Generation Reserves:

The Grid Security Question

A cost-benefit study shows the value of adding synchronized generating reserves to prevent blackouts on the scale of Aug.14.

By Rajat K. Deb

If nothing else, the blackout of Aug. 14 showed just how physically vulnerable the electric transmission network has become to problems that begin at a very localized level. That vulnerability stems in part of the greater volume of long-distance transactions imposed on the grid by today's power industry.

But the blackout also revealed a greater truth, one that can be spelled out in economic terms. Considering the huge social cost of such events, it should be worth our while to consider virtually any investment of a reasonable scale that might provide us a fair degree of security against a repeat occurrence.

And if that investment could take the form of a simple addition to the supply of generation—rather than the more costly and politically more complicated alternative of adding transmission lines—then so much the better.

As it happens, that turns out to be precisely the case—that judicious and targeted additions of generation reserves, synchronized with the grid for easy availability, could have turned things around in the Midwest on Aug. 14, according to the findings of a study conducted by my firm.

The study of the Eastern Interconnection we performed, using a real-life configuration of the system, indicates that grid reliability can be achieved not only by transmission investment, but also by increasing the availability and flexibility of the generation resources. Grid operators face a challenge in allocating reserves, both synchronized and standby, across various control areas within the grid. Using a model that optimizes market operations centrally across the grid, and which takes into consideration grid security and cost in day-ahead markets and dispatch, can enhance the reliability of the system and reduce the occurrence and extent of blackouts.

In fact, the Federal Energy Regulatory Commission (FERC) has recommended a very similar sort of solution. For example, FERC Order 2000 clearly has identified the procurement of ancillary services to maintain grid reliability as a vital function of regional transmission organizations (RTOs). More recently, in its standard market design (SMD), FERC recommends a security constrained unit commitment (SCUC)—another hallmark of PJM and other regional grid groups that have developed bid-based power markets with locational marginal pricing (LMP).

Consequently, it is our belief that these functionalities proposed by FERC are crucial and will go a long way in improving grid reliability. Some grid operators are missing some elements of SCUC. An ideal implementation of SCUC should incorporate sufficient N-1 and N-2 contingency planning (first- and second-level contingencies), as well as remedial action schemes applied to certain groups of transmission lines, in conjunction with sufficient amounts of synchronized operating reserves that support the generation resource commitment.

Simulations and Observations

We performed simulations that included bidding, unit commitment and dispatch, as well as planned and forced generator outages, and forecast the amount of unserved energy (or load curtailment) in each hour at each location on the network. In our analysis, we varied the level of synchronized operating reserve to examine its effect on unserved energy.

Our analysis, based on representative transmission grid data available from FERC filings, incorporated many of the line and generator outages that took place on Aug. 14. The system represented includes the greater part of the Eastern Interconnection and is made up of approximately 5,000 buses and 6,500 transmission lines, of which 2,500 are monitored. Table 1 summarizes characteristics of the modeled system.

To perform the simulations, we used LCG Consulting's proprietary model, UPLAN-NPM,[1] which integrates a detailed representation of generating resources, demand, and the transmission network. UPLAN models contingencies accurately and has a rich structure to capture all the elements of day-ahead market that allocate resources for energy, synchronized reserve, standby reserve, and capacities across the entire network. We also modeled the dispatch of the allocated resources using an optimal power flow.

TABLE 1 — SIMULATED SYSTEM

System Details	Description
System Configuration	NY-ISO, PJM, IeMO, MISO
Transmission System	4,948 buses, 6,530 lines, 445 N-1 contingencies, 2,553 monitored lines
Loads	37 load serving control areas, 227 GW peak load, 4,524 GWh demand for on 14
Supply	2,433 generating stations with a cumulative available capacity of 308 GW

TABLE 2 — SEQUENCE OF GRID FAILURES

Scenario No.	Time	Description
1	3:06 PM	Eastlake unit trips, Chamberlain-Harding line off
2	3:32 PM	Hanna-Juniper line off
3	3:41 PM	Star-South Canton, Tidd-South Canton lines off
4	4:06 PM	Sammis-Star line off
5	4:09 PM	E.Lima-Fostoria, Muskingum-Ohio Central lines off
6	4:09:31PM	MCV and KinderMorgan units (1,800 MW total) trip
7	4:10:40 PM	30 transmission lines in Michigan go out of service; ITC separated from rest of Michigan
8	4:10:46 PM	12 additional generating units in Michigan trip

