RELIABILITY TRADEOFFS

Recent events have raised questions about how to reach the level of reliability customers expect and that utilities can reasonably achieve.

Following the August 14 blackout and outages caused by Hurricane Isabel, utilities, customers, legislators, and regulators face questions about what constitutes the "right" level of reliability. While it's difficult to attach an exact value to these events, the economic impact has been severe and has put a strain on public tolerance. The cost of bringing reliability to "acceptable" levels and the desire to support such investments has not been fully assessed, nor is it clear what constitutes a reasonable balance between reliability performance and the willingness or ability of customers to pay.

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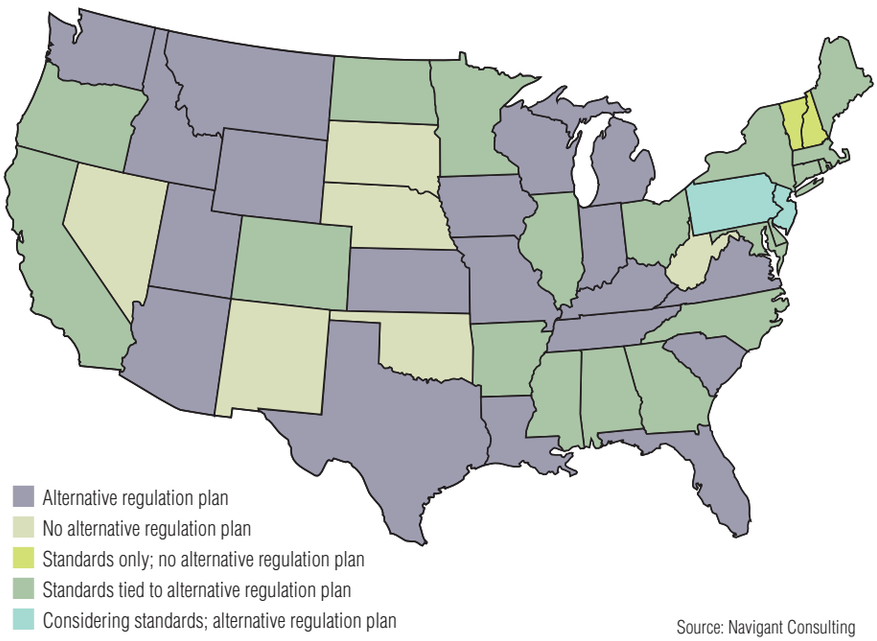
FIGURE 1

STATES ENACTING RULES FOR PERFORMANCE BASED RATES



Source: Navigant Consulting

Utilities have been reluctant to undertake massive investments in their power delivery systems, partly due to regulatory pressure to hold down rates and to avoid uneconomic investments. Notions of moving lines underground, making equipment less prone to failure, and increased redundancy all have appeal, but often are expensive alternatives. Further, the level of investment needed to improve or harden the system to maintain high reliability under all conditions may be greater than ratepayers are prepared to accept.

Meanwhile, state public utility commissions (PUCs) increasingly use performance-based rates (PBR) as a mechanism to hold utilities accountable for reliability performance. (See Figure 1.) PUCs even have imposed financial penalties for sub-par performance—such as a penalty of more than $3 million against a Northeastern utility in 2001 for failing to meet PBR targets and service quality benchmarks.

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Other states such as California and Texas previously developed utility-specific targets for customers and feeders that experience interruptions exceeding predetermined thresholds. The industry has seen striking examples in those states of regulators' willingness to impose fines and mandates: In one case, a Western utility was penalized more than $20 million for inadequate vegetation management practices. Another utility is still reeling from an ongoing investigation by state regulators into its reliability reporting practices.

It's clear the pressure is on. Indeed, the industry may need to find new ways to measure reliability *and* also make critical investment choices that are in the best interests of all industry stakeholders.

Taking Major Events into Account

Research demonstrates that customers perceive and care about differences in reliability, making it a driver of customer satisfaction (along with rates, image, and other aspects of customer service). For example, JD Power & Associates' residential customer satisfaction survey correlates customer satisfaction with power reliability and quality against the perceived frequency of power interruptions. (See Figure 2.) The relationship of these two factors is not perfect. For example, one "outlier" Northeastern utility has excellent reliability by industry standards, but its customers remain unsatisfied.

