INTERNATIONAL COMPARISON OF MAJOR BLACKOUTS AND RESTORATION

AEMC Reliability Panel

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PROJECT OVERVIEW

Utility and regulatory structure in the Australian NEM

The Australian Energy Market Commission (AEMC) and the Reliability Panel are part of the utility regulatory structure of the Australian National Electricity Market (NEM). The NEM is a wholesale market for supplying electricity to retailers and end-users in Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania. Operations are based in five interconnected regions that largely follow state boundaries.

The AEMC operates within a broader market governance structure alongside the Australian Energy Market Operator (AEMO) and the Australian Energy Regulator (AER). The AEMC determines the policy environment and governance structures that shape Australia's developing energy markets and sets the operating requirements and obligations of market participants. The AEMO manages the NEM and gas markets.

Among the services the AEMO manages is System Restart Ancillary Services (SRAS). The objective of SRAS is to provide reasonable assurance that the system can be restarted following a regional blackout. The AEMO is to procure the least-cost combination of SRAS submissions that meet the System Restart Standard (SRS).

The SRS is determined by the Reliability Panel to meet the requirements of the National Electricity Rules (NER). Specifically, the SRS identifies the maximum amount of time that SRAS are allowed energize a specified generation level target. The SRS also identifies a number of other parameters, including the strategic, geographic, technology and fuel diversity of SRAS, as well as the principles that AEMO must consider when developing the boundaries of electrical sub-networks.

Developments in 2015 regarding SRAS and black start

In April 2015 the AEMC published a final rule change that amended some of the arrangements in relation to the procurement of SRAS. On 30 June 2015, the AEMC provided Terms of Reference to the Reliability Panel to initiate a review of the SRS. Among other things, this required the Panel to undertake a review of the SRS to meet the requirements revised in July 2015 following a final rule determination made by the AEMC. The Panel is required to complete its Review of the Standard by December 2016.

As part of its response, the AEMC released an Issues Paper in November 2015 describing the issues associated with SRAS. Various stakeholders submitted responses to this issue paper in December.

On 29 January 2016 the AEMC issued a request for proposals (RFP) as one element in the AEMC's and Reliability Panel's response to these requirements. The RFP solicited a consultant to provide an international comparison of major supply disruptions in electricity systems and regulatory arrangements for power system restoration.[1] The RFP requested an international comparison of events where the power system has collapsed to a black system condition—commonly called a blackout.[2]

The AEMC selected DGA Consulting Pty. Limited (DGA) to perform this work.

The AEMC sought as wide a review as possible of different relevant international events and regulatory arrangements. The AEMC requested two main parts of the work:

1. An international comparison of major blackouts; and
2. An international review of regulatory arrangements to prevent or mitigate such outages including restoration.

This report addresses these two main parts in Tasks 1 and 2, below.

The AEMC also elected to have DGA perform an additional task proposed by DGA to describe black-start plans in two islanded systems (Ireland and Hawaii) where large amounts of intermittent generation (wind and solar) are being installed. Initial inquiries revealed that such planning in those jurisdictions was not well advanced and the chapter was adjusted to explore the challenges introduced by, and potential mitigation approaches for, significant levels of intermittent generation.

1. A major supply disruption is as defined in Chapter 10 of the NER—the unplanned absence of voltage on a part of the transmission system affecting one or more power stations and which leads to a loss of supply to one or more loads.

2. Black system is defined in Chapter 10 of the NER—the absence of voltage on all or a significant part of the transmission system or within a region during a major supply disruption affecting a significant number of customers' electricity supply disruption event.

TASK 1—INTERNATIONAL COMPARISON OF MAJOR BLACKOUTS

The process and experience of restoring the system after a blackout is an important element of the required work. While there are usually published reports and other information regarding the causes of specific blackouts, there is usually little published information about restoration. In the report, we have relied, in part, on information provided informally by various utility experts in the affected jurisdictions.

Context for comparison

The AEMC is interested in comparing international practices related to blackouts and black-start generation. Some of the issues that the AEMC is interested in comparing include the causes of the blackouts, how well black-start units performed, the timing of restoration steps, how interconnections were used in restoration, how quickly service was restored, and problems that occurred during restoration.

Regarding timing of restoration, the common understanding in the NEM is a three-stage process as depicted in Figure 1.

- Stage 1—the AEMO initially assesses events and system conditions. The focus is on restoring generation and transmission networks to supply auxiliaries of generating units from SRAS by energizing a limited transmission network. Distribution Network System Providers (DNSPs) reconnect load as directed by Transmission System Network Providers (TNSPs) and the AEMO to stabilize the system. (Restoration may include limited supply to sensitive loads where practical).
- Stage 2—the majority of the transmission network is energized and available/required generating units are started. The focus is on restoring the transmission network and ramping up generation. DNSPs progressively reconnect load under direction from TNSPs, mainly to stabilize the system, giving priority to sensitive loads where practical.
- Stage 3—the distribution networks energize and distributed generation progressively restarts. Remaining distribution loads are progressively restored. The end of Stage 3 restores normal operation. (Any network damage or repairs required may delay restoration of some loads.)

Figure 1: Three stages of restoration used by NEM

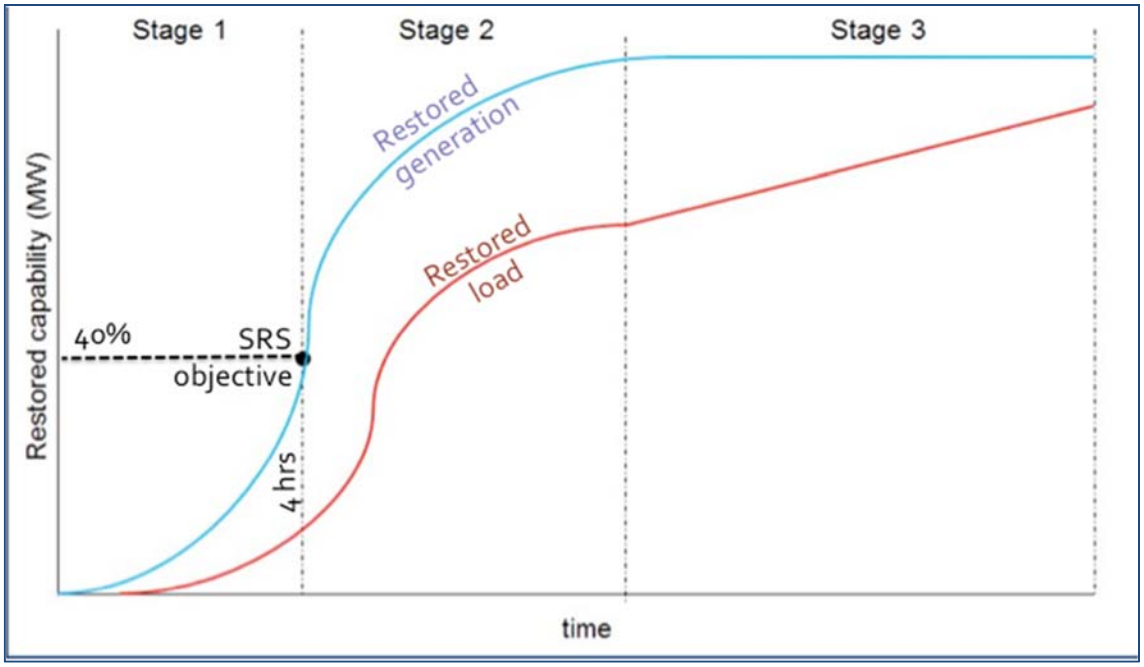

Figure 1 shows the object of the present SRS is to restore generation such that 40% of the demand could be supplied within 4 hours.

International comparison

This chapter describes five major international blackouts as requested in the AEMC's RFP. Fortunately, major blackouts are infrequent, however, this means there are only a limited set of events to choose from. These blackouts were selected in consultation with the AEMC from a list of suggestions by DGA. The five selected were:

- 2003 Eastern USA;
- 2013 Sarawak, Malaysia;
- 2008 Oahu, Hawaii;
- 2003 Italy; and
- 2011 San Diego, California.

The AEMC included specific items to describe each blackout in their RFP. Each of these is summarized in Table 1, below. In addition, report sections below describe these events in greater detail.

Table 1: International comparison of major supply disruptions

Characteristic		Event				
		2003 Eastern US	2013 Sarawak	2008 Oahu, Hawaii	2003 Italy	2011 San Diego
General description		Major regional outage (see page 8)	Total system outage (see page 23)	Total island outage (see page 26)	National outage (see page 30)	Regional blackout (see page 41)
Time from the initial system collapse to restoring normal operations	NEM Stage 1	6 hours*	3 hours	5 hours	3 hours[‡]	N.A.
	NEM Stage 2	10 hours[Δ]	4 hours	9 hours	4½ hours[‡]	4-6 hours*
	NEM Stage 3	2 days for most 4 days for a few	8½ hours	96% in 18 hours	99% in 15 hours	12 hours
Time for restart services to come online to begin system restoration		Less than 30 minutes for hydro and pumped hydro	30 minutes	Less than 30 minutes	30 minutes[‡]	Only interconnections were used
The physical extent of the event (capacity or lost energy, etc.)		61,800 MW	1,600 MW	1,000 MW	35,000 MW	8,000 MW
Human errors, if any, that triggered or helped propagate the event		Situation awareness	Switching error	None	Situation awareness	None
Protection equipment failures, if any, that triggered or helped propagate the event		Software in EMS	Errors at Bakun dam	None	Multiple	None
The contribution of specific load or generation types to the triggering of, or restoring power following the event		None	None	None	None	None
Any unusual power system frequency, voltage or stability issues that contributed to the triggering or propagation of the event		Northern Ohio had barely enough reactive reserves	Synchronizing 100 km 275 kV lines at Bakun	Loss of generation saw frequency fall 47 Hz (60 Hz normal)	Frequency dropped to 47 Hz when inter-connections tripped	None

* Estimated
Δ The blackout was so extensive that some parts of the transmission system took longer to restore.
‡ The Italian peninsula is very long, so the times are for the main northern portion of system.

Characteristic	Event				
	2003 Eastern US	2013 Sarawak	2008 Oahu, Hawaii	2003 Italy	2011 San Diego
Any natural phenomena that contributed to the cause and impact of the major supply disruption event, such as weather or seismic conditions	None	None	Lightning storm	None	None
The readiness of generation and supply equipment and the linkages with restoration time	Some non-black-start generation had problems	Normal	Normal	Normal, but only 8 of 31 TTHL units operated	Normal
The readiness of network assets and the linkages to restoration time	Mostly normal, with some damage in this extensive blackout	Normal	Normal	Normal	Normal
Any equipment damage and the extent to which this affected the restoration	None	None	A critical 138 kV line had physical damage	None	None
The extent to which power system topology contributed to the propagation or containment of the event, and the subsequent restoration of the power system	Natural break points limited propagation Also, some pockets remained with power	The 100 km 275 kV line to Bakun were a problem restoring	None	Italy is very long peninsula, it was hard to energize Sicily	There are only two major transmission paths
Whether designated restart services were the only source of restoration, or whether supply from neighboring power systems was utilized to assist in the restoration process	Interconnections were an important part of restoration	No interconnections	No interconnections	Interconnections were critical in restoration	The system was re-energized solely from the interconnections—no black-start was used
Did the system restart plan operate as expected, in relation to timeframes and the energizing process?	There were problems across the areas blacked out	Yes, except for switching problems at Bakun	Several failed restarts between hours 3 to 5	Yes	Yes, but there was a 30-minute “discussion” between TO's about transmission during re-energizing

Characteristic	Event				
	2003 Eastern US	2013 Sarawak	2008 Oahu, Hawaii	2003 Italy	2011 San Diego
Any particular element of the restart process that presented specific hurdles in system restoration (resources, generation, transmission, distribution, load switching, etc.)	The widespread nature made situation awareness a challenge	Switching errors at Bakun substation	None	Controlling voltages	None
The economic cost of the event, such as value of lost load or impacts on gross domestic/national product	6 to 10 billion USD			150 million USD	120 million USD
Any social impact attributable to the event	There was major economic and social disruption	Chaos during rush hour in Kuching, the capital	International embarrassment	Occurred in early in morning during holiday festivities	Occurred in early afternoon just before rush hour
The cost of the restart services called upon to restore the system following the event	None	None	None	None	None
Any key lessons learned or recommenda-tions arising from investigations of the event undertaken by affected parties or third, parties including whether the event was caused by an expected or unexpected sequence of events	See text beginning at page 22	Keep personnel current with black-start training	Nothing special	Coordinate UFLS generation trip settings	Nothing special

Summary

Some of the highlights from Table 1 are briefly discussed here with additional details provided in the sections below.

For each of the outages studied, the restoration times comparable to NEM stage 1 were 3-6 hours and roughly consistent with the SRS. Most generation was energized (NEM stage 2) in 4-6 hours. The notable exception is the 2003 US blackout. And, all customer load was restored (NEM stage 3) in 12-16 hours, again with the US exception.

The social impact varied somewhat among the blackouts. Hawaii was embarrassed because President Obama and his family were there—along with the international press corps. The US blackout affected a large portion of the country for several days and had a major economic impact. In contrast, the Italian blackout occurred during the evening of a national holiday when economic activity was low with shops and businesses closed for the day.

The estimated cost of the blackouts ranged from USD 6-10 billion to 120 million. The approximate USD cost per MWh were 7,500 (US 2003), 2,500 (San Diego), and 900 (Italy 2003).

Black-start generators performed as expected by energizing in about 30 minutes. The trip-to-house-load generation (TTHL) in Italy performed poorly with only 8 of 31 units starting. (The Italian system operator has since instituted a rigorous testing regime for these units.)

All the system operators used their interconnections very early in restoring their systems, and San Diego restarted without activating any of its black-start resources.

All the systems had some electrical islands remain in service throughout the blackout. And, in all cases except Hawaii, the transmission system was intact following the initial event.

2003 Eastern US

At 16:10 on 14 August 2003 one of the world's worst blackouts occurred in the eastern US. The outage affected an estimated 50 million people and 61,800 megawatts (MW) of electric load in the states of Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey and the Canadian province of Ontario. Power was not restored for 4 days in some parts of the United States. Parts of Ontario suffered rolling blackouts for more than a week before power was fully restored. Estimates of total costs in the United

States range between $4 billion and $10 billion (USD).[3] In Canada, the national gross domestic product was down 0.7% in August, there was a net loss of 18.9 million work hours and manufacturing shipments in Ontario were down $2.3 billion (CDN).[4]

The cascading blackout began in Ohio, spread eastward, and caused such widespread outages for three principal reasons:

1. The loss of a key 345 kV line in Ohio, following the loss of other transmission lines and weak voltages within Ohio that triggered many subsequent line trips.
2. Many of the key lines which tripped between 16:05 and 16:10, operated on zone 3 impedance relays (or zone 2 set to operate like zone 3) that responded to overloads rather than true faults on the grid.[5] The speed at which they tripped spread the reach and accelerated the spread of the cascade beyond the northern Ohio area.
3. Relay protection settings for the transmission lines, generators and under-frequency load-shedding in the northeast US were not entirely appropriate and were certainly not coordinated and integrated to reduce the likelihood and consequences of a cascade.

Compared with other blackouts new causal features of the August 14 blackout include: inadequate interregional visibility over the power system; dysfunction of a control area's SCADA/EMS system; and lack of adequate backup capability to that system.

This blackout also occurred before various regional control and monitoring systems were fully operational at the Midwest Independent System Operator (MISO).

