Proceedings of the 2014 Winter Simulation Conference
A. Tolk, S. Y. Diallo, I. O. Ryzhov, L. Yilmaz, S. Buckley, and J. A. Miller, eds.

SIMULATION OF THE SEPTEMBER 8, 2011, SAN DIEGO BLACKOUT

Edgar C. Portante
Stephen F. Folga
James A. Kavicky
Leah Talaber Malone

Argonne National Laboratory
9700 South Cass Avenue
Argonne, IL 60432, USA

ABSTRACT

The development of predictive tools for emergency management has recently become a subject of major consideration among emergency responders, especially at the federal level. Often the news of an impending high-consequence threat causes significant stress on these agencies because of their inability to apprise management of probable impacts with sufficient certainty. This paper documents Argonne National Laboratory's effort to demonstrate the predictive capability of its newly enhanced tool called *EPfast* in estimating the impacts of postulated events on our power system. Specifically, the study focuses on *EPfast*'s ability to estimate power outage areas resulting from random system contingencies. The San Diego September 8, 2011, blackout that affected most of southern California was selected for simulation using *EPfast*. Results showed agreement with actual reported impacts in both spatial and quantitative terms. The method, assumptions, and data used are presented here, and results showing their potential application to emergency planning are discussed.

1 INTRODUCTION

The San Diego September 8, 2011, blackout event was thoroughly reviewed by both the North American Electric Reliability Council (NERC) and Federal Energy Regulatory Commission (FERC) and described extensively in FERC-NERC (2012). The resulting blackout was limited both in geographical extent (it involved largely the San Diego Gas and Electric [SDGE] service area) and in duration (it lasted for about 11 minutes in most places). The event was also observed as a typical case characterized by cascading line outages leading to uncontrolled islanding that eventually led to partial system collapse. As such, the San Diego event provides a good case for benchmarking specialized tools such as *EPfast* (Portante et al. 2011). *EPfast* is a highly efficient electric system simulator developed by Argonne. Its basic functions are to (1) explore the tendency of a power system to break into island grids following an event, (2) track cascading line outages leading to the island grid formations, and (3) estimate the magnitude and spatial extent of the blackout area resulting from the disruption.

2 DESCRIPTION OF THE SAN DIEGO 2011 EVENT

2.1 Initiating Disturbance

On the afternoon of September 8, 2011, an 11-minute system disturbance occurred in the Pacific Southwest, leading to cascading outages and leaving about 2.7 million customers without power. The outages affected parts of Arizona, southern California, and Baja California, Mexico. All of the San Diego area lost power, with nearly 1.5 million customers losing power, some for up to 12 hours. The disturbance occurred near rush hour, on a business day, snarling traffic for hours. Schools and businesses closed, some flights and public transportation were disrupted, water and sewage pumping stations lost power, and beaches were closed due to sewage spills; all impacted emergency management operations in the region. In addition, millions went without air conditioning on a hot day.

The loss of a single 500-kilovolt (kV) transmission line initiated the event but was not the sole cause of the widespread outages. The system is designed and operated to withstand the loss of a single line, even one as large as 500 kV. The affected transmission line—Arizona Public Service's (APS's) Hassayampa-North Gila 500-kV line (H-NG)—is a segment of the Southwest Power Link (SWPL), which is a major transmission corridor that transports power from east to west, from generators in Arizona, through the service territory of the Imperial Irrigation District (IID), and into the San Diego area. The transmission line had tripped on multiple occasions (including July 7, 2011) without causing cascading outages. Figure 1 shows the electric transmission network in the southern California region, highlighting the location of the H-NG 500-kV line (indicated by the red "X") in Arizona. Figure 2 shows the schematic depiction of the San Diego electric system.

