Restructuring vs. Reliability

A Tale of Declining Standards

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I. Introduction

During the latter half of the 20th century, the United States electric grid performed remarkably well in almost all instances. Because of this, consumers have taken the transmission grid for granted. Through the efforts of dedicated engineers, the U.S. grid has avoided blackouts of major proportions on all but a handful of occasions since the 1960s. However, responsibility for the grid has become ill-defined and fragmented during electric restructuring. It is therefore crucial that reliability standards be examined closely yet again.

The electric industry has fostered the impression that North American utilities voluntarily adhere to a set of uniform reliability criteria. That is far from the case. As will be shown, industry reliability criteria are not uniform. Moreover, utilities often do not adhere to the criteria that they admit are applicable to them. But, because compliance is voluntary, utilities typically incur no economic sanctions for failing to do so. Some members of the industry, led by the North American Electric Reliability Council ("NERC"), recognize the need for mandatory compliance with minimum standards backed by economic sanctions for noncompliance, and they have undertaken initiatives to put such sanctions in place.

This article focuses on the disordered state of transmission reliability criteria now in use in the United States. A major factor contributing to this disordered state is the increasing fragmentation within the industry with respect to control, authority, and responsibility over generation and transmission. Experience has shown that the potential for reliability to suffer has increased as a result of that fragmentation. It is particularly timely to address the decline in reliability because policymakers are reviewing formation of a number of regional transmission organizations ("RTOs") that are often assumed to address and resolve reliability problems. Policymakers are also proposing to address the problem through federal legislation such as the "Electric Reliability Act" (one purpose of which is to enforce mandatory reliability standards).

Much of the fragmentation is attributable to restructuring of the industry. Restructuring has resulted in many utilities divesting generation and/or transmission facilities. Divestiture

* The authors are indebted to Mr. Harrison Clark for his thorough review of this paper and for his valuable suggestions. However, any errors or omissions remain the responsibility of the primary authors.

removes the unified control over generation and transmission that has been helpful in maintaining reliability. The wave of industry mergers has also adversely affected reliability as divestiture is often made a condition to approval in order to ensure competitive power markets. As noted above, it is often assumed that regional transmission organizations can or will take up the slack, but it is far from clear that RTOs will be given the authority necessary to step into the shoes of utilities that divest generation or transmission.

Restructuring has encouraged the formation of many new entities that have an incentive to engage in transactions that force operation of the grid at (or even beyond) its safe operating limits. Thus, the grid now tends to operate at or near its limits for longer periods, thereby increasing risk of failure.

One problem is that controls and system protection (relaying) on both generation and transmission must be carefully coordinated in order to optimize overall bulk power system reliability. To some extent, deficiencies in the transmission function can be offset by enhancements in the generation function and vice versa,[1] a synergism that is lost when the generation function is separated from the transmission function. Prior to being restructured, vertically integrated utilities possessed nearly complete control over planning and operation of all three utility functions: generation, transmission, and distribution. This centralized control tended to enhance reliability because overall bulk power reliability is greatly dependent upon the configuration of — and the operating procedures applied to — both transmission and generation facilities. Furthermore, regulators could look to vertically integrated utilities to provide reliability and could impose economic sanctions when utilities failed to do so.

With industry restructuring, vertically integrated utilities are disappearing, and regulators cannot look to them alone to provide reliability or hold them accountable when reliability declines. Indeed, in the restructured industry, regulators may be unable to determine where responsibility lies for failures in reliability. For instance, control over bulk power reliability is likely to be transferred to RTOs. RTOs have varying amounts of authority, expertise, and institutional knowledge with which to carry out functions previously performed by vertically integrated utilities, and RTOs that are

1 For example, reliability can be increased by upgrades in transmission interconnection capability or by adding generation. Enhanced interconnections reduce the overall need for generation additions. By the same token, applying special relaying or enhanced control devices to generation enables utilities to increase transfer capabilities of regional transmission grids (separation schemes, generation and load dropping schemes, fast acting voltage regulators, power system stabilizers). Also, FERC's pro forma open access transmission tariff recognizes that the firm transfer capability of the transmission grid can be enhanced through the redispatch of generation and mandates redispatch under some conditions.

voluntarily formed tend to be held to a lesser standard. A great number of problems can slip through the cracks in the transition to a restructured market controlled by an RTO even when the most authoritative RTO has the best of intentions.[2] Unlike the case with a vertically integrated utility, an RTO is not readily susceptible to pressure from regulators to improve its performance (such as the pressure that regulators can apply to utilities by lowering allowed rates of return). The much-sought-after independence of an RTO serves to insulate it from economic pressure. And the RTO may not possess the authority to remedy a reliability problem even if it were susceptible to pressure.

