_i = \ln(\lambda_i)$ **(5-17)**

The median (or 50th percentile) of λ_i is the exponential of the median of the raw data, y_i. And, in a normal distribution, the geometric mean and median have the same value.

median of $\lambda_i = \exp(\text{median}_f)$ **(5-18)**

By rearranging it is possible to write:

$\text{median}_f = \ln(\text{median of } \lambda_i)$ **(5-19)**

By the definition of geometric mean (and thus the median) can be related to the 5th and 95th values as follows.

GM of λ = exp(mean of f) $\approx (\lambda_{95\%} \times \lambda_{5\%})^{1/2}$ **(5-20)**
where f=ln(λ) and λ is Log-normally distributed, f is normally distributed

Using the 5th and 95th of λ is a good approximation to the geometric mean when fitting data.

There are other equations to write the error factor (EF) as follows:

EF = 95th percentile / 50th percentile = 50th percentile / 5th percentile **(5-21)**

= (95th percentile / 5th percentile)^2 **(5-22)**

Using equations from above, the following holds.

median of $\lambda_i = (\mu_\lambda) / \exp(\sigma_f^2/2)$ **(5-23)**

Median = $\exp(\mu_f)$ **(5-24)**

mean of $\lambda = \mu_\lambda \approx \exp(\mu_f+(\sigma_f^2/2))$ **(5-25)**
This is the first moment of the Log-normal distribution.[31]

[31] First central moment is the mean. The second central moment is the variance, the square root of which is the standard deviation. The third central moment is skewness or the symmetry of the probability distribution. A distribution that is normal has a skewness of zero. A distribution that is skewed to the left, the tail of the distribution is on the left, will have a negative skewness. A distribution that is skewed to the right, the tail of the distribution is

By substitution: μ_λ= (median of λ)($\exp(\sigma_f^2/2)$) **(5-26)**

Proof:

Median of $\lambda = \exp(\mu_f)$

Mean of λ
$\approx \exp(\mu_f + (\sigma_f^2/2))$
$= \exp(\mu_f)*\exp(\sigma_f^2/2)$
= (median of λ)$*\exp(\sigma_f^2/2)$

Variance of $\lambda = \sigma_\lambda^2 = \exp(2\mu_f+\sigma_f^2) * [\exp(\sigma_f^2)-1]$ This is the second moment of the log-normal distribution. Alternatively: $\sigma_\lambda^2 = (\mu_\lambda)^2 * [\exp(\sigma_f^2)-1]$

Proof:

Variance of λ
= (mean of λ)$^2*(\exp(\sigma_f^2) - 1)$
$= (\mu_f)^2*(\exp(\sigma_f^2) - 1)$

Note that
$\exp(2\mu_f + \sigma_f^2)$
$= \exp(2\mu_f)*\exp(\sigma_f^2)$
$= [\exp(\mu_f)*\exp(\sigma_f^2/2)]^2$
= (mean of λ)^2

To demonstrate the use of these equations, take the following steps with a colloquial Excel spreadsheet.

(1) Generate n values (x_1 through x_n) using a random number generator (an inherently normal distribution)

(2) Fit the random values to a Log-normal distribution

(3) Calculate the statistics of the normal distribution using the Excel functions AVERAGE(), MEDIAN(), STDEV(), and VARIANCE()

(4) To generate the lognormal distribution, fill a nearby column with f_i, where f_i = EXP(x_i)

(5) Calculate the statistics of the lognormal distribution (column with y_i,) using the Excel functions AVERAGE(), MEDIAN(), STDEV(), and VARIANCE()

(6) Calculate the statistics of the lognormal distribution using the transformation formulas discussed above, e.g., $\sigma_x^2 = \exp(2\mu_f+\sigma_f^2) * [\exp(\sigma_f^2)-1]$

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on the right, will have a positive skewness (like the log-normal distribution). The fourth central moment is kurtosis or the peakedness or how tall and skinny versus short and squat the probability distribution.

You find that the statistics calculated from step #5 are identical to the statistics calculated from step #6.

6
CONCLUSIONS

This report shows through a statistical method how the likelihood of a grid-induced LOOP is a strong function of the location of the plant (i.e., regional dependence) as well as the season of the year (i.e., seasonal dependence). To establish a statistically meaningful data set, grid-centered LOOP events were enriched by merging traditional LOOP events with events hypothesized to be pre-cursors to LOOP events.

This report demonstrates the use of modern GIS software to characterize the power grid near to nuclear power plants (NPPs). A limited investigation of local impact of grid networks and "islanding" of the grid around the NPPs was inconclusive.

This report establishes correction factors for grid-centered LOOP frequency on a regional level. The characterization of the nearby grid allows individual plants to tailor the grid-event likelihood into a plant-specific grid-centered LOOP frequency.

The report further describes the duration of grid-centered LOOPs (directly related to the LOOP-non-recovery probability). The data yielded average LOOP durations from three to nine hours. The effect on the non-recovery probability as a result of this unexpected behavior is left to a future report.

7
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A
GRID-INDUCED PLANT TRIP EVENTS

A review of the EPRI data base and associated event LERs for non-weather related LOOPs indicates that in the past 10 years four grid-type events impacted more than one site. Three of these events occurred on the WSCC grid and were noted on December 14, 1994, August 10, 1996 and June 14, 2004. Of these, two of the three events (December 14, 1994 and August 10, 1996) resulted in transmission failures and trips at multiple plants, but no loss of offsite power occurred at any of the nuclear plants.

> *The western transmission failure of August 10, 1996 marked a hot day in Los Angeles. Relatively inexpensive hydropower was available from the northwest. Large amounts of power were flowing southward when voltage problems in the northwest became evident. A line sagged into a tree at Oregon. Lines tripped; generating plants tripped. The system separated into four islands. Frequency in the Northern California island dropped. All five sets of load shedding relays actuated causing about 50 percent of Northern California load to be shed. Many power plants tripped, including Diablo Canyon units 1 and 2. Southern California, Arizona and New Mexico were part of the southern island. Frequency dropped there also, triggering load shedding. Palo Verde units 1 and 3*[32] *in the southern island tripped. Neither nuclear site (i.e., Diablo, PVNGS) lost all off-site power as a result of the event. A transient resulted in tripping of 190 generating units.* [33]

The more recent "bird" event affecting PVNGS on June 14, 2004 isolated all the Palo Verde units from the grid and also propagated the transmission failure to the San Onofre site (although no significant impact[34] on San Onofre operation was noted).

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[32] Reference 7: On August 10, 1996, Palo Verde Units 1 and 3 were operating at approximately 100 percent power, when both reactors tripped on low Departure from Nucleate Boiling Ratio (DNBR) following a major grid perturbation. The grid perturbation was characterized by an initial substantial load decrease followed by a significant load demand increase. The reactor trip was generated due to power exceeding the Variable Over Power Trip (VOPT) setpoint within the Core Protection Calculators (CPC). Power exceeded the VOPT setpoint when Steam Bypass Control System (SBCS) Valves (SBCV) opened in response to turbine load fluctuations induced by the grid perturbation. The Unit 1 and Unit 3 shift supervisors classified the events as uncomplicated reactor trips. There were no ESF actuations and none were required. Required plant equipment and safety systems responded to the event as designed in each unit. Unit 2 survived the transmission failure because it had a less negative moderator temperature than the other units, which were nearer end-of-life. Both units started up the following day.

[33] http://www.nrc.gov/reading-rm/doc-collections/commission/tr/1997/19970423b.html – discussion of Slide 11.

[34] A voluntary LER by SCE reported a frequency fluctuation. San Onofre and Columbia experienced frequency oscillations, but remained operating throughout the event. See Reference 6.

EPRI Plant Trip Database (excluding LOOPs)

Date	Plant Name	LER or ADAMS	LER Title	Action Taken	Cause	Lines Without Power	Grid Condition	Operating Mode
3/3/2000	Brunswick 1							
		32400001	Loss of Offsite Power During Refuel Outage	Scram signal; EDGs loaded	Human error – utility transmission techs mispositioned switch	1 line	Power lost	Refueling
3/5/2001	Seabrook							
		44301002	Reactor Trip Due To Power Arc Flashover Across The "B" Phase 345 Kv Transmission Line Bushings	Reactor trip after 3rd line lost (LOSP)	Weather - snow	LOOP	Power lost	100
2/27/2002	San Onofre 3							
		36202001	Loss of Offsite Power with Consequential RPS/ESF Actuations due to Maintenance Error	Scram	Human error – distribution tech failed to isolate test signal	1 line	Power lost	100
4/24/2003	Grand Gulf 1							
		41603002	Automatic Reactor Scram (#107) due to a Partial Loss of Offsite Power	Scram	Equipment – relay Equipment – line trap	2 lines	Power lost	100
5/15/2003	Comanche Peak 1							
		44503003	Reactor Trip on Units 1 and 2 due to Grid Disturbances	Scram	Equipment – relay	1 line	Overcurrent (line fault)	100
5/15/2003	Comanche Peak 2							
		44503003	Reactor Trip on Units 1 and 2 due to Grid Disturbances	Scram	Equipment – relay	1 line	Overcurrent (line fault)	99.8
8/3/2003	Indian Point 2							
		2473004	Automatic Turbine / Reactor Trip due to 345 KV Grid Disturbance	Scram	Weather – lightning	0 lines	Overfrequency	100
8/14/2003	Ginna							
		24403002	Major Power Grid Disturbance Causes Loss of Electrical Load and Reactor Trip	Scram	Grid perturbation	? lines	Underfrequency	100