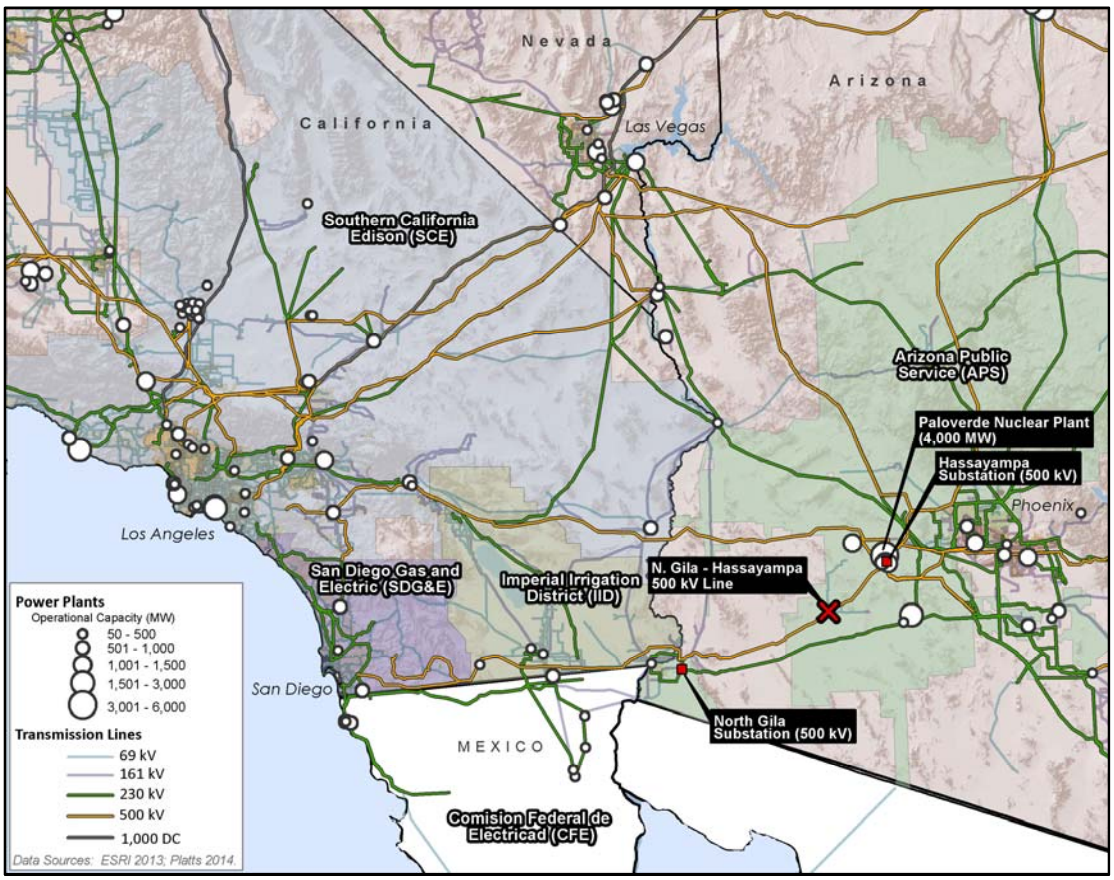

Figure 1: Electric transmission network in southern California and Arizona (Platts 2013).

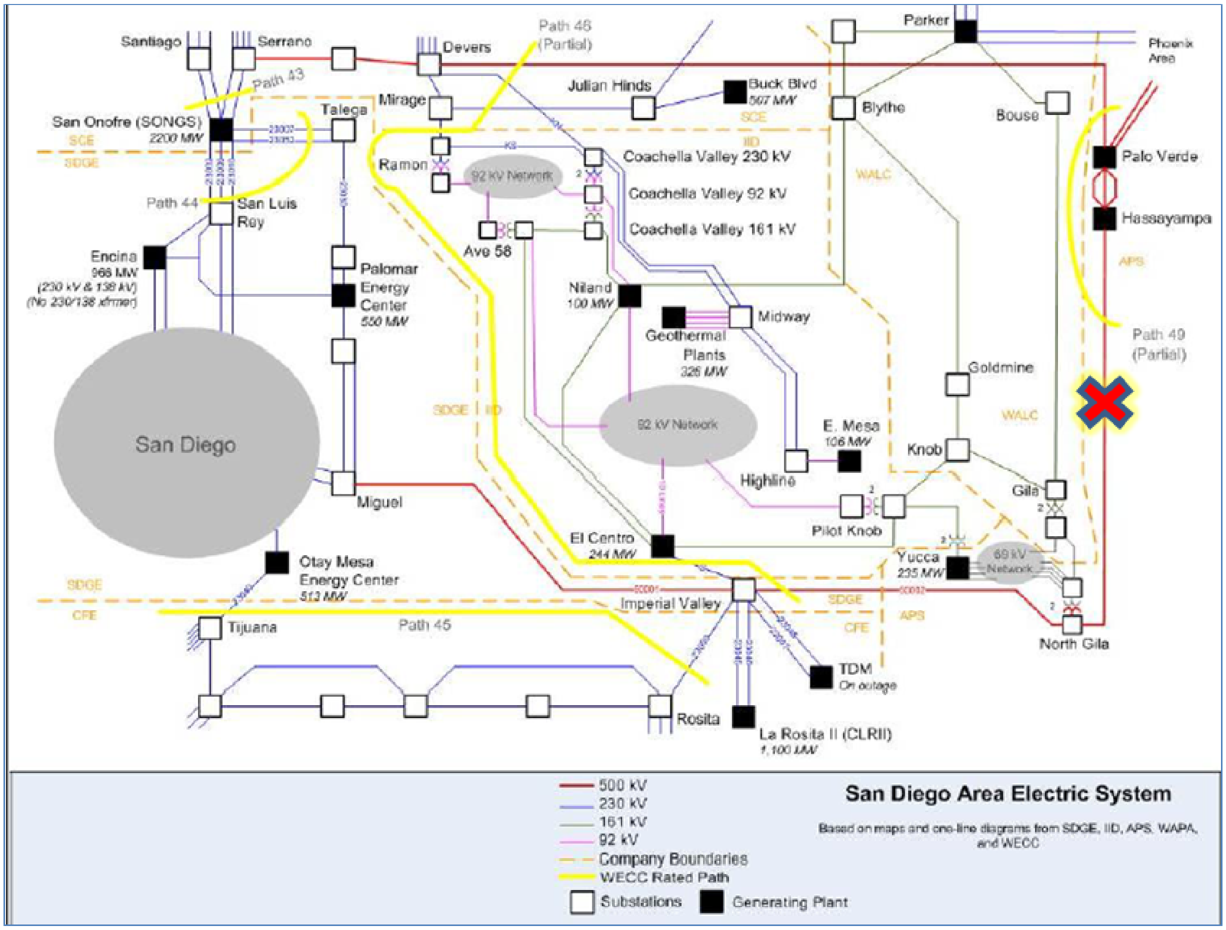

Figure 2: Schematic representation of the San Diego area transmission system (FERC-NERC 2012).

