The San Diego Blackout 8 September 2011

The same neglects as in previous blackouts

Blackouts cannot be avoided. A blackout is always an unfortunate concatenation of circumstances. Blackout investigation reports are extremely useful for power system operators. They are opportunities to evaluate your own power system for possible weak spots.

The San Diego blackout is a typical case. The blackout affected the following areas:

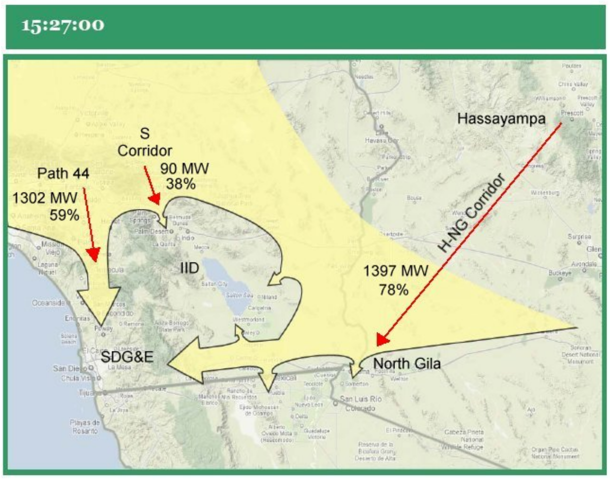
- San Diego Gas & Electric (SDG&E): 4293 MW lost for up to 12 hours.
- Comisión Federal de Electricidad (CFE): 2205 MW lost for up to 10 hours
- Imperial Irrigation District (IID): 929 MW lost for up to 6 hours
- Arizona Public Service (APS): 389 MW lost for up to 6 hours
- Western Area Power Administration – Lower Colorado (WALC): 74 MW lost for up to 6.5 hours

The Bulk Power System in the western part of North America is coordinated by WECC (Western Electricity Coordinating Council).

The power systems concerned are planned and operated in accordance with current operating standards. Nevertheless a routine switching to isolate a capacitor bank could start cascading outages which after 11 minutes had caused the loss of nearly 8 GW load. The investigation report[1] explains the complex combination of circumstances which undermined the defence lines of the operational security.

This note will give a brief overview of the sequence of events and comment on selected findings with particular relevance to European grid conditions. Interested readers are encouraged to read the full FERC/NERC report.

The Sequence of Events



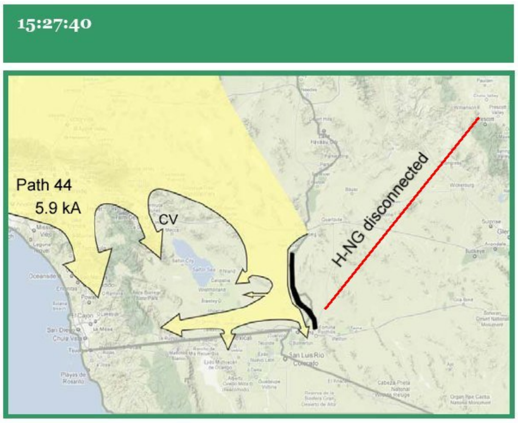
September is generally considered a "shoulder" season, when demand is lower than peak seasons and generation and transmission maintenance outages are scheduled.

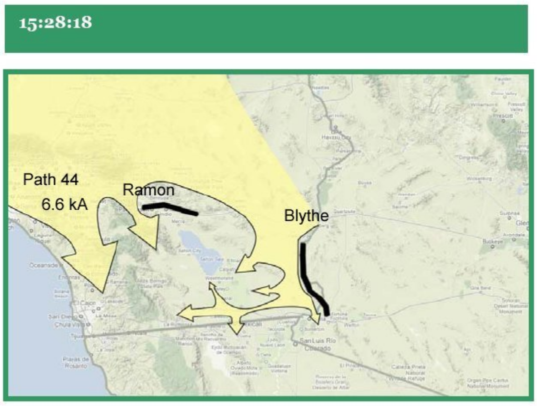
8 September was a rather normal, hot day. The SDG&E import was 2539 MW or 89% of system operating limits. The transport corridors were operated well within safe limits.