As noted, the wave of industry mergers has also adversely affected reliability. It is often the case that each of the merging utilities adheres to different reliability criteria prior to their merger. Once merged, they have an incentive to adhere to the least stringent of their pre-merger criteria. In a recent Missouri merger, the merged company adopted the least stringent of the standards applied by its three predecessor companies. Over time, such elections tend to stretch out the timing of capital outlays for needed transmission facilities and thereby reduce reliability. In addition, some mergers involve utilities located in different reliability councils, and those councils also adhere to inconsistent planning and operating criteria. Again, the merged company has an economic incentive to adhere to the most lax criteria so as to minimize its cost of complying and to seek membership in an RTO that promises higher returns or fewer intrusions into management's prerogatives. The proponents of mergers have a substantial economic incentive to demonstrate that their merger will produce savings, all too often through layoffs of engineering employees. When engineering muscle is cut along with the fat, reliability eventually suffers.[3]

2 A matter of continuing concern is the "seams issue," the inconsistency between planning and operating criteria employed by RTOs/ISOs. This inconsistency has led to problems when market participants attempt to schedule power across the seams between ISOs/RTOs. Many RTOs and ISOs tend to have expertise as a consequence of being staffed with expatriates from now-reduced utility transmission planning departments. Yet the RTO institution is still new. Accordingly, old rules do not necessarily apply. As a result, a new RTO is unlikely to foresee all potential problems as evidenced by the recent experience of the California ISO. Lack of RTO authority is probably the most enduring contributor to the decline in reliability, especially lack of authority over generators.

3 The adverse effect of electric industry layoffs on reliability has been the subject of technical papers by respected industry experts. See J.F. Hauer and C.W. Taylor, "Information, Reliability, and Control in the New Power System," Proceedings of the American Control Conference, Philadelphia, Pennsylvania, June 1998, p. 2987. Also see J.F. Hauer, W.A. Mittelstadt, and others, "Information Functions and Architecture for Networked Monitoring of Wide Area Power System Dynamics: Experience with the

Although utilities in this country ostensibly comply with NERC and regional reliability criteria, many have instead adopted and implemented their own (often lax) criteria and use their own planning practices and procedures that measure transmission system reliability in different ways. In addition, utilities often apply more demanding criteria when assessing the transmission system's adequacy for provision of a third party's power transfer. This is a result of the voluntary nature of the reliability system, put into place by utilities themselves. Therefore, no uniform reliability standards are currently in effect, and unless the Electric Reliability Act (or something like it) is passed there will be few mandatory obligations to comply with any national standards that carry with them sufficient economic sanctions or exposure to other liabilities.

However laudable the objectives of the pending legislation, it is likely to create inconsistent reliability criteria from region to region unless some sort of probabilistic approach is taken. Therefore, one possibility might be to impose standards based on the frequency of power outages. Because most customer outages are distribution-related, the standard would need to differentiate between large-scale outages and small, localized ones. Large-scale outages can have major social implications, such as looting and huge economic loss, that differentiate them from the much more frequent and smaller-scale distribution outages. For purposes of legislation, this probabilistic approach might provide a more rational basis for determining when society needs a new transmission line in order to maintain reliability.

Differences can, and perhaps should, exist among the specific planning criteria employed by various regions, owing to the lack of homogeneity from region to region. Nonetheless, there is a case for standardizing contingency criteria within a region characterized by homogeneous loads and line lengths, although even within a region there could be different system structures and constraints to reliability.