2.2 Cascading Outages and Resulting Blackout

The tripping of the H-NG line that day altered the power flow pattern in that region, causing the surviving lines around the H-NG corridor to overload. Overloaded lines tripped as power flow levels exceeded their designed capacity. As a result of the cascading outages, customers in the SDGE, IID, APS, Western Area Power Administration-Lower Colorado (WALC), and Comision Federal de Electricidad (CFE) territories lost power, some for multiple hours extending into the next day. Specifically:

- SDGE lost 4,293 megawatts (MW) of firm load, affecting more than 1.4 million customers.
- CFE lost 2,150 MW of net firm load, affecting approximately 1.1 million customers.
- IID lost 929 MW of firm load, affecting approximately 146,000 customers.
- APS lost 389 MW of firm load, affecting approximately 70,000 customers.

Figure 3 shows the dispersal pattern of substations that experience load curtailment (at about 15:38:30 on September 8), while Figure 4 shows the effective blackout region resulting from the event (at 15:38:38).

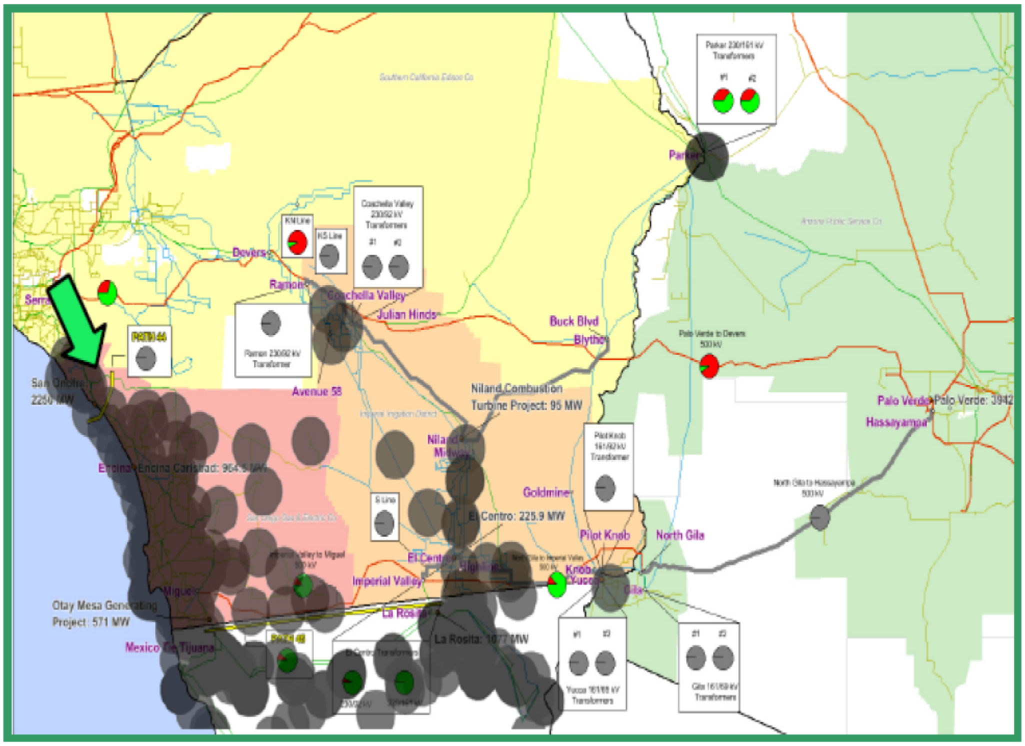

Figure 3: Blackout area in the San Diego-Yuma area at 15:38:30 (FERC-NERC 2012).

