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The Brief History of Mandatory Reliability Standards

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The North American Electric Reliability Corporation ("NERC") has been around since the early 1960s as a voluntary industry organization. The Energy Policy Act of 2005 ("EPAct 2005") required the Federal Energy Regulatory Commission ("FERC" or "the Commission") to designate an Electric Reliability Organization ("ERO"). NERC, the only obvious candidate, was designated ERO by the Commission in Order No. 672 on July 20, 2006.

The development of reliability standards has long been NERC's primary responsibility. For years before its designation as ERO, NERC developed reliability standards for industry's voluntary adoption. Designation as ERO broadened NERC's authority considerably, but development of standards remains a central pillar of NERC's mission.

On April 19, 2007, the Commission approved NERC's *pro forma* agreement with the eight regional entities receiving NERC's delegation of authority to monitor and enforce compliance with the approved reliability standards. The eight regional entities cover the continental United States, most of Canada, and parts of Mexico. The entities are:

- Florida Reliability Coordinating Council,
- Midwest Reliability Organization,
- Northeast Power Coordinating Council,
- ReliabilityFirst Corporation,
- SERC Reliability Corporation,
- Southwest Power Pool,
- Texas Regional Entity, and
- Western Electricity Coordinating Council ("WECC").

<u>The Reliability Standards</u>

On March 15, 2007, FERC issued Order No. 693, which approved the first 83 NERC reliability standards. These standards became effective and enforceable on June 18, 2007. On May 18, 2007, the Commission issued Order No. 696, which subjected previously exempt Qualifying Facilities to the reliability standards.

On the same day, FERC approved over 700 violation "risk factors" associated with requirements and subrequirements of the 83 reliability standards. The risk factor framework recognizes that not all of the requirements associated with reliability standards are equally important. Under the risk factor framework, reliability standard violations may draw different size penalties based on whether the requirement violated is deemed to be a high-risk requirement, a medium-risk requirement, or a low-risk requirement. The Commission made clear that risk factors are not part of the reliability standards. Rather, they are part of the NERC policy for evaluating the severity of violations.

Generally, the Commission will only approve regional-specific standards when they are either (1) “more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not,” or (2) “necessitated by a physical difference in the Bulk-Power System.” On June 8, 2007, the Commission approved eight additional reliability standards applicable only to the WECC region (Docket RR07-11). The eight additional standards are:

- WECC-IRO-STD-006-0 (Qualified Path Unscheduled Flow Relief);
- WECC-PRC-STD-001-1 (Certification of Protective Relay Applications and Settings);
- WECC-PRC-STD-003-1 (Protective Relay and Remedial Action Scheme Misoperation);
- WECC-PRC-STD-005-1 (Transmission Maintenance);
- WECC-BAL-STD-002-0 (Operating Reserves);
- WECC-TOP-STD-007-0 (Operating Transfer Capability);
- WECC-VAR-STD-002a-1 (Automatic Voltage Regulators);
- WECC-VAR-STD-002b-1 (Power System Stabilizers).

On December 27, 2007, in Order No. 705, FERC adopted three additional reliability standards relating to planning and operation that NERC developed. The three new standards were:

- FAC-010-1 (System Operating Limits Methodology for the Planning Horizon),
- FAC-011-1 (System Operating Limits Methodology for the Operations Horizon), and
- FAC-014-1 (Establish and Communicate System Operating Limits).

They require planning authorities to “determine system operating limits for the Bulk-Power System in the planning and operation horizons.” The Commission concurrently approved 63 of the 72 violation risk factors that NERC submitted with the standards, and regional differences for WECC regarding the FAC-010-1 and FAC-011-1.

On January, 18, 2008, FERC approved eight reliability standards that NERC developed related to critical infrastructure protection (“CIP”). The standards are intended to protect the bulk-power system from “cyber attacks.” The eight new standards are:

- CIP-002-1 (Critical Cyber Asset Identification),
- CIP-003-1 (Security Management Controls),
- CIP-004-1 (Personnel & Training),
- CIP-005-1 (Electronic Security Perimeters),
- CIP-006-1 (Physical Security of Critical Cyber Assets),
- CIP-007-1 (Systems Security Management),
- CIP-008-1 (Incident Reporting and Response Planning), and
- CIP-009-1 (Recovery Plans for Critical Cyber Assets).

On October 16, 2008, FERC issued Order No. 716, which added another standard: NUC-001-1 Nuclear Plant Interface Coordination. This standard specifically requires a nuclear plant generator operator and its suppliers of back-up power and transmission and/or distribution services to coordinate concerning nuclear licensing requirements for safe nuclear plant operation and shutdown and system operating limits.

