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EPFAST: A MODEL FOR SIMULATING UNCONTROLLED ISLANDING IN LARGE POWER SYSTEMS

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ABSTRACT

This paper describes the capabilities, calculation logic, and foundational assumptions of *EPfast*, a new simulation and impact analysis tool developed by Argonne National Laboratory. The purpose of the model is to explore the tendency of power systems to spiral into uncontrolled islanding triggered by either man-made or natural disturbances. The model generates a report that quantifies the megawatt reductions in all affected substations, as well as the number, size, and spatial location of the formed island grids. The model is linear and is intended to simulate the impacts of high-consequence events on large-scale power systems. The paper describes a recent application of the model to examine the effects of a high-intensity New Madrid seismic event on the U.S. Eastern Interconnection (USEI). The model's final upgrade and subsequent application to the USEI were made possible via funding from U.S. Department of Energy's Office of Infrastructure Security and Energy Restoration.

1 INTRODUCTION

Of the various energy infrastructures that currently operate in the United States, the electric infrastructure is unique, primarily because it is the only system that operates in perfect electrical synchronism. This unique feature requires that the system operate at a prescribed frequency of 60 hertz (cycles per second). Any significant deviation from this frequency can trigger sensitive relays to shed load and trip lines, which may lead to widespread system instability.

High-impact natural events such as earthquakes, solar storms, and hurricanes can "jolt" the power system, cause large-scale interruptions, and eventually lead to total system collapse. System collapse is usually preceded by a wave of cascading line failures and splintering of the integrated system into smaller, but numerous, island grids. For many of our nation's emergency response organizations, such as the Federal Emergency Management Agency (FEMA) and the U.S. Department of Energy's Office of Infrastructure Security and Energy Restoration (DOE- ISER), it is important to estimate the impacts of the postulated natural events on the electric system in order to develop appropriate mitigation and recovery plans. *EPfast* was primarily developed in response to the need for such impact assessments.

2 EPFAST CAPABILITIES

2.1 Analysis and Information Retrieval Capabilities

Argonne designed *EPfast* (written in C Sharp language) to be used as both an impact analysis tool and an information retrieval tool. When used as an impact analysis tool, *EPfast* provides:

- A system-wide quantitative estimate (tabular) of impacts in terms of megawatts (MW) shed per substation, number of islands formed, surviving components of each island (in terms of both lines and nodes), and new supply and demand levels in each of the islands after stabilization.
- A graphical overview of impacts in terms of the extent of blackout (percent reduction in load per utility), spatial location of the major island grids, and thus, insights into possible restoration strategy options.

In contrast to the N-1 and N-2 contingency cases run in North American Electric Reliability Corporation (NERC)-based reliability studies, *EPfast* can simulate simultaneous, multiple-component losses (e.g., instant simultaneous loss of 300 nodes and 700 lines during an earthquake) within the power system.

When used as an information retrieval tool, *EPfast* provides the following pre-disruption information through its user-friendly “point-and-click” graphical user interface (GUI):

- Information on normal systems operations (Figure 1), including:
  - Flow magnitude and direction of flow in all lines of the given network;
  - Line reactance, capacity and loading levels;
  - Demand at each substation; and
  - Capacity and operational output of generators.
- Color-coded graphical depiction of the system diagram distinguishes heavily loaded lines from those that are operating within prescribed limits.