II. Transmission System Reliability Criteria

The most prevalent industry criterion for measuring transmission reliability is the "N–1" (N minus one) criterion. Under that criterion, a utility is required to design its system so that it experiences no equipment overloads, voltage violations or instability following a contingency outage of the single most crucial element, whether that piece of equipment is a generator, a transmission line, a communication link, or a transformer. Usually, concern is focused on peak-demand conditions. The name "N–1" is given to the criterion because it specifies that the utility should always be able to serve

(footnote continued from previous page)

Evolving Western System Dynamic Information Network," WAMS Workshop I, Denver, Colorado, April 15-16, 1997.

peak demands during a sudden, unplanned outage of the single piece of equipment that most limits its ability to serve load.

One problem with the N–1 criterion is that it is often applied in different ways by individual utilities and by each regional reliability council. These differences are discussed in later sections of this paper. Another problem arises from the greatly simplified nature of the criterion itself. That is, the same quantitative criteria applied to two differently structured systems can result in very different qualitative measurements of reliability. This occurs in large part because the probability and consequences of experiencing a generation or transmission line outage can differ widely from system to system and in part because the stress placed on remaining elements can differ widely. For example, in a sparse network composed of long lines, the adverse effect of a single outage from lightning can be far greater than the effect of a lightning-related outage of a short line in a dense network composed primarily of short lines. Even when no violations of criteria occur, the remaining system is much more fragile and thus susceptible to cascading. That is, the impact of single and multiple contingencies could be higher on a sparse network of long lines in that such a network would tend to possess fewer parallel paths to cushion the adverse impacts of these contingencies. Additionally, the sparse network of long lines may be greatly affected by routine imperfections or outages (often at lower voltages). Widespread use of probabilistic criteria could lessen these problems, but developing such criteria (and the needed data) is easier said than done.

As noted, the N–1 standard can have varying impacts from system to system in terms of reliability. But on any given system, rigorously enforcing a uniform N–1 standard should provide important benefits to customers who ultimately pay the price for poorly designed and poorly operated transmission systems.[4] That is the primary focus of the discussion that follows. There is a downside to stringent criteria, however, when their interpretation and application are left in the hands of a transmission owner with economic incentives to deny transmission access to a competing entity. In that situation, a transmission owner's rigorous enforcement of unduly stringent criteria provides a means of limiting access available to those competing entities.

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[4] Customers would realize further benefits if regulators cracked down on the practice among utilities of holding one another harmless for negligence. There is a philosophy that each utility should "bury its own dead," and inherent in that philosophy is that each utility has the responsibility to protect itself and its customers from the consequences of electrical problems initiated in neighboring systems. In practice, it is difficult to achieve the goal of this philosophy at any reasonable costs. As a result, local utilities and their customers can be harmed as a result of negligence on the part of a neighboring utility and are typically without recourse when they are harmed.

An additional issue is the relative difficulty of applying the criteria. In one of two 1996 Western Systems Coordinating Council ("WSCC") disturbances, the Bonneville Power Authority ("BPA") admitted that it was unknowingly operating outside of the criteria and stated that this was the chief cause of the disturbance. It appears that BPA simply had not done enough studies (or the correct studies) to determine whether it was operating outside of the criteria. The insufficiency of studies was most likely not caused by ineptness or a shortage of manpower. The studies are of such magnitude and complexity that even the best engineers with ample budgets could overlook exposures. This is a particular concern in WSCC both because of the complexity of the criteria and the complexity of the WSCC system.

III. Current State of the Transmission Systems Adequacy and Planning Practices

Transmission systems of the United States demonstrate greatly varying abilities to accommodate transregional flows and the associated bulk power transactions. Those abilities are the essential means by which competing suppliers can provide benefits to customers. The adequacy of transmission systems varies greatly throughout the country in part because they have been planned and built using differing transmission-planning reliability criteria.[5] This is to be expected because the historical pattern of granting exclusive franchise areas to a single, vertically integrated utility supplier did not lend itself to the development of a robust bulk-power supply infrastructure. The adequacy of transmission systems has been further compounded by mergers that sometimes realize savings by adopting the most lax standard used by the merging companies. Indeed, even absent mergers, many utilities are turning over very deficient transmission systems to independent system operators ("ISOs") and RTOs. As a result, the cost of raising standards often is shifted to the ISOs/RTOs and to the marginal transmission customer through cost-allocation procedures adopted by the ISOs and RTOs. The inequities of this