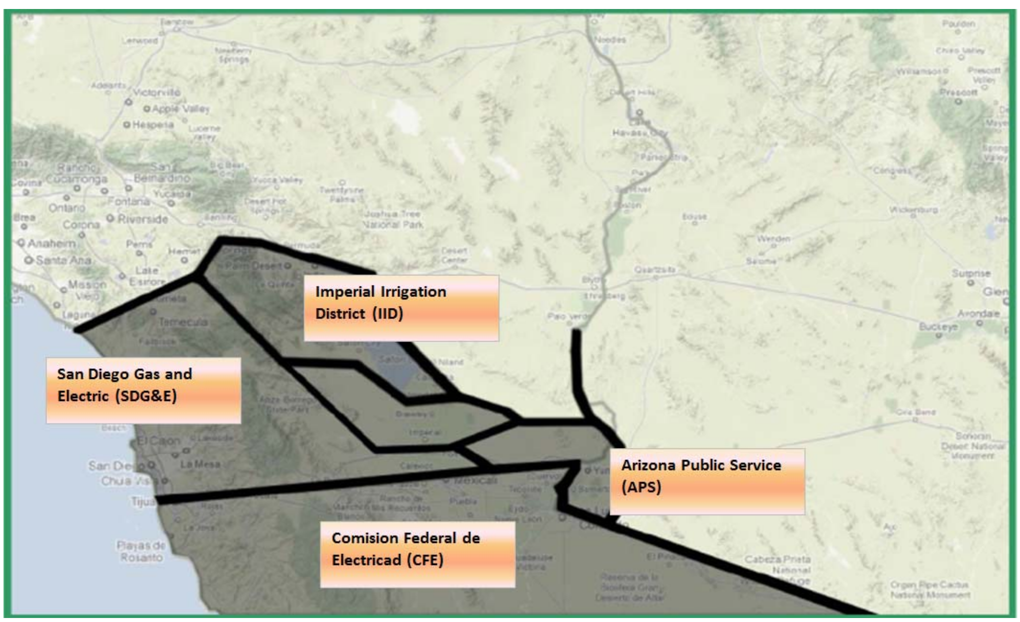

Figure 4: Territorial coverage of blackout area at 15:38:38 (FERC-NERC 2012).

3 ARGONNE'S EVENT RECONSTRUCTION AND SIMULATION APPROACH

The ideal approach to reconstruct the pre-event operating environment is to follow all the steps taken by the NERC-FERC team in gathering time-stamped data from the affected utilities and including these parameters as input data for simulation models. Such an approach, however, is generally time consuming and resource intensive and involves the collection of proprietary data. Because this extensive data collection approach is not feasible for Argonne staff, an alternate approach was adopted. Argonne, with respect to *EPfast,* is particularly interested in capturing three data sets or parameters, namely:

- Demand schedule,
- Generator dispatch, and
- Network configuration.

Argonne's approach focuses on simulating the event in the context of the entire Western Electricity Coordinating Council (WECC) network. The WECC network extends roughly from northern Mexico to Canada, including most of the states west of the Mississippi River. Considering the operating characteristics of the entire WECC system is important, because during summer months, California (including SDGE) receives a significant amount of power from the Pacific Northwest.

3.1 Demand Adjustment

Ideally, the adjustment of demand is made on a per-bus level, whereby empirical MW demand at each load bus in the WECC system is compared with that of the current *EPfast* per-bus load data set and changes are made to reflect the former set. In the absence of proprietary pre-event empirical data, the FERC 714 hourly data set from 2006–2012 was considered to adjust WECC's total coincident demand to represent the network conditions for September 8, 2011 (FERC 2013). However, this proved to be difficult, because the FERC 714 regional categorization is quite different from its utility categorization adopted in the FERC 715 data, which forms the basis of the input data for *EPfast.* The FERC 714 data set, including Part 3, Schedule 2 (Planning Area Hourly Demand), is completed by each electric utility that operates a balancing authority area and by each group of electric utilities, which are bound together through pooling contracts, holding company operations, or other contractual arrangements that operate a balancing authority area. The FERC 715 data set, however, must be completed by each transmitting utility that operates integrated transmission system facilities that are rated at or above 100 kV. Therefore, the difference in reporting requirements for the two data sources has the potential to cause data inconsistency concerns when there is no access to additional information that is not publicly available. For example, initial FERC 714-based calculations resulted in a total WECC load of about 115,000 MW, compared to 169,851 MW specified in the FERC 715 WECC 2010 heavy summer case. Considering the discrepancy, Argonne opted to maintain its current WECC demand level of about 169,851 MW as reflected in WECC's filing to FERC provided in 2010 HS3b (i.e., 2010 heavy summer base case). In comparison, the FERC 2011 HS2A base case for WECC showed a total peak demand of 171,561 MW, or an increase of about 1% in demand with respect to the 2010 HS3b values.

The total demand in the SDGE service territory (determined by aggregating all SDGE-owned load buses) as reflected in the *EPfast* input file based on the 2010 HS3b base case is 4,768 MW. The actual SDGE demand at 15:00 hours on September 8, 2011, was about 4,240 MW, likely representing lower load levels (caused by milder temperatures) than the levels found during heavy, peak-summer conditions.

3.2 Generator Dispatch Adjustment

The preferred method for adjusting the generator dispatch schedule is conducted on a per-bus level, whereby the empirical MW output at each generator bus in the WECC system is compared with that of the current *EPfast* per-bus generator data set. Again, changes would reflect the values found in the pre-event empirical data set. However, as various FERC 714 data sets were examined, it was noted that no FERC 714 data set contained information characterizing the hourly dispatch of generators in the WECC region. The FERC 714 data set in Part 2, Schedule 1 (Balancing Authority Generating Plants), only contains information on each plant's available capacity and its net internal load. Given this finding, Argonne again opted to retain the dispatch schedule contained in WECC's filing to FERC under case 2010 HS3b while accounting for the power plant availability provided in the FERC 714 data.

The dispatch schedule of the power plants inside the SDGE service territory as reflected in the final *EPfas*t data set is presented in Table 1. The generator output and rating as shown in the table are expressed in per-unit values using a 100-megavolt-ampere (MVA) base. Capacity factor values are shown as percentages. The actual values in MW can be determined by multiplying the per-unit values by 100. Thus, the assumed total internal generation within SDGE is 2,293 MW using the 2010 HS3b values. Utilization rates for the generators are quite large, as indicated by the elevated capacity factor values; this is consistent with the high-demand condition prevailing during this period.