What is known, however, is that higher frequency of outages leads to lower customer satisfaction with power quality and reliability. But the economic implication of increasing customer satisfaction is daunting. For example, an increase in the System Average Interruption Frequency Index (SAIFI) of just 0.5 moves the "satisfaction" index up by 10 points. And, since "power quality and reliability" is only one of the components of total satisfaction—often with a weighting of 20-24 percent—the impact of this change might only be 2 to 4 points. Utilities familiar with this problem understand that moving SAIFI up by 0.5 could require a massive investment. For a utility with one million customers, a change of 0.5 in SAIFI would require avoiding 500,000 customer interruptions per year. If the cost of avoiding each interruption were $100 each (not untypical), the investment required could be $50 million. Yet it would only improve overall customer satisfaction by a few points.

As noted, commissions are not shy about imposing financial penalties when thresholds are not met; however, the penalty may be sufficiently low such that utilities may find that it's cost-effective to pay the penalty rather than implement the improvements needed to meet the threshold. Other commissions impose fixed penalties, such as $25 per customer once the threshold is exceeded. A utility may view the payment as a kind of "insurance" for customers that experience an above average number of failures.

Notably, commissions typically set

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Vegetation management and line relocation might mitigate a storm's effects. Hurricane-force winds are a different matter.

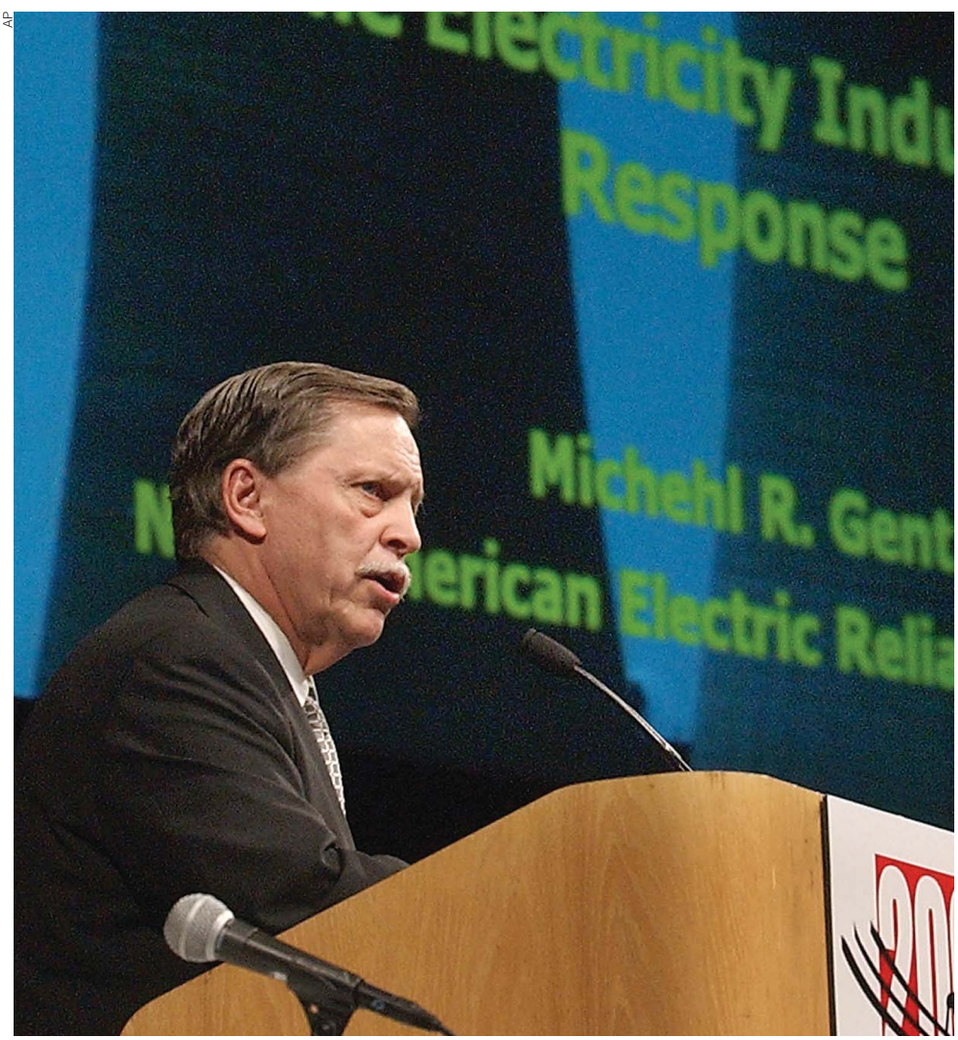
reliability thresholds that utilities must meet. They rely on the Institute of Electrical and Electronic Engineers' (IEEE) established standards that attempt to normalize reliability measurement by using statistical methods to weed out the "spikes" in the indices that arise from major storms.