5 For example, there are considerable differences in the extent to which remedial action schemes (also called special protection systems or "SPS") are applied. In the eastern United States, SPS are generally limited to detection and action within a station. In the West, they can span hundreds or thousands of miles. Also, the geographical distribution of generation and load and the availability of rights-of-way contribute as much to variations in reliability as do the criteria or willingness of the owners to expend capital on improving reliability. For instance, mountains or existing land use often preclude construction of new transmission where it is needed. Long distances, electrical characteristics, and economics force fewer and higher voltage lines onto a few rights-of-way that are less reliable than a larger number of lower voltage lines dispersed over multiple rights-of-way.

scenario are often exacerbated by "native load priorities" that also shift burdens to marginal transmission customers.

The proposed Electric Reliability Act envisions a national regulatory organization and would give the Federal Energy Regulatory Commission ("FERC") the legal power to enforce implementation of national reliability standards. The current version of this bill states that the future electric reliability organization would propose standards that would then be subject to approval by FERC. Only affiliated regional reliability entities (those that have been given authority by the electric reliability organization to implement and enforce compliance with standards in specific geographic areas) could request variances from the proposed standards. But, again, FERC would have the final say as to whether such variances would be granted.

Although each utility in the continental United States is located within a regional reliability council, and regional reliability councils are members of NERC, utilities historically have not been obligated to comply with their individual council's criteria, nor have councils been obligated to comply with NERC criteria. NERC has been in the process of establishing a compliance program, but, again, it is based on voluntary compliance.[6] In some cases, self-imposed economic sanctions have been put in place by the reliability councils and by the members within these reliability councils. NERC itself was self-imposed by the industry following the 1965 Northeast Blackout, and its formation helped the industry avoid federal control being imposed over reliability standards.

The present NERC Planning Standards are fairly generic and are characterized by a lack of clarity. The extent to which NERC Standards are incorporated into regional reliability criteria greatly depends on how particular regional councils interpret the standards. Some reliability councils provide only general guidelines while others develop very specific criteria. Although utilities agree in principle to comply with the regional criteria, there are many cases in which utilities base their planning practices on less stringent criteria.

As noted previously, the most common transmission-planning reliability criterion is known as N–1, or single contingency planning. Although a single contingency outage should not result in any load shedding, multiple (less probable) contingencies usually do result in load or generation shedding. However, the interpretation of a contingency varies from utility to utility. Substantial differences exist not only in the definition of single contingency and less probable contingency, but also in the determination of permissible loading limits, voltage

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6 See "Assessment of the 1999 NERC 'Pilot' Compliance Program," approved by the NERC Adequacy Committee, November 17, 1999. WSCC began collecting penalties in September, 1999, in connection with its regional compliance program.

deviations, the type of operating procedures implemented in the planning process, and the assumed condition of the system when the contingency occurs. For example, starting conditions may be either typical or at an extreme; e.g., a generating plant is at its usual 80 percent of rating rather than at a peak rating of 95 percent or 100 percent.

An equally important but rarely considered issue is that a system's equipment is never perfect, yet it is often assumed to be fully available in both planning and operating studies. That is, the models simulate perfect equipment when in fact many pieces of essential equipment may be out of service or fail to function as planned. Voltage regulator tuning, stabilizer tuning, outages of lower voltage lines, and capacitor bank outages, among others, are often neglected or overlooked, a fact repeatedly documented in studies of major disturbances. Load modeling, particularly modeling of the dynamic attributes of loads, is usually optimistic and often simply ignores the dynamic character of loads even when operating experience indicates that this is significant to system performance. Additionally, the very simplifications necessary to streamline operating and planning studies often serve to make the criteria less effective than they would otherwise be. The high cost of conducting detailed studies is always a practicality issue, but those industry observers who have focused on the matter believe that there is so much to be gained from rigorous analyses that high costs alone should not preclude carrying out those analyses.

For example, there are disturbances that are possible, but unlikely, for which it is not feasible to prevent islanding and/or loss of load on the Western Interconnection. Accordingly, the WSCC criteria recognize the necessity for islanding and load shedding for certain disturbances. But such islanding and load shedding should be controlled so as to limit the adverse impacts of the disturbance and to leave the Western Interconnection in such a condition as to permit rapid load restoration and reestablishment of inter-connections. Uncontrolled cascading is unacceptable, even under the most adverse, yet credible disturbances.