The initiating event was a routine switching to isolate a capacitor bank at North

[1] Arizona-Southern California Outages on September 8, 2011 – FERC/NERC, April 2012

Gila in Arizona. The switching was carefully planned. The technician had completed step 6, but was distracted by other communication and wrote the time on the line for step 8 in his check list. Therefore he skipped two steps and continued with step 9. The result was an arc over the switch and the automatic disconnection of the 500 kV line Hassayampa-North Gila (H-NG).



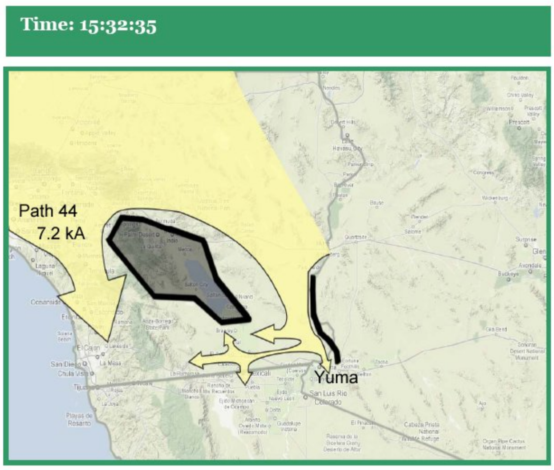


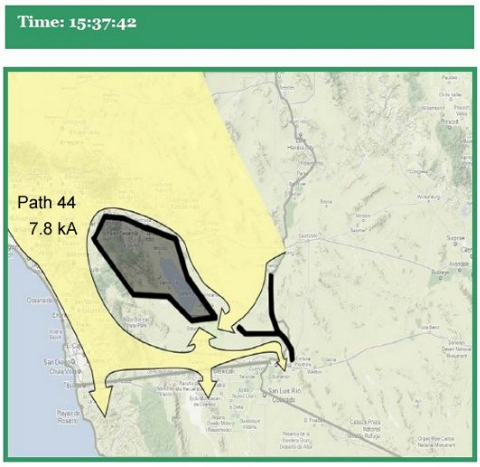
After the disconnection of H-NG the flows were redistributed. Flow on path 44 increased by 84% to 2,362 MW or 5.9 kA. At 8.0 kA the SONGS[2] separation scheme would be initiated.

At IID's Coachella Valley (CV) the load of two 230/92 kV transformers increased from 83% to 130% of their nominal rating due to parallel flows in 500 kV, 161 kV and 92 kV grids. At 15:28:16 both transformers tripped for overload. The tripping open-ended the 230 kV line CV-Ramon.

The loss of the CV banks caused a severe voltage depression on the WALC 161 kV system south of Blythe.

Four minutes after the loss of the CV banks the Ramon 230/92 kV transformer tripped for overload and within seconds IID experienced 444 MW under-voltage load shedding. IID also began losing generators and transmission lines. During this phase the current on path 44 peaked at 7.8 kA, but stabilised at 7.2 kA.





[2] SONGS: San Onofre Nuclear Generation Station

CAISO (California Independent System Operator) attempted to bring path 44 back within its limit of 2,500 MW by redispatch. It would have taken 30 minutes.

About 8 minutes after H-NG tripped two 161/61 kV transformers tripped in the Yuma area. The path 44 current increased to 7.4 kA. One minute later another couple of transformer tripped in the same area and the path 44 current increased to 7.8 kA approaching the 8.0 kA limit for initiation of the SONGS separation scheme.

Several other lines and generators tripped and 11 minutes after H-NG tripped the SONGS separation scheme operated. The operation effectively separated SDG&E from the rest of the Western Interconnection. It created an island consisting of the SDG&E system, the remaining Yuma-area load, and CFE's California Control Area.

The SDG&E/CFE/Yuma island had a significant imbalance between generation and load. The activations of the Under Frequency Load Shedding (UFLS) programs was not able to prevent the island from collapsing.

Selected findings

Power system security has been compared with air traffic security. In both cases complex systems must be operated in accordance with a security strategy which requires specific instructions to be followed to the letter.