One might question the logic of removing major events from incentive pricing mechanisms. Such exclusions suggest there is a disconnect when PBR is applied to normal events versus the profound economic impact of major events. (IEEE recommends major event delays be reported separately to regulators.)

At the federal level, the Federal Energy Regulatory Commission (FERC) is actively engaged in establishing national reliability standards. Energy legislation would also give FERC authority to mandate transmission upgrades and site new lines.

Reliability and Cost Trade-Offs

Utilities face an array of challenges as they try to upgrade their systems to withstand all types of major events. One of them is that the investments needed to minimize the impact of hurricanes and ice storms may be far different from those needed to avoid area-wide grid failures such as the Northeast blackout. Storm prevention often focuses on greater tree trimming or selective line relocations, relatively straightforward activities compared with complex facility and control upgrades—or new transmission—that may be needed to update the grid. Similarly, areas prone to lightning problems may rely on solutions that are not necessarily suitable for mitigating damage from hurricanes or ice storms.



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Michehl Gent of the North American Electric Reliability Council argues to make NERC standards mandatory.

FIGURE 2

POWER QUALITY AND RELIABILITY SATISFACTION

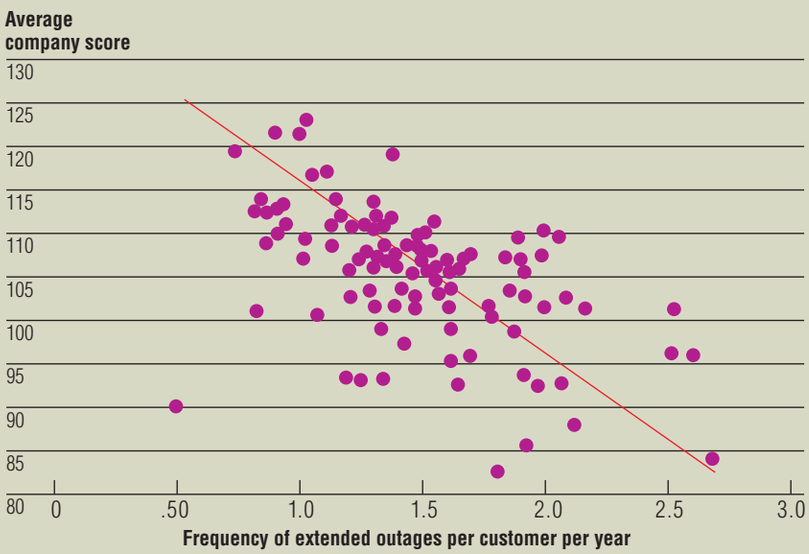
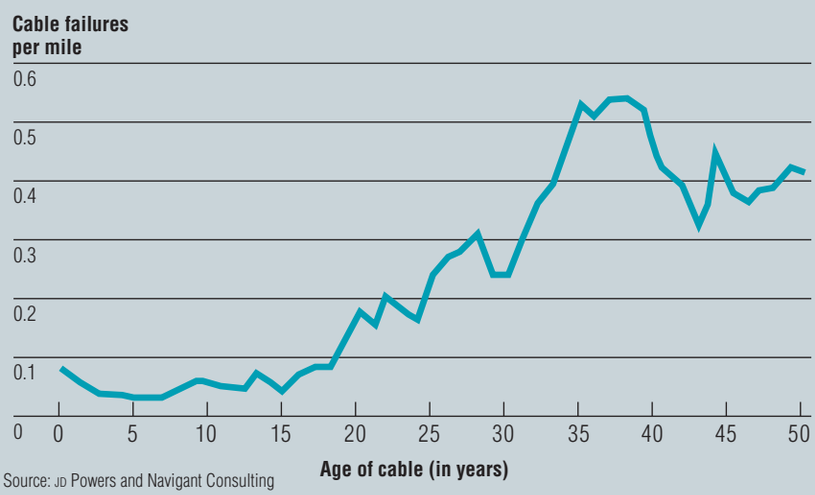