On March 19, 2009, FERC issued a Notice of Proposed Rulemaking ("NOPR") to approve six Modeling, Data and Analysis ("MOD") Reliability Standards that would require certain users, owners and operators of the transmission system to develop consistent methodologies for the calculation of available transfer capability ("ATC"). NERC originally submitted such standards to the Commission on August 29, 2008 and November 21, 2008. The proposed standards are:

- MOD-001-1 – Available Transmission System Capability Reliability Standard would require transmission service providers and transmission operators to select and implement one of three methodologies for calculating ATC for each path for each time frame (hourly, daily or monthly) for the facilities in its area. The three proposed methodologies are as follows:
    1. MOD-028-1 – Area Interchange Methodology – This methodology would require a determination of incremental transfer capability via simulation, from which total transfer capability can then be mathematically derived. Total transfer results are generally reported on an area to area basis.
    2. MOD-029-1 – Rated System Path Methodology – This methodology would include an initial total transfer capability, determined via simulation. As with the area interchange methodology, capacity benefit margin, transmission reliability margin, and existing transmission commitments are subtracted from the total transfer capability, and postbacks and counterflows are added, to derive ATC.
    3. MOD-030-1 – Flowgate Methodology – This third methodology for calculating ATC begins with an identification of key facilities as flowgates. Total flowgate capabilities are determined based on facility ratings and voltage and stability limits. The impacts of existing transmission commitments are then determined by simulation. To determine the available flowgate commitments, the transmission service provider or operator must subtract the impacts of existing transmission commitments, capacity benefit margin, and transmission reliability margin, and add the impacts of postbacks and counterflows. Available flowgate capability can then be used to determine ATC.

- MOD-008-1 – Transmission Reliability Margin Methodology would require entities to prepare and keep current implementation documents that provide for the calculation of Transmission Reliability Margin, which is the transmission transfer capability set aside to mitigate risks to operations, such as deviations in dispatch, load forecast, outages, and similar other conditions.

- MOD-004-1 – Capacity Benefit Margin Methodology would require entities to prepare and keep current implementation documents that provide for the calculation of Capacity Benefit Margin, which is transmission transfer capability set aside to allow for the import of generation upon the occurrence of a generation capacity deficiency.

<u>Modifying and Interpreting the Standards</u>

FERC is authorized only to approve or reject the reliability standards that NERC submits. EPAct 2005 does not empower FERC to modify standards directly. Even as the Commission approved the original 83 standards, it requested that NERC modify and resubmit 56 of them. On July 21, 2008, the Commission issued Order No. 713, which approved modifications of five previously-approved Reliability Standards, including two of the 56 modifications requested by the Commission. Modifications were approved for:

- INT-001-3 (Interchange Information).
- INT-004-2 (Dynamic Interchange Transaction Modifications).
- INT-005-2 (Interchange Authority Distributes Arranged Interchange).

- INT-006-2 (Response to Interchange Authority).
- INT-008-2 (Interchange Authority Distributes Status).

In response to NERC's proposed modification of a sixth standard, IRO-006-4 (Reliability Coordination – Transmission Loading Relief), the Commission neither accepted nor rejected NERC's interpretation, but asked the ERO for more information.

Order No. 713 also approved NERC interpretations of five other reliability standard requirements:

- BAL-001-0 (Real Power Balancing Control Performance), Requirement 1.
- BAL-003-0 (Frequency Response and Bias), Requirement 3.
- BAL-005-0 (Automatic Generation Control), Requirement 17.
- VAR-002-1 (Generator Operation for Maintaining Network Voltage Schedules), Requirements 1 and 2.

It is expected that the Commission will review and approve modifications and interpretations in the future on an ongoing basis.

The Risk Factors

Each reliability standard is broken down into requirements and subrequirements. Of course, not all requirements and sub-requirements are equal—some are administrative in nature, whereas others go directly to the integrity of the power grid. Recognizing this fact, FERC approved NERC proposals to rate each requirement and sub-requirement on a scale of low, medium and high.

The "Low" risk factor applies to those requirements and subrequirements that are "considered administrative in nature where a violation would not be expected to affect the reliability of the Bulk-Power System." The medium risk level applies to those that "while unlikely to cause or contribute to Bulk-Power System instability or cascading failures, could, however, directly affect the electrical state, capability, monitoring and control of the Bulk-Power System." High risk requirements are those that "could conceivably cause or contribute to Bulk-Power System instability or cascading failures." The process of assigning risk factors is a continuing process parallel to the approval of reliability standards. In May 2007, the Commission approved over 700 risk factors, which correspond to the original 83 standards.

On June 26, 2007, FERC approved 22 more violation risk factors (Docket No. RR07-12) that also pertain to the original 83 approved standards. NERC proposed two additional risk factors relating to three additional proposed standards, but the Commission delayed action on these because the standards to which they related had not been approved yet. Approving violation risk factors before the standards they apply to, it seems, is putting the cart before the horse.

Violation Policy

Under a Penalty Review Policy for Reliability Standards Violations approved by FERC on April 17, 2008, NERC may impose penalties on companies that violate the standards it administers, either directly or through the eight regional entities to which it has delegated such authority, subject to FERC review.