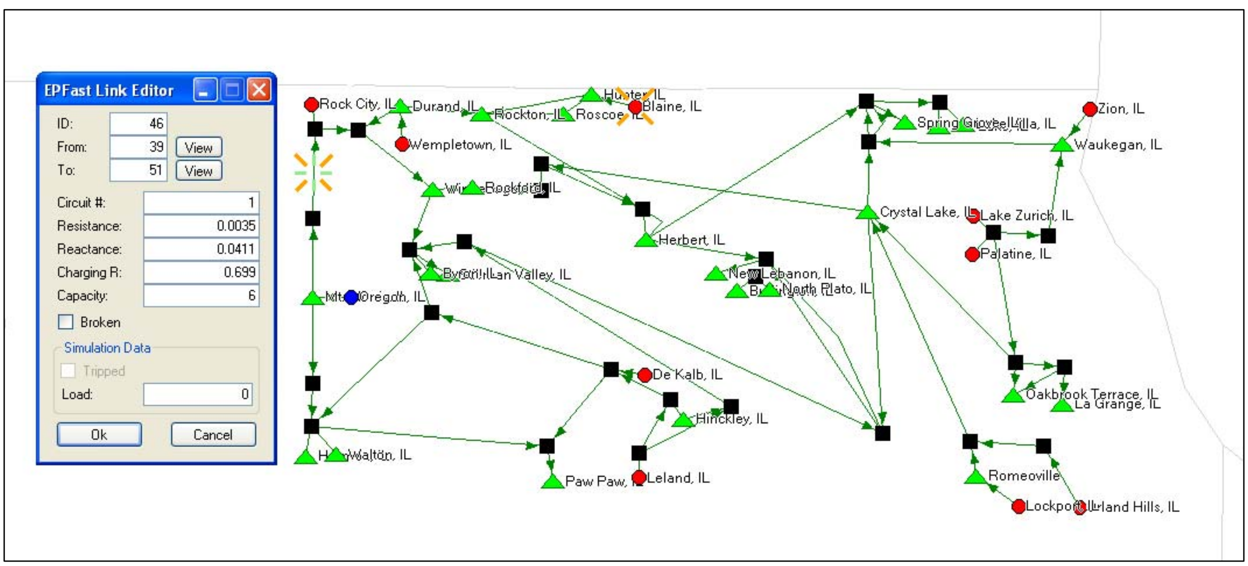

Figure 1: *EPfast’s* depiction of a 64-bus network and data associated with a selected link. Data can also be similarly displayed for any selected node.

2.2 Accommodation of Large-Scale Power Networks

The *EPfast* tool has recently been redesigned to accommodate large-scale power systems comprising up to 200,000 nodes and 300,000 lines. Because the model employs a DC load flow formulation, it is possible to solve the set of linear load flow equations describing the system by using commercial solvers such as LINDO (http://www.lindo.com/). Use of a linear programming (LP) solver was adopted after serious problems were encountered when using the traditional matrix inversion method; large errors begin to show up as the system size increased (e.g., in excess of 2,000 nodes).

2.3 GUI, Spatial, and Tabular Outputs

The GUI in *EPfast* is designed for easy "point, click, and analyze" use. An analyst can point to any node, select a transmission line to "outage," and execute a simulation run. Spatial output includes a picture of the simulated event (Figure 2), which shows the transmission lines involved and the islands formed in different colors.