EPRI Plant Trip Database (excluding LOOPs)

Date	Plant Name	LER or ADAMS	LER Title	Action Taken	Cause	Lines Without Power	Grid Condition	Operating Mode
8/14/2003	Oyster Creek							
		21903003	Actuation of Reactor Protection System due to Grid	Scram	Grid perturbation	0 lines	Overvoltage	100
9/15/2003	Peach Bottom 2							
		27703	Dual Unit Scram due to 230 KV Grid Disturbance	Scram	Weather – lightning; Equipment - relay	1 line	Undervoltage	?
9/15/2003	Peach Bottom 3							
		27703	Dual Unit Scram due to 230 KV Grid Disturbance	Scram	Weather – lightning; Equipment - relay	1 line	Undervoltage	?
9/18/2003	Surry 1							
		280-030918-1	Surry Unit 1 Manually Scrammed after Loss of Circulating Water Pumps		Surry Unit 1 Manually Scrammed after Loss of Circulating Water			
9/18/2003	Surry 2							
		281-030918-1	Surry Unit 2 Manually Scrammed after Loss of Circulating Water Pumps		Surry Unit 2 Manually Scrammed after Loss of Circulating Water			
12/20/2003	St Lucie 2							
		328-031220-1	LER 389-03-005 - Automatic Reactor Trip Due to Loss of Turbine Generator Excitation		LER 389-03-005 - Automatic Reactor Trip Due to Loss of Turbine Generator Excitation			
12/22/2003	Comanche Peak 2							
		446-031222-1	OE17751 - Metal Reflector Hood for Main Turbine Generator Exciter Caused a Unit 2 Trip and Rectifier Wheel Damage		OE17751 - Metal Reflector Hood for Main Turbine Generator Exciter Caused a Unit 2 Trip and Rectifier Wheel Damage			
5/21/2004	Surry 2							
		281-040521-1	OE18594 - Catastrophic Failure of Coupling Capacitor Voltage Transformer Caused Unit Trip and Switchyard Fire.		OE18594 - Catastrophic Failure of Coupling Capacitor Voltage Transformer Caused Unit Trip and Switchyard Fire.			

EPRI Plant Trip Database (excluding LOOPs)

Date	Plant Name	LER or ADAMS	LER Title	Action Taken	Cause	Lines Without Power	Grid Condition	Operating Mode
7/13/2004	Clinton	461-040713-1	Automatic Reactor Scram Resulting From A Transmission Line Fault		Automatic Reactor Scram Resulting From A Transmission Line Fault			
8/14/2004	Brunswick 1	325-040814-2	LER 325-04-002 Manual Reactor Shutdown During Loss of Offsite Power Event (LER 325-04-002)		Manual Reactor Shutdown During Loss of Offsite Power Event (LER 325-04-002)			
9/6/2004	Crystal River 3	316-040906-1	LER 302-04-003 - Reactor Trip And Emergency Feedwater Actuation Caused By 230 Kilovolt		LER 302-04-003 - Reactor Trip And Emergency Feedwater Actuation Caused By 230 Kilovolt Switchyard/Transmission Faults			

B

EIA DATA

There are various reports publicly available to characterize the electric power grid in the vicinity of nuclear power plants. The United States Department of Energy, Energy Information Agency publishes a month report entitled “Electric Power Monthly,” which among other things tabulates information reported on Form EIA-417. EIA-417 is a federally mandated report on electric power grid incidents. This is an interesting source of grid information from the perspective of statistics as it contains approximately a dozen events per month. The publically available data is slightly non-normal in structure. A more normal form of the data from EIA is tabulated in this Appendix.

U.S. Department of Energy Energy Information Administration Form EIA-417 (2002)	*EMERGENCY INCIDENT AND DISTURBANCE REPORT*	Form Approved OMB No. 1901-0288 Approval Expires: 08/31/05

NOTICE: The timely submission of Form EIA-417 by those required to report is mandatory under Section 13(b) of the Federal Energy Administration Act of 1974 (FEAA) (Public Law 93-275), as amended. Failure to respond may result in a penalty of not more than $2,750 per day for each civil violation, or a fine of not more than $5,000 per day for each criminal violation. The government may bring a civil action to prohibit reporting violations, which may result in a temporary restraining order or a preliminary or permanent injunction without bond. In such civil action, the court may also issue mandatory injunctions commanding any person to comply with these reporting requirements. Title 18 U.S.C. 1001 makes it a criminal offense for any person knowingly and willfully to make to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction. A person is not required to respond to collection of information unless the form displays a valid OMB number. Data reported on Form EIA-417 in Schedule 1, lines 4, 5, 6, 7, and 8 are considered to be confidential. Schedule 2 is considered confidential. All other data are not confidential. (See form instructions for a full list of legal citations covering data collection authorization.)

RESPONSE DUE: Submit a completed Schedule 1 as an initial report within 60 minutes of the incident. A final report (completed copy of the Form EIA-417, Schedule 1 and 2) is due within 48 hours of the event. Electronic submission by facsimile or e-mail is the preferred method of notification.

SCHEDULE 1. -- EMERGENCY ALERT NOTICE

LINE NO.				
	ORGANIZATION FILLING			
1.	Alert Status (check one)	Preliminary Alert [ ]	Update Notice [ ]	Final Report [ ]
2.	Organization Name			
3.	Address of Principal Business Office			
	NAME OF OFFICIAL THAT NEEDS TO BE CONTACTED FOR FOLLOW-UP AND ANY ADDITIONAL INFORMATION			
4.	Name			
5.	Title			
6.	Telephone Number			
7.	FAX Number			
8.	E-mail Address			
	INCIDENT AND DISTURBANCE DATA			
9.	Geographic Area(s) Affected			Unknown at this time [ ]
10.	Date/Time Incident Began (mm-dd-yy/hh:mm) using 24-hour clock			
11.	Estimated Date/Time of Restoration (mm-dd-yy/ hh:mm) using 24-hour clock			Unknown at this time [ ]
12.	Date/Time Incident Ended (mm-dd-yy/ hh:mm) using 24-hour clock			
13.	Did the incident/disturbance originate in your system/area? (check one response)	Yes [ ]	No [ ]	Unknown [ ]
14.	Estimate of Amount of Demand Involved (megawatts)			Unknown at this time [ ]
15.	Estimate of Number of Customers Affected			Unknown at this time [ ]
16.	Internal Organizational Tracking Number			

17. Type of Emergency Check all that apply (a)	18. Cause of Incident Check if known or suspected (b)	19. Actions Taken Check all that apply (c)
Major Transmission System Interruption [ ]	Weather or Natural Disaster [ ]	Implemented a Warning, Alert, or Contingency Plan [ ]
Major Generation Inadequacy [ ]	Transmission Equipment [ ]	Made Public Appeals [ ]
Major Distribution System Interruption [ ]	Operator Action(s) [ ]	Reduced Voltage [ ]
Other [ ]	Suspected Malicious/Intentional	Shed Interruptible Load [ ]
	Physical [ ]	Shed Firm Load [ ]
	Cyber/Computer/Telecom [ ]	Repaired/Restored [ ]
	Inadequate Electric Resources to Serve Load [ ]	Other [ ]
	Fuel Supply Deficiency (e.g., gas, oil, water) [ ]	
	Unknown Cause [ ]	
	Other [ ]	

Figure B-1
Form EIA-417, "Electric Emergency Incident and Disturbance Report"

The Department of Energy (DOE), under its relevant authorities, has established mandatory reporting requirements for electric emergency incidents and disturbances in the United States. DOE collects this information from the electric power industry on Form EIA -417 to meet its overall national security and Federal Energy Management Agency's Federal Response Plan (FRP) responsibilities. DOE will use the data from this form to obtain current information regarding emergency situations on U.S. electric energy supply systems. DOE's Energy Information Administration (EIA) will use the data for reporting on electric power emergency incidents and disturbances in monthly EIA reports. The data also may be used to develop legislative recommendations, reports to the Congress and as a basis for DOE investigations following severe, prolonged, or repeated electric power reliability problems..

Form EIA-417 must be submitted to the Operations Center if one of the following apply:

1. Uncontrolled loss of 300 MW or more of firm system loads for more than 15 minutes from a single incident
2. Load shedding of 100 MW or more implemented under emergency operational policy
3. System-wide voltage reductions of 3 percent or more
4. Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system
5. Actual or suspected physical attacks that could impact electric power system adequacy or reliability; or vandalism which target components of any security systems
6. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability
7. Fuel supply emergencies that could impact electric power system adequacy or reliability
8. Loss of electric service to more than 50,000 customers for 1 hour or more
9. Complete operational failure or shut-down of the transmission and/or distribution electrical system

The timely submission of Form EIA-417 by those required to report is mandatory under Section 13(b) of the Federal Energy Administration Act of 1974 (FEAA) (Public Law 93-275), as amended.