Despite recognizing the necessity for controlled islanding, WSCC sometimes has failed to provide remedial action schemes needed to prevent uncontrolled cascading. An example was the removal of the remedial action scheme known as the Northeast/Southeast Separation Scheme ("NE/SE Separation Scheme"). This scheme was put in place as a result of system disturbances caused by cascading outages in the 1960s and 1970s. However, after the California-Oregon Transmission Project entered service in 1993, this protective scheme was removed, based in part on the premise that disturbances elsewhere would not cascade into the three lines of the California-Oregon Interconnection. Later events (and some earlier events) demonstrated that premise to be incorrect. The NE/SE Separation Scheme removal was implemented without notice to regulators or consumers in order to resolve a largely political dispute among utilities over the cost/benefit balance of the scheme. Its removal worsened the effects of the cascading outages that started in the Pacific Northwest and propagated into California on August 10, 1996. Significantly, the NE/SE Separation Scheme was rearmed at 1:00 a.m. on August 11, 1996.

WSCC also had established a criterion requiring the installation of power system stabilizers ("PSS"). However, some of its members did not comply with that requirement. In the case of the August 10, 1996, disturbance, post-contingency studies indicated that Southern California Edison's 14-year failure to comply with the WSCC requirement to install PSS at its San Onofre Nuclear Generating Station contributed substantially to the onset of the August 10, 1996, disturbance.[7] Edison also failed to equip several affiliated PURPA Qualifying Facilities with PSS. Interestingly, these 1996 disturbances occurred at a time when Edison's management was focused on state and national deregulation and had diverted some of its operating engineering staff to those efforts.

IV. Transmission Reliability Criteria in the United States

A. NERC Planning Standards

In September of 1997, the NERC Board of Trustees approved the NERC Planning Standards. The approval of these standards marked a significant change for NERC and significantly affects the development of the reliability council planning criteria. Prior to the Planning Standards, NERC only provided "Planning Principles and Guides" that were very general. The NERC Planning Standards provide more specific planning requirements that apply uniformly across bulk electric systems, and that do not distinguish between internal and external systems.[8] The NERC Planning Standards represent a definite improvement in what is needed for RTO/ISO grid-planning criteria. However, a major question still exists concerning the cost impact of implementing a stringent interpretation of the NERC Planning Standards and whether they address all the other vagaries of traditional criteria (system differences, unrealistic modeling, etc.). Each

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7 WSCC policy called for equipping each generator rated at 75 MVA or greater with PSS. San Onofre has two units rated 1252 MVA each, the largest two units in WSCC that were not equipped with PSS.

8 This feature of the amended standards removed a "safe harbor" that sheltered many sub-par or overstressed transmission systems from scrutiny and that removed incentives for the owners to upgrade. Under the prior rules, the regional standards required only that an outage not adversely affect anyone other than the owner. The existing NERC Standards apply the same requirement on all transmission facilities, even those owned by the system on which the outage originates. This makes the NERC Standards stricter than those regional standards that do not yet reflect this change.

specific interpretation of the NERC Planning Standards has its own cost of compliance. In order to lessen this difficulty, it will be necessary to define a clear minimum set of standards and then lessen the latitude given to owners and RTOs/ISOs to interpret them liberally. However, something more will be needed before it will be practical and fair to impose adequate economic sanctions for failure to comply with a single standard in all regions. A single standard would only seem fair if the minimum standards are probability-based. Within a single region characterized by relatively homogeneous load densities and line lengths, a single non-probabilistic standard may suffice.

The NERC transmission system standards define four categories[9] of system conditions: i) no contingency, ii) single contingency, iii) multiple contingency, and iv) extreme contingency. NERC's definitions are generic in nature. "No contingency" means that all facilities are in service; "single contingency" means that a single element such as a line, transformer, or generator is lost;[10] and "multiple or extreme contingency" means that a combination of two or more facilities are lost.