TABLE 3 — INCREMENTAL UNSERVED ENERGY, CONSUMERS' COST[1] AND PRODUCERS' COSTS WITHOUT CONTINGENCY PLANNING RELATIVE TO THE REFERENCE CASES

Scenario No.	Online Synchronized Reserves	Incremental Unserved Energy (GWh)	Incremental Consumer Cost (thousands of dollars)	Incremental Cost of Production (thousands of dollars)
7	None	35.91	64,728	11,677
7	3.5%	28.15	33,876	9,510
7	7%	18.38	15,356	6,593
8	None	82.91	208,021	23,990
8	3.5%	73.44	156,364	22,898
8	7%	63.46	102,157	20,060

1. These costs represent incremental costs or benefits over the reference case, which simulates the normal case, without any of the outages associated with the blackout, and the same level of operating reserves as in the cases with outages.

TABLE 4 — INCREMENTAL UNSERVED ENERGY, CONSUMERS' COST, AND PRODUCERS' COST WITH CONTINGENCY PLANNING

Scenario No.	Incremental Unserved Energy (GWh)	Incremental Consumer Cost (thousands of dollars)	Incremental Cost of Production (thousands of dollars)
7	12.81	18,624	8,245
8	45.90	82,283	19,995

Simulations With Flexible Operating Reserves to Avoid Cascading Outages

The sequence of eight scenarios described in Table 2 represents the cascading events that took place between 1:30 p.m. and 4:10 p.m., on Aug. 14.[2] The scenarios reflect escalating line and generator outages preceding the blackout itself, and they include the results relating to the last two scenarios of failures that ultimately led to the blackout. For instance, Scenario 8 event is equivalent to a full-scale Aug. 14 event.

For the sake of simplicity, we focus on two of these scenarios (Nos. seven and eight). For those two cases, we describe the results that would have followed (how much loss of load, how much incremental cost to duplicate the lost production and deliver power to consumers, etc.) if, at the time of the events of Aug. 14, the grid operators in the Midwest and the Eastern Interconnect had had at their disposal any one or more of three different hypothetical sets of synchronized generation reserves and contingency plans, or lack thereof. To make the comparisons relevant, we assumed certain costs for operating this system, by estimating the costs for the region covering the Midwest, New York, Ontario, and PJM.

These results, shown in Table 3, clearly indicate that increases in the availability of synchronized operating reserves reduce the amount of unserved energy. For scenario 7, raising the synchronized reserve requirement from 0 to 3.5 percent reduces the level of unserved energy by more than 7.7 GWh (22 percent), and raising the requirement further to 7 percent lowers unserved energy by 17.5 GWh (49 percent) (*see table 3*). Similarly, for scenario 8, increasing the synchronized reserve requirement from 0 to 3.5 percent and then to 7 percent lowers the unserved energy by 9.5 GWh (11.5 percent) and 19.5 GWh (23.5 percent), respectively.

Furthermore, as synchronized reserves are increased, the incremental production costs are lower, as are the incremental consumer costs. Increasing the synchronized reserves to 7 percent lowers the consumer cost, as the consumers do not have to pay high energy prices for emergency sources.

These declines in consumer cost are magnified in scenario 8.

Comparing the two cases for 0 percent and 7 percent reserves of synchronized generation, we notice that for the latter case, sales increase by 19.45 GWh (82.91-63.46), due to decreased unserved energy (or load curtailment). The production cost accordingly decreases by $3.93 million (23.93-20), due to decreased payments of unserved energy, which is assumed to be $200/MWh for load interruption. The impact of the lower production cost results in lowering of the market prices of electricity and $106 million (208-102) in direct benefits to ratepayers, because 19.45 GWh of additional energy was available at a lower price in a day (*see Table 3*).