Under the new policy, entities subject to a NERC notice of penalty (or FERC on its own motion) may file an application for review within 30 days of the notice being filed with the Commission. Interventions on the application for review are due within 20 days. FERC stated that, generally, it will take action on the application within 60 days of the application for review, although this time period may be extended. The policy was also modified to permit FERC to review penalty settlements, though the Commission reiterated its encouragement of the settlement process and stated that such settlements will generally be allowed to stand.

On June 19, 2008, FERC approved Reliability Standard Violation Severity Levels (Docket RR08-4). Severity levels attempt to reflect “how bad” the violation was. The severity level is the degree to which a requirement or subrequirement has been violated, the last piece of the NERC penalty-setting matrix for standard violations. There are four levels: Lower, Moderate, High, and Severe.

Once a violation is found, an assessment is made regarding badly the requirement or subrequirement has been violated, at which point FERC will determine an appropriate penalty. Incidentally, repeated violations do not increase the severity level. Once a violation of that subrequirement is found, it is categorized according to the above severity levels. The determination of the violation severity level will be considered in light of the requirement’s risk factor designation to come up with an appropriate penalty amount.

On June 4, 2008, just short of a year after the first reliability standards became mandatory, NERC filed 37 notices for 106 violations with the Commission. Most were for administrative “low-risk” violations issued without financial penalties. However, financial penalties in the amounts of $180,000 and $75,000 were levied against two companies for violations of standard FAC-003-1 (Vegetative Management). Both of these violations were self-reported, and one was the result of a settlement.

However, the most-violated standards were CIP-001-1 (Critical Infrastructure Protection: Sabotage Reporting), comprising 46% of the violations, PRC-005-1 (Protection and Control: Transmission and Generation Protection System Maintenance and Testing), comprising 22% of the violations, and FAC-008-1 (Facilities Design, Connections, and Maintenance: Facility Ratings Methodology), comprising 14% of the violations.

<u>Going Forward: Who Pays the Penalties? Who Pays for Compliance?</u>

One problem with penalties for violations of the mandatory reliability standards is what RTOs and ISOs should do when assessed penalties that are attributable to one of their members. The organizations themselves are non-profit organizations, and they are registered as the entity responsible for many reliability standards, even where ultimate responsibility for compliance of those standards has been delegated. This raises the possibility that an RTO/ISO may be penalized for a violation that was the responsibility of a member. In such a case, who should pay?

The Midwest Independent System Operator, Inc. (“MISO”) proposed tariff changes that would have allowed it to investigate who was at fault for the violation, and pass such penalties it received through to that member. In the case where MISO was unsuccessful in identifying the responsible party, the revised tariff would let it socialize the penalty among all its members. On May 31, 2007, the Commission declared the proposed practice improper (Docket No. AD07-12) without prejudice for refiling, and scheduled a staff technical conference on the subject. The technical conference was held on September 18, 2007. At the conference, NERC promised to do its best to identify the responsible party, although it “stops short of committing to determine the percentage of parties’ culpability for violating standards when multiple parties contribute to a violation, deferring instead to the registered entities as being accountable to NERC in the first instance for all penalty cost liability.”

On March 20, 2008, the Commission issued an Order Providing Guidance. The Commission found that although the penalties “raised legitimate concerns regarding their not-for-profit status,” it is not appropriate to automatically pass the penalties through because such tariff amendments could eliminate “the appropriate incentives to proactively comply with Reliability Standards if they have blanket authority to automatically pass through monetary penalties to their customers.” MISO’s proposal was also inappropriate because the Federal Power Act (“FPA”) assigns the responsibility for investigating reliability violations to the ERO alone—the RTO or ISO should not be permitted a “second, *de novo* hearing on the issue of determining responsibility for Reliability Standard violations.” The Commission stated that the proper process would be for the RTO or ISO to request recovery on a case-by-case basis through an FPA section 205 filing.

On September 18, 2008, FERC issued an order accepting PJM’s proposal to address this matter (Docket No. ER08-1144). The Commission found that PJM’s Schedule 11 will allow for a reasonable penalty recovery, without a universal pass-through.” Instead, “PJM or its Members may only pass through penalties when NERC or one of its Regional Entities concludes from its fact-finding that the targeted entity substantially contributed to the Reliability Standards violation.”

If NERC has traced the “root cause” of a violation to a single culprit, PJM’s revised tariff permits the RTO to pass associated penalties to that entity. When NERC has identified several contributing violators, PJM will establish a process to permit apportionment “on a basis reasonably proportional to the parties’ relative fault consistent with the NERC’s root cause analysis.” If PJM members disagree with the apportionment, they are directed to non-binding dispute resolution procedures.

Once an apportionment has been fixed, the penalties will be submitted to FERC in an FPA section 205 filing. Any portion of the penalty found to be the fault of PJM itself will be paid from “the sum of (i) projected current year stated rate revenues less projected current year operating expenses (excluding the penalties), and (ii) any earnings retained in the financial reserve portion of the deferred regulatory reliability fund,” and will not be simply passed through to members. If this is not sufficient, PJM will file a section 205 filing with FERC.

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