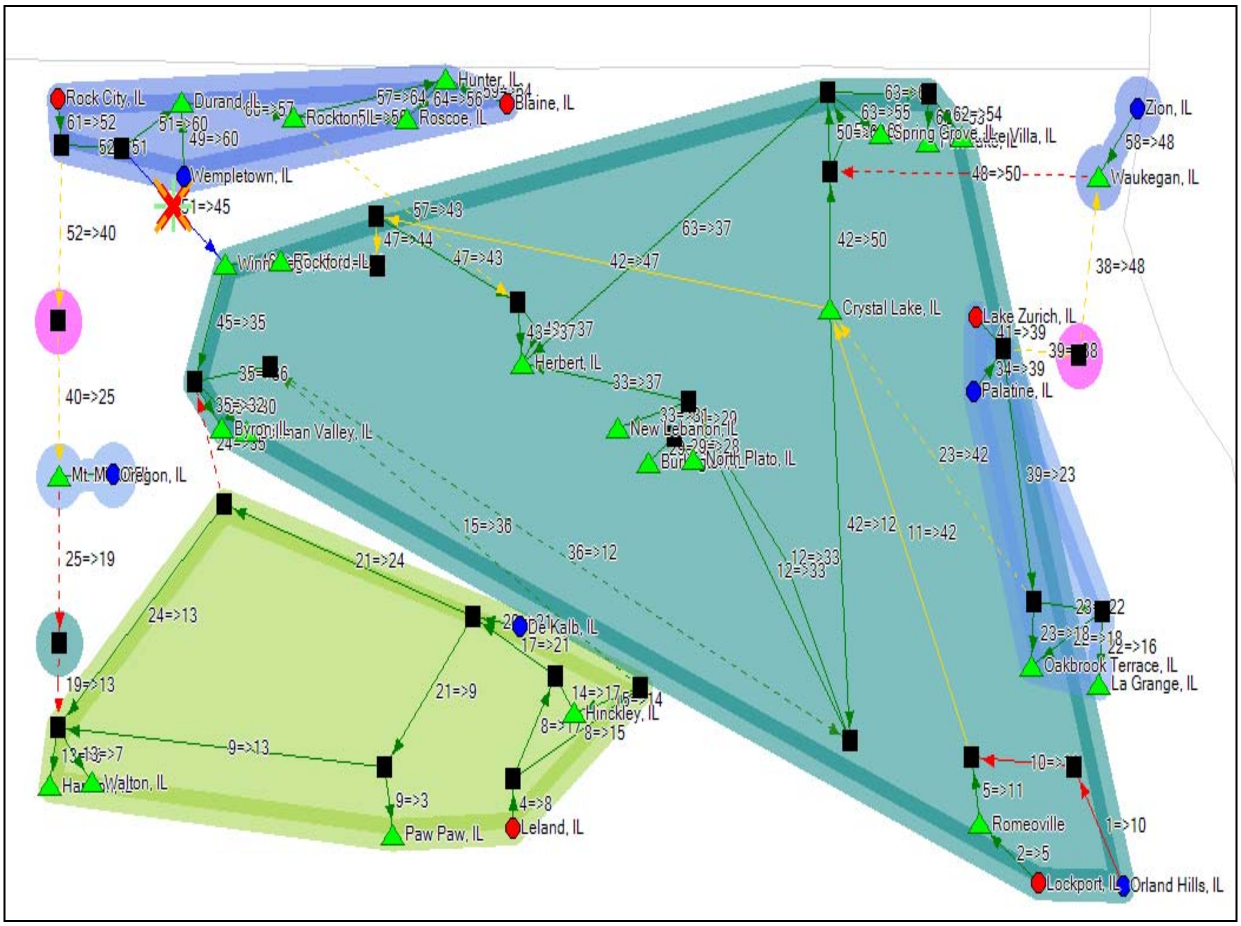

Figure 2: *EPfast's* depiction of the nine island grids formed as a result of an uncontrolled islanding from an initially intact 64-bus network

Output includes detailed tables that show values for both pre- and post-disruption conditions. All reports and spatial and tabular results are generated in hypertext markup language (HTML) format. A summary table of results is automatically generated for every run. The summary table includes the information shown in Figure 3.

Islands

Island No.	Buses	Generators	Loads	Lines	Gen Capacity (MW)	Total Load (MW)	Total Generation (MW)	Sim Load (MW)	Sim Generation (MW)	Load Lost (MW)	Load Lost (%)	Generation Change(MW)	Generation Change(%)
4	13	2	4	14	1200	385.16	719.228	385.16	385.16	0	0	-334.068	-46.45
5	1	0	0	0	0	0	0	0	0	0	0	0	0
6	2	1	1	1	1200	454.32	846.152	454.32	454.32	0	0	-391.832	-46.31
7	1	0	0	0	0	0	0	0	0	0	0	0	0
8	9	3	4	9	1800	366.28	1163.458	366.28	366.28	0	0	-797.178	-68.52
10	28	2	13	32	1200	2732.36	719.228	1023.076	1023.076	1709.284	62.56	303.848	42.25
11	7	2	2	7	1200	107.72	423.076	66.89587	66.89587	40.82413	37.9	-356.18013	-84.19
12	1	0	0	0	0	0	0	0	0	0	0	0	0
13	2	1	1	1	600	101.74	296.152	63.182192	63.182192	38.557808	37.9	-232.969808	-78.67
Totals:	64	11	25	64	7200	4147.58	4167.294	2358.914062	2358.914062	1788.665938	43.13	-1808.379938	-43.39

Figure 3: One of *EPfast's* summary tables showing pre- and post-disruption characteristics of the various island grids formed as a result of cascading line outages. The table also shows the estimated load lost (i.e., depth of blackout) as a result of the disruption.

3 SIMULATION METHODOLOGY AND ASSUMPTIONS

3.1 Simulation Modes

The model has two modes of simulation: islanding mode and standard load flow. The former assumes that the components that will experience the outage have been marked for non-inclusion in the model and proceeds with an iterative calculation, searching for cascading line overloads at each stage until the island grids have been stabilized and no further overloading occurs. The mode is described in detail in Section 3.3. The standard load flow mode employs a non-iterative calculation and is ideally used for plant siting and line reinforcement studies, in which a single simulation run is usually all that is needed to achieve the goal. In each mode, the DC load flow formulation is employed. The DC load flow logic is briefly described in Section 3.2.

3.2 DC Load Flow Formulation

The DC load flow program is used to determine line flows when scheduled power injection and node demand values are provided. In the DC load flow formulation, the relationship between the bus real power injections and the bus voltage phase angles is as follows (Stott and Alsac 1974):

$$[\Delta P] = [B'] [\Delta\theta] \tag{1}$$

Where:

- $[\Delta P]$ = vector of net bus power injection, in per unit
- $[\Delta\theta]$ = vector of net changes in bus voltage phase angle, in radians
- $[B']$ = matrix consisting of constant line admittances, in per unit

The DC load flow is only good for calculating real power flows (i.e., MW) in transmission or distribution lines and transformers (Wollenberg and Wood 1996). It gives no indication of what happens to voltage magnitudes or megavolt-ampere reactive (MVAR) or megavolt ampere (MVA) flows.