Table 1: SDGE generator dispatch schedule as reflected in the *EPfast* data set.

Plant Name	Output (per unit)	Rating (per unit)	Capacity Factor (%)
Division	0.45	0.47	96
Encina 1	0.96	1.06	91
Encina 2	0.96	1.03	93
Encina 3	0.96	1.09	88
Encina 4	2.41	2.99	81
Encina 5	2.89	3.29	88
PEN_CT1	1.59	1.73	92
PEN_CT2	1.59	1.73	92
PEN_ST	1.78	2.29	78
GoalLine	0.46	0.49	94
MEF MR2	0.44	0.48	92
OTAYMGT1	1.59	1.65	96
OTAYMGT2	1.59	1.66	95
OTAYMST1	2.03	2.72	75
PASSMWQ1	0.44	0.47	94
SOUTHBY1	1.35	1.45	93
SOUTHBY2	1.35	1.49	91
KUMEYAAY	0.05	0.05	100
Total	22.93	26.58	87

3.3 Network Configuration Adjustment

Because of the previous findings regarding the demand and generator dispatch adjustments, a consistent network description reflecting the 2010 dispatch schedule and demand levels as described in the 2010 HS3b base case was adopted by Argonne. To improve confidence in recent transmission line additions in the WECC region since 2010, Argonne compared WECC's FERC 715 diagrams for 2010 and 2011 and concluded that the network configurations are essentially the same, with no major line additions made during the period.

3.4 Summary of Adjustments

In summary, Argonne made use of the 2010 WECC heavy summer case (2010 HS3b), which represents a peak period during the month of August. The use of 2010 values over 2011 values appears reasonable since there is only a 1% disparity between the two data sets with respect to overall WECC coincident demand. Moreover, no significant line additions were made between September 2010 and September 2011, which makes reconfiguring the 2010 network unnecessary.

3.5 Logic of *EPfast* for Estimating Power Outage Areas

The primary application of *EPfast* is to explore the possibility of uncontrolled islanding caused by successive (or cascading) steady-state line overloads and help in estimating associated outage areas that could affect emergency response efforts. Such overloads are initially triggered by a major, nonreclosable, line-to-line fault or simply by a de-energization of a major transmission line caused by a seismic or some other natural event. To provide this capability, *EPfast* operates under several assumptions:

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 or by adjusting the threshold limits for line tripping.
2. Whenever line overloading occurs, the line is assumed to be open and to remain open until a major restoration effort is completed. During initial and the ensuing line tripping, the load levels and generator outputs throughout the system 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 (e.g., via automatic load shedding) or the generator outputs (e.g., via output reduction) to settle to a new, balanced operating point. More specifically, when demand exceeds available generation, the load at nonessential buses is shed to maintain supply/demand balance; when generation exceeds demand, generation sources are reduced proportionately to regain balance. The direction of the adjustments is always toward reducing either load levels or generation output, to minimize the possibility that further overloading would occur after the system experienced a major breakup (i.e., splintering into many island grids).
    c) The re-dispatch, as well as balancing of generation and demand within the island grids, is completed by invoking an optimal power flow program or by employing a heuristics-based methodology. But first, if the demand exceeds the 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 the demand equals the generation dispatch.
4. This iterative process continues as long as island grids are formed and line overloading is detected. The process stops when no additional island grids are formed and no further line overloading occurs.
5. *EPfast* tracks the lines tripped, islands formed, and changes in demand and generation levels at each affected bus within the islands, and it defines the outage area. Outage areas consist of nodes exhibiting significant load reductions and are portrayed as a series of graphical shapes that represent possible blackout regions.

The literature abounds with papers on the subject of grid collapse, islanding, cascading line failures, and blackout area estimation (IEEE 2008; Koc et al. 2013). Most of these publications, however, are academic in nature, involving small pilot systems and simple high-level statistical analysis of aggregated power-outage-related data. *EPfast* is unique in the sense that it can handle large actual systems in standard node-link framework and can measure the outage area in terms of both geospatial extent and load loss on a per-bus basis.

4 RESULTS OF SIMULATION AND RELATED DISCUSSIONS

4.1 Pre-event Depiction of the WECC Interconnected Power System

The pre-event depiction of WECC's network using *EPfast's* graphic user interface is shown in Figure 5. The location of the H-NG line is shown and indicated by a red "X" symbol. The pre-event load flow simulation reveals a flow of 1,193 MW through the 500-kV H-NG transmission line, with flow direction toward North Gila (westward). The loading of the H-NG line is about 63%. The flow through the Celilo-to-Sylmar direct-current transmission line is 2,856 MW at a loading level of about 92%. The flow direction on this transmission line is toward Los Angeles. Palo Verde Nuclear Generating Station (dispatched at 2,150 MW out of 4,000 MW of available capacity) was chosen as the slack bus for the simulation, because of the large spare capacity that the units usually exhibit relative to the other power plants in the region.