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3. ICF Consulting ICF (a US consulting firm) estimated the costs to be between $6.8 and $10.3 billion, *The Economic Cost of the Blackout, An issue paper on the Northeastern Blackout, August 14, 2003*, undated. Anderson Economics Group estimated $4.5 to $8.3 billion, *Preliminary Estimate: Economic Impact of a 1-to-3 day Blackout In Northeast U.S., August 2003*, undated

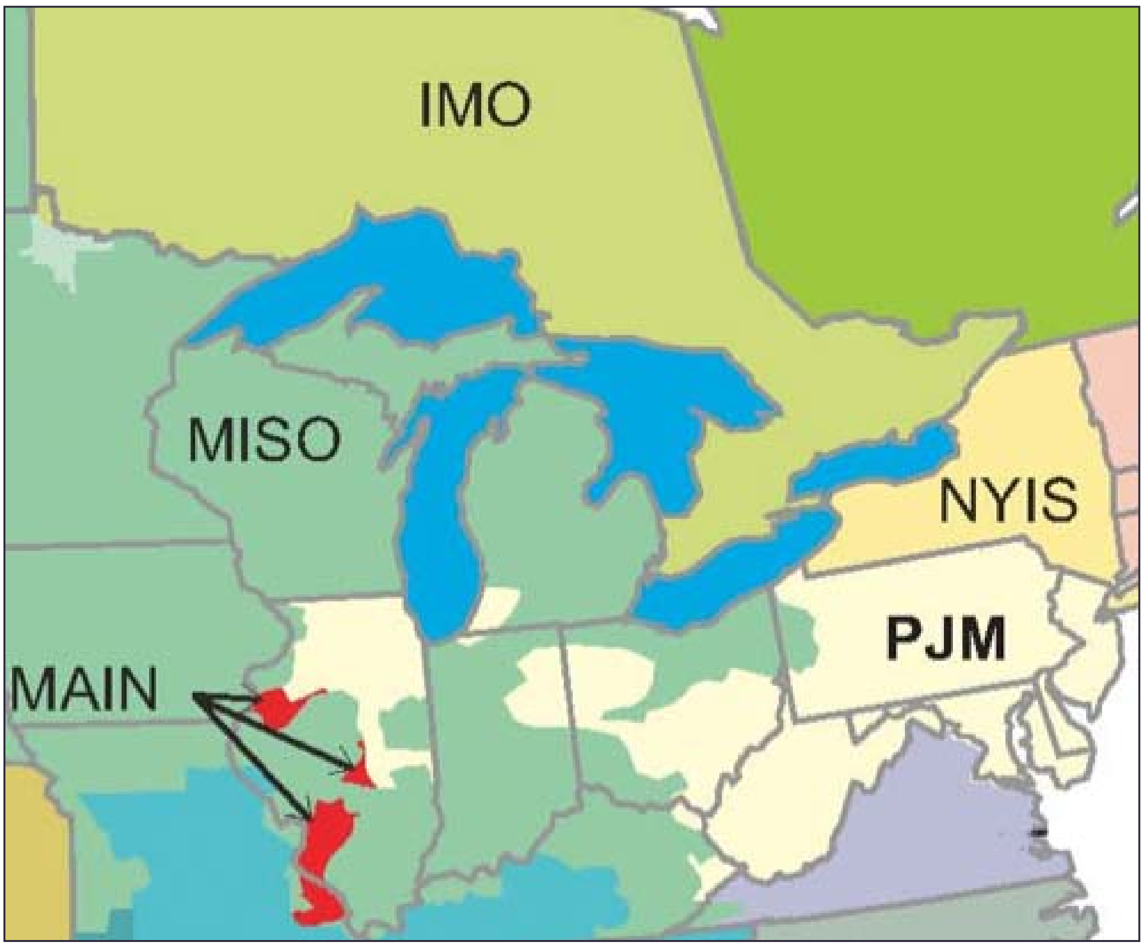
4. Statistics Canada, *Gross Domestic Product by Industry*, August 2003, Catalogue No. 15-001; *September 2003 Labour Force Survey; Monthly Survey of Manufacturing*, August 2003, Catalogue No. 31-001.

5. Relays are commonly set for zones. Zone 1 monitors the immediate equipment and will operate quickly—usually in a few cycles. Zone 2 relays monitor farther, usually as a backup for relays at he other end of the line, they operate more slowly than zone 1. Zone 3 monitors even farther and operates more slowly than zone 2, this are the last hope to interrupt a fault if both zones 1 and 2 fail.

The situation before the blackout

The general area affected by the August 2003 blackout is shown in Figure 2. The Reliability Coordinators involved were the MISO, the Ontario Independent Market Operator (IMO), the New York Independent System Operator (NYISO), and the PJM Interconnection (PJM). Reliability Coordinators provide reliability oversight over a wide region, they prepare reliability assessments, provide a wide-area view of reliability, and coordinate emergency operations in real time for one or more control areas. They may operate, but do not participate in, wholesale or retail market functions.

Figure 2: Reliability Coordinators in the affected area



The general conditions on the regional systems were fairly normal for a summer day:[6]

- Loads were high, but below peak summer conditions—about 90% of previous peak loads;
- Inter-regional transfers were high, but with the normal range;
- Voltages were within acceptable limits, with operators acting to boost voltages as is normal during a summer afternoon;
- Frequency was typical for a summer afternoon;
- All system elements were within normal and contingency limits; and
- Temperatures were warm, but generally about 5º C below August high temperatures.

There were a handful of generators on planned maintenance, however, in a regional system with an expected load of about 300,000 MW, this is normal.

The blackout

There were four stages of the blackout's initiating sequence:

1. A normal afternoon degrades;
2. The northern Ohio system operator's computer failures;
3. Three Ohio 345 kV transmission line failures and many phone calls; and
4. The collapse of the northern Ohio 138 kV system and the loss of a key 345 kV line.

Beginning at 12:15, inaccurate input data rendered MISO's state estimator (a system monitoring tool) ineffective. About 13:30 a 612 MW generation unit in northern Ohio tripped (Eastlake 5) and shut down automatically.[7] Losing this unit did not put the grid into an unreliable state, however.

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6. Much of this section of this report is based on U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, 5 April 2004.

7. Eastlake 5 tripped off-line as the operator sought to increase the unit's reactive power output, the unit's protection system detected that var output exceeded the unit's var capability and tripped the unit off-line. The loss of the Eastlake 5 unit did not put the grid into an unreliable state—i.e., the system was still able to safely withstand another contingency. However, losing the unit required northern Ohio to import additional power to make up for the loss of the unit's output (612 MW), made voltage management in northern Ohio more challenging, and gave system operators less flexibility in operating their system.

The initial events

Shortly after 14:14, the alarm and logging system in the northern Ohio system operator's control room failed and was not restored until after the blackout. After 15:05, some 345-kV transmission lines in central Ohio began tripping out because the lines were contacting overgrown trees within the lines' right-of-way areas.

About 15:46 when the local system operator and MISO and neighboring utilities had begun to realize that the northern Ohio system was in jeopardy, the only way that the blackout might have been averted would have been to drop at least 1,500 MW of load around Cleveland and Akron. No such effort was made, however, and by 15:46 it may already have been too late for a large load-shed to make any difference.

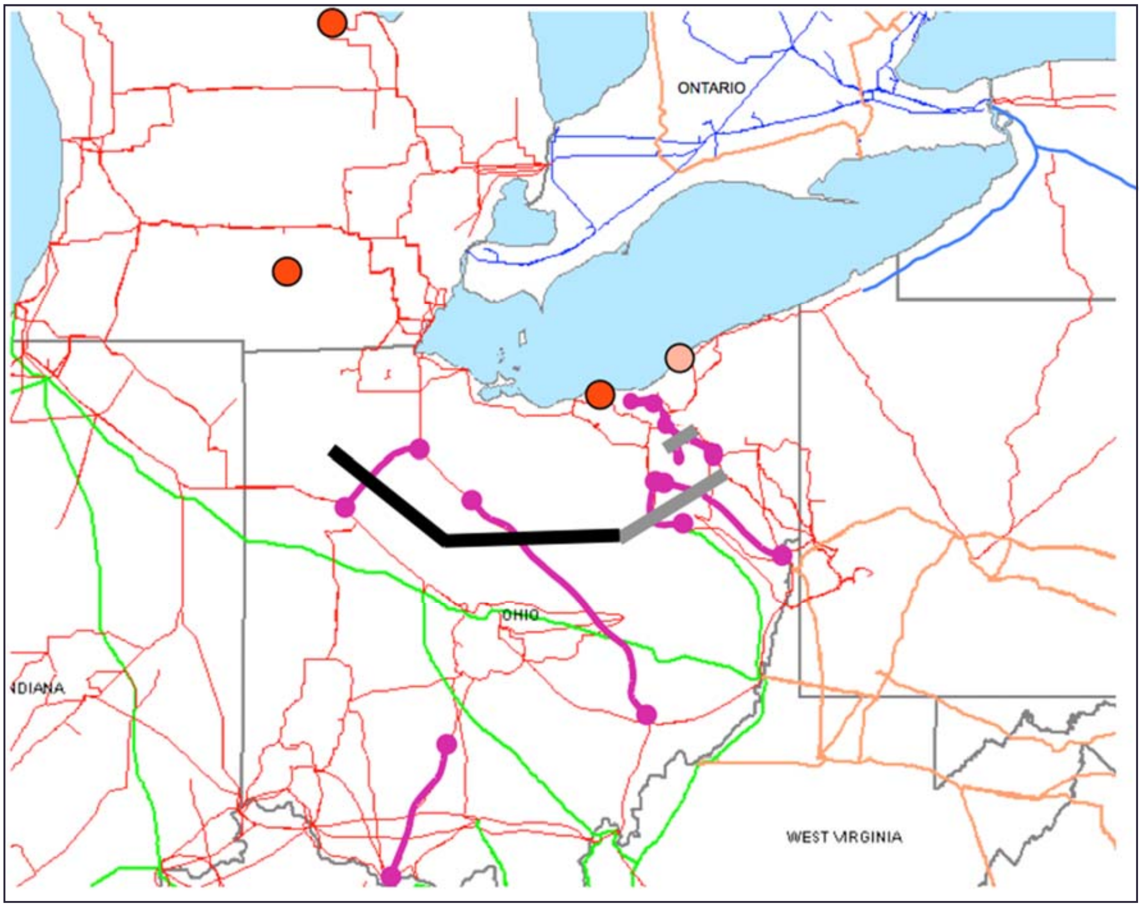
Northern Ohio separates

After 15:46, losing some key 345 kV lines in northern Ohio caused the underlying network of 138-kV lines to overload and trip, leading in turn to the loss of a critical 345 kV line at 16:06—the event that triggered the initial uncontrollable 345 kV cascade portion of the blackout sequence. The loss of this 345 kV line shut down the 345-kV path into northern Ohio from eastern Ohio. Although the area around Akron (northwest Ohio) was already blacked out due to earlier events, most of northern Ohio remained interconnected. The loss of this heavily overloaded key 345 kV line instantly created major and unsustainable loading on lines in adjacent areas, and the cascade spread rapidly as lines and generating units automatically tripped by protective relay action to avoid physical damage.

The situation at 16:10:27 is shown in Figure 3 with Ohio in the center, Michigan and Ontario to the north, and Pennsylvania and New York to the east.[8] The heavy line shows the interface where lines have tripped. As can be seen, northern and southern Ohio are no longer interconnected.

8. **Figure 3**, **Figure 4**, **Figure 5** and **Figure 6** are taken from the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, 5 April 2004

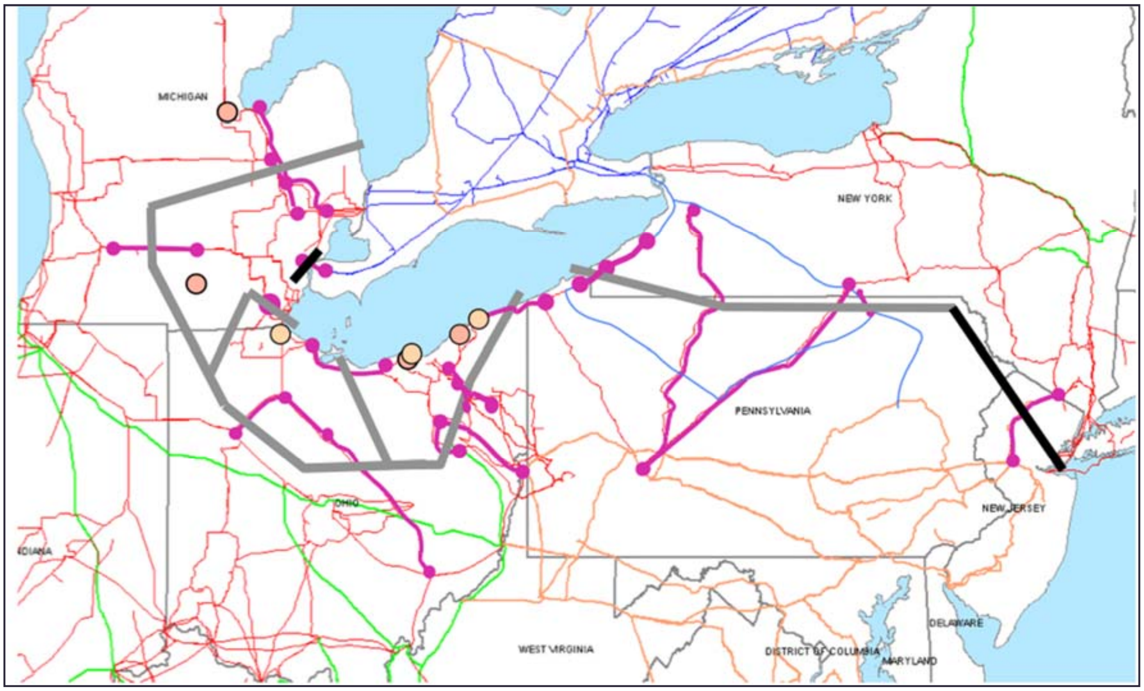
Figure 3: Situation at 16:10:27 emphasizing separation border



The separations rapidly spread

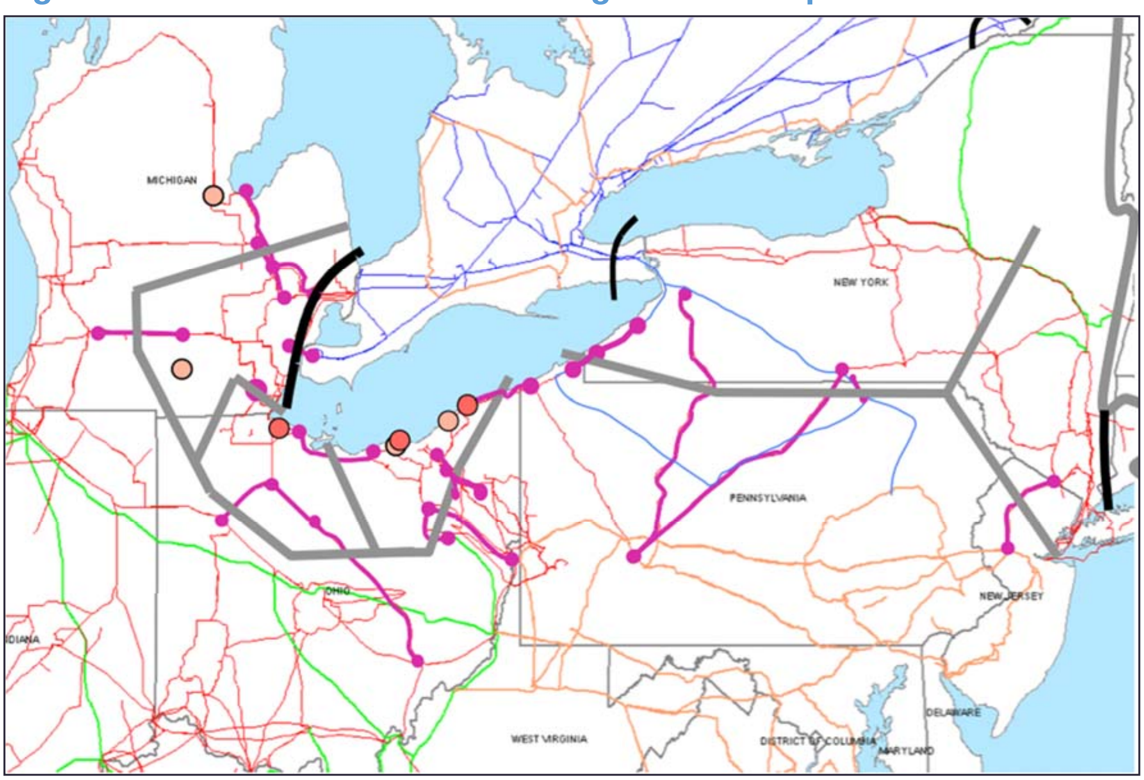
During the next 18 seconds numerous automatic protection devices operated. The situation at 16:10:45 (Figure 4) shows how the separation area expanded to include northern Ohio, southeastern Michigan, Ontario, and New York.

Figure 4: Situation at 16:10:45 emphasizing separation border



Less than three minutes later the blackout was complete as shown in Figure 5.