Of course, the impact of the blackout to the society is not necessarily restricted to the direct cost of megawatt-hours of electricity loss. If we consider all the indirect costs such as loss of industrial/commercial production, and the temporary collapse of infrastructure, it may run to billions of dollars. For instance, the *Salt Lake Tribune* in its Aug. 28 issue estimates the Aug. 14 blackout cost to the entire society to be more than $4 billion.[3]

Generation For Reliability: Seven Recommendations

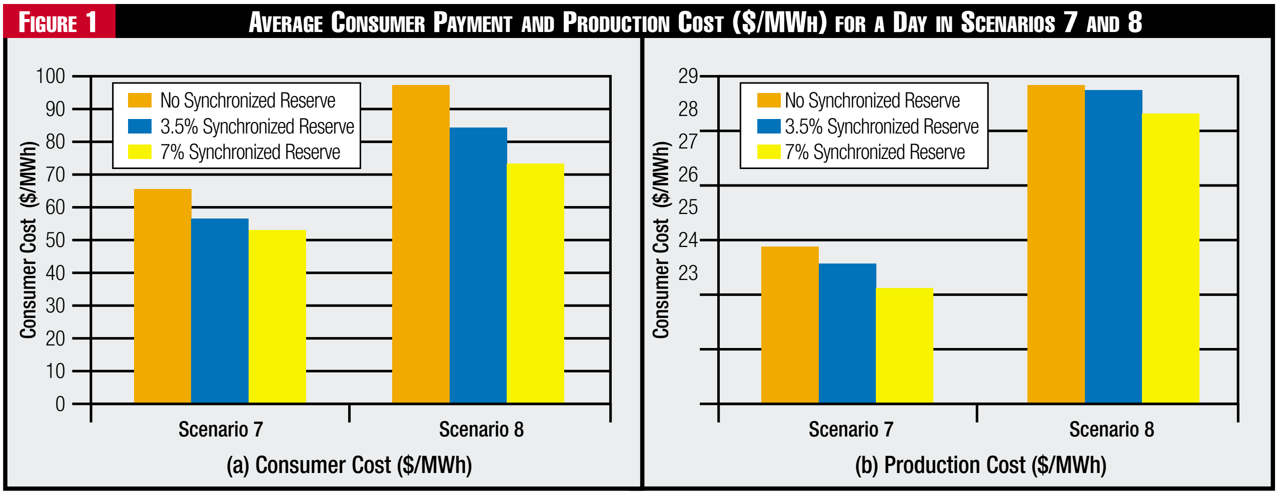
- Optimize the operating reserve, using more flexible generators with quick response.
- Increase the synchronized (on line) operating reserves.
- Select on line reserve units, taking into consideration location, response time, and frequency of loop flow in the system.
- Improve interregional coordination among different control areas so as to determine the quality, quantity, and strategic location of the reserves
- Encourage investment in transmission.
- Conduct integrated generation-transmission studies on a regular basis across the entire grid for a large number of contingency scenarios, using a model that realistically represents the system, such as UPLAN, over a period of time, over the operating horizon of the system.
- Reduce the cost of improving reliability by conducting integrated generation-transmission optimization over the planning horizon of the system.

The cost of providing additional reserve for an entire year may in fact be far lower than the societal cost.

As an example, consider that for a large system of 100 GW, an additional 4 percent of synchronized spinning reserve requires approximately 4,000 MW per hour. If we assume the cost of spinning reserve to be $5/MW, then the total cost per year is estimated to be $175.2 million (5x4,000x8,760), or $3.5 billion in 20 years—far less than the total societal cost of a blackout every 20 years of $4 billion (*see Figure 1*). In other words, if we can avoid even a single blackout in 20 years, then the cost associated with carrying 4 percent additional synchronized reserve is justified. Also, NERC already has recommended spinning reserve of 3 to 4 percent for each of the control areas.

Figures 1 (a) and 1 (b) show the impact of securing sufficient synchronized reserves on consumers' cost (payment) and production cost on a $/MWh basis, respectively. This reflects the ability of the system to respond efficiently by strategic selec-

Figure 1 **Average Consumer Payment and Production Cost ($/MWh) for a Day in Scenarios 7 and 8**



tion of reserves, even without the use of contingency planning.

Contingency planning can further improve the ability of the system to handle emergencies, as the following results show. In Table 4, we show results with contingency planning, assuming a 3.5 percent synchronized operating reserve. The incremental values for consumers' costs and production costs shown are in comparison with the reference case in which 3.5 percent synchronized operating reserves and contingency planning also were in effect, but in which no outages or failures leading up to the blackout occurred.