Given the Ps (i.e., power injections, + for generators and – for loads), the bus angles can be found using the following equation:

$$[\Delta\theta] = [B']^{-1} [\Delta P] \tag{2}$$

The power flowing through each line using the DC power flow is then:

$$P_{ik} = (\theta_i - \theta_k)/ x_{ik} \tag{3}$$

where x_{ik} is the line reactance between nodes i and k.
The power injection in a node i is therefore as follows:

$$Pi = \Sigma^{N}_{k=1} P_{ik} \tag{4}$$

where N is the total number of buses.

3.3 Solving the DC Load Flow Problem Using LINGO

LINGO is a popular subcomponent of the LINDO system of solvers and is designed for solving linear optimization problems. LINGO 10 is the version used in *EPfast.* The optimization problem in *EPfast* is formulated as follows:

$$\text{Objective Function} = \min \Sigma^{G} (a_j y_j + b_j) \tag{5}$$

Where:
- y = generator output in per unit of generator j
- a and b = coefficient of linearized production cost curve for generator j
- j = index for the participating generator, j =1,2,3, …G
- G= total number of participating generators

Subject to the following constraints:

$$P_i - \Sigma^{N} P_{ik} = 0$$
$$\text{Lower}_j < P_j < \text{Upper}_j$$

Where:
- Pi = net power injection into bus i (positive for generators and negative for loads)
- P_{ik} = power flow from bus k to i (flow is zero if bus k is not linked to bus i)
- N = total number of buses
- Lower_j = lower bound operating limit for generator j
- Upper_j = upper bound operating limit for generator j

For steady-state simulation with fixed generator output (i.e., scheduled dispatch), the lower and upper bound values were set equal to the generator output, y.

In order to speed up calculation and minimize the number of variables in LINGO, the objective function was modified as follows:

$$\text{Objective Function} = \min \Sigma^{G} y_j - \text{total load} = \text{Min } y_{slack} \tag{6}$$

Because the slack generation, y_{slack}, is actually a fixed number equal to the difference between total supply and total demand, there is effectively no optimization being made. The intent is simply to cause LINGO to solve the equality constraints (which are the load flow equations) quickly. Equation (5) remains an essential formulation approach as *EPfast* is further upgraded to find optimal generator dispatch solutions.

3.4 Calculation Logic for the Uncontrolled Islanding Simulation

As stated earlier, the purpose of *EPfast* is to explore the possibility of uncontrolled islanding caused by successive (or cascading) steady-state line overloads. Such overloads are initially triggered by a major, non-reclosable, line-to-line fault or simply by a de-energization of a major line due to a seismic event or other natural causes. In this simple logic, several assumptions are made:

1. A steady-state condition is assumed. The effects of transient power swings, transient frequency excursions, and transient voltage variations are neglected. Transient effects are incorporated later as part of the heuristics solution.
2. Whenever line overloading occurs, the line is assumed to be open and to remain open until a major restoration effort is completed. During the initial and the ensuing line trippings, the load levels and generator outputs throughout are assumed to remain constant, until the system breaks into island grids.
3. When the system splinters into several island grids (as a result of cascading overloads), the following further assumptions are made:

    a) Island grids that do not have power sources are assumed to be under total blackout.
    b) Island grids with power sources are assumed to be able to adjust either the loads (i.e., via automatic load shedding) or generator outputs (i.e., via output reduction) to settle to a new, balanced operating point. More specifically, when load exceeds demand, load at non-essential buses is shed to maintain supply/demand balance; when generation exceeds demand, generation sources are reduced proportionately to regain balance. Note that the direction of the adjustments is always toward either reducing load levels or reducing generation output in order to minimize the possibility that further over loading will occur after the system experiences a major breakup (i.e., splintering into many island grids).
    c) The re-dispatch, as well as balancing of generation and load within the island grids, can be done by invoking an optimal power flow program or employing a heuristics-based methodology. But first, if the load exceeds generation in an island, a load-shedding scheme is assumed (in actuality, the scheme may be triggered by frequency and voltage relays) in which loads are dropped systematically until load equals generation.

3.5 Illustrative Example of the Calculation Logic

In the *EPfast* islanding and re-dispatching logic, the sequential occurrence of the propagating disturbance is shown in Figures 4, 5, 6, 7, and 8 to illustrate how a disrupted line can cause cascading failures in an electrical system. As described above, the simulation is done under steady-state assumptions, neglecting the effects of power swings that usually occur seconds after the initial disturbance. As such, the impact presented is somewhat underestimated.

Figure 4 shows the system prior to the disturbance. During normal conditions, the line loading levels range from 1 to 89%, indicating a heavily loaded system. Line 54–28 is shown as the most heavily loaded line, at 89% capacity.

Sequence 1. In Sequence 1, Line 54–28 trips as the result of a seismic event. This is depicted in Figure 5, in which the tripping of the line is highlighted by change in the color of the line to orange and the broken line representation.

Sequence 2. Sequence 2 is presented in Figure 6, which shows how the tripping of Line 54–28 causes Line 61–18 to overload.