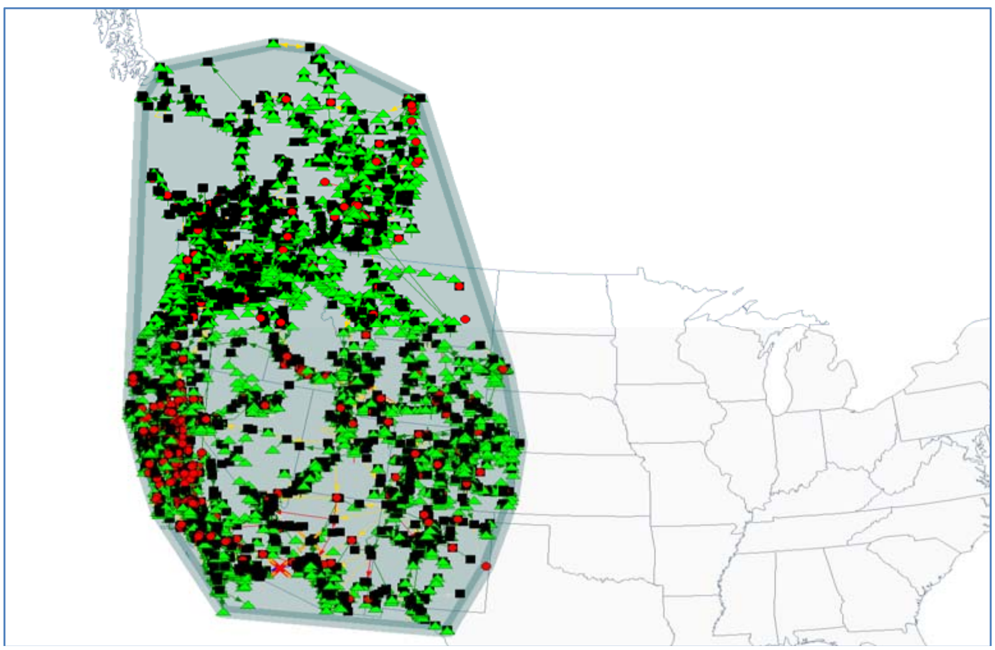

Figure 5: *EPfast's* depiction of WECC's power system network showing the break (red "X") in the H-NG line (Energy Visuals 2010).

4.2 Post-Event Depiction

EPfast simulation of the H-NG line outage indicated the occurrence of cascading line overloads leading to the formation of 19 single- and multiple-node island grids. The affected nodes in these island grids are shown in Figure 6. The affected load buses within these island grids experience a load curtailment between 30% and 100%, as shown in Table 2. Table 3 summarizes the amount of MW lost in pertinent regions around and including SDGE.

EPfast records the progression of the pertinent transmission lines that trip immediately following the initial outage of the H-NG 500-kV transmission line. The exact sequence of the tripped lines is tracked by examining the *EPfast* solution iterations.

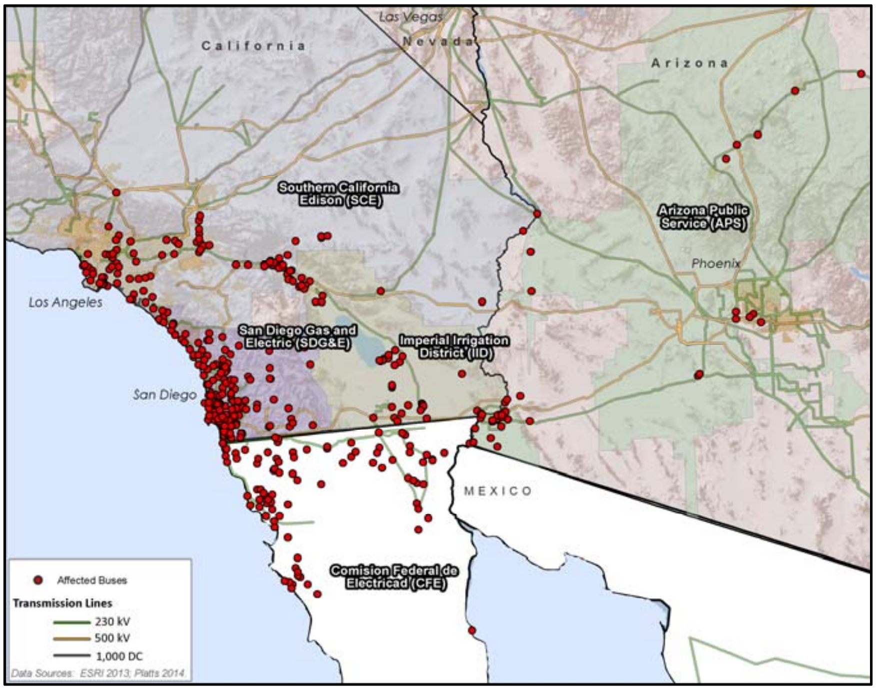

Figure 6: Location of load buses that experience significant load curtailments based on *EPfast* simulation results for the San Diego September 8, 2011, blackout (Portante et al. 2011; Energy Visuals 2010).

Table 2: Island grids formed and levels of load shedding based on *EPfast* simulation results for the San Diego September 8, 2011, blackout.