FIGURE 2 **UNSERVED ENERGY (GWH) FOR DIFFERENT SYNCHRONIZED OPERATING RESERVE MARGINS FOR A DAY IN SCENARIOS 7 AND 8**

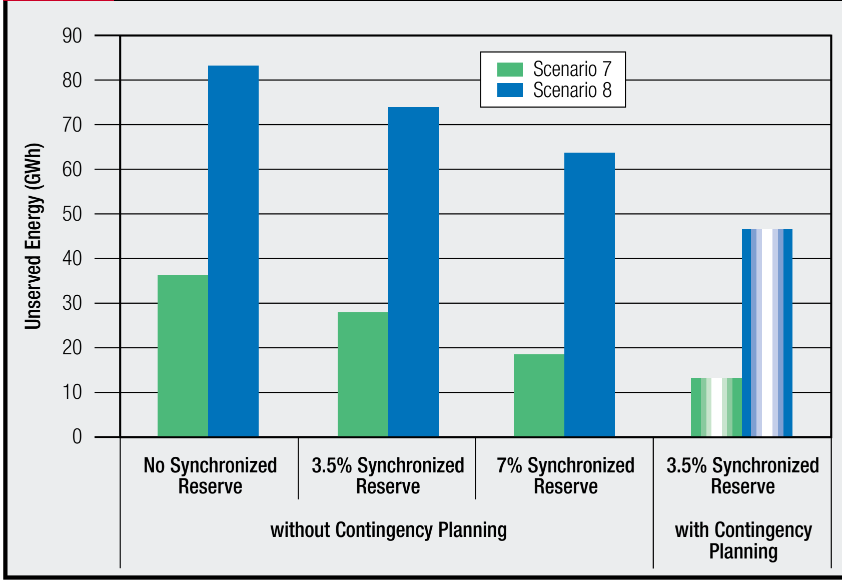
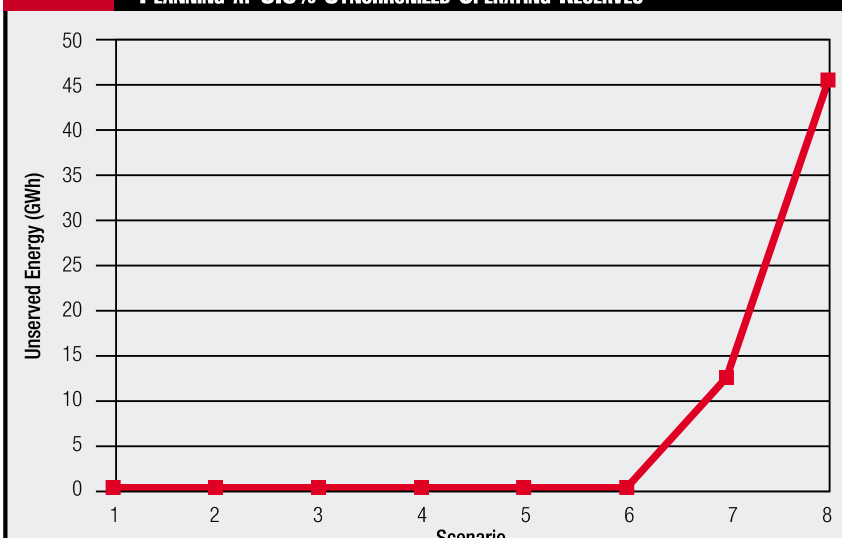


FIGURE 3 **LEVEL OF UNSERVED ENERGY (GWH) UNDER 8 SCENARIOS WITH CONTINGENCY PLANNING AT 3.5% SYNCHRONIZED OPERATING RESERVES**



This case can be compared to the 3.5 percent case without contingency planning in Table 3. Figure 2 summarizes the unserved energy for all four cases in scenarios 7 and 8. With contingency planning, we can see that unserved energy is 12.81 GWh, lower by 55 percent, and 45.90 GWh, 38 percent lower, in scenarios 7 and 8 respectively. Contingency planning involves preventive actions for the failure of a line or power plant that changes the flows across the power system, putting other lines at risk and creating new vulnerabilities, experts say. Sometimes the contingency analysis will identify a single line or generating station that, if it failed, would cause a cascading blackout. To eliminate the possibility of additional failures causing a blackout, operators change the power flows by starting some generators and reducing power to others. Contingency planning is a part of SCUC, which has been proposed in FERC's SMD.

The consumers' cost has decreased by $15 million and $74 million, respectively, for scenarios 7 and 8 compared with the no-SCUC cases, as shown in Table 4.