Sequence 3. As Line 61–18 overloads, it too tripped. As it trips, simulation shows that seven other lines begin to overload, as shown in Figure 7.

*Sequence 4***.** The seven overloaded lines finally trip, splintering the system into the six island grids shown in Figure 8. Island grids 4 and 6 are considered “lost” because of the absence of generation sources.

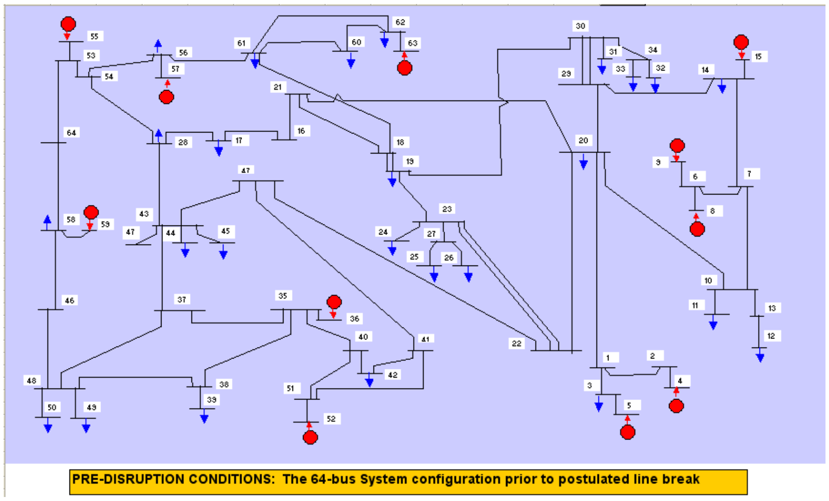

Figure 4: Base case pre-disruption system configuration

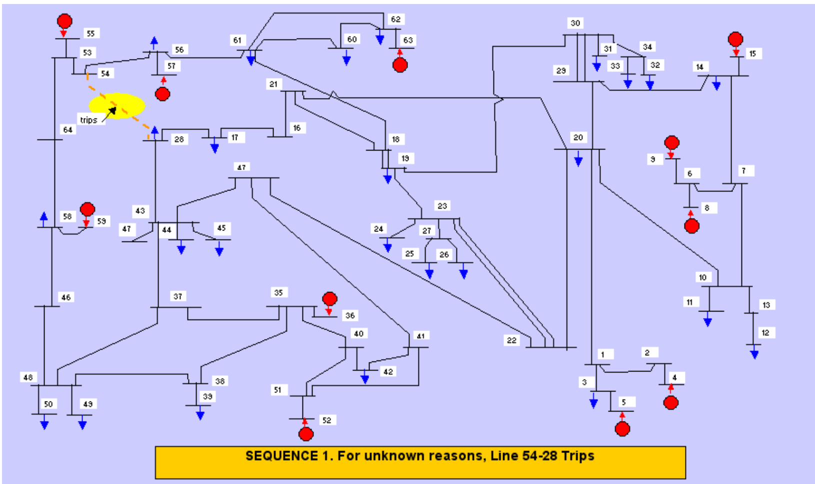

Figure 5: Sequence 1 begins with the tripping of line 54–28

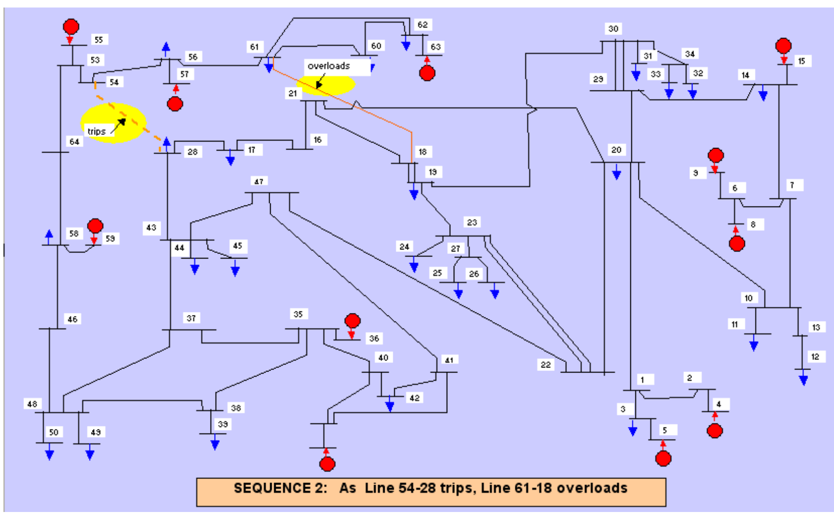

Figure 6: Sequence 2 depicts the overloading of line 61–18 as line 54–28 trips

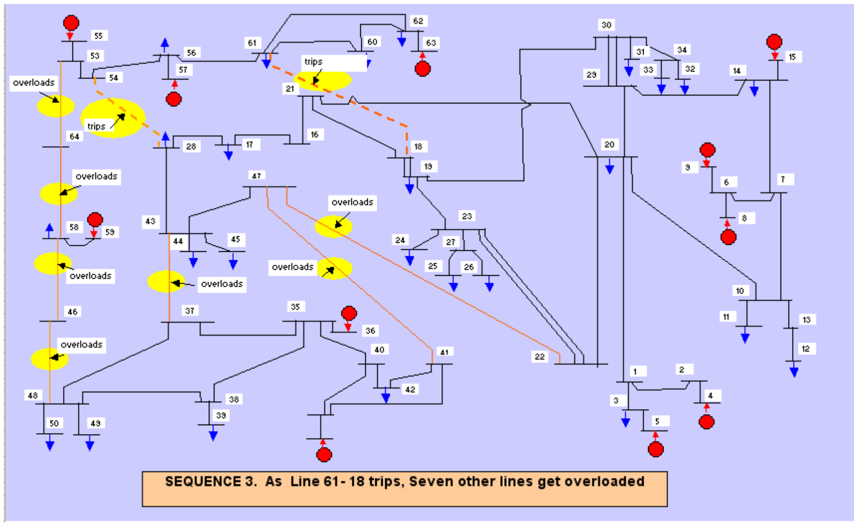

Figure 7: With lines 54–28 and 61–18 out, seven other lines begin to overload

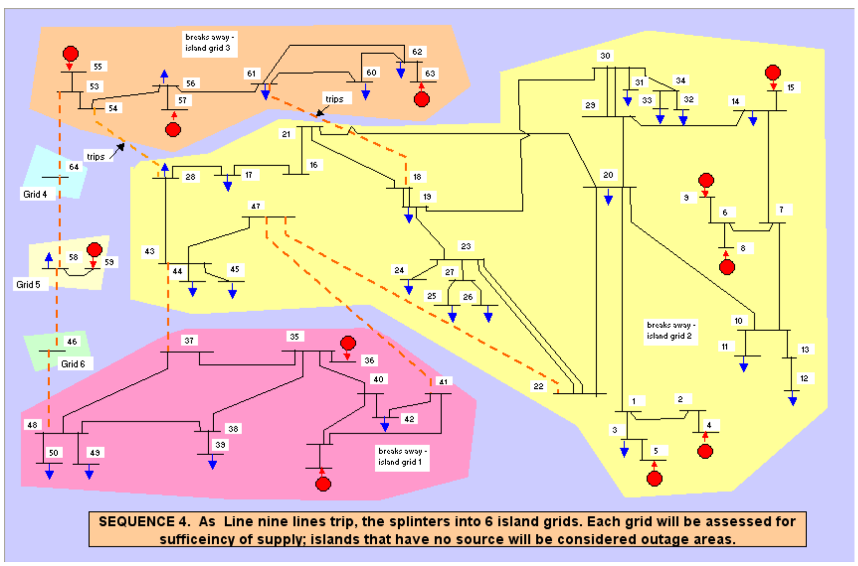

Figure 8: System breaks into six island grids, each of which is inherently imbalanced in terms of supply and demand

Grid #1 exhibited an imbalance, with generation greater than demand (i.e., an imbalance of 340 MW). Steady-state assumptions require that the generator outputs be reduced in proportion to their pre-disturbance levels. The reduction suggests that Grid # 1 has settled to a new operating point. Subsequent simulation of the new condition (i.e., with the new dispatch schedule) resulted in no further overloads.

Grid #2 exhibited a more substantial imbalance of about 1,500 MW. In the case of Grid #2, demand is greater than supply, and several non-essential loads had to be shed. The resulting configuration was then simulated. Results indicated that no further overloads occurred, and the island grid is considered to have stabilized.

In Grid #3, an imbalance of about 700 MW was noted, with total generation greater than demand. Subsequently, generator outputs were decreased proportionately (i.e., with respect to their pre-disturbance output levels). The resulting configuration was then simulated. Results indicated that no further overloads occurred.

4 EPFAST USED TO SIMULATE POTENTIAL COLLAPSE OF U.S. EASTERN INTERCONNECTION

4.1 Data Sources and System Size

DOE-ISER recently engaged the services of Argonne to examine the impact of a high-intensity New Madrid earthquake on the USEI. Specifically, DOE wanted to know whether USEI would collapse and how the impacts would be distributed across the region.