Item No.	Island Number	No. of Buses	No. of Loads	Original Load (MW)	Load Lost (MW)	Load Lost (%)
1	5	5	0	–	–	0.0
2	6	5	2	74	74	100.0
3	8	2	0	–	–	0.0
4	9	2	0	–	–	0.0
5	13	2	1	33	33	100.0
6	14	4	3	46	46	100.0
7	15	2	1	6	6	100.0
8	16	1	0	–	–	0.0
9	17	6	2	13	6	48.0
10	18	2	1	133	133	100.0
11	19	2	1	696	696	100.0
12	20	2	0	–	–	0.0
13	21	5	1	292	179	61.2
14	22	2	1	33	33	100.0
15	24	760	260	23,969	7,493	31.3
16	25	35	16	391	121	30.9
17	26	1	0	–	–	0.0
18	27	2	0	–	–	0.0
19	28	2	0	–	–	0.0
Total		842	289	25,687	8,820	34.3

Table 3: Load (in MW) shed per utility system based on *EPfast* simulation results for the San Diego September 8, 2011, blackout.

Affected Region	ANL *EPfast* Simulation (MW)
SDGE	5,137
CFE	2,111
IID	966
APS	437
Others	168
Total	8,820

4.3 Comparison of Actual Versus *EPfast* Simulation Results

Figure 7 compares the actual and *EPfast*-based depiction of the blackout areas, while Table 4 compares the amount of disrupted load in the four most significant regions affected by the event.

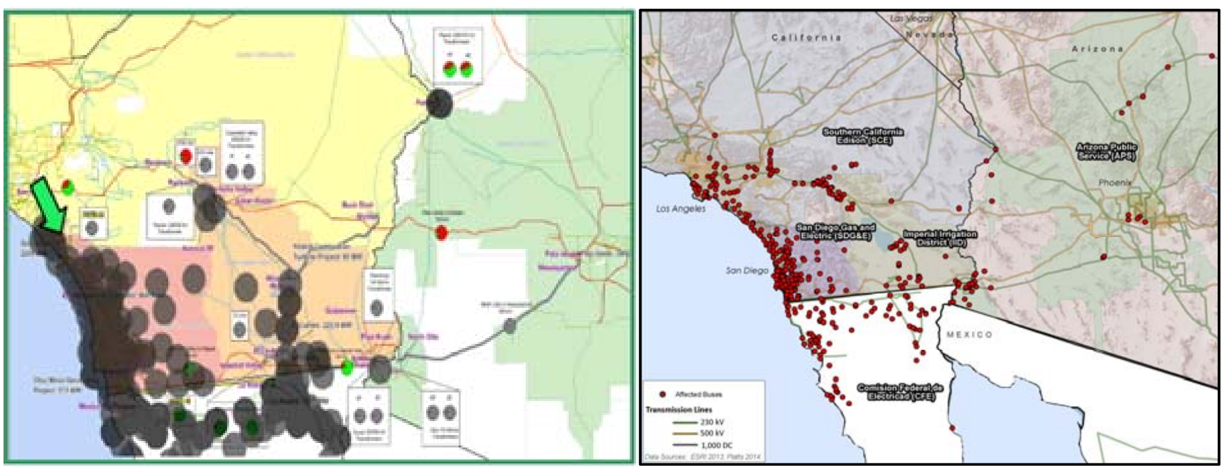

Figure 7: Comparison of locations of final outage areas in FERC Report (at 15:38:38) versus *EPfast* simulation results (FERC-NERC 2012, Energy Visuals 2010).

Table 4: Comparison of lost load for actual versus *EPfast* simulation results.

Affected Region	FERC-NERC Report (MW)	*EPfast* Simulation (MW)	Deviation (%)
SDGE	4,203	5,137	22
CFE	2,150	2,111	–1.8
IID	929	966	4
APS	389	437	12
Total	7,671	8,651	13

An examination of Figure 7 and Table 4 reveals that the *EPfast* simulated results are in agreement with the historic results following the event, both spatially and quantitatively. The *EPfast* results remain close to the actual results despite the fact that the demand and generator dispatch profiles used in *EPfast* are based on the FERC 2010 HS3b base case power flow data. In addition, *EPfast* completed not just 7—but 18—iterations. However, it was observed that the results remained essentially the same for all iterations beyond iteration 5, indicating the occurrence of a "plateau" in the solution trajectory. This plateau region is an indication to *EPfast* users that a reasonable solution has been reached and further iterations beyond this region may only provide additional extraneous solutions. The overall deviation in results relative to the actual outcome could be attributed to many factors, including the fact that *EPfast* linearized a complex nonlinear system, thereby ignoring momentary but important voltage and frequency perturbations. It also did not account for the automatic actions of disturbance-mitigating devices, such as power system stabilizers and tap-changing transformers. It is felt that the assumption about load and generation dispatch schedules was not a major factor in causing the errors since the model was run under essentially the same summer peak load environment.