Some reliability councils and utilities have been reticent in embracing an important part of the NERC Planning Standards. That portion of the standard requires that each system plan, design, and construct transmission systems to be able to operate within thermal, voltage, and stability limits for a single contingency while an additional facility is out-of-service for planned maintenance.[11] The customary approach is to assume that no

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[9] "Transmission System Criteria," *NERC Planning Standards*, September 1997, Table I, p. 14.

[10] In point of fact, the single contingency standard should — and in many regions does — encompass the concept of a common mode failure such as the case in which the loss of a transmission tower with multiple circuits is deemed to be a single element.

[11] *NERC Planning Standards,* September 1997, p. 9, S2:

> "The transmission systems also shall be capable of accommodating planned bulk electric equipment maintenance outages and continuing to operate within thermal, voltage, and stability limits under the conditions of the contingencies as defined in Category B of Table I (Event resulting in the loss of a single component)."

NERC does not clearly specify what system conditions are required for testing on this standard other than stating that:

> "These systems should be capable of performing this function under a wide variety of expected system conditions (e.g., forced and maintenance equipment outages, continuously varying customer demands) while continuing to operate reliably within equipment and electric system thermal, voltage, and stability limits."

"Transmission System Criteria," *NERC Planning Standards,* September 1997, p. 10, ln. 3.

facility maintenance is planned at the time of system peak demand. That assumption is questionable given that numerous facilities are almost always out of service for repair in every peak period. To be sure, it is important to distinguish a maintenance outage planned long in advance from an outage for repair that was forced or involuntarily planned only shortly before the peak period. But for off-peak seasons, the assumption is more than questionable. It is clearly inappropriate because maintenance is routinely planned long in advance of — and carried out during — off-peak seasons.[12]

In any event, this standard exceeds the existing criteria of many utilities. Many utilities do not explicitly plan a system to accommodate maintenance on-peak or off-peak. They assume that a system that can handle peak load or peak transfers without maintenance outages will be able to handle maintenance outages when there is less stress and that maintenance can be scheduled when there is less stress. Examining combinations of contingencies and maintenance outages is important because it provides a margin to accommodate the multiple involuntary outages that every system experiences. Individually, these outages may not be significant, but collectively they can be as severe as an involuntary outage of a highly critical element. Reports of major system disturbances repeatedly indicate that major contributing factors to disturbances are outages of critical equipment for maintenance or repair and that those outages were not widely known or their significance was not understood or previously studied.

NERC's unclear definition leaves the matter open to differing interpretations of this otherwise useful standard, allowing each analyst the latitude of studying combinations of contingency and maintenance outages only during low demand levels or low power transfers. Although most regions probably analyze combinations of contingency and maintenance outages under stressed system conditions to some extent, only a few explicitly comply with this NERC standard.

In summary, it is important that yearly on-peak system conditions, which are characterized by interregional power transfers affected by the highest demand level, should be tested using these criteria. It is also important that daily and seasonal off-peak system conditions should also be tested using these criteria. In many situations, transfers are high or even highest during off-peak periods, and hence the off-peak period is as critical or more critical than the

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12 Mr. J.A. Casazza, a long-time observer of electric operations and planning, noted in a recently published article that he frequently visits control centers. In this admittedly unscientific survey, he has never found fewer than three transmission lines out of service — and as many as 18 on one occasion. "Reliability and Tools for Our Times," *IEEE Computer Applications in Power,* Vol. 13, No. 4, October 2000, p. 21.

peak period (meaning that maintenance or repair of critical equipment cannot be carried out during off-peak periods unless system transfer ratings are adjusted downward).

NERC Standards specify the use of normal ratings as the thermal limit for a “no contingency” event. Normal ratings are continuous — for use throughout a normal peak day load cycle. In any other contingency event, NERC defines an “applicable rating” for the thermal limit. NERC states that “applicable rating” refers to the applicable normal and emergency facility thermal rating as determined and consistently applied by the system or facility owner. This loose definition allows each utility to set its own applicable ratings for whatever advantage may accrue. Consequently, utilities have developed a wide range of applicable ratings.

Similarly, NERC defines voltage limits with reference to the same term, “applicable ratings.” Again, that broad definition allows utilities to specify very different voltage deviation standards. In one recent merger, a utility maintaining system voltage within ±5 percent of nominal was acquired by a utility using a ±10 percent voltage criterion. The merged company adopted the laxer ±10 percent criterion.