The USEI load flow data (Summer 2010 case), was provided by the Eastern Reliability Assessment Group and the shake maps were provided by the United States Geological Survey through FEMA. The USEI system used in the model consisted of about 56,000 buses and 76,000 lines, with a total load of about 660,000 MW. Figure 9 shows the New Madrid Seismic Zone (NMSZ) shake map with a shape file of pertinent power plants overlaid on top of the seismic footprint. Figure 10 shows the location of the high-voltage transmission lines and substations in the vicinity of the fault. Fragility curves taken from FEMA's HAZUS model (FEMA 2003; Oikawai, Fukushima, and Takase 2001) were used to determine the damaged states of the various electrical equipment. At least 111 and 84 high-voltage lines and substations, respectively, would cease operation instantly as a result of the earthquake (Portante et al. 2009). The event was assumed to be of magnitude 7.7 on the Richter scale.

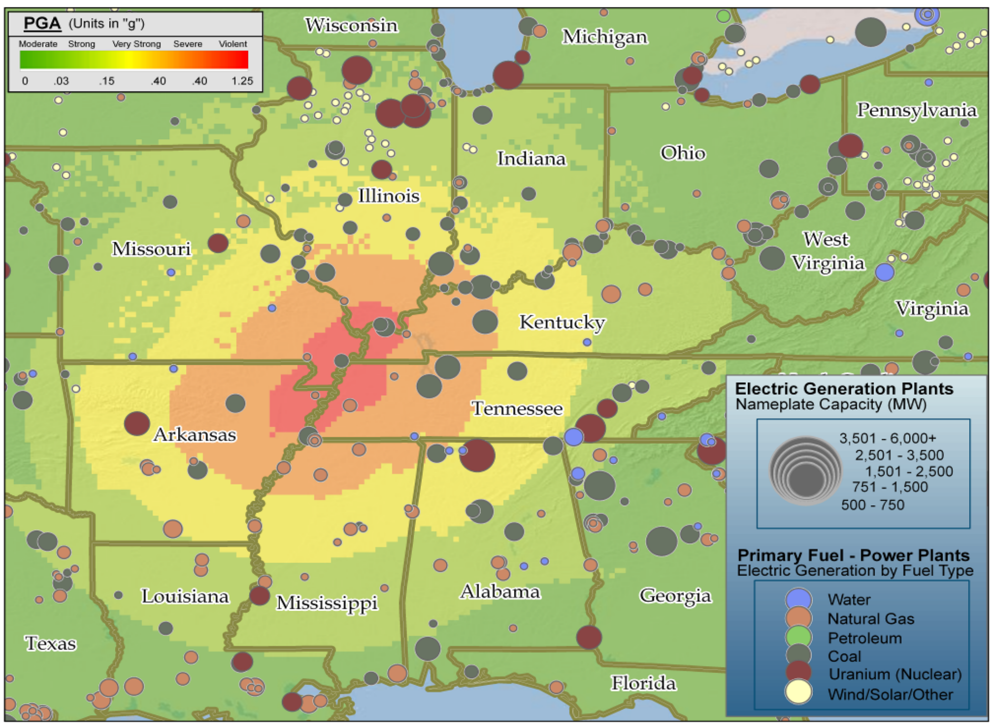

Figure 9: Location of power plants on top of the New Madrid shake map (The shake map shown is the simplified peak ground acceleration [PGA] ground motion map. Power plant geographic information system [GIS] layer courtesy of PowerMap [Platt's PowerMap 2007].)

The simulation results indicate that USEI would break into 30 large island grids and most likely collapse. In the process, it was estimated that the USEI would lose loads representing anywhere from 40–80% of its original demand. The analysis employed heuristics to account for the effects of transient instability, such as power swings, sharp frequency decay, and voltage collapse. Figure 11 shows the location of some of the largest island grids formed, while Figure 12 depicts the geographical extent of the blackout.