Table B-1
Major Disturbances and Unusual Occurrences

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
1/2/1999 4:00:00 PM	Duke Power Co. (SERC) Charlotte, NC Ice Storm | On January 2, 1999, at about 1600 EST, a winter storm hit the Duke Energy service territory (the Piedmont area of North Carolina and South Carolina). The ice storm resulted in about 240,000 customers being out of electric service. The hardest hit areas were west and south of Charlotte, North Carolina. As of 1100 hours on January 5, about 25,600 customers were still without service. Service was restored to all customers by about 1800 hours EST on January 6. Most of the damage was done to the Duke Energy distribution system. The storm had little or no impact on neighboring utilities. MWe Lost: 900	Weather	98
1/14/1999 7:29:00 PM	Potomac Electric PowerCo. (MAAC) Washington, DC Ice Storm | On January 14-15,1999, the Washington DC Metropolitan area experienced a severe ice storm. Ice accumulation caused tree branches to make contact with overhead conductors, causing short circuits on hundreds of transmission and distribution feeders and resulting in thousands of downed power lines and blown fuses. The service areas of Potomac Electric Power Co. (PEPCO), the northern portion of Virginia Power (VP), and Baltimore Gas & Electric (BG&E) were affected. PEPCO reported that at the storm's peak, thirteen 13 kV substations in Montgomery County were shut down and service was interrupted to more than 230,000 customers in Montgomery and Prince Georges Counties in Maryland. Due to the severity of the storm, which lasted for about 18 hours, and the extensive damage to the PEPCO system, outside electrical contractors were called in to assist in the restoration process. Over 300 line and tree crews worked double shifts in the restoration effort. MWe Lost: 900	Weather	146
1/17/1999 4:12:00 PM	Potomac Electric PowerCo. (MAAC) Norbeck Substation Equipment Failure | On January 17, 1999, a 69 kV oil circuit breaker at the Norbeck substation failed with a resultant fire. Subsequent 69 kV breaker trippings and operator actions resulted in the loss of the 69 kV bus at Norbeck. The Norbeck facility supplies eight 13 kV distribution substations in the northern and central sections of Montgomery County, Maryland. Critical customers affected included three hospitals, one Metro traction power facility, and two Metro passenger stations. MWe Lost: 90	Equipment	14
1/17/1999 7:00:00 PM	Tennessee ValleyAuthority (SERC) Western TN Severe Storms | On January 17, 1999, at about 1900 CST, thunderstorms, accompanied by tornadoes, moved through the Tennessee Valley Authority (TVA) system, causing interruptions to both TVA and power distributor facilities. Hardest hit areas were west and middle Tennessee. Ten TVA substations and 15 transmission lines were knocked out of service by the storms. Twenty TVA structures (both steel and wood) were either damaged or destroyed. Two 500 kV transmission lines will be out of service for an extended period of time due to storm damage. Service to the majority of customers was restored by January 18, 1999. MWe Lost: 50	Weather	69

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
5/3/1999 3:30:00 PM	Western Resources(SPP) Kansas CIty Severe Storms MWe Lost: 300	Weather	219
5/10/1999 5:00:00 AM	Reliant Energy Houston (ERCOT) Houston, TX Severe Storms MWe Lost: 1400	Weather	72
5/17/1999 5:00:00 PM	Consumers Energy(ECAR) Michigan Severe Storms MWe Lost: 150	Weather	0
6/7/1999 10:00:00 AM	ISO-New England(NPCC) New England Control Area Voltage Reduction MWe Lost: 21900	Equipment	12
6/8/1999 12:24:00 AM	New York Power Pool(NPCC) New York State Weather MWe Lost: 153	Weather	18
6/8/1999 9:41:00 AM	Consolidated Edison(NPCC) Consolidated Edison System Weather MWe Lost: 128	Weather	7
6/8/1999 10:10:00 AM	New York Power Pool(NPCC) New York State Voltage Reduction MWe Lost: 82	Equipment	9
7/6/1999	ISO-New England(NPCC) New England Control Area Voltage Reduction MWe Lost: 1000	Equipment	0
7/23/1999 1:14:00 PM	Alliant (MAIN) East Control Area Equipment Failure MWe Lost: 125	Equipment	2

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
7/23/1999 2:42:00 PM	Entergy (SPP) Entergy Firm Load Shedding | The Entergy system went into the day on Friday, July 23rd projecting that industrial interruptible demand and some scheduled wholesale limited-firm demand would have to be curtailed to maintain the required level of operating reserves. During the day, about 2,100 MW of generation was forced out of service. With adequate amounts of purchased power unavailable, Entergy was forced to shed 900 MW of firm demand from 14:42 EDT until about 17:00 EDT. Entergy made a public appeal around noon on the 23rd requesting a voluntary reduction in electrical usage. MWe Lost: 900	Equipment	2
7/23/1999 4:00:00 PM	Detroit Edison (ECAR) Entire Service Area Severe Storms | On Friday, July 23, 1999, at about 16:00 EDT, Detroit Edison Company's service territory was severely impacted by a catastrophic lightning and windstorm with winds of over 50 mph. Service was interrupted to about 125,000 customers. Damage to the DE system was limited to the 4.8, 13.2, 24, and 40 kV systems. The interconnected grid system was not damaged. By 17:00 EDT on the 24th, about 40,000 customers were still without electric service when a second wind and rain storm hit the area. Electric service to an additional 75,000 customers was interrupted by this storm. Again, damage was limited to the 4.8, 13.2, 24, and 40 kV systems. All customers were restored by 23:59 EDT on the 25th. MWe Lost: 1700	Weather	128
7/24/1999 4:00:00 PM	Detroit Edison (ECAR) Entire Service Area Severe Storms | By 17:00 EDT on the 24th, about 40,000 customers were still without electric service when a second wind and rain storm hit the area. Electric service to an additional 75,000 customers was interrupted by this storm. Again, damage was limited to the 4.8, 13.2, 24, and 40 kV systems. All customers were restored by 23:59 EDT on the 25th. MWe Lost: 1000	Weather	104
7/26/1999 7:00:00 PM	Cinergy (ECAR) Cinergy Service Area Public Appeal MWe Lost: 300	Equipment	0
7/29/1999 5:00:00 PM	Cinergy (ECAR) Cinergy Service Area Public Appeal MWe Lost: 300	Equipment	0
7/30/1999 7:00:00 PM	Cinergy (ECAR) Cinergy Service Area Public Appeal MWe Lost: 500	Equipment	2

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
7/31/1999 3:00:00 PM	Detroit Edison (ECAR) Entire Service Area Severe Storms I On Saturday, July 31, 1999, at about 15:00 EDT, Detroit Edison Company's service territory was severely impacted by a catastrophic lightning and windstorm with winds of over 70 mph. Electric service was interrupted to about 191,000 customers. Damage to the DE system was primarily confined to the 4.8, 13.2, and 40 kV systems. However, one 120 kV line was damaged. All customers were restored by 23:59 EDT on August 3rd. MWe Lost: 2000	Weather	81
8/24/1999 6:19:00 AM	Public Service ofColorado (WSCC) Golden, Colorado Equipment Failure MWe Lost: 425	Equipment	1
8/31/1999 10:49:00 AM	Pacific Gas & ElectricCompany (WSEC) Entire Service Area Equipment Failure MWe Lost: 470	Equipment	1

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
9/15/1999 3:00:00 PM	Carolina Power & Light(SERC) Eastern North Carolina and Northern South Carolina Severe Storm | Hurricane Floyd | During the period September 14-16, 1999, Hurricane Floyd moved up the East Coast causing unprecedented flooding in many areas in addition to wind damage. Floyd hit Florida first, on September 14. By 21:00 EDT, Florida Power & Light Company reported that about 74,000 customers were out of service. As the storm moved northward, by 08:00 EDT on August 15, the number of customers out of service had grown to 235,000 despite the fact that 170,000 customers had been restored to service. By 18:00 CDT on August 15, the numbers were 350,000 customers restored, 210,000 still out of service. None of FP&L's generating stations received any major damage. South Carolina Electric & Gas Company reported 160,000 customers out of service at 12 noon on August 15. By 06:00 CDT, service was restored to 70,000 customers. System protection removed SCE&G's Canady Unit Nos.1 & 2 during the storm resulting in a loss of generation of 250 MW. Several 230 kV and 115 kV circuits were removed from service. Floyd moved through Carolina Power & Light Company's South Carolina service area around mid-day on August 15 and spread to the eastern part of North Carolina on August 16. CP&L reported that the number of outages peaked at about 537,000 at 09:00 EDT on August 16. Several transmission lines were reported damaged. Service was restored to essentially all customers capable of receiving service by 17:00 CDT on September 21. Virginia Power reported about 300,000 customers were without electric service as Floyd moved through on August 16. Five substations were removed from service as a precautionary measure to decrease damage from the expected storm surge and flooding. The 230 kV tie line to CP&L also was reported out of service due to the storm. Floyd began causing problems on the Orange & Rockland Electric Company system around 14:45 EDT on August 16. O&R reported numerous problems on the transmission and distribution system, and electric service interruption to about 100,000 customers. Eleven major transmission lines were reported out of service as a result of tree contact. Ten of the eleven were returned to service by 22:00 EDT on September 18, and the remaining circuit was restored by 17:33 EDT on September 19. MWe Lost: 2600	Weather	0
9/18/1999 10:00:00 PM	Orange & RocklandUtilities (NPCC) New York Severe Storm MWe Lost: 200	Weather	20