The security strategy for power systems has long ago been well developed based on experiences from previous blackouts. However, several operators seem to ignore important details of the instructions. A selection of the 27 findings in the San Diego blackout investigation report is presented below.

No	Finding	Comment
1	Failure to Conduct and Share Next-Day Studies	It is important to analyze system security for each time step of the day-ahead planning, but it is equal important to share the details with neighboring system operators. This problem has also been an issue for disturbances in Europe.
2	Lack of Updated External Networks in Next-Day Study Models	As above: is the data on neighboring grids sufficient and updated every day?
3	Sub-100 kV Facilities Not Adequately Considered in Next-Day Studies	In West Denmark we avoided parallel loops via 60 kV grids. The cost of this policy was a small risk of brief local interruptions of service.
6	External and Lower-Voltage Facilities Not Adequately Considered in Seasonal Planning Process	Shortage of reactive resources plays an important role in practically every blackout.
8	Not Sharing Overload Relay Trip Settings	This problem was decisive in the European power failure in November 2006.
11	Lack of Real-Time External Visibility	"External" could be neighboring systems or local sub-100 kV systems
12	Inadequate Real-Time Tools	The tools should be adequate "and run frequently enough to provide their operators the situational

		awareness necessary to identify and plan for contingencies and reliably operate their systems”
13	Reliance on Post-Contingency Mitigation Plans	This case is interesting because the contingency was considered, but the mitigation plan was based on manual procedures for which the time was insufficient in this case.
17	Impact of Sub-100 kV Facilities on BPS (Bulk Power System) Reliability	It is the most robust solution to avoid parallel loops in the sub-100 kV systems. If such loops cannot be avoided they should be efficiently included in the seasonal and daily planning and in the real time control. This measure could have prevented the collapse.
18	Failure to Establish Valid SOLs (System Operating Limits) and Identify IROLs (Interconnection Reliability Operating Limit)	The investigation team says that the cascading events show that an IROL was violated on 8 September, but not recognized by WECC.
24	Not Recognizing Relay Settings When Establishing SOLs	Some protective relays were set to trip below the established emergency rating. The transformers concerned tripped during the restoration process and delayed the restoration to the Yoma load pocket.
25	Too Narrow Margin Between Overload Relay Protection Settings and Emergency Rating	A narrow margin between emergency rating and overload relay protection setting does not allow the operator time to take relevant control actions. Both CV transformers tripped at 127% of their normal rating.[3]
27	Phase Angle Difference Following Loss of Transmission Line Not Measurable	WECC was informed that H-NG line would be restored quickly. However, due to a 72 degrees phase angle difference this was not possible because the synchrocheck relay was set at 60 degrees. The problem was that the operator had no idea of the phase angle. The case suggests widespread use of PMUs (Phasor Measurement Units).

Hopefully the findings and recommendations of the investigation team will serve as checklist for European transmission system operators. Most of them probably have room for improvement.

The work of the investigation team was divided into
- Planning (findings 1 to 10)
- Situational awareness (findings 11 to 16)
- System analyses (findings 17 to 27)

This structure does not include design of equipment. The fatal operation of the disconnect switch at the capacitor bank could have been blocked if essential conditions for the operations were not fulfilled. It is an open discussion to which degree such preventing precautions should be installed, but the investigation report does not mention the question.

[3] PRC-023-1 R.1.11 requires relays to be set to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greatest.

The same neglects as in 2003

On August 14, 2003, an estimated 50 million people throughout the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout.

Appendix C of the new investigation report is an interesting comparison of the two events. It concludes:

> “First, affected entities in both events did not conduct adequate long-term and operations planning studies necessary to understand vulnerabilities on their systems. Second, affected entities in both events had inadequate situational awareness leading up to and during the disturbances. In addition to these two underlying causes, both events were exacerbated by protection system relays that tripped facilities without allowing operators sufficient time to take mitigating measures.”

This is a very good summary.

The detailed comparison of findings is alarming evidence that the recommendations from 2003 to a large extent have been neglected.

It is a question if the operational security of the power systems is generally considered to be satisfactory or if the transmission system operators should regularly document that a certain minimum of security rules are fulfilled.