5 CONCLUSIONS

Reconstructing a past event for simulation can bring forth a myriad of issues, particularly in terms of aligning the assumptions and ensuring the input data's accuracy in order to properly characterize the pre-event operating state of the system. Nevertheless, this study shows that Argonne's post-event simulation of the San Diego September 8, 2011, blackout using *EPfas*t and publicly available data performed satisfactorily, yielding simulation results that closely resemble the actual impacts observed, in both spatial (geographic extent and shape of blackout area) and quantitative (amount of MW lost per service territory) terms. The study demonstrated that *EPfast* has the capacity to perform as a predictive tool for identifying system vulnerabilities and forecasting, to a reasonable extent, the potential consequences of exploiting such weaknesses caused by natural events. Although *EPfast* simulation results demonstrate a slight margin of error with respect to post-event analysis methods privy to unlimited proprietary data, they nevertheless also establish that tools like *EPfast* can bound and quantify the impacts posed by loss of critical assets in the power grid. Clearly, there is a need to undertake more tests on *EPfast's* performance by using other past actual events to establish reliability trends as well as appropriate calibration procedures to increase the accuracy. Calibration mechanisms for now include adjusting the overload threshold for line tripping and limiting the number of iterations. Efforts are also being undertaken to improve the computational speed of the tool. Leveraging on the capability demonstrated so far, *EPfas*t was selected as an integral part of the Hurricane-Electric Sector Impact Assessment tool currently being formalized by Argonne for the U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability (DOE-OE). The Hurricane-Electric Sector Impact Assessment tool has an enhanced predictive modelling capability that is envisioned to forecast the probable impacts from an approaching hurricane on the electric infrastructure at least 72 hours before landfall. By applying *EPfast* to DOE-OE's efforts, it is hoped that government, state, and local agencies that are overseeing emergency planning efforts will be more properly informed of the likely consequences of a large-scale natural event, such as a hurricane.

ACKNOWLEDGMENTS

The authors wish to acknowledge the contributions of the following organizations: Argonne's Decision and Information Sciences Division and Infrastructure Assurance Center for providing technical, financial, and logistical support for the production of this paper. The submitted manuscript has been created by UChicago Argonne, LLC, Operator of Argonne National Laboratory ("Argonne"). Argonne, a U.S. Department of Energy Office of Science laboratory, is operated under Contract No. DE-AC02-06CH11357. The U.S. Government retains for itself, and others acting on its behalf, a paid-up nonexclusive, irrevocable worldwide license in said article to reproduce, prepare derivative works, distribute copies to the public, and perform publicly and display publicly, by or on behalf of the Government.

REFERENCES

Energy Visuals. 2010. "Transmission Atlas." Energy Visuals, Inc.

FERC. 2013. "Form No. 714 – Annual Electric Balancing Authority Area and Planning Area Report." Federal Energy Regulatory Commission. Accessed January 17, 2014. http://www.ferc.gov/docs-filing/forms/form-714/elec-subm-soft.asp.

FERC-NERC. 2012. "Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations." North American Electric Reliability Corporation Accessed January 17, 2014. http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.

IEEE. 2008. "Initial Review of Methods for Cascading Failure Analysis in Electric Power Transmission Systems." Institute of Electrical and Electronic Engineers. Accessed July 7, 2014. http://ieeexplore.ieee.org/xpls/abs_all.jsp?arnumber=4596430&tag=1.

Koc¸ Y., T. Verma, N. A. M. Araujo, and M. Warnier. 2013. "MATCASC: A Tool to Analyze Cascading Line Outages in Power Grids." In *Proceedings of the 2013 IEEE International Workshop on Intelligent Energy Systems*, 143–148.

Platts. 2013. "POWERmap Desktop Mapping Software." Platts, McGraw Hill Financial.

Portante, E. C., B. A. Craig, L. T. Malone, J. Kavicky, S. Cedres, and S. F. Folga. "EPfast: A Model for Simulating Uncontrolled Islanding in Large Power Systems." In *Proceedings of the 2011 Winter Simulation Conference*, edited by S. Jain, R.R. Creasey, J. Himmelspach, K.P. White, and M. Fu, 1763-1774. Piscataway, New Jersey: Institute of Electrical and Electronic Engineers, Inc.

AUTHOR BIOGRAPHIES

EDGAR C. PORTANTE is a principal energy systems engineer at Argonne National Laboratory. His research interests include performance and vulnerability assessments of energy systems, including electric power and natural gas systems. He earned a Masters degree in Electrical and Computer Engineering from the Illinois Institute of Technology, a Master of Management degree from the Asian Institute of Management, and a Master of Science degree in Power Systems Engineering from the University of the Philippines. His e-mail address is ecportante@anl.gov.

STEPHEN M. FOLGA is a Senior Manager at Argonne National Laboratory. He is the manager of the Energy Systems Analysis and Assessment branch of the Infrastructure Assurance Center at Argonne. He earned a Ph.D. in Gas Engineering and a B.S. degree in Chemical Engineering from the Illinois Institute of Technology. His e-mail address is sfolga@anl.gov.

JAMES A. KAVICKY works as an energy systems engineer in Argonne National Laboratory's Infrastructure Analysis and Assessments Group. He has provided his expertise on electric power, natural gas, and other infrastructures for reports for the U.S. Department of Homeland Security, U.S. Department of Defense, and U.S. Department of Energy. He has a Ph.D. in Electrical Engineering (Power Systems) from the Illinois Institute of Technology. His e-mail address is kavicky@anl.gov.

LEAH TALABER MALONE works at Argonne National Laboratory in the Energy Systems Analysis and Assessment branch of the Infrastructure Assurance Center. The core of her work involves geospatial analysis of critical infrastructure in the energy sector. She earned a Master of Urban Planning and Policy from the University of Illinois at Chicago and a B.S. degree in Geography and Geographical Information Sciences (GIS) from Elmhurst College. Her e-mail address is ltalaber@anl.gov.