General voltage criteria discussed in this paper focus on the quality of power provided to customers and typically have little to do with the propensity of a transmission system to experience far more serious consequences. More serious consequences would include voltage collapse, lack of control over interchange of reactive power, or avoidance of steady-state instability. It is not always clear what general voltage criteria are intended to achieve, but, when the objective of a voltage criterion is to maintain voltage stability, that objective is usually explicitly indicated. Comprehensive voltage criteria should address and provide standards for each type of voltage problem: power quality, reactive interchange, voltage collapse, and steady-state instability.

B. Reliability Councils’ and ISO Criteria

In essence, reliability councils’ criteria were defined to preclude a disturbance on one utility propagating to the systems of other members. However, in order to comply fully with 1997 NERC Planning Standards the councils should adopt criteria that do not distinguish between internal and external systems. Although all of the reliability councils declare their compliance with NERC Standards, many of them apply a self-interpretation of NERC’s definitions. Each reliability council’s criteria document is organized differently using varying requirements. However, they all use N–1 contingency for planning purposes (some of them including a single contingency along with a maintenance outage) and a set of multiple contingencies that differ from council to council. Some of the councils precisely define contingencies, applicable ratings, operating steps, and voltage standards, while others provide only a very general guidance. The following table illustrates some differences and similarities between the regional standards.

Table: Reliability Councils' Specified Reliability Criteria
General Comparison of Regional Council Standards

Reliability Councils	Single Contingency Plus Maintenance Outages	Detailed Multiple Contingency Situations	Detailed Definitions for Loadings Limits	Detailed Definitions for Voltage Limits
ECAR (East Central Area Reliability Coordination Agreement)	Yes	Yes	Yes	No
ERCOT (Electric Reliability Council of Texas)	Yes	Yes	No	No
FRCC (Florida Reliability Coordinating Council)	In the process of establishing new standards	In the process of establishing new standards	In the process of establishing new standards	In the process of establishing new standards
MAAC (Mid-Atlantic Area Council)	Yes	Yes	Yes	Yes
MAIN (Mid-American Interconnected Network)	No	Yes	No	No
MAPP (Mid-Continent Area Power Pool)	No	Yes	Yes	Yes
NPCC (Northeast Power Coordinating Council)	No	Yes	No	No
SERC (Southeastern Electric Reliability Council)	Yes	Yes	No	No
SPP (Southwest Power Pool)	No	Yes	No	Yes
WSCC (Western Systems Coordinating Council)	Yes	Yes	Yes	Yes

C. Utilities' Criteria

The application of the NERC and regional criteria to any particular utility system is often customized by that system to its specific characteristics. Each utility's transmission system is configured in a way that is specific to the geographic region it serves. There are also various ways of achieving reliability objectives. Therefore, considerable differences can exist between the specific planning criteria employed by various systems. However, certain minimum criteria should be uniformly specified and implemented by all utilities, at least within a single homogeneous region.

This article would become even more voluminous if we recounted all of the utilities' criteria that we reviewed. Therefore, only a limited number of standards were selected to provide examples of selected contingencies, required applicable ratings, and allowed voltage deviations.

Contingency Simulation

Each utility bases its transmission planning standards on a single contingency and also on less probable contingency considerations. However, differences exist in the simulation of contingencies. The following table lists some examples showing a variety of both the definitions and simulations of contingency outages.

Utility	Examples of Various Contingency Simulations or Definitions
BG&E, PEPCO and PECO Energy	Simulate the contingency for each single facility in addition to the previous loss of a bulk power facility and subsequent readjustment
Atlantic Electric	Simulates a single branch outage in addition to generator unavailability for 95% peak load. In addition, also simulates one facility on maintenance with load at 65% of peak load
UGI Utilities, Inc.	Considers a double circuit on a single structure as a single contingency
AEP	Usually limited to single contingencies for the low-voltage transmission system (23 kilovolts to 88 kV), single or double contingencies for the high-voltage transmission system (138 kV and 161 kV), and more severe multiple contingencies are considered for the extra high-voltage (EHV) transmission system
Commonwealth Edison (ComEd)	Simulates all applicable limits for normal conditions, multiple generator contingencies (up to three), and for single transmission contingencies during the outage of any single generating unit. Contingencies simulated at load levels of up to 105% of the forecast peak. In addition, ComEd developed a facility outage probability index for each class of equipment at various load levels

Applicable Ratings

Utilities' criteria specify that contingency simulations should include all the automatic actions that are part of the post-contingency operating procedure. Following an outage, the system must be capable of readjustment so that all equipment will be loaded within the applicable ratings. Definitions of applicable ratings vary from utility to utility.