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
1/23/2000 8:00:00 PM	Duke Power Co. (SERC) South Carolina Ice Storm l In the early morning hours of Sunday, January 23, a winter storm that started out as snow and transitioned to sleet/freezing rain struck the Duke Power Company service territory. Customer outages totaled 109,000 by midnight, January 24. As of 0833 EST on January 24, about 58,000 customers were still without service. Most of these customers were in the Anderson, and Greenville, South Carolina areas. The entire Duke Power service territory experienced additional snow and high winds on Monday, January 24, resulting in additional customer outages. Customer outages during the storm peaked at 133,000 at 1100 EST on Tuesday the 25. MWe Lost: 450	Weather	112
1/24/2000 7:00:00 PM	Carolina Power & Light (SERC) North Carolina & Northern South Carolina Ice Storm l The severe winter storm, which affected Duke Power beginning on January 23, moved into the South Carolina Electric & Gas service territory on January 24. System protection removed three 115 kV transmission lines from service due to storm conditions. The lines were restored to service by midnight, January 25. Electric service to all customers was restored by 1200 EST on January 26. A winter storm, starting as freezing rain and sleet, moved into the Carolina Power & Light Company service area on Monday evening, January 24, around 1900 EST. By Tuesday, January25, the storm dumped more than 20 inches of snow and left 173,000 customers without electric service. Downed trees and distribution lines hampered restoration of service, making roads impassible in the hardest hit areas. The storm also caused interruptions on four transmission lines. Following the storm, electricity was restored to 78% of the affected customers within the first 24 hours and more than 90% were restored within three days. Service was restored to essentially all customers capable of receiving service by 1200 EST on January 30. MWe Lost: 960	Weather	0
1/29/2000 10:00:00 PM	Duke Power Co. (SERC) South Carolina Ice Storm l On Saturday, January 29, 2000, a winter storm brought sleet/freezing rain to the Duke Power Company service territory during the late evening of January 29 and continued through the early evening of January 30. The number of customers without electric service peaked at about 81,000 at 2000 hours EST on January 30. Most of these customers were in the Charlotte, North Carolina and upstate South Carolina areas. By 1300 EST on January 31, the number of customers without service was reduced to about 40,000 in the Charlotte, Salisbury, and Greensboro/High Point/Burlington areas of North Carolina and the Greenwood County, South Carolina area. MWe Lost: 300	Weather	110

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
3/18/2000 4:00:00 PM	El Paso Elec. Co. (ERCOT) Texas Transmission Line Loss | Prior to this disturbance, Public Service Company of New Mexico's (PNM) 345 kV San Juan Generating Station – Ojo Switching Station line was out of service so a static ground wire could be replaced. A brush fire near and beneath a PNM transmission corridor about four miles south of the Four Corners Generating Station caused system protection to open the 345 kV San Juan Generating Station – BA Switching Station and the Four Corners Generating Station – West Mesa Switching Station lines, and the230 kV Four Corners Generating Station – Pillar Switching Station line. The dispatchers tested and tried to restore the 345 kV lines to service, but were not successful. PNM dispatchers initiated manual load shedding. Voltages in the area continued to sag causing under-voltage load shedding in addition to the manual load shedding implemented by EPE and PNM dispatchers. At about 1643, system protection removed from service EPE's 180 MW Newman Generating Unit No. 4. PNM and EPE continued shedding load to restore stability to their systems. At 1649, Texas-New Mexico Power Company shed 60 MW of interruptible demand. At 1718, the EPE 345 kV Arroyo Switching Station – West Mesa Switching Station line opened as did the 115 kV PNM and Plains Electric G&T Coop lines leaving central and northern New Mexico customers without electricity. EPE restored electric service to its customers by about 1720. At 1753, the EPE Arroyo Switching Station – West Mesa Switching Station 345kV line was restored, and PNM restored about 200 MW of customer demand. At 1814, the 230 kV Four Corners Generating Station – West Mesa Switching Station system was returned to service. By 1830, PNM restored about 50% of the affected demand. At 1835, the 345 kV San Juan Generating Station – BA Switching Station line was restored to service after confirming that the structure fire on it was out and the firefighters were safe. By 1845, PNM restored service to about 65% of the customers who were without electric service. At 1925, field crews verified the structure fire on the 345 kV Four Corners Generating Station – West Mesa Switching Station line was under control and the line was restored to service. By 2020, PNM estimates it restored most all of the affected customers with the exception of a few isolated pockets of demand. The 345 kV San Juan Generating Station – Ojo Switching Station line was not restored until 1012 MST on March 19. The delay in restoring the San Juan – Ojo line was due to darkness and construction activities. The BA Switching Station – Blackwater HVDC Station line was not restored until 1052 on March 19. MWe Lost: 400	Equipment	1

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
3/18/2000 7:08:00 PM	Public Service of NewMexico (WSCC) New Mexico Transmission Line Loss l Prior to this disturbance, Public Service Company of New Mexico's (PNM) 345 kV San Juan Generating Station – Ojo Switching Station line was out of service so a static ground wire could be replaced. A brush fire near and beneath a PNM transmission corridor about four miles south of the Four Corners Generating Station caused system protection to open the 345 kV San Juan Generating Station – BA Switching Station and the Four Corners Generating Station – West Mesa Switching Station lines, and the230 kV Four Corners Generating Station – Pillar Switching Station line. The dispatchers tested and tried to restore the 345 kV lines to service, but were not successful. PNM dispatchers initiated manual load shedding. Voltages in the area continued to sag causing under-voltage load shedding in addition to the manual load shedding implemented by EPE and PNM dispatchers. At about 1643, system protection removed from service EPE's 180 MW Newman Generating Unit No. 4. PNM and EPE continued shedding load to restore stability to their systems. At 1649, Texas-New Mexico Power Company shed 60 MW of interruptible demand. At 1718, the EPE 345 kV Arroyo Switching Station – West Mesa Switching Station line opened as did the 115 kV PNM and Plains Electric G&T Coop lines leaving central and northern New Mexico customers without electricity. EPE restored electric service to its customers by about 1720. At 1753, the EPE Arroyo Switching Station – West Mesa Switching Station 345kV line was restored, and PNM restored about 200 MW of customer demand. At 1814, the 230 kV Four Corners Generating Station – West Mesa Switching Station system was returned to service. By 1830, PNM restored about 50% of the affected demand. At 1835, the 345 kV San Juan Generating Station – BA Switching Station line was restored to service after confirming that the structure fire on it was out and the firefighters were safe. By 1845, PNM restored service to about 65% of the customers who were without electric service. At 1925, field crews verified the structure fire on the 345 kV Four Corners Generating Station – West Mesa Switching Station line was under control and the line was restored to service. By 2020, PNM estimates it restored most all of the affected customers with the exception of a few isolated pockets of demand. The 345 kV San Juan Generating Station – Ojo Switching Station line was not restored until 1012 MST on March 19. The delay in restoring the San Juan – Ojo line was due to darkness and construction activities. The BA Switching Station – Blackwater HVDC Station line was not restored until 1052 on March 19. MWe Lost: 1040	Equipment	0
4/1/2000	City of LakeWorth Utils(FRCC) Florida On Saturday, April 1, 2000, at 0852 EST, a potential transformer at the Hypoluxo Substation failed, causing all circuit breakers at the station to open. This action separated the City of Lake Worth from the rest of Florida. Lake Worth's remaining generating resources were insufficient to supply the demand, resulting in a drop in frequency and system protection subsequently removed the Lake Worth generating facility from service. Due to routine maintenance being performed at the time, Florida Power & Light Company had the electric supply interrupted to three substations, which also were supplied through the Hypoluxo Substation. MWe Lost: 46	Equipment	0

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
4/1/2000	Virginia Power & Electrical Co. (SERC) Virginia Relay Malfunction & Fire l A high-voltage bushing on OX substation transformer No. 3, failed and faulted to ground, causing a fire at 1647 EST on Saturday, April 1, 2000. The transmission lines supplying the station were de-energized to permit fire fighting.	Equipment	0
5/21/2000	Duke Power (SERC) North Carolina Thunder/Lightning l Thunderstorms with lightening moved into the Duke Power Company service territory, interrupting service to about 50,000 customers on May 20, 2000 at about 2300. By 1100 EDT on May 21, the number of customers without service was reduced to 1500. Electric service to all remaining customers was restored by 1600 EDT on May 22. MWe Lost: 150	Weather	24
5/25/2000 10:00:00 AM	Duke Power (SERC) North Carolina Severe Weather l A band of thunderstorms cut across the Duke Power Company service territory, hitting the Greensboro, NC and Alamance County, NC areas at about 1000 EDT on May 25, 2000. Service to 147,000 customers was interrupted at the peak of the storms. By 1500 EDT on May 26, the number of customers out of service was reduced to 119,200. By 1200 EDT on May 27, the number of customers without service was reduced to 57,000. MWe Lost: 450	Weather	188
6/14/2000 1:13:00 PM	Calif. Indep. SystemOperator (WSCC) California Generating Resources Loss l A Stage 1 Emergency was declared at 1313 PDT on June 14, 2000 for the San Francisco Greater Bay Area due to a lack of 979 MW of generating resources and declining local area voltages. To avoid the possibility of a voltage collapse, blocks of about 130 MW of firm demand were shed for about one hour then restored in rotating fashion. About 500 MW of interruptible also was shed. The Stage 1 Emergency was cancelled at 1630 PDT. MWe Lost: 130	Equipment	0
6/14/2000 3:45:00 PM	American Electric Power(ECAR) Ohio Relay Trouble l A three-phase fault occurred on a 13 kV feeder at 1545 PDT on June 14, 2000. Due to a system protection malfunction, the fault was not cleared for 19 cycles resulting in the loss of 294 MW of demand. MWe Lost: 294	Equipment	0