Similarly, the producers' costs for the day have decreased by $1.3 million and $2.9 million, respectively. This case clearly demonstrates the benefits of contingency planning across the entire network. In this case, the blackout is controlled, and as a result is confined to a much smaller area. That reduces unserved energy considerably, and consumers benefit because of increases in the efficiency of the generation. This case shows that we can obtain better security with the existing system, which is economically beneficial to the customers.

By comparing the daily costs that producers incur when contingency planning is in place with their costs when no contingency planning is used, we can quantify the cost to producers of contingency planning on a typical day when no outages occur. The two cases, besides assuming no outages or failure, incorporate 3.5 percent synchronized operating reserves. They show that the recurring cost of committing additional units

GLOSSARY:

Security Constrained Unit Commitment (SCUC): The commitment of sufficient amount of generation resources to meet sufficient demand while meeting all transmission constraints, reserve requirements, and generator operating constraints.

Synchronized Operating Reserve: Operating reserves provided by synchronized resources such as regulation or spinning reserves that can respond immediately to dispatch instructions.

Security Constrained Economic Dispatch (SCED): The determination of the generation dispatch that incorporates all transmission security constraints such as flow limits, interface limits, and contingency constraints necessary for reliability. SCED assures that the units committed by SCUC are dispatched across the entire network to minimize the total dispatch cost and provide additional security by committing out-of-schedule units to meet unforeseen requirements at the dispatch time.

and operating them at minimum loading to provide security-constrained unit commitment and economic dispatch adds $1.969 million per day ($719 million per year), which is approximately 1.95 percent more than the annual operating cost of $39 billion. In terms of total customer payments, that represents an increase of 0.04 cents per kilowatt-hour. FERC proposes both operating reserve (ancillary services) and contingency planning. Our analysis has shown that the combination of 3.5 percent synchronized reserve and appropriate N-1 and N-2 contingency planning provides the greatest benefits in a cost-effective manner.

Figure 3 shows how the contingency planning with 3.5 percent synchronized reserve can effectively eliminate unserved energy in scenarios 1 through 6. Scenarios 7 and 8 assume that the sequence of cascading outages already has taken place and the affected generators and the transmission lines are no longer available to the system operator. In reality, the SCUC may prevent the sequence of cascading outages well before the blackout takes place. Our simulations illustrate that even if the operator is unable to stop the outages, the customer disruption is contained, and unserved energy is considerably reduced.

Rajat K. Deb, Ph.D., is president of LCG Consulting, Los Altos, Calif. He has more than 30 years' experience in energy industry and academia, and has contributed extensively to both theory and practice in the energy field. Dr. Pushkar Wagle, Dr. Paresh Rupanagunta, Richard Clark, Nick Brown, and Anrica Deb have provided valuable comments and suggestions for this paper. Dr. Deb can be reached at deb@energyonline.com or 650-962-9670.

Endnotes

1. UPLAN-Network Power Model (NPM) is fully compliant with FERC's standard market design (SMD) and meets all the functional requirements of a regional transmission organization (RTO) proposed in FERC Order 2000. The model can accurately dispatch generators as well as forecast locational marginal and zonal prices. Locational marginal pricing (LMP) is the basis for congestion management in the proposed SMD and is used in many RTO/ISOs, including PJM and NY-ISO. UPLAN's Security Constrained Unit Commitment (SCUC) and Security Constraint Economic Dispatch (SCED) for real-time dispatch meet all the requirements of optimally allocating generating and transmission resources to meet all the constraints and fulfill the security requirements as specified by contingencies. UPLAN also models remedial action schemes to mitigate contingencies by taking appropriate remedial actions specified by ISOs and RTOs. UPLAN-NPM uses an Optimal AC/DC Power Flow algorithm with an embedded full-fledged contingency analysis package for real-time generator dispatch to manage congestion and determine LMP. The real-time dispatch algorithm is compatible with the programs used by most of the ISO/RTOs in the United States.
   In UPLAN-NPM, a multi-area, multi-commodity Nash equilibrium algorithm simulates the day-ahead market and determines the forward electricity prices as well as ancillary service prices such as regulation, spinning, reserve, and capacity prices.
2. As reported by the International Transmission Co., Aug. 17, 2003, *ITC Analysis of Grid Collapse*.
3. Anne D'Innocenzio, *The Salt Lake Tribune*, Wednesday, Aug. 28, 2003, estimates the cost of Aug. 14, 2003, outage to be more than $4 billion.