FIGURE 3

EQUIPMENT AGE: NOT A PROXY FOR CONDITION



Source: JD Powers and Navigant Consulting

Age alone is not always a determinant of equipment condition. In fact, replacing infrastructure components based on age is one of the *least* cost-effective ways of improving service. Better indicators are specific failure history, test results, or defective equipment. Other industries, including aerospace, automotive, and natural gas pipelines, have learned not to rely on age for replacement decisions.

Utility operations personnel often refer to wood poles as an example of how replacement based on age alone is fraught with problems. Crews are quick to point out that native pole species dating to the 1950s (or earlier) can have less decay than poles recently purchased from plantations. Similarly, many transmission lines in the United States and Canada built in the early part of the last century have withstood repeated storms and events without failure. Proactive maintenance has proven to be a wise choice for many transmission owners.

A significant amount of equipment often must be replaced to materially reduce failure rates, and not only older equipment, either. (See Figure 3.) Further, modified maintenance practices can bring equipment performance up to par with newer equipment.

The bottom line is that decisions to replace equipment should be made using fact-based criteria. There are several key features of such an approach:

- identifying the aspects of reliability that actually affect customer satisfaction;
- finding ways to cost-effectively redesign the system to build in redundancy and to mitigate effects through sectionalizing and automation;
- identifying conditions that can be remotely monitored on a cost-effective basis, and developing predictive relationships that allow for targeted actions and responses;
- establishing the best or new ways to mitigate the root causes, and improve restoration times and customer notification;
- computing the "bang per buck" for each type of remediation, replacement, redesign, etc., then optimizing and prioritizing accordingly; and
- continuously monitoring the effectiveness of the programs and identifying new insights that arise "after the smoke clears."

Evaluating Storm Resistance

Efforts to make a system resistant to storms or other types of outages may require a complete revision in design standards or widescale change-out of equipment. The costs to utilities would increase dramatically, and customer willingness to pay for infrequent

events likely will erode when confronted with the price tag. For example, following the 1998 ice storm, Ontario Hydro performed a post-storm assessment that concluded that their existing design standards needed modification, and their equipment needed upgrading system-wide to be able to withstand a similar "once-in-a-hundred -years" ice storm. Given the exorbitant costs, approaches and remedies that would apply retroactively were not undertaken.

Recent storm data does not always support the notion that a widespread overhaul of design and construction standards will improve reliability. For example, in a report to the North Carolina Natural Disaster Task Force, the state utility commission reported damage statistics and restoration data that appear to belie the idea that wholesale equipment replacement might reduce the number of interruptions caused by major storms or events. The commission demonstrates that despite 1-inch ice buildup over 40 counties, relatively few poles or crossarms were damaged compared to system totals. By comparison, utilities typically add or change up to 2-3 percent of poles annually, well below damage totals. Similarly, some utility equipment fared reasonably well during Hurricane Isabel, while some utilities hit hard by the storm reported that fewer than 0.1 percent of their poles were damaged.

Nevertheless, accurate or not, 3,200 damaged poles imply 3,200 outages. (See Table 1.) Anecdotal evidence suggests that even if fewer poles were damaged, the number of outages likely would have remained unchanged since failures were mostly due to line contact with trees. In fact, crossarm or insulator failures may actually reduce damage that otherwise might occur if utility hardware remained intact upon tree contact.

Not surprisingly, a major culprit in many recent storms is tree-related damage caused by uprooted trees and fallen limbs. Utility reports to commissions for recent ice storms and Hurricane Isabel indicate trees as one of the leading outage causes.