Most utilities use normal ratings, summer and winter, as a definition for maximum loading under normal system conditions. However, some utilities also use normal ratings under selected contingency conditions. In addition, there are utilities that define normal ratings as a percentage of thermal ratings. The following table provides several examples from particular utilities' practices.

Utility	Applicable Ratings
Allegheny Power	Lines are rated for both summer and winter for continuous, six-hour, and half-hour periods of service while transformers use a one-hour, short time emergency rating
AEP	For bulk transmission system, facility normal ratings should not be exceeded for single contingencies. For area transmission studies, the emergency ratings of 138 kV facilities should not be exceeded for single contingencies. If one facility is out of service, loadings on the remaining facilities should not exceed the emergency ratings before the implementation of operating procedures
ComEd	Normal ratings to be applicable not only for normal conditions but also for single generator outages at the forecast level of peak load. Emergency ratings are applicable for system loads above the forecasted peak, or for any multiple generator or transmission equipment outage contingency. ComEd has a practice of allowing facilities to be loaded up to 120% of emergency ratings within the specified period of time needed in order to implement post-contingency operating steps
Public Service Electric & Gas (PSE&G)	The emergency ratings apply only after forced outage of a generation, transmission, switching station, substation, sub-transmission, or distribution facility following a normal condition. If the contingency occurs at 81-100% of peak load, then one-day emergency ratings are applied. If the contingency occurs at 80% or less of peak load, loadings on the remaining facilities must remain within normal ratings. For contingencies that involve more than a single element, PSE&G developed other ratings

Voltage Deviations

Most utilities require that voltage under normal conditions remain within a ±5 percent range of nominal. However, some utilities expand the typical range depending on the nominal voltage level. Under contingency conditions, most utilities specify the limits as a percentage deviation of the pre-contingency voltage level. Others determine their contingency limits based on the nominal voltage. The following table provides several examples from particular utilities' practices.

Utility	Voltage Deviations
BG&E	Typical operating ranges under normal conditions are 97% to 104% for 115 kV, 95% to 105% for 230 kV, and 95% to 110% for 500 kV
GPU	Normal condition voltage between 95% and 105% of nominal values. The upper limit may exceed 105% in specific cases. Voltage variations on the bulk transmission system will be limited to 5% of the pre-contingency level. However, on the bulk system the permissible voltage drop may be other than 5% at specific locations depending on conditions
PSE&G	Voltage range under normal conditions is 98% to 105% of nominal. For emergency conditions, voltage range is 95% to 105%
Atlantic Energy	Voltage limitation of ± 5% of the nominal voltage for both normal and contingency conditions
Missouri Public Service (MPS)	MPS specified that its 345 kV, 161 kV, and 69 kV transmission system would operate under any first contingency condition under summer peak load conditions with no abnormally low voltages on the transmission system except for some conditions. A bus voltage was considered to be abnormally low if it fell below 90% of the nominal value
Kansas City Power and Light	Voltage standard of ±5% of nominal for more probable contingencies
AEP	High-voltage limits are typically 105% of nominal. Minimum voltages depend on the voltage level. A single outage should not cause a voltage change to be less than –10% of nominal on the EHV system and –8% of nominal on 138 kV facilities

V. A Final Word

As has been shown, various utilities and regional reliability councils have differing standards for the determination of transmission reliability. While differing standards worked in the regulated, vertically integrated electric utility industry of old (when there were fewer entities with an economic incentive to overschedule the use of transmission), the new regime requires that more thought be put into the definition and determination of reliability standards. An approach such as probabilistic, minimum criteria is likely to be an appropriate solution to the wide variations in the reliability standards within the United States.

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