Figure 5: Situation at 16:13 showing the final separated area

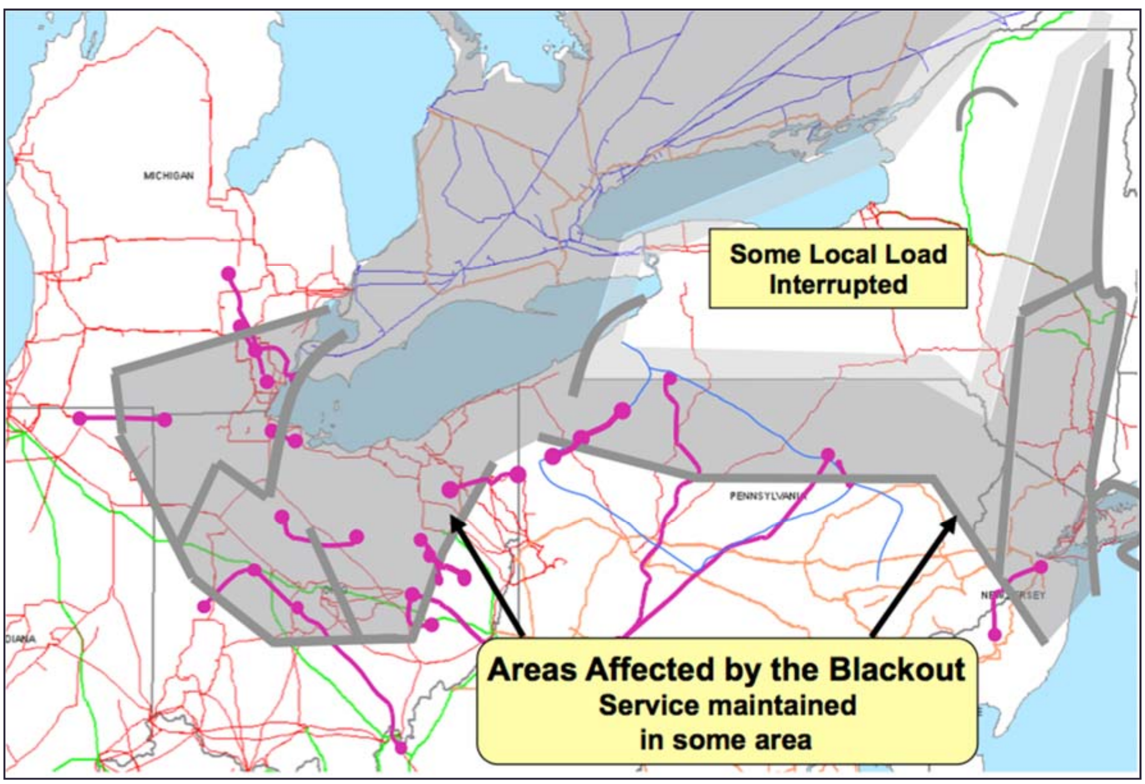


The cascade became a race between the power surges and the relays. The lines that tripped first were generally the longer lines with relay settings using longer apparent impedance tripping zones and normal time settings. Lines in Pennsylvania, that are not highly integrated into the electrical network, tripped quickly and split the grid between the sections that blacked out and those that recovered without further propagating the cascade.

The vast majority of trip operations on lines along the blackout boundaries between Pennsylvania and New York (for instance) showed high-speed relay targets that indicate that a massive power surge caused each line to trip. To the relays, this power surge altered the voltages and currents enough that they appeared to be faults. The power surge was caused by power flowing to those areas that were generation-deficient (northern Ohio and southeastern Michigan) or rebounding back. These flows occurred purely because of the physics of power flows—power flows from areas with excess generation flowing into areas that are generation-deficient.

Figure 6 shows the area affected by the blackout. Portions of Ohio, Michigan, Ontario and New York lost power.

Figure 6: The area that was ultimately blacked-out



Restoration

As might be expected, there was a certain amount of chaos following such a huge blackout. Once the extent of the area was recognized, restoration proceeded in a reasonably orderly way. With such a large affected area and so much equipment involved, however, there were numerous setbacks and equipment misopertion, usually related to high voltages when transmission circuits were energized before there was either sufficient load or generation connected.

It should be noted that there were small pockets of the system within the affected area that remained with power. These were areas where transmission tripping and other actions left them with generation and load in approximate balance.

By the first evening (August 14), power had been restored to:

- Albany, New York, and its surroundings;
- New London County, Connecticut;
- Parry Sound, Ontario
- Many areas of the Niagara Region in Ontario;
- Areas of Ontario near Niagara Falls (supplied from the city of Niagara Falls, Ontario, which never lost power);
- Parts of Southwestern Ontario, particularly areas near the Bruce Nuclear Power Plant, lost power for only 4–8 hours;
- Parts of downtown Toronto, Mississauga, London, Ontario, Cornwall and Pembroke;
- Portions of western Ottawa including Kanata and south to Kingston;
- Three-quarters of the millions of customers who had lost power in New Jersey; and
- Parts of Pennsylvania, Ohio, Michigan, and Long Island.

That night some areas of Manhattan regained power at approximately 05:00 (August 15), the New York City borough of Staten Island regained power around 03:00 on August 15, and the Niagara Falls area at 08:00.

By early evening of August 15, two airports, Cleveland Hopkins International Airport and Toronto Pearson International Airport, were back in service.

Half of the affected part of Ontario had power by the morning of August 15, though even in areas where it had come back online, some services were still disrupted or running at lower levels. The last areas to regain power were usually suffering from trouble at local electrical substations not directly related to the blackout itself.

By August 16, power was fully restored in New York and Toronto. Toronto's subway and streetcars (trams) remained out of service until August 18 to prevent the possibility of equipment being stuck in awkward locations if the power was interrupted again. Power had been mostly restored in Ottawa, though authorities warned of possible additional disruptions and advised conservation while restoring power continued for other areas. Ontarians were asked to reduce their electricity use by 50% until all generating stations could be brought back on line. Four generating stations remained out of service on the 19th. Illuminated billboards were largely dormant for the week following the blackout, and many stores had only a portion of their lights on.

New York

The NYISO Restoration Plan relies on black start facilities at three locations in the state to energize the basic minimum power system.[9] Two of these locations, the Niagara and St. Lawrence hydro generation facilities, remained in service following the event.

At 16:27, the NYISO instructed New York utilities to begin black-start procedures. One of them (NYPA) began black-start procedures at a key pumped-storage generator by "stripping" the north and south 345kV buses. These procedures had been thoroughly reviewed in simulated drills as recently as June. Implementing them provided a more certain set of initial conditions from which to begin restoration of critical 345kV facilities, which had been lost along the Hudson Valley. The only complication encountered during this sequence was an inability to synch the two black-start units onto a 345kV line. This line could not be closed at the plant due to the large voltage disparity between the plant bus and the 345 kV bus. System voltages were further stabilized when another 345 kV line was restored at 19:05. Subsequently, all the connected 345 kV lines were restored in the next 15 minutes.

One of the NYISO's first objectives was to resynchronize the New York transmission system with the PJM 500 kV interconnection in Pennsylvania, to restore normal frequency control to

9. This New York section is based on material in the NYISO's *Final Report: On the August 14, 2003 Blackout*, February 2005.

the Western New York Island. Initial synchronization occurred at 18:52 when the NYISO was able to coordinate the balance of generation and load levels at the required frequency for the sync–check relay to operate and parallel the two systems.

The NYISO also directed Con Edison (New York City) personnel to manually close into the PJM 500 kV grid via synchroscope operation at 19:06. Ultimately a second New Jersey tie was restored at 19:08 providing a more secure interconnection with the PJM 500 kV and 345 kV transmission systems. Following these events, the frequency control in the Western New York Island returned to near normal.

In preparing to synchronize with ISO-NE, voltages were stabilized in the eastern area of New York. After successfully reclosing with PJM, system frequency in New York stabilized. The effort was then to strengthen the New York system to provide more stable voltages to tie into ISO-NE. This was accomplished while restoring lines into the Con Edison area.

The NYISO and ISO-NE operators coordinated the required actions with their associated TOs. ISO-NE used a pumped-storage hydro facility near the New York border to synchronize using a synchroscope. The connection was made at 01:53 on August 15th.

Throughout this event, load and generation balance was essential. The NYISO operators instructed all TOs to notify the NYISO of all load restorations and generator availability. The TOs were instructed to match load with generation as it became available. Voltage control was also an important consideration. In some cases, load was restored from generation, in other parts of New York load was restored to control high voltages during line restoration. This process of coordination was very successful due to the repeated training for this type of event and the excellent communications between the NYISO and the Transmission Owner operators.

By 06:00 on August 15th, 56% of the load had been restored in New York. At 7:35 the NYISO activated various energy and load management programs and also requested the public to voluntarily curtail electric use and announced temporary waivers of air emissions limitations. The NYISO was preparing for the morning load to begin picking up. At 08:00, in a conference call, the NYISO notified TOs that load shedding might be required due to the morning load pickup. The group agreed that the existing load-shed allocation process would be modified and that the load shed allocations would be calculated based on the percentage of the current TO load to the total New York load at that time.

Michigan

In Michigan there were two major utilities affected by the blackout—Consumers Energy and Detroit Edison.[10] Detroit Edison serves Detroit and the surrounding area in southeastern Michigan. Consumers Energy serves areas to the west of Detroit Edison. (Detroit Edison was hit much harder by the blackout than Consumers Energy.) The transmission system is owned and operated by two independent companies—the Michigan Electric Transmission Company (METC) for the transmission system formerly owned by Consumers Energy and the International Transmission Company (ITC) for the transmission system formerly owned by Detroit Edison.

MISO was also involved—the regional transmission organization covering all or parts of Indiana, Illinois, Iowa, Kansas, Kentucky, Manitoba, Michigan, Minnesota, Montana, North Dakota, Ohio, Pennsylvania, South Dakota, and Wisconsin. (See Figure 2 on page 10, above.)

Consumers Energy

Restoration efforts began immediately following the event. Local headquarters in the affected areas were instructed to remain open. A conference call was established at 17:15 to determine initial actions. Subsequent calls were held every two to three hours thereafter. Independent calls were also held with METC on a similar schedule.

On the Consumers Energy/METC system there were significant generator outages, numerous line outages. There were two major areas without power, the Lansing area and the southeast corner of Consumers Energy's service territory.

Immediately following the event, Consumers Energy started generation in response to the loss of units. Consumers Energy believed at that time it was under-generating, but interconnection frequency continued to be above 60 Hertz, which would generally be an indication of over-generation. In consultation with transmission operators, Consumers Energy maintained its generation level until the status of the system, both in Michigan and in neighboring areas, could be assessed. Between 17:00 and 19:00 power output from the Ludington Pumped-Storage facility was reduced in order to moderate high frequency levels and manage available stored water for later restoration needs of Detroit Edison. Consumers

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10. This Michigan section is based on Michigan Public Service Commission's *Report on August 14th Blackout*, November 2003.

Energy also obtained additional supplies of electricity from in-state independent power producers and the major utility to its south, American Electric Power (AEP).

Restoration efforts followed black-start procedures; beginning by assessing the 138 kV and 46 kV breakers that were open. The open breakers were plotted on a geographic map of the electric system in order to determine the boundaries of the affected areas. System Control Centers then began the process of opening up all breakers contained within the affected area via supervisory control and data acquisition (SCADA) and field personnel.

The return of generation at the Whiting facility (a 328 MW coal plant built in 1952 that also has a 15 MW simple-cycle combustion turbine) and restarting generators at Kinder Morgan power plant (a 540 MW gas-fueled combined-cycle plant built in 2002) were a top priority. These units provide both local power supply and area voltage support. Nearly all the 138 kV system was restored by 19:25. During restoration of the 138 kV system some 46 kV and 138 kV connected load was also restored.

As generation, particularly the Kinder Morgan power plant, began ramping toward full output, the 46 kV system was restored in the affected area. By 22:05 all 46 kV lines had been energized and all load was returned to service.

According to Consumers Energy's Outage Management System, up to 118,400 customers were out of service during the 16:00 through 22:00 on August 14th.

At 22:30 an important 138 kV Line tripped and did not re-close due to loss of substation power. This resulted in large flows on the remaining two critical 138 kV lines, causing them to open at their source ends. The system within the subject geographic area was then in nearly the same state as it was following the primary 16:09 outage.

The 138 kV system was restored again by 00:55 and the 46 kV system along with all of the connected customers was restored by 01:35.

Consumers Energy personnel handled several reliability concerns over the next two days. These included problems in adhering to the derated capability of the critical 345 kV line, the clearance status of 138 kV lines located within the affected area, and large power flows between the METC and ITC systems. In addition, continued hot weather, unit outages caused by the event, and uncertain power availability to supplement Consumers Energy's own internal generation led to a forecast of a deficiency in Consumers Energy's operating reserve.

The final concern was possible separation between the Consumers Energy/METC and the Detroit Edison/ITC systems due to any one of three single-contingencies involving tie lines between the two systems on 16 August. With Detroit Edison being generation deficient, it was dependent upon the Consumers Energy/METC system interface for power supply. With power flows between the two systems reaching the 3,000 MW range, analysis indicated a single contingency would load other ties above emergency capabilities. This could start a cascading outage resulting in separation. A number of options were implemented to prevent this from occurring including patrols of the tie lines identified by the analysis.

Detroit Edison

The Detroit Edison service territory-wide outage invoked the utility's black start procedures. These procedures were initially developed after the 1965 outage. They directed all the available field operations staff to the proper locations to support the restoration effort. (Consumers Energy also had similar procedures from that time.) Given the telecommunication and traffic issues that occurred immediately after the incident, these procedures saved valuable time restoring the system.

The conventional mobile and landline phone systems are not designed for emergencies. The volume of calls overloads the systems and it is often impossible to even get a dial tone to make a call. Similarly, after such an event, once people realize the situation they take to their automobiles all at once and traffic quickly comes to a stop. Having personnel know where to position themselves before traffic snarls, allows them to be in-place when needed as part of the restoration process. This is not a situation unique to Detroit; it common in any urban area when a blackout occurs.

Detroit Edison faced the difficult prospect of restarting its entire generation fleet. Basically, they lost all their generation—about 9,500 MW. This included about 7,500 MW in coal plants built between 1949 and 1985, a 780 MW gas-fueled plant from 1979, and a 1,130 MW nuclear unit (1988). One of the coal units tripped to house load and was restored within a few hours. A 330 MW (four gas turbines) independent power producer was returned to service at 20:15. A large gas unit and another coal unit were restored by midday the next day. Detroit Edison personnel also resolved issues at various peaking facilities to provide 950 MW of additional capacity on August 15.[11]

11. Additional details can be found in Chart 3.8 of the Michigan PUC blackout report.

The other Detroit Edison generation took longer.

All the units were inspected following the outage and four units had ruptured discs that were replaced. The smaller coal units were restored beginning as early as 03:30 on August 15th. By the afternoon of the 15th, seven of these units, totaling 1,420 MW, were back in service. The remaining units were restored by the afternoon of August 19th—four days after the blackout.

In addition to Detroit Edison's generation, purchases from outside the service territory in coordination with independent power producers were crucial to timely restoration.

Lessons learned

The North American Electric Reliability Corporation (NERC) Steering Group recommended three categories to address the shortcomings identified in the investigation:

1. Actions to remedy specific deficiencies: specific actions directed to First Energy, MISO, and PJM to correct the deficiencies that led to the blackout.
2. Strategic initiatives by NERC and the regional reliability councils to strengthen compliance with existing standards and to formally track completion of recommended actions from August 14, and other significant power system events:
    a. Strengthen the NERC Compliance Enforcement Program;
    b. Initiate control area and reliability coordinator reliability readiness audits;
    c. Evaluate vegetation management procedures and results; and
    d. Establish a program to track implementation of recommendations.
3. Technical initiatives to prevent or mitigate the impacts of future cascading blackouts:
    a. Improve operator and reliability coordinator training;
    b. Evaluate reactive power and voltage control practices;
    c. Improve system protection to slow or limit the spread of future Cascading Outages;
    d. Clarify reliability coordinator and control area functions, responsibilities, capabilities and authorities;
    e. Establish guidelines for real-time operating tools;

f. Evaluate lessons learned during system restoration;

g. Install additional time-synchronized recording devices as needed;

h. Reevaluate system design, planning and operating criteria; and

i. Improve system modeling data and data exchange practices.

2013 Sarawak

On 27 June 2013 the Malaysian State of Sarawak suffered a total grid failure resulting in a statewide blackout.[12] At 17:36 the system frequency started to decay, falling below 47 Hz within 10 seconds, followed by cascading tripping of generation and transmission within the Sarawak power grid.

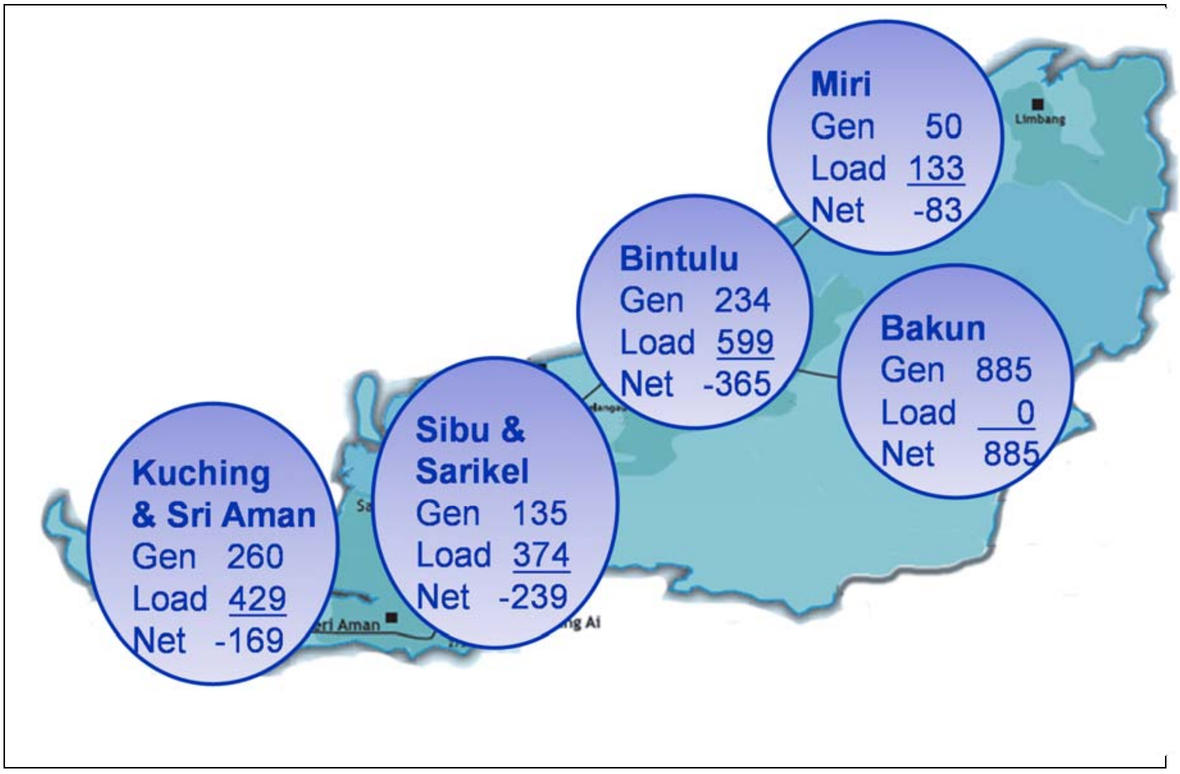
The situation before the blackout

It was a fairly typical summer afternoon. Before the blackout system load was about 1,555 MW with 2,034 MW of generation operating in the system. This is a little less than 90% of the most-recent twelve-month peak load. System frequency was 50 Hz (normal). Most of the generation (57%) was at a relatively new hydroelectric plant—Bakun.