Vegetation management is one of the largest maintenance expenses. Real estate agents use the phrase "location, location, and location" to describe home value. Utilities have a similar expression for storm-related outage causes— "trees, trees, and trees."

TABLE 1

ICE STORM STATISTICS, DECEMBER 2002

Damage statistics	Duke Power	Progress Energy
Poles damaged	3,200	1,322
Cross-arms broken	4,420	2,193
Total poles	1,480,355	1,073,441
Percent of total	0.2	0.1

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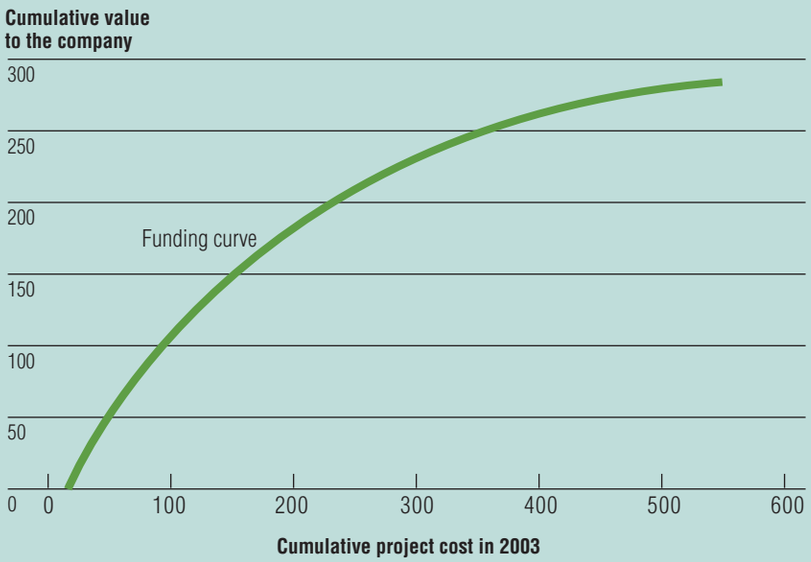
Though restoration after storms can be time-consuming, replacing equipment wholesale does not storm-proof the grid.

FIGURE 4

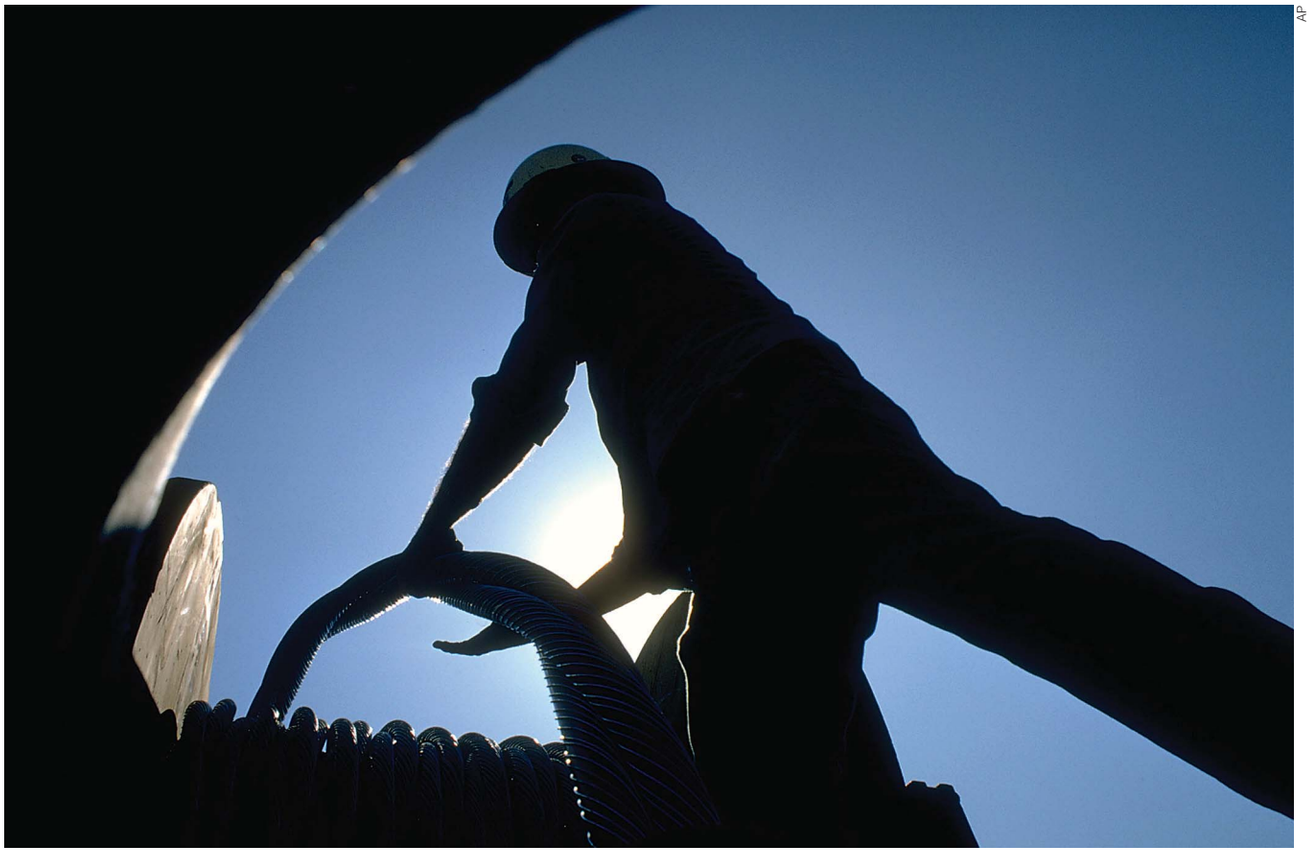
THE DEFINITIVE VALUE OF RELIABILITY INVESTMENTS
(millions of $)