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
6/14/2000 3:54:00 PM	Tucson Electric Power(WSCC) Arizona Tripped Lines Fire | A fire of unknown origin passed under and through Tucson Electric Power Company's (TEP) 345 kV right of way (ROW) in the Apache National Forest in NW New Mexico on the afternoon of June 14, 2000. At 1545 PDT, system protection opened the two 345 kV lines. To maintain system security, TEP initiated a rotating load shedding	Equipment	1
6/28/2000 5:52:00 PM	Virginia Power/NorthCarolina Power (SERC) Virginia & North Carolina Line Outages / Switch Fire | System protection opened a 230 kV line on June 28 when a tree fell on. Later in the day, at about 1752 EDT, lightning struck a switch on a second 230 kV line, causing an outage to the line and a fire on the switch. This double contingency outage removed both 230 kV lines, leaving only a single 115 kV line to supply electricity to the area. The area demand exceeded the capacity of the 115 kV line, resulting in a voltage collapse and loss of service to the area. One of the two 230 kV lines was restored to service at 1855 EDT and service to the area was restored at 1912 MWe Lost: 175	Equipment	1
7/3/2000	Alaska Elec Light & Power (ASCC) Alaska B-phase to ground fault MWe Lost: 35	Equipment	0
7/6/2000 10:36:00 AM	Connectiv(MAAC) Delmarva Peninsula Firm Load Shedding MWe Lost: 120	Equipment	0
7/9/2000 2:00:00 PM	Connectiv(MAAC) Virginia Firm Load Shedding MWe Lost: 12	Equipment	6
8/18/2000 6:30:00 PM	Duke Power (SERC) North Carolina Severe weather | Major thunderstorms, accompanied by high winds, moved through the Duke Power service territory, beginning at about 1800 EDT on August 18, 2000. At the peak of the storm, 130,000 customers were without electric service. Service to all customers was restored by 2400 EDT on August 21. MWe	Weather	42
8/28/2000 11:00:00 PM	Southern Indiana Gas &Elec (ECAR) Indiana Tripped line MWe Lost: 15	Equipment	1

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
1/17/2001 1:45:00 AM	Calif. Indep. System Operator (WSCC) California Firm Load interruption MWe Lost: 500	Equipment	34
1/20/2001 8:15:00 AM	Calif. Indep. System Operator (WSCC) California Firm Load interruption MWe Lost: 300	Equipment	31
3/6/2001 9:17:00 AM	New England (NPCC) Boston & Northeast Massachusetts Interruption of Firm Power MWe Lost: 340	Equipment	2
3/19/2001 11:46:00 AM	CA Independent System Operator (WSCC) Southern California Area Interruption of Firm Power & Public Appeal MWe Lost: 400	Equipment	9
3/20/2001 9:17:00 AM	Calif. Indep. System Operator (WSCC) Southern California Area Interruption of Firm Power MWe Lost: 300	Equipment	5
5/7/2001 4:45:00 PM	Calif. Indep. System Operator (WSCC) California Interruption of Firm Power (Public Appeal) MWe Lost: 300	Equipment	1
5/8/2001 3:10:00 PM	Calif. Indep. System Operator (WSCC) California Interruption Of Firm Power (Public Appeal) MWe Lost: 400	Equipment	2
5/8/2001 3:12:00 PM	Southern California Edison (WSCC) California Interruption of Power MWe Lost: 225	Equipment	2
6/6/2001 4:22:00 PM	Central Power and Light Company (ERCOT) Rio Grand Valley of Texas Firm Load Interruption MWe Lost: 350	Equipment	3
1/29/2002 8:00:00 PM	Kansas City Power & Light (SPP) Metropolitan Kansas City Area Ice Storm MWe Lost: 500	Weather	0

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
1/30/2002 6:00:00 AM	Oklahoma Gas & Electric (SPP) Oklahoma Ice Storm | On January 29, 2002, a major winter storm with freezing rain and ice caused system-wide power outages to a large portion of the distribution systems in parts of Oklahoma, Kansas, and Missouri. Approximately 570,000 customers were affected by the storm, which continued through January 31, 2002. The storm caused numerous downed conductors and equipment damage. Some high voltage transmission facilities were also affected. MWe Lost: 500	Weather	198
1/30/2002 4:00:00 PM	Missouri Public Service (SPP) Missouri Ice Storm MWe Lost: 210	Weather	269
2/27/2002 10:48:00 AM	San Diego Gas & Electric (WSCC) California Interruption of Firm Load | On February 27, 2002 at 1042 MST, during a routine work on a section of a high voltage transmission substation bus, a technician working on the breaker failure relay for a breaker on a bus accidentally initiated system protection, which it to remove from service a section of the bus. As a result of this incident, other system protection equipment removed from service about 1,100 MW of generation and de-energized several high voltage transmission lines, which depressed nearby voltages and over loaded an adjacent high voltage transmission line. The control area operator ordered San Diego Gas & Electric Company to shed about 340 MW of local customer demand to restore the voltage and return the overloaded transmission line within normal operating limits. MWe	Equipment	1
3/9/2002	Consumers Energy Co. (ECAR) Lower Peninsula of Michigan Severe Weather | On Saturday, March 9, 2002 at about 1200 hours EST, a cold front moved through the state of Michigan accompanied by high winds and heavy rain. Gusts up to 60 mph were reported. The winds subsided by Sunday afternoon. About 190,000 customers were left without electric service. Electric service was restored to all but 6,900 customers as of 0600 hours Monday. Electric service was expected to be restored to almost all but a few customers by 2400 hours on March 11, 2002. MWe Lost: 190	Weather	60
7/9/2002 12:27:00 PM	Pacific Gas & Electric (WSCC) California Interruption of Firm Power MWe Lost: 240	Equipment	7
7/19/2002 11:51:00 AM	Pacific Gas & Electric (WSCC) California Interruption of Firm Power (Unit Tripped) MWe Lost: 240	Equipment	5

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
7/20/2002 12:40:00 PM	Consolidated Edison Co. of New York (NPCC) New York Fire MWe Lost: 278	Equipment	8
8/2/2002 12:43:00 PM	Central Illinois Light Co. (MAIN) Illinois Interruption of Firm Power MWe Lost: 232	Equipment	6
8/9/2002 8:23:00 AM	Lake Worth Utils (SERC) Florida Interruption of Firm Power MWe Lost: 51	Equipment	4
8/25/2002 3:41:00 AM	Pacific Gas & Elec. (WSCC) California Interruption of Firm Power MWe Lost: 120	Equipment	6
8/28/2002 2:09:00 PM	Lakeworth Utils (SERC) Florida Severe Weather | On August 28, 2002 at 1409 EDT, electric service to 25,000 customers was interrupted due to severe weather and multiple lightning strikes. Because of the system configuration as a result of previous disturbances in July and August, 2002, the loss of a single distribution feeder led to a complete system shutdown. By 1538, electric service to all customers was restored. In addition, the system configuration was returned to normal with the installation of a new transformer and the completion of repairs due to the prior disturbances. MWe	Weather	1
10/3/2002 3:33:00 AM	Entergy Corporation (SPP) Coastal Areas of Southern Louisiana Hurricane Lily | On October 3, 2002 at about 0333 CDT, Hurricane Lili caused widespread customer outages along the Louisiana coast. The storm then moved ashore and continued to cause damage and widespread customer outages throughout	Weather	212
11/6/2002 10:00:00 PM	Pacific Gas & Electric Co. (WSCC) Northern and Central California Winter Storm | On November 6, 2002 at about 2200 PST a severe winter storm caused wide spread customer outages throughout much of California. Most of the damage sustained was in the distribution system, while some transmission facilities were also affected. About 877,000 customers were affected by this storm. About 1,000 MW of generation was curtailed due to high waves along the coast. MWe Lost: 270	Weather	74

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
12/3/2002 6:30:00 PM	Entergy Corporation (SPP) Arkansas Ice Storm | On December 3, 2002 at about 0630 CST, a major ice storm caused wide spread customer outages throughout Arkansas. Most of the damage sustained occurred in the distribution systems. However, some transmission facilities were also damaged. About 43,000 customers were affected by this storm. MWe Lost: 100	Weather	148
12/11/2002 1:09:00 PM	Dominion-Virginia Power/North Carolina Power (SERC) Northern Virginia to Fredericksburg Staunton to Harrisonburg Winter Storm MWe Lost: 63	Weather	57
12/14/2002 11:00:00 AM	Pacific Gas & Electric (WSCC) Northern and Central California Winter Storm | On December 14, 2002 at about 1100 PST a severe winter storm caused wide spread customer outages throughout northern and central California. The storm continued through Sunday night and into Monday December 16, 2002. Most of the damage sustained was in the distribution system, while some transmission facilities were also affected. About 2,100,000 customers were affected by this storm. MWe Lost: 180	Weather	125
12/19/2002 6:00:00 AM	Pacific Gas & Electric (WSCC) Northern and Central California Winter Storm | On December 19, 2002 at about 1100 PST a severe winter storm caused wide spread customer outages throughout northern and central California. This was the second severe winter storm in the past week. Most of the damage sustained was in the distribution system, while some transmission facilities were also affected. MWe Lost: 56	Weather	59
12/25/2002 5:00:00 PM	PPL Corporation (MAAC) Eastern Pennsylvania Winter Storm MWe Lost: 250	Weather	12
2/27/2003 11:32:00 AM	Duke Energy Corporation (SERC) Piedmont, North Carolina Winter Ice Storm MWe Lost: 1000	Weather	44
4/3/2003 7:00:00 PM	Consumers Energy (ECAR) Lower Michigan Peninsula Ice Storm MWe Lost: 300	Weather	70
4/4/2003 3:11:00 AM	Niagara Mohawk Power Corporation (NPCC) New York, Severe Storm MWe Lost: 200	Weather	35

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
4/15/2003 11:00:00 AM	Byran Texas Utilities (ERCOT) Cities of Bryan, College Station and surrounding areas Relaying Malfunction MWe Lost: 212	Equipment	3
5/2/2003 5:00:00 PM	Duke Energy Company Duke Power Control Area (SERC) Piedmont, North and South Carolina Severe Thunderstorms MWe Lost: 1500	Weather	43
5/2/2003 8:00:00 PM	Southern Company (SERC) Central Georgia, Alabama Severe Thunderstorms MWe Lost: 130	Weather	12
5/15/2003 2:52:00 AM	Center Point Energy (ERCOT) North Texas Interruption of Firm Power MWe Lost: 476	Equipment	1
5/15/2003 2:00:00 PM	We Energies(MAIN) Upper Michigan Peninsula Flood MWe Lost: 240	Weather	768
7/1/2003 3:15:00 PM	Arizona Public Service Company (WSCC) Phoenix, Arizona Breaker Failure MWe Lost: 1000	Equipment	1
7/2/2003 1:54:00 PM	Pacific Gas and Electric Company (WSCC) Northern California Unit Tripped MWe Lost: 200	Equipment	2
7/4/2003 6:00:00 AM	We Energies (MAIN) Southeast Wisconsin Severe Thunderstorms MWe Lost: 150	Weather	4
7/4/2003 9:00:00 AM	Consumers Energy (ECAR) Lower Michigan Peninsula Severe Thunderstorms MWe Lost: 75	Weather	55
7/4/2003 11:41:00 PM	Cinergy (ECAR) Southwest Ohio, Portions of Indiana Severe Storms MWe Lost: 200	Weather	45

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
7/5/2003 3:00:00 AM	Com Ed (MAIN) Northern Illinois Severe Storms MWe Lost: 80	Weather	4
7/8/2003 4:00:00 AM	American Electric Power (ECAR) Ohio Severe Thunderstorms MWe Lost: 11000	Weather	84
7/9/2003 5:14:00 PM	Dominion Virginia/North Carolina Power (SERC) Northern Central and Eastern Virginia Severe Thunderstorms MWe Lost: 120	Weather	2
7/15/2003 8:24:00 AM	American Electric Power-Texas Central Company (ERCOT) Texas Hurricane Claudette MWe Lost: 230	Weather	146
7/21/2003 5:15:00 PM	PPL Electric Utilities (MAAC) Pennsylvania Severe Storms MWe Lost: 500	Weather	60
7/28/2003 6:55:00 PM	Arizona Public Service/PVNGS-3 trip (WSCC) Arizona Breaker Closed MWe Lost: 440	Equipment	2
8/14/2003 4:10:00 PM	PJM Interconnection, LLC (MAAC) Northern New Jersey Erie, Pennsylvania area Unknown * MWe Lost: 4100	Equipment	14
8/26/2003 4:00:00 PM	Baltimore Gas and Electric (MAAC) Maryland: Anne Arundel County, Baltimore County, Calvert County, Carroll County, Howard County, Montgomery County, Prince George's and Baltimore City. Severe Thunderstorms MWe Lost: 625	Weather	92
8/26/2003 4:00:00 PM	Baltimore Gas and Electric (MAAC) Maryland: Anne Arundel county, Baltimore county, Calvert county, Carroll county, Howard county, Montgomery county, Prince George's and Baltimore city. Severe Thunderstorms MWe Lost: 625	Weather	68
8/26/2003 4:22:00 PM	Potomac Electric Power Company (Pepco) (MAAC) Washington, D.C., Montgomery County, Prince Georges County, Maryland Severe Thunderstorms MWe Lost: 1500	Weather	122

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
9/7/2003 5:19:00 AM	American Transmission Company, LLC (MAIN) Upper Michigan Peninsula Transmission Equipment MWe Lost: 310	Equipment	13
9/7/2003 5:19:00 AM	American Transmission Company, LLC (MAIN) Upper Michigan Peninsula Transmission Equipment MWe Lost: 310	Equipment	13
9/18/2003 8:20:00 AM	Dominion-Virginia Power/ North Carolina Power (SERC) North Eastern North Carolina, Eastern Central , and Northern Virginia Hurricane Isabel MWe Lost: 6512	Weather	278
9/18/2003 11:45:00 AM	Carolina Power and Light (SERC) Eastern North Carolina Hurricane Isabel MWe Lost: 1655	Weather	12
9/18/2003 12:00:00 PM	Baltimore Gas and Electric (MAAC) Central Maryland (Baltimore City, Baltimore County, Anne Arundel County, Hartford County, Montgomery County, Calvert County, Prince George's County, Carroll County and Howard County) Hurricane Isabel MWe Lost: 2000	Weather	203
9/18/2003 2:00:00 PM	Allegheny Power (MAAC) Maryland, West Virginia, Virginia and Pennsylvania Hurricane Isabel MWe Lost: 3085	Weather	154
9/18/2003 9:00:00 PM	PPL Electric Utilities (MAAC) All PPL including: Williamsport, Harrisburg, Lancaster, Scranton and Allentown areas Hurricane Isabel MWe Lost: 1300	Weather	92
11/5/2003 3:16:00 PM	PJM Interconnection (MAAC) Maryland/Virginia border Tornado MWe Lost: 350	Weather	1
11/5/2003 3:16:00 PM	PJM Interconnection (MAAC) Maryland/Virginia border Tornado MWe Lost: 350	Weather	1
11/12/2003 5:00:00 PM	Consumers Energy (ECAR) Lower Michigan Peninsula Wind Storm MWe Lost: 75	Weather	97

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
11/12/2003 6:00:00 PM	DTE Energy (ECAR) Southeastern Michigan Storm with High Winds MWe Lost: 75	Weather	119
11/13/2003 6:00:00 AM	Baltimore Gas and Electric (MAAC) Central Maryland (Baltimore City, Baltimore County, Anne Arundel County, Harford County, Montgomery County, Calvert County, Prince George's County, Carroll County and Howard County) High Winds MWe Lost: 375	Weather	82
11/13/2003 7:30:00 AM	Niagara Mohawk (NPCC) New York Storm with High Winds MWe Lost: 180	Weather	47
11/13/2003 11:00:00 AM	Potomac Electric Power Company (Pepco) (MAAC) Washington, D.C., Montgomery County, Prince Georges County, Md Major Wind Storm MWe Lost: 400	Weather	45
11/13/2003 1:40:00 PM	Dominion-Virginia Power/ North Carolina Power (SERC) Northern Virginia, Richmond area, Eastern Virginia Wind Storm MWe Lost: 300	Weather	2
12/1/2003 6:16:00 PM	REMVEC (NPCC) Cape Cod and part of SE Massachusetts Wild Fire – Transmission Equipment MWe Lost: 630	Weather	2
12/4/2003 7:00:00 AM	Puget Sound Energy (WECC) Eastern portions of King County and Pierce County High Winds MWe Lost: 175	Weather	96
12/4/2003 10:15:00 PM	Wisconsin Electric Power Company (MAIN) Upper Peninsula of Michigan and Northeastern Wisconsin Fault on 138 KV line MWe Lost: 500	Weather	82
12/4/2003 10:34:00 PM	American Transmission Company, LLC (MAIN) Northeast Wisconsin and Central/Western Upper Peninsula of Michigan Fault on 138 KV line MWe Lost: 650	Weather	58
12/5/2003 4:49:00 AM	City of Homestead (FRCC) State of Florida - Dade County Transmission Equipment MWe Lost: 27	Weather	2

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
12/5/2003 7:00:00 AM	Upper Peninsula Power Company (MAIN) Northeast Wisconsin and Central/Western Upper Peninsula of Michigan Transmission Equipment MWe Lost: 14	Weather	13
12/20/2003 3:51:00 PM	Pacific Gas and Electric (WECC) San Francisco, California Cable Failure MWe Lost: 150	Weather	32
12/22/2003 11:15:00 AM	Pacific Gas and Electric (WECC) Central California Coast Earthquake MWe Lost: 220	Weather	0
12/28/2003 9:00:00 PM	Pacific Gas and Electric (WECC) Northern California Winter Storm MWe Lost: 160	Weather	87
1/1/2004 7:30:00 AM	Pacific Gas and Electric Company (WECC) Northern California Winter Storm MWe Lost: 170	Weather	33
1/7/2004 12:01:00 AM	Puget Sound Energy (WECC) King County Snow Storm MWe Lost: 150	Weather	89
1/8/2004 3:00:00 PM	National Grid (New York) (NPCC) Lake Placid/Saranac, New York Public Appeal to Reduce Load MWe Lost: 100	Equipment	52
1/14/2004 6:00:00 AM	National Grid (New York) (NPCC) Lake Placid/Saranac, New York Public Appeal to Reduce Load MWe Lost: 100	Equipment	78
1/26/2004 2:00:00 PM	Southern Company (SERC) North and Central area of Georgia Ice Storm MWe Lost: 150	Weather	30
1/26/2004 4:00:00 PM	Progress Energy - Carolinas (Carolina Power and Light) (SERC) Central and Eastern North Carolina and Northern and Eastern South Carolina Ice Storm MWe Lost: 475	Weather	87

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
1/28/2004 1:09:00 PM	Baltimore Gas & Electric Company (MAAC) Harford County, Maryland Ice Storm MWe Lost: 300	Weather	40
2/5/2004 8:00:00 PM	Allegheny Power (MAAC) Maryland, Southeastern West Virginia, Northern Virginia, Northern Pennsylvania and South Central Pennsylvania Ice Storm MWe Lost: 220	Weather	96
2/14/2004 8:00:00 PM	National Grid (Niagara Mohawk) (NPCC) Lake Colby, Lake Placid, Tupper Lake Public Appeal to Reduce Load MWe Lost: 30	Equipment	7801
2/17/2004 2:25:00 PM	Crockett Cogeneration (WECC) San Francisco Bay area, California Lightning struck Intertie Breaker MWe Lost: 10	Weather	10
2/25/2004 12:01:00 PM	Pacific Gas and Electric Company (WECC) Northern California Winter Storm MWe Lost: 300	Weather	22
2/26/2004 12:00:00 PM	Southern Company (SERC) Georgia Severe Storm MWe Lost: 1000	Weather	-11
3/4/2004 5:00:00 AM	Electric Reliability Council of Texas (ERCOT) North Texas High Winds - Severe Storm MWe Lost: 300	Weather	298
3/7/2004 6:30:00 PM	Duke Energy Company/Duke Power Control Area (SERC) North and South Carolina Severe Storm MWe Lost: 1000	Weather	62
3/8/2004 6:22:00 PM	Southern California Edison (WECC) Southern California not including LA Inadequate Resources MWe Lost: 300	Equipment	1
3/17/2004 1:27:00 PM	El Paso Electric Company (WECC) El Paso, Texas Faulty Switch MWe Lost: 300	Equipment	1

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
4/10/2004 8:00:00 PM	CenterPoint Energy (ERCOT) Houston, Texas and surrounding suburban areas Thunderstorms MWe Lost: 100	Weather	44
4/12/2004 5:30:00 AM	Florida Power & Light (FRCC) FPL's service territory mostly in Naples and Ft. Myers Florida Storm with High Winds MWe Lost: 250	Weather	5
4/27/2004 12:35:00 PM	Snohomish County PUD #1 (WECC) Snohomish County Washington Strong Winds MWe Lost: 300	Weather	95
5/3/2004 2:30:00 PM	Southern California Edison (WECC) Central and Southern California Heat Storm MWe Lost: 662	Weather	5
5/11/2004 3:30:00 PM	CenterPoint Energy (ERCOT) Houston, Texas and surrounding suburban areas Strong Thunderstorms MWe Lost: 85	Weather	3
5/21/2004 4:00:00 AM	Detroit Edison (ECAR) Southeast Michigan Severe Thunderstorms MWe Lost: 630	Weather	88
5/21/2004 5:30:00 AM	Allegheny Power (MAAC) Western Pennsylvania, Northern West Virginia, Western Maryland, Northern Virginia High Winds and Heavy Rains MWe Lost: 60	Weather	115
5/21/2004 11:00:00 AM	American Electric Power (ECAR) Northern and Southern Michigan, AEP Fort Wayne/Michigan Region, Buchanan, Elkhart, New Buffalo, South Bend, St. Joseph, Three Rivers areas Severe Thunderstorms MWe Lost: 303	Weather	130
5/21/2004 1:00:00 PM	Consumers Energy (ECAR) Lower peninsula of Michigan following cities: Grand Rapids, Kalamazoo, Battle Creek, Jackson, Bronson, Jonesville, Flint Severe Thunderstorms MWe Lost: 200	Weather	119

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
5/21/2004 4:00:00 PM	Detroit Edison (ECAR) Southeast Michigan Severe Thunderstorms MWe Lost: 630	Weather	76
6/1/2004 5:00:00 PM	TXU Electric Delivery (ERCOT) Collin, Dallas, Denton, Ellis, Parker, and Tarrant Counties, Texas Severe Storms with Strong Winds MWe Lost:	Weather	32
6/2/2004 1:46:00 AM	American Electric Power (ECAR) Shreveport, Louisiana Severe Thunderstorms with Strong Winds MWe Lost: 350	Weather	134
6/2/2004 2:35:00 AM	American Electric Power (ECAR) Tulsa, Oklahoma Severe Thunderstorms with Strong Winds MWe Lost: 280	Weather	111
6/12/2004 5:37:00 PM	Lincoln Electric System (MAPP) Lincoln, Nebraska Tornado MWe Lost: 428	Weather	0
6/23/2004 5:35:00 PM	Idaho Power Company (WECC) Southern Idaho Load Shedding MWe Lost: 157	Equipment	2
6/23/2004 5:35:00 PM	Idaho Power Company (WECC) Southern Idaho Load Shedding MWe Lost: 157	Equipment	2
6/23/2004 7:00:00 PM	Southern Company (SERC) Georgia and Alabama Thunderstorms MWe Lost: 50	Weather	1
6/23/2004 7:00:00 PM	Southern Company (SERC) Georgia and Alabama Thunderstorms MWe Lost: 50	Weather	1
7/7/2004 1:30:00 PM	Dominion - Virginia Power/North Carolina Power (SERC) Central Virginia Severe Thunderstorms MWe Lost: 120	Weather	10

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
7/7/2004 1:30:00 PM	Dominion - Virginia Power/North Carolina Power (SERC) Central Virginia Severe Thunderstorms MWe Lost: 120	Weather	10
7/13/2004 1:34:00 PM	City of Tallahassee (FRCC) Leon County, Florida Units Tripped MWe Lost: 283	Equipment	4
7/13/2004 1:34:00 PM	City of Tallahassee (FRCC) Leon County, Florida Units Tripped MWe Lost: 283	Equipment	4
7/13/2004 4:30:00 PM	Cinergy Services (ECAR) West, West Central and Southern Indiana Severe Thunderstorms MWe Lost: 600	Weather	88
7/13/2004 4:30:00 PM	Cinergy Services (ECAR) West, West Central and Southern Indiana Severe Thunderstorms MWe Lost: 600	Weather	112
7/20/2004 2:26:00 PM	Southern California Edison (WECC) Soledad Canyon near Acton, California Wildfire/Shed Interruptible Load MWe Lost: 214	Weather	36
7/20/2004 2:26:00 PM	Southern California Edison (WECC) Soledad Canyon near Acton, California Wildfire/Shed Interruptible Load MWe Lost: 214	Equipment	12
7/21/2004 5:30:00 PM	Commonwealth Edison (MAIN) Chicago, Illinois Severe Thunderstorms MWe Lost: 200	Weather	26
7/21/2004 5:30:00 PM	Commonwealth Edison (MAIN) Chicago, Illinois Severe Thunderstorms MWe Lost: 200	Weather	26
7/25/2004 10:00:00 PM	Southern Company (SERC) Georgia, Alabama, Florida panhandle, Southern Mississippi Severe Storms MWe Lost: 61	Weather	1

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
7/25/2004 10:00:00 PM	Southern Company (SERC) Georgia, Alabama, Florida panhandle, Southern Mississippi Severe Storms MWe Lost: 61	Weather	1
8/3/2004 9:00:00 PM	Commonwealth Edison (MAIN) Northern Illinois Severe Storm MWe Lost: 127	Weather	34
8/3/2004 9:00:00 PM	Commonwealth Edison (MAIN) Northern Illinois Severe Storm MWe Lost: 127	Weather	10
8/4/2004 12:46:00 PM	Southern California Edison (WECC) Northwest Orange County, California Fault at Barre Substation MWe Lost: 480	Equipment	1
8/4/2004 12:46:00 PM	Southern California Edison (WECC) Northwest Orange County, California Fault at Barre Substation MWe Lost: 480	Equipment	1
8/13/2004 8:00:00 AM	Progress Energy Florida (FRCC) Florida counties of Hardee, Highlands, Lake, Orange, Osceola, Polk, Seminole, Volusia Hurricane Charley MWe Lost: 1300	Weather	244
8/13/2004 8:00:00 AM	Progress Energy Florida (FRCC) Florida counties of Hardee, Highlands, Lake, Orange, Osceola, Polk, Seminole, Volusia Hurricane Charley MWe Lost: 1300	Weather	244
8/13/2004 1:30:00 PM	Seminole Electric Cooperative (FRCC) Florida counties of Collier, Hendry, Glades, Highlands, Charlotte, Desoto, Lee, Hardee, and Polk Hurricane Charley MWe Lost: 700	Weather	3464
8/13/2004 1:30:00 PM	Seminole Electric Cooperative (FRCC) Florida counties of Collier, Hendry, Glades, Highlands, Charlotte, Desoto, Lee, Hardee, and Polk Hurricane Charley MWe Lost: 700	Weather	11

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
8/13/2004 3:00:00 PM	Florida Power & Light (FRCC) West Coast of Florida from Naples to Charlotte and in an area centered around Daytona Beach Hurricane Charley MWe Lost: 1400	Weather	8
8/13/2004 3:00:00 PM	Florida Power & Light (FRCC) West Coast of Florida from Naples to Charlotte and in an area centered around Daytona Beach Hurricane Charley MWe Lost: 1400	Weather	8
8/13/2004 4:43:00 PM	Tampa Electric Company (FRCC) Eastern Hillsborough, Polk County, Florida Hurricane Charley MWe Lost: 250	Weather	4
8/13/2004 4:43:00 PM	Tampa Electric Company (FRCC) Eastern Hillsborough, Polk County, Florida Hurricane Charley MWe Lost: 250	Weather	4
8/13/2004 10:04:00 PM	Utilities Commission, City of New Smyrna Beach (FRCC) New Smyrna Beach, Florida Hurricane Charley MWe Lost: 65	Weather	18
8/13/2004 10:04:00 PM	Utilities Commission, City of New Smyrna Beach (FRCC) New Smyrna Beach, Florida Hurricane Charley MWe Lost: 65	Weather	42
8/14/2004 1:00:00 PM	Progress Energy - Carolinas (SERC) Central and Eastern North Carolina and Northern and Eastern South Carolina Hurricane Charley MWe Lost: 500	Weather	10
8/14/2004 1:00:00 PM	Progress Energy - Carolinas (SERC) Central and Eastern North Carolina and Northern and Eastern South Carolina Hurricane Charley MWe Lost: 500	Weather	10
8/20/2004 3:31:00 PM	National Grid USA (NPCC) Boston, Massachusetts Major Transmission Line Tripped due to Lightning Strike MWe Lost: 22700	Weather	6
8/20/2004 3:31:00 PM	National Grid USA (NPCC) Boston, Massachusetts Major Transmission Line Tripped due to Lightning Strike MWe Lost: 22700	Equipment	6

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
8/29/2004 9:52:00 AM	South Carolina Electric and Gas Company (SERC) Southeastern South Carolina Tropical Storm Gaston MWe Lost: 450	Weather	8
8/29/2004 9:52:00 AM	South Carolina Electric and Gas Company (SERC) Southeastern South Carolina Tropical Storm Gaston MWe Lost: 450	Weather	8
8/30/2004 6:58:00 PM	Dominion - Virginia Power/North Carolina Power (SERC) Central Virginia, South to North Carolina and East to the Virginia Coast Tropical Storm Gaston MWe Lost: 150	Weather	21
8/30/2004 6:58:00 PM	Dominion - Virginia Power/North Carolina Power (SERC) Central Virginia, South to North Carolina and East to the Virginia Coast Tropical Storm Gaston MWe Lost: 150	Weather	21
9/3/2004 9:00:00 PM	Fort Pierce Utilities Authority (FRCC) City of Fort Pierce, Florida Hurricane Frances MWe Lost: 125	Weather	65
9/4/2004 8:00:00 AM	Florida Power & Light (FRCC) West Palm Beach to Daytona Beach, Florida Hurricane Frances MWe Lost: 6000	Weather	48
9/4/2004 10:00:00 AM	Tampa Electric Company (FRCC) Hillsborough, Pasco, and Polk County, Florida Hurricane Frances MWe Lost: 1100	Weather	201
9/5/2004 1:00:00 AM	Orlando Utilities Commission (FRCC) Orlando, Florida Hurricane Frances MWe Lost: 200	Weather	112
9/5/2004 7:00:00 AM	Progress Energy Florida (FRCC) Alachua, Citrus, Columbia, Dixie, Franklin, Gilchrist, Gulf, Hamilton, Hardee, Hernando, Highlands, Jefferson, Lafayette, Lake, Levy, Madison, Marion, Orange, Osceola, Pasco, Pinellas, Polk, Seminole, Sumter, Suwannee, Taylor, Volusia and Wakulla Hurricane Frances MWe Lost: 2100	Weather	185
9/6/2004 1:00:00 PM	Southern Company (SERC) Florida, Mississippi, Alabama, Georgia Hurricane Frances MWe Lost: 3000	Weather	95

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
9/7/2004 10:00:00 AM	Georgia System Operations (SERC) Georgia Hurricane Frances MWe Lost: 2200	Weather	26
9/15/2004 7:00:00 PM	Southern Company (SERC) Florida, Mississippi, Alabama, Georgia Hurricane Ivan MWe Lost: 916	Weather	48
9/16/2004 2:00:00 AM	Alabama Electric Cooperative (SERC) Baldwin County, Alabama, Escambia County, Florida, Washington County, Alabama Hurricane Ivan MWe Lost: 263	Weather	8
9/16/2004 9:00:00 PM	Duke Energy Company/Duke Power Control Area (SERC) Western North and South Carolina Hurricane Ivan MWe Lost: 500	Weather	115
9/17/2004 4:30:00 AM	Progress Energy -Carolinas (SERC) Western North Carolina Hurricane Ivan MWe Lost: 400	Weather	32
9/26/2004 2:00:00 AM	Tampa Electric Company (FRCC) Hillsborough, Pasco, and Polk County, Florida Hurricane Jeanne MWe Lost: 1250	Weather	46
9/26/2004 3:00:00 AM	Orlando Utilities Commission (FRCC) Orlando and St. Cloud, Florida Hurricane Jeanne MWe Lost: 350	Weather	102
9/26/2004 6:00:00 AM	Progress Energy Florida (FRCC) Alachua Bay Brevard Citrus Columbia Dixie Flagler Franklin Gilchrist Gulf Hamilton Hardee Hernando Highlands Hillsborough Jefferson Lafayette Lake Leon Levy Madison Marion Orange Osceola Pasco Pinellas Polk Seminole Sumter Suwannee Taylor Volusia Wakulla Hurricane Jeanne MWe Lost: 1800	Weather	138
9/27/2004 8:00:00 AM	Southern Company (SERC) Georgia Hurricane Jeanne MWe Lost: 854	Weather	6
10/18/2004 10:30:00 PM	Pacific Gas and Electric Company (WECC) Northern California Severe Storm with High Wind Gusts MWe Lost: 140	Weather	59

EIA Events (excluding LOOPs)

Date	Description of Outage	Category	Outage Duration (min)
10/28/2004 3:27:00 PM	Pacific Gas and Electric Company (WECC) San Jose, California Major Transmission Distribution System Interruption MWe Lost: 103	Equipment	3
10/30/2004 10:00:00 AM	Consumers Energy (ECAR) Lower peninsula of Michigan. following area: Grand Rapids, Kalamazoo, Battle Creek, Greenville, Jackson, Flint, Lansing, Allegan, Temperance Severe Storm with High Wind Gusts MWe Lost: 60	Weather	32
10/30/2004 12:30:00 PM	DTE Energy (ECAR) Southeastern Michigan High Wind Gusts MWe Lost: 700	Weather	73
11/14/2004 4:55:00 AM	ISO New England (NPCC) For New Brunswick Electric Power Coordination of joint Reliability Coordinators and Control Area Functions Nova Scotia Heavy Snow, High Winds and Rain/Major Distribution System Interruption MWe Lost: 165	Weather	45
11/23/2004 10:00:00 PM	CenterPoint Energy (ERCOT) Houston, Texas and surrounding suburban areas Strong Thunderstorms MWe Lost: 150	Weather	27
11/24/2004 10:00:00 AM	Southern Company (SERC) Georgia Strong Thunderstorms MWe Lost: 100	Weather	6
12/1/2004 10:00:00 AM	Baltimore Gas & Electric Company (MAAC) Central Maryland (Baltimore City, Baltimore County, Anne Arundel County, Hartford County, Montgomery County, Calvert County, Prince George's County, Carroll County and Howard County) High Winds MWe Lost: 270	Weather	38
12/23/2004 3:37:00 AM	American Electric Power (ECAR) Columbus District Major Freezing Rain and Ice Storm MWe Lost: 800	Weather	211
12/27/2004 7:50:00 AM	Pacific Gas and Electric Company (WECC) Salinas, California and surrounding communities Severe Weather/Line Relayed MWe Lost: 100	Weather	3

C
DURATION DATA

This is the duration (in minutes) for the events published in Reference 2.

Table C-1
LOOP Duration Data

Date	Plant	Type[35]	Category	Best Estimate	UE Duration
03/11/97	Zion 1	P	Ia	240	0
04/01/97	Pilgrim	W	Ia	184	1198
06/16/97	Indian Point 2	P	Ia	42	111
06/16/97	Indian Point 3	P	Ia	42	111
06/21/97	Three Mile Island 1	P	Ia	90	90
08/01/97	Oyster Creek	P	Ia	40	0
05/20/98	Fort Calhoun	P	Ia	109	88
06/24/98	Davis Besse	W	Ia	1383	725
09/06/98	Braidwood 1	W	Ia	528	520
09/06/98	Braidwood 2	W	Ia	528	520
01/06/99	Clinton	G	Ia	270	626
08/31/99	Indian Point 2	P	Ia	720	793
08/31/99	Indian Point 3	P	Ia	720	793
05/15/00	Diablo Canyon 1	P	Ia	2014	1996
05/15/00	Diablo Canyon 2	P	Ia	2014	1996
08/02/01	Quad Cities 1	W	Ib	15	154
08/02/01	Quad Cities 2	W	Ib	15	154
03/25/03	Palisades	P	Ia	91	3251

[35] P: plant-centered plant-switchyard plant-lightning strike, W: weather-related, G: grid-centered

Date	Plant	Type[35]	Category	Best Estimate	UE Duration
07/29/03	Salem 1	P	Ia	512	480
07/29/03	Salem 2	P	Ia	512	480
08/14/03	Indian Point 2	G	Ia	554	585
08/14/03	Indian Point 3	G	Ia	554	585
08/14/03	Davis Besse	G	Ia	645	1619
08/14/03	Fermi 2	G	Ia	1282	1286
08/14/03	Fitzpatrick	G	Ia	105	517
08/14/03	Nine Mile Point 1	G	Ia	105	517
08/14/03	Nine Mile Point 2	G	Ia	105	517
08/14/03	Perry	G	Ia	1662	1662
06/14/04	Palo Verde 1	G	Ia	110	254
06/14/04	Palo Verde 2	G	Ia	110	254
06/14/04	Palo Verde 3	G	Ia	110	254
9/25/04	St Lucie 1	W	Ia	667	667
9/25/04	St Lucie 2	W	Ia	667	667

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