The load and generation balance of the five regions in Sarawak just before the blackout are shown in Figure 7. The figure shows that four areas are importing power, with Bakun exporting. All five areas had some local generation operating. These load and generation balances were important regarding load shedding and forming electrical islands.

12. Much of this section is based on *27 June 2013 Sarawak Blackout DNV KEMA Independent Review*, Ministry of Public Utilities Sarawak, Final report, Prepared by KEMA, Inc., 6 October 2013.

Figure 7: Regional load and generation just before blackout



The blackout

At 17:36 Generation at the Bakun, which was delivering 885 MW to the system, dropped its output by 662 MW in about 10 seconds causing system frequency to drop below 47.5 Hz. To protect all the other generators in the system from damage, safety tripping was automatically activated, resulting in the shutdown of most other power stations in the grid.

The under-frequency load shedding system activated, shedding about 500 MW of load in five steps. Frequency continued to decline, however, and the system went black 14 seconds after the initial event began.

The initiating event was the sudden ramp-down of generation at Bakun dam. It appeared that someone inside the plant accessed the power plant control system and inadvertently initiated the shutdown. Normally, the controls are connected only to a special local computer communication network. On the day of the blackout, the three units that ramped-down were also connected to the normal internal office computer network. It appears that someone at the plant inadvertently instructed the three units to ramp down. There is no evidence that this was any kind of cyber attack.

Restoration

Restoring the Sarawak system load took more than six hours following the blackout. Nearly half of this time—almost three hours—was due to operator errors and equipment malfunctions at Bakun during restoration.

There were also some difficulties at the Bintulu power plant that delayed restoring local loads in the Bintulu area. While three units were operating immediately after the blackout, the other Bintulu units could not be restarted without external power.

Sarawak restoration plans are designed to guide individual generating plant operators and the system operator in quickly restoring the system. Each of these has a plan with specific steps for restoration.

Briefly, Sarawak's overall black-start restoration plan includes:

1. Determine the post-blackout system and equipment status;
2. Communicate with relevant parties;
3. Mobilize personnel;
4. Prepare generating plants and the grid system for systematic restoration;
5. Re-energize electric islands;
6. Re-synchronize the electric islands to restore the interconnected grid system; and
7. Confirm that the system is back to normal and all loads are energized.

Once the generating units are started at a low level, they are ready for step 5. Closing distribution feeder circuit breakers connects customer load. In this way each generator increases it output by serving load in its geographic area. These are the "electric islands" as the local generation and load is not connected to generators in other areas.

In Sarawak, the plan is to form three electric islands:

1. Kuching/Sibu-Sarikel;
2. Bintulu local; and
3. Bakun to Miri 275 kV.

After the electrical islands are running at a reasonable level, they are ready to start interconnecting with the transmission network and the other islands. This is step 6, above.

During the 27 June blackout event, the Sibu-Sarikel electric island formed (almost exactly as planned), but not the Bintulu or Bakun/Miri electric islands. Kuching has a gas/diesel power plant and Batang AI is a hydroelectric plant. These were both connected to the system, restoring load in the Kuching area within about 30 minutes of the blackout.

Following the blackout, three gas-fuelled gas turbine units at Bintulu remained operating at full speed with no load. The other five units tripped off. About 45 minutes after the blackout (at 18:25), the 33 kV bus was energized and auxiliary power restored for four of these units. During the next three hours, power was partially restored to load in the Bintulu area. About three hours later (21:35, 4 hours after the blackout started) power was restored to Bakun that allowed auxiliary power to be restored to the remaining Bintulu units.

During the overnight hours the remaining Bintulu units were restarted and synchronized with the grid. This allowed load to be fully restored in the early hours of the next day.

As mentioned above, problems at Bakun delayed restoration by about three hours. While there were a number of black-start errors within the plant, the most significant were operation errors in the 275 kV switchyard at the plant. The Bakun dam and switchyard are remote—a three-hour drive from Bintulu. This meant that power plant personnel operated breakers and switches at the Bakun 275 kV switchyard. Since the plant is remote with long transmission lines (about 100 km), voltage control is an essential element in reconnecting the plant to the main Sarawak grid. Switching errors at Bakun caused significant high voltages that set back the normal restoration process.

Lessons learned

Maintaining continuity of plant personnel at remote power plants can be a continuing problem. The Bakun dam is quite remote, with no education, entertainment or similar options for employees or their families. No doubt some of the problems there resulted from the churn of staff at the plant.

Personnel must be kept current in their black-start training.

2008 Oahu, Hawaii

About 18:30 on 26 December 2008 a lightning storm knocked out power throughout the Hawaiian island of Oahu after sunset, forcing President-elect Barack Obama and his family to spend the night at their seaside vacation home in the dark as winds swept in from the ocean. Utility crews restored power to the property around 06:00, and by midday electrical service was back for many of the island's 900,000 residents and thousands of tourists, whose high-rise hotels stood mostly dark.

The situation before the blackout

Just prior to the lightning storm, Hawaiian Electric Company's (HECO's) 138 kV transmission and 46 kV sub-transmission systems were in their normal configuration with all lines in service. Generation operation was normal (1,300 MW) to serve the 1,040 MW load. Spinning reserves were 260 MW, 80 MW above the HECO 180 MW minimum spinning reserve. HECO's dispatch center and power plants were properly staffed. Locations of Oahu generation are shown on Figure 8 and their status just before the blackout is shown in Table 2.

Figure 8: Oahu generation

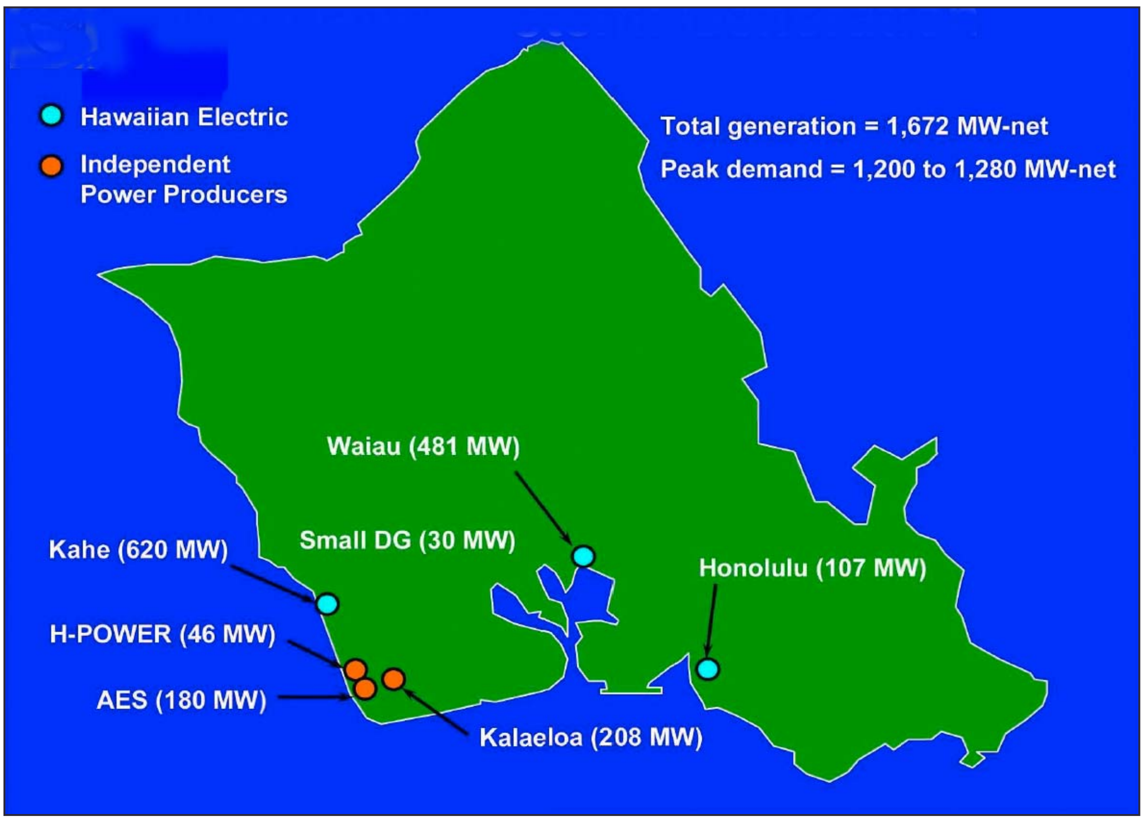


Table 2: Summary of HECO generation

Unit	Rated (MW)	Available (MW)	Actual (MW)
2 HECO CTs	103	103	0
2 IPP CTs	164	164	162
18 HECO diesels	30	30	0
10 HECO steam	863	863	607
3 IPP steam	270	270	268

The blackout

The Island of Oahu experienced a severe lightning storm on December 26, 2008 that lasted from approximately 18:00 to 18:50. During this storm the HECO transmission system experienced five separate short-circuit events caused by lightning strikes on or near 138 kV transmission lines.

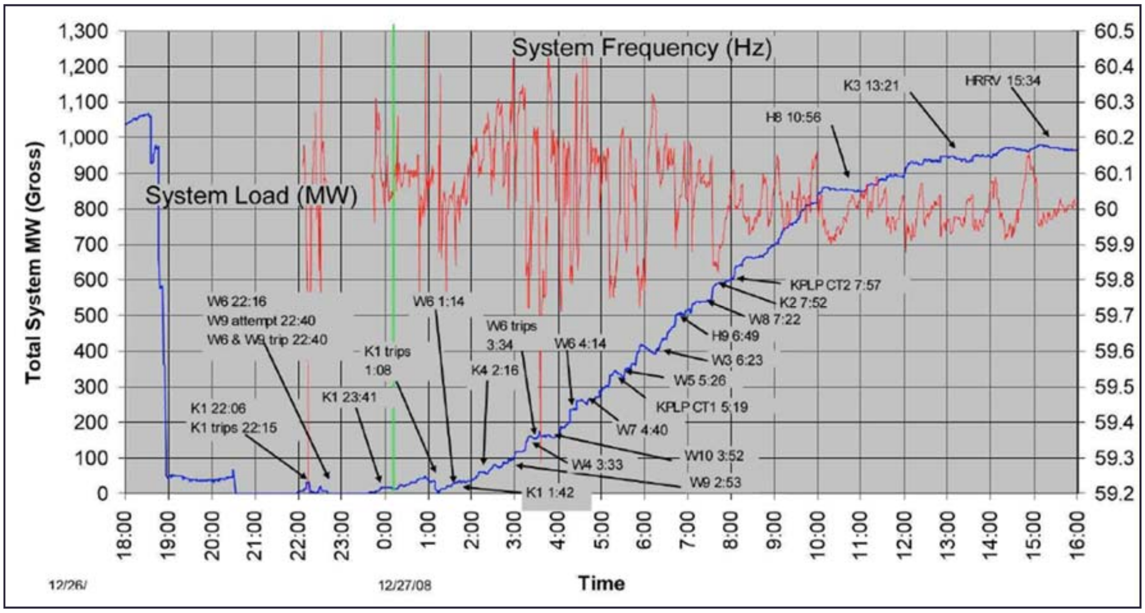
One of these was a 3-phase fault on an important 138 kV transmission line just outside Honolulu. This fault momentarily depressed voltages across the HECO system to the point where approximately 145 MW of voltage-sensitive customer equipment automatically shut down. This voltage dip also impacted the normal operation of certain generation plant auxiliary systems—leading to power plant tripping. This, in turn, initiated a sequence of power system events during the next few minutes that ultimately lead to the island-wide blackout.

As system frequency declined, Under-frequency load shedding (UFLS) operated as expected in five stages. Distributed diesel generators began transferring from auto to manual control and shutting down, most likely due to the frequency drop.

Restoration

Power Engineers (a US engineering consulting firm) found that HECO's restoration efforts were prudent and restored service to its customers expeditiously considering the circumstances. Figure 9 shows the timeline of generator starts as service was restored between about 19:00 and 15:00 the next day when all circuits were restored along with 96% of customers. A few pockets remained without service until the next morning.

Figure 9: Oahu restoration timeline



The restoration timeline shows several failed generation restarts until just after 01:00. Generation and load are then restored at a fairly linear rate through 10:00 when more than 80% of the load was restored.

The Power Engineers review found that "HECO could not have reasonably anticipated or prevented the damaging effects and instability caused by the lightning initiated 3-phase short-circuit to prevent the power outage from initially occurring or from it becoming island-wide under the circumstances."[13] The report continues "the HECO system was in proper operating condition and was appropriately staffed by personnel at the time of the lightning storm. The system operated appropriately under the circumstances. In response to the various lightning strikes, automatic protective relays that are designed to sense a disturbance on HECO's transmission system operated as designed."

Lessons learned

This blackout repeats the experience with other blackouts when operators are challenged in restoring service during the first few hours following the blackout.

13. Power Engineers, *Outage Report*, 31 March 2009, pages 3-4.

2003 Italy

Early in the morning of 28 September 2003, Italy experienced a major blackout affecting all of Italy—except the islands of Sardinia and Elba. Power was out in Italy for 12 hours and part of Geneva, Switzerland for 3 hours. It was the largest blackout in the series of blackouts in 2003, affecting a total of 56 million people. It was also the most serious blackout in Italy in 70 years.

The night of 27 September 2003 is the night of the annual overnight *Nuit Blanche* in Rome. Thus, many people were on the streets and all public transportation was still operating at the time of the blackout despite being very late at night. The blackout caused the carnival to end early. Several hundred people were trapped in underground trains. Coupled with heavy rain at the time, many people spent the night sleeping in train stations and on streets in Rome.

Throughout Italy, 110 trains were canceled, stranding 30,000 people. All flights in Italy were also cancelled. Police described the scene as chaos but there were no serious accidents.

The blackout, however, did not spread further to neighboring countries, such as Austria, Slovenia and Croatia, which are connected to Italy.

The situation before the blackout

In the years before 2003, Italy's electricity imports grew sharply due to Italy's significantly higher electric production costs than the rest of Europe. The fact that Switzerland was not integrated with the European electricity market and operation meant that the increasing imports into Italy were also flowing on unscheduled parallel paths through Switzerland. This meant that loads on cross-border transmission lines often deviated from scheduled exchanges with ever-growing amounts flowing on the Swiss transmission lines. The resulting power flows were not always well coordinated between the European system and Switzerland.

At the time of the event, the Italian load was very low—27,444 MW, including 3,487 MW of pump load. Italy was generating 20,493 MW and importing 6,951 MW as shown in Table 3. The table also shows the significant difference between scheduled and actual flows on the interconnections with Switzerland and France and, to a lesser extent, with Slovenia.

Table 3: Italian imports at 03:00 28 September 2003

Interconnection	Imports		
	Scheduled	Actual	Excess
Switzerland	3,068	3,610	542
France	2,650	2,212	-438
Slovenia	467	638	171
Austria	223	191	-32
Greece	285	300	15
Total	6,693	6,951	258

The blackout

Early in the morning of 28 September 2003 Italy was importing about 6,700 MW (25% of demand).[14] The Italian power system was operating under n-1 security conditions, and was capable of correctly dealing with the loss of any individual element of the grid, including any interconnection, or the loss of the largest unit in service.

At 03:01, a 380 kV interconnection between Switzerland and Italy tripped. The line tripped due to a flashover with trees. Several attempts made by the automatic re-closing facilities were unsuccessful. A manual re-closing attempt made at 03:08 also failed because of an overly high phase angle (42°) between Italy and Switzerland.

A nearby parallel circuit then overloaded. This overload was acceptable in such emergency circumstances, but for no more than15 minutes according to operating standards. Unfortunately, operator actions did not reduce the overload in time. After 24 minutes (03:25), this overloaded line also tripped when it flashed-over with a tree.

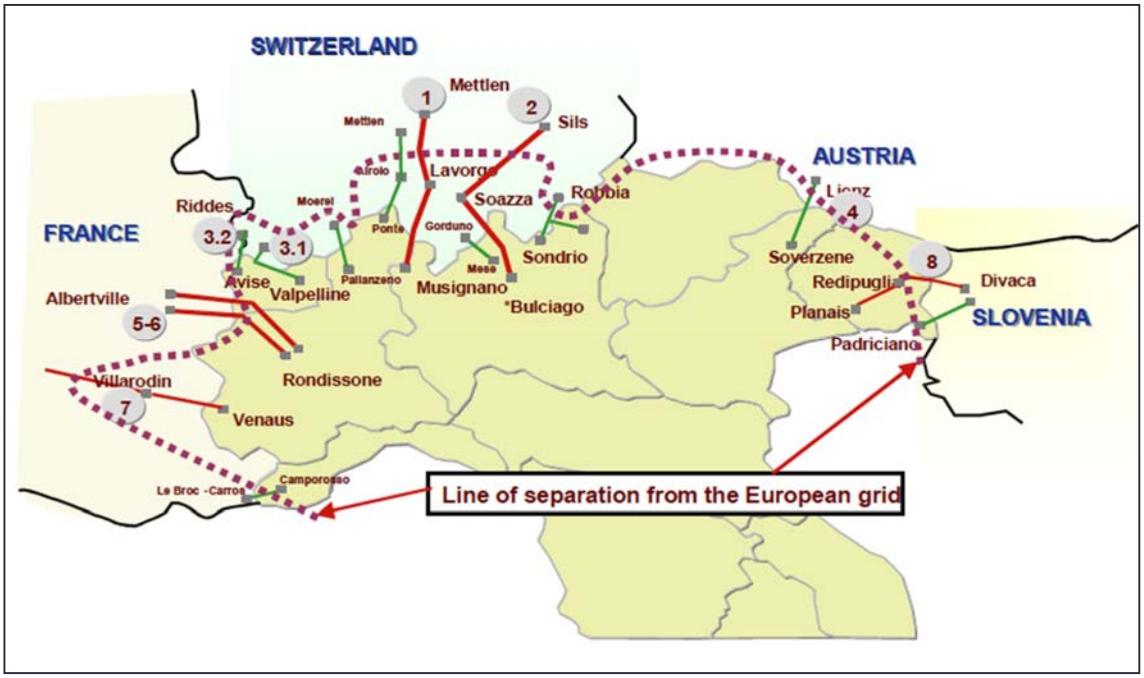
A parallel 220 kV line then tripped immediately. Almost simultaneously the Italian grid lost its synchronism with the Union for the Coordination of Electricity Transmission (UCTE) main

14. Much of this Italian section is based on the UCTE report: *Final Report of the Investigation Committee on the 28 September 2003 Blackout in Italy*, April 2004.

grid.[15] All remaining interconnections between Italy and UCTE were disconnected by the normal action of protective devices. By 03:26 Italy was an electrical island.

The separation sequence of the interconnections is shown in Figure 10. While the first two lines separated within 24 minutes, the other 7 interconnections opened within about 90 seconds.

Figure 10: Separation sequence of Italian interconnections



At this point, the Italian system had generation equal to only 75% of its load. Even so, generation was nearly able to meet load, however, it was not enough to arrest the frequency decline. In the three minutes after separation, the frequency declined to 47 Hz when a nearly complete collapse of the Italian network was inevitable.

Some underfrequency relays activated to form electrical islands of two well-defined portions of the network and the related load in southern Italy. A thermal unit should have fed each island, but only one generating unit was in a normal configuration, so, only one successfully islanded.

15. UCTE, was an association of TSOs in 23 countries across continental Europe. UCTE is responsible for coordinating the operation and development of electricity transmission grid in and among its member countries

Thirty-one thermal units initiated the sequence to trip to "house-load". Only eight of them successfully completed the sequence and remained in isolated operation on house-load.

Restoration

The restoration plan for Italy is a set of coded guidelines that are used by operating personnel to restore supply after a large area incident or blackout. This plan is based on several restoration paths designed to work in parallel: to restore the auxiliary services of shut down plants, to reconnect the thermal power plants that successfully islanded or tripped to the house-load, and to stabilize the load of such plants.

The restoration "paths" designed and used for restoring the network after the blackout were:

- 13 in northern Italy
- 9 in central-south Italy
- 4 in Sicily

There are 24 hydro or gas turbine units with black-start capability used to restore the paths.

While no specific performance index exists, the overall success of the plan depends on four key variables:

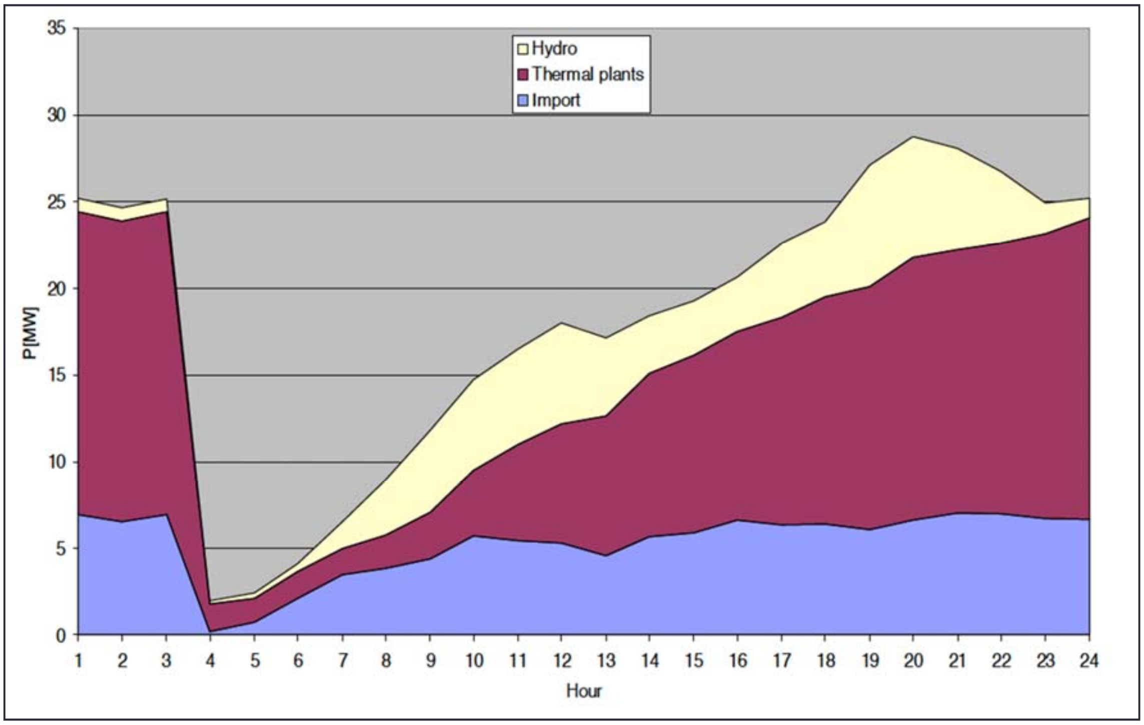
1. The number of available thermal units, operating on their house-load after separation from the grid;
2. The readiness of hydro and gas-turbine units to perform black-start;
3. The reliability of telecontrol and their telecommunication systems to operate; and
4. The availability of hydro, conventional thermal and gas-turbine units.

In this blackout, most of the restoration processes were performed satisfactorily in comparison to the severity of the total outage. Even so, it took more than 18 hours to fully restore service as can be seen in the table on the right.

Restored load (%)	Time Hr:min
50	6:30
70	10:00
99	15:00
100	18:12

An overall view of the timing of the restored load and the supply sources can be seen in Figure 11.

Figure 11: Italy restoration timeline



The post-blackout review by the UCTE found that the blackout:

- Was not caused by some extraordinary "out of criteria" event such as a severe storm, a cyber-attack, or simultaneous lightning strikes on several lines, etc…
- Was triggered by causes in Switzerland where the initial events were out of reach for action by the Italian operators.
- There were countermeasures for returning the system to a secure state after the first contingency (from a purely technical point of view), but human, technical and organizational factors prevented the system from returning to a secure state.
- Italian system restoration was performed successfully, however, it would have been shorter if more units had successfully switched to house load operation or have performed black-start correctly.

The restoration occurred in 4 stages:

1. Stage 1 (03:28 to 08:00)—diagnosis and Northern Area resupply;
2. Stage 2 (08:00 to 12:00)—Intermediate steps
3. Stage 3 (12:00 to 17:00)—The complete resupply of Mainland

4. Stage 4 (17:00 to 21:40)—The final stage and the re-supply of Sicily

Italian restoration stage 1—03:28 to 08:00

Approximately 3 hours after the blackout (06:30):

- Northwestern Italy was almost completely energized and reconnected to the French grid;
- Eastern Milan area was synchronized with Switzerland;
- All northwestern Italy thermal plant buses were energized and 750 MW were synchronized and operating at minimum output;
- Eastern Venice area was fed by Slovenia; and
- Part of the northern Florence area had been connected to Lombardy.

Around 08:00 at the end of the first stage:

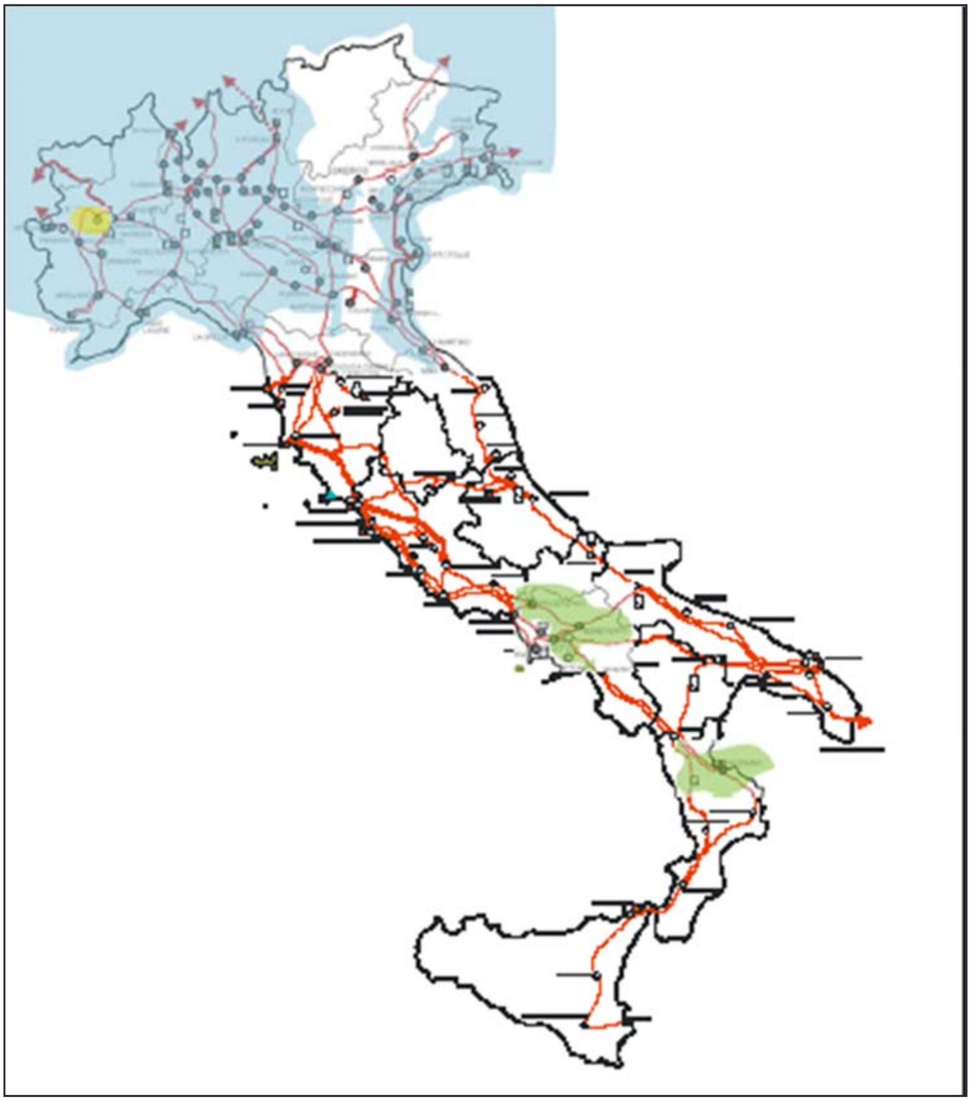
- The northeastern grid was not yet meshed with the rest of the Northern System but it was synchronous with it via the UCTE system. The substations in that area were energized and stable enough to start generator auxiliary services.
- In the central-southern area, no significant progress had been made.

During the first stage some failures occurred, such as difficulties in starting black-start units, voice and data communication problems and lack of information from the field.

The SCADA system of the National Control Center in Rome lost complete visibility of the data recorded in the Florence area and northern Rome area from 06:31 to 13:17. Two strategies were adopted in the central, southern areas and in Sicily: first, create as many islands as possible in the southern areas, and, second proceed step by step from North to South relying on interconnection with UCTE and on operating hydroelectric resources.

Figure 12 shows the situation at the end of Stage 1.

Figure 12: Italy at the end of Stage 1 restoration



Italian restoration stage 2—08:00 to 12:00

Restoring the power system continued at a slower pace than desired because of switching difficulties, mainly due to telecontrols and to minor problems of disconnectors in some key substations. Additionally, as the accident happened before the pumped-hydro plants had completed filling their upstream basins, available hydro energy decreased. To compensate imports were increased.

The market operator asked Distributors to interrupt industrial loads and implement the 1st level of load shedding (rotating load shedding plan) from 11:00 to 18:00 in the northern and central-northern regions that were electrically restored, but the response was not effective.

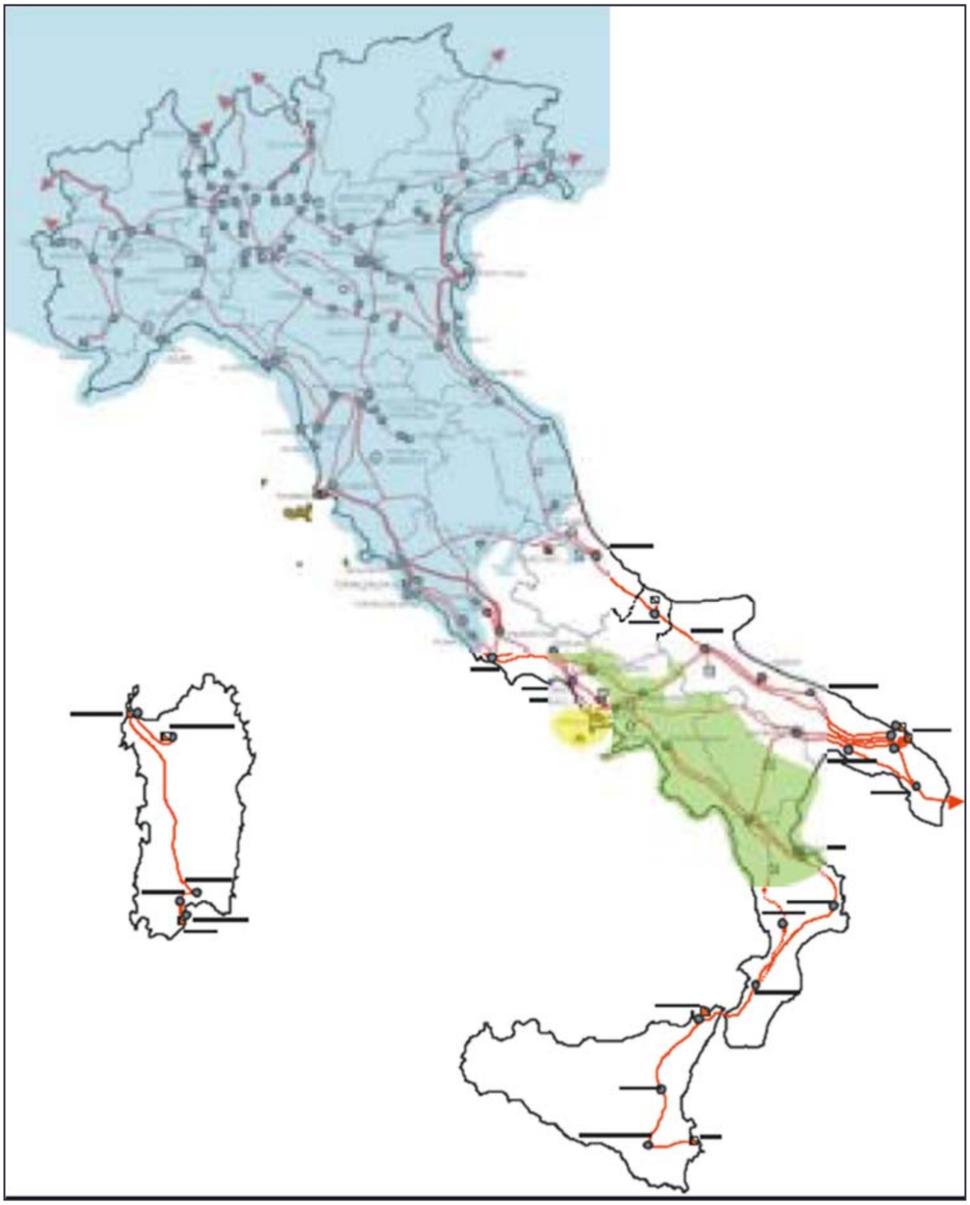
In the Rome area, at 09:28 after a few attempts to deliver voltage from a hydro black-start unit which had failed owing to voltage instability, another 310 MVA unit east of Rome was started in order to better control the same restoration path. From 10:06 the re-supply of the metropolitan area of Rome began.

At the end of stage 2, load in the Northern area was practically restored. Although the 380 kV grid was re-energized to Rome and the Adriatic backbone was energized up to Marche region, the re-supplied load was still low.

In the Southern area two electric islands in southern Rome and in the extreme southwest region of Calabria were interconnected and expanded.

Figure 13 shows the situation at the end of Stage 2.

Figure 13: Italy at the end of Stage 2 restoration



Italian restoration stage 3—12:00 to 17:00

Only one thermal power plant in the south was still not re-energized. The status of the grid and the lack of generation in Central-Southern Italy induced high power flows from North to South, creating an at-risk situation. A situation that became worse during the evening peak period. Imported energy from Greece became critical because it enabled the power flows between northern-southern macro areas, to be relieved of restoring security conditions. The situation was resolved by restoring the link with Greece; allowing imports of up to 500 MW.

By the end of Stage 3 all of the Italian peninsula and parts of Sicily were re-energized as shown in Figure 14.

Figure 14: Italy at the end of Stage 3 restoration

Italian restoration stage 4—17:00 to 21:40

All the various problems described above were amplified in the Sicilian grid.

After several unsuccessful attempts to restore the service independently, without the mainland interconnection, it was decided to supply the island from Calabria. This was done at 16:38 but the exchange could not exceed 200 MW. Thus, the re-supply time was limited by the need to adjust the load ramp in Italy. With the Sicilian grid restored, the Italian power system was again under control and emergency conditions ended at 21:40, a little more than 18 hours after the blackout. Rolling blackouts continued to affect about 5% of the population on the next two days (29–30 September) as the electricity company, ENEL, continued its effort to restore supply.

Lessons learned

The UCTE review made eleven recommendations, however, only a few might be applicable to the NEM:

- National regulations should, insofar as they are not yet implemented, provide for:
  - Binding defense plans with frequency coordination between load shedding, if any, and generator trip settings;
  - Binding restoration plans with units sufficiently capable of trip-to-house-load (TTHL) operation and black-start capability;
- A support tool for dynamic analysis and monitoring of the UCTE system is needed, so, the ongoing Wide Area Measurement System (WAMS) installation program was accelerated;
- Regions should have binding defense plans with frequency coordination between load shedding, if any, and generator trip settings; and
- On-load tap-changing transformer blocking in case of severe voltage drop should be accepted practice.

As with other blackouts, there was a period of confusion while the situation was understood, interconnections were used freely as available as part of the restoring the system, and some black-start and TTHL generators failed to perform. Having all the TTHL generation available would not have changed the overall plan—restoring interconnections would remain the first step—however, restoration would have been both quicker and smoother. It has been estimated that nearly all the Italian load (except Sicily) could have been restored in 12 hours rather than 18.

2011 San Diego, US

On the afternoon of 8 September 2011, an 11-minute system disturbance occurred in the Pacific Southwest, leading to cascading outages and leaving approximately 2.7 million customers without power.[16] The outages affected parts of Arizona, Southern California, and Baja California, Mexico. All of the San Diego area lost power, with nearly one-and-a-half 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. Millions went without air conditioning on a hot day.

The situation before the blackout

September 8, 2011, was a relatively normal, hot day in Arizona, Southern California, and Baja California, Mexico, with heavy power imports into Southern California from Arizona. In fact, imports into Southern California were approximately 2,750 MW, just below the import limit of 2,850 MW. (September is generally considered a "shoulder" season, when demand is lower than peak seasons and generation and transmission maintenance outages are scheduled.)

Despite September being considered a shoulder month, temperatures in the Imperial Valley (far southeastern California desert east of San Diego) reached 46° C. The load of the utility serving the Imperial Valley area headed toward near-peak levels of more than 900 MW, requiring it to dispatch local combustion turbine generation according to established operating procedures. Forty-four minutes before the initial event the local utility operator did not notice that the loss of one key transformer would overload a second transformer above its trip point. The loading on these transformers was pivotal to this event.

16. Adapted from the FERC/NERC *Staff Report on the September 8, 2011 Blackout*, April 2012.

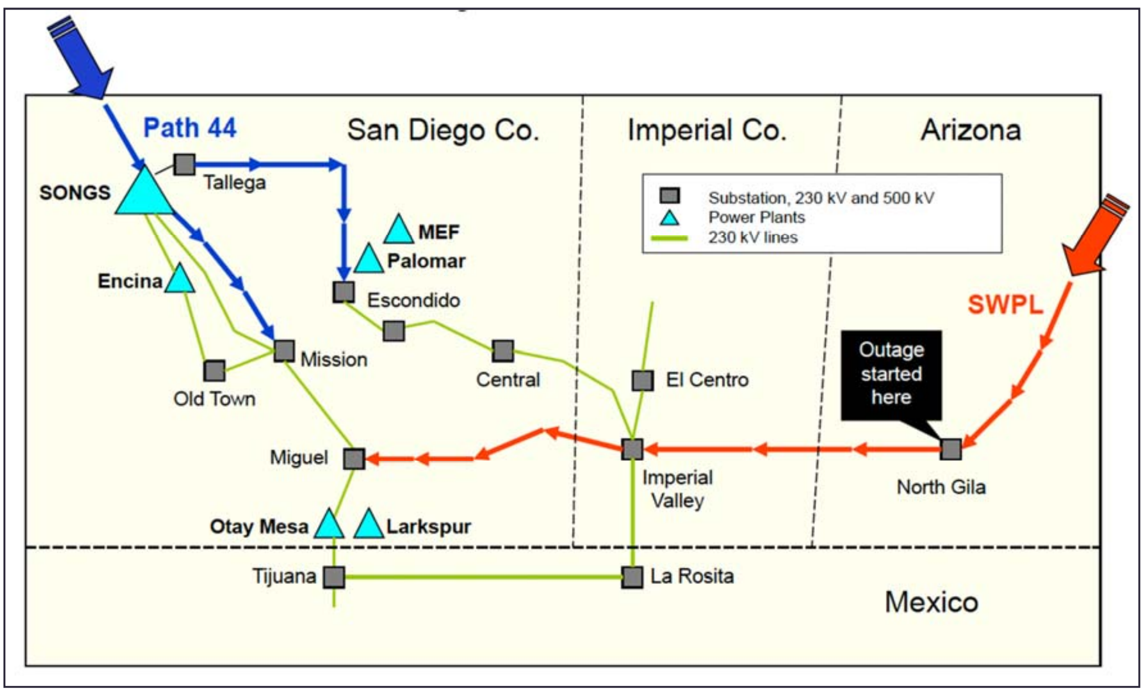
The supply and demand conditions of San Diego County before the blackout are shown in Table 4. (Note that this is only part of the area affected by the blackout.)

The important elements of the system are shown in Figure 15. The central San Diego central business district is in the area around the Old Town and Mission substations shown in the figure. The figure also shows the two critical import paths in to the area—500 kV from the east and 230 kV from the north. The San Onofre nuclear plant is labeled "SONGS" in the figure.

Table 4: San Diego County pre-event supply and demand

	MW
Supply	2,229
Power plants	1,809
Mexico	420
Imports	2,657
From north	1,287
From east	1,370
Demand	4,293

Figure 15: San Diego area map of event



The blackout

At about 14:00 there were problems at the 500 kV North Gila substation in Arizona. An experienced technician inadvertently skipped two of the sixteen steps necessary to resolve the problem. This resulted in arcing, leading to a phase-to-phase fault that tripped the SWPL–North Gila 500 kV line.

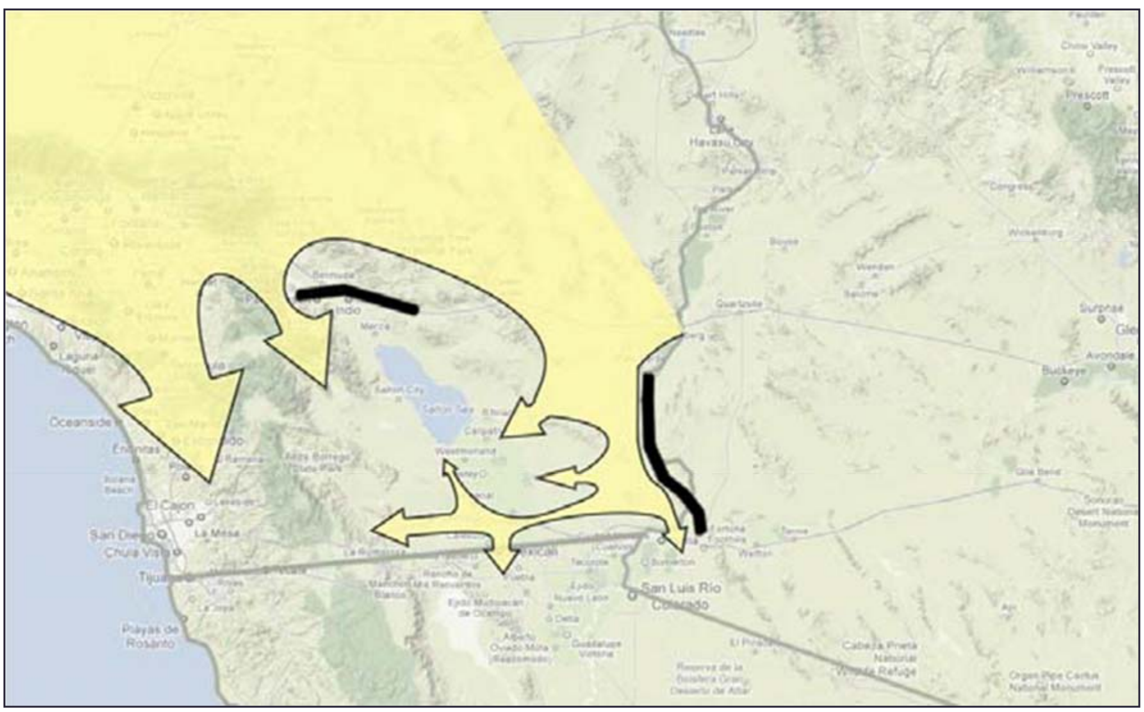
Arizona utility operators erroneously believed that they could return the line to service in approximately 15 minutes, because they had no situational awareness of a large phase angle difference caused by the outage. More time would have been needed to redispatch generation to reduce the phase angle difference to the allowed value.

As a result of the line trip, flows redistributed across the remaining lines into the San Diego, Imperial Valley, and Yuma areas. Immediately after the trip transformers at Imperial Valley loaded to 118% of their emergency ratings. Both transformers tripped in 40 seconds. About a minute later, all the transmission with flows from Arizona tripped and some from northern California.

The majority of the flow diverted to the northern entry to the San Diego area, Path 44. Flow on Path 44 increased by approximately 84%, from 1,293 MW to 2,362 MW.

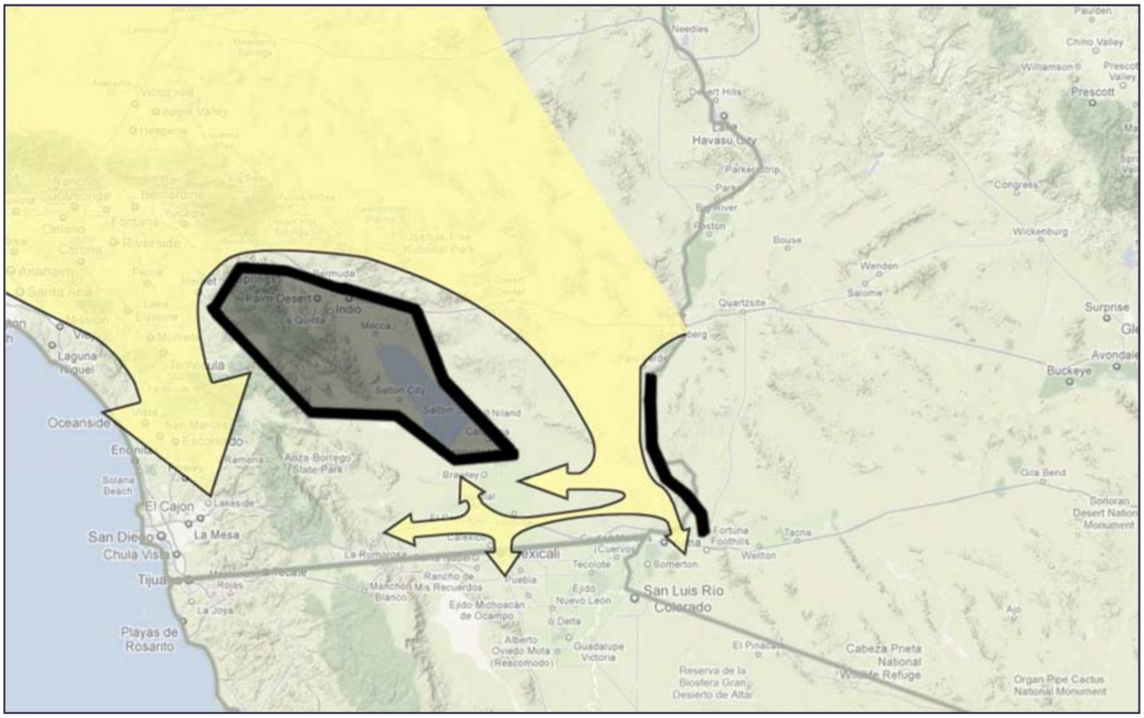
The situation at this time is shown in Figure 16

Figure 16: The southern California situation at 15:28



Automatic distribution under-voltage protection in the Imperial Valley area system began tripping distribution feeders and shedding load. From 15:32:11 to 15:33:46, 444 MW of this load tripped. Generators and other transmission lines in the area also started tripping by about 15:35. The situation at this time is shown in Figure 17.

Figure 17: The southern California situation at 15:32



Looking at loading from the north, aggregate loading on the south of SONGS 230 kV transmission lines increased from approximately 6,700 amps to as high as 7,800 amps. (There is a SONGS separation scheme that activates at 8,000 amps.) The loading settled around 7,200 amps and remained there.

Between 15:35 and 15:37, additional transmission tripped in the eastern part of the area. The aggregate loading south of SONGS increased from approximately 7,200 amps to approximately 7,800 amps. When the last line tripped aggregate current on Path 44 increased to 8,400 amps, well above the trip point of 8,000 amps.

By this time, the south-of-SONGS lines were the San Diego area's (including Imperial Valley and Mexico's northern Baja peninsula) only source of critical imported generation. If the aggregate current was brought below 8,000 amps, the blackout could have been avoided, but at this point no operator action could have occurred quickly enough. Had there been formal operating procedures that recognized the need to promptly shed load as the aggregate current approached 8,000, and had operators been trained on the 8,000 amp set point, it is possible that operation of the SONGS separation scheme could have been averted by earlier control actions.

Milliseconds after the Imperial Valley line outages; several smaller generators totaling 432 MW tripped, pushing the south-of-SONGS flow to 9,500 amps.

At 15:38, not quite 11 minutes after the initial line tripped, the SONGS separation scheme operated, effectively separating all five south of SONGS 230 KV transmission lines and separated the entire San Diego area from the rest of the Western Interconnection.

The electrical island created by operation of the SONGS separation scheme left a significant imbalance between generation and load. As a result, the frequency in the island rapidly declined. In less than a second, the UFLS programs began activating within the island. This led to the final cascading loss of generation and load in the area.

The final blackout totals are shown in Table 5.

Table 5: San Diego blackout statistics

Company	Generation lost (MW)	Demand interrupted (MW)	Customers affected
San Diego Gas & Electric	2229	4293	1,387,336
Southern California Edison	2428	0	117*
CFE (Mexico) Comision Federal de Electricidad	1915	2205	1,157,000
Imperial Irrigation District	333	929	144,000
Arizona Public Service	76	389	69,694
Western Area Power Association	0	74	18,000
Total	6982	7890	2,776,147
* These customers are served via San Diego Gas & Electric facilities			

Restoration

None of the affected entities needed to implement black start plans because they all were able to access sources of power from their own or a neighbor's system that was still energized. The restoration process generally proceeded as expected, and some entities restored load more quickly than they had expected. Table 6 shows how long it took the affected entities to fully restore their lost load, generation, and transmission. Table 7 is a similar table of generation restoration times.

Table 6: San Diego area load restoration times

Entity	Load lost (MW)	Time until demand fully restored	Date restored	Demand fully restored (hrs)
San Diego Gas & Electric	4,293	03:23	9/9	12.0
Southern California Edison	2,205	01:37	9/9	10.0
Imperial Irrigation District	929	21:40	9/8	6.0
Arizona Public Service	389	21:12	9/8	6.0
Western Area Power Association	74	22:23	9/8	6.5

Table 7: San Diego area generation restoration times

Entity	Generation lost (MW)	Generation restored		
		Time	Date	Hours
San Diego Gas & Electric	2,428	06:33	9/12	87
Southern California Edison	2,229	06:20	9/10	39
CFE (Mexico) Comision Federal de Electricidad	1,915	23:43	9/10	56
Imperial Irrigation District	333	20:42	9/8	5
Arizona Public Service	76	20:37	9/8	5

Lessons learned

It is possible to completely restore large amounts of load using only interconnections.

The official review by FERC and NERC had only a few important recommendations:

- They felt the regional coordinator (WECC) could have taken a more active role in coordinating the restoration efforts. The regional coordinator has the largest area of visibility and more advanced real-time study tools than the transmission operators. During a multi-system restoration, issues are likely to arise between neighboring systems that may require either a neutral decision maker, or rapid technical analysis of unplanned system conditions.
- There was a 30-minute debate between Southern California Edison and San Diego Gas & Electric regarding resetting the SONGS separation scheme lockout relay. This delayed restoring the transmission path from the north.

TASK 2—INTERNATIONAL COMPARISON OF REGULATORY ARRANGEMENTS TO PREVENT OR MITIGATE BLACKOUTS INCLUDING RESTORATION

The primary purpose of this Task is to provide international comparisons to the NEM SRS. Each example describes the regulatory arrangements related to the SRS. To the extent possible, the report identifies any documents that establish similar requirements to the SRS.

The chapter describes five international examples of the regulatory arrangements designed to prevent or ameliorate major supply disruptions in the electricity system. The examples were selected in consultation with AEMC Reliability Panel from a list of suggestions by DGA. The selected systems are from four different countries, and three continents.

The five selected were:

- PJM, US;
- South Africa;
- Italy;
- ERCOT, US; and
- Ireland

The AEMC Reliability Panel included specific items to compare in their RFP. Each of these is summarized in Table 8, below.

Context for comparison

The AEMC Reliability Panel is interested in comparing international regulation and procedures related to blackouts and black-start generation. Some of the issues that the AEMC is interested in comparing include the minimum black-start requirements regarding amounts and response times. These are in comparison with the SRS that requires the AEMO to procure enough black-start capacity to energize enough generation to supply 40% of the load within 4 hours.

Table 8: International comparison of regulatory arrangements to prevent or ameliorate blackouts

Characteristic	System/region				
	PJM (page 50)	South Africa (pg 53)	Italy (page 53)	ERCOT (page 54)	Ireland (page 56)
Any specific variables for system restoration (and their values), such as time for restoration of auxiliaries or generation, specific volume of generation capability to be restored, or reliability requirements for restart units	Synchronize in 3 hours 4 hours to energize nuclear units	Each black-start plant must energize a large coal plant in 4 hours	None, only general comments	Unwritten understanding of 4 hours for nuclear plants	Thermal black-start plants must synchronize within 30 minutes of being energized
Any requirement for the system to be able to restore certain quantities or percentages of total load within a specific timeline	Time only for nuclear units Restore “critical load”	None	None	No time required Amount is confidential	None There are priority loads
Any specification of the scale of the power system event that must be addressed (such as whether the event is assumed to be sub-regional, regional or countrywide), and how this affects the level of restart services to be procured	Assumes both zonal and system-wide blackouts, but the plan is to use the zonal black-start resources to restore the system.	National	National	Entire system	National
Any deterministic requirements, such as a minimum number of restart services that must be procured (ie including any contingency/reserve restart services)	At least 2 for each zone Can be located in adjacent zone	2 plants for entire nation—a pumped-hydro plant and 2 large diesel at a coal plant	None	None, but multiple black-start units will be needed for such a large system	At least one black-start unit in each of four subsystems
Any system specific requirements, such as a requirement to restore transmission corridors to a stable voltage	None	All generators >200 MW must be capable of TTHL for 2 hours	None	None	None
Any restoration priority for specific loads (eg sensitive economic loads such as aluminum smelters, critical services such	Nuclear plants Critical natural-gas infrastructure	Nuclear plant	Hospitals, etc. all have emergency generators Large industrial loads	Nuclear plants Natural-gas pipeline compressors and	None

Characteristic	System/region				
	PJM (page 50)	South Africa (pg 53)	Italy (page 53)	ERCOT (page 54)	Ireland (page 56)
as hospitals) or specific generators (such as nuclear power stations), including whether the system operator must prioritize these generators when restarting the power system	Specific loads may be designated by zone operators		also have local generation to supply their critical loads	processing stations	
Any specific assumptions regarding the underlying condition of the power system, such as specific network or generator outages	Generally normal conditions (see text)	None	Peak load	Summer peak	Peak and off-peak
Any requirements related to the diversity (eg fuel, strategic, electrical or geographic location) of restart services	None	None	None	None	None

The eight characteristics in Table 8 can simplified as follows:

1. Specific system restoration variables—the only requirements were to re-energize the system bus of nuclear generators within 4 hours;
2. Load restoration amounts and timing—none of the systems had such requirements;
3. Assumed blackout scale—varied among the systems;
4. Deterministic requirements—most require multiple sources, but allowed using the interconnections;
5. System-specific requirements—generally none;
6. Restoring priority loads—nuclear plants and natural gas pumping stations;
7. Underlying system condition assumptions—normal conditions; and
8. Diversity requirements—none.

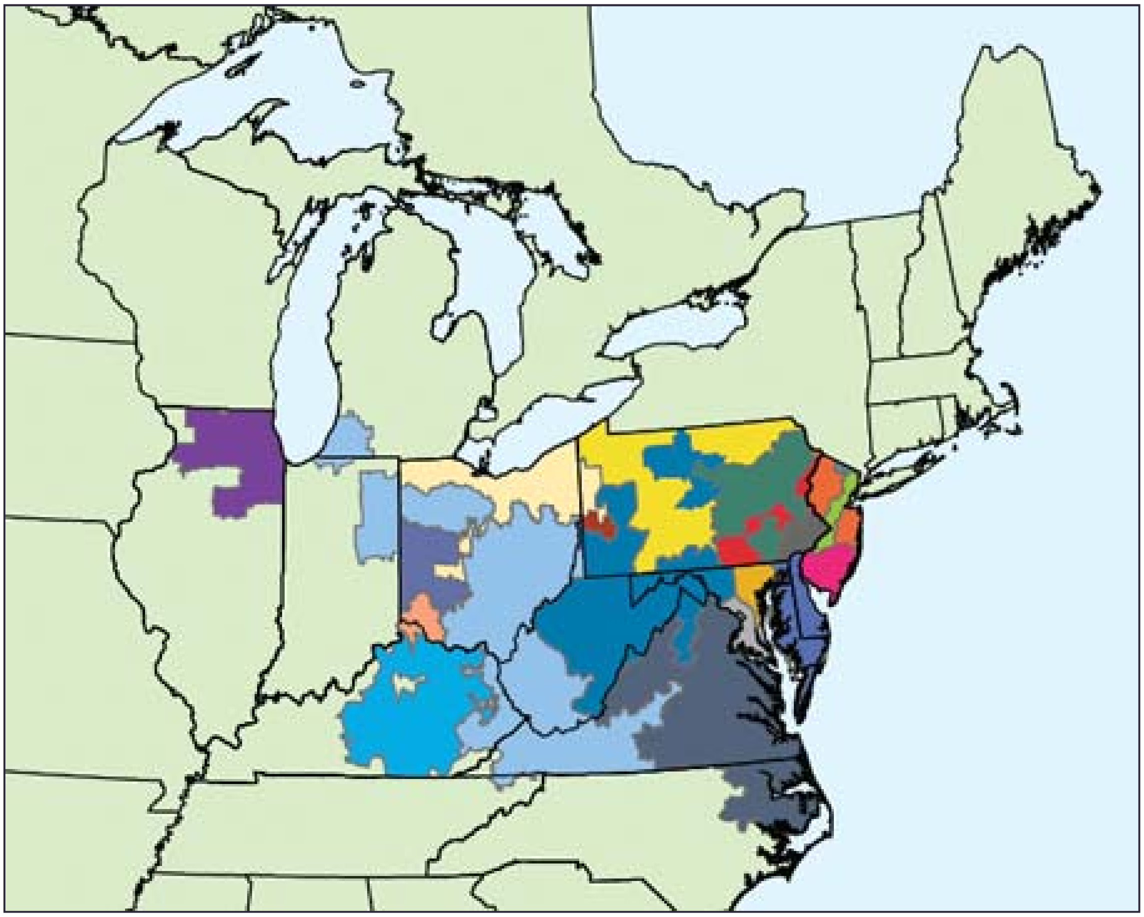
Cases where the responses shown in the table are non-trivial are discussed below.

PJM, US

The PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. Acting as a neutral, independent party, PJM operates a competitive wholesale electricity market and manages the high-voltage electricity grid to ensure reliability for more than 61 million people. PJM includes the 21 transmission zones shown in Figure 18 with 184,000 MW of generation. Each zone is responsible for acquiring the necessary black-start capacity.[17]

17. PJM's black-start requirements are described in PJM *Manual 12: Balancing Operations* and *Manual 36: System Restoration Attachment A: Minimum Critical Black Start Requirement*. The manuals are available at www.pjm.com/documents/manuals.aspx.

Figure 18: PJM's 21 transmission zones



Specific system restoration variables

Black-start generation is intended to energize units with a hot-start time of four hours or less. Black-start generating units must be able to close the output breaker to a dead bus within three hours of a request from the local transmission owner or PJM. PJM may require some black-start resources to adhere to less than a three-hour start time. (A three-hour start time may not be appropriate to meet nuclear power off-site safe-shutdown load restoration requirements.)

There must be enough black-start generation in each zone to be able to start 110% of the "critical load." The transmission operator in each PJM zone determines the critical load. Critical loads include:

- Cranking power to critical generation (thermal units with hot-start times less than 4 hours);
- Cranking power to combustion turbines;

- Off-site nuclear station light and power (2 independent feeds);
  - Including units off-line prior to disturbance;
  - Ensure a "safe" shutdown of nuclear or other generation;
  - Facilitate a station "start-up";
- Units with a hot-start time of 4 hours or less;
- Critical gas infrastructure (key in a quick restart);
- Power to electric infrastructure;
  - Light and power to critical substations;
  - Pumping plants for underground cable systems;
- Critical communication equipment*;
- Critical command and control facilities*; and
- Under-frequency load-shed circuits*.

(Items marked with an asterisk (*), can be supplied by local storage or generation.)

Underlying system condition assumptions

The following assumptions are applied to planning for a System Restoration:

- Total zone blackout (no assistance from external systems);
- Normal weather pattern (not a result of a natural disaster or extreme weather);
- Intermediate to peak load level (marginal steam units hot);
- Minimal equipment damage (transmission/generation);
- Normal working hours (sufficient personnel located in the field or on-call);
- Variables such as the current scheduling strategies, the amount of nuclear units operating, load levels, weather conditions, equipment damage and the amount of direct purchases may impact restoration times. Longer restoration times may result from disturbances during off-peak hours or disturbances resulting from extreme weather patterns. Faster restoration times may be possible dependent upon actual system separation boundaries, the ability to import generation and status of equipment.
- Other high priority load which should be considered early in the restoration process include:

- Cranking power to generation with greater than 4 hour start time;
- Power to electric infrastructure in accordance with timeframe defined in restoration manual;
- Light and Power to restore critical substations (if applicable);
- Pumping plants for underground cable systems;
- Critical Communication Equipment;
- Critical command and control facilities; and
- Under-frequency load-shed circuits.

South Africa

The South African system reflects many characteristics of a centralized system. Black-start requirements are set in the Grid Code. The Code requires two black-start plants for the nation. One is a 4 x 250 MW pumped-hydro plant and the other is two 20-30 MW diesels located at a large coal plant.

The Code also requires all units >200 MW to be able to trip to house load (TTHL) for at least two hours. Interestingly, these units are not counted as part of the black-start requirements.

The emphasis is on starting the large coal units.

Italy

Italian maps and other data were discussed above regarding the 2003 blackout beginning on page 30. Recent Italian peak load was about 51,000 MW, though the all-time peak of almost 57,000 MW occurred in 2007.

The Terna Group is the grid operator for the Italian electric transmission system. Terna is the largest independent Transmission System Operator (TSO) in Europe. It owns the National High Voltage Transmission Grid, and is responsible for the transmission and dispatch of the electricity for the entire Country with ~3,500 employees. It operates about 63,900 km of three-phase conductors, 21 interconnections, and 491 substations.

The Italian restoration plan is a public document, but it is all in Italian.[18] There are two priorities in the Italian restoration plan:

1. Restore corridors from the rest of Europe across the Alps to quickly energize portions of the internal grid, and
2. Emphasize real testing of restoration strategies and training of the operators.

The black-start strategy combines restoration with supply from the rest of Europe (1st priority) and creating electric islands, with the islands progressively meshed and synchronized with the rest of the system.

While there is no market for black-start service in Italy, a number of generating units are designated as black-start and, as such, are bound by agreements with Terna (e.g. they have to agree on their maintenance period, are subject to periodic testing of black-start capability, etc.).

The units with black start capacity are identified in studies performed by Terna. The key variables are geographical location, transmission grid topology, and the possible restoration transmission corridors. The selected black-start units are defined and tested through dynamic simulations and real time testing, whenever possible.

ERCOT, US

The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to 24 million Texas customers—representing about 90 percent of the state's electric load (see Figure 19). As the independent system operator for the region, ERCOT schedules power on an electric grid that connects more than 70,000 km of transmission lines and 550 generating units. The system peak load is about 70,000 MW. There are more than 1,400 active entities that generate, move, buy, sell or use wholesale electricity.

18. *Piano di Riaccensione del Sistema Elettrico Nazionale*, (Restoration Plan of the National Electric System).

Figure 19: ERCOT area of Texas

In ERCOT, black-start service is an ancillary service provided by a resource able to start without support of the ERCOT transmission grid. It is procured competitively every two years. ERCOT is allocated a specific amount of funding to spend to procure black-start services.

Factors used in selecting black-start units include:

- Fuel supply (not diversity), capability to run on auxiliary fuel supply;
- Location relative to major load center or transmission corridor that connects next-start resources;
- Start- up time, ramp rates; and
- Resource cost.

Ireland

Ireland is, literally, an island. There are two HVDC interconnections with the UK—500 MW to the Dublin area from Wales and 500 MW to the Belfast area from Scotland. Otherwise, they depend on their own island resources to supply load. It should also be noted, that the HVDC links do not have black-start capability. Peak load on the island is about 6,500 MW and is supplied by almost 10,000 MW of generation. In addition, wind generation is more than 2,600 MW, and is expected to triple.

Restoring priority loads

Priority loads include the power system control centers themselves, hospitals, airports and other loads of national importance. In general, Ireland does not have the kind of priority loads that Australia has; e.g. smelters.

Underlying system condition assumptions

Ireland can have a national blackout at any time, day or night, so a variety of load conditions are studied.

TASK 3—CHANGES ANTICIPATED FOR BLACK-START PLANNING IN SYSTEMS WITH VERY HIGH LEVELS OF RENEWABLE GENERATION

A few regions in the world are experiencing the effect of very high penetration levels of renewable generation. These include Hawaii, Ireland, Denmark, and South Australia, among others. These systems will face some new challenges as the proportion of renewable energy generation increases further. This chapter addresses some of these challenges and potential mitigation measures, especially as they apply to the NEM.

Nature of renewable generation affecting blackouts and black-start

There is a range of renewable energy generation considered from wind and photovoltaic (PV) to renewables that include hydro, geothermal, waste heat, etc. The latter can be dispatched like conventional generation—that is, their output can be controlled up or down and they do not rely on variable energy sources like the wind or sunshine. This chapter focuses on the two types of renewable energy generation that are problematic for system operation—wind and solar.

Wind is usually easier to integrate than solar. Wind blows day or night, though on-shore wind tends to vary more and often stops during very hot weather. Offshore wind, on the other hand, tends to blow more steadily day and night. In addition, wind generators have some rotational inertia in their rotating blades that reduces their instantaneous variability.

Solar generation, in contrast, only produces energy during the day from a few hours after sunrise to a few hours before sunset. Solar is also subject to very rapid output changes as clouds pass overhead.

Another important difference is in project size. Wind generation is MW-scale units that are often part of a wind farm, while rooftop PV is kW scale in individual units. (There are also large-scale solar projects that are MW scale.) This is an important difference.

Rooftop PV is usually connected at low voltages at homes or businesses. These small projects operate based on local control and are invisible to system operators. When a distribution feeder has many rooftop PV systems, it can produce enough power to back-feed power to the substation.

The MW scale projects will usually be connected at higher voltages and can be monitored in real time by system operators. Furthermore, wind is usually produced in wind farms that include multiple units with a single connection point that includes real-time monitoring.[19]

Both wind and solar generators produce direct current (DC). Both use an inverter to transform the DC into alternating current (AC) power. These characteristics provide at least two advantages:

1. They can charge batteries directly—avoiding AC/DC transformation losses; and
2. The inverters offer some potentially useful features—very rapid control, and, advanced (four-quadrant) inverters can control both power (MW) and voltage (var).

The impact of these factors on blackouts and system restoration is discussed below.

Impact on blackouts

Wind and solar PV generation can have some positive benefits, but they can cause serious operating problems. Even so, there are mitigation measures that can be useful in preventing blackouts or assisting restoration.

System inertia

In conventional generation, rotating inertia provides a rapid reserve of power that helps stabilize system frequency. When a system loses generation the frequency declines. The rotating inertia of conventional generation instantly increases generator output as they slow. During these conditions generators can briefly provide much more than rated output. After a few seconds governor and other controls will increase the energy (from steam or natural gas) delivered to the generator, increasing its output.

Since the final stages of blackouts usually occur in less than a minute—faster than humans can understand and respond—it is automatic actions that prevent blackouts. One of these is the inertial response of generators. This slows the speed that frequency falls, giving other automatic systems time to respond. (This happened in all the blackout examples cited as part of Task 1.)

19. All the wind generation in South Australia is in wind farms of at least 30 MW.

In major power shortages, UFLS and under-voltage load-shedding (UVLS) are designed to arrest the frequency decline and give the generator governors time to increase generation enough to prevent a total collapse. All of this is pretty automatic. In the minutes and hours that follow, system operators are then able to restore normal operation.

Rooftop PV generation has no rotational inertia and wind has very little. So, as system frequency declines they continue producing the same output. Rooftop PV systems also do not respond to voltage variations. (More on this under "Possible mitigation measures" starting on page 64.)

In addition, inverters used with wind and PV are usually sized at about 105% of the source's maximum rated output, providing little room for short bursts of power like conventional generation. Conventional generators, in contrast, provide very high fault currents. While this might seem to be a bad thing, it is important in protecting the system. Protective relays and fuses are set to respond when fault currents occur that are much higher than in normal operation. Conventional generators will briefly provide 400% or more of their rated output under fault conditions. This brief surge of current is what signals relays to operate and causes fuses to "blow." Without such high fault current from conventional generators or some other source, protection plans and settings will have to be completely revised.

As the amounts of wind and PV increase during operation, there will be less conventional generation operating as part of normal economic dispatch.[20] This will significantly reduce the rotating inertia of the system. It will also reduce fault current levels that will disrupt system protection schemes. The result is that much more rapid frequency swings occur during contingencies. Thus, automatic systems designed to prevent a blackout will have much less time act.

Ramp-rates (rate of change of frequency)

Besides inertial response discussed above, conventional generators can increase and decrease their output over a period of minutes automatically or under operator control. It is generator governors that vary the energy input to the turbines that produce electricity. Along with any inertial response, these controls are used to maintain a nearly constant

20. Wind and PV have near-zero short-run marginal costs and will be dispatched ahead higher cost conventional generation.

frequency as customer load and other conditions change from second to second during the day. This ability is measured as ramp-rate and usually stated as MW/minute.

The amount of ramp-rate for a unit depends on it size and technology. Generally, larger units have higher ramp-rates; and combustion turbines have higher ramp-rate than steam units. The system operator must see that the combined ramp-rates of the operating generators are enough to meet the expected changes in system load.

The output of wind and PV often has steep "ramps" as opposed to the controlled, gradual "ramp" up or down generally experienced with electricity demand and the output of conventional generation. Managing these ramps can be challenging for system operators, particularly if "down" ramps occur as demand increases and vice versa.

There can be rapid fluctuations in output of rooftop PV systems from passing clouds. If the conventional generators cannot ramp fast enough to match the variability of the PV (or wind) systems, a frequency mismatch may affect the whole system. This could lead to under-frequency load shedding or even blackouts.

Under-frequency and under-voltage response

As mentioned above, a distribution feeder with a lot of rooftop PV can back-feed the substation during sunny days. This can be a challenge in setting protective relays and fuses in these feeders. In pre-blackout conditions this back-feed can cause serious problems with UFLS and UVLS.

Normally UVLS and UFLS are designed to shed load when load exceeds generation and either frequency or voltages fall too far and/or too fast. Reducing load in such conditions allows generators to regain balance with load and slowly restore normal conditions.

If a feeder that is part of the UVLS or UFLS system is back-feeding it will have the wrong impact. Instead of helping restore the generation-load balance by reducing system load it will reduce system *generation*, and make the situation worse. The opposite of what was intended.

Complicating matters further, is that such a back-feed can only occur during daylight, and typically between 10:00 and15:00 when sunshine is brightest. So such a feeder would need to be excluded from UFLS and UVLS during these daylight hours, but otherwise be included normally.

As discussed above, high levels of wind and solar PV will reduce the amount of conventional generation operating. The resulting reduced rotating inertia means that system frequency will fall faster when a generator is lost. (Frequency will also increase faster when a large load is lost.) This makes the system less robust and more susceptible to blackouts.

There is a related issue that is important with wind and PV—low-voltage ride-through. Most inverter controls are designed to disconnect when voltages fall to a certain amount. In systems with high levels of wind and PV, voltages can fall faster and farther than systems with more conventional generation. In these situations, voltages can remain low longer, and, rather than disconnect, the wind and PV should remain connected longer to see if voltage recovers. Otherwise, tripping the wind and PV during power-shortage conditions will make conditions worse.

Coincident frequency reaction

Many utilities established policies and design standards for wind and rooftop PV generation before it was clear how much of this generation could be installed on the system. Wind and rooftop PV commonly disconnect when losing source power and wait a fixed period to restart once power is restored. This keeps repair crews safe when repairing damage that caused a local outage. These systems also disconnect when the frequency drops to a set level or voltage gets too low.

Since all these wind and PV systems respond with the same settings, they are coincident. They will all drop out at about the same frequency or voltage. This can produce additional shocks to the system during a major disturbance—increasing the chance of a blackout.

Over voltages

High levels of wind and rooftop PV can cause high voltages in the transmission system and on distribution feeders. Voltages tend to be higher at generating sources and these generators raise voltages. This can be a special problem on distribution feeders with a lot of rooftop PV. Voltages can become high enough that the substation equipment cannot keep voltages within acceptable limits.

Both these resources use inverters to convert their DC output to AC on the system. These inverters generally use the simplest and least expensive designs—especially for rooftop PV. These inverters only control the power output and do not control voltage or var output. (More on this below.)

Restart capability

One advantage of wind and PV compared with conventional generation is that they can be restarted and brought to full output very quickly—assuming the sun is shining and the wind is blowing. It can take only a minute or two if conditions are right. Most inverters are designed as "frequency takers"—they match the system frequency and voltage of the power system. They are able to match a fairly wide range of frequencies—a wider range than conventional generators.

Inverters can be designed to provide their own frequency signal, independent of the overall system. Wind or PV generators, especially those with associated energy storage, could be used to restart after blackout and form an electrical island. Such an arrangement could speed restoration and add considerable flexibility.

Impact on restoration

High amounts of wind and rooftop PV in a system will impact system restoration following a blackout. One of the obvious impacts is that lower amounts of conventional generation will be "warm" or available for TTHL. This conventional generation would be among the first resources used to restart the system. With more renewable generation there will be less conventional generation operating, making restoration harder.

Restoring the system after a blackout involves re-energizing the transmission system while balancing generation and load, and controlling voltages. Wind generation has some advantages over rooftop PV in restoration. Wind generation is connected to the transmission system, monitored in real-time by the system operator, and, within limits, can be dispatched. Wind forecast models could estimate the amount of energy that wind generation can produce following a blackout. These wind generators can be used in restoring the system—especially if their inverters have voltage control.

Rooftop PV does not have the visibility or control that wind generation has. These PV systems disconnect when power is lost. As power is restored to distribution feeders, these PV systems would remain off. Connecting these feeders would add the expected to load used to balance generation in the restart process. However, after a set delay, the PV systems would automatically spring back to life reducing the net load on the feeder and complicating restoration. On feeders with a lot of PV the impact would be even worse.

Of course, these problems with PV would only occur during the daytime. So system operators would need different procedures for day or night conditions. And, since a major blackout might take 12 hours or more to fully restore, restoration would probably occur partially in the day and partially in the night.

Possible mitigation measures

There are some reasonable measures to mitigate the negative impacts of wind and rooftop PV. There are also some more extreme options.

Conventional generation

Obviously enough conventional generation with black-start capability would allow a successful restart. Most simple-cycle combustion turbines can black start. Similarly, the combustion turbine sections of combined-cycle plants can usually also provide black-start capacity.

Increased inertia and fault currents

System inertia and fault current are reduced as more wind and solar generation (and less conventional generation) operates. One solution is to use synchronous condensers to increase rotating inertia and fault currents. Synchronous condensers are physical devices connected to the power system that rotate at synchronous speed. The actual device is very similar to the electrical portion of an electric generator. It includes a rotor, stator and exciter just like a generator. The big difference is that they do not have anything that provides mechanical power to produce MW. Generally it is the mechanical power source that is by far the largest and most complex part of a generating plant. A synchronous condenser is a much smaller and simpler device. They provide rotating inertia (though much less than a complete generator) and they can briefly provide fault current of about 400% of rated output.

It is also possible to provide “virtual” or “synthetic” inertia using electrical storage with inverters. These devices can provide power to help stabilize system frequency. They operate continuously, briefly supplying and absorbing power to moderate frequency fluctuations. During more extreme frequency excursions, they can provide their full output.

UVLS and UFLS systems

The UVLS and UFLS systems need to be reviewed and rethought. The faster frequency drop with high levels of wind and PV, requires re-evaluating settings for UVLS and UFLS. In general, more customer load will need to be shed to control the frequency drop. More feeders will need to be controlled by the UFLS and UVLS systems and they will probably need more "steps." These steps will need to start at a higher frequency and trip more load to effectively stop the frequency decline or voltage collapse.

The UVLS and UFLS systems also need to be adjusted for day and night operation. Feeders with a lot of rooftop PV will need different settings for day and night times. This may require different hardware, communication and control systems than now used.

Present practice and regulations set the standards for connecting rooftop PV. These include requirements about disconnecting when feeder power is lost and the delay in restarting after power is restored to the feeder. The coincident restart of these PV units is a problem. A flexible requirement that allows rooftop PV to use different restart delays would reduce the coincidence problem.

Inverter capability and design

Advances in inverter design can give them four-quadrant control. This means that they can control ±MW and ±var output (all four quadrants). This is a big advantage because these inverters can help control voltage either by raising or lowering their var output.

These four-quadrant inverters are becoming the standard for new wind and large PV systems in the US and Europe. They are not now required in the NEM. These inverters cost somewhat more than their simpler brethren, but offer vital functionality as the amounts of wind and PV become high. They become even more valuable when associated with energy storage (discussed below).

South Australia interconnections

South Australia is the part of the NEM that has the most wind and PV. The state is interconnected with Victoria through a 500/275 kV AC double-circuit transmission line at Heywood and an HVDC connection to Red Cliffs. The HVDC connection is limited to about 220 MW and 460 MW for the AC connection. (The AEMO is in the process of increasing the AC connection limit to 650 MW.)

The South Australia load is typically 1,000 MW to 1,500 MW. Installed thermal generation is about 2,500 MW. The state has about 600 MW of PV and 1,500 MW of wind with several hundred MW more under construction. There will be many hours when this wind and PV will almost completely serve the load with no operating conventional generation. We understand that there have been times when the South Australia load was entirely served by renewable generation.

This is a very vulnerable interconnection in that the loss of the AC interconnection would likely cause a statewide blackout during hours when wind and solar generation was high. Strengthening the interconnection between South Australia and Victoria could significantly improve this situation.

Energy storage

Energy storage may be the "great wild card" regarding integrating wind and PV. Inexpensive energy storage would mitigate most of the issues discussed above. It could be used to control ramp rates of wind and PV, allow greater voltage control and improve feeder stability.

Regulators could require storage for new wind generators to control ramp-rates and provide some black-start capability. Other studies have shown that, as wind and solar account for more than about 15% of peak load, storage for ramp-rate control should be required.[21] Other systems have found that limiting ramp-rates to 10% of rated output per minute was effective.

Energy storage would allow four-quadrant inverters to function under a wide range of conditions. They could provide ramp-rate and voltage control as discussed above. They could also be used to improve stability by quickly varying their output under transient conditions.

Besides dedicated energy storage, customer devices like electric vehicles can provide much of the same benefits. It is also possible that the transmission owner could place energy storage at key substations to improve system operation under normal and black-start conditions.

Of course, this depends on the economics of storage. Technically, however, energy storage would be very effective in mitigating the impact of high wind and PV penetrations in the supply system. Properly designed inverter controls would allow storage to be used as black-start capacity to help restore the system.

21. P. J. Palermo, Chen, K., Korinek, D., "Small Island Experience—Planning to Integrate Large Amounts of Wind and Solar Generation", Cigré International Symposium, *Best Practice in Transmission and Distribution in a Changing Environment*, Auckland, September 2013

CONCLUSIONS

General conclusions regarding major blackouts

1. Outages

   a. Transmission versus generation causes—the blackouts reviewed in Task 1 were all initiated by unexpected transmission events. A transmission failure leads to a very rapid increase in loading or decline in voltages leading to a series of other equipment trips. The result is a sudden, usually large, uncontrolled customer outage.
   In contrast, with a generation shortage there is usually at least several hours of advance warning of an impending shortage. These result in controlled rotating customer outages.

   b. Not at peak load—none of the events occurred under peak load conditions. It is common to study peak conditions, but the system is often more vulnerable during off-peak seasons when generating units are not dispatched or on maintenance. There are also usually transmission maintenance outages—that have led to errors that cause outages.

   c. In all these blackouts there were multiple contingencies, beyond normal operating and planning criteria.

2. Restoration

   a. Situational awareness is an important first step. In some cases, lack of awareness was an important factor that delayed restoration.

   b. Where interconnections were available (not Hawaii or Sarawak) operators used them early in restoring the system.

   c. There are usually electrical islands that maintain service through the blackout.

   d. With widespread outages

      - Usually some equipment fails beyond the initiating causes; and
      - Some setbacks occur during restoration, usually due to voltage control problems.

General conclusions regarding black-start requirements

1. Energizing parts of the system within 3-4 hours is common, but fully restoring the system may take 12 hours or more.
2. None of the systems require a percentage of load to be ready to be restored. Some have specific critical loads, usually nuclear power station auxiliary supplies, that need to be restored first and to be energized in 3-4 hours.
3. Multiple black-start resources should be available, though they can be in neighboring networks.
4. There are few specific requirements for voltage control, though, obviously, voltages must be within safe limits.
5. Black-start studies are usually conducted for normal conditions.
6. None of the systems reviewed here, consider fuel diversity in identifying black-start generation.

Specific comments for the AEMC and NEM situation:

1. In a major blackout there will be quite a bit of initial confusion—30 minutes to assess the situation and for restoration to begin is common;
2. The four-hour requirement for the SRS objective as shown in Figure 1 on page 4 is consistent with international experience with major blackouts;
3. International experience shows that fully restoring customer load can take 12 hours or more following a major blackout;
4. Practicing a black-start plan, as demonstrated by Detroit Edison and Consumers Energy, speeds restoration;
    a. Positioning personnel;
    b. Opening breakers for a "clean start;" and
    c. Understanding voltage issues in a black-start;
5. Not all planned generation will operate as expected;
6. There will usually be some electrical "islands" that remain in service;
7. All generators, that can help following the blackout, will help regardless of the SRAS status;

8. Controlling high voltages on transmission lines will be a common problem, so operators should have relevant training;
9. The AEMO must have clear authority to settle any disputes between stakeholders during restoration;
10. Transmission interconnections are used early in restoring the system.
11. A study of UFLS and UVLS is needed to determine the proper amounts, frequency settings, and step sizes;
12. A survey should be made of feeders in South Australia, and any other place with high PV penetration, to identify those with significant amounts of rooftop PV;
13. Consider revising connection standards for wind and rooftop PV in South Australia regarding:
    a. Restart settings,
    b. Low-voltage ride-through, and
    c. Low- and high-frequency ride-through,
    d. Storage for ramp-rate control (and black-start support);
14. Consider adding requirements for storage associated with large wind farms and as community storage;
15. Additional interconnections between South Australia and Victoria should be studied;
16. A survey should be made of combustion turbines and combined-cycle gas fueled units regarding their black-start capability;
17. There should be adequate communication and control with wind farms so that system operators can maintain control for at least four hours without external power;
18. Develop methods to include wind in restoration plans for South Australia; and
19. Ways to monitor and include rooftop PV in restoration should be investigated.