But, needless to say, utility efforts to increase trimming often are met with stiff resistance from homeowners and town arborists alike. Some states, such as Maryland, limit the amount of tree trimming. The customer perception of the value of reliability often goes beyond utility rates to how it may impact property values and aesthetics. Absent significant increases in trimming, future tree-related outages likely will occur much as they have in the past.

After major storms such as Isabel, there is often a collective clamor for massive undergrounding of overhead lines. Such ideas appear to have merit, but with a stiff pricetag. In a 2000 report to the Public Service Commission of Maryland, a task force concluded that the cost of undergrounding lines

There's no wind underground, but undergrounding is costly and presents new issues regarding corrosion, damage detection, and repair.



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in the state for the two largest utilities would range from $4.2 billion to $5.7 billion. The attendant increases in residential rates of 36 and 46 percent, respectively, provided a sobering reality check. Interestingly, the task force cautioned the commission that long-term reliability of the underground system wouldn't necessarily be superior to an equivalent overhead system for *normal* events. Clearly, the tradeoff in cost versus improved reliability in this case proved less than acceptable.

Getting to the "Right" Level

An analytical approach that ranks candidate reliability improvement options as a function of value provides some assurance that utilities will spend limited funds wisely.

An example is the so-called funding curve, a composite of mitigation and improvement options sorted to programs that provide the greatest reliability gains per dollars. (See Figure 4.) Each point on the curve represents discrete investments, capital or expense, and their associated values. Value is determined by objectively quantifying the benefits of improved reliability.

Challenges to the funding curve approach are twofold: First, rigorous analytical models that accurately predict reliability gains are essential; second, the value of reliability based on the frequency and duration of interruptions also must be identified. Customers' willingness to pay is one threshold used to quantify the value of reliability.

But properly employed, the method offers utility management a fact-based approach to ranking investment options. It avoids the "beauty contest" syndrome that often evolves when management is faced with a bewildering array of project choices during the budget process. Some have used the expression "bang for the buck" as a characterization of the funding curve approach; which, perhaps, is appropriate since the curve demonstrates how the value of candidate programs declines as more dollars are spent. Eventually, investments reach the point of stagnant and ultimately diminishing returns (portrayed in the upper right section of the curve).

Intense regulatory scrutiny and low customer tolerance to higher rates mean the industry must look closely at how to ensure the "right" level of reliability, given the necessary tradeoffs. They can do this by determining the value of reliability to them and their customers, and then making investment choices based on the results. ◆