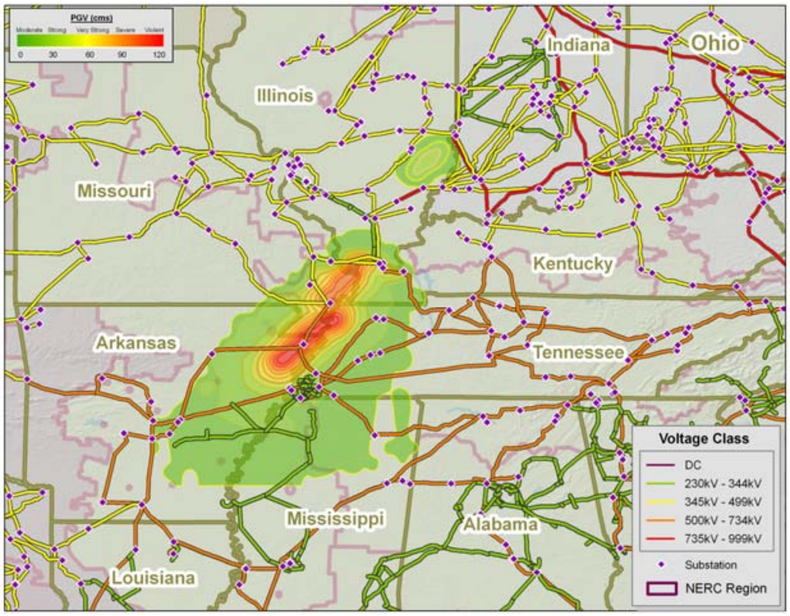

Figure 10: High-voltage transmission lines and substations in the NMSZ (The shake map shown is the simplified peak ground velocity (PGV) ground motion map. Transmission line and substation GIS layer courtesy of PowerMap (Platt's PowerMap 2007).)

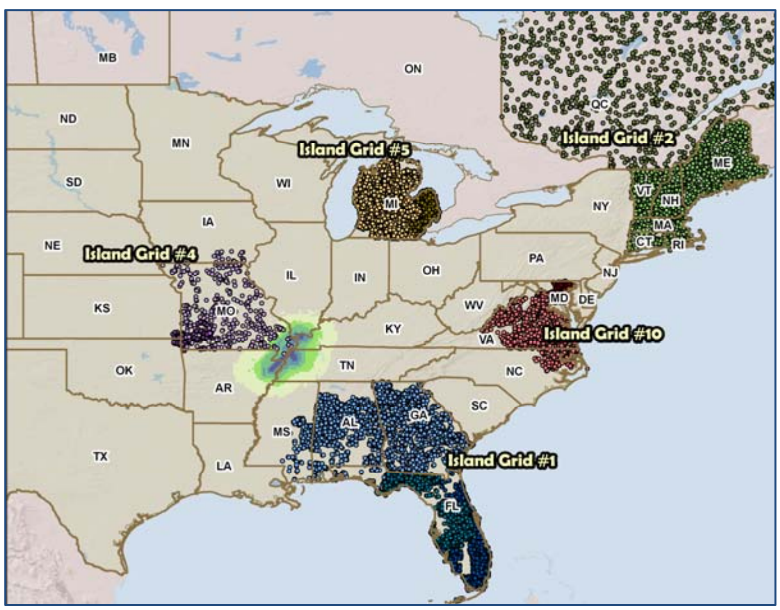

Figure 11: Location of five of the ten largest island grids

4.2 Validity of Results and *EPfast* Performance

Because the current work in relation to the NMSZ is the first of its kind in terms of the intent and the scale of the electric network being simulated, validation by comparison or benchmarking with previous work may be difficult. In addition, the large number of uncertainties associated with any seismic event could cause results to vary substantially. With regard to *EPfast* performance, less than 10 minutes was required to complete the simulation of a 56,000-node network.

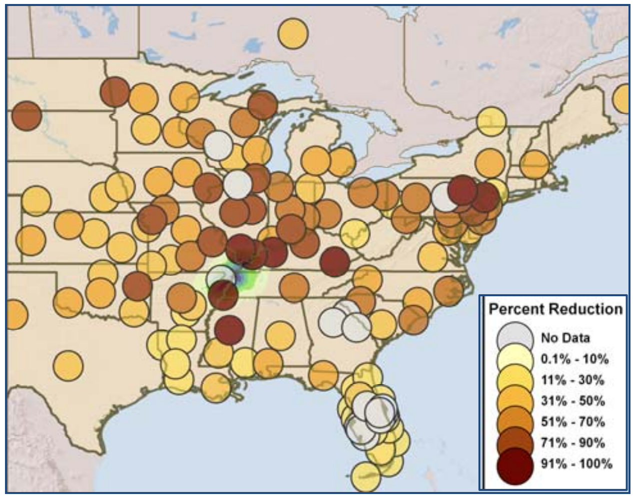

Figure 12: Extent of blackout in the USEI as a result of New Madrid seismic event (Shaded circles represent centroids of areas where supply defficiency could occur.)

5 CONCLUSIONS

EPfast is a rapid response tool that is ideal for assessing the potential collapse of large power systems via the uncontrolled islanding phenomenon. The model can handle simultaneous outage of clusters of electric network components; a capability that is beyond the current standard of N-1 and N-2 contingency reliability tests. Assessing the full extent of the impact on the electric system is complex and requires the consideration of transient events, such as frequency decays, voltage collapse, and generator-tripping power swings. Such an assessment also requires consideration of the various mitigating measures available to electric utilities, such as load shedding, fault protection schemes, and automatic-controlled islanding plans. The use of a heuristics-based assessment to supplement steady-state simulations can result in a reasonable quantification of the